

**IN THE TENNESSEE PUBLIC UTILITY COMMISSION
AT NASHVILLE, TENNESSEE**

IN RE:)
)
ATMOS ENERGY CORPORATION)
FOR APPROVAL OF ITS 2022 ANNUAL) **DOCKET NO. 22-00010**
RATE REVIEW FILING PURSUANT)
TO TENN. CODE ANN. § 65-5-103(d)(6))
)

**CONSUMER ADVOCATE’S RESPONSES TO
ATMOS’ FIRST SET OF DISCOVERY REQUESTS**

To: Erik Lybeck, Esq.
Neal & Harwell, PLC
1201 Demonbreun Street, Suite 1000
Nashville, TN 37203
Email: elybeck@nealharwell.com

The Consumer Advocate Unit in the Financial Division of the Office of the Tennessee Attorney General (“Consumer Advocate”), by and through counsel, pursuant to Rules 26, 33, and 34 of the Tennessee Rules of Civil Procedure, Tennessee Public Utility Commission (TPUC or The “Commission”) Rule 1220-1-2-.11, and the Agreed Procedural Schedule entered by the Hearing Officer in this Docket, hereby submits its responses to the *First Set of Discovery Requests of Atmos Energy Corporation* (“Atmos” or “Company”) filed on April 7, 2022.

General Objections

All of the General Objections made herein are applicable to and are hereby incorporated into each and every response herein, and each response herein is made subject to and without waiver of these General Objections.

- A. The Consumer Advocate objects to each of the Company’s requests on the grounds that each is overly broad, unduly burdensome, and oppressive.

- B. The Consumer Advocate objects to the Company's discovery requests to the extent that they purport to impose the obligations upon the Consumer Advocate beyond those contemplated by the Tennessee Rules of Civil Procedure, TPUC Rules, and Tennessee law.
- C. The Consumer Advocate objects to each of the Company's requests to the extent that each purports to call for information and/or documents prepared in anticipation of litigation, and/or information and/or documents protected by the attorney-client privilege, the work product doctrine, the common-interest doctrine, or any other applicable protection or privilege.
- D. The Consumer Advocate objects to each of the Company's requests to the extent that they are not applicable in the context of a proceeding before the TPUC, cite an incorrect legal conclusion, or mischaracterize or improperly summarize statements made by the Consumer Advocate's expert witnesses in their pre-filed direct testimonies.
- E. By providing the objections contained herein, the Consumer Advocate does not waive or intend to waive, but rather, intends to preserve, all objections with regard to competence, relevance, materiality, and admissibility of the discovery information or documents in any subsequent proceeding on the related subject matter. Moreover, the Consumer Advocate intends by this set of responses to preserve all objections to vagueness, ambiguity, and undue burden in connection with requests to produce documents, including those that are not in the Consumer Advocate's possession, custody, or control.
- F. The responses made herein are made to the best of Consumer Advocate's present knowledge after a reasonably diligent search for responsive information. The Consumer Advocate will supplement its responses in line with the requirements of the Tennessee Rules of Civil Procedure as well as TPUC Rules and expressly reserves its right to supplement or amend its answers, if and as appropriate, including with respect to objections that may arise at a later time than this filing.

Without waiving these General Objections as they apply to each individual request, the Consumer Advocate presents the following responses:

CONSUMER ADVOCATE'S RESPONSES

1-01. Referring to your statement that "A Cash Working Capital calculation aims to determine the cash on hand needed to finance daily operations." Please provide

citations to all support relied upon for that definition of Cash Working Capital.

(Reference Page 9, A17, Lines 1-2)

RESPONSE:

Leonard Saul Goodman addressed this issue in *The Process of Ratemaking*, which states:

The working capital allowance in rate base covers only those cash funds and temporary securities that must be held by the company for operating expenses, rents and taxes (other than income taxes) prior to the collection of revenues from ratepayers. Cash funds held by the company for capital purposes, such as to pay interest or dividends or to support construction, may or may not be covered. Some jurisdictions authorize a separate AFUDC, or for materials and supplies.

Studies that measure the funds needed to pay operating expenses and taxes (other than income taxes) prior to the collection of the revenue in the same accounting period are typically “lead-lag” studies. In a lead-lag study, the witness measures the number of days before expenses must be paid (“expense lead” or “lead days”) against the days before revenues are received (“revenue lag” or “lag days”). If there is a net lag, then investors are supplying working capital, which should be included as an additional element of rate base. If there is no difference between the two, then no working capital allowance is required.¹

Depreciation is not an expense that needs to be paid and thus does not meet the definition of lead-lag study components mentioned above. Also, the Consumer Advocate addressed this issue through Mr. Dittemore’s Direct Testimony² and in its Post Hearing Brief³ in TPUC Docket No. 18-00017.

1-02. Regarding the cost rate associated with the Company’s short-term debt, you argue that the Company has failed to adequately support such a rate. Do you agree or disagree that the Company correctly calculated the cost rate associated with short-term debt? If you disagree, please explain why you believe the Company’s calculation is incorrect. (Reference Page 11, Q24 & A24)

RESPONSE:

¹ LEONARD SAUL GOODMAN, *THE PROCESS OF RATEMAKING* VOL. II, p. 832 (Public Utility Reports, Inc. 1998). A copy of two pages that address “Lead-Lag” studies are attached as ***Exhibit CA Response DR 1-01***.

² *Direct Testimony of David Dittemore* at 17:5- 20:2, TPUC Docket No. 18-00017 (July 3, 2018).

³ *Consumer Advocate’s Post Hearing Brief*, p.p. 32-34, TPUC Docket No. 18-00017 (September 10, 2018).

I agree the Company has correctly calculated the cost of its Short-Term debt.

1-03. Is it Mr. Dittimore's belief that short-term debt should be permanently excluded from the capital structure or only when the cost of short-term debt exceeds the imbedded cost of long-term debt? (Reference Page 11, Q24 & A24)

RESPONSE:

Mr. Dittimore is not suggesting in his testimony that Short-Term debt should be permanently excluded from the capital structure, nor is his testimony that Short-Term debt should be automatically excluded when the cost of Short-Term debt exceeds the cost of Long-Term debt. The issue is whether a 69% cost rate for Short-Term debt is a reasonable cost to be incurred by customers.

1-04. Is it Mr. Dittimore's belief that the fees paid by the Company for its short-term debt facilities are excessive? Please provide any analysis or comparison of fees paid for short-term debt facilities that Mr. Dittimore reviewed or relied upon. (Reference Page 11, Q25 & A25)

RESPONSE:

Mr. Dittimore believes the fees paid by the Company for Short-Term debt facilities are excessive when compared with Short-Term debt balances incurred in the test period.

1-05. Referring to your statement that "The existing approach used by the Company is inconsistent with the regulatory theory supporting Cash Working Capital." Please identify the basis for Mr. Dittimore's regulatory theory supporting Cash Working Capital, including citations to all sources relied upon. (Reference Pages 8-9, Q17 & A17)

RESPONSE:

Please see the response to Discovery Request No. 1-01.

1-06. Referring to your modification of the Company's proposed capital structure. Is the inclusion of short-term debt in the Company's capital structure consistent with the methodology used in prior ARM dockets? In general rate case proceedings? If anything other than a unqualified yes, please explain. (Reference Pages 10-11, Q23 & A23)

RESPONSE:

The inclusion of Short-Term debt in the Company's capital structure is consistent with the methodology used in prior ARM dockets and general rate case proceedings. However, the application of a 69% cost rate is not consistent with cost rates adopted in prior proceedings. Further, I do not recall seeing a capital structure cost rate this high proposed in any prior regulatory proceeding. I reject the apparent implication that any cost rate associated with Short-Term debt should be recoverable simply because the Commission has previously included Short-Term debt within the Company's approved capital structure. The Company has the burden of supporting the reasonableness of its proposed costs of capital.

1-07. Admit or deny, Mr. Dittmore provides his opinion but no literature supporting his assertion regarding the exclusion of depreciation expense and return on equity from the cash working capital study. (Reference Page 8, Q17 & A17)

RESPONSE:

Admit. Also see literature support provided in response to Discovery Request No. 1-01.

1-08. Please provide a copy of the cited TPUC rules on the recognition of non-cash items within the lead-lag study. If no such rules promulgated by TPUC exist, please so state. (Reference Page 10, Q20 & A20)

RESPONSE:

The are no rules that Mr. Dittmore is aware of which speak to the recognition of non-cash items within the lead-lag study. The question within testimony should be modified to ask whether the Commission has ruled on the recognition of non-cash items within the lead-lag study in recent rate cases.

1-09. Is it Mr. Dittmore's belief that every accounting methodology approved in another jurisdiction is appropriate for adoption by the TPUC? If anything other than a unqualified yes, please explain. (Reference Page 10, Q21 & A21)

RESPONSE:

Mr. Dittmore does not necessarily believe every accounting methodology approved in another jurisdiction is appropriate for adoption by TPUC. Please note that TPUC has adopted the exclusion of the return on equity component in the cash working capital calculation in TPUC Docket No. 18-00017.⁴ Each proposed methodology should be evaluated on its own merit. The reference to adoption of such methodology in other states; however, provides a counterargument to claims that no cites were provided where the proposed methodology has been adopted in other states.

In addition to cases cited in testimony, the return on equity component has also been excluded in the following dockets in other state Commissions:

- Illinois. *Order, In re: Northern Illinois Gas Company d/b/a Nicor Gas Proposed General Increase in Gas Rate and Revisions to Other Terms and Conditions of Service*, Illinois Commerce Commission, Docket 17-0124 (January 31, 2018).

⁴ *Amended Order*, pp. 47-49 TPUC Docket No. 18-00017 (January 15, 2019).

- Hawaii. *Decision and Order, In re: Hawaii Electric Company*, Hawaii Public Utilities Commission (March 6, 1991).
- Kansas. *In the Matter of the Application of Kansas Gas Service, A division of ONEOK, Inc. for Adjustment of its Natural Gas Rates in the State of Kansas*, Schedule 6-H (Pdf p. 66 of 101), Docket No. 06-KGSG-1209-RTS (May 15, 2006). In this case, the utility did not request inclusion of either the return on equity or depreciation expense in its cash working capital study as demonstrated on pdf page 66 of the separate attachment.

Copies of these three documents are attached as collective ***Exhibit CA Response DR 1-09***.

RESPECTFULLY SUBMITTED,



KAREN H. STACHOWSKI (BPR No. 019607)

Senior Assistant Attorney General

VANCE L. BROEMEL (BPR No. 011421)

Senior Assistant Attorney General

Office of the Tennessee Attorney General

Financial Division, Consumer Advocate Unit

P.O. Box 20207

Nashville, Tennessee 37202

Phone: (615) 741-2730

Fax: (615) 741-8151

Email: Karen.Stachowski@ag.tn.gov

Email: Vance.Broemel@ag.tn.gov

CERTIFICATE OF SERVICE

I hereby certify that a true and correct copy of the foregoing was served via electronic mail,
with a courtesy copy by U.S. mail, upon:

Erik Lybeck, Esq.
Neal & Harwell, PLC
1201 Demonbreun Street, Suite 1000
Nashville, TN 37203
Email: elybeck@nealharwell.com

This the 11th day of April, 2022.



KAREN H. STACHOWSKI

Senior Assistant Attorney General

Alternative to direct inclusion in rate base. Some commissions will prefer to consider certain "regulatory assets," namely non-property accounts created from investor funds and representing deferred costs,¹ as additional working capital to be included in rate base, rather than allow a direct enlargement of rate base. To be sure, a form of rate base treatment is allowed, but admission to rate base here is being allowed only indirectly through the working capital calculation.

An example of such indirect inclusion of a regulatory asset in rate base is afforded by the FASB Statement 106 costs involving post-retirement benefits other than pensions.² SFAS 106 requires the accrual of these costs during the period the employees earn them in lieu of cash accounting that would allow companies to expense these costs as they are paid. To the extent the company with commission approval funds the past liability as a deferred cost, it may be entitled to rate base treatment of the unamortized balance.³ In the alternative, a commission⁴ may prefer to include the unamortized balance as additional working capital, and in this way indirectly introduce such balance in the rate base.

The unamortized balance of the deferred SFAS 106 costs are considered "regulatory assets," which although not a property account nevertheless represents investment which the agency has expressly permitted to be carried on the company's books and for which it may permit rate base treatment. The Ohio commission in this connection pointedly added that the company which includes such an item in rate base is "on notice that manipulation ... of its financial structure ... is contrary to the intent of the deferral, and, as such, will not be tolerated"; specifically the deferral of the incremental SFAS 106 costs must not raise the equity return above the authorized return.⁵

"Lead-lag" studies. The working capital allowance in rate base covers only those cash funds and temporary securities that must be held by the company for operating expenses, rents, and taxes (other than income taxes) prior to collection of revenues from ratepayers. Cash funds held by the company for capital purposes, such as to pay interest or dividends or to support construction, may or may not be covered. Some jurisdictions authorize a separate AFUDC,⁶ or for materials and supplies.

Studies that measure the funds needed to pay operating expenses and taxes (other than income taxes) prior to the collection of the revenue in the same accounting period are typically "lead-lag" studies. In a lead-lag study, the witness measures the number of days before expenses must be paid ("expense lead" or "lead days") against the days before revenues are received ("revenue lag" or "lag days"). If there is a net lag, then investors are supplying working capital, which should be included as an additional element of rate base. If there is no difference between the two, then no working capital allowance is required.

¹ See p. 742, *supra*.

² See p. 331, *supra*.

³ Re Idaho Power Co., 143 PUR4th 49 (Id.PUC, 1993).

⁴ Re Puget Sound Power and Light Co., 147 PUR4th 80, 121-22, 137 (Wash.UTC, 1993).

⁵ Re Ohio Power Co., 143 PUR4th 63, 65 (Ohio PUC, 1993).

⁶ For discussion of the AFUDC and interest during construction (IDC), see p. 807.

Let us assume that a utility company on average pays its expenses, including any disbursement float,¹ 30 days after incurring the cost; there is a cash "lead" of 30 days. Let us further assume that on average the same company collects its customer bills 20 days after a meter is read; there is a revenue "lag" of 20 days in collecting cash. In terms of revenue lag there is actually a negative 10 days, because it continues to hold customer revenues before expending those revenues on average for another 10 days after collection. In this case ratepayers are supplying the working capital, and no working capital allowance will be included in rate base; indeed a deduction from rate base may be in order.

Revenue lag. To develop the revenue lag, if any exists, a witness essentially measures average time lag between meter readings and the issuance of bills (by class or for large individual customers), collection lag by different types or sizes of accounts, and the lag in collection of off-system power sales.

If test year (1990) and subsequent year lags in collection of revenues were abnormal due to "the extraordinary impact of the poor economy in 1990 and 1991," should the agency employ a normal year 1989, or some average of 1989 with another year? The Rhode Island commission opted for an average lag of the three years, 1989-91 as "the most representative."²

The Michigan commission allowed no working capital for a utility that was regularly marketing its accounts receivable and in the test year would likely sell more than enough to satisfy its working capital needs.³

As the West Virginia commission aptly noted, the parties should avoid searching for "increasingly trivial adjustments ... to cash working capital"; it will deny small adjustments that might readily be offset by other small, unaccounted-for adjustments.⁴

A lead-lag study precludes the rate base use of the company's actual average working capital on hand.⁵ The inclusion of both average cash and working funds on hand in the rate base as well as funds calculated under the lead-lag method would result in double-counting the working capital allowance.

Expense lead. A company is not entitled to include minimum bank deposits maintained for the sole purpose of avoiding bank service charges at least not without its showing how much the bank charges would be if the minimum balances were not maintained.⁶ In a lead-lag study, if the company makes its federal income tax payments later than the statutory payment dates, then it is appropriate for an agency to use the actual payment dates and percentages; otherwise, as the Ohio commission noted, the federal income tax lag will be understated and investors will earn a return on capital they have not invested.⁷

¹ Re Illinois Power Co., 131 PUR4th 1, 22 (Ill.CC 1992).

² Re Narragansett Elec.Co., 132 PUR4th 458, 466-67 (R.I.PUC, 1992).

³ Re Consumers Power Co., 122 PUR4th 486, 500 (Mich.PSC, 1991).

⁴ Re Monongahela Power Co., 125 PUR4th 126, 149-50 (W.Va.PSC, 1991).

⁵ Northwestern Bell v. Iowa State Comm.Comm'n, 359 N.W.2d 491, 499 (Iowa 1984).

⁶ New England Tel. & Teleg. Co. v. Mass.DPU, 360 Mass. 443, 275 N.E.2d 493 (1971).

⁷ Re Columbus Southern Power Co., 133 PUR4th 525, 551-52 (Ohio PUC, 1992).

STATE OF ILLINOIS
ILLINOIS COMMERCE COMMISSION

Northern Illinois Gas Company	:	
d/b/a Nicor Gas Company	:	
	:	17-0124
Proposed General Increase in	:	
Gas Rates and Revisions to Other	:	
Terms and Conditions of Service.	:	

ORDER

January 31, 2018

Table of Contents

I.	INTRODUCTION	1
A.	Procedural History	1
II.	OVERALL REVENUE REQUIREMENT	4
III.	TEST YEAR.....	4
IV.	RATE BASE	4
A.	Overview.....	4
B.	Uncontested Issues	4
1.	Accumulated Deferred Income Taxes (“ADIT”) Adjustments	4
2.	2017 Qualified Infrastructure Plant Amounts.....	5
3.	Original Cost of Gross Plant Balance.....	5
C.	Contested Issues	6
1.	Advanced Metering Infrastructure	6
2.	Cash Working Capital	18
3.	Net Pension Asset.....	21
4.	Certain Gas Main Extension Projects.....	29
5.	2017 Qualified Infrastructure Plant Amounts.....	34
D.	Recommended Rate Base.....	36
V.	OPERATING EXPENSES	36
A.	Uncontested Issues	36
1.	Invested Capital Tax Expense.....	36
2.	Advertising Expense	36
3.	Miscellaneous Expense	36
4.	Lobbying Expense.....	36
5.	Employee Benefits Expense	37
6.	Uncollectibles Expense	37
7.	Charitable Contributions Expenses.....	37
8.	Outside Professional Services Expense	37
9.	Incentive Compensation Expense.....	37
10.	Interest Synchronization.....	38

11.	Amount of Rate Case Expense	38
B.	Contested Issues	39
1.	Rate Case Expense Amortization Period	39
2.	Employee Level and Payroll Costs.....	40
3.	Payment Fee Costs.....	47
VI.	CAPITAL STRUCTURE AND RATE OF RETURN.....	50
A.	Uncontested Issues	50
1.	Remaining Construction Work-In-Progress (“CWIP”) Accruing Allowance for Funds Used During Construction (“AFUDC”) Adjustment.....	50
B.	Contested Issues	51
1.	Capital Structure	51
2.	Cost of Short-Term Debt, Including Credit Facility Fees	64
3.	Cost of Long-Term Debt.....	70
4.	Cost of Common Equity	71
5.	Flotation Cost Adjustment	102
C.	Recommended Rate of Return on Rate Base.....	109
VII.	COST OF SERVICE AND ALLOCATION ISSUES.....	110
A.	Contested Issues	110
1.	Embedded Cost of Service Study	110
2.	Allocation of Certain Customer Care Costs.....	123
VIII.	RATE DESIGN	132
A.	Uncontested Issues	132
1.	Revisions to Transportation Charges	132
2.	Revisions to Existing Rates.....	132
3.	Revisions to Existing Riders.....	132
4.	Other Tariff Revisions	133
B.	Contested Issues	135
1.	Residential Customer Charge [Rate].....	135
2.	Residential Billing Determinants.....	140
3.	Bill Credits	142
4.	Proposed Rider 35 – Payment Fee Adjustment	142

IX.	Gross Revenue conversion factor	146
A.	Uncontested Issues	146
1.	Invested Capital Tax Adjustment.....	146
2.	Impact of Increase in State Corporate Tax Rate	146
X.	FINDINGS AND ORDERING PARAGRAPHS.....	146

STATE OF ILLINOIS
ILLINOIS COMMERCE COMMISSION

Northern Illinois Gas Company	:	
d/b/a Nicor Gas Company	:	
	:	17-0124
Proposed General Increase in	:	
Gas Rates and Revisions to Other	:	
Terms and Conditions of Service.	:	

ORDER

By the Commission:

I. INTRODUCTION

A. Procedural History

On March 10, 2017, Northern Illinois Gas Company d/b/a Nicor Gas Company ("Nicor Gas" or the "Company"), filed with the Illinois Commerce Commission (the "Commission") pursuant to Section 9-201 of the Public Utilities Act (the "Act"), 220 ILCS 5/9-201, the following tariff sheets: 11th Revised Sheet No. 1.5, 6th Revised Sheet No. 4, 6th Revised Sheet No. 5, 6th Revised Sheet No. 7, 6th Revised Sheet No. 8, 6th Revised Sheet No. 9, 8th Revised Sheet No. 10, 8th Revised Sheet No. 11, 5th Revised Sheet No. 11.5, 8th Revised Sheet No. 12, 8th Revised Sheet No. 13, 4th Revised Sheet No. 14, 4th Revised Sheet No. 17.53, 2nd Revised Sheet No. 17.53.1, 8th Revised Sheet No. 18, 8th Revised Sheet No. 19, 2nd Revised Sheet No. 21.3, 5th Revised Sheet No. 21.4, 10th Revised Sheet No. 22, 8th Revised Sheet No. 24, 10th Revised Sheet No. 25, 8th Revised Sheet No. 26, 8th Revised Sheet No. 27, 4th Revised Sheet No. 35, 5th Revised Sheet No. 35.5, 1st Revised Sheet No. 37.2, 1st Revised Sheet No. 38.1, 4th Revised Sheet No. 40, 9th Revised Sheet No. 41, 4th Revised Sheet No. 42, 2nd Revised Sheet No. 42.1, 2nd Revised Sheet No. 42.2, 5th Revised Sheet No. 43, 4th Revised Sheet No. 44, 7th Revised Sheet No. 46, 6th Revised Sheet No. 47, 11th Revised Sheet No. 48, 10th Revised Sheet No. 49, 8th Revised Sheet No. 50, 4th Revised Sheet No. 50.1, 6th Revised Sheet No. 51, 9th Revised Sheet No. 52, 5th Revised Sheet No. 53, 13th Revised Sheet No. 54, 7th Revised Sheet No. 56, 7th Revised Sheet No. 57, 6th Revised Sheet No. 62, 15th Revised Sheet No. 75.1, 10th Revised Sheet No. 75.5, 10th Revised Sheet No. 75.6, 9th Revised Sheet No. 76, 10th Revised Sheet No. 77, 7th Revised Sheet No. 78, 3rd Revised Sheet No. 79, 2nd Revised Sheet No. 79.1, 2nd Revised Sheet No. 79.2, 3rd Revised Sheet No. 79.3, 1st Revised Sheet No. 79.4, 2nd Revised Sheet No. 79.5, 1st Revised Sheet No. 79.6, 1st Revised Sheet No. 87.1, 1st Revised Sheet No. 88, Original Sheet No. 88.1, and Original Sheet No. 88.2.

This rate filing embodied a general increase in rates for natural gas service as well as other proposed changes in terms and conditions. Notice of the proposed

changes reflected in this rate filing was posted in Nicor Gas' business offices and published in a newspaper of general circulation in Nicor Gas' service area, as evidenced by publisher's certificates, in accordance with the requirements of Section 9-201(a) of the Act, 220 ILCS 5/9-201(a), and the provisions of 83 Ill. Adm. Code Part 255. The Commission issued an Order on March 15, 2017 suspending the tariffs up to and including August 6, 2017, and initiating this proceeding. Subsequently, the Commission resuspended the tariffs on July 12, 2017 up to and including February 6, 2018.

Staff of the Commission ("Staff") participated in this proceeding, and the Illinois Attorney General's Office (the "AG") filed an appearance. Petitions to Intervene were filed on behalf of the Citizens Utility Board ("CUB"); the Retail Energy Supply Association ("RESA"); International Brotherhood of Electrical Workers Local 19, ALF-CIO ("Local 19"); Nucor Kankakee, Inc. ("Nucor"); ArcelorMittal USA LLC, ExxonMobil Power and Gas Services, Inc., FCA US LLC, Cargill, Inc., and Caterpillar Inc. (collectively, "Illinois Industrial Energy Consumers" or "IIEC"); and the Illinois Propane Gas Association ("IPGA"). These Petitions all were granted by the Administrative Law Judges ("ALJs").

Pursuant to due notice as required by law and by the rules and regulations of the Commission, a prehearing conference was held in this matter before duly-authorized ALJs at the Commission's office in Chicago on March 30, 2017. The evidentiary hearing was held on September 6 and 7, 2017, at which time the written testimony and exhibits of Nicor Gas, Staff, AG, CUB, RESA, IPGA, and IIEC were admitted into the record. The record was marked "Heard and Taken" on October 17, 2017.

The following witnesses testified on behalf of Nicor Gas: Melvin D. Williams, President, Nicor Gas; Elizabeth W. Reese, Executive Vice President and Chief Financial Officer, Southern Company Gas; Michael J. Morley, Managing Director of Regulatory Accounting, Southern Company Gas; Matthew Kim, Vice President and Controller, Southern Company Gas; Steven M. Murphy, Vice President of Engineering and Construction, Southern Company Gas; Patrick E. Whiteside, Vice President of Nicor Gas Business Support, Nicor Gas; Margaret Schiemann, Director of Infrastructure Programs and Support, Nicor Gas; David M. Meiselman, Managing Director of Rate Design and Tariff Administration, Southern Company Gas; Daniel P. Yardley, Principal, Yardley Associates; Thomas J. Flaherty, Partner, Strategy&, the strategy consulting business of PricewaterhouseCoopers Advisory Services LLC; Dr. Bente Villadsen, Principal of The Brattle Group; John J. Spanos, Senior Vice President, Gannett Fleming Valuation and Rate Consultants, LLC; John Hengtgen, Consultant, Hengtgen Consulting LLC; James M. Garvie, Compensation, Benefits & Human Resources Operations Vice President, Southern Company Services, Inc.; Stephen Wassell, Vice President of Storage & Peaking Operations, Southern Company Gas; Mary Lou Grzenia, Manager of Customer Select & Gas Transportation, Nicor Gas; Ellen K. Rendos, Managing Director, Collections and Remittance in the Customer Experience Department, Southern Company Gas; and Jeffery T. Buxton, Executive Consultant, Black & Veatch Management Consulting, LLC.

The following witnesses testified on behalf of Staff: Theresa Ebrey, Accountant, Financial Analysis Division; Dianna Trost, Accountant, Financial Analysis Division;

Rochelle Phipps, Senior Financial Analyst in the Finance Department of the Financial Analysis Division; Cheri L. Harden, Rate Analyst in the Rates Department, Financial Analysis Division; Mark Maple, Senior Gas Engineer in the Energy Engineering Program, Safety & Reliability Division; and Dr. David Rearden, Senior Economist in the Policy Program, Policy Division.

The following witnesses testified on behalf of the AG: David J. Effron, a regulatory consultant, and Scott J. Rubin, an independent consultant and attorney.

IIEC and CUB presented joint witness Michael P. Gorman, a consultant in the field of public utility regulation. IIEC presented additional witness Brian C. Collins, also a consultant in the field of public utility regulation.

RESA presented witness Joseph Olikier, Senior Regulatory Counsel for IGS Energy.

IPGA presented witness Aaron DeWeese, Executive Vice President, IPGA.

On September 29, 2017, the following parties filed Initial Briefs: Nicor Gas, Staff CUB, IIEC, IIEC-CUB, RESA, the AG, and IPGA. On October 11, 2017, the parties filed Reply Briefs, and on October 13, 2017, the parties filed draft orders or statements of position.

On October 20, 2017, CUB, IIEC and the AG jointly filed a Motion to Strike and Motion for an Expedited Schedule and Ruling on the Motion ("Motion"). In the Motion, CUB-IIEC-AG alleged portions of the Reply Brief and Draft Order of Nicor Gas did not conform with Section 200.800(a) and (c) of the Commission's Rules of Practice (83 Ill. Adm. Code 200.800(a), (c)), make statements of fact not supported in the record, and are in violation of Section 10-103 of the Public Utilities Act. 200 ILCS 5/10-103. Motion at 1. Nicor Gas and Staff filed responses to the Motion on October 24, 2017, in accordance with an ALJs' Ruling. On October 25, 2017, Nicor Gas filed a Response to Staff, and CUB-IIEC-AG filed a Reply. On October 26, 2017, the ALJs denied CUB-IIEC-AG's Motion, stating "the ALJs will give the proposals of the parties the weight that they feel[] is warranted." Ruling at 1. The ALJs also afforded the parties the opportunity to respond to Nicor Gas' Reply Brief and Draft Order arguments in a Response, and allowed Nicor Gas to Reply.

On October 30, 2017, CUB-IIEC-AG filed a Motion to Modify the Schedule, requesting more time to file a Response to Nicor Gas' arguments. The ALJs granted the Motion to Modify the Schedule. On November 1, 2017, CUB-IIEC-AG filed a Petition for Interlocutory Review of the ALJs' October 26, 2017 Ruling on the Motion to Strike.

At the Commission's Regular Open Meeting on November 8, 2017, the Commission denied the Petition for Interlocutory Review, affirming the ALJs' October 26 Ruling, but issued an Order Directing Additional Hearings, which ordered the ALJs to "hold additional hearings, and orders the parties to provide additional testimony and briefing on the return on equity methodology first raised by Nicor Gas in its Reply Brief with an expedited schedule." Order Directing Additional Hearings at 1.

The ALJs convened an emergency status hearing on November 9, 2017 to determine a schedule. The Company filed a Stipulation of Nicor Gas and Staff

("Stipulation") and Supplemental Testimony on November 15, 2017. Staff and IIEC-CUB filed Supplemental Testimony on November 22, 2017. Nicor Gas filed Supplemental Rebuttal Testimony on November 28, 2017. An evidentiary hearing was held on December 1, 2017. Staff, the Company, IIEC-CUB and the AG filed Supplemental Initial Briefs on December 7, 2017. Reply Briefs were filed on December 13, 2017 by the same parties.

A Proposed Order was issued on December 22, 2017. On January 5, 2018, Briefs on Exceptions were filed by Nicor Gas, Staff, the AG, IIEC, IIEC-CUB, IPGA and RESA. On January 12, 2018, Reply Briefs on Exceptions were filed by Nicor Gas, Staff, the AG, IIEC and IIEC-CUB.

II. OVERALL REVENUE REQUIREMENT

The overall revenue requirement is shown in the attached Appendix to this Order.

III. TEST YEAR

Nicor Gas proposed the use of a forecasted calendar year 2018 as the test year, which is permissible under the Commission's Rules. No party objected to the proposed 2018 test year, and it is adopted.

IV. RATE BASE

A. Overview

Nicor Gas' proposed 2018 test year rate base reflects the capital investments for which the Company requests a rate of return. Nicor Gas calculated its proposed rate base by starting with the Company's Gross Plant balance, subtracting its Accumulated Reserve for Depreciation and Amortization for such Plant, and then adding and subtracting various other appropriate items. Additionally, in order to narrow the issues in this proceeding, the Company calculated its test year rate base using an average rate base at the beginning and end of the test year, which is consistent with the Commission's decisions in prior Nicor Gas rate cases. The Company reserved its right to argue against using an average rate base in future rate cases. No party contested the Company's use of an average test year rate base. Based upon certain adjustments to rate base made during the course of this proceeding, Nicor Gas now is proposing a test year rate base of \$2,516,693,000.

B. Uncontested Issues

1. Accumulated Deferred Income Taxes ("ADIT") Adjustments

Staff and Intervenors proposed various adjustments to Nicor Gas' calculation of Accumulated Deferred Income Taxes ("ADIT"), which was included in the Company's 2018 test year revenue requirement as a deduction to rate base. Staff Ex. 2.0 at 16; AG Ex. 1.0 at 14. Nicor Gas accepted these adjustments in its responses to Staff and Intervenor discovery, as well as in the testimony of Nicor Gas witness Morley. Nicor Gas Ex. 16.0 at 11.

a. ADIT Last In, First Out Adjustment

Staff witness Trost and AG witness Effron proposed removing the deferred tax asset from Nicor Gas' ADIT balance that resulted from The Southern Company's 2016

acquisition of Nicor Gas' parent company, Southern Company Gas, formerly known as AGL Resources Inc., and the timing differences between the tax basis and book basis of the Company's Last In, First Out ("LIFO") gas storage inventory. Nicor Gas accepted Mr. Effron's proposed adjustment, and the Company revised its ADIT balance accordingly. Nicor Gas Ex. 16.0 at 11. Ms. Trost and Mr. Effron both testified that the Company accepted their proposals related to this item. Staff Ex. 7.0 at 2; AG Ex. 3.0 at 2. The ADIT LIFO adjustment is not contested and is approved.

b. Net Operating Loss Deferred Tax Asset

AG witness Effron proposed an adjustment to Nicor Gas' 2018 test year ADIT balance to remove the portion of the Net Operating Loss ("NOL") Deferred Tax Asset ("DTA") that was attributable to the Company's Qualified Infrastructure Plant ("QIP") investments during the 2018 test year. AG Ex. 1.0 at 16. Nicor Gas accepted Mr. Effron's proposed adjustment to the portion of the NOL DTA that was attributable to its 2018 QIP investments; however, the Company presented evidence that it was necessary to prorate the adjustment. Nicor Gas Ex. 16.0 at 10. Mr. Effron subsequently accepted the Company's revised calculation. AG Ex. 3.0 at 2. The NOL DTA adjustment is not contested and is approved.

c. Proration of Certain ADIT Adjustments

AG witness Effron proposed adjustments to Nicor Gas' test year ADIT balance to reflect the proration of two items. First, Mr. Effron proposed an adjustment to ADIT to reflect the proration of Company adjustments associated with removing 2018 QIP ADIT amounts from rate base as well as Nicor Gas' proposed depreciation rates. AG Ex. 1.0 at 17. Nicor Gas witness Morley accepted this proposed adjustment; however, Mr. Morley corrected Mr. Effron's calculation to accurately reflect the adjustment's impact on the Company's test year ADIT balance. Nicor Gas Ex. 16.0 at 8. Mr. Effron subsequently accepted Nicor Gas' revised calculation. AG Ex. 3.0 at 2.

Second, Mr. Effron proposed an adjustment to ADIT to reflect the proration of the NOL DTA included in the Company's test year ADIT balance. AG Ex. 1.0 at 18. Mr. Morley testified that, while Nicor Gas considered Mr. Effron's adjustment appropriate, the Company did not agree with the method in which Mr. Effron calculated the prorated balance. Mr. Morley provided a corrected calculation in his rebuttal testimony, and Mr. Effron subsequently accepted Nicor Gas' revised calculation. Nicor Gas Ex. 16.0 at 10; AG Ex. 3.0 at 2. Therefore, these adjustments are not contested and are approved.

2. 2017 Qualified Infrastructure Plant Amounts

This Section is contested and is moved to Section IV.C.5., below.

3. Original Cost of Gross Plant Balance

Nicor Gas presented evidence that its Gross Plant balance for the calendar year ending on December 31, 2016 was \$6,072,988,000. Nicor Gas Ex. 3.1 at 6. Based on the Company's evidence, Staff witness Trost recommended that the Commission conclude and make a finding in the Final Order in this proceeding that Nicor Gas' December 31, 2016 plant balance of \$6,072,988,000, as reflected on the Company's Schedule B-5, be approved for purposes of an original cost determination, subject to any adjustments ordered by the Commission in this proceeding. Ms. Trost further

recommended that the Commission include an ordering paragraph in its Final Order identifying and unconditionally approving \$6,072,988,000 as the original cost of Nicor Gas' Gross Plant at December 31, 2016. Staff Ex. 2.0 at 25. Accordingly, Nicor Gas requests that the Commission include in the Final Order in this docket the following ordering paragraph:

It is further ordered that the \$6,072,988,000 original cost of plant for Northern Illinois Gas Company at December 31, 2016, as presented in Staff Exhibit 2.0, is unconditionally approved as the original cost of plant.

The Original Cost of Gross Plant Balance in the amount of \$6,072,988,000 is not contested and is approved. Further, the Commission adopts the above suggested language in the Findings and Ordering paragraphs.

C. Contested Issues

1. Advanced Metering Infrastructure

a. Nicor Gas' Position

Nicor Gas states that the costs associated with its deployment of AMI in 2017 and 2018 appropriately are included in rate base, as this investment will be "prudently incurred and used and useful in providing service to [the Company's] customers" as required by Section 9-211 of the Act. 220 ILCS 5/9-211. More particularly, Nicor Gas avers that AMI deployment will improve system operations and will be beneficial to customers in a number of ways, including the cost savings reflected in the project's positive net present value ("NPV") of \$28 million. Nicor Gas Ex. 6.0 at 20; Nicor Gas Ex. 18.0R2 at 4; Nicor Gas Ex. 32.0 at 2; Nicor Gas Ex. 26.0R at 8; Nicor Gas Ex. 38.0 at 3. Nicor Gas also notes that Staff witness Maple testified that he is satisfied with the Company's evidentiary presentation, that he supports the AMI project, and that he is not proposing any adjustments to the Company's requested rate base or depreciation expense with regard to the AMI project. Staff Ex. 9.0 at 1.

Nicor Gas maintains that it is undisputed that automated meter technology is widely used in the gas and electric industries. Nicor Gas states that, as of 2016, thirty-five percent of natural gas utilities nationally had upgraded to AMI technology, and another quarter of gas utilities were considering upgrading from automated meter reading ("AMR") technology. Nicor Gas Ex. 26.0R at 5. Nicor Gas witness Buxton, an industry expert from Black & Veatch, explained that gas utilities across the country have been utilizing automated reading technologies for years to reduce meter reading expenses, increase the meter reading frequencies, and improve process efficiencies; however, the decreasing cost and increasing functionality of AMI solutions now has matured to a point where a number of gas utilities are adopting AMI for not just meter reading but also for operations data improvement. Nicor Gas avers that this convergence in cost and functionality supports full deployment of the Company's proposed AMI project. Nicor Gas Ex. 26.0 at 4-5.

Nicor Gas points out that the experience nationally mirrors the experience in Illinois. The Peoples Gas Light and Coke Company ("Peoples Gas") completed installation of AMR technology devices on all its customers' natural gas meters in the

1990s, and Ameren Illinois Company d/b/a Ameren Illinois (“Ameren”) also installed AMR devices in significant portions of its service territory. Nicor Gas Ex. 6.0 at 21. Nicor Gas further states that it has had its own experience with meter automation, having deployed two pilot programs in 2000 and 2012, while observing the industry-wide progression and maturation of automated meter technology. Nicor Gas now also has the benefit of the corporate knowledge and expertise gained from joining The Southern Company Gas family, which has successfully developed and deployed versions of automated meter technology at the other six of its local gas distribution companies (“LDCs”). Accordingly, Nicor Gas asserts that it is firmly situated to deploy AMI and will be able to avoid any potential setbacks that may arise during deployment without the benefit of first-hand knowledge. Nicor Gas Ex. 18.0R2 at 12.

Nicor Gas states that the evidence shows numerous customer and operational benefits to be achieved with installation of AMI across the Company’s service territory, including the following:

- Encoder receiver transmitters (“ERTs”), which are individual radio modules or devices attached to a customer’s current natural gas meter, will communicate data on customer consumption and other parameters electronically with Nicor Gas, thereby enhancing system operations, safety, and reliability;
- ERTs will eliminate estimated meter reads for residential and small commercial customers, thereby enhancing the customer experience by providing timely and accurate consumption information, and correspondingly reducing call center volume and cancel/rebills;
- ERTs will supplement the current practice of daily meter reads for large commercial customers, thereby enhancing the customer experience;
- Customers will be able to easily track their consumption and have access to that data, enabling them to make energy- and money-saving adjustments;
- Various data measurements – such as pressure reads and corrosion reads – will enable Nicor Gas to operate the delivery system more efficiently and better plan for and implement system improvements; and
- Nicor Gas will be able to read meters remotely and without having to dispatch technicians, thus simplifying the process for customer moves and avoiding the expense and environmental impact of service vehicles. Nicor Gas Ex. 6.0 at 22.

Nicor Gas further states that there are numerous sources and indicators suggesting growing consumer demand for AMI technology and access to energy usage information, including a recent energy efficiency program evaluation confirming that customers participated in numerous energy efficiency programs and offers as a result of receiving home energy reports. Nicor Gas states that this demonstrates that customers take action to control their energy usage when they are informed about their consumption. Nicor Gas residential customers have higher satisfaction if they review their natural gas usage, according to data from the 2016 J.D. Power Gas Utility

Residential Customer Satisfaction Study. Nicor Gas Ex. 18.2 at 2. Furthermore, Nicor Gas' three-year trend also shows a significant growth in the number of customers reviewing their usage history.

Nicor Gas explains that it enlisted the assistance of Black & Veatch, a global leader in engineering, procurement, and construction services for energy companies, to work with the Company to develop a Benefit/Cost Analysis ("BCA"), which demonstrates the substantial benefits to be obtained implementing AMI. Nicor Gas Ex. 6.0 at 22; Nicor Gas Ex. 18.02R at 15; Nicor Gas Ex. 26.0R at 6-9. Nicor Gas witness Buxton explained that the BCA was developed using reliable models that Black & Veatch used with other utilities analyzing AMI deployment and a repeatable methodology that included the following key activities:

1. Development of an exhaustive list of potential AMI benefits;
2. Conducting discovery workshops with key functional groups to identify viable and applicable benefits;
3. Validation of identified benefits with internal stakeholders and development of high-level functional requirements needed to enable the identified benefits;
4. Conducting quantification workshops to identify key data needed to estimate the value of the identified benefits and development of benefit quantification models to capture potential benefits valuation;
5. Development of high-level deployment planning and IT release planning to provide program timing for benefit realization, capital planning and incremental O&M costs;
6. Development of cost models to identify the initial and ongoing incremental costs associated with the AMI technology implementation based on the functional requirements needed to realize the expected benefits and the timing of the associated costs;
7. Validation of individually-quantified benefits and overall program metrics against the identified benchmarks; and
8. Application of expected depreciation schedules and tax impacts on net cash flows and resultant financial metrics.

Nicor Gas Ex. 26.0R at 6. Nicor Gas states that this process was facilitated by Black & Veatch staff and diligently followed by the Nicor Gas team and its key functional stakeholders to quantify and validate the expected benefits from AMI deployment, as well as associated costs. The avoided operational costs reflected in the BCA are based on actual and specific cost data and annual budgets as measured by Nicor Gas and provided to Black & Veatch for inclusion in the BCA.

Nicor Gas explains that the BCA demonstrates that the NPV of the AMI project is a positive figure of approximately \$28 million in year 20 of the project. Nicor Gas notes that Staff witness Maple agreed that a positive NPV demonstrates that a capital project is beneficial to customers, and that Nicor Gas adequately demonstrated the validity of its study of the AMI project as reflected in the BCA. Staff Ex. 9.0 at 3. Nicor Gas states that the most significant driver of the savings reflected in the BCA is the expected avoided costs of monthly manual meter reading due to the implementation of AMI, but that the savings also reflect financial benefits such as the avoided injuries from meter reader activities, the avoided costs of additional handheld meter reading equipment, and the avoided costs of additional fleet vehicles. Nicor Gas Ex. 26.0R at 8. It is Nicor Gas' position that, even though the Company historically has performed manual meter reads on a bi-monthly basis in accordance with the requirements of Part 280 of the Commission's Rules, 83 Ill. Adm. Code Part 280, monthly manual meter reads is the more appropriate baseline to be used for comparison purposes in the BCA.

Nicor Gas states that, going forward, the Company will eliminate estimated meter reads and move to monthly meter reads, whether through AMI or on a manual basis. Nicor Ex. 18.0R2 at 7-8. The Company's practice of conducting manual meter reads on a bi-monthly basis raises a number of issues that impact the Company's operations and its interactions with customers, including the possibility of unlawful gas use, customer billing disputes based on untimely and inaccurate consumption information, increased call center volume and cancel/rebills to address needed corrections in billed usage amounts, and imposing on customers potentially large true-up bills. Nicor Gas points out that, if the Commission does not approve AMI, the significant savings reflected in the BCA from the avoided costs of monthly manual meter reading will no longer come to fruition, as the Company will need to double its meter reading workforce, equipment, and vehicles to effectuate monthly manual reads. Nicor Gas further emphasizes that monthly meter reads alone, however, will not address issues related to personnel safety, property intrusion, and inaccessible meters. The deployment of AMI will enable Nicor Gas to entirely avoid any issues with estimated reads and significantly reduce other issues. Nicor Gas Ex. 18.02R at 10.

Notwithstanding the AMI project's positive \$28 million NPV as shown in the BCA, AG witness Effron claims that the benefits to customers are too "remote" and "speculative," and that the NPV analysis is not sufficient to support AMI deployment. Nicor Gas argues the AG's opposition to the AMI project is fundamentally flawed and should be rejected for several reasons. AG Ex. 1.0 at 10. First, Mr. Effron's reservations regarding the BCA are unfounded in light of the known and tangible benefits that AMI technology will provide to Nicor Gas' customers as demonstrated by the Company's evidence. Nicor Gas Ex. 38.0 at 2. Second, Mr. Effron's criticism of the NPV calculation shown in the BCA is contradicted by Staff witness Maple's testimony that an NPV analysis "is commonly used to analyze the profitability of a particular project or investment" and that a twenty-year period is a "typical length for NPV studies, particularly for projects that come before the [Commission]." Staff Ex. 5.0 at 4. Third, Mr. Effron presents a misguided understanding of what an NPV represents by asserting that the NPV must be analyzed in relation to the size of the project, which is not the standard by which the Commission reviews capital projects as explained by Mr. Maple. AG Ex. 5.0R at 4.

As an alternative to elimination of the AMI project, Mr. Effron proposes that recovery of the costs should be deferred until after the Company establishes that the AMI project is cost-effective. AG Ex. 5.0R at 5. Nicor Gas maintains that Mr. Effron's proposal is contrary to the Commission's long-standing and routine practice of allowing utilities to recover the costs of capital projects through the traditional ratemaking process. Nicor Gas also explains that Mr. Effron's proposed deferral mechanism is not on point here because if the Commission were not to approve cost recovery for the AMI project, the Company would not move forward with AMI deployment and, instead, would move to manual monthly meter reads and update its revenue requirement accordingly. Finally, Mr. Effron's alternative proposal is entirely unnecessary here given that the Company's proposed AMI project has a demonstrated positive NPV.

b. Staff's Position

Staff states that this issue is not contested between the Company and Staff. In direct testimony, Mr. Maple raised concerns regarding the cost-benefit analysis originally conducted by the Company, given its negative NPV result. Staff Ex. 5.0 at 4. Nicor Gas addressed Mr. Maple's concerns in the rebuttal testimonies of Mr. Whiteside and Mr. Buxton. Nicor Gas Ex. 18.0; Nicor Gas Ex. 26.0. Subsequently, Mr. Maple reviewed the revised cost study that Nicor Gas conducted with Black & Veatch that showed the project had a positive NPV and opined that the study is valid. Staff Ex. 9.0 at 2. One change in the revised study was Nicor Gas' decision to eliminate estimated bi-monthly meter reads and instead move to monthly meter reads, which resulted in significant potential benefits. Mr. Maple opines that the study and the testimonies of Mr. Buxton and Mr. Whiteside provide additional support for the Company's proposal to move from manual meter reads to AMI. Mr. Maple reviewed the data provided by Nicor Gas in recalculating the time that technicians spend on meter-related activities, the source of the data, and the methodology utilized by the Company in determining the calculation. Id. Based upon the review that Mr. Maple conducted of the cost analysis provided by the Company, Staff does not propose any adjustment to the Company's requested rate base or depreciation expense with regards to the AMI project.

c. AG's Position

The AG asserts that Section 9-211 of the Act requires that only utility plant that is used and useful shall be incorporated into customer rates. 220 ILCS 5/9-211. The AG added that the burden of proof is on the Company to demonstrate that its forecasted levels of plant in service are supported by actual circumstances, will provide customer benefits, and are prudently incurred. The AG claims that Nicor Gas offered several arguments in support of its request for approval of AMI in its service territory to meet its statutory burden. The AG states that some of Nicor Gas' arguments are outright false, and none are persuasive. The AG recommends that the Commission reject Nicor Gas' arguments.

The AG contends that Nicor Gas' claim that thirty-five percent of natural gas utilities nationally have upgraded to AMI technology is simply false. On cross-examination, Company witness Buxton could identify only two gas-only utilities in the country that have deployed AMI. Tr. at 81-82. The AG alleges that Nicor Gas' claim that it is the last utility within The Southern Company family of utilities to deploy an

automated metering technology is not relevant. Further, the automated meter technology deployed by the Southern Company Gas companies is limited to AMR, not AMI as requested by the Company in this case. AG Ex.5.0R at 2. Nicor Gas conflates AMI and AMR which are different technologies. AG witness Effron quotes Nicor Gas' response to data request AG 7.03 wherein Nicor Gas stated: "AMI technology is a two-way communication network which provides interval meter data," whereas "AMR technology as a one-way remote collection of consumption data from a customer's meter." AG Ex. 1.0 at 5. Thus, the AG concludes that Nicor Gas' argument that as a member of The Southern Company family it might benefit from the AMR experience of the other LDCs is meritless as none have any experience with the deployment of AMI. AG Ex. 5.0R at 2. The AG notes that Nicor Gas' AMI experience is limited to two pilots of AMR technology in 2000 and in 2012. Neither pilot resulted in a formal study or report of data collected. AG Ex. 1.0 at 5-6.

The AG asserts that equally disingenuous is the Company's argument that Nicor Gas is the last major utility in Illinois to deploy an automated metering technology. Again, Nicor conflates AMI and AMR. The AG pointed out that deployment of AMI by other Illinois utilities is limited to the electric utility and the combination electric and gas utility that are legislatively authorized by the Energy Infrastructure Modernization Act ("EIMA") to spend a capped amount on AMI and recover the cost of AMI in rates. See, e.g., 220 ILCS 5/16-108.5(b)(1)(B) and 16-108.5(b)(2)(B). Unlike those companies, Nicor Gas is not subject to EIMA and is not legislatively authorized to deploy and recover the cost of AMI. The AG added that the other major gas-only utility in Illinois, Peoples Gas, installed AMR devices on its customer's natural gas meters, not AMI, as Nicor Gas proposes to do here.

The AG further states that Nicor Gas' reliance on utilities that have deployed AMI under the aegis of EIMA is unavailing for additional reasons. In particular, the AG stated that unlike the utilities subject to EIMA, Nicor Gas is not subject to the conditions and requirements of the statute. EIMA utilities must report on the progress of the investment, identify the types of investment and cost, the pace of deployment, publicity efforts, consumer access and use of the data available as a result of interval metering, bill impact, and twenty-nine different metrics. The performance metrics concern specific objectives such as a reduction in outages, a reduction in estimated bills, and a reduction in line losses. 220 ILCS 5/16-108.5(f). In addition, the utilities subject to EIMA are subject to spending requirements and spending caps (Id. at 5/16-108.5(b)), hiring requirements and reporting (Id.), and a rate cap. Id. at 5/16-108.5(g). In addition, financial penalties are imposed if these metrics are missed. Id. The AG points out that if the Commission were to approve AMI deployment, Nicor Gas' ratepayers would have none of these regulatory safeguards the General Assembly provided for customers of EIMA-eligible utilities.

The AG also argues that the Black & Veatch BCA that Nicor Gas relies on to support its AMI request is seriously flawed. The AG notes that Black & Veatch had to run three iterations of its BCA before it could come up with a \$28 million "net benefit" for AMI deployment. Nicor Gas supplied Black & Veatch new inputs for each iteration. Black & Veatch's first iteration produced a result showing that costs exceeded benefits by \$75 million. AG Ex. 1.0 at 9. Black & Veatch ran a second iteration using new

assumptions provided by Nicor Gas. The second iteration resulted in a net benefit of \$16 million. Id. at 9. Nicor Gas then had Black & Veatch run a third iteration, which resulted in the \$28 million benefit now being claimed.

The AG added that the total capital costs of the AMI project are estimated to be about \$260 million, making a benefit of \$28 million over twenty years far from compelling. As AG witness Efron pointed out, when the benefit is so slim relative to the cost, “[n]ot a lot would have to go wrong for the [NPV] to turn negative.” AG Ex. 5.0R at 4.

The AG further argues that the costs for AMI are themselves unsupported. First, there are assumptions in the BCA that may understate the cost. Nicor Gas witness Morley testified that in the third version of the analysis, submitted as Nicor Gas Exhibit 26.1, that no indirect or overhead capital costs were included. Tr. at 121. He could not say whether other overhead costs such as those associated with labor or operations and maintenance were included in the cost. Id. at 122. Excluding these costs could potentially understate the cost, erroneously resulting in a positive benefit result.

The AG claims that Nicor Gas witness Morley testified that he could not detail what assumptions were used in the AMI investment figure included in Nicor Gas’ rebuttal BCA. The difference in cost included in the 2018 test year rate base and the investment included in the BCA was substantial. In surrebuttal testimony, Nicor Gas reduced its AMI costs included in rate base of \$90.2 million (AG Ex. 1.0 at 5) by \$32 million (Nicor Gas Ex. 30.1R, Revised Schedule B-2, col. (E), line 1) to agree with the investment included in the BCA presented as Nicor Gas Ex. 26.1R. However, the rate base reduction for AMI represented only “direct costs” because the “overhead costs not applied to AMI as a result of the reduction in direct costs will simply be reallocated to different plant in service categories.” Nicor Gas Ex. 30.0R at 8:162-164. Nicor Gas claims that the AMI average plant balance originally proposed by Nicor Gas *net of indirect costs* was \$81.275 million, and a revised cost, again *net of indirect costs*, was reduced by 38% to \$50.323 million. Tr. at 125. The AG argues that this is a major change in cost assumptions that affects the BCA and its conclusions. However, Nicor Gas’ witness could not explain the source of the change other than that it was given to Black & Veatch consultant Buxton to put into his BCA. Id. at 125.

The AG contends that given the slim margin of benefits associated with the 20-year BCA, a significant change in cost should cause the Commission to question the credibility of the conclusion that there will be some benefit to consumers, even though the benefit is not reached for more than 15 years, in 2033. AG Ex. 5.0R at 4. Mr. Buxton confirmed during cross-examination that the Black & Veatch BCA incorporated no sensitivity analyses to test how the net benefits figure would change if the project were over-budget by, for example, 10% or indeed any other percentage. Tr. at 104. Likewise, no sensitivity analysis was incorporated in the study to adjust for such plausible scenarios as operation and maintenance (“O&M”) benefits that are less than anticipated, a delay in realization of O&M benefits, a delay in realization of tax benefits from accelerated depreciation, or modification of the rate of return discount rate. Id. at 104-105.

The AG states that the Company argued that AG witness Effron's criticisms of the BCA are unfounded in light of the known and tangible benefits that AMI technology will provide. The AG counters that the record shows that although Nicor Gas may realize immediate benefits from deploying AMI, ratepayers are not as fortunate. The utility does not address when ratepayers would receive the alleged "known and tangible benefits" claimed in the BCA. Further, notwithstanding three iterations of the Company's BCA, the BCA cannot be relied on to provide such evidence any more than the previous three versions for the following four reasons.

First, the BCA includes the benefits from expected reductions in truck rolls to the field to connect and disconnect service and investigate meter issues (Nicor Gas Ex. 26.0R at 12), but the cost of the additional disconnect valve to the AMI meter that would allow remote connection and disconnection is *not* included in the BCA. Tr. at 101-102. Second, the BCA does not consider the overhead costs associated with AMI, as noted above. Nicor Gas Ex. 30.0R at 7-8. Third, the BCA has not been subject to any sensitivity analysis. Tr. at 104-105. Finally, the BCA's positive net present value is not significant enough to support the investment.

The AG states that the benefits of the AMI project are not provided to ratepayers in the Company's test year revenue requirement. According to the AG, Nicor Gas, in its surrebuttal testimony, finally provided data supposedly showing ratepayers would realize only \$684,000 in savings from the deployment of AMI in the 2018 test year. But those savings have to be compared to the additional costs customers would be required to pay. The AG explains that the increase in depreciation expense and the rate of return on the AMI investment that is included in the revenue requirement dwarf the meager savings for ratepayers. The AG argues that the reality is that the cost of AMI deployment to ratepayers would be \$10,457,000 annually until Nicor Gas files its next rate case. Meanwhile, the AG states that the Company will reap the immediate benefits of AMI deployment, including an increased rate base and increased return to shareholders.

The AG responds to Nicor Gas' citation to amendments to Part 280 of the Commission's Rules as support for the AMI deployments because Section 280.90 describes a "utility's responsibilities to obtain *actual* readings...*at least* every second billing period". The implication here, is that this amended rule, approved several years ago, has created costly mandates that support approval of the proposed AMI investment. The AG states that the Company is currently in compliance with the amendments to Part 280 without deploying AMI. The AG adds that although the Company maintained that there is an increased cost of \$110,500 per year associated with inaccessible meters that could be avoided with AMI deployment that was not captured by the BCA, there is no evidence that the increased cost Nicor Gas claims it will avoid was removed from the requested revenue requirement that includes the cost of AMI. Moreover, the AG points out that AMR meters would allow Nicor Gas to conduct remote meter reads. The costs associated with leaving a door tag at inaccessible meters that Nicor Gas claims can be avoided through AMI deployment could also be avoided by installing AMR meters that can be read remotely.

The AG rejects Nicor Gas' argument that there are "numerous sources and indicators suggesting growing consumer demand for AMI technology and access to

energy usage information”, citing a recent energy efficiency program evaluation that confirms customer interest in usage information. The AG states that there are several problems with the Company’s assertion. First, Nicor Gas witness Whiteside admitted that, in fact, Nicor Gas has no specific reports or studies directly from customers that show a desire for AMI investment. Nicor Gas Ex. 18,0R2 at 13. In addition, Nicor Gas’ claims that customers are interested in reviewing their usage history and in an “easy-to-understand format” is not tantamount with customers clamoring for hourly usage information supplied through AMI meters, as the Company implies. The AG also notes that Nicor Gas customers already receive “home energy reports” that compare a customer’s monthly usage with his or her comparable neighbor’s usage. Hourly consumption data is not needed or used for those reports.

The AG contends that Nicor Gas’ reference to a 2016 J.D. Power Report does not stand for what the Company alleges. As is clearly evident in Nicor Gas Exhibit 18.2, the survey compared the “satisfaction” of customers who compared their usage using *existing* Nicor Gas tools with those who did not. The survey does not show support for AMI and the Commission should give it no evidentiary weight.

The AG also notes that Nicor Gas, like other electric and gas utilities, has been obligated to provide energy efficiency programs to consumers since Section 8-104 (220 ILCS 5/8-104) of the Act was adopted by the General Assembly in 2013. Those programs include access to usage information so that customers can monitor the progress in achieving reductions in energy use. The AG argues that the reports are not reliant on AMI data, and are not necessary for customers to have a clear understanding of what appliances, measures or usage behavior contribute to decreased usage, and ultimately lower bills.

The AG adds that as a result of an adjustment to disallow the direct costs of AMI, other necessary adjustments to the revenue requirement are necessary. There is an impact on QIP caused by the overheads that would be reallocated from AMI to QIP. Nicor Gas Ex. 3.0R at 8. The Company included all investment subject to Rider QIP through December 31, 2017 in the requested revenue requirement (*Id.* at 14) and removed the 2018 QIP from the Company’s test year rate base. *Id.* at 24-25. The AG states that the increased overhead reallocated to QIP results in: 1) an increased amount of projected 2017 QIP included in the revenue requirement; and 2) an additional adjustment to remove the reallocated overhead assigned to 2018 QIP.

The AG adds that because the overhead reallocated from AMI increases 2017 QIP, the language setting forth the amount of projected 2017 QIP included in the revenue requirement should be amended. The projected 2017 QIP included in the revenue requirement in this proceeding will be reconciled to the actual cost of 2017 QIP in the proceeding to reconcile the Company’s Rider QIP through December 31, 2017 pursuant to Section 9-220.3(e) of the Act, in the annual reconciliation proceeding in which the Commission’s examines the reasonableness and prudence of the QIP investment made during that calendar year. The AG explains that in the reconciliation case, there will be an amount recognized as the difference between the actual cost of 2017 QIP and the projected 2017 QIP included in the Company’s revenue requirement in this proceeding.

The AG urges that if the Commission chooses to not adopt Mr. Effron's recommendation to reject the Company's AMI proposal, it should adopt his alternative proposal that the Commission delay recovery of AMI investments until such time the utility can establish that the program provides net benefits to ratepayers. Mr. Effron recommended that the Commission accomplish this through use of a deferred recovery mechanism. The AG explains that if the Commission adopts the AG's deferral mechanism, overhead costs would continue to be allocated to AMI and the associated overhead would not be reallocated to other construction projects.

Nicor Gas asserts that Mr. Effron's alternative proposal is contrary to the Commission's long-standing and routine practice. The AG points out that the third iteration of Nicor Gas' BCA shows that the costs outweigh the benefits for the first 15 years of the project, justifying the deferral of cost recovery to the time that consumers supposedly will realize some benefit. The AG explains that this has the effect of matching costs and benefits and ensuring that consumers are protected until such time Nicor Gas can establish there is a net benefit to customers from AMI deployment. The record makes clear that given the uncertainty associated with actual, future consumer benefit, at a minimum, the Commission should reject approving proposed inclusion of significant costs of the investment in rates now.

The AG responds to Nicor's assertion that Mr. Effron's reliance on a 2010 Maryland Public Service Commission ("MD PSC") case wherein the MD PSC approved a deferral mechanism for the Baltimore Gas and Electric Company's ("BGE") AMI initiative is misplaced. The AG states that Nicor Gas mischaracterizes the MD PSC's Order. The AG explains that the MD PSC approved the establishment of a regulatory asset for the AMI Initiative for future recovery into base rates at the time that the Company had delivered a cost-effective AMI system, precisely what Mr. Effron recommends here. The ordering paragraphs of the MD PSC Order state:

(2) That Baltimore Gas and Electric Company is authorized to establish a regulatory asset for the AMI Initiative that may include the incremental costs to implement the AMI Initiative, as well as the net depreciation and amortization costs relating to the meters, and an appropriate return for those costs, and at the time that the Company has delivered a cost-effective AMI system, the Company may seek cost recovery into base rates;

In the Matter of the Application of Baltimore Gas and Electric Company for Authorization to Deploy a Smart Grid Initiative and to Establish a Surcharge for the Recovery of Cost, MD PSC Case No. 9208 (Order No. 83531, Aug. 13, 2010), 2010 Md. PSC LEXIS 12, 283 P.U.R. 4th 165 at 50-51 (emphasis added).

According to the AG, these findings make clear that, contrary to Nicor Gas' characterization of that order, the MD PSC's treatment of the proposed AMI investment was completely analogous to Mr. Effron's proposed alternative treatment of the Company's proposed AMI investment.

The AG contends that if the Commission adopts Mr. Effron's alternative proposal to defer recovery of AMI until the utility can prove there is a net benefit to ratepayers,

the costs of AMI should be removed from the revenue requirement in this proceeding and deferred to a future rate proceeding. Since the Commission would be deferring the costs of AMI, the overhead costs would continue to be allocated to AMI and would not be reallocated to other construction projects, such as 2017 and 2018 QIP.

The AG also responds to Staff's discussion of Nicor Gas' AMI proposal. The AG notes that Staff witness Maple expressed dissatisfaction with the early BCA produced by Nicor Gas, but ultimately accepted the AMI proposal based on his review of iterations of the BCA that eventually produced the \$28 million in alleged benefits. The AG states that Mr. Maple never addressed nor responded to the many valid criticisms presented by Mr. Effron in his direct and rebuttal testimonies of the BCA. Likewise, Staff never addresses the disconnection between Nicor Gas' claimed benefits of AMI in consideration of the differences and applications of AMI for electric versus gas utility systems. Staff Ex. 9.0. The AG adds that Mr. Maple's rebuttal testimony makes clear that his particular interest and focus on the analysis of the proposed AMI investment was related to his support for monthly meter reads – not AMI specifically. *Id.* at 1. The possibility of Nicor Gas choosing to use AMR technology to move to monthly meter reads, instead of the more expensive AMI technology, is not addressed in Mr. Maple's testimony.

In sum, the AG requests that the Commission reject Nicor Gas' AMI proposal. In the alternative, the AG urges that the Commission delay recovery of AMI investments until such time the utility can establish that the program provides net benefits to ratepayers. The AG proposes that the Commission accomplish this through use of a deferred recovery mechanism.

d. CUB's Position

CUB finds the record evidence inadequate to support an affirmative declaration to move forward with deployment of AMI at this time. CUB notes that Nicor Gas submitted BCAs, conducted by Black & Veatch, which Nicor Gas claims support implementation of AMI and the inclusion of these assets in rate base. CUB observed that the BCAs conducted – just over the course of this proceeding – range from a negative NPV of \$75 million, (AG Ex. 1.0 at 9), to a positive NPV of \$28 million. Nicor Gas Ex. 26.0R, 9. According to CUB, one factor that influenced the over \$100 million swing in the BCAs from a negative net present value to a positive one is whether Nicor Gas will continue reading meters on a bi-monthly basis or will accelerate meter reading to monthly. Tr. at 90. CUB recognizes customer benefits in moving to monthly meter reads, like far fewer problems with inaccurate estimates resulting in customer over- or under-charges. However, for several reasons, the data in the record does not provide CUB with sufficient confidence in the BCA results, and thus prohibits a clear conclusion that the benefits of this expensive capital project outweigh the costs.

First, CUB avers that the BCAs were based – at least partially – on unverified information provided to Black & Veatch from Nicor Gas. Tr. at 91. While the Black & Veatch witness who conducted the BCA on behalf of Nicor Gas testified that the BCA included “fully loaded labor costs,” CUB maintains that the record is not clear whether these costs include all overhead costs. *Id.* at 94. CUB notes that Mr. Buxton did not independently verify these costs. *Id.* at 95. CUB further points to Mr. Buxton's

additional testimony that the estimate for IT systems and integration costs must be reviewed by The Southern Company to validate the forecasts, but that review is not yet complete, and he could not say when it would be completed. Id. at 97. Thus, CUB concludes that the record does not reveal whether the costs attributed to AMI deployment are reliable or accurate. AG Ex. 1.0 at 5.

Second, CUB states that the record demonstrates that Nicor Gas did not thoroughly investigate the potential efficiencies that could be achieved by working with Commonwealth Edison Company (“ComEd”) in sharing AMI resources, considering ComEd has deployed electric AMI meters throughout most of its territory. Tr. at 58. CUB observes that, when Nicor Gas witness Whiteside was asked whether Nicor has considered working with ComEd to share AMI resources, Mr. Whiteside responded “[w]e explored it peripherally, but did not do an in-depth investigation.” Id. at 63. CUB takes the position that the Commission should not be satisfied by this answer and should demand additional research and analysis be conducted regarding the potential efficiencies of sharing AMI resources.

Thus, CUB supports the AG in recommending that the Commission deny recovery of costs relating to AMI. CUB further recommends the Commission require – in a future proceeding – more reliable, updated cost data after the RFP review process is complete and require the Company to perform a more in-depth investigation into working with ComEd to share AMI resources before the Commission gives the green light to this capital-intensive program.

e. Commission Analysis and Conclusion

The record demonstrates that many customer and operational benefits will be achieved by installing AMI across Nicor Gas’ service territories. Furthermore, AMI will enhance safety. The Commission points out that the most significant driver of the savings reflected in the BCA is the cost savings by eliminating monthly manual meter reading due to the implementation of AMI. These determinations are not disputed by any party. The AG states that the benefits to customers are “remote and speculative.” The Commission disagrees, and the record is clear that customers realize significant benefits, such as the use of ERTs, which allow customers more decision-making capability with their gas usage.

The AG questions the fact that BCA was modified several times to show positive benefits. However, the Commission finds that there will always be modifications to a large-scale project such as AMI, and revisions to a BCA to consider all costs and benefits is appropriate. Nicor Gas used actual and specific cost data and annual budget information to comprise the BCA, and worked closely with Black & Veatch to provide the most accurate and up to date data. As Staff witness Maple testifies, a NPV analysis is commonly used to evaluate large-scale projects such as AMI. Moreover, a twenty year period is a typical length of NPV studies.

CUB urges the Commission to deny recovery of costs related to AMI because the Company did not do an in-depth review of whether there were cost savings that could be achieved by partnering with ComEd. The Commission points out that the Company did explore that possibility, but found that because significant portions of the utilities’ service territories did not overlap, technology sharing probably would not be reasonable.

Tr. at 73. The AG also points out that it is not relevant that Nicor Gas is the only The Southern Company subsidiary to not move towards automated meter technology. The Commission finds that while it agrees with the AG that AMR and AMI are not identical, it is certainly relevant that more and more gas utilities are moving towards automated meter technology because customers realize benefits. As Nicor Gas has shown its customers will receive positive benefits and safety will be improved, the Commission supports this effort. The AG and CUB's proposals to remove AMI costs from depreciation expense and rate base are rejected.

2. Cash Working Capital

a. Pension Expense Lead

(i) Nicor Gas' Position

Nicor Gas presented evidence of its Cash Working Capital ("CWC") requirement, which the Company determined through a lead-lag study that analyzes the timing of applicable cash inflows to a utility in conjunction with an analysis of the timing of applicable cash outflows from the utility. Nicor Gas Ex. 13.0 at 3. One such component of the lead-lag study is an expense lead, which is the time difference between when a good or service is provided to Nicor Gas and when the Company pays for that good or service. Nicor Gas Ex. 13.0 at 12. Nicor Gas' lead-lag analysis included several expense lead categories, including Employee Benefits, which is comprised of Pensions and Other Post-Employment Benefits ("OPEB"). Certain Staff and Intervenor witnesses proposed adjustments to the Pension Expense and OPEB Expense leads used in the lead-lag analysis.

Nicor Gas states that the pension expense lead included in its lead-lag study should be assigned a zero-expense lead time because the Company has proposed to include its pension expense and OPEB expense net liability as a 100% reduction to rate base. Nicor Gas Ex. 13.0 at 14. Accordingly, it is Nicor Gas' position that including the pension expense lead again in the CWC calculation at anything other than a zero lead would be, in effect, double counting the accrued expenses impact on rate base. Nicor Gas Ex. 16.0 at 22. Nicor Gas states that, if the Commission eliminates the Net Pension Asset from the Company's revenue requirement, then the Company accepts the proposals to use the intercompany billing lead for the pension amount included in the CWC calculation. Nicor Gas Ex. 30.0R at 10.

(ii) Staff's Position

Staff witness Trost presented an adjustment to CWC based on Staff's calculation of CWC using the Gross Lag Approach, which is the same methodology used by the Company. Staff Ex. 7.0 at 2-3; Nicor Gas Ex. 16.0 at 21. The final balance of CWC will be established using the revenue requirement and methodology that is ultimately approved by the Commission in this proceeding.

Concerning the pension expense lead, the Company agrees with AG witness Effron that if the pension asset is eliminated from rate base, then the intercompany billing lead should be used for the pension amount in the CWC calculation. Consistent with Staff's position on the pension asset discussed in IV. C. 3. below, the intercompany

billing lead of 45.09 days is reflected at Staff RB Appendix A, Schedule 9, page 1 of 3, line 7, column (E). Staff Ex. 7.0 at 3.

(iii) AG's Position

The AG states that Nicor Gas did not oppose the AG's position on this point assuming the Commission agrees with the AG and Staff that the utility's net pension asset not be included in rate base.

(iv) Commission Analysis and Conclusion

The Commission adopts the intercompany billing lead proposed by Staff and the AG, and the Commission declines to include the utility's net pension asset in rate base, as discussed below.

b. Other Post-Employment Benefits Expense Lead

(i) Nicor Gas' Position

The Company proposes assigning its OPEB expense a zero-expense lead for the same reasons supporting Nicor Gas' proposal to assign the pension expense lead a zero-expense lead time. Nicor Gas Ex. 30.0R at 10. The Company notes that no Staff or Intervenor witness disputes Nicor Gas' proposal to include its OPEB liability in the Company's revenue requirement as a reduction to rate base. Nicor Gas notes that AG witness Effron first proposed setting the Company's OPEB expense lead based on actual payment data, and he later revised his proposal to set Nicor Gas' OPEB expense lead at the Company's employee benefits lead. Nicor Gas argues that Mr. Effron significantly changed his recommendation but, nonetheless, that the Company refuted both recommendations through the testimony of its witnesses.

Nicor Gas argues that the AG's reliance on the Commission's prior Order in Docket Nos. 14-0224/14-0225 (Cons.) – a rate case involving North Shore Gas Company ("North Shore Gas") and Peoples Gas – is misplaced because the Commission did not make a specific finding on the utilities' proposals to set their OPEB expense leads at zero days. Rather, the Commission in that docket agreed with Staff's proposal to use an OPEB payment date in December, rather than January, as had been proposed by the utilities, and adopted Staff's OPEB expense lead calculations in lieu of the OPEB expense leads proposed by the utilities.

Nicor Gas also argues that its proposal to assign a zero expense lead to the Company's OPEB Expense should be analogized to a prior ComEd rate case wherein the Commission found:

The evidence shows that ComEd's pension expense has been applied as a reduction to ComEd's pension asset and that the OPEB expense is included as a component of operating reserves, which reduces rate base. Because these amounts are therefore already accounted for in ComEd's formula rate and revenue requirements, the Commission concludes that applying Staff's proposed payment lead of 203.24 days for pension and OPEB

expense would improperly result in a double count reduction to ComEd's rate base.

Commonwealth Edison Co., Docket No. 14-0312, Order at 10 (Dec. 10, 2014).

The Company disagrees with the AG's argument that, because Nicor Gas is not a "participating utility" under EIMA, the Commission's findings in Docket No. 14-0312 are inapplicable to this matter. Nicor Gas states that this argument is a red herring for two reasons. First, the determination of the appropriate CWC expense lead time is entirely unrelated to whether a utility is otherwise subject to EIMA. Second, the discussion of EIMA in Docket No. 14-0312 is contained in a section of that order summarizing ComEd's position, not in the Commission's Analysis and Conclusions. The Company argues that the AG fails to identify any findings by the Commission in Docket No. 14-0312 that differentiate appropriate OPEB expense leads for EIMA participating utilities versus non-participating utilities.

The Company argues that the Commission should reject the AG's proposal and assign Nicor Gas' OPEB Expense a zero-expense lead. However, if the Commission ultimately determines that it should assign the OPEB Expense a lead value other than zero, then the Company does not object to the Commission setting the OPEB Expense lead at Nicor Gas' employee benefits lead.

(ii) AG's Position

The AG requests that the Commission approve the OPEB expense lead days as proposed by AG witness Effron rather than the zero-expense lead days proposed by Nicor Gas. Company witness Morley stated that Nicor Gas considers use of the other employee benefit expense lead days to be a reasonable basis for OPEB expense in the calculation of CWC if the Commission accepts the proposal of Mr. Effron. Nicor Gas Ex. 30.0R at 10.

The AG states that Mr. Morley summarized Company witness Hengtgen's argument that the accrued OPEB expenses and any routine cash payments associated with OPEB expense are already included in rate base since the OPEB liability is included as a deduction to rate base and including it again would be in effect double counting the accrued expenses impact on rate base. Nicor Gas Ex. 16.0 at 24. However, according to the AG, Nicor Gas' argument is contrary to the Commission's decisions in prior cases on this issue.

The AG points out that in the Commission's Order in North Shore and Peoples Gas' most recent rate cases, Docket Nos. 14-0224/14-0225 (Cons.), the Commission concluded that an OPEB expense lead should be reflected in the CWC calculation while also reducing rate base for the OPEB liability. AG Ex. 3.0 at 5.

Nicor Gas claims that that the Commission's Order approving zero-lag days for OPEB in the CWC calculation in the formula rate proceeding for ComEd in Docket No. 14-0312 supports its position. The AG responded that the Order described why the treatment of the OPEB lead for ComEd differed from the treatment of the OPEB lead for North Shore and Peoples Gas in the Commission's Order in Docket Nos. 12-0511/12-0512 (Cons.). ComEd's OPEB accrued expense amounts and cash payments were fully accounted for in the revenue requirement under formula rates, pursuant to

ComEd's status as a participating utility under EIMA. North Shore and Peoples Gas are not participating utilities under EIMA, unlike ComEd. According to the AG, therefore, the ComEd 2014 Order does not support Nicor Gas' position with regard to the regulatory treatment of the OPEB expense lead in the CWC calculation.

(iii) Commission Analysis and Conclusion

The Commission agrees with Nicor Gas' proposal to assign a zero-expense lead to the Company's OPEB expense. The Commission also agrees that Nicor Gas should receive the same accounting treatment for OPEB as ComEd received in Docket No. 14-0312. The fact that Nicor Gas is not a participating utility under EIMA is not relevant to the consideration of OPEB expense – there is no language in Section 16-108.5 of the Act that treats OPEB expenses differently for participating utilities. The Commission's rationale for setting a zero expense lead to avoid double counting a reduction in rate base in Docket No. 14-0312 is reasonable for the facts of this case. Therefore, the AG's proposal is not adopted.

3. Net Pension Asset

a. Nicor Gas' Position

Nicor Gas states that, although the Commission has previously considered utility requests to include their net pension asset in rate base, the Commission should not treat those decisions as precedential, and must base its decision on the facts before it in this proceeding. As a result, the Company argues that the Commission should approve Nicor Gas' proposal to include its net pension asset in rate base because it provides a direct and measurable benefit to Nicor Gas' customers.

Nicor Gas explains that it established its pension plan in 1954 to provide eligible Company employees with a pre-defined fixed income upon their retirement. Nicor Gas witness Matthew Kim, Vice President and Controller for Southern Company Gas, testified that these future retirement benefits create a pension obligation, which the Company must fund up to a certain percentage in accordance with the applicable pension plan rules. Nicor Gas Ex. 17.0 at 4. Nicor Gas records the pension obligation as a liability on its books and subsequently incurs an equivalent Pension Expense, which customers have historically funded through base rates. The Company may choose to: 1) partially fund its pension plan up to the minimum required percentage, thereby reducing the pension obligation; 2) fully fund the pension plan, thereby eliminating the pension obligation; or 3) overfund the plan, thereby creating an asset. The Company states that at present, its pension plan is overfunded, creating a net pension asset of \$92 million, which is comprised of the 2018 simple average balance of the Company's gross pension asset in the amount of \$152 million offset by \$60 million in ADIT. Nicor Gas Ex. 4.0 at 3-5.

Nicor Gas argues that the history and characteristics of its pension plan and contributions thereto support Nicor Gas' proposal to include its net pension asset in rate base. The Company explains that, historically, there have been three sources of funding for the pension obligation: 1) the Company's customers, through the Pension Expense in base rates; 2) Nicor Gas shareholder contributions to the plan; and 3) appreciation of the plan's investments. To date, the Company has contributed a

cumulative total of \$136 million to its pension plan. Nicor Gas Ex. 4.0 at 8; Nicor Gas Ex. 17.0 at 2. However, Nicor Gas has shown a net pension asset on its books since 1995. As a result, Company customers have not contributed to Nicor Gas' pension plan through a pension expense since 1995. Additionally, the Company states that it has provided pension expense credits to its customers since 1995, totaling approximately \$116 million, which is 85% of the total amount that customers have contributed to the pension plan since its inception in 1954. Nicor Gas avers that these pension expense credits have provided a benefit to customers in the form of reduced rates. Nicor Gas Ex. 17.0 at 4.

The Company argues that, contrary to Staff and Intervenor assertions, customers could not have created a pension asset because the pension expense included in base rates was only designed to recognize in earnings the amount of money required to fund the pension trust to the level equivalent to the current pension liability on the Company's books. Put another way, ratepayer contributions never exceeded the Company's pension liability and therefore never created an asset. Nicor Gas Ex. 17.0 at 4. The Company also notes that, since Nicor Gas customers have not been required to contribute to the Company's pension plan since 1995—as a result of the net pension expense credit—the value of the gross pension asset included in the net pension asset could only have been funded by Company-raised capital, market appreciation, or a combination of the two.

Additionally, the Company argues that, even if customer contributions created the net pension asset, nearly all of those funds have been returned to customers in the form of pension expense credits. Nicor Gas asserts that no Staff or Intervenor witness presented any evidence that reconciled the \$152 million gross pension asset included in the net pension asset with either: 1) the lack of customer contributions to the Company's pension plan since 1995; or 2) Nicor Gas' refund to its customers of \$116 million of the total \$136 million lifetime pension plan contribution. Nicor Gas Ex. 31.0 at 2.

The Company argues that the Commission should analogize Nicor Gas' requests to include its net pension asset in rate base to its proposal to include its OPEB liability in rate base. Nicor Gas witness Kim testified that, as the Company's OPEB liability will serve to reduce rate base, the net pension asset should serve to increase rate base. Nicor Gas argues that this so-called "symmetry argument" has been accepted by other regulatory commissions in other jurisdictions and is consistent with ratemaking principles. Nicor Gas Ex. 4.0 at 7-9.

Based on this evidence, Nicor Gas requests that the Commission approve the Company's proposal to include its net pension asset in the Company's test year rate base.

b. Staff's Position

Staff witness Trost proposed an adjustment to reduce rate base by a net \$92.168 million to exclude the Company's pension asset, since it was funded by ratepayers. This testimony by Ms. Trost is significant because, for ratemaking purposes under Illinois law, a public utility may not receive a return on investment from ratepayers for ratepayer-supplied funds. City of Alton v. Ill. Commerce Comm'n, 19 Ill. 2d 76, 85-6, 91

(1960); DuPage Utility Co. v. Ill. Commerce Comm'n, 47 Ill. 2d 550, 554 (1971). See also, Bus. and Prof'l People for the Pub. Interest v. Ill. Commerce Comm'n, 146 Ill. 2d 175, 258 (1991) ("BPI II"). The Commission made this same determination in Nicor Gas' last three rate cases, and the facts remain unchanged in this docket. The Company has presented no new different evidence to support inclusion of the pension asset in rate base; thus, there is no reasonable basis to support the Company's position that shareholders are now entitled to a return on the pension asset. Ratepayers, not shareholders, funded the net pension asset. Staff Ex. 2.0 at 4.

Staff notes that Nicor Gas witness Daniel Yardley discusses the pension asset as if it were funded by shareholders. Id. However, the Company's description of the pension asset in this case does not comport with the Commission's orders in Docket Nos. 08-0363, 04-0779 and 95-0219. In those dockets, the Commission rejected the same argument made by Mr. Yardley based on the same basic facts that the Company presents in the instant proceeding. In Docket No. 95-0219, the Commission found:

...the proposal to eliminate the net Pension Asset from rate base is consistent with past Commission orders which found that the overfunded pension asset was created from ratepayer supplied funds... [.]

N. Ill. Gas Co., Docket No. 95-0219, Order at 9 (Apr. 3, 1996). Similarly, in Docket No. 04-0779, the Commission found:

Nicor has not presented any additional evidence since the 1996 Order to show why the Commission should arrive at a different conclusion [about the pension asset] now. **It remains true that the pension asset was created by ratepayer-supplied funds, not by shareholder-supplied funds...**Therefore, the Commission finds no reason to change the treatment of the pension asset.

N. Ill. Gas Co., Docket No. 04-0779, Order at 23 (Sept. 20, 2005) (emphasis added) ("2004 Rate Case Order"). Finally, in Docket No. 08-0363, the Commission found:

The Commission finds that **the facts have not changed** since the time these two Orders issued and adopts the Staff and AG/CUB's proposal to remove \$142,044,000 from rate base.

N. Ill. Gas Co., Docket No. 08-0363, Order at 18 (Mar. 25, 2009) (emphasis added) ("2008 Rate Case Order").

Staff argues that the basic facts in this case remain the same as the three prior Nicor Gas rate cases. The Company has presented no evidence to support including the pension asset in rate base; thus, there is no reasonable basis to support the Company's position that shareholders are now entitled to a return on the pension asset.

Staff states that the pension asset is a cumulative balance from previous years. The pension asset that Nicor Gas seeks to include in rate base in this case includes the cumulative transactions that took place since its pension plan began. The Company makes in this proceeding the same assertions it did in the last three cases and presents no new evidence that the funds contributed in the past were not provided by ratepayers. There have been no additional contributions required of or provided to the pension fund

by the Company since 1995 (Staff Ex. 2.0, Attach. A, 2) which is well before Nicor Gas' last rate case, and nothing has changed about how the pension was funded. Further, the Company's projected pension contributions for 2017 and 2018 are zero given the overfunded status of its pension trust fund. Id. As noted above, the Commission has analyzed the Company's pension asset three prior times with a fact pattern similar to that in this proceeding and concluded such pension asset was supplied by ratepayers and therefore did not merit inclusion into rate base. Staff Ex. 2.0 at 5-6.

Staff notes that a pension credit results when the Company's expected return on its assets exceeds the service and interest costs of the period, as well as prior period amortizations of gains or losses. Stated differently, this means that the Company has earned more money in its pension trust fund than it has incurred obligations for its pension trust fund. Although the pension credit reduced past revenue requirements, the pension credit did not take money away from the Company or the shareholders. To suggest that the Company funded the pension asset since ratepayers previously rightfully received pension credits is illogical and misrepresents the facts. Staff Ex. 7.0 at 5. The Commission has previously recognized that pension credits were appropriate.

In its 2004 rate case, the Company argued that, at a minimum, the pension credit should not be deducted from operating expenses in computing the revenue requirement. 2004 Rate Case Order at 21. However, the Commission rejected this position and found:

Therefore, the Commission finds no reason to change the treatment of the pension asset. The Company acknowledged that, due to the overfunded status of the pension plan, it was not required to contribute to the pension trust from 1997 through 2003. [Cite omitted]. **The pension credit is an item that Nicor will realize in the test year. The Commission agrees with Staff that ratepayers should not be denied the benefits associated with the previous overpayment for pension expense which they funded.**

2004 Rate Case Order at 23 (emphasis added).

The Commission has previously denied inclusion of a pension asset in rate base on the basis that it was not reasonable to allow the shareholders a return on ratepayer supplied funds. In Docket Nos. 09-0166/09-0167 (Cons.), the Commission denied inclusion of Peoples Gas' pension asset in rate base, since there was no evidence in the record it was created with shareholder funds:

The Utilities have given us no reason to overturn our decision from their last rate case. Although the Utilities state that the pension asset was created with shareholder funds, no evidentiary support was provided. **The Commission finds no support in the record to allow for the inclusion of Peoples Gas' pension asset in rate base which in turn would allow shareholders to earn a return on ratepayer supplied funds.**

N. Shore Gas Co. and The Peoples Gas Light and Coke Co., Docket Nos. 09-0166/09-0167 (Cons.), Order at 36 (Jan. 21, 2010) (emphasis added). The Commission's ruling on this issue was upheld by the Illinois First District upon appeal. People ex rel. Madigan v. Ill. Commerce Comm'n, 2011 IL App (1st) 100654 (2011) ¶¶ 69, 71.

The Commission again denied inclusion of the pension asset in the subsequent three North Shore/Peoples Gas rate cases. See *generally*, N. Shore Gas Co. and The Peoples Gas Light and Coke Co., Docket Nos. 11-0280/11-0281 (Cons.), Order at 33 (Jan. 10, 2012); N. Shore Gas Co. and The Peoples Gas Light and Coke Co., Docket Nos. 12-0511/12-0512 (Cons.), Order at 90 (Jun. 18, 2013); N. Shore Gas Co. and The Peoples Gas Light and Coke Co., Docket Nos. 14-0224/14-0225 (Cons.), Order at 49 (Jan. 21, 2015).

The Commission has also twice declined to include a pension asset in rate base for Illinois-American Water Company ("IAWC"). In Docket No. 11-0767, the Commission ruled that IAWC's proposal to include a pension asset in rate base was not substantively different than those the Commission has considered, and rejected, in past rate case decisions. Ill.-American Water Co., Docket No. 11-0767, Order at 8 (Sept. 19, 2012). In Docket No. 16-0093, IAWC attempted to receive a debt return on its pension asset. The Commission denied the adjustment, citing not only IAWC's past case history and the fact that no new facts were provided in Docket No. 16-0093, but also noting the following:

It is well-established law that the Commission is not bound by precedent and is required to look at the facts of each case to make a decision. *Mississippi Fuel Corp. et al v. Ill. Commerce Comm'n*, 1 Ill.2d 509, 513 (1953). While the Commission is not bound by precedent, when the Commission deviates from past practices it must articulate a reasoned basis to do so. *Citizens Utility Bd. v. Ill. Commerce Comm'n*, 166 Ill.2d 111, 132 (1995). Any departure by the Commission from prior orders or decisions must not be arbitrary and capricious. *United Cities Gas Co. v. Ill. Commerce Comm'n*, 235 Ill.App.3d 577, 591 (4th Dist. 1992). Moreover, "...while ordinarily an administrative action taken pursuant to statutory authority is entitled to great deference, an agency action that represents an abrupt departure from past practice is not entitled to the same degree of deference by a reviewing court." *Commonwealth Edison Co. v. Ill. Commerce Comm'n*, 180 Ill. App.3d 899, 909 (1st Dist. 1988). **The Commission cannot find any new facts provided by IAWC which warrant a departure from its normal practice in this area.**

Ill.-American Water Co., Docket No. 16-0093, Order at 12-13 (Dec. 13, 2016) (emphasis added).

Further, in Docket No. 14-0066, the Commission ruled against MidAmerican Energy Company ("MidAmerican") when it proposed to include a pension asset in rate base, because the Company failed to show the pension asset was funded by anything other than ratepayer funds. The Commission stated in part:

As Staff notes, prior Commission decisions denied inclusion of prepaid pension asset because they were created by ratepayer supplied funds. In the current proceeding, rather than show the funds supplying the pension asset were from a source other than ratepayer funds, **MidAmerican attempts to redefine the Commission's definition of ratepayer supplied funds.** MidAmerican argues that because the Company must finance the pension asset as a matter of law and normal business operations, MidAmerican's financing responsibility is not based on ratepayer funding. This argument is not persuasive.

The Commission notes that the FERC Order is not binding on the Commission in this proceeding; however, the Commission may look to FERC Orders for guidance. Nevertheless, even recognizing the FERC accounting treatment discussion, Staff is correct in that **the Company failed to show that the accumulated pension funds that generated the excess income earned over the net periodic pension cost, i.e. what generates the reduction in pension expense, is not from ratepayer supplied funds.**

MidAmerican Energy Co., Docket No. 14-0066, Order at 12 (Nov. 6, 2014) (emphasis added). Nicor Gas presents no new different evidence regarding the pension asset in this proceeding and therefore, there is no basis to warrant an abrupt departure from past Commission practice. Staff Ex. 2.0 at 7-12.

Staff points out that the Company states that, if it has a pension liability, as is the case with OPEB, that liability serves to reduce rate base and "conversely, a Net Pension Asset serves to increase rate base" ("symmetry argument"). Nicor Gas Ex. 4.0 at 7. This "symmetry argument" to include a pension asset in rate base has no bearing on the proper exclusion of an OPEB liability from rate base. OPEB liabilities represent other post-employment benefits that had not been paid out to the OPEB trust by the end of the year but for which the utility has already received recovery of from rates. Rate base is properly reduced by these OPEB liabilities to recognize that such costs are already recovered from ratepayers by their inclusion as an operating expense. It would not be reasonable to allow shareholders a return on this cost-free source of capital to the Company. The Company's symmetry argument does not take this into account. The Commission has also rejected the Company's symmetry argument in the past.

Staff states that in Docket Nos. 07-0241/07-0242 (Cons.), both Peoples Gas and North Shore excluded their OPEB liabilities from rate base, i.e., neither utility reduced rate base for the OPEB liabilities. Peoples Gas also had a pension asset, which it did not include in rate base. Peoples Gas similarly argued for symmetrical treatment; that is, excluding both its pension asset and OPEB liability from rate base. The Commission instead found that the pension asset should be excluded from rate base, and that the OPEB liabilities should be reflected as a reduction to rate base:

The Commission agrees with the positions asserted by GCI and Staff. Their arguments are persuasive and fully supported by the evidence. Further, they have each established that the treatment we are being urged to assign to this item today, is the same the treatment that we adopted in a

number of previous decisions. On all these grounds, **the Commission accepts that a rate base deduction of \$7,094,000 (\$4,074,000 net of related deferred taxes) is required for the North Shore accrued OPEB liability and a rate base deduction of \$55,653,000 (\$31,570,000 net of related deferred taxes) is required for the Peoples Gas accrued OPEB liability in the determination of the Utilities' rate bases.** Further, we note that **the underlying rationale for these adjustments is that such funds are supplied by ratepayers and not by shareholders such that shareholders are not entitled to earn a return on these funds.** Accordingly, the undisputed record showing that Peoples Gas and North Shore contributed \$15,278,614 and \$1,862,247, respectively, to the pension plans during the test year, does not change the treatment of the OPEB liability. Nor are we convinced that such contributions should impact shareholders, given that these funds were provided by ratepayers through the collection of utility revenues. We observe no discussion of or opposition to this particular recalculation that the Utilities propose on basis of their contribution, however, it appears to the Commission that recognizing these contributions is inconsistent with, the theoretical basis that we are applying here, i.e., these contributions are ratepayer-funded.

N. Shore Gas Co. and The Peoples Gas Light and Coke Co., Docket Nos. 07-0241/07-0242 (Cons.), Order at 36 (Feb. 5, 2008) (emphasis added).

The Commission ruled in the same manner in the last three North Shore/Peoples Gas rate cases. N. Shore Gas Co. and The Peoples Gas Light and Coke Co., Docket Nos. 11-0280/11-0281 (Cons.), Order at 33 (Jan. 10, 2012); N. Shore Gas Co. and The Peoples Gas Light and Coke Co., Docket Nos. 12-0511/12-0512 (Cons.), Order at 90 (Jun. 18, 2013); N. Shore Gas Co. and The Peoples Gas Light and Coke Co., Docket Nos. 14-0224/14-0225 (Cons.), Order at 49 (Jan. 21, 2015).

Staff states that the Company continued to assert its “symmetry argument” in rebuttal testimony (Nicor Gas Ex. 17.0 at 3), not addressing the orders discussed above. Rather, Nicor Gas appears to rely on decisions in other regulatory commissions where its affiliates operate, which do not directly apply. *Id.* at 4. The Georgia proceeding approved an alternative form of regulation. The Virginia cite pertained to the effect of the pension asset or liability on the cash working capital calculation, not inclusion in rate base. The New Jersey cite pertained to a stipulation. Staff Ex. 7.0 at 6.

c. AG's Position

The AG asks that the Commission adopt AG witness Effron's proposed adjustment to remove the prepaid pension asset from rate base. Staff witness Trost also recommended that the Company's pension asset be removed from rate base because the pension asset was not provided by shareholder supplied funds. Staff Ex. 7.0 at 2-3.

The AG explains that the prepaid pension asset reflects contributions to the pension fund exceeding periodic pension cost, or pension income, accrued pursuant to the Statement of Financial Accounting Standards 87. The AG noted that in Nicor Gas'

last three rate cases, Docket Nos. 95-0219, 04-0779, and 08-0363, the Commission rejected the Company's request to include the prepaid pension asset in rate base. In addition, the Commission has consistently rejected the inclusion of a pension asset in rate base in North Shore's and Peoples Gas' last rate case – Docket Nos. 14-0224/14-0225 (Cons.) – and IAWC's recent rate case – Docket No. 16-0093. AG Ex. 1.0 at 12-13.

Company witness Matthew Kim claimed that customer contributions did not fund Nicor Gas' net pension asset since customers have received a net pension expense credit since 1995. According to Mr. Kim, this means that the net pension asset should be included in rate base. Nicor Gas Ex. 17.0 at 2-3. The AG responds that a pension credit results when the Company's expected return on its assets exceeds the service and interest costs of the period, as well as prior period amortizations of gains and losses. This means that Nicor Gas' pension trust earned more than was incurred to meet its obligations; it does not mean that the Company's investors funded the pension asset. Nicor Gas has not made any pension contributions since 1995. Staff Ex. 7.0 at 3-5.

The AG concludes that Nicor Gas presented no compelling reasons for the Commission to change the treatment of the prepaid pension asset that has been consistently applied in Nicor Gas' previous rate cases as well as other Illinois utilities' rate cases. The Commission should come to the same conclusion as it did in those many prior cases and reject Nicor Gas' suggestion that it do otherwise in this proceeding.

The AG urges that the Commission adopt its adjustment to remove the prepaid pension asset and related accumulated deferred income taxes from rate base as shown on AG Schedule B-2 attached to the AG's Initial Brief. The net effect of this adjustment is to reduce Retirement Benefits, Net by \$148,521,000 and related accumulated deferred income taxes \$57,867,000, for a net reduction to the Company's rate base of \$90,654,000.

d. IIEC-CUB's Position

IIEC-CUB support the positions of the AG and Staff regarding the net pension asset. Both AG witness Effron and Staff witness Trost recommend that the Company's pension asset be removed from rate base because the pension asset was not provided by shareholder supplied funds. Staff described in detail numerous prior Commission decisions with respect to Nicor Gas and other Illinois utilities where the Commission recognized that pension credits were inappropriate. IIEC-CUB point out that Nicor Gas has made the same arguments here as in previous rate cases in which the request for a pension asset was denied (Staff Ex. 2.0 at 5-6), and Nicor Gas does not even address these prior cases. IIEC-CUB agree with Staff and the AG that Nicor Gas has presented no evidence distinguishing its current request for inclusion of a pension credit from cases previously decided by the Commission, and therefore there is no reason for the Commission to depart from its established findings on this issue now. Under these circumstances, IIEC-CUB conclude that the Commission should reject Nicor Gas' request to include a pension asset in rate base.

e. Commission Analysis and Conclusion

The Company has a pension asset in the amount of \$92 million and seeks its inclusion in rate base under the theory that it was created by shareholder-supplied funds, because ratepayers have not contributed to the pension fund since prior to 1995. Staff, the AG and IIEC-CUB point out that the Commission has rejected this argument in Nicor Gas' last three rate cases, as well as numerous other Article IX rate cases with similar facts, discussed at length above. The Company argues that the Commission should "not treat those decisions as precedential, and must base its decision on the facts before it in this proceeding" because the pension asset "provides measurable benefits to ratepayers." However, if the Commission deviates from its past rulings, it must explain and give reasons for its departure from an established past practice. Furthermore, Commission decisions are entitled to less deference where it departs from past practices. City of Naperville, Docket No. 03-0779, Order at 38 (Sep. 9, 2004); Citizens Utility Bd. v. Ill. Commerce Comm'n, 683 N.E. 2d 938 (1st Dist. 1997). Nicor Gas has not demonstrated sufficient evidence to show that the pension asset is comprised of any shareholder funds. Therefore, the Commission declines to include the Company's pension asset in rate base.

4. Certain Gas Main Extension Projects

a. Nicor Gas' Position

Nicor Gas explains that included in the Company's test year rate base are costs Nicor Gas incurred in extending its system to provide gas service to two communities. First, Nicor Gas invested \$5,858,848 to construct approximately 50 miles of new gas distribution main and related facilities to serve the Lake Carroll subdivision in Carroll County, Illinois. Nicor Gas Ex. 32.0 at 15. Second, Nicor Gas invested \$1,129,828 to construct approximately five and one-half miles of new gas distribution main and related facilities to serve customers in and near the town of Fairdale, located in DeKalb County, Illinois, as part of the rebuilding efforts after a tornado destroyed or significantly damaged most structures. Nicor Gas also has incurred initial costs associated with its plans to construct approximately 10 miles of new gas distribution main near the towns of Sheridan and Serena in LaSalle County, Illinois, but these costs are not included in rate base. Nicor Gas Ex. 32.0 at 14.

Nicor Gas states that it presented support for the prudence and reasonableness of all the Company's investment in plant included in rate base, including the costs associated with the Lake Carroll and Fairdale main extension projects. Nicor Gas also points out that the Commission already has determined that the extension projects at issue are necessary to serve the public interest by issuing certificates of public convenience and necessity to construct, operate, and maintain each of these projects in conjunction with granting Nicor Gas the ability to serve the respective areas. N. Ill. Gas Co., Docket No. 13-0361, Order (Sept. 10, 2013); N. Ill. Gas Co., Docket No. 15-0510, Order (Mar. 23, 2016); N. Ill. Gas Co., Docket No. 15-0476, Order (Mar. 29, 2016).

Nicor Gas observes that IPGA concedes the prudence of the Company's construction costs associated with these projects because Nicor Gas provided testimony showing that the final construction costs of each project were either below the estimates provided in the approval proceedings, or where they exceeded estimates,

were justifiable. Accordingly, the prudence of the costs associated with the Company's gas main extension projects is uncontested.

Nicor Gas notes that, even though it now concedes the prudence of these costs, IPGA nevertheless maintains the position that the Commission should remove \$263,405 from the test year revenue requirement because Nicor Gas' system expansion through three projects allegedly was subsidized by existing customers. Nicor Gas argues that IPGA's proposal has no basis in the law or in fact, and is contrary to the application of sound regulatory policy. It also is contrary to public policy in this State in that IPGA's proposal would disincentivize Nicor Gas from constructing natural gas main extensions that directly lead to economic recovery and development as demonstrated, for example, by the Company's role in supporting the rebuilding of the community of Fairdale. Nicor Gas further states that IPGA's alleged concern about subsidies is nothing more than a veiled attempt to protect its members from competition, at the expense of customers who seek to have natural gas service, as the Commission itself recognized in another recent proceeding. See, e.g., N. Ill. Gas Co., Docket No. 15-0218, Order at 11 (Feb. 23, 2017) ("IPGA is concerned about more competition in the areas where propane or electric are currently the only options available for heating.").

To refute IPGA's positions, Nicor Gas states that it presented the testimony of operational and ratemaking policy experts who demonstrated why the Company's recovery in the test year rate base of the construction costs for main extension projects is completely consistent with basic tenets of utility ratemaking and the economics of natural gas distribution service. First, Nicor Gas witness Whiteside explained that the Company conducts an economic analysis associated with every main extension project. He further explained that, "[i]n determining whether a proposed project is economically feasible, the Company analyzes the expected incremental revenues to be provided to the Company's system over a period of twenty years." Nicor Gas Ex. 32.0 at 14. Mr. Whiteside also explained that given the timing of the in service dates for the Lake Carroll project (2014) and the Fairdale project (2015), the Company has received only a few years of incremental revenues from the new customers added to the Nicor Gas system due to these projects. Therefore, an insufficient amount of time has passed to achieve the offsetting of costs that inevitably will take place over the 20 year horizon that is incorporated within the Company's economic analysis.

Second, Nicor Gas witness Yardley provided the appropriate context for the notion of subsidization in the ratemaking process. Specifically, Mr. Yardley explained that one goal of ratemaking is fairness, which is accomplished through pricing services based on their underlying cost. Nicor Gas Ex. 36.0 at 17. While the elimination of subsidies contributes to fairness, some level of inter-class and intra-class subsidies typically exist in the rates of a LDC such as Nicor Gas. In fact, Mr. Yardley pointed out that all witnesses presenting testimony here concerning the proper allocation of Nicor Gas' requested increase in base revenues among rate classes acknowledge that the resulting rates continue inter-class subsidies due to the need to moderate revenue changes to individual rate classes. Mr. Yardley further explained that it is both reasonable and likely for subsidies to occur when customers initially are added to an LDC system, that the cost of serving incremental customers ultimately declines below

the average cost to serve other customers, and that revenues from customer growth reduce the costs recoverable from all customers. Nicor Gas Ex. 36.0 at 17, n. 2.

Finally, Nicor Gas states that IPGA fails to offer any applicable legal support for its proposal. Instead, IPGA points to Section 501.600(f) of the Commission's Rules, which does not apply in this rate case. Nicor Gas also states that the provision does not call for the hindsight analysis that IPGA asks the Commission to apply here after the Company has completed construction. Instead, it permits a utility that has not yet constructed a main extension to petition the Commission for a determination of the reasonableness of the extension. 83 Ill. Adm. Code 501.600(f).

Nicor Gas concludes that it has demonstrated the prudence of the costs associated with the main extension projects at issue and, therefore, it should be permitted to recover these costs incurred to provide service to customers.

b. IPGA's Position

IPGA intervened in this proceeding because Nicor Gas has filed several requests with the Commission in the past few years for authority to expand its delivery system to areas that had previously been too remote for the Company to economically serve. IPGA members provide service to many of the customers that Nicor Gas seeks to serve through these line extensions. While IPGA has no objection to Nicor Gas competing for their customers, it does not believe that Nicor Gas should be able to do so using subsidies from its ratepayers. IPGA therefore intervened in this proceeding in order to ensure that Nicor Gas demonstrates that its line extensions are economically viable on their own.

During the past several years the Commission has approved four delivery system extensions requested by Nicor Gas. The orders in three of those cases, Docket No. 13-0361 (Lake Carroll), Docket No. 15-0476 (Sheridan/Serena), and Docket No. 15-0510 (Fairdale), were entered before this case was filed. Nicor Gas' test year rate base, expenses and revenues include the impact of these three projects. The order in the fourth case, Docket No. 16-0579 (Deer Run Estates), was entered on April 19, 2017. In another proceeding impacting Nicor Gas' system expansion, the Commission approved Rider 33, which establishes an alternate procedure that can be used by a community to obtain an extension of the Nicor Gas delivery system. N. Ill. Gas Co., Docket No. 15-0218, Order (Feb. 23, 2017).

This rate proceeding is the first opportunity for the Commission to determine, based on actual line extension costs and customer connections, whether Nicor Gas' line extension projects are being subsidized by ratepayers. As stated by IPGA witness Mr. Aaron DeWeese: "The overriding economic principle should be that a line extension is economically justifiable when it can pay for itself." IPGA Ex. 1 at 3. The new customers served by these lines only paid 8.37% of the total estimated costs of the four new projects through up front deposits. Recovery of the remaining 91.63% would be the responsibility of all ratepayers. IPGA Ex. 1.0 at 5. Thus, the question of economic justification requires an analysis of whether the customers connected to the new lines provide sufficient revenue over the life of the lines to pay back that 91.63%.

Nicor Gas is requesting rate base treatment for the Lake Carroll, Sheridan/Serena, and Fairdale projects. Nicor Gas' schedules show that the total jurisdictional operating income from the new customers, offset by test year expenses from the system extensions, will be \$85,000. IPGA Ex. 2.1 at 1. The total rate base increase from the three projects during the test year will be \$4,427,000. IPGA Ex. 2.1 at 2-4; IPGA Ex. 2.0 at 4. Assuming Nicor Gas is awarded a rate of return of 7.87% (Part 285 71, Revised Schedule A2), then the revenue requirement will increase by \$348,405. Because the new customers are only providing net revenues of \$85,000, existing ratepayers will be subsidizing Nicor Gas' system expansion by \$263,405 during the test year and will continue to provide that subsidy until Nicor Gas' next rate case. IPGA Ex. 2.0 at 4. The subsidization will be larger because Nicor Gas has not broken out the increase in operation and maintenance expenses from its line extensions nor its eventual replacement costs. These are costs that the Commission has determined are relevant when deciding if a utility should be required to make a line extension under 83 Ill. Adm. Code 501.600(f), which requires that a utility should receive fair compensation "for its investment, operation, maintenance and replacement of the extension." Those elements should be part of any long term economic analysis of line extensions in this case. IPGA Ex. 1.0 at 6.

IPGA points out that Nicor Gas does not dispute that rates in the test year reflect a subsidy by ratepayers, but argues over time, they will be compensated. Thus, Nicor Gas witness Mr. Yardley testified that "it is both reasonable and likely for subsidies to occur when customers are initially added to an LDC system . . . Over time, the cost of serving incremental customers declines below the average cost to serve other customers leading to a subsidy in the opposite direction." Nicor Gas Ex. 36.0 at 17. Nicor Gas did not provide any evidence showing when, if ever, this reverse in subsidy would occur and whether it would be sufficient to overcome the initial subsidy by existing ratepayers.

IPGA also notes that Nicor Gas argues that because the Commission granted its requests under Section 8-406 of the Act for certificates of convenience and necessity to begin the construction of these line extensions, the issue of whether they should be placed in rate base and fully recovered has already been decided. Nicor Gas ignores the fact that the Commission did not make a rate base determination in those cases and that modifying rates to reflect that new construction requires Commission approval in a rate proceeding brought under Article IX of the Act. IPGA explains that the Act requires that a utility placing plant in rate base demonstrate that costs were prudently incurred and that the plant is used and useful: "The Commission, in any determination of rates or charges, shall include in a utility's rate base only the value of such investment which is both prudently incurred and used and useful in providing service to public utility customers." 220 ILCS 5/9-211.

That determination of prudence and used and useful cannot be made in a proceeding initiated under Section 8-406 for a certificate of public convenience and necessity. In New Landing Utility, Inc. v. Ill. Commerce Comm'n., 58 Ill. App. 3d 868 (2nd District, 1977), the Appellate Court reviewed the provisions in the previous version of the Act for issuing certificates of public convenience and necessity and for approval of rates and stated:

In light of these rather extensive provisions we feel that it was clearly the legislature's intent that the Commission deal with rates when petitioned under one of the above described sections of the Act and not when petitioned under section 55 (Ill. Rev. Stat. 1973, ch. 111 2/3, par. 56) for a certificate of public convenience and necessity.

New Landing, 58 Ill.App.3d at 872.

IPGA states that this Article IX rate proceeding is the appropriate forum to decide if, pursuant to Section 9-211, Nicor Gas' line extensions are used and useful, providing actual figures of current and anticipated new customers and the projected revenues from those new customers compared to the projected lifetime costs of the lines. There is no question that rates will reflect a subsidy by existing ratepayers at least until the next rate case and possibly beyond. Nicor Gas has not provided any evidence of when, if ever, that subsidy will end and whether ratepayers will eventually be compensated for that subsidy through increased revenues from new customers connected to those lines. Because Nicor Gas has failed to demonstrate that its line extension projects will not be subsidized by existing customers, IPGA recommends that the Commission reduce the rates approved in this proceeding by the amount of \$263,405, adjusted to reflect the final rate of return approved by the Commission.

c. Commission Analysis and Conclusion

Nicor Gas incurred costs in extending its system to provide gas service to two communities in Carroll and LaSalle Counties. The Commission previously determined that it was in the public interest for Nicor Gas to make the necessary investments to serve the Lake Carroll, Fairdale, and Sheridan-Serena areas when it granted Nicor Gas certificates of public convenience and necessity to construct, operate, and maintain facilities in those areas.

IPGA asks the Commission to remove \$263,405 from the revenue requirement because the costs of these projects were subsidized by existing customers and urges the Commission to determine whether the line extensions "paid for themselves." Moreover, IPGA states that it is the Company's responsibility to show that the new extensions are used and useful. IPGA cites to Section 9-211 of the Act and New Landing to point out that the determination of prudence and used and useful should be in this docket.

The Commission agrees with Nicor Gas that no party contests the prudence of the Company's construction costs because Nicor Gas provided testimony showing that the final construction costs of each project were either below the estimates provided in the approval proceedings, or where they exceeded estimates, were justifiable. As for whether the Company has shown that the extensions are used and useful, the Commission finds the testimony of Nicor Gas witnesses Yardley and Whiteside demonstrate that the projects are too new to achieve the proper offsetting of costs, which would typically take close to 20 years. The Commission evaluates investments over the long-term, not under a short-term analysis as IPGA suggests. Accordingly, the Commission declines to adopt IPGA's adjustment.

5. 2017 Qualified Infrastructure Plant Amounts

a. Nicor Gas' Position

Nicor Gas presented evidence that the rate base component of its proposed 2018 test year revenue requirement included, for the first time, plant investments subject to the Company's Rider QIP. Nicor Gas Ex. 3.0 at 14. Nicor Gas witness Morley explained that the Company proposed to transfer all Rider QIP investments made through December 31, 2017 to the Gross Plant component of Nicor Gas' test year rate base. Staff witness Trost requested that Nicor Gas include in its rebuttal and surrebuttal testimony a schedule reflecting: (1) the most recent 2017 actual QIP amounts that the Company is including in rate base; (2) any forecasted 2017 amounts that the Company also is including in rate base; and (3) the sum of (1) and (2), which should represent the amounts at the end of the QIP forecast period used in the Company's rate case. Staff Ex. 2.0 at 23. Nicor Gas complied with Ms. Trost's request and included the requested schedules in its rebuttal and surrebuttal testimony. Nicor Gas Ex. 16.0 at 17; Nicor Gas Ex. 30.0R at 5.

Nicor Gas explains that Ms. Trost and the Company are in agreement that the Commission should include in the Final Order in this docket an ordering paragraph that specifically identifies each of the 2017 QIP amounts to be included in base rates. Accordingly, Nicor Gas requests that the Commission include in the Findings and Ordering paragraphs in the Final Order the following language:

The 2017 QIP amounts included in base rates are comprised of Gross Plant of \$717,097,000, related accumulated depreciation of \$133,908, 942 (increase to Gross Plant), related accumulated deferred income taxes of \$156,705,580 (decrease to Gross Plant), and \$15,209,816 for annualized depreciation expense less annualized depreciation expense applicable to the plant being retired.

Nicor Gas further explains that Ms. Trost and the Company are in agreement that the prudence and reasonableness of the Company's 2016 and 2017 QIP costs be reviewed in the annual QIP proceedings. Nicor Gas Ex. 16.0 at 17; Nicor Gas Ex. 30.0R at 5; Staff Ex. 2.0 at 22. To that end, Ms. Trost recommends that the Commission include in the Findings and Ordering paragraphs in the Final Order the following language regarding the future review of QIP costs:

The Commission finds that the Company's 2016 and 2017 QIP costs included in rate base in this proceeding are subject to review in the annual QIP reconciliations proceedings and costs related to such 2016 and 2017 QIP are subject to refund for prudence and reasonableness adjustments in annual QIP reconciliation and future rate base proceedings.

Nicor Gas states that the AG argues for the first time in its Initial Brief that the Commission should not approve the Company's proposed ADIT figures related to its 2017 QIP amounts. Nicor Gas asserts that the AG fails to identify a single piece of testimony or exhibit prepared by its witnesses that supports the AG's proposal. Rather,

the AG improperly relies on a single statement in a workpaper that has not undergone expert analysis or verification. The Company avers that it provided its best estimate of the 2017 QIP amounts and also emphasizes that Staff accepted those estimates. Accordingly, Nicor Gas requests that the Commission reject the AG's proposal and approve the 2017 QIP amounts identified in Staff's proposed ordering paragraph.

b. AG's Position

The AG argues that the Commission should not accept the amounts for ADIT associated with the 2017 QIP as presented in Nicor Gas Ex. 20.2R. According to the AG, the ADIT balance presented on Nicor Gas Ex. 30.2R submitted in the Company's surrebuttal case changed from the balance presented on Nicor Gas Ex. 16.2 included in its rebuttal case. The Company provided no explanation or support for this change. As explained by the Company in a Note on Nicor Gas Exhibit 30.1R, WP B-2.1, when the balance of QIP in rate base is adjusted "the impact to accumulated deferred income taxes would have an offsetting impact to the Company's NOL by the same amount, resulting in a net impact to ADIT of zero." Thus, the updated balance of ADIT associated with 2017 QIP in Nicor Gas Ex. 30.2R should not change from the balance reflected on Nicor Gas Exhibit 16.2.

Nicor accuses the AG of raising this issue for the first time in its Initial Brief. Nicor added that AG did not raise this issue in testimony. The AG responds that Nicor Gas ignores the fact that the Company changed the ADIT associated with QIP in its surrebuttal testimony. Given that the procedural schedule offered the AG no opportunity to respond to the change in Nicor Gas' position in its surrebuttal testimony, Nicor Gas' argument is baseless.

The AG also argues that the 2017 QIP plant amounts would change if the Commission adopted the AG's proposal that Nicor Gas' AMI proposal be rejected. As an alternative to outright rejection of Nicor Gas' AMI position, the AG proposed that the Commission delay recovery of AMI investments by using a deferred recovery mechanism. The AG explained that if the Commission adopts the AG's deferral mechanism, overhead costs would continue to be allocated to AMI and the associated overhead would not be reallocated to other construction projects.

In addition, the AG requests that the Commission include in its Order in this case a finding that the inclusion of any QIP amounts in base rates (whether for 2017, 2018, or any other year) be conditional and subject to prudence review in ongoing or future QIP reconciliation cases.

c. Commission Analysis and Conclusion

The AG states that the Company provided no information as to why the ADIT amounts changed between rebuttal and surrebuttal. However, the Company explained its rationale for the change in Nicor Gas Exhibit 30.1R, WP B-2.1. As Nicor Gas points out, Staff accepted the Company's best estimates. The evidence demonstrates that Nicor Gas' QIP investments made through December 31, 2017 should be included in the test year rate base. The Commission finds that the Company's 2016 and 2017 QIP costs included in rate base in this proceeding are subject to review in the annual QIP reconciliation proceedings and costs related to such 2016 and 2017 QIP are subject to

refund for prudence and reasonableness adjustments in annual QIP reconciliation and future rate base proceedings.

D. Recommended Rate Base

Upon giving effect to the determinations above, the Commission finds that the Company's rate base is hereby approved as shown in the rate base schedules attached as an Appendix to this Order.

V. OPERATING EXPENSES

A. Uncontested Issues

1. Invested Capital Tax Expense

Staff witness Ebrey proposed an adjustment to Nicor Gas' initial proposed Invested Capital Tax ("ICT") to reflect an incremental increase in the Company's proposed ICT based on the increase in operating income resulting from the rate increase the Company has requested in its rate filing. Staff Ex. 1.0 at 21. Nicor Gas accepted Ms. Ebrey's proposal and excluded ICT taxes in the calculation of the Gross Revenue Conversion Factor ("GRCF"). Nicor Gas Ex. 16.0 at 33. This adjustment is uncontested and is approved.

2. Advertising Expense

Staff witness Ebrey proposed a reduction to the Company's initial proposed Advertising Expense in the amount of \$18,000. Staff Ex. 1.0 at 22. AG witness Effron proposed a reduction to Nicor Gas' initial proposed Advertising Expense in the amount of \$16,000. AG Ex. 1.0 at 37. The Company accepted Ms. Ebrey's and Mr. Effron's proposals, but determined that a reduction in the amount of \$18,113 was appropriate. Ms. Ebrey and Mr. Effron acknowledged that Nicor Gas had accepted their proposals and did not object to the Company's calculation of the appropriate reduction. Nicor Gas Ex. 16.0 at 7. This adjustment is uncontested and is approved.

3. Miscellaneous Expense

Staff witness Ebrey and AG witness Effron both proposed a reduction to Nicor Gas' initial proposed Miscellaneous Expense in the amount of \$1,023,000 as a result of the Company's acknowledgement in discovery that the civic participation costs allocated from AGL Services Company should have been eliminated from Nicor Gas' cost of service. Staff Ex. 1.0 at 22; AG Ex. 1.0 at 37. Nicor Gas accepted this proposed adjustment and reduced its Miscellaneous Expense accordingly. Nicor Ex. 16.0 at 7. This adjustment is uncontested and is approved.

4. Lobbying Expense

Staff witness Ebrey and AG witness Effron proposed a reduction to Nicor Gas' initial proposed Lobbying Expense in the amount of \$124,000 to remove lobbying expenses based on Section 9-224 of the Act. Staff Ex. 1.0 at 22; AG Ex. 1.0 at 37. Nicor Gas accepted this proposed adjustment. Nicor Gas Ex. 16.0 at 7. This adjustment is uncontested, and it is approved.

5. Employee Benefits Expense

AG witness Effron proposed a reduction to Nicor Gas' initial proposed Employee Benefits Expense in the amount of \$1,581,000 as a result of the inadvertent overstatement of the Company's 2018 forecast of welfare and social benefits. AG 1.0 at 37. Nicor Gas accepted Mr. Effron's proposed adjustment. Nicor Gas Ex. 16.0 at 8. This adjustment is uncontested and is approved.

6. Uncollectibles Expense

Staff witness Ebrey proposed to adjust the uncollectibles percentage from 0.75% per the Company's proposal to 1.23% based on the most recent 5-year average of net write-offs of uncollectible accounts to more accurately reflect the accounts the Company has not collected. Nicor Gas accepted Ms. Ebrey's proposed adjustment. Nicor Gas Ex. 16.0 at 8. This adjustment is uncontested and is approved.

7. Charitable Contributions Expenses

In conformance with 83 Ill. Adm. Code Part 325, Nicor Gas presented evidence in support of the Company's charitable contributions reflected in Nicor Gas' revenue requirement. Nicor Gas Exs. 7.0-7.2. Staff witness Ebrey proposed a reduction to Nicor Gas' initial proposed Charitable Contributions Expense in the amount of \$55,000. Staff Ex. 1.0 at 14. Nicor Gas accepted Ms. Ebrey's proposed adjustment. Nicor Gas Ex. 16.0 at 9. This adjustment is uncontested, and it is approved.

8. Outside Professional Services Expense

AG witness Effron proposed a reduction to Nicor Gas' initial proposed Outside Services Expense Adjustment in the amount of \$262,000. AG Ex. 1.0 at 35. Nicor Gas accepted this proposed adjustment. Nicor Gas Ex. 16.0 at 10. This adjustment is uncontested and is approved.

9. Incentive Compensation Expense

AG witness Effron proposed an adjustment to eliminate a portion of Nicor Gas' initial proposed Incentive Compensation Expense based on his assertion that the costs are based on underlying financial goals and should not be recoverable in rates. AG Ex. 1.0 at 28. It is Nicor Gas' position that all of its incentive compensation costs are reasonable and represent one of the compensation component costs of attracting and retaining the talent necessary to ensure that the Company continues to provide safe and reliable service to its customers at a reasonable cost. Nicor Gas Ex. 20.0 at 3. In order to narrow the issues in this case, however, Nicor Gas agreed to withdraw its request to recover the portion of its incentive compensation costs that is based on financial performance. In particular, the Company made an adjustment to eliminate \$6,710,000 in Administrative and General Expense associated with Incentive Compensation Expense and also a \$156,000 reduction in taxes other than income. Nicor Gas Ex. 30.0R at 12. The Company also incorporated the impact to rate base for the capitalized portion of Incentive Compensation. These adjustments are reflected in Nicor Gas' revised proposed total revenue requirement.

AG witness Effron testified that Nicor Gas had resolved this issue by accepting his Incentive Compensation adjustment to the Company's test year revenue

requirement. AG Ex. 3.0 at 2. Staff witness Ebrey initially proposed an adjustment to the Company's Incentive Compensation Expense, but later accepted Mr. Effron's Incentive Compensation adjustment based upon additional support and justification provided by the Company. Staff Ex. 6.0 at 2. Similarly, IIEC-CUB witness Gorman withdrew his proposed adjustments to Nicor Gas' Incentive Compensation Expense based upon the Company's acceptance of Mr. Effron's Incentive Compensation adjustment. IIEC-CUB Ex. 3.0R at 51. Accordingly, Nicor Gas' proposed Incentive Compensation Expense, as revised in this proceeding, is not a contested issue and is therefore approved.

10. Interest Synchronization

Staff witness Ebrey and AG witness Effron proposed interest synchronization adjustments that were derivative of their other proposed adjustments. Staff Ex. 1.0 at 5; AG Ex. 1.0 at 36. While Nicor Gas witness Morley testified that the Company did not agree with Ms. Ebrey's and Mr. Effron's specific adjustments, Mr. Morley stated that the Company did not dispute Ms. Ebrey's and Mr. Effron's underlying methodologies in computing the interest synchronization adjustment. Nicor Gas Ex. 16.0 at 31. Ms. Ebrey acknowledged that the interest synchronization adjustments were derivative, and testified that it was "[her] belief that Staff and the Company agree that the final inputs will reflect the Commission conclusions on all issues." Staff Ex. 6.0 at 5. Mr. Effron did not address the issue of interest synchronization in his rebuttal testimony. Staff confirms that the final adjustment amount for interest synchronization will reflect the Commission's conclusions on all of the adjustments on the contested issues in this case. Staff Ex. 6.0 at 5. Accordingly, this issue is no longer contested.

11. Amount of Rate Case Expense

In conformance with the Commission's Rules, 83 Ill. Adm. Code Part 288, Nicor Gas presented evidence that its Rate Case Expense of \$5,196,500 is true and accurate, reasonable, reviewed and approved prior to payment, and not duplicative. Nicor Gas Exs. 3.5 and 27.0; Nicor Gas Ex. 30.0R at 14. To support this expense, Nicor Gas submitted a summary schedule identifying all of the compensation costs for which the Company seeks recovery, which the Company updated during the course of the proceeding. Nicor Gas Exs. 3.3, 16.3 and 30.3. Nicor Gas also presented as evidence true and accurate copies of invoices and other supporting documentation that the Company received from its outside counsel and third party experts for work performed in connection with this rate case. Nicor Gas Exs. 3.5, 16.4 and 30.4. As required by Section 288.30(f) of the Commission's Rules, Nicor Gas moved into evidence all updates and supporting documentation of the Rate Case Expense amounts the Company requests for recovery in rates. 83 Ill. Adm. Code 288.30(f).

No party disputed the amount of Nicor Gas' Rate Case Expense. Staff witness Ebrey testified that she had no issues with the Company's Rate Case Expense, and she further recommended that the Commission include a conclusion in its Order in this proceeding regarding the justness and reasonableness of the Company's Rate Case Expense. Staff Ex. 6.0 at 10.

The Commission has considered the estimated costs to be expended by Nicor Gas to compensate attorneys and technical experts to prepare and litigate rate case

proceedings and assesses that the amount included as the basis for Rate Case Expense in the revenue requirement of \$5,196,500 is just and reasonable pursuant to Section 9-229 of the Act. Therefore, Nicor Gas' Rate Case Expense of \$5,196,500 is approved.

B. Contested Issues

1. Rate Case Expense Amortization Period

a. Nicor Gas' Position

Nicor Gas proposes to recover its Rate Case Expense over a four-year amortization period. Nicor Gas Ex. 16.0 at 29. The Company adjusted its proposal to a four-year period after considering the direct testimony of Staff witness Ebrey and AG witness Effron. Staff Ex. 1.0 at 15; AG Ex. 1.0 at 34. In support of the four-year amortization period, Nicor Gas witness Morley explained that the interval since the Company's last rate case was the result of Nicor Gas' parent companies being the subject of two reorganizations, which impacted the Company's ability to file a rate case. Nicor Gas Ex. 30.0R at 13. Mr. Morley testified that a four-year amortization period for recovery of the Company's rate case-related costs was consistent with Mr. Effron's recommendation in his direct testimony that the amortization period should be no more than five years. AG Ex. 1.0 at 35. Staff witness Ebrey agreed that a four-year amortization period was appropriate. Staff Ex. 6.0 at 10.

Nicor Gas states that Mr. Effron modified his proposed amortization period in his rebuttal testimony from "no more than five years" to five years. AG Ex. 3.0 at 10. The Company argues that Mr. Effron improperly relies on a calculation of the intervals between Nicor Gas' last four rate cases, which includes intervals from rate cases more than 20 years ago. The Company asserts that the AG's calculation was performed in a vacuum that fails to consider the change in Nicor Gas' management philosophies concerning rate case intervals as well as the regulatory environment under which the Company now operates. Nicor Gas identifies its "Investing in Illinois" program and associated Rider QIP investments as significant factors that will impact the Company's rate case intervals going forward. The Company explains that, under Rider QIP, Nicor Gas will have to file a rate case to zero-out the investment cap in order to continue to invest in qualified system modernization projects. As a result, Nicor Gas requests that the Commission approve the Company's proposed four-year rate case expense amortization period.

b. Staff's Position

Staff proposed a 6-year amortization period for rate case expense based on the Company's historic frequency of filing rate cases as opposed to the 2-year amortization period proposed by the Company in its initial filing. Staff Ex. 1.0 at 15. In rebuttal testimony, the Company offered as its explanation for the delay of over 8 years since its last rate case filing that the conditions of past mergers prohibited rate case filings for defined periods. The Company offered a 4-year amortization period for rate case expense as a compromise in rebuttal testimony. Nicor Gas Ex. 16.0 at 29-30. Staff accepted the Company's rebuttal proposal based on the additional explanation provided. Staff Ex. 6.0 at 2.

c. AG's Position

The Company proposes to amortize its projected rate case expense of \$5.197 million over four years. The Company originally proposed an amortization period of two-years but modified its proposal to a four-year period in its rebuttal testimony. Nicor Gas Ex. 16.0 at 29.

The AG responds that although the four-year period is superior to Nicor Gas' original proposal, the AG continues to recommend a five-year amortization period. The Company's past history of filing rate cases does not support a four-year amortization.

The AG states that Nicor Gas' argument that the interval since the last rate case is longer than anticipated because the Company has been the subject of two reorganizations after the Company's last rate case (Nicor Gas Ex. 16.0 at 29-30) does not provide a sufficient basis for a shorter amortization period. The average time between rate case filings for the Company's most recent four rate cases is more than seven and one-half years. The AG's proposed amortization period of five years is already less than the Company's history of recent rate case filings. The AG concludes that the Company provided no substantive reason why a four-year amortization period should be accepted instead of a five-year amortization period. The AG adds that if the Company were to file its next rate case prior to the full recovery of the rate case costs incurred in this case, the Commission has generally allowed the recovery of the unamortized rate case expense in the succeeding rate case. Nicor Gas Ex. 16.0 at 29.

Based on the Company's history of filing rate cases, the AG recommends that rate case expense be amortized over a period of five years. Amortizing the rate case over five years results in annual amortization expense of \$1,039,000, which is \$260,000 less than the annual amortization expense reflected by the Company.

d. Commission Analysis and Conclusion

The Commission adopts the Company's revised proposal of a four-year amortization period for rate case expense. As stated above, the amount of rate case expense is uncontroverted, yet the Company and the AG disagree about the period of time over which the Company would collect the rate case expense amount from ratepayers. The Commission understands that Nicor Gas was barred from filing rate cases due to the conditions of the last two merger dockets, and finds the four-year period to be a reasonable compromise between the Company's original proposal of two years, and Staff's original proposal of six years.

2. Employee Level and Payroll Costs

a. Nicor Gas' Position

Nicor Gas proposes an increase of 117 full-time equivalent employees ("FTE") for its 2018 test year and argues that such increase is reasonable, necessary for the continued provision of safe and reliable gas service, and will be prudently incurred by the end of the 2018 test year. Nicor Gas Ex. 6.0 at 38. Nicor Gas maintains that the Company's proposed 2018 FTE increase is not only reasonable, but necessary to respond to significant demands facing the Company's workforce including, but not limited to, accelerated replacement of aging infrastructure, a changing federal and state regulatory landscape on pipeline safety, and an aging workforce, among others.

Nicor Gas explains that events around the country are reshaping the regulatory landscape on pipeline safety and creating additional demands on the Company's workforce in order to meet new or enhanced requirements. Nicor Gas points out that the Commission has directed Nicor Gas to work with Staff in implementing a Pipeline Safety Management System in line with the American Petroleum Institute's ("API") Recommended Practice ("RP") 1173, which provides a recommended framework to pipeline operators with safety management system requirements that are intended to reveal and manage risk, promote a learning environment, and continuously improve pipeline safety and integrity. The Southern Co., et al., Docket No. 15-0558, Order at 9-10 (Jun. 7, 2016). Additionally, in December 2016 the Pipeline and Hazardous Materials Safety Administration ("PHMSA") amended its pipeline safety regulations to, among other requirements, require operators of interstate aquifer reservoirs constructed before July 18, 2017 to comply with certain sections of API RP 1171, which addresses well and reservoir integrity. PHMSA also has proposed new and more stringent standards to its pipeline safety standards, which could affect a number of existing regulations such as the processes for verifying pipeline Maximum Allowable Operating Pressure. Nicor Gas states that it will utilize current and new workforce resources to ensure compliance with these new and enhanced regulations. Nicor Gas Ex. 6.0 at 33-35.

Nicor Gas further explains that it is working with the Commission's Pipeline Safety Program Staff to modify the Company's "soft close" process in accordance with PHMSA's minimum safety standards (whereby natural gas service may remain active for a period of time after the Company receives a request to discontinue serve and before the Company identifies a new customer of record). Nicor Gas Ex. 6.0 at 35. In particular, the Company will begin utilizing additional FTEs to make site-specific determinations to assess a particular address' susceptibility to break-ins, vandalism, and other unauthorized interference when determining to leave the gas on during the occupant transition period. As a result, Nicor Gas states that it anticipates an increase in its yearly on-site inspections in 2018, with more than 44,000 additional premises requiring a physical turn off and a corresponding turn on. Nicor Gas Ex. 6.0 at 35-36. Similarly, the Company states that it will refine the manner in which it grades, and then repairs, above ground leaks discovered during system surveys, with the refined approach resulting in an additional 10,000 repairs each year.

Nicor Gas maintains that it will utilize current workforce resources to the extent possible, but it must also recruit new workforce resources as it deems necessary, to fully ensure compliance with all of these new and enhanced regulations. Nicor Gas witness Whiteside further explained that the Company is focused on the full range of activities necessary for effective workforce development, including attracting people to careers in energy starting from an early age through high school, developing current employees through rotational and mentoring programs and plan for vacancies as employees retire, and retaining employees through employee engagement initiatives. Nicor Gas Ex. 1.0 at 7. Nicor Gas points out that the Company is well underway in executing on its workforce development plan to add 117 FTEs by the end of 2018, with 6 FTEs hired through August 2017, another 3 FTEs hired in September 2017, and another 40 FTEs to be hired in the fourth quarter of 2017. Nicor Gas notes that the

Company did not change its revenue requirement in this proceeding to reflect this accelerated rate of recruitment.

Nicor Gas argues that IIEC-CUB's proposed adjustment to reduce the Company's test year FTE level to a historical figure is unwarranted, unreasonable and will result in unsafe conditions. Nicor Gas avers that IIEC-CUB's adjustment implies that the Company must experience a safety issue or a decline in service before the Company would be justified expanding its workforce. Nicor Gas notes that there is no dispute that the Company has a proven record of providing safe, efficient, and reliable service precisely because the Company proactively addresses safety and workforce related issues. The Company further asserts that the Company's ability to continue that proven record is reliant upon an adequately trained and well-staffed workforce; therefore, the Company must be allowed to expand its workforce as it deems necessary. Nicor Gas Ex. 6.0 at 33; Nicor Gas Ex. 18.0R at 22. Accordingly, Nicor Gas argues that its proposed FTE increase not only is reasonable and prudent, but that to reach any other conclusion could jeopardize the Company's proven record of providing safe, efficient, and reliable service.

b. Staff's Position

Staff did not take issue with the Company's rebuttal position on payroll expense; therefore, this issue is uncontested between Staff and Nicor Gas.

c. IIEC-CUB's Position

IIEC-CUB propose an adjustment to decrease payroll expense to recognize fewer employees in the 2018 test year than Nicor Gas reported for the test year. IIEC-CUB Ex. 3.0R at 45. IIEC-CUB aver that Nicor Gas' FTE employee level has been stagnant since 2015. Id. at 45. IIEC-CUB argue that the evidence in this proceeding does not support Nicor Gas' requested increase in employee count for the test year.

For its 2018 test year revenue requirement, Nicor Gas proposes an average of 2,030 FTE employees, an approximate 5% increase over the average 2015 and 2016 levels, as well as the January through May 2017 average level. IIEC-CUB Ex. 3.0R at 46. Included in this FTE level are an additional 117 FTE employees at December 2018, above the level budgeted for December 2017.

IIEC-CUB request that the Commission affirmatively reject Nicor Gas' proposed FTE level, and the related payroll expense impact on the revenue requirement. According to IIEC-CUB, the evidence in the record demonstrates Nicor Gas' budget with regard to average FTE is significantly overstated from both historical and current levels. Indeed, says IIEC-CUB, the Company does not rebut nor challenge this empirical evidence and the Company's claims regarding the need for, or the timing of, the additional 117 FTE are dubious at best.

IIEC-CUB point out that the utility has the burden of proof in its rate filing. 220 ILCS 5/9-201(c). IIEC-CUB aver that, in the context of a future test year, simply saying it will incur a particular expense at a later point in time is not sufficient to permit recovery of that utility's expense in rates. Rather, the Commission must base its decision on the substantial evidence in the record. IIEC-CUB claim that the record in this case, beyond the simple assertions of additional employee hires, does not support Nicor Gas'

position. IIEC-CUB conclude that the Commission can have no confidence in Nicor Gas' speculative 2018 test year FTE level and related payroll expense, and argue that a more justifiable level of FTE employees is the current level of average FTE for the 12 months ending May 2017. IIEC-CUB state that the record demonstrates that the May 2017 employee levels represent the best, most credible evidence of what the employee levels will be in 2018.

IIEC-CUB reference Table 2 from Mr. Gorman's revised rebuttal testimony as the best illustration of the overstated FTE levels proposed by Nicor Gas. IIEC-CUB Ex. 3.0R at 46. This Table shows only an increase of 7 FTE from average 2015 to 2016, and 6 FTE from the 12-month average 2016 to average 2017 May. IIEC-CUB claim the table shows that Nicor Gas is predicting a substantial increase of 98 FTE in the 12-month average for the 2018 test year.

Mr. Gorman demonstrated that, through May 2017, the rate of increase in average FTE year over year, has declined from .4% in 2016 to .3% in 2017, year to date. He further showed that the actual May 2017 FTE level is the same as the actual May 2015, and 106 FTE less than the average budgeted level for 2018. IIEC-CUB Ex. 3.0R at 46-47. Thus, when considering the near term 2015 and 2016 FTE levels, and 2017 FTE data, IIEC-CUB concluded that Nicor Gas' proposed 2018 FTE level is overstated and unrealistic.

IIEC-CUB suggest that there could be any number of reasons for Nicor Gas' stagnant FTE levels, including: employee resignations, retirements, and transfers. During 2016, Nicor Gas hired 148 FTE. However, in the same year, IIEC-CUB point out that Nicor Gas experienced a 158 FTE reduction due to retirements, resignations and transfers. According to IIEC-CUB, the employee resignations, retirements, and transfers more than offset the hires in 2016, resulting in a reduction of 10 FTE. IIEC-CUB Ex. 3.0R at 47. The trend in 2016 is a net reduction in FTE employees, not an increase, when comparing year end levels, say IIEC-CUB. IIEC-CUB Ex. 3.0R at 46, Table 2.

IIEC-CUB demonstrate that the more current FTE data for 2017 also refutes Nicor Gas' speculative 2018 FTE proposal. At the time of Mr. Gorman's direct testimony filing in late June 2017, Nicor Gas had budgeted a modest increase of only an average of 15 FTE in 2017 compared to 2016, less than a 1% increase. In fact, Mr. Gorman showed that the actual average level of FTE for the first quarter of 2017 was lower than the actual average level during the first quarter of 2016. IIEC-CUB Ex. 1.0 at 7-8. Mr. Gorman's analysis demonstrates that this trend showed a downward decline in FTE levels when comparing 2017 with 2016. The downward trend in 2017 FTE levels remained unaltered at the time IIEC-CUB filed rebuttal testimony in August 2017. IIEC-CUB point to the fact that while Nicor Gas hired 82 FTE in 2017, it still experienced an employee reduction of 60 FTE due to resignations, retirements and transfers. This reflects only a net increase of 22 FTE through May 2017, year to date. Even assuming Nicor Gas maintains the current workforce level of 1,924 throughout 2017, IIEC-CUB claim that it would still only be 106 FTE, more than 5.2% below the 2,030 average FTE level Nicor Gas used to determine payroll expense for the 2018 test year. IIEC-CUB Ex. 3.0R at 48.

IIEC-CUB aver that the impact of retirements cannot be overly emphasized: throughout the gas workforce of The Southern Company, 22% of the employees are eligible for retirement. During the period 2017 through 2022, 41% of the employees are eligible for retirement. Mr. Gorman rightly concluded that Nicor Gas will have to exhibit an enormous employee resource effort just to maintain its current workforce level. IIEC-CUB Ex. 3.0R at 49.

IIEC-CUB point out that none of the aforementioned described data or trending analysis was ever challenged by Nicor Gas. Instead, say IIEC-CUB, Nicor Gas relied on the 2017 budget and subjective observations about its workforce to support the 2018 test year FTE level. IIEC-CUB conclude that Nicor Gas has provided no credible evidence that it will or can ramp-up its workforce from the .3% to .4% average increase in FTE (6 to 7 employees) recently experienced, to over 5%, or 98 employees in the 2018 test year.

IIEC-CUB state that Nicor Gas asserts: “that its ongoing commitment to an accelerated replacement of aging infrastructure has placed a correlating demand on the Company’s workforce, requiring additional FTEs to design, replace, install, operate, and maintain the new plant in service.” The Company refers to hires from 2013-2016 and 60 more positions that took effect in 2014. IIEC-CUB argue that Nicor Gas’ repeated claims that additional FTEs are required because of Nicor Gas’ aging infrastructure are not borne out by the record. IIEC-CUB point out that Mr. Whiteside stated: “None of the FTEs referenced in the indicated testimony are related to the accelerated infrastructure replacement.” IIEC-CUB Cross Ex. 1.0. According to IIEC-CUB, by the Company’s own admission, the accelerated rate of replacing Nicor Gas’ aging infrastructure has nothing to do with the additional FTE for 2018. Further, IIEC-CUB maintain that the number of employees the Company has hired from 2013 through 2016 does not by itself support the level of additional hires it claims it will make in the test year. Nicor Gas Ex. 6.0 at 33.

IIEC-CUB respond to Nicor Gas’ suggestion that events reshaping the regulatory landscape on pipeline safety are creating additional demands on the Company’s workforce, which in turn justifies its requested FTE level. IIEC-CUB explain that Nicor relies on Mr. Whiteside’s testimony discussing recent pipeline safety regulations that may incorporate safety standards for interstate gas storage operations. Nicor Gas Ex. 6.0 at 34-35. IIEC-CUB aver that, here and elsewhere, Nicor Gas relies upon vague and undefined phrases such as a “changing federal and state regulatory landscape,” a phrase repeated several times, or “federal and state regulatory safety guidelines,” neither of which provide evidence of defined and specific workforce needs. In fact, IIEC-CUB point out that, when asked whether the pipeline safety regulation compliance efforts he described in testimony warranted additional FTEs, Mr. Whiteside answered, “No.” IIEC-CUB Cross Ex. 1.0.

Another example of the “changing regulatory landscape” Nicor Gas offers as support for its claim that additional FTEs are needed in the test year is the API RP 1171. IIEC-CUB observe that, while the API RP 1171 provision is cited no less than five times, the testimony supporting that regulatory action as contributing to Nicor Gas’ FTE requirements notes only that Nicor Gas “...is taking steps to work towards compliance, which *may* require the Company to make significant new system inspection

requirements and incremental accelerated capital investments *in the future*.” Nicor Gas Ex. 6.0 at 35(emphasis added). IIEC-CUB maintain that the conditional nature of this statement itself undermines the support for Nicor Gas’ requested FTE level. But when asked whether this workforce requirement had any bearing on any new FTE to date, IIEC-CUB point to Mr. Whiteside’s admission that “[n]o incremental FTEs have been hired to date to address the *potential impacts* to the implementation of the rules related to API RP 1171.” IIEC-CUB Cross Ex. 1.0 (emphasis added).

Nicor Gas makes general references to other standards and regulations, but as IIEC-CUB observed above, Mr. Whiteside couches these standards or regulations as being “proposed” and fails to state whether these standards or regulations will require Nicor Gas to take affirmative action. Nicor Gas Ex. 6.0 at 35. IIEC-CUB continue that Nicor Gas states only that these standards *could* require action on its part: “PHMSA also has proposed new and more stringent standards to its pipeline safety standards, which *could* affect a number of existing regulations such as the processes for verifying pipeline Maximum Allowable Operating Pressure.” IIEC-CUB conclude that the record evidence is clear that incremental FTEs have yet to be hired. According to IIEC-CUB, merely alleging that the impact of AP RP 1171 “may” require action in the future, or that the other regulations are “proposed,” or regulatory bodies “could” take additional action is not a sufficient basis for the Commission to conclude Nicor Gas’ requested FTE level is just and reasonable and supported by the record.

IIEC-CUB next respond to the Company’s claims that an aging workforce is an additional justification for its inflated FTE level. See Nicor Gas Ex.6.0 at 37. Nicor Gas claims it will hire an additional 12 FTE for this purpose. Id. at 38. Nicor Gas identified seven programs to address its aging workforce, that it has either initiated, or in which it is participating, which it claims will lead to the need for additional FTEs in the 2018 test year. Yet, according to IIEC-CUB, several of these programs are geared to making students and teachers aware of gas energy career opportunities and are clearly unrelated to the Company’s FTE requirement. IIEC-CUB point out that one of the programs was focused on students in grades 5 through 8. Of all the programs listed, IIEC-CUB maintain that Nicor Gas could only specifically point to 11 new hires since the Company joined the program in 2015. IIEC-CUB Ex. 3.0 at 50.

Given the nature of the aging workforce efforts or other programs, and the limited hires to date, IIEC-CUB conclude that the Commission should doubt Nicor Gas’ undue emphasis on its aging and changing workforce programs, as a justification for additional FTEs in 2018. IIEC-CUB aver that it is simply unrealistic to assume that Nicor Gas will hire an additional 12 FTE under these programs, given the nature of the programs and recent trend in hires for this purpose.

IIEC-CUB state that a significant portion of the additional 117 FTE for which Nicor Gas is requesting recovery are the result of the proposed “soft close” process, which addresses segments of pipeline that become unsafe and must be replaced, repaired, or removed from service. Nicor Gas Ex. 6.0 at 35-36. IIEC-CUB point out that this process is still considered “proposed” because, as Mr. Whiteside stated in his direct testimony, Nicor Gas was still “engaged in discussion” with the Staff about the process. Id. at 35. IIEC-CUB observe that the exact amount of FTE is not known in the record

because Nicor Gas has lumped in the soft close FTE with FTE associated with “repair above ground leaks found during system surveys, and operation support.” *Id.* at 39.

Mr. Whiteside claims the Pipeline Safety Report (“Staff Report”) of December 21, 2016, is the impetus for the soft close process and the need for additional FTE. Nicor Gas Ex. 6.0 at 35. IIEC-CUB argue that he failed to point out that the Staff Report has its genesis in an investigation at a much earlier point in time. See IIEC-CUB Cross Ex. 1.0 (Conf.). According to IIEC-CUB, Nicor Gas has been or should have been aware of the concerns raised in the Staff Report for a considerable period of time. Even so, IIEC-CUB conclude that the fact that the Company admits that it is still in discussions with Staff undermines the credibility of any timetable that Nicor Gas suggests.

In response to Nicor Gas’ claims that Mr. Gorman “...speculates that Nicor Gas will not meet its 2018 FTE goal by referring to historical and current trend,” IIEC-CUB maintain that it is actually the Company that is engaging in speculation. IIEC-CUB aver that Nicor Gas is relying on speculative FTEs, in addition to a *budgeted* 2017 workforce level that Nicor Gas has been unable to achieve through May 2017, due to continued significant retirements and resignations. In fact, say IIEC-CUB, 2017 actual FTEs through May 2017 are barely maintaining the levels achieved in 2016. On the other hand, IIEC-CUB maintain that there is no speculation in Mr. Gorman’s analysis, as Mr. Gorman updated his analysis through May 2017, which analysis makes abundantly clear that Nicor Gas will not achieve the workforce level it *projects* in 2018.

IIEC-CUB argue that there is absolutely no evidence in the record from which to justify Nicor Gas’ statement that adoption of IIEC-CUB’s position would lead to an “unreasonable and unsafe result.” To be certain, IIEC-CUB wholly expect Nicor Gas to provide adequate, safe and reliable natural gas service, and to abide by all rules and regulations that are in place. However, IIEC-CUB conclude that there is no evidence that Nicor Gas is not providing such service today under its existing FTE level.

In the rebuttal filing, IIEC-CUB adjusted their recommended revenue requirement based on the considerations and arguments above. Mr. Gorman took into account employee data through May 2017, and employee budget corrections for 2018. His adjustment includes the FTE level for the 12-month average ending May 2017, and results in a reduction of \$7.836 million in Nicor Gas’ revenue requirement. IIEC-CUB Ex. 3.0R at 50-51.

IIEC-CUB note that the actual FTE, in May for both 2015 and 2016, is higher than the average for each entire year. If the employee trends exhibited in 2015 and 2016 were to continue, assert IIEC-CUB, then the average level of employees would decline in months following May 2017. Also, in light of the data showing the significant number of employees that have left the Company just through July 2017 – 88 employees – and the level of employees leaving Nicor Gas that occurred in 2016 – 158 employees – IIEC-CUB aver that its revenue requirement downward adjustment in the amount of \$7.836 million is conservative, since it is based on the 12 months ending May 2017 FTE levels. See IIEC-CUB Cross Ex. 1.0 at 11-13; IIEC-CUB Ex. 3.0R at 47, 51.

d. Commission Analysis and Conclusion

Nicor Gas presented evidence that its proposed increase of 117 FTEs in the 2018 test year is reasonable and necessary for the continued provision of safe and reliable gas service. IIEC-CUB argue that the Company's 2018 FTE level should be obtained from a historical trend, rather than derived from objective observations of what the Company anticipates its workforce will need to address in the 2018 test year and beyond. The Commission finds that Nicor Gas' future workforce needs cannot be addressed using a historical FTE average as IIEC-CUB suggest, because such an analysis ignores the evidence supporting the Company's need to increase its workforce size. Specifically, Nicor Gas emphasized the need to increase staffing due to PHMSA requirements and Commission directives from the last merger docket to work with Pipeline Safety Staff on an operators' framework, as well as the Company's soft close process. Nicor Gas also discussed the need for an increase in on-site inspections. IIEC-CUB's claims that these projects are "still in discussion" does not take away from the need to hire more staff to fill these roles.

The Commission finds that Nicor Gas has met its burden of establishing that the forecasted 2018 FTE level is both reasonable and will be prudently incurred. Therefore, the Commission adopts the Company's proposed test year employee level and associated costs, including the 117 FTE increase.

3. Payment Fee Costs

a. Nicor Gas' Position

Nicor Gas is proposing to include Payment Fee Costs in base rates for the 2018 test year as part of its broader customer-focused initiative. Currently, customers are assessed a \$2.00 convenience fee when paying through an authorized walk-in agent, and a \$2.95 convenience fee when making payment through a third-party service by phone, online, or through email. Nicor Gas Ex. 8.0 at 9. Nicor Gas states that, based on complaints to the Company and customer behavior, customers do not like having to pay an additional fee in order to pay the gas bill. For 2018, the Company forecasts \$8.4 million in Payment Fee Costs, which is based on historical data. Nicor Gas seeks to recover only its actual Payment Fee Costs. To that end, Nicor Gas proposes Rider 35 – Payment Fee Adjustment ("Rider 35"), which will recover or refund the amount by which the Company's actual annual Payment Fee Costs in a calendar year exceeds or is less than the Payment Fee Costs included in base rates. Any over-or-under recoveries of the Company's actual Payment Fee Costs for a reporting year will be reflected in the customer's Monthly Customer Charge. As an alternative to recovering the \$8.4 million baseline amount of Payment Fee Costs in base rates, Nicor Gas proposes to recover its actual, annual Payment Fee Costs through Rider 35 instead of through base rates. Nicor Gas Ex. 33.0R at 3.

Nicor Gas disagrees with Staff's claim that this cost is not necessary to provide utility service. The Company asserts that providing customers with different channels to pay their bills is directly related to the provision of utility service. In particular, Nicor Gas asserts that bill payment is directly related to the provision of utility service as set forth in Part 280 of the Commission's Rules. The Company argues that the fact that certain

payment channels include third-party vendor fees does not relegate that payment channel to a non-utility service.

The Company also disagrees with Staff's claim that the Payment Fee Costs proposal violates cost causation principles. Staff Ex. 1.0 at 19. Nicor Gas explained that the payment options offered to customers related to the Payment Fee Costs will be available to all of Nicor Gas' customers. Nicor Gas Ex. 19.0 at 4; Nicor Gas Ex. 33.0R at 2; Nicor Gas Ex. 23.0 at 2. In this regard, the Company argues that the Payment Fee Costs are analogous to the Company including the Call Center costs, e-billing costs, or the costs associated with making its Customer Select program in base rates. While only certain customers may use these services, and thus impose the need for the costs of these programs, all customers help to pay for these costs as the services are available to all customers. As such, Nicor Gas concludes that its Payment Fee Costs are consistent with cost causation principles.

Nicor Gas disagrees with the AG's claim that the Company's proposed recovery is not appropriate because the number of customers participating, and the ultimate cost per transaction, are unknown and must be considered speculative. AG Ex. 1.0 at 27. The Company states that the AG's claim is incorrect, and points to the fact that the forecasted 2018 Payment Fee Costs are based on historical data. Accordingly, the Company's forecasted Payment Fee Costs are based on data that is neither "speculative" nor "unknown" as the AG claims.

b. Staff's Position

The Company proposed an adjustment to increase its operating expenses by \$8,406,000 to voluntarily reflect the estimated costs of fees to be incurred by customers who choose to pay their utility bills through third-party vendors. Nicor Gas Schedule C-2.3. Staff witness Ebrey recommended disallowing those costs since they are not necessary for the provision of utility service. Moreover, she noted that it is unreasonable for the Company to foist an optional cost willingly incurred by a sub-group of customers upon all customers as it is contrary to the cost causation regulatory goal or objective under the Act. Staff Ex. 1.0 at 19.

Staff argues that the Company's arguments for the need to reflect the payment fees in base rates fall short. The Company indicates that there is a correlation between fee-free payments and the collection of accounts receivable. However, the data provided in this case indicates that the uncollectibles rate based on write-offs of accounts has dropped by 54% (1.65% to 0.89%) between 2012 and 2016 (the last year for which data was provided). Staff Ex. 6.0 at 7. Staff notes that the Company further indicates that there is a long history of customer complaints concerning the fees for payments made to third party vendors. However, the Company admitted that "there would have been minimal reason for a customer to complain about fees associated with bill pay prior to February 2016 given the opportunity to bypass the fee simply by enrolling in paperless billing." Nicor Gas Ex. 23 at 3.

The Company opines that the costs for payments made through third-party vendors is analogous to costs for Customer Call Centers in that the costs for both should be socialized among all customers. Nicor Gas Ex. 19.0 at 73-81. Staff disagrees, pointing out that Customer Call Centers are a requirement of all utilities in

the State of Illinois under 83 Ill. Admin. Code 501.50 and, as such, do not represent discretionary costs of the utility. Staff Ex. 6.0 at 6-7. The Company is under no such requirement for providing customers with fee-free payments through third-party vendors.

c. AG's Position

AG witness Effron testified that the future costs associated with the fee-free payment program are unknown. As a result, the AG proposes that the Commission remove the Company's *pro forma* adjustment for fee-free payment costs of \$8.406 million from the Company's requested revenue requirement. AG Ex. 1.0 at 27-28.

The AG claims that the evidence shows that the Company's proposed adjustment for fee-free processing costs is not sufficiently quantifiable to include in its requested revenue requirement. According to the AG, both the number of customers that will take advantage of the fee-free payment processing and the ultimate cost per transaction are unknown. AG Ex. 1.0 at 27-28. The AG adds that the uncertainties regarding the prospective costs of the fee-free payment program are greater than the uncertainties related to other operating costs of the Company for which the Company has a historical basis upon which to project costs in the 2018 test year. AG Ex. 3.0 at 9. Thus, the AG asserts the future fee-free processing costs are speculative and uncertain.

In response to Nicor Gas' assertion that Staff's claim that including the payment fee cost of \$8.4 million baseline amount is contrary to cost causation principles by comparing the fee-free proposal to including the Call Center or e-billing in base rates, the AG notes that costs associated with the Call Center or e-billing in base rates are not comparable to the proposed fee-free payment program. By today's business standards, every viable business must have a fully operational call center to handle the concerns of customers and a fully functional e-billing option. Businesses are not expected to provide a fee-free payment program for its customers.

The AG urges that the Commission accept the adjustment proposed by AG witness Effron and Staff witness Ebrey to reduce *pro forma* test year operating expenses by \$8,406,000 as reflected in AG Schedule C-2 and in Staff Ex. 6.0, Schedule 6.08.

d. CUB's Position

CUB supports the AG and Staff in recommending that the Commission reject Nicor Gas' request to recover \$8.4 million for Payment Fee Costs in base rates. While the estimated amount to be included in rates is based on historical amounts, CUB points out that the Company acknowledges that socializing these convenience payments "may facilitate more customers making timely payments." Nicor Gas Ex. 33.0R at 2-3. CUB posits that, if the number of transactions increases dramatically, the cost of which appears in this record to be static (\$2.00 for walk-in payments and \$2.95 for third-party payments), the amount recovered under proposed Rider 35 will also escalate, for which all customers will pay (through a true-up under proposed Rider 35). Further, CUB avers that the record does not show whether Nicor Gas' actual costs for these services are just and reasonable, or whether those costs would decrease as the number of transactions increases. According to CUB, the record is also unclear why Nicor Gas changed from using an alternative third-party vendor to process customer

payments, which offered customers the opportunity to submit a payment, fee-free, if the customer enrolled in paperless billing. Because of these uncertainties, CUB supports the AG and Staff in recommending that Nicor Gas' request to include Payment Fee Costs and associated approval of Rider 35, be rejected by the Commission.

e. Commission Analysis and Conclusion

Nicor Gas is proposing to include Payment Fee Costs in base rates for the 2018 test year. Currently, customers are assessed a \$2.00 convenience fee when paying through an authorized walk-in agent and a \$2.95 convenience fee when making payment through a third-party service by phone, online, or through email. For 2018, the Company forecasts \$8.4 million in Payment Fee Costs, which is based on historical data. The Company seeks to recover these costs through a rider mechanism.

Staff argues this cost is not necessary to provide utility service and violates cost-causation principles. The AG argues that the costs and customer participation levels are speculative, and CUB states that Nicor has not shown its costs are just and reasonable.

It is fundamental that the Commission should disallow recovery of any cost of capital in excess of that reasonably necessary for provision of services. Citizens Utility Bd. v. Ill. Commerce Comm'n, 276 Ill.App.3d 730 (1st Dist. 1995). The Commission agrees with Staff that providing fee-free payments are not necessary to provide utility service, and Nicor Gas is under no obligation, statutory or otherwise, to provide alternative bill payment options to customers without associated fees. Moreover, the Commission agrees with the AG that the costs are speculative, since the Company uses estimates that pre-date paperless billing. Fee-free paperless billing is no longer an option, as Staff points out. The Commission also agrees with CUB that the Company has not shown that these third party costs are reasonable. For example, could different vendors provide these services at less cost? Finally, the Company's comparison to Call Centers is inapposite. As Staff points out, under the Commission's Rules, utilities are required to provide Call Centers. 83 Ill. Admin. Code 501.50.

The Commission also rejects the Company's proposal for Rider 35, discussed below in Section VII.B.4.

VI. CAPITAL STRUCTURE AND RATE OF RETURN

A. Uncontested Issues

1. Remaining Construction Work-In-Progress ("CWIP") Accruing Allowance for Funds Used During Construction ("AFUDC") Adjustment

There is no disagreement in this case regarding whether an adjustment should be applied to the long-term capital components to account for any remaining construction work in progress ("CWIP") accruing an allowance for funds used during construction ("AFUDC"). This adjustment recognizes that the Commission's formula for calculating AFUDC assumes: (1) short-term debt is the first, but not the only, source of funds financing CWIP; and (2) any CWIP not funded by short-term debt is funded proportionally by the remaining sources of capital (*i.e.*, long-term debt and common equity). As such, during those months in which the Company's CWIP balance exceeds

its short-term debt balance, a portion of CWIP is assumed to be funded by the long-term sources of capital. Staff Ex. 3.0 at 67-69. This assumption is reflected in ratemaking capital structures by first adjusting the monthly short-term debt balances to remove the portion of short-term debt reflected in the calculation of AFUDC and then removing any remaining CWIP accruing AFUDC from long-term debt and common equity balances on the basis of their relative proportion of total long-term capital. Staff Ex. 8.0 at 68-69. Such adjustments ensure there is no double counting of any portion of the affected capital components. The proposed capital structures of Staff and the Company reflect this adjustment. Staff Ex. 8.0, Sch. 8.03; Nicor Gas Ex. 29.2.

B. Contested Issues

1. Capital Structure

a. Nicor Gas' Position

As part of the Stipulation, Nicor Gas recommends a forecasted December 31, 2017 capital structure that contains 52.00% common equity, 47.414% long-term debt and 0.586% short-term debt. Nicor Gas Ex. 39.1. Nicor Gas and Staff state that this capital structure is supported by the record, and incorporates a short-term debt ratio equivalent to IIEC/CUB's proposal, a long-term debt ratio within the range bounded by the AG's proposal on the low end and IIEC/CUB's proposal on the high end (with Nicor Gas' and Staff's original recommendations within the same range), and a common equity ratio that falls within the range established by IIEC/CUB's proposal and Nicor Gas' original proposal (with Staff's original recommendation and the AG's recommendation within that same range). Nicor Gas Ex. 39.1.

Nicor Gas' previously proposed capital structure, which is reflected in the Stipulation's capital structure, was 54.504% common equity, 42.942% long-term debt, and 2.553% short-term debt. Nicor Gas Ex. 29.1. While Nicor Gas recommends the capital structure proposed in the Stipulation, Nicor Gas' positions supporting its previously proposed capital structure are included here since the Stipulation is based on the recommendations advanced by the parties in their briefs. Nicor Gas states that its proposed capital structure appropriately takes into account the Company's need for stable and assured access to capital markets at reasonable costs and terms, the need for financial stability and security, and the need to balance the costs and benefits of leverage. The Company claims that its proposed capital structure will support its investments and cash flow needs, while maintaining the strong credit ratings the Company has long enjoyed.

Nicor Gas argues that the capital structures proposed by Staff, IIEC-CUB, and the AG do not accurately take into account Nicor Gas' current and continuing capital investment. Nicor Gas Ex. 29.0R at 3. Nicor Gas argues that the parties' estimates, because they are all based on capital structures outside of the test year, ignore the evidence in the record and do not properly reflect what Nicor Gas' capital structure will be in the test year. Id. at 4.

Nicor Gas opposes Staff's argument that the long-term components of Nicor Gas' capital structure should be measured using a December 31, 2017, measuring period. Id. at 7. The Company observes that no party objects to its use of a future test year and

that only by using a test year capital structure will the test year cost of capital be properly calculated. Nicor Gas argues that using a measuring period outside of the test year is not appropriate. Nicor Gas also notes that Staff initially accepted its capital structure and then retracted that acceptance in response to Nicor Gas' deferral of the issuance of a fraction of its new capital until later in the test year. Nicor Gas argues that Staff's change in position, from recommending a capital structure substantially the same as the one that the Company proposes, to presenting a different capital structure with different measurement periods, is unwarranted. The Company argues that there is no evidence to support Staff's doubt as to the accuracy of Nicor Gas' updated forecast. Nicor Gas contends, to the contrary, that Staff's change in position is an overreaction to a prudent business decision to make a change in the timing of the issuance of new capital and points out that the adjustment has no material impact on Nicor Gas' capital plan or test year-end target capital structure. Further, Nicor Gas argues that its deferral of \$130 million in capital is not a significant change, especially considering that Nicor Gas' year-end 2017 balance of capital will be \$2.4 billion of long-term capital, and its 2018 plan includes \$900 million of new capital to support investments and replace or refund prior debt. Nicor Gas Ex. 15.0 at 1; Nicor Gas Ex. 29.0R at 8.

Nicor Gas also argues that no party has established, or even argued, that its proposed capital structure is unreasonable, and asserts that the Commission should not reject a utility's capital structure unless it is unreasonable. Indeed, Staff accepted the Company's capital structure in its direct testimony, implicitly finding it to be reasonable. Nicor Gas also points out that while the AG proposes an alternative capital structure that it describes as "fairer," the AG not only fails to establish that claim, but also does not argue that Nicor Gas' proposed capital structure is unreasonable.

Nicor Gas contends that the AG's proposed capital structure should not be adopted because, in addition to looking at historical practices and attempting to "reconcile" rate base with capitalization, it is unreasonable. Nicor Gas argues that rate base and capitalization are not necessarily, and in fact rarely are, equal, and there is no rule requiring a utility to account for the difference between rate base and capitalization.

b. Staff's Position

As part of the Stipulation, Staff recommends a forecasted December 31, 2017 capital structure that contains 52.00% common equity, 47.414% long-term debt and 0.586% short-term debt. Nicor Gas Ex. 39.1. Nicor Gas and Staff state that this capital structure is supported by the record, and incorporates a short-term debt ratio equivalent to IIEC/CUB's proposal, a long-term debt ratio within the range bounded by the AG's proposal on the low end and IIEC/CUB's proposal on the high end (with Nicor Gas' and Staff's original recommendations within the same range), and a common equity ratio that falls within the range established by IIEC/CUB's proposal and Nicor Gas' original proposal (with Staff's original recommendation and the AG's recommendation within that same range). Nicor Gas Ex. 39.1.

While Staff recommends the capital structure proposed in the Stipulation, Staff's positions supporting its previously proposed capital structure are included here since the Stipulation is based on the recommendations advanced by the parties in their briefs.

Ms. Phipps recommends a forecasted December 31, 2017 capital structure that contains 52.66% common equity, 42.33% long-term debt and 5.01% short-term debt. Staff Ex. 8.0 at 3; Sch. 8.01. Staff's recommended long-term debt and common equity balances are based on the Company's projected balances for December 31, 2017, less the remaining CWIP accruing AFUDC adjustment discussed in Section VI.A.1. Staff Ex. 8.0 at 31, Schs. 8.03, 8.04 and 8.05. Ms. Phipps recommends an average short-term debt balance measured over the period beginning June 2017 through June 2018 because short-term debt balances tend to fluctuate substantially during a year, so that any single balance might not be representative of the amount employed throughout the year. Staff Ex. 8.0 at 31. Averaging short-term debt balances over twelve months in which the midpoint is the measurement date for the long-term capital components, as Ms. Phipps does, is a methodology that has been repeatedly approved by the Commission. See, e.g., AmerenCILCO, Central Ill. Public Service Co. d/b/a AmerenCIPS and Ill. Power Co. d/b/a Ameren IP, Docket Nos. 07-0585-07-0580 (Cons.), Order at 159-160 and 165 (Sept. 24, 2008); South Beloit Water, Gas and Electric Co., Docket Nos. 03-0676/03-0677 (Cons.), Order at 20-21 (Oct. 6, 2004).

Ms. Phipps compared the Company's December 31, 2017 common equity ratio to the common equity ratio for the gas distribution industry and concluded that the Company's 52.66% common equity ratio compares favorably to the 51.07% mean common equity ratio for the gas distribution industry. Staff Ex. 3.0 at 71-72; Staff Ex.8.0 at 32.

Staff states that Nicor Gas wrongly takes issue with Staff's proposal and suggests capital structure is subject to test year rules. Nicor Gas Ex. 37.0 at 45. The cost of capital, and therefore its components, is not subject to the Commission's test year rules. 83 Ill. Adm. Code 285.115. This administrative rule is also supported by the Supreme Court's decision in BPI II, which concluded that since post-in-service carrying costs are recovered through the utility's authorized rate of return rather than as an operating expense in the revenue requirement formula, they are not test year items. BPI II at 242. Clearly, the Court's association of post-in-service carrying costs with a utility's authorized rate of return indicates that the authorized rate of return, which is based on a utility's cost of capital, is not subject to test-year rules.

Ms. Phipps recommends moving the capital structure measurement date up to December 31, 2017, rather than using the Company's proposed average 2018 capital structure, for ratemaking purposes. Nicor Gas Ex. 29.0R at 5. This change is necessary because the accuracy of forecasts diminish as the time horizon lengthens and Nicor Gas has already made significant adjustments to its proposed capitalization for 2017 since its initial rate case filing in March 2017, which raises questions about the accuracy of the Company's projections. Staff Ex. 8.0 at 32. In its March 2017 rate case filing, Nicor Gas indicated that during 2017 the Company planned to issue \$500 million of new long-term debt and receive a \$200 million common equity infusion. In rebuttal testimony filed four months later, in July 2017, Nicor Gas changed its forecasts. The Company explained that it reduced its 2017 long-term debt issuance by 20% (from \$500 million to \$400 million) and reduced its 2017 equity infusion by 15% (from \$200 million to \$170 million), and forecasted the remaining debt issuance and equity infusion would occur 2018. Id. The fact that such a significant shift in forecasts occurred so soon after

the rate case was filed raises concerns about the probability that the revised forecast would remain unchanged through the end of 2018.

Moreover, Ms. Phipps explained that Nicor Gas determined that it has sufficient liquidity to defer \$130 million of long-term capital financing originally planned for 2017. Id. at 33. The Company's rate increase from the instant docket, which is expected to be in effect during the first quarter of 2018 and thereafter, should further improve the Company's liquidity position such that the \$530 million of new long-term capital that the Company projects it will issue at the end of 2018 may not be required. Id.; Tr. at 27. Together, these suggest that further variances from the Company's proposed average 2018 capital structure forecast may still occur. Staff's projected December 31, 2017 capital structure, with a shorter time horizon than the Company's average 2018 capital structure, decreases the impact of any variances and should be adopted for ratemaking purposes.

Nicor Gas opposes Staff's December 31, 2017 capital structure measurement date based on the fact that the Company's revised forecasts for 2018 produce an average 2018 capital structure that is very similar to the Company's original proposal. Nicor Gas Ex. 29.0R at 5. However, that the Company's forecasted 2018 capital structure remains virtually unchanged, despite deferring \$130 million of long-term capital financing, only underscores the fact that the Company's forecasted capital structure is less reliable than it was initially. Nicor Gas suggests its projected 2018 capital structure may not be "outside the range of reasonability" for a gas utility company; not only is that such a low bar as to be virtually meaningless, it is irrelevant. Staff continues, based on the record evidence, the Company's projected 2018 capital structure in this proceeding is unreasonable for ratemaking purposes because it is not likely to represent the Company's actual capital structure during the time period the new rates will be in effect.

Nicor Gas seeks to justify a ratemaking capital structure that is more heavily weighted in higher cost long-term debt and equity than lower cost short-term debt by claiming it has "prudently and with foresight responded to changing interest rate and capital market conditions by reducing significantly its reliance on short-term debt." Nicor Gas Ex. 15.0 at 9, 17; Nicor Gas Ex. 29.0R at 8; AG Cross Ex. 3. Staff states this statement rings hollow as the Company's actions run counter to its argument. Contrary to the Company's claim that it is "reducing significantly its reliance on short-term debt", Nicor Gas forecasts now project higher and more frequent short-term debt balances during 2017 and 2018 than originally forecasted as a result of delaying a portion of its planned 2017 long-term debt issuance until late 2018.

For all of the foregoing reasons, Staff concludes that it is more reasonable to use a forecasted December 31, 2017 capital structure measurement date rather than the Company's average 2018 capital structure for ratemaking purposes.

c. AG's Position

The AG explains that the physical facilities a utility uses to provide service to its customers – its rate base – necessarily requires capital investment. The AG adds that the link between a utility's rate base and its capitalization is inescapable, yet Nicor Gas' projected capital structure, as its revenue requirement in this case proposes, is

inadequate to the task of supporting its investments in utility plant. The AG urges the Commission to reject the Company's proposed capital structure and adopt instead a capitalization that more realistically reflects Nicor Gas' actual financial needs. The AG states that Nicor Gas did not take proper account of the short-term debt that has been used and the record evidence shows will be used, to finance its rate base. AG witness Effron's analysis of the Company's proposed capital structure explains why it improperly provides a windfall to Nicor Gas and why his proposal is more realistic and fairer to ratepayers.

AG witness Mr. Effron testified, a utility "is authorized to earn a return on that investment to the extent, and only to the extent, that the investment is supported by *investor-supplied funds*. The utility is not authorized to earn a return on any investment not supported by investor-supplied funds." AG Ex. 3.0 at 11. Nicor Gas witness Reese agreed that there is a relationship between a utility's capital investment and its rate base, the investment upon which the utility earns its profits. Ms. Reese further acknowledged under cross-examination that even if a utility's rate base and capitalization are not identical, there is a relationship between the two. Tr. at 23. Yet, according to the AG, Nicor Gas attempts to evade the implications of this connection, even as its witness admits that the relationship exists. In order to determine just and reasonable rates, the AG observes that the Commission must ensure that Nicor Gas' revenue requirement accounts for the Company's realistic short-term capital needs as a component of its actual capitalization.

AG witness Effron explained in his direct testimony – and Nicor Gas' witness Reese concedes – that while a utility's rate base and capitalization are, in practice, rarely equal, that rate base "must, by definition, be supported by investor-supplied capital." AG Ex. 1.0 at 39. Ms. Reese agreed that rate base investments are financed by a utility's capitalization and that increases to that rate base must be accounted for through increased capitalization. Tr. at 23-24. Mr. Effron further explained that if a utility's test year rate base exceeds the forecasted test year capitalization, the difference must be accounted for. AG Ex. 1.0 at 39.

The AG states that Nicor Gas' filing shows plant growth through 2017 and into the 2018 test year, with an average forecasted jurisdictional rate base balance for the 2018 test year of \$2,516,693,000. Nicor Gas Ex. 30.1R, Revised Schedule B-1, In. 18. The 2018 QIP investment of \$142,832,000 (Nicor Gas Ex. 30.1 at 5, Schedule B-2, In. 18) must also be considered in the determination of the utility's needs for capitalization during the 2018 test year, bringing the total rate base to \$2,659,525,000 (\$2,516,693,000 + \$142,832,000). That growth has to be financed in some way. The AG contends that neither Nicor Gas' originally forecasted capital structure nor the modified capital structure it presented in its rebuttal testimony is adequate to finance its projected 2018 test year rate base. Its final total capitalization comes to \$2,497,536,000, a shortfall of \$161,989,000 from its projected rate base. Nicor Gas Ex. 30.1, Revised Schedule D-1, In 4. The AG argues that the investment in facilities used to provide utility service must be backed by either investor-supplied funds or non-investor supplied funds. AG Ex. 3.0 at 12. Funds from sources other than investors do not earn the utility a return and rate base that earns a return must be supported by investor-supplied funds, otherwise known as capitalization. Id. If a utility's forecasted

rate base is greater than its forecasted capitalization, the additional funds used to support the rate base investment must come from somewhere. According to the AG, Nicor Gas has not identified where these additional funds will come from. Id.

The AG explains that in his analysis of Nicor Gas' revenue requirement, Mr. Effron testified that the reason for this shortfall is that Nicor Gas' capital structure has materially underestimated the short-term debt that will actually be used to finance its rate base. AG Ex. 1.0 at 40. The consequence of this imbalance is that Nicor Gas' proposed cost of capital is greater than its capital needs justify, and the subsequent calculation of the Company's revenue requirement includes a windfall to investors. Id. at 41. The AG argues that a proper assessment of Nicor Gas' capital needs, includes a larger short-term debt balance, resulting in a lower rate of return on the Company's rate base and a lower revenue requirement.

The AG proposes a capital structure of 52.45% common equity, 41.327% long-term debt and 6.220% short-term debt. AG Ex. 3.0 at 14; AG Ex. 3.1, Schedule D, p. 15. In contrast, Nicor Gas' capital structure proposes 54.504% common equity, 42.942% long-term debt and 2.553% short-term debt. Nicor Gas Ex. 29.0R at 3. The AG asserts that Nicor Gas' recent capital requirements include a greater reliance on short-term debt than is reflected in the Company's revenue proposal. The average balance of short-term debt outstanding in 2016 was over \$300 million. AG Ex. 1.0 at 41. The average balances of short-term debt outstanding in 2014 and 2015 were also in excess of \$330 million. AG Ex. 3.0 at 13; AG Cross Ex. 2. Thus, the AG claims that based on actual experience in recent years, the Company will rely on short-term debt to augment its long-term debt and common equity to finance its rate base.

The AG states that Mr. Effron's capital structure recommendation will prevent the overstatement of revenues to be paid by ratepayers – and the corresponding windfall for investors – that will result if the Company's actual balance of short-term debt in 2018 turns out to be significantly greater than the balance projected on AG Cross Ex.1, AG Ex. 1.0 at 41. The AG points out that Nicor Gas' short-term debt balance was an issue in the 2008 Rate Case, where the Commission concluded it was “equitable and reasonable” to incorporate one-half of the balance of short-term debt outstanding in its capital structure. Id. at 41-42. The AG observes that the recommended short-term debt balance that Mr. Effron proposes in this case follows the same principle that the Commission sought to follow in that case, “to insure fair treatment and to protect against any undue or sustained adverse impact on utility earnings.” Id. at 42.

The AG states that Nicor Gas' average balance of short-term debt in 2016 (excluding CWIP accruing AFUDC) was \$322,825,000. One half of that amount, consistent with the Commission's treatment in the 2008 rate case, is \$161,413,000. The AG argues that including this amount as the short-term debt component in Nicor Gas' projected 2018 test year capital structure, addresses two outstanding issues. First, it reconciles the difference between the Company's rate base and the capitalization supporting that rate base. Secondly, it more realistically reflects Nicor Gas' actual short-term debt balances of the past three years. Taking this very reasonable approach towards Nicor Gas' capital structure recognizes the Company's financing needs while at the same time it protects ratepayers from the burdens of an inflated rate base.

The AG responds to Nicor Gas' criticisms that AG witness Effron erred in applying the principle that rate base earning a return for a utility must be supported by investor-supplied funds in the form of capitalization. The Company's view includes the further suggestion that arguments presented against its capital structure "rest on witnesses' inferences from past periods when interest rates and Nicor Gas' investment needs were different..." Nicor Gas Ex. 29.0 at 5. The AG asserts that neither of Nicor Gas' claims undermine Mr. Effron's analysis.

The AG notes that Nicor Gas readily admitted that its capitalization must support its rate base. Tr. at 23-24. According to the AG, Nicor Gas nonetheless offered no explanation as to the huge gap between its 2018 test year rate base and its final total capitalization. Rather than explaining the substantial gap or to defend its proposed capital structure, Nicor Gas continued to rely on the vague suggestion that "there is no theoretical, mathematical or accounting reason why the two numbers should match." Id. The AG argues that Nicor Gas' stance that it need not account for this divergence cannot be reconciled with its admission that rate base earning a return must be supported by investor-supplied funds. It is further evident, as Nicor Gas witness Reese admitted under cross-examination, that even if the two amounts are not identical, there is a relationship between the two. But no matter how dismissive Nicor Gas has been about the need to reconcile its projected rate base and proposed capitalization, the Commission cannot ignore a \$162 million gap of this nature. The AG argues that it is not theoretically, mathematically, or financially justifiable, no matter the Company's claims to the contrary.

Nicor Gas also claims that rising interest rates for short-term debt require it to include less short-term debt in its capital structure. The AG responds that following cross-examination, Nicor Gas witness Reese testified on the interest rate trends for commercial paper. She described those rates as almost zero in 2008, rising slightly in 2015 and again on several occasions in 2017. Tr. at 33-34. The AG notes that on further cross-examination, she admitted the trend she observed has landed current short-term debt rates at "a little bit above 1 percent." Id. at 36. The AG points out that the rising interest rate trend for short-term debt that Nicor Gas claims justifies its proposed capital structure (and the almost \$162 million gap between its rate base and capitalization projections) amounts to a one percent increase over the course of nine years. The AG observes that the Commission should not rely upon this modest move in the cost of short-term debt to justify overlooking a very material \$162 million shortfall in the Company's capitalization.

The AG requests that the Commission should, as it did in Nicor Gas' last rate case, address the massive gap between the Company's projected capitalization and its rate base by assigning one half of the Company's average balance of short-term debt to its capital structure. Failing to do so means a windfall for investors. As recommended by AG witness Effron, the Commission should act to prevent an unfair burden on ratepayers by including \$161,413,000 in Nicor Gas' capital structure to close most of this gap and lower the cost of capital to be included in Nicor Gas' base rates.

d. IIEC-CUB's Position

Nicor Gas witness Reese sponsors the Company's proposed capital structure, which is based on the projected 13-month average capital structure for the calendar test year period ending on December 31, 2018. IIEC-CUB Ex.1.0 at 33.

IIEC-CUB point out that the Company asserts that its proposed capital structure would support its access to capital at reasonable cost and maintain its financial stability and balance sheet strength. Ms. Reese further testified that her proposed capital structure will support the Company's investments and cash flow needs while maintaining strong credit standing and ensuring Nicor Gas' continued access to capital markets under reasonable terms. Nicor Gas Ex. 2.0 at 16.

While the objectives enunciated by Nicor Gas witness Reese are reasonable, IIEC-CUB aver that Nicor Gas' proposed capital structure is not. IIEC-CUB claim that the proposed capital structure is far more expensive than necessary to accomplish the Company's stated financial goals. IIEC-CUB propose a capital structure with more balanced weights of debt and equity that will achieve Nicor Gas' stated goals of financial integrity and access to capital but at a more reasonable cost to customers. The proof of this conclusion, according to IIEC-CUB, is evidenced by: (1) a review of Nicor Gas' historical capital structure and bond rating; (2) a review of regulated gas utility industry capital structures that have supported access to significant amounts of capital under reasonable terms and conditions for the industry; and (3) a review of credit rating metrics that shows that IIEC-CUB's proposed capital structure produces credit metrics that are conservatively strong enough to support Nicor Gas' investment grade credit rating and financial integrity, but at a much lower cost to customers.

IIEC-CUB witness Gorman recommended a capital structure specifically designed to meet the objectives identified by Ms. Reese. While Mr. Gorman provided un rebutted evidence in support of a reasonable capital structure, IIEC-CUB maintain that Ms. Reese simply made assertions without any empirical support or verifiable justification. Mr. Gorman developed a ratemaking capital structure that reflects Nicor Gas' actual capital structure mix used over the last five years. He projected a test year capital structure based on determining appropriate capital structure weights that was based on the 2016 actual capital structure, adjusted for the amount of short-term debt excluding debt supporting CWIP. IIEC-CUB suggest that reflecting short-term debt in excess of CWIP is consistent with the Commission's findings in Nicor Gas' 2008 Rate Case Order. IIEC-CUB modified its proposed capital structure in rebuttal based on the Company's concern regarding exposure to interest rate risk. IIEC-CUB Ex. 3.0R at 43-44. IIEC-CUB recommend the following capital structure be used to set rates for Nicor Gas: a capital structure of 51.07% common equity, 48.344% long-term debt and 0.586% short-term debt. IIEC-CUB conclude that this capital structure will produce a much lower cost to retail customers, but is more than adequate to support the credit strength, financial integrity, and access to capital goals stated by Nicor Gas in support of an appropriate ratemaking capital structure.

The overall rate of return and related income tax can be impacted by the capital structure used to set rates. Mr. Gorman explained that a capital structure too heavily weighted with common equity creates an excessive rate burden on ratepayers as it

unnecessarily increases Nicor Gas' claimed revenue deficiency. IIEC-CUB Ex. 1.0 at 38. This is because common equity is far more expensive than debt capital and is subject to income tax expense. Id. Indeed, testified Mr. Gorman, common equity capital is more than three times as expensive on a revenue requirement basis than debt capital. Id. IIEC-CUB maintain that an approved capital structure for Nicor Gas should have a reasonable ratio of common equity and debt capital to balance ratepayer cost and Nicor Gas' financial risk and credit rating.

Mr. Gorman demonstrated the reasonableness of his proposed capital structure and the excessive weight of common equity in the Company's proposed capital structure. According to IIEC-CUB, one proof of this finding is a comparison of a leverage ratio considered by credit rating agencies in assessing utilities' bond ratings. Credit rating agencies consider leverage risk by developing an "adjusted" debt ratio. Mr. Gorman explained that this adjusted debt ratio reflects both on-balance sheet debt and off-balance sheet obligations. IIEC-CUB Ex. 1.0 at 42.

IIEC-CUB claim that Standard & Poor's ("S&P's") methodology for developing an adjusted debt ratio supports Mr. Gorman's conclusion that Nicor Gas' proposed capital structure has too little debt and too much equity, whereas Mr. Gorman's proposed capital structure has more of a reasonable debt/equity balance, which supports Nicor Gas' bond rating. IIEC-CUB Ex.1.0 at 43.

Using IIEC-CUB's proposed capital structure, Nicor Gas would have an adjusted debt ratio of 51.4%. IIEC-CUB report that Nicor Gas' current bond rating is A- and therefore its debt ratio would be reasonably in line with a debt ratio for a utility with a bond rating of A-. IIEC-CUB Ex. 1.0 at 42. Indeed, a little over 66% of all utilities with A- bond rating have debt ratios in excess of 50%. IIEC-CUB Ex. 1.0 at 43, Table 11. As such, IIEC-CUB claim their proposed capital structure is consistent with a majority of regulated utility companies who have bond ratings similar to that of Nicor Gas.

In significant contrast, IIEC-CUB point out that the Company's debt ratio would be 46%, as recommended by Company witness Reese. IIEC-CUB claim that this adjusted debt ratio is considerably lower than a majority of regulated utility companies with bond ratings similar to Nicor Gas. As such, IIEC-CUB state that Nicor Gas' proposed new capital structure, which reflects a significant increase in equity and reduction in debt ratio relative to the past five years, will result in a capital structure that is considerably out of line with industry norms, and is out of line with a capital structure that is adequate to support its investment grade bond rating. IIEC-CUB argue that Nicor Gas has provided no evidence in support of this changed capital structure and has provided no proof that this capital structure is necessary to accomplish the financial objectives articulated by Company witness Reese.

IIEC-CUB aver that the Company's proposed capital structure is seriously at odds with its actual historical capital structure, the Commission's findings in its most recent rate case, and capital structures found reasonable by other regulatory Commissions for utilities in rate case decisions.

Nicor Gas' actual historical capital structure over the period 2011-2016 is shown on IIEC-CUB Exhibit 1.5. IIEC-CUB point out that Nicor Gas maintained a consistent common equity ratio including all investor capital (including total short-term debt) of less

than approximately 45% as a percentage of total capital. In its projected capital structure, Nicor Gas is projecting a material increase to its common equity ratio of total capital to over 54% for the future test year. IIEC-CUB conclude that this increase in common equity ratio is not reasonable or justified. IIEC-CUB Ex. 1.0 at 35.

IIEC-CUB maintain that the Company's proposed capital structure in this docket is a material change from the Commission's capital structure findings in its last rate case. In the 2008 Rate Case, the Commission rejected the Company's original capital structure, which did not include short-term debt, and approved a ratemaking capital structure that did include short-term debt. 2008 Rate Case Order at 51; 2008 Rate Case Order on Reh. at 13. In the 2008 Rate Case Order, the Commission approved a capital structure that was composed of 51.07% common equity. IIEC-CUB Ex. 1.0 at 35, citing 2008 Rate Case Order on Rhg., Appendix A at 8.

In support of the Company's proposed capital structure, IIEC-CUB state that Ms. Reese refers to prior Nicor Gas orders that go back to 1995, more than 20 years ago. Nicor Gas Ex. 2.0 at 17. IIEC-CUB aver that these dated Commission orders are not useful in establishing a capital structure in today's environment. As discussed above, Nicor Gas was awarded a common equity ratio of 51.07% in the 2008 Rate Case, which IIEC-CUB point out is significantly lower than the Company's requested 54.2% equity ratio but comparable to IIEC-CUB's proposed common equity ratio of 50.9%. IIEC-CUB Ex. 1.0 at 37.

According to IIEC-CUB, Nicor Gas' historical capital structure awards are also comparable to recent awards to other Illinois utilities. The Commission need look no further than its recent decision in an Ameren gas rate case. There, Ameren agreed to set rates using a ratemaking capital structure that contains no more than 50% common equity. The Commission affirmed the capital structure that Ameren, Staff and IIEC all agreed should be used for ratemaking purposes. IIEC-CUB Ex. 1.0 at 37. Similarly, in the last IAWC case, the Commission approved a capital structure that contained 49.80% common equity. Ill.-American Water Co., Docket No. 16-0093, Order at 47 (Dec. 13, 2016). IIEC-CUB conclude that Nicor Gas' proposed capital structure is an outlier and far too expensive to be reasonable.

IIEC-CUB witness Gorman also provided evidence on capital structures typically used to set rates for regulated gas companies. A summary of the industry average common equity ratio used to set rates for regulated companies over the last eight years is summarized in IIEC-CUB Ex. 1.0 at Table 9.

IIEC-CUB show that Nicor Gas' proposed common equity ratio is significantly higher than the common equity ratio normally set for regulated natural gas companies. In comparison, IIEC-CUB's proposed capital structure including a common equity ratio of 51.07%, is reasonably in line with the median approved capital structure for the regulated gas industry over the last five years specifically, and eight years generally. As such, IIEC-CUB conclude that capital structure is reasonably consistent with industry norms for awarding a utility's overall rate of return.

IIEC-CUB note that it is important to recognize the authorized returns on equity and capital structures used to set rates have supported regulated utility companies' credit ratings, access to capital and strong stock price valuations. IIEC-CUB state that

industry awarded returns on equity and capital structures have met the standards of Hope and Bluefield of providing fair compensation, maintaining financial integrity, and have allowed the utilities access to significant capital under reasonable terms and prices. FPC v. Hope Natural Gas Co., 320 U.S. 591 at 64 S.Ct. 281 (1944) ("Hope"); Bluefield Waterworks & Imp. Co. v. Pub. Serv. Comm'n of the State of W. Vir., 262 U.S. 679 at 43 S.Ct. 675 (1923) ("Bluefield").

IIEC-CUB refute Nicor Gas' assertion that its proposed capital structure will maintain the strong credit ratings it has long enjoyed. IIEC-CUB claim that this statement does not support its proposed capital structure in this case for several reasons. First, its *current* capital structure has maintained its strong credit ratings. According to IIEC-CUB, what the Company now proposes is excessive. Second, IIEC-CUB maintain that the Company has provided no quantitative support, no justification from credit rating agencies' perspective, comments from the investment community, or any other source supporting its proposal to drastically increase the amount of common equity used to support its investments in utility infrastructure in this proceeding. IIEC-CUB aver that the Company's lack of evidence stands in stark contrast to that of IIEC-CUB. See *generally* IIEC-CUB Ex. 1.0 at 33-44.

IIEC-CUB observe that a primary argument relied upon by Nicor Gas is its increased capital investment risk. However, IIEC-CUB argue that the Company's evaluation of capital investment risk is severely flawed and deficient, because Nicor Gas ignores the substantial mitigation of this risk to the Company via the implementation of the QIP surcharge. According to IIEC-CUB, this surcharge allows Nicor Gas to adjust charges to customers to match charges with capital investment costs. Under current rates, approximately 15% of Nicor Gas' base revenue was being collected through the QIP surcharge. Thus, IIEC-CUB determined that the surcharge mitigates to a substantial degree its investment risk associated with increased capital investment.

IIEC-CUB respond to Nicor Gas' claim that the primary capital structure dispute centers on the claim that it will not actually achieve its year end 2018 capital structure. According to IIEC-CUB, the Company's arguments ignore the clear and un rebutted evidence that its business and financial risks place it among the strongest credit standing regulated utilities in the country. IIEC-CUB Ex. 1.0 at 30. IIEC-CUB maintain that Nicor Gas' bond rating of A- for Standard & Poor ("S&P") and A2 for Moody Investor Services ("Moody's") respectively, has been preserved while its historical actual capital structure has contained far less common equity than the Company's proposed 54% common equity ratio of total capital supporting rate base in this proceeding. *Id.* at 55.

In supporting its capital structure, IIEC-CUB state that they reviewed Nicor Gas' historical capital structure, and note that it has supported stable strong investment grade bond ratings during this historical period. But beyond a review of Nicor Gas' historical capital structure, IIEC-CUB argue that they considered far more market information to support its capital structure than that admitted to by the Company. IIEC/CUB Ex. 3.0R at 43. First, IIEC-CUB took into account leverage metrics consistent with industry practices to support a bond rating similar to, or stronger than, Nicor Gas. IIEC-CUB maintain that this review of S&P's adjusted debt leverage metrics demonstrated that the Company's proposed increased common equity ratio under its

forecasted capital structure would result in a capital structure mix that is far less leveraged and far more heavily weighted with common equity than an overwhelming majority of regulated utility companies with the same or stronger bond rating. IIEC-CUB Ex. 1.0 at 42- 43; IIEC-CUB Ex.1.7, Table 11.

Second, IIEC-CUB compare the Company's proposed capital structure to the common equity ratios typically awarded to natural gas companies by regulatory commissions. This comparison showed a relatively stable practice in the industry of awarding overall rates of return using capital structures for regulated natural gas companies with common equity ratios of approximately 49.9%-52.45%. IIEC-CUB observe that this stable capital structure position for natural gas companies has persisted for the last eight years. IIEC-CUB Ex. 1.0 at 39- 40, Table 9.

Furthermore, Nicor Gas takes issue with Mr. Gorman's testimony that the evidence in the case shows that Nicor Gas' previously approved common equity ratio has supported its bond rating in the past and will continue to do so in the future, by claiming that Mr. Gorman's analysis "ignores the uncontroverted evidence that it is investing several times greater than historical average levels of investment." Mr. Gorman testified that he did not ignore Nicor Gas' investment needs. He addressed it several times in his direct and rebuttal testimonies. IIEC-CUB, Ex. 1.0 at 32-33, 40; IIEC-CUB Ex. 1.4; IIEC-CUB, Ex. 3.0R at 7-8. What the Company chooses to ignore, according to IIEC-CUB is Mr. Gorman's conclusion: that his recommended capital structure would support Nicor Gas' need to access capital for its ongoing capital needs.

Finally, IIEC-CUB also demonstrate the substantial increase in Nicor Gas' revenue requirement if its proposed capital structure were to be adopted. Adjusting the Company's capital structure up to 54.20% equity rather than using a capital structure consistent with Nicor Gas' last approved regulatory capital structure (with 51.07% equity), and one that is consistent with industry average capital structures used to set rates for natural gas delivery companies, results in an increased revenue requirement of \$10.6 million, according to IIEC-CUB. IIEC-CUB Ex. 3.0R at 42. Nicor Gas' proposed capital structure with 54.20% equity is a substantial component of Nicor Gas' total claimed revenue deficiency in this proceeding. Based on this clear evidence, IIEC-CUB asserted that the Company's proposed increased common equity ratio is not needed to maintain its strong investment grade bond rating, maintain its financial integrity, and access to capital under reasonable terms and prices. Therefore, the increased cost of the Company's proposed capital structure is unjustified and should be denied.

IIEC-CUB next tackle Nicor Gas' issue with Staff's evidence that the Company's projected forecasted test year capital structure does not align with the capital structure the Company actually uses to finance its utility plant and equipment. IIEC-CUB observe that Staff had changed its proposed capital structure in reaction to the deferral of certain debt issuances. Staff Ex. 8.0 at 1-2. Staff's proposed capital structure is based on projected debt balances. Staff Ex. 8.0 at 31. IIEC-CUB point out that Staff witness Phipps testified that the Company's long-term debt forecast is not reliable and that is why she revised her capital structure. Tr. 248 and 249.

According to IIEC-CUB, Staff demonstrated that, though the Company's projection is to substantially increase its common equity ratio for the forecasted 2018

test year, its actual practices have been to use more of a balanced mix of debt and equity. IIEC-CUB summarize Staff's position as arguing that the Company has not made a reasonable effort to achieve the substantial increase in common equity ratio that reflects the projected test year capital structure. IIEC-CUB state that instead Staff's evidence shows that the Company's practice appears to align with the prudent expectation, to continue to finance its capital structure using a mix of debt and equity, that aligns with what it has actually used historically, and which has successfully supported its stand-alone investment grade bond rating that is among the strongest in the regulated utility industry. IIEC-CUB Ex. 3.0R at 8-9.

The Company argues that the timing changes in investment capital do not mean that it will not ultimately achieve its projected capital structure within the test year: "Deferring issuances does not change investment needs, nor did the deferrals materially change any year end 2018 equity or debt ratio." Nicor Gas Ex. 29.0 at 9. IIEC-CUB argue that the timing changes in its debt issuance is not the issue. What is more important to IIEC-CUB is whether there is a need for the Company to increase its common equity ratio in the test year. IIEC-CUB conclude that there is no such need, and in fact it is imprudent for it to do so because it unnecessarily increases cost to its customers. IIEC-CUB aver that the Company's proposed capital structure unjustifiably increases rates to retail customers with no verifiable benefit to customers. IIEC-CUB conclude that the Company should not be allowed to set rates reflecting a substantial change to its capital structure that substantially increases charges to customers and which is not necessary in order to achieve the financial objectives the Company clearly identifies.

e. Stipulation

On November 15, 2017, Staff and the Company entered a Stipulation to address rate of return issues in this docket, including capital structure. According to the Stipulation, based upon the totality of evidence in the record, Staff and Nicor stipulate that an overall rate of return of 7.256% is reasonable for ratemaking purposes. (Stipulation, 3.) This overall rate of return is based, in part, on a capital structure comprising 47.414% long-term debt, 0.586% short-term debt and 52.00% common equity.

The Stipulation recognizes that the long-term debt ratio of 47.414% falls within the range established by the AG's proposal on the low end (41.327%) and IIEC/CUB's proposal on the high end (48.344%), with Nicor Gas (42.942%) and Staff (42.329%) recommendations also falling within this range. Stipulation, 4.

The Stipulation recognizes that the short-term debt ratio of 0.586% is equivalent to IIEC/CUB's proposal. (Id.)

The Stipulation recognizes that the common equity ratio of 52.00% falls within the range established by IIEC/CUB's proposal (51.07%) and Nicor Gas (54.504%), with Staff (52.664%) and AG (52.454%) recommendations also falling within this range. (Id.)

f. Commission Analysis and Conclusion

In considering non-unanimous settlements or stipulations, the Illinois Supreme Court has held that any non-unanimous proposal to resolve issues in a litigated

proceeding at the Commission must be supported by substantial evidence based on the entire record before the Commission, and otherwise be in accordance with established law. Bus. and Prof'l People for the Pub. Interest v. Ill. Commerce Comm'n, 136 Ill.2d 192, 216-217 (1989) ("BPI I"). "Substantial evidence" means more than a mere scintilla, but it does not have to rise to the level of a preponderance of the evidence. ComEd, 405 Ill.App.3d at 398, 344 Ill.Dec. 662, 937 N.E.2d 685.

As described above, the Commission finds the Stipulation introduced by Nicor Gas and Staff to be reasonable, as all components fall within the range of proposals advocated by each party, and therefore adopts a December 31, 2017 capital structure for Nicor Gas that contains 52.00% common equity, 47.414% long-term debt and 0.586% short-term debt.

2. Cost of Short-Term Debt, Including Credit Facility Fees

a. Nicor Gas' Position

As part of the Stipulation, Nicor Gas recommends a short-term debt cost of 1.33% and a credit facility cost of 0.023%. Nicor Gas Ex. 39.1. Nicor Gas and Staff state that this short-term debt cost is supported by the record, as it falls within the range established by Staff's and Nicor Gas' testimony setting out different methods of establishing such costs. Notably, the IIEC/CUB and AG short-term debt cost recommendations also fall within that same range. It also adopts the Staff's proposed credit facility cost. Nicor BOE. at 12; Nicor Gas Ex. 39.1. Nicor Gas' previously proposed short-term debt cost, which is taken into account in the Stipulation, is 3.79%. Nicor Gas Ex. 29.1. While Nicor Gas recommends the short-term debt cost included in the Stipulation, Nicor Gas' positions supporting its previously proposed short-term debt cost are included here since the Stipulation is based on the recommendations advanced by all the parties in their briefs.

Nicor Gas' original proposal presents a cost of short-term debt, including interest costs and credit facility fees, of 3.79% per year. Nicor Gas Ex. 29.1; Nicor Gas Ex. 2.0 at 20-21. Nicor Gas argues that this rate is realistic and based on reliable forecasts of short-term interest rates during the period when that debt will be outstanding. Nicor Gas presented evidence to support that cost, including both analysts' and economic forecasts — types of evidence about future costs that are routinely accepted in establishing forward-looking components of the cost of capital.

Nicor Gas argues that Staff's proposed 1.00% cost of short-term debt is not realistic because it is based on outdated information and does not take into account the current climate of rising interest rates. Staff Ex. 3.0 at 72-73; Tr. at 234. Nicor Gas presented evidence that the interest rate Staff used to derive its proposal had risen more than 15% from the date it was pulled to the date of the hearings in this proceeding. Nicor Gas Ex. 29.0R at 19. Nicor Gas asserts that since this is 60-day debt, nearly all of the short-term debt outstanding in the test year will be issued in 2018; only the small amount of debt issued at the end of 2017 will extend into 2018. Nicor Gas argues that it is inappropriate to apply this interest rate to debt that will be outstanding during the test year, essentially all of which will be issued in 2018.

Nicor Gas also disagrees with Staff's proposal to lower the Company's cost of short-term debt in light of its affiliated companies. Nicor Gas disagrees with Staff's contention that Nicor Gas' Moody's and S&P ratings are negatively impacted by its affiliation with Southern Company Gas and The Southern Company. Staff Ex. 8.0 at 43. Nicor Gas supports its argument with the most recent Moody's report, issued in July 2017, which identifies Nicor Gas' affiliation with The Southern Company as a credit strength. Nicor Gas Ex. 29.0R at 20.

Nicor Gas also opposes Staff's proposal to include credit facility fees as a cost to the overall cost of capital, rather than to the cost of short-term debt. Staff Ex. 8.0 at 37-38. Nicor Gas argues that regardless of whether it makes an impact in this particular case, as Staff argues it does not, these fees are properly recovered as a cost of the debt that they support. Nicor Gas Ex. 2.0 at 20-21.

Nicor Gas argues that IIEC-CUB and the AG's proposals of 1.85% and 1.97%, respectively, should also be rejected because they are based on historical interest rates. IIEC/CUB Ex. 1.0 at 45; AG Ex. 1.0 at 43. Nicor Gas argues that these proposals ignore the current interest rate trend and economists' forecasts and will result in an underestimated interest cost for the debt outstanding in the test year. Nicor Gas further notes that, although AG witness Effron proposes a 1.97% cost of short-term debt in his testimony, the AG did not advocate for this position in briefing.

b. Staff's Position

As part of the Stipulation, Staff recommends a short-term debt cost of 1.33% and a credit facility cost of 0.023%. Nicor Gas and Staff state that this short-term debt cost is supported by the record, as it falls within the range established by Staff's and Nicor Gas' testimony setting out different methods of establishing such costs. Notably, the IIEC/CUB and AG short-term debt cost recommendations also fall within that same range. It also adopts the Staff's proposed credit facility cost. Staff BOE. at 11; Nicor Gas Ex. 39.1.

Staff's previously proposed short-term debt cost, which is taken into account in the Stipulation, is 1.00% per year, with credit facility fees of 0.023%. Staff Ex. 3.0 at 72-73; Staff Ex. 8.0 at 35-36; Sch. 8.01 and 8.06. While Staff recommends the short-term debt cost included in the Stipulation, Staff's positions supporting its previously proposed short term debt cost and credit facility fees are included here since the Stipulation is based on the recommendations advanced by all the parties in their briefs.

Ms. Phipps estimated the Company's cost of short-term debt using current commercial paper rates. Specifically, she recommends a 1.00% cost of short-term debt for the Company, which she calculated by converting the June 8, 2017 0.98% discount rate on 60-day, AA non-financial commercial paper into an annual yield. Staff Ex. 3.0 at 72-73.

Staff disagrees with Nicor Gas on its usage of forecasted interest rate over current short-term debt rate. Nicor Gas Ex. 25.0 at 14-15. Although the Company suggests that forward curves should be used to estimate the cost of short-term debt, it does not propose any methodology for estimating the cost of short-term debt in that manner. Staff Ex. 8.0 at 34. The Commission cannot evaluate a methodology that is

not specified and the Company's proposal should be rejected. Moreover, forward rates reflect expectations regarding future rates, but actual interest rates in the future may differ from those expectations. Staff Ex. 8.0 at 39.

Ms. Phipps testified that Section 9-230 of the Act prohibits including any increased cost of capital which is the direct or indirect result of the public utility's affiliation with unregulated or non-utility companies in a utility's allowed rate of return when it states:

In determining a reasonable rate of return upon investment for any public utility in any proceeding to establish rates or charges, the Commission shall not include any (i) incremental risk, (ii) increased cost of capital...which is the direct or indirect result of the public utility's affiliation with unregulated or nonutility companies.

220 ILCS 5/9-230. Thus, in accordance with Staff's understanding of Section 9-230 of the Act, Ms. Phipps adjusted the debt ratings – including commercial paper ratings – for Nicor Gas to remove any incremental risk or increased cost of capital resulting from the Company's affiliation with unregulated or nonutility companies. Staff Ex. 3.0 at 79.

Ms. Phipps explained that the credit ratings that S&P and Moody's assign Nicor Gas are negatively affected by the Company's affiliation with unregulated and nonutility companies. Ms. Phipps explained that when The Southern Company acquired AGL Resources, Inc., S&P raised the issuer credit ratings on AGLR and its subsidiaries, including Nicor Gas stating, "We are raising the issuer credit rating on AGL Resources, Inc. and...Nicor Gas Co...to 'A-' from 'BBB+', in line with that of its new parent." Staff Ex. 3.0 at 75-76. Importantly, S&P expressly states that Nicor Gas' issuer rating is capped at the group rating level. Id. at 77. As S&P explains, "The recent acquisition of AGL Resources, Inc. is sufficiently large to somewhat de-emphasize, but not offset, the impact of [The Southern Company's] non-utility operations, including Southern Power." Id.

Further, S&P expressly states that the standalone credit profile of Nicor Gas is 'a+', which is two notches higher than the A- issuer rating that S&P currently assigns Nicor Gas. Staff Ex. 3.0 at 80. Thus, Ms. Phipps assumes that Nicor Gas' corporate credit rating from S&P would be A+ or higher if not for its affiliation with AGLR and The Southern Company. Id. at 80-81. An A+ issuer rating from S&P correlates to a commercial paper rating of A-1, which is higher than the commercial paper rating that S&P currently assigns Nicor Gas. Id. at 81.

Ms. Phipps also explained that Moody's expressly states that the rating it assigns Nicor Gas considers that Nicor Gas supports, at least partially, Southern Company Gas' holding company debt. Id. at 77-78. Therefore, Ms. Phipps concluded that Moody's rating methodology indicates an implied standalone issuer rating of A1 for Nicor Gas, which is one notch higher than the Company's actual issuer rating of A2 from Moody's, after removing the effects of its affiliation with unregulated or nonutility companies. Staff Ex. 3.0 at 78-81. An A1 issuer rating corresponds to a commercial paper rating of P-1, which is the commercial paper rating that Moody's assigns Nicor Gas. Id. at 80.

Staff points out that the Illinois Appellate Court noted the prohibition against including any costs stemming from a utility's affiliation with an unregulated or nonutility company and specifically pointed to the word "any" as evidencing the legislature's intent to "modify its prohibition of considering incremental risk or increased cost of capital in determining a reasonable [rate of return]." Ill. Bell Tel. Co. v. Ill. Commerce Comm'n, 283 Ill.App.3d 188, 205-207 (2nd Dist. 1996). Accordingly, the Commission has no discretion to consider the causes of a utility's increased cost of capital due to its affiliation with a non-utility company; any increase must be excluded. "We hold that if a utility's exposure to risk is one iota greater, or it pays one dollar more for capital because of its affiliation with an unregulated or nonutility company, the Commission must take steps to ensure that such increases do not enter its ROR calculation." Id. The Court concluded that, if the Commission found that an affiliation caused an increased cost of capital, the Commission would have to determine the amount of this increase and then remove it from the rate of return calculation. Id. at 210.

Staff states that the Act says that a utility ultimately bears the burden of proving that its proposed rates are just and reasonable. 220 ILCS 5/9-210(c). However, the Commission must ensure that, if a utility pays more for capital because of its affiliation with an unregulated or non-utility company, such increased costs are not considered in its rate of return calculation. The record evidence demonstrates that is the situation in this proceeding.

Staff adjusted Nicor Gas' debt costs to remove the effects of Nicor Gas' riskier unregulated and non-utility affiliates after thoroughly examining rating reports and publications regarding Nicor Gas and the rating methodologies of S&P and Moody's. Staff Ex. 3.0 at 77-78. The Company's proposed debt costs do not include these legally mandated adjustments. Thus, the Company's arguments should not be given any weight in this proceeding.

Ms. Phipps recommends a weighted cost of credit facility fee of 0.023% for the Company based on the actual annual cost associated with the revolving credit facility. Staff Ex. 8.0 at 35-36; Sch. 8.01 and 8.06. Credit facility fees are the one-time, upfront costs and annual fees associated with revolving credit facilities. Staff Ex. 3.0 at 73.

On May 11, 2017, the Company and its affiliate Southern Company Gas Capital Corporation ("SCGCC") entered into five-year revolving credit facilities totaling \$1.9 billion. Staff Ex. 3.0 at 73. The revolving credit facilities have a \$500 million borrowing sub-limit for Nicor Gas and a \$1.4 billion borrowing sub-limit for SCGCC. Staff Ex. 8.0 at 34. Thus, Ms. Phipps calculated Nicor Gas' pro rata share of one-time fees (i.e., upfront fees, arranger fees, legal and bank out-of-pocket expenses) and Nicor Gas' annual administrative and facility fees based on the Company's \$500 million borrowing sublimit. Staff Ex. 8.0 at 34.

The Company's cost of short-term debt and bank commitment fees (or credit facility costs – i.e., fixed costs the Company incurs for the ability to borrow up to \$500 million on a short-term basis via its revolving credit facility) are based on Nicor Gas' actual corporate credit ratings from each of the credit rating agencies. Nicor Gas Ex. 15.0 at 25. Nicor Gas' actual credit ratings are lower than the implied standalone credit ratings of Nicor Gas. Given that Section 9-230 of the Act requires the Commission to

remove any incremental or increased cost of capital which is the direct or indirect result of a public utility's affiliation with unregulated or non-utility companies, Ms. Phipps calculated facility fees using the margin that corresponds to the Company's implied standalone issuer credit ratings. Staff Ex. 8.0 at 35.

Staff states that currently, the Company's senior unsecured debt ratings are A2 from Moody's, A- from S & P and A+ from Fitch Ratings ("Fitch"). Staff Ex. 3.0 at 80. Ms. Phipps explained that the implied standalone senior unsecured debt ratings of Nicor Gas would be A1/A+ from Moody's/S&P, if not for the Company's affiliation with unregulated or non-utility companies. Staff Ex. 8.0 at 35. Her conclusion is based on the statements of S&P and Moody's regarding how those rating agencies view the effect of Nicor Gas' non-utility affiliates on the Company's credit ratings. Id. Fitch assigns Nicor Gas an unsecured debt rating of A+. Id. Thus, Ms. Phipps calculated annual facility fees by multiplying the \$500 million sublimit applicable to Nicor Gas by the Level II facility fee rate, as required by Section 9-230 of the Act. Id.

The sum of the Company's annualized one-time expenses and annual administrative and facility fees equal the Company's total credit facility dollar costs for ratemaking purposes. Staff Ex. 8.0 at 35; Sch. 8.06. To calculate the cost of credit facility fees that should be added to the Company's cost of capital, Ms. Phipps divided the total annual credit facility fees by total capitalization. Id. This calculation results in a credit facility fee cost of 0.023% for the Company. Staff Ex. 8.0 at Sch. 8.01 and 8.06. Thus, Ms. Phipps recommends adding 2 basis points (0.02%) to Nicor Gas' overall cost of capital for the costs associated with the Company's revolving credit facility. Staff Ex. 8.0 at 36.

Ms. Phipps explained that Nicor Gas pays fixed credit facility costs for its loan agreement which allows the Company to borrow short-term funds on demand. This fixed cost is properly shown as a separate line item on the cost of capital schedule, rather than included in the cost of short-term debt as advocated by the Company, because credit facility fees do not vary with the amount of short-term debt the Company actually borrows. Staff Ex. 8.0 at 36. Ms. Phipps' calculation includes all costs the Company incurred with the revolving credit facility that are permissible under Section 9-230 of the Act. Staff Ex. 8.0 at 37; Sch. 8.06. Moreover, by separating the fixed costs (i.e., credit facility fees) from the interest expense, Ms. Phipps' approach provides additional detail and clarity. Staff Ex. 8.0 at 38. The methodology advocated by Staff has been adopted by the Commission in numerous past rate proceedings and should be adopted in this case as well. See, e.g., Ameren Ill. Co. d/b/a Ameren Ill., Docket No. 13-0192, Order at 167 (Dec. 18, 2013); Central Illinois Light Co. d/b/a AmerenCILCO, Central Ill. Public Service Co., d/b/a AmerenCIPS and Ill. Power Co. d/b/a AmerenIP, Docket Nos. 09-0306-09-0311 Cons., Order at 152-158 (Apr. 29, 2010).

As discussed more fully below, Staff supports the cost of short-term debt set forth in the Stipulation. If the Commission declines to adopt the stipulated cost of short-term debt, it should adopt a cost of short-term debt in accordance with Staff's recommendations.

c. IIEC-CUB's Position

IIEC-CUB aver that Nicor witness Reese's proposed short-term debt cost of 8.52% reflects Nicor Gas' proposed short-term debt balance, which is significantly less than the historical short-term balance. Therefore, Mr. Gorman adjusted the Company's proposed short-term debt cost to 1.85%, to reflect the higher short-term debt balance included in his proposed capital structure. IIEC-CUB Ex. 1.0 at 44-45.

To correct the short-term debt level, Mr. Gorman applied the Company's 2017 short-term debt interest rate of 1.47% to the 13-month average short-term debt balance of \$335,133,000 as developed on IIEC-CUB Exhibit 1.6, page 2, to obtain the interest expense of \$4,910,000. He next applied this interest expense along with Nicor Gas' estimated 2017 bank fee expense of \$1,304,000 to the 13-month average short-term debt balance, which results in an adjusted cost of short-term debt of 1.85%. IIEC-CUB Ex. 1.0 at 45. However, in recognition of the Company's concern about exposure to a large amount of short-term debt interest rate risk, Mr. Gorman proposed a capital structure that still reduces the excessive amount of common equity requested by Nicor Gas but addresses the interest rate exposure for the Company. IIEC-CUB Cross Ex. 3.0R at 43-44, Table I.

IIEC-CUB maintain that the short-term debt level proposed by Mr. Gorman is reasonable because it reflects Nicor Gas' projected cost of debt for 2017 and Mr. Gorman's adjusted capital structure, which includes a short-term debt balance consistent with Nicor Gas' historical level as discussed elsewhere. IIEC-CUB Ex. 1.0 at 45.

IIEC-CUB disagree with Nicor Gas' assessment of rising interest rates. Mr. Gorman's IIEC-CUB Exhibit 1.20 shows that economists consistently have been projecting that interest rates will increase over several years. However, IIEC-CUB observe that those yield projections have turned out to be overstated in almost every case. Indeed, IIEC-CUB point out that actual Treasury yields have decreased or remained flat over the last several years rather than increased as the economists' projections indicated. As such, IIEC-CUB conclude that current observable interest rates are just as likely, maybe more likely, to accurately predict future interest rates as are current economists' projections. IIEC-CUB Ex. 1.0 at 105. IIEC-CUB therefore argue that the Company's reliance on rising interest rates lacks evidentiary support.

d. Stipulation

The Stipulation between the Company and Staff recommends a 1.33% cost of short-term debt and a weighted cost of 0.023% for credit facility cost. The Stipulation recognizes that the cost of short-term debt falls within the range established by Staff (1.00%) and Nicor Gas (3.73%) – with IIEC/CUB (1.85%) and the AG (1.97%) recommendations also falling within that range. Stipulation, 4. Thus the Company and Staff recommend that the Commission adopt the cost of short-term debt agreed to in the Stipulation.

e. Commission Analysis and Conclusion

The Commission finds that prior to the Stipulation proposed by Staff and the Company, each party's short-term debt cost proposals relied on questionable

assumptions that led to recommendations that were either too high or too low. The Commission finds the recommendation of 1.33% for short-term debt cost as proposed by the Stipulation to be a balanced and reasonable recommendation. Furthermore, the Stipulation is supported by substantial evidence that includes both the Supplemental and Supplemental Rebuttal testimony of Dr. Villadsen and the evidence provided by other witnesses supporting a 1.33% cost of short-term debt and a weighted cost of 0.023% for credit facility cost. It falls within the range established by Staff (1.00%) and Nicor Gas (3.73%) – with IIEC/CUB (1.85%) and the AG (1.97%) recommendations also falling within that range. Nicor Gas Ex. 39.1 at 4. The arguments against the Stipulation largely consisted of assertions that only their witnesses' views should prevail. IIEC/CUB Init. No specific reasons were offered as to why a 1.33% short-term debt cost is unreasonable.

3. Cost of Long-Term Debt

a. Nicor Gas' Position

As part of the Stipulation, Nicor Gas recommends a long-term debt cost of 4.49%. Nicor Gas Ex. 39.1. Nicor Gas and Staff state that this long-term debt cost is supported by the record, as it is equal to Staff's long-term debt cost proposal and considers the full record of proposals in this proceeding. Nicor Gas Ex. 39.1.

While Nicor Gas recommends the long-term debt cost included in the Stipulation, Nicor Gas' positions supporting its previously proposed long-term debt cost are included here since the Stipulation is based on the recommendations advanced by all the parties in their briefs. Nicor Gas' original proposal includes a cost of long-term debt of 4.52%. Nicor Gas Ex. 29.0R at 2. Nicor Gas states that this rate takes into account Nicor Gas' adoption of Staff's proposed adjustment to the calculation of the interest rate applicable to the 2018 debt issuance. Nicor Gas Ex. 14.0 at 27; Nicor Gas Ex. 29.1. Nicor Gas argues that Staff's proposed long-term debt interest rate of 4.49% should be rejected because: (1) it does not take into account economists' forecasts of rising interest rates; and (2) because it inappropriately penalizes Nicor Gas for its affiliate relationships. Nicor Gas Ex. 15.1 at 1.

b. Staff's Position

As part of the Stipulation, Staff recommends a long-term debt cost of 4.49%. Nicor Gas Ex. 39.1. Nicor Gas and Staff state that this long-term debt cost is supported by the record, as it is equal to Staff's pre-Stipulation long-term debt cost proposal and considers the full record of proposals in this proceeding. Nicor Gas Ex. 39.1.

c. IIEC-CUB's Position

Mr. Gorman used the Company's proposed cost of long-term debt in his calculation of an overall weighted cost of capital. IIEC-CUB accepted the Company's first proposed cost of long-term debt. IIEC-CUB Ex.1.0 at 44.

d. Stipulation

The Stipulation between Staff and the Company adopts Staff's proposal of 4.49% cost of long-term debt.

e. Commission Analysis and Conclusion

Prior to the Stipulation entered between Staff and the Company, Staff was the only party to provide significantly substantive evidence to support their long-term debt cost recommendation. IIEC-CUB simply adopted the first long-term debt cost suggested by Nicor. IIEC-CUB Ex.1.0 at 44. Nicor no longer supports that position, even if the Stipulation was to be disregarded. Nicor Gas Ex. 29.0R at 2. Thus, the Commission finds the long-term debt cost in the Stipulation to be reasonable, as it is equal to Staff's long-term debt cost proposal, and therefore adopts the long-term debt cost of 4.49%.

4. Cost of Common Equity

a. Nicor Gas' Position

As part of the Stipulation, Nicor Gas recommends a cost of common equity ("return on equity" or ROE) of 9.80%. Nicor Gas Ex. 39.1. This recommendation is based on the proposals of all the ROE witnesses in this proceeding. Dr. Villadsen testified that the Stipulation "constitute[s] a reasonable approach to weighing the cost of equity calculations and recommendations of all the witnesses" and the 9.80% ROE utilized by the Stipulation falls within the range of ROE estimates she obtained and considered in her own analysis. Nicor Gas Ex. 40.0 at 3. Dr. Villadsen's opinion of the Stipulation does not reflect any lack of confidence in her own views; it reflects the acknowledged fact that there is a range of reasonable results.

The Company's original recommendation was developed by Nicor Gas witness Dr. Bente Villadsen, who calculated her ROE estimate using methodologies accepted in modern corporate finance and who relied on input data – including interest rate and equity risk premium data – matched to the future test year costs being measured and to the particulars of Nicor Gas, including its operating and financial risk characteristics. Nicor Gas Ex. 11.0 at 6-32, 54-62. Nicor Gas notes that Dr. Villadsen also relied upon sample data from comparable publicly-traded natural gas utilities subject to rate regulation and utilized multiple calculation methods and analyzed Nicor Gas' particular activities and risks to ensure that the recommended ROE fairly represents Nicor Gas' situation. Id. at 66-67.

Nicor Gas stresses that it is important for the Commission to consider a variety of models, as they provide different insights into the required return, and that the Commission has regularly considered the results from several methodologies in determining the allowed ROE. Dr. Villadsen considered the Capital Asset Pricing Model ("CAPM"), the Discounted Cash Flow ("DCF") model, and a specific type of general Risk Premium model. Id. at 2.

Dr. Villadsen presented a CAPM analysis that calculated Nicor Gas' cost of equity based on risk free rates matched to the future test year during which Nicor Gas' capital costs will be incurred. Nicor Gas Ex. 11.0 at 34. Dr. Villadsen's CAPM analysis applied techniques including the "Hamada adjustment" to consider Nicor Gas' financial risk in light of differences among the degrees of financial leverage of Nicor Gas and the publicly-traded companies on whose market stock returns the other CAPM inputs are based. Dr. Villadsen also utilized an empirical CAPM model to correct for known biases in the CAPM methodology. Nicor Gas Ex. 25.0 at 31. While Nicor Gas acknowledges

that the Hamada adjustment has not yet been affirmatively endorsed by the Commission, Nicor Gas argues that it is established and recognized without controversy in both academia and by financial practitioners as being essential to arriving at unbiased results. Id. The result of Dr. Villadsen's CAPM-based methods produced a reasonable range of ROEs for Nicor Gas of 10.0% to 11.0%, with a midpoint of 10.5%. Nicor Gas Ex. 11.0, Figure 19 at 63.

Dr. Villadsen performed a DCF model analysis that calculated Nicor Gas' cost of equity based on the value of its estimated future cash flows and the growth of those flows. Id. at 45- 47. Nicor Gas asserts that this methodology is forward looking and reflects forecasts of future Nicor Gas' market performance. Id. at 48. Dr. Villadsen also calculated the degree to which the impact on the required equity returns is affected by the differences in financial leverage between Nicor Gas and the sample of companies from which her market data – and the market data the other witnesses used – was taken. Id. at 58. The result of her DCF-based methods was range of reasonable ROEs of 9.4% to 10.4%, with a midpoint of 9.9%. Id. at 50.

Nicor Gas states that the particular risk premium model Dr. Villadsen employed, which she refers to as an “implied risk premium” methodology, relies on the evaluation of decades of market data by regulatory agencies and uses statistical techniques to assess how those allowed returns vary with respect to the level of risk-free interest rates. Id. at 66-67. The risk premium method determines the risk premium over and above a risk-free rate (or a bond yield) that investors in other regulated companies have access to and use the information to derive a cost of equity using the expected/forecasted risk-free rate (or bond yield) at the time rates go into effect. Nicor Gas argues that the use of a risk premium model is necessary to account for Nicor Gas' position in relation to the returns of entities which Nicor Gas will have to compete with for investor capital. The result of her implied risk premium methods was range of reasonable ROEs of 10.1% to 10.3%. Nicor Gas Ex. 37.0 at 5.

Nicor Gas asserts that while various risk premium models have been rejected in the past, the CAPM is an accepted risk premium model itself, and Dr. Villadsen's risk premium model, which uses statistical regression to account for prevailing risk free interest rates at the time various historical allowed ROEs were granted, has not been rejected by the Commission. Based on the record in this case, Nicor Gas argues that it provides the Commission with additional, useful data and should be considered in this case. Nicor Gas asserts that this model should gain increasing use in the utility industry, particularly as the sample of companies available for “traditional” DCF analysis shrinks due to mergers and the addition of non-utility activities. The implied risk premium model, Nicor Gas states, provides reliable independent data in light of this circumstance. Finally, Nicor Gas argues that, in addition to Dr. Villadsen's calculations being supported by the evidence, her use of such a model is supported by its wide approval in the field of economics as well as by its use by other regulatory commissions. Nicor Gas Ex. 11.0 at 2.

Dr. Villadsen took the results of her CAPM, DCF, and implied risk premium model analyses and calculated a reasonable range of ROEs for Nicor Gas of 10¼ - 10¾ percent. Nicor Gas argues that it is appropriate, after calculating the range of reasonable ROEs, to place Nicor Gas in the higher end of the range to account for its

measurably high operating leverage. Id. at 3. Dr. Villadsen determined Nicor Gas' operational leverage by calculating indicators of fixed versus variable costs and by empirically measuring the sensitivity of Nicor Gas' operating profits to changes in sales revenue. Nicor Gas Ex. 25.0 at 40-42. Nicor Gas argues that, in comparing these calculations to corresponding metrics for the proxy companies, Dr. Villadsen showed conclusively and quantitatively that Nicor Gas has higher operating leverage than the sample companies. Nicor Gas notes that while Staff devotes much attention to some theorized causes of the higher operating leverage, they do not counter the fact that Nicor Gas has a higher operating leverage. Nicor Gas asserts that the existence of higher operating leverage, not why it exists, is the relevant question for Nicor Gas' cost of capital. Nicor Gas further points out that, considering that the Company's capital expenditures have been and are expected to continue to be substantially higher than capital expenditures by the average company in the sample, Dr. Villadsen took Nicor Gas' elevated operating leverage into account in determining that Nicor Gas should be placed higher in the range of reasonable ROE estimates. Nicor Gas notes that this is a reasonable methodology that is academically supported and accepted in the field of financial economics. Id. at 7.

Nicor Gas argues that the use of a risk premium method is important because the Company competes for capital, and Nicor Gas' allowed return must allow it to complete on equal term with other "similar risk" companies. Nicor Gas asserts that the use of a risk premium method provides information about available returns for other utilities, which investors take into consideration in valuing an investment in Nicor Gas.

Nicor Gas and Staff stipulate that, based upon the totality of the evidence in the record concerning Nicor Gas' 2018 Test Year ROR, an overall ROR of 7.256% is reasonable, for ratemaking purposes, and will seek approval of such an ROR in this docket based upon the following inputs:

Capital Component	Ratio	Cost	Weighted Cost
Short-term Debt	0.586%	1.33%	0.008%
Long-term Debt	47.414%	4.49%	2.129%
Common Equity	52.000%	9.80%	5.096%
Credit Facility Cost			0.023%
Total	100%		7.256%

Dr. Villadsen presented Supplemental Testimony assessing the reasonableness of the Stipulation's recommended overall ROR of 7.256% and determined that it falls within a reasonable range that she recommends. Nicor Gas Ex. 39.0R at 3. In arriving at this conclusion, Dr. Villadsen also noted that the Stipulation is consistent with the view that the Commission can assess the totality of the evidence to determine a reasonable ROR. Id. at 3.

In the first phase of the docket, Nicor Gas presented to the ALJs and the Commission alternative methods to arrive at a reasonable cost of capital based on the evidence. On Reopening, Nicor Gas provided additional support for those averaging methodologies. See Villadsen Rev. Supp., Nicor Gas Ex. 39.0R at 2. The alternative calculations Nicor Gas suggested in its Reply Brief and draft order are methods of

taking into consideration the evidence in the record as a whole, consistent with past Commission practice of utilizing results from different witnesses and methodologies to determine a reasonable ROE for ratemaking purposes. Id. The Stipulation entered into by Nicor Gas and Staff proposes a reasonable overall rate of return based on the evidence in the record. Nicor Gas and Staff have examined all the evidence from all parties in the record and each concluded that an ROR of 7.256% falls within the range of reasonable results and is an appropriate ROR for ratemaking purposes. See Nicor Gas Ex. 39.1.

Dr. Villadsen also testified that an ROR of 7.256% falls within the range of reasonable ROR results for the Company. Nicor Gas Ex. 39.0R, 3. She observed that this ROR falls “within a reasonable range observed for regulated natural gas utilities in the recent past, which is conservative given present conditions of rising interest rates and cost of capital.” Nicor Gas Ex. 40.0 at 2-3. Furthermore, Dr. Villadsen states that the 9.8% “(i) is part of an agreement that considers other aspects of the rate case and produces a reasonable overall allowed ROR, (ii) is in the range of what has been recommended, and (iii) recognizes that the Commission in past decisions has relied on various methods to arrive at an allowed ROE by aggregating the evidence presented.” Id. at 4.

Nicor Gas claims that the components of the 7.256% ROR are substantially supported by the record. See Nicor Gas Ex. 39.1 at ¶¶ 2-7, and the evidence cited therein. These inputs consider the proposals of all parties, not just Nicor Gas and Staff, and take into account the full record in this proceeding. Specifically, the Stipulation’s short-term debt ratio is equivalent to IIEC-CUB’s proposal, and the cost of short-term debt falls within the range established by Staff’s and Nicor Gas’ recommendations – with IIEC-CUB’s and the AG’s short-term debt costs also falling within that range. The Stipulation’s long-term debt ratio falls within the range established by the AG’s proposal on the low end and IIEC-CUB’s proposal on the high end, with Nicor Gas’ and Staff’s recommendations also falling within this range, and the long-term debt cost is equivalent to Staff’s proposal. The Stipulation’s common equity ratio falls within the range established by IIEC-CUB’s proposal and Nicor Gas’ proposal – with Staff’s recommendation and the AG’s recommendation also within this range. The Stipulation’s ROE falls within the range established by IIEC-CUB’s and Nicor Gas’ recommendations. In addition, the ROE includes a credit facility cost that is equivalent to Staff’s position.

Mr. Gorman proposes that the Commission reject the Stipulation by inserting an unreasonably low ROE of 9.20%, which is substantially similar to the 9.15% ROE he personally supported. Id. at 2. Relative to industry standards, Mr. Gorman’s recommendation is based on an approach that is inconsistent with his own past practice when estimating the cost of capital. Nicor Gas Ex. 40.0 at 5. If adopted, that ROE would be the lowest awarded to Nicor Gas in more than four decades. It also would be far lower than any other ROE the Commission has recently awarded to a major Illinois utility. The Company explained previously why IIEC-CUB’s ROE methodology is unreasonable and should not be adopted. Furthermore, IIEC-CUB’s witness Mr. Gorman stated that Dr. Villadsen’s Risk Premium study could be modified to produce a reasonable ROE for the Company of 9.80%. IIEC-CUB Ex. 1.0 at 100.

The Stipulation reflects what Nicor Gas and Staff both conclude to be a reasonable ROR, as well as capital cost components that are substantially supported by the record. See Nicor Gas Ex. 39.1. In conclusion, Nicor Gas recommends that the Commission adopt for ratemaking purposes a 2018 test year with an overall ROR of 7.256% and an ROE of 9.80%. That ROR, and its components, fall within the range of proposals found in the evidentiary record and, produce a reasonable overall result.

b. Staff's Position

Pursuant to its Stipulation with the Company, Staff recommends that the Commission allow the Company an ROE of 9.80%. In support of this recommendation, Staff submits that the totality of the evidence in the record supports a reasonable overall rate of return of 7.256% based on specific inputs including an ROE of 9.80%. Stipulation at 1, 3-4. Staff further states that the evidence supports a proposed ROE for the test year that ranges as follows: IIEC/CUB, 9.15%; Staff, 9.16%; and Nicor Gas, 10.7%. Id. at 3. In arriving at its proposed ROE in this proceeding, Staff observes that “the ROE of 9.80% falls within the range established by IIEC/CUB (9.15%) and Nicor Gas (10.70%)[, and that] the ROE falls within a range established if all three ROE proposals (Nicor Gas, Staff, IIEC/CUB) were averaged (9.67%) and Staff’s and Nicor Gas’ ROE proposals were averaged (9.93%)[.]” Id. at 4. In its Brief on Exceptions, Staff argues that, if the Commission declines to adopt the Stipulation in total (including an ROE of 9.80%), then in the alternative the Commission should adopt Staff’s initially recommended ROE of 9.16%. Prior to filing the Stipulation, Staff entered substantial evidence into the record in support of its initial recommended ROE of 9.16%, including the thorough testimony of its expert witness, Ms. Phipps.

There are hundreds of pages of testimony in evidence discussing how the various parties estimated their respective recommended ROE for Nicor Gas. Estimating ROE is necessary because Nicor Gas does not have publicly-traded stock; thus, the appropriate ROE for the Company must be calculated using available information about publicly-traded companies of similar size and risk. Because the available information serves as a proxy for the characteristics of the actual Company, some level of subjectivity and personal judgment will factor into any ROE recommendation.

Staff argues that Nicor Gas must demonstrate that its proposed ROE is just and reasonable. The Act specifically states “the burden of proof to establish the justness and reasonableness of the proposed rates...in whole and in part, shall be upon the utility.” 220 ILCS 5/9-201(c). The Company must demonstrate the reasonableness of its proposed rates by proving that all the components of its proposed increase including the ROE are reasonable. See Ia.–Ill. Gas & Elec. Co v. Ill. Commerce Comm’n, 19 Ill.2d 436 at 445, 167 N.E.2d 414 (1960); Candlewick Lake Utilities Co. v. Ill. Commerce Comm’n, 122 Ill.App.3d 219 at 222–23, 460 N.E.2d 1190 (1983).

Staff states that the key consideration in determining the cost of equity is to ensure that the methodologies used to calculate ROE reasonably reflect investors’ views of the market in general and the subject company in particular. A company’s ROE should allow it to attract equity capital on reasonable terms so the company is able to provide safe, reliable service at just and reasonable rates. The law is well-settled on the factors a regulatory body such as the Commission should consider when determining

the appropriate ROE. First, the Commission must consider whether the ROE is consistent with other businesses which experience comparable risk. Second, the Commission should ascertain whether the approved ROE can support credit quality and ensure access to capital. Third, the Commission must determine that the end result leads to just and reasonable rates for consumers. See e.g., Hope at 591; Bluefield at 679.

Staff states that the authorized ROE is the return on investment the Commission determines Nicor Gas is entitled to earn, if the Company acts prudently and its sales and operation projections are accurate. The Company's actual ROE is the money left over at the end of each year after all expenses have been paid or booked; in other words, actual return on investment as impacted by actual revenues and expenses. Whether the actual ROE equals the authorized ROE depends on the utility's actual performance during the year. An authorized ROE that is too low might restrict the Company's access to capital at a reasonable cost. Conversely, an ROE that is too high will lead to utility rates for residential, commercial and industrial customers that are not just and reasonable. In other words, the Commission must balance the right of utility investors to earn a fair return on their investment with the right of customers to pay no more than just and reasonable rates for gas delivery services. Staff Ex. 3.0 at 8. Finding the appropriate balance is crucial because the profits realized by shareholders are funded by ratepayers.

Ms. Phipps analyzed and recommended an ROE for Nicor Gas, by seeking to replicate Dr. Villadsen's unadjusted results. Specifically, Ms. Phipps performed the same DCF and CAPM analyses as Dr. Villadsen performed, making changes to the inputs in the Company's analyses as necessary to conform her evaluation to methodologies previously and repeatedly approved by the Commission. Those corrections did not result in material differences between Staff's initial ROE recommendation as compared to the Company's initial and unadjusted ROE.

Ms. Phipps calculated the Company's cost of equity by applying the same DCF model and CAPM, as Dr. Villadsen. Staff Ex. 3.0 at 27-45. She also used the same proxy group of gas companies as Dr. Villadsen, with one exception (the "Gas Sample"). Id. at 23-24. Ms. Phipps' ROE analysis used more recent market data than used by the Company and adjusted for several disagreements with the Company's methodology. Id. at 22. Ms. Phipps' analysis is very similar to the ROE analysis presented by Staff and approved by the Commission in Nicor Gas' 2008 rate case. Id. at 3-5. While Ms. Phipps performed both a constant growth DCF analysis and a non-constant growth DCF ("NCD CF") analysis, she did not consider the results of the NCD CF in order to mirror the methodology utilized by the Company. Id. at 27.

In support of their initial ROE recommendations, Staff's and Nicor's expert witnesses testified to their disagreement on numerous methodologies. Staff opposed the Company's use of both an implied bond yield plus risk premium ("risk premium") analysis and an ECAPM analysis, citing previous Commission Orders rejecting such methods. Staff witness Ms. Phipps referred to the Commission's final order in the 2011 Ameren rate case, stating: "[a]mong the many problems the Commission finds with this [risk premium analysis] approach is its reliance on utility authorized returns on equity throughout the U.S." Staff Ex. 3.0 at 65 (quoting Ameren Ill. Co. d/b/a Ameren Ill.,

Docket no. 11-0282, Order at 125). Ms. Phipps further alleged that the Company's risk premium analysis inappropriately uses historical data for a future-looking ROE, and that the Company failed to provide all the necessary data to evaluate the utilities within the dataset, such as credit ratings, capital structure and ratemaking adjustments. Ms. Phipps also argued that the adjusted beta component in the Company's ECAPM analysis was unnecessary, double-counted the Company's difference in risk from the proxy group, and resulted in an inflated ROE. Staff Ex. 3.0 at 60, 64-65; Staff Ex. 8.0 at 27-30. With regard to the witnesses' CAPM analyses, Ms. Phipps opposed Company witness Ms. Villadsen's use of a projected U.S. Treasury bond yield as the risk-free rate input. Ms. Phipps testified that, according to the tenets of the Efficient Market Hypothesis ("EMH"), current interest rates reflect investors' expectations about future interest rates. Staff Ex. 3.0 at 55-56; Staff Ex. 8.0 at 25-26.

Dr. Villadsen addresses the perceived differences in financial risk through two types of adjustments. The first, a market-to-book ("M/B") adjustment, is intended to account for the difference in the market value capital structures of the Gas Sample companies and the book value capital structure of Nicor Gas, which Dr. Villadsen contends is a source of risk. Staff Ex. 3.0 at 10. Ms. Phipps disagrees that the M/B adjustment is necessary, arguing that Dr. Villadsen confused the measurement tool - the common equity ratio - with the phenomenon to be measured - financial risk. *Id.* at 12. A company's actual financial risk is a product of its contractually required debt service payments, not how that debt is measured. *Id.* at 13.

Dr. Villadsen's second adjustment to address a difference in financial risk is a Hamada leverage adjustment, which is used to separate the financial risk of a leveraged firm from its business risk. Like the M/B adjustment, Dr. Villadsen's Hamada adjustment is based on the premise that an upward adjustment to a market-based cost of equity estimate is required before it can be applied to a book value capital structure to determine utility rates. Staff argued that Nicor Gas is not a publicly-traded company, thus it does not have a market value and that even if there is a difference in the market value cost of equity of the Gas Sample and the book value of Nicor Gas' cost of equity, the Company offers no evidence that supports the idea that this in turn leads to increased risk that is not already accounted for by the various other components of ROE calculation methods. Staff further argued that the Commission has previously rejected M/B adjustments and Hamada adjustments. See, e.g., N. Shore Gas Co. and The Peoples Gas Light and Coke Co., Docket Nos. 14-0224/14-0225 (Cons.), Order at 126-127, 132-133 (Jan. 21, 2015); Aqua Ill., Inc., Docket No. 11-0436, Order at 25-26, 38 (Feb. 16, 2012); Central Ill. Light Co. d/b/a AmerenCILCO, Central Ill. Pub. Serv. Co. d/b/a AmerenCIPS and Ill. Power Co. d/b/a AmerenIP, Docket Nos. 09-0306-09-0311 (Cons.), Order at 216-217 (Apr. 29, 2010); N. Shore Gas Co. and The Peoples Gas Light and Coke Co., Docket Nos. 09-0166/09-0167 (Cons.), Order at 99-100, 127-129 (Jan. 21, 2010); N. Shore Gas Co. and The Peoples Gas Light and Coke Co., Docket Nos. 07-0241/0242 (Cons.), Order at 95-96, 99 (Feb. 5, 2008); Central Ill. Light Co. d/b/a AmerenCILCO, Central Ill. Pub. Serv. Co. d/b/a AmerenCIPS, Ill. Power Co. d/b/a AmerenIP, Docket Nos. 06-0070/06-0071/06-0072 (Cons.), Order at 141 (Nov. 21, 2006); South Beloit Water, Gas and Electric Co., Docket No. 03-0676/03-0677 (Cons.), Order at 39 (Oct. 6, 2004); Central Ill. Pub. Serv. Co. (AmerenCIPS) and Union Electric Co., Docket Nos. 02-0798/ 03-0008/ 03-0009 (Cons.), Order at 87 (Oct. 22, 2003);

Consumer Ill. Water Co., Docket No. 03-0403, Order at 42 (Apr. 3, 2004); Interstate Power Co. and South Beloit Water, Gas and Electric Co., Docket Nos. 01-0528/01-0628/01-0629 (Cons.), Order at 7, 12-13 (Mar. 28, 2002); Ill. Power Co., Docket Nos. 99-0120/99-0134 (Cons.), Order at 56 (Aug. 25, 1999); and Commonwealth Edison Co., Docket No. 94-0065, Order at 92-93 (Jan. 9, 1995).

In addition to an upward adjustment based on a perceived difference in financial risk, Nicor Gas argues it is entitled to a higher ROE due to an alleged difference in business risk (also referred to as “operating risk”) between the Company and the Gas Sample. Operating risk refers to the risk of the underlying assets independent of financing. Nicor Gas Ex. 25.0 at 24. Ms. Phipps explained that comprehensive business risk assessments by S&P and Moody’s provide no indication that Nicor Gas faces elevated business risk relative to the Gas Sample. Staff Ex. 3.0 at 77; Staff Ex.8.0 at 18.

Nicor Gas suggests it is entitled to an upward adjustment to its ROE recommendation because the Company has higher operating risk when compared to the Gas Sample because Nicor Gas’s proportion of fixed costs (i.e., operating leverage) is greater than the Gas Sample. However, Staff argues that, in applying this upward adjustment, Dr. Villadsen did not fully explain the calculation and exact quantity of the adjustment. Staff Cross Ex. 3.

Dr. Villadsen’s argument for a higher ROE is premised on the supposition that the Company is exposed to greater likelihood of variability in “its cash flows correlated with economic ups and downs” because fixed costs – unlike variable costs - cannot be avoided if sales decrease for some reason. Nicor Gas Ex. 11.0 at 59-60. Dr. Villadsen argues that fixed costs make up a larger portion of Nicor Gas’ cost structure than the Gas Sample. Nicor Gas Ex. 25.0 at 40. In response, Staff argues that the Company provided no evidence showing their inability to recover those fixed costs due to volatility in sales.

Finally, in opposition to the Company’s ROE adjustments, Staff points out that Nicor Gas has a QIP Rider in place. One of the things that can have an impact on whether actual earned ROE is equal to the authorized ROE is regulatory lag; the longer the time between the incurring expenses and recouping the costs of those expenses from rate payers, the more risk a company faces. Rider QIP reduces the regulatory lag by providing for annual reconciliations which improve the Company’s ability to recover fixed capital expenditures and thus reduces the Company’s risk. Staff Ex. 3.0 at 26-27.

Staff initially argued that Nicor Gas is not entitled to any upward adjustment based on either a purported difference in financial risk or in operating leverage. In fact, Ms. Phipps testified in favor of a downward adjustment to the ROE of six basis points, from 9.22% to her final recommendation of 9.16%, based upon her calculation of Nicor’s and the Gas Sample utilities’ four (4) financial metrics used by Moody’s to assess the financial strength of regulated gas and electric companies. Ms. Phipps offered that after comparing those metrics to Moody’s published benchmarks, the resulting ratios for Nicor were indicative of a higher credit rating than for the Gas Sample, thereby indicating Nicor is less risky than the Gas Sample and deserving of the six basis point downward adjustment. Staff Ex. 8.0 at 47-48; Staff Ex. 3.0 at 47-51.

Staff argued that the appropriate ROE for Nicor Gas should be determined based on the facts of this docket, considering such things as the prevailing market conditions, the Company's ratemaking capital structure, and the existence of cost-recovery mechanisms. Similarly, authorized ROEs for other utilities resulted from consideration of the unique circumstances which existed in those proceedings at the time those ROEs were awarded. Staff argued that the Company's recommended ROE should not be compared to authorized ROEs for other utilities without considering circumstances such as interest rates when the ROE was authorized; whether the decision resulted from litigation, a settlement, or an automatic adjustment; was a future or historic test year used; is a stand-alone entity or a subsidiary of a larger holding company and, the approved capital structure.

The Company compares its ROR proposal and the ROR recommendations of Staff, IIEC/CUB and the AG to the allowed ROR for litigated natural gas utility rate cases during the last 24 months. Staff, however, notes that weighted ROE (i.e., ROE x common equity ratio) is a key component of the allowed ROR. Staff Ex. 8.0 at 3. Ms. Phipps showed that the Company's initial proposal, which resulted in a weighted ROE of 5.83%, substantially exceeded the 4.72% average weighted ROE for Illinois gas and water utilities from 2014-2016 and the 4.61% average weighted ROE authorized for Illinois gas utilities over the same period. *Id.* at 4. The average weighted ROEs granted to gas utilities (4.78%) and water utilities (4.64%) across the nation since 2014 are far below the Company's initial proposal that resulted in a weighted ROE of 5.83%. *Id.* at 6. In contrast, the weighted ROE recommendations of the AG (4.69%) and IIEC/CUB (4.66%) as well as Staff's initial recommendation (4.82%), are much closer to the average weighted ROEs authorized by the Commission and regulatory bodies across the country in recent years. *Id.* at 4. Staff ultimately recommends a weighted ROE of 5.096%, pursuant to the Stipulation. Stipulation at 4.

Staff states that the Stipulation resolves ROR issues between the Company and Staff and sets forth a common agreement and recommendation to the Commission concerning the allowed ROR and its calculation. Staff entered into the Stipulation with the Company in order to reduce the uncertainty of litigation, to conserve resources, to avoid or to reduce the scope and complexity of the issues between them, and to simplify the resolution of issues in this rate case. Nicor Gas Ex. 39.1 at 1. Staff recognizes the requirement that any resolution of issues by the Commission without unanimous support must be supported by substantial evidence based on the entire record before the Commission, and otherwise be in accordance with law. Bus. and Prof'l People for the Pub. Interest v. Ill. Commerce Comm'n, 136 Ill.2d 192, 216-217 (1989) ("BPI I").

The Stipulation is supported by evidence in the record. The Stipulation provides for an overall ROR of 7.256% for ratemaking purposes. Company witness Villadsen testified that, the ROR was reasonable and within the range of what she had recommended in prior testimony. Nicor Gas Ex. 39.0R at 1; Nicor Gas Ex. 40.0 at 2. In addition, the individual components which combined to make up the ROR are supported by various witnesses' testimony in this proceeding. The components of the Stipulation ROR and the record evidence supporting those components are discussed in detail below. The only component of ROR that appears to be in dispute at this point in the proceeding is the cost of common equity. Per the Stipulation, Staff and the Company

propose a cost of common equity of 9.80%, while IIEC-CUB propose a cost of common equity equal to 9.20%. IIEC-CUB Ex. 5.0 at 3.

c. IIEC-CUB's Position

IIEC-CUB state that, excluding the financial risk ROE adder, one that has routinely been rejected by the Commission, the Company's methodologies indicate a DCF and CAPM ROE in the range of 9.0% to 9.8%. IIEC-CUB 1.0 at 83, Table 15. The Company also proposed a risk premium return in the range of 10.07% to 10.025%. Id. IIEC-CUB witness Gorman recommended a return on Common equity of 9.15%. Staff witness Phipps recommended a return on Common equity of 9.16%. IIEC-CUB aver that the Company's proposed return recommendation (9.0%-9.8%), even before the financial risk adders are included, is an outlier. Both Staff and IIEC-CUB recommended rejection of the financial risk ROE adder proposed by Nicor Gas.

IIEC-CUB aver that the Commission should reject the Company's excessive ROE recommendation, and its unjustified and flawed ROE financial risk adders, and adopt a return of 9.15%. IIEC-CUB conclude that this ROE will fairly compensate Nicor Gas' investors for their capital at reasonable cost to its customers, and therefore an ROE of 9.15% strikes a fair and reasonable balance between the interests of all stakeholders.

IIEC-CUB state that the objective of the rate of return witnesses in this proceeding is to estimate the market-required ROE for Nicor Gas. IIEC-CUB point out that the determination of an appropriate return is governed in part by two well-established decisions of the U.S. Supreme Court that are well-known to ROE experts: Bluefield and Hope. IIEC-CUB Ex. 1.0 at 46. The Commission has relied on Bluefield and Hope in formulating its decisions in determining a fair return. In accord with the above legal guidance, IIEC-CUB recommend the Commission approve a return on common equity of 9.15% for Nicor Gas, as it is reasonable and consistent with the governing legal standards. According to IIEC-CUB, the Company's requested ROE of 10.7% is excessive and would result in unjust and unreasonable rates.

IIEC-CUB observe that the authorized ROEs for both electric and gas utilities have been steadily declining over the last 10 years, recently trending to about 9.60%. IIEC-CUB point out that the declining trend in ROEs has also been observed by the credit rating agencies. According to IIEC-CUB, credit rating agencies expect that regulators will continue to lower the returns for U.S. utilities while maintaining a stable credit profile. Id. at 18.

IIEC-CUB further state that regulated utilities' credit ratings have improved recently, and the outlook has been labeled "Stable" by credit rating agencies, including S&P and Fitch. Id. at 22-23.

IIEC-CUB aver that credit ratings have remained strong, even while ROEs are declining, and that the utilities have access to external capital, as evidenced by projected utility capital expenditures and investments from S&P Id. at 19-20. In addition, IIEC-CUB point to the Company's current strong corporate bond ratings from S&P and Moody's and S&P's positive assessment of the Company's financial and business risk. Id. at 31-32.

IIEC-CUB maintain that the Commission should recognize and take into account when evaluating Nicor Gas' investment risk, that Nicor Gas' rider, the QIP surcharge mechanism, mitigates this risk. This surcharge mechanism allows Nicor Gas to charge customers for increased capital investment outside of a rate case. Under current rates, IIEC-CUB point out that approximately 15% of Nicor Gas' base revenue was being collected through the QIP surcharge. Capital investments in the surcharge will be rolled into rates, and the QIP surcharge will then be available to Nicor to adjust charges to customers based on capital investments that occur beyond the test year. Id. at 32-33.

IIEC-CUB's witness Mr. Gorman used several models based on financial theory to estimate Nicor Gas' cost of common equity: (1) a constant growth DCF model using consensus analysts' growth rate projections; (2) a constant growth DCF using sustainable growth rate estimates; (3) a multi-stage growth DCF model; and (4) a CAPM. IIEC-CUB aver that these models are commonly relied upon by the Commission in assessing a utility's return on common equity.

As Nicor Gas does not issue stock, the models IIEC-CUB noted were applied to a group of publicly traded utilities with investment risks similar to Nicor Gas.

The proxy group utilized by Mr. Gorman has an average corporate credit rating from S&P of A-, which is identical to Nicor Gas' credit rating. The proxy group has an average corporate credit rating from Moody's of A3, which is a notch lower than Nicor Gas' credit ratings of A2. Id. at 49.

Mr. Gorman's proxy group has an average common equity ratio of 46.8 % (including short-term debt) from SNL and 53.1% (excluding short-term debt) from *The Value Line Investment Survey* in 2016. IIEC-CUB's originally proposed capital structure has a common equity ratio of 50.9% (including short-term debt), which was adjusted to 51.07% in Rebuttal testimony. IIEC-CUB capital structure for Nicor is higher but reasonably comparable to the proxy group's long-term capital structure ratio of 46.8%. Id. at 49-50. IIEC-CUB claim that its proxy group was shown to have comparable total investment risk to that of Nicor Gas.

Mr. Gorman used several versions of the DCF model in his analysis of the cost of equity for Nicor Gas. IIEC-CUB explain that the DCF model posits that a stock price is valued by summing the present value of expected future cash flows discounted at the investor's required rate of return or cost of capital. The DCF model requires a current stock price, expected dividend, and expected growth rate in dividends as described in full in Mr. Gorman's testimony. Id. at 50-51.

Mr. Gorman did include a quarterly compounding adjustment to his DCF return estimate because it is the Commission's standard practice to include this quarterly compounding return in DCF estimates. Id.

For the constant growth DCF model analyses, Mr. Gorman used the average of the weekly high and low stock prices of the proxy group over a 13-week period ended June 2, 2017. He explained that he did so because an average stock price is less susceptible to market price variations than a spot price. Id. at 52. For the dividend component of the DCF model, Mr. Gorman used the most recently paid quarterly

dividends from *Value Line Investment Survey* of June 2, 2017. The dividend was annualized (multiplied by 4) and adjusted for next year's growth. Id. at 52.

Mr. Gorman relied on a consensus, or mean, of professional security analysts' earnings growth estimates as a proxy for the investor consensus dividend growth rate expectations. He then used the average of three sources of analysts' growth rate estimates: Zacks, Yahoo! SNL, and Reuters. Id. at 53. The growth rates Mr. Gorman used in his DCF analysis are shown in IIEC-CUB Exhibit 1.9. The average growth rate for the proxy group is 6.14%. The results of the average and median constant growth DCF returns for Mr. Gorman's proxy group for the 13-week analysis are 9.10% and 8.72%, respectively. Id. at 54.

Mr. Gorman also used a sustainable growth rate DCF analysis to develop his ROE recommendation. He explained that a sustainable growth rate is based on the percentage of the utility's earnings that are retained and reinvested in utility plant and equipment. The average sustainable growth rate for the proxy group using this internal growth rate model is 5.58%. Id. at 56-57. A DCF estimate based on these sustainable growth rates is developed in IIEC-CUB Exhibit 1.13. As shown there, a sustainable growth DCF analysis produces proxy group average and median DCF results for the 13-week period of 8.80% and 8.58%, respectively.

Mr. Gorman also performed a multi-stage growth DCF analysis that reflects the possibility of non-constant growth, or changing growth, for a company over time. The multi-stage growth DCF model reflects three growth periods: (1) a short-term growth period, which consists of the first five years; (2) a transition period, which consists of the next five years (6 through 10); and (3) a long-term growth period, starting in year 11. Id. at 58.

For the short-term growth period, Mr. Gorman relied on the consensus analysts' growth projections described above in relationship to his constant growth DCF model. For the transition period, the growth rates were reduced or increased by an equal factor, which reflects the difference between the analysts' growth rates and the GDP growth rate. For the long-term growth period, Mr. Gorman assumed each company's growth would converge to the maximum sustainable growth rate of 4.2%, taken from a recently published GDP growth rate outlook over the next 5 to 10 years. Id. at 58-64.

For the stock price, dividend, and growth rates for the multi-stage growth DCF analysis, Mr. Gorman relied on the same 13-week average stock prices and the most recent quarterly dividend payment data discussed above. Id. at 65. The results of IIEC-CUB's average and median DCF returns on equity for the proxy group using the 13-week average stock price are 7.51% and 7.44%, respectively. Id.

Mr. Gorman expressed some concern with the constant growth DCF using a sustainable growth rate and the multi-stage growth DCF model, because they produce results around and even under 8.0%. He ultimately concluded that the DCF studies support an ROE of 8.90%, placing primary reliance on the constant growth DCF results, which he considers a reasonable DCF return estimate. Id. at 66.

IIEC-CUB explain that the CAPM method of analysis is based upon the theory that the market required rate of return for a security is equal to the risk-free rate, plus a

risk premium associated with the specific security. Id. at 67. According to IIEC-CUB, the CAPM theory suggests that the market will not compensate investors for assuming risks that can be diversified away. Therefore, IIEC-CUB state that the only risk that investors will be compensated for is systematic or non-diversifiable risks. IIEC-CUB further maintain that the beta is a measure of the systematic or non-diversifiable risks. Id.

For the risk-free rate, Mr. Gorman used *Blue Chip Financial Forecasts'* projected 30-year Treasury bond yield of 3.70% for his CAPM analysis, because long-term Treasury bonds are considered to have negligible credit risk. Id. at 68.

Mr. Gorman used the average proxy group beta from *Value Line* of 0.72, and developed two versions of a market risk premium estimate. One version a forward-looking estimate and a second based on long term historical average. First, Mr. Gorman's forward-looking estimate was derived by estimating the expected return on the market (as represented by the S&P 500) and subtracting the risk-free rate from this estimate. He estimated the expected return on the S&P 500 by adding an expected inflation rate to the long-term historical arithmetic average real return on the market. Deriving the estimates from the stated sources, Mr. Gorman testified that the forward-looking market risk premium had a value of 7.80%. Id. at 70.

Second, according to IIEC-CUB, the historical estimate was based on the Duff & Phelps study that estimated the arithmetic average of the achieved total return on the S&P 500- 12.0%, and the total return on long-term Treasury bonds- 6.00%. The indicated market risk premium is 6.0% (12.0% - 6.0% = 6.0%). Id. 70-71. Thus, Mr. Gorman's market risk premium ranges from 6% to 7.8%, with a 6.9% mid-point.

IIEC-CUB claim that the Duff & Phelps analysis indicates a market risk premium that falls somewhere in the range of 5.5% to 6.9%, which suggests the 6.9% mid-point is at the high end of that study. Mr. Gorman explained his disagreement with the Duff & Phelps study but nevertheless uses its conclusion for the purpose of demonstrating the reasonableness of his market risk premium estimates. Id. at 71-73.

IIEC-CUB point out that the Commission has previously relied on Staff's position that a market risk premium should be based on prospective estimates of the market return and current risk-free rate. IIEC-CUB claim that Staff has historically relied on a DCF model of the S&P 500 to develop the market risk premium. Because of this preference for a forward-looking development of a market risk premium, IIEC-CUB explain that Mr. Gorman provided two versions of a prospective market risk premium for use in his CAPM study: a risk premium estimate of the forward-looking market risk premium, and a DCF return on the market. Id. at 73. Mr. Gorman's analysis concluded that the resultant value for the prospective market risk premium is 7.8%, and the DCF-derived market risk premium is 7.9%. Id. at 73-76.

As shown in IIEC-CUB Exhibit 1.17, using the CAPM equation, based on Mr. Gorman's low prospective market risk premium of 7.8% and his high prospective DCF market risk premium of 7.9%, a risk-free rate of 3.7%, and a beta of 0.72, IIEC-CUB's CAPM analysis produces return estimates of 9.32% to 9.39%, with a midpoint of 9.35%, rounded to 9.40%. Id. at 76.

IIEC-CUB explain that Mr. Gorman's recommended ROE of 9.15% will support an investment grade bond rating for the Company and is at the midpoint of Mr. Gorman's estimated range of 8.90% to 9.40%, the low-end being based on his DCF return, and the high-end being based on his CAPM return. Id. at 77-80. The low-end of Mr. Gorman's range relies primarily upon two of his three DCF constant growth models, despite Mr. Gorman's admission that one of those models produced unreasonably low average and median ROEs that are inconsistent with market evidence of required risk premiums and security valuations. Id. at 66.

IIEC-CUB aver that Dr. Villadsen, relies extensively on Nicor Gas' extensive capital expenditure program and alleged increased operating leverage relative to the proxy group, along with her 10-basis points adder to account for past unrecovered flotation costs, to justify a return in the upper end of her range. Nicor Gas Ex. 11.0 at 63.

Mr. Gorman described that the model ROE results of Dr. Villadsen's studies as applied to her proxy group indicates that Nicor Gas' current market ROE is in the range of 7.2% to 9.8% based on her DCF and CAPM studies and 10.1% to 10.3% based on her risk premium studies. Mr. Gorman further explained that Dr. Villadsen then increases her market ROE estimate by adding an ROE adder in the range of 1.4% to 1.9%, using an After-Tax Weighted Average Cost of Capital ("ATWACC") adder methodology. This ATWACC adder increases her recommended range from 9.0% to 10.3% up to 10.7%. IIEC-CUB disputes Dr. Villadsen's assertion that this ATWACC ROE adder is necessary to properly recognize Nicor Gas' financial risk when applying a market ROE to its book value common equity. Nicor Gas Ex. 11.0 at 12; IIEC-CUB Exhibit 1.0 at 83, Table 15; IIEC-CUB Ex. 1.0 at 83-84. IIEC-CUB argue that removing the ATWACC ROE adder and incorporating more reasonable adjustments, supports an ROE in the range of 9.0% to 9.8%. Id. at 84.

Mr. Gorman disagrees with Dr. Villadsen's application of the ATWACC adjustment to her DCF, CAPM and ECAPM returns, as well as her use of beta adjustments within her CAPM and ECAPM models. Mr. Gorman takes issue with her risk premium analysis because it is based only on a simple inverse relationship between equity risk premiums and interest rates. Equity risk premiums should be measured based on the current market's assessment of investment risk of equity versus debt securities. While interest rate changes are one factor in assessing this risk differential, they are not the only factor. Dr. Villadsen's model is simply unreliable. Id. at 84-85. However, Mr. Gorman subsequently testified that simple modifications to Dr. Villadsen's risk premium analysis would produce a reasonable recommended ROE of 9.8%. Id. at 100.

IIEC-CUB claim that the ATWACC increases the estimated market ROE based on Dr. Villadsen's CAPM and DCF analyses to a higher ROE that can be applied to Nicor Gas' book value common equity. Id. at 85. Mr. Gorman makes substantially the same argument against the ATWACC adder that Staff expert witness Ms. Phipps made against the M/B and Hamada adjustments – that it is unnecessary because the Company's risk remains the same whether measured by a market or book value of common equity. Id. at 86.

According to IIEC-CUB, the ATWACC adder is also poor regulatory policy as it does not produce clear and transparent objectives for management, due to the adjusted ROE's dependence on market-based capital structure, which is unpredictable and may have unintended consequences on management's capital structure decisions. This could then lead to unstable rates from case to case. However, as management does have control over its book value capital structure, basing the company's ROE on book-value capital structure provides a clearer and more transparent path for regulatory oversight. Id. at 88.

Mr. Gorman also identified several regulatory decisions that found the ATWACC methodology to be poor regulatory practice, and rejected such an adjustment. California Public Utilities Commission, Docket No. A.08-05-002, California-American Water Company, May 2009; Arizona Corporation Commission, Arizona-American Water Company, Docket No. W-01303A-05-0405, July 2006; Ohio Public Utilities Commission, Cause Nos. 07-551-EL-AIR et al., Ohio Edison Company et al., January 2009 Public Service Commission of Wisconsin, Wisconsin Electric Power Company, 5-UR-1594 103.

IIEC-CUB conclude that the substantial evidence in this record justifies rejecting the use of the ATWACC adder, which has been rejected by other regulators as well. IIEC-CUB recommend that the Commission should affirmatively and clearly reject its use in this case.

IIEC-CUB point out that Dr. Villadsen produced a traditional CAPM before any adders in the range of 9.0% to 9.4%. Applying the Empirical CAPM ("ECAPM") before any adders produces a return estimate in the range of 9.4% to 9.8%. IIEC-CUB Ex. 1.0 at 90.

Dr. Villadsen proposes an ROE adder to reflect a leveraged beta adjustment. This leveraged beta adjustment adds 60 to 120 basis points to the base CAPM return. Id. at 91. IIEC-CUB conclude that the leveraged beta adjustment is as unreliable and flawed as is the ATWACC adder.

In producing this beta adjustment, IIEC-CUB point out that Dr. Villadsen applies the Hamada method for de-levering and re-levering the beta component in both the CAPM and the ECAPM, with and without the effect of income taxes. The effect of the Hamada formula is to increase the *Value Line* beta from 0.73 to 0.89 (without taxes) and 0.84 (with taxes). The Hamada model produces CAPM results in the range of 9.8% to 10.6% and ECAPM results in the range of 10.0% to 10.8%. Id. at 91-92.

IIEC-CUB aver that the false assumptions grounded in the de-levering of the beta suggest that the utility's financial risk can be measured only by changes in common equity weights of capital structure, and that financial risk is the only relevant systematic risk reflected in beta. Id. at 92. Mr. Gorman explains that a utility company's financial risk is a component of capital structure mix, but also can be impacted by its embedded cost of debt, debt maturity and other liquidity factors. IIEC-CUB conclude that the approach utilized by Dr. Villadsen does not include a complete assessment of the utility's financial risk, and that financial risk is not the only systematic risk that should be considered in adjusting beta. Id. IIEC-CUB similarly oppose Dr. Villadsen's use of beta adjustments within her ECAPM and CAPM studies for reasons that are, for purposes of

this proceeding, substantially the same as Staff witness Ms. Phipps', described above. Id.; IIEC-CUB Ex. 3.0R at 20-27.

IIEC-CUB point out that Dr. Villadsen's DCF model results fall in the range 7.2% to 9.1%, with the higher estimate produced by her simple constant growth DCF model. Once again, she applied the ATWACC adder to the DCF model, which increased the DCF range to 8.6% to 11.0%. Nicor Gas Ex. 11.0 at 50; IIEC-CUB Ex. 1.0 at 96.

IIEC-CUB also address Dr. Villadsen's alternative multi-stage DCF model, which uses a 30-year historical GDP growth of 4.75%, and increases the low-end of her range from 8.6% to 9.3% for the full sample or 9.5% for the subsample. She concludes that the multi-stage DCF is downwardly biased due to the low consensus analysts' GDP growth rate projection of 4.1%. From this, she considers that a range within plus/minus 60 basis points from her ATWACC DCF results will constitute a reasonable DCF range of 9.4% to 10.4%. Nicor Gas Ex. 11.0 at 50.

IIEC-CUB argue that there are two problems with this multi-stage DCF model, one of which is the ATWACC adder already discussed above. The second problem, according to IIEC-CUB, is Dr. Villadsen's adjustment to the consensus analysts' GDP growth rate of what she considers to be a historically low 4.1%. IIEC-CUB argue that a consensus of analysts is more accurate than the opinion of one analyst. Therefore, IIEC-CUB argue that the Commission should not give the Company's multi-stage DCF model any evidentiary weight. IIEC-CUB Ex. 1.0 at 97-98.

IIEC-CUB next point to the fact that Dr. Villadsen's risk premium analysis measured the relationship of authorized ROEs to long-term Treasury yields between 1990-2016 through a regression analysis. Nicor Gas Ex. 11.3. According to IIEC-CUB, she used the resulting regression formula to predict a risk premium based on a forecasted long-term Treasury yield of 4.0% from January 2017. This regression formula and her forecasted normalized Treasury yield of 4.0% produced an estimated risk premium of 6.25%, which resulted in an ROE of 10.25%. According to IIEC-CUB, using actual forecasted Treasury yield of 3.6%, and the regression formula-produced risk premium of 6.47%, results in an ROE of 10.07%. IIEC-CUB Ex.1.0 at 98.

IIEC-CUB aver that there are numerous deficiencies with Dr. Villadsen's risk premium analysis because its simplistic, linear relationship between equity risk premiums and interest rates, is not based on basic risk and return valuation principles. The analysis ignores investment risk differentials, as Dr. Villadsen bases her adjustment to the equity risk premium exclusively on changes in nominal interest rates. Dr. Villadsen's 4.0% risk-free rate does not reflect independent market economists' outlooks for future interest rates and cannot be used to accurately measure the correct market ROE for Nicor Gas. Id. at 98-100.

Therefore, and as noted above, Mr. Gorman correctly observes that disregarding Dr. Villadsen's simplistic inverse relationship and using a projected Treasury yield published by independent economists of 3.7%, added to an equity risk premium of 6.1%, produces a reasonable risk premium ROE for Nicor Gas of 9.8%. Id. at 100.

IIEC-CUB state that Dr. Villadsen attempts to support her 10.7% ROE by assessing the market and interest rates environment. According to IIEC-CUB, she

concludes that low interest rates resulted in high utility spreads and that market volatility in 2016 has been elevated relative to the volatility observed in the past. *Id.* at 101. Mr. Gorman gauged current market/investor perceptions of utility risk and concluded that capital costs are low and investors highly value utility stocks.

IIEC-CUB Exhibit 1.19 shows the yield spread between utility bonds and Treasury bonds over the last 37 years. IIEC-CUB claim that these yield spreads show that utility capital costs are lower than they have been historically relative to Treasury bond yields, and also that the bond yield spreads expand above historical norms as the investment risk of the security increases. According to IIEC-CUB, this information allows for a balanced determination of the current market sentiment for utility investments. IIEC-CUB claim that the market is currently placing high value on utility securities recognizing their low risk and stable characteristics. IIEC-CUB Ex. 1.0 at 101-103.

IIEC-CUB aver that Nicor Gas' ROE presentation reflects a troubling theme seen repeatedly in the ROE recommendations by utility witnesses in recent years. IIEC-CUB cite to several cases in which ROE witnesses go beyond the results of the tried and true models the Commission has relied upon in affirming a return on common equity for a utility, and propose subjective adders and adjustments to inflate the ROE recommendation. Illinois-American Water Co., Docket No 16-0093, Order at 50 (Dec. 13, 2016); Aqua Ill. Inc., Docket No. 14-0419, Order at 38-39 (March 25, 2015); Peoples Gas Light and Coke Co. et al, Docket Nos. 14-0224/14-0225 (Cons.), Order at 126 (Jan. 21, 2015). IIEC-CUB claim that the purpose of so doing is obvious; by expanding the range of ROE recommendations among the witnesses, the utility (Nicor Gas in this case) hopes to influence the Commission in setting a higher ROE. IIEC-CUB maintain that Nicor Gas' witness, too, is employing subjective adders and adjustments to inflate an ROE recommendation. IIEC-CUB aver that the Commission should hold firm and reject Nicor Gas' ROE position in full.

According to IIEC-CUB, Dr. Villadsen relied on an adder to her ROE recommendation, the ATWACC adjustment. IIEC-CUB conclude that the primary difference between Nicor Gas' recommended ROE and the pure market-based models relied upon by IIEC-CUB and Staff is the use of the ATWACC adjustment.

Nicor Gas asserts Mr. Gorman arrived at his 9.15% ROE recommendation only by omitting from his analysis any risk premium analysis, claiming that this is a technique he typically employs. Nicor Gas Ex. 37.0 at 5. IIEC-CUB maintain that the record shows Mr. Gorman's analyses are much more than a risk premium analysis. Moreover, Mr. Gorman directly addressed this issue in his direct testimony, testifying that he did not consider a risk premium analysis because "[t]he Commission has consistently rejected the use of the risk premium methodology in determining a utility's cost of equity in rate cases." IIEC-CUB Ex. 1.0 at 67.

IIEC-CUB state that the stipulated ROE is inherently arbitrary and lacks record support. The stipulated ROE of 9.8% is the average of two values as Mr. Gorman explained. IIEC-CUB Ex. 5.0 at 3-4. The Stipulation provides that the stipulated ROE of 9.8% falls within the range established by IIEC/CUB (9.15%) and Nicor Gas (10.70%). However, the bottom of the range (9.67%) used to calculate the stipulated

ROE is actually the average of the three ROE proposals (Nicor Gas, Staff, and IIEC-CUB). The top of the range (9.93%) is actually the average of the Staff and Nicor Gas ROE proposals. Nicor Ex. 39.1 at 4. Thus, the stipulated ROE is the result of averaging the 9.67% value with the 9.93% value, and arriving at the midpoint of 9.8%. IIEC-CUB Ex. 5.0 at 4-5.

IIEC-CUB argues that the stipulated ROE of 9.8% is produced by an averaging method unlike any averaging method previously considered by the Commission, and that it is arbitrary and convoluted on its face. Nicor fails to explain why Nicor's excessive 10.7% ROE should be counted *twice* in the averaging method. IIEC-CUB Ex. 5.0 at 4. Giving the Nicor ROE any weight, much less doubling its impact, results in the average ROE that is inflated and produces retail rates that are not just and reasonable. Id. at 4.

IIEC-CUB argue that the stipulated ROE is flawed because of its reliance on Nicor Gas' originally-proposed excessive 10.7% ROE. Mr. Gorman opines that unreliable adders to DCF and CAPM returns, adjusted Value Line betas, a lack of regulatory and academic support for both of these methods, and inclusion of 10 basis points for unproven costs make the Company's initial recommended ROE inflated and unreasonable. IIEC-CUB Ex. 5.0 at 5.

Further, Mr. Gorman claims that Dr. Villadsen wrongly claims *Value Line* publishes leverage and capital structure risk metrics using market data. *Value Line* publishes capital structure weights and leverage factors based on book value measures. IIEC-CUB Ex. 3.0R at 14-15. The significance of Dr. Villadsen's misuse of the *Value Line* data is that it falsely implies book value common equity and capital structure data cannot be used to measure a utility's financial risk. It can, and indeed *Value Line* provides data on capital structure weights to investors based on book value data, not market data in the economic and financial tables in its company reports. IIEC-CUB Ex. 1.0 at 87.

The effect of the ATWACC adder is demonstrative. Dr. Villadsen's quarterly DCF analysis produced a 9.1% ROE. Yet, the ATWACC markedly inflates that result by an additional 1.4-1.9%. IIEC-CUB Ex 1.0 at 83, Table 15. The ATWACC is "[t]he primary difference between the Company's recommended return on equity and the pure market-based models relied upon by IIEC/CUB and Staff" Thus, the ATWACC adder should be completely disregarded by the Commission in the context of any averaging method it may adopt.

IIEC-CUB reminds the Commission that Staff was equally critical of Dr. Villadsen's adjustment to address an alleged financial risk. Staff argued that "the Company offers no evidence that supports the idea that this [difference in the market value cost of equity of the Gas Sample and the book value of Nicor Gas's cost of equity] in turn leads to increased risk that is not already accounted for by the various other components of ROE calculation methods. In fact, the Commission has, in long-standing practice, rejected M/B [market to book] adjustments and Hamada adjustments."

IIEC-CUB state that excluding these ill-advised beta adjustments to Dr. Villadsen's CAPM return, the Company's CAPM would have supported a return of 9.0% to 9.4%. IIEC-CUB Ex. 1.0 at 83, Table 15 at 90.

In the same manner that the Stipulation ROE unduly relies on Nicor's ROE of 10.7%, and inappropriately does so twice, Nicor's ROE is also driven by Dr. Villadsen's reliance on a risk premium analysis. Dr. Villadsen's risk premium analysis resulted in ROEs of 10.25% and 10.07%, which were incorporated in her final recommendation. IIEC-CUB Ex. 1.0 at 83.

Mr. Gorman testified that "[t]he Commission has consistently rejected the use of the risk premium methodology in determining a utility's cost of equity in rate cases." IIEC-CUB Ex. 1.0 at 67. As the Commission recently confirmed: "[m]oreover, this Commission has routinely rejected risk premium analysis as a valid basis for determining return on equity. North Shore Gas Co. et al, Docket Nos. 14-0224/0225 (Cons.), Order at 141 (Jan 21, 2015).

Dr. Villadsen complained that Mr. Gorman used a risk premium analysis in other jurisdictions. Nicor Gas Ex. 40 at 8-10. However, Mr. Gorman testified that he did not perform such an analysis because this Commission does not rely on the model's results. IIEC-CUB Ex. 1.0 at 67.

IIEC-CUB state that another defect with the 10.7% ROE and its use in the averaging methodology, is its inclusion of a 10 basis points for flotation costs which are, once more, twice counted in the Stipulation. This flotation cost ROE adder is not based on actual Nicor Gas common stock flotation costs and, therefore, is not a reasonable and justified adder to the ROE. IIEC-CUB Ex. 5.0 at 5. Nicor Gas has not shown these costs to be a known and measurable expense and, thus, appropriate for inclusion in Nicor's cost of service. IIEC/CUB Ex. 1.0 at 106; IIEC/CUB Ex. 3.0R at 31.

Mr. Gorman explained flotation expenses must be accounted for, verified and shown to be reasonable, before they are included in a utility's revenue requirement. Nicor Gas' evidence failed to identify any flotation costs that have not been fully recovered since Nicor Gas was acquired by The Southern Company. The flotation costs identified by Nicor represented costs incurred to sell stock to the public that was subsequently acquired by Southern Company when it acquired Nicor Gas. Therefore, there is no evidence that Nicor Gas has any flotation cost on its existing common stock. IIEC-CUB Ex. 1.0 at 105-106; IIEC-CUB Ex. 3.0R at 30-32.

Assuming the Commission might adopt the averaging method over IIEC-CUB's objection, IIEC-CUB corrected for the deficiencies in the 10.7% ROE, which would result in a 9.2% ROE. If the Commission approves the other rate of return components in the Stipulation such as the stipulated capital structure, embedded debt cost of long-term and the embedded short-term debt, then the resultant return on common equity is 9.2%, as shown in Table 1 from Mr. Gorman's testimony. The 9.2%, when used with the stipulated capital structure and the stipulated cost of long term and short term debt, produces a rate of return that is 6.944%. The 9.2% ROE is based on the averaging parties' return positions in a manner that is consistent with past ICC decisions generally, and Nicor Gas' last rate case specifically. IIEC-CUB Ex. 5.0 at 2.

Mr. Gorman explained further, that eliminating the financial risk ROE adders proposed by the Company (in the range of 1.4% to 1.9%) has the effect of reducing the Company's 10.7% ROE recommendation to an ROE in the range of 9.0% to 9.4% using the DCF and CAPM methodologies normally relied on by the Commission. IIEC-CUB

Ex. 1.0 at 83. Averaging these ROE results supports an ROE of 9.2% in this proceeding based on methodologies offered by the Company (corrected), Staff (9.16%), and IIEC-CUB (9.15%). IIEC-CUB Ex.5.0 at 7.

Thus, if the Commission finds the rate of return components of the Stipulation reasonable but corrects for Nicor Gas' 10.7% ROE, and chooses an averaging method of ROEs as described in the preceding paragraph, the resultant rate of return (6.944%) reflected in Table 1 is a fair rate of return.

Mr. Gorman assessed the Stipulation's apparent methodology for calculating the ROE as follows:

The new methodologies offered by Nicor moreover have no support in accepted industry ROE practices, nor are they supported by credible interpretation of academic methods of measuring a market based ROE estimate. The use of these new adder methodologies proposed by Nicor in this case have significantly inflated its recommended ROE.

IIEC-CUB Ex. 5.0 at 5.

IIEC-CUB urge the Commission to recognize that this attempt to inflate the ROE is not valid and should be rejected. The Commission should consider only the correct application of the CAPM and DCF models that the Commission has traditionally relied upon in determining a fair rate of return. The Commission should not be swayed by the untested and unreliable adders and adjustments now being used by utilities in their ROE proposals.

The Commission has historically and correctly rejected utility efforts to inflate their recommended ROEs. The Commission rejected leverage adjustments in the following proceedings: North Shore Gas Co. et al, Docket Nos. 14-0224/14-0225 (Cons.), Order at 134 (Jan. 21, 2015) North Shore Gas Co. et al, Docket Nos. 09-0166/09-0167 (Cons.), Order at 128-129 (Jan. 21, 2010); North Shore Gas Co. et al, Docket Nos. 07-0241/07-0242 (Cons.), Order at 95, 99 (Feb. 5, 2008).

Similarly, size adjustments alleged to impact financial risk have been rejected in numerous cases, including Ill.-American Water Co., Docket No. 11-0767, Order at 110 (Sept. 19, 2012); Ill.-American Water Co., Docket No. 09-0319, Order at 112-113 (April 13, 2010); and Aqua Ill., Inc., Docket No. 11-0436, Order at 38 (Feb. 16, 2012). IIEC-CUB find that the Commission has recognized the utility adjustments as subjective adders that have no bearing in estimating a fair rate of return.

IIEC-CUB state that the stipulated ROE is unlike any other averaging method previously utilized by the Commission. Dr. Villadsen proclaims several times that the stipulated ROE is consistent with Commission precedent, and similar to past or prior decisions. See *generally* Nicor Ex. 40. However, Mr. Gorman explained in his testimony why the decisions relied upon by Nicor were unlike or inapposite to this case. Notably, Dr. Villadsen never directly refutes Mr. Gorman on this point. In three of the recent cases Mr. Gorman cited, the Commission decided on the utility ROE by some averaging of the parties' DCF and CAPM results without relying on a utility inflated ROE analysis, which is not the case in the Stipulation here. In the 2010 Aqua case, the utility

agreed with the Staff ROE with a slight modification. In the more recent 2016 IAWC case in Docket No. 16-0093, the Commission averaged the ROEs of IAWC and IIEC-CUB, which included the utility's excessive ROE, but disregarded the Staff's ROE recommendation. That case is on appeal.

IIEC-CUB notes that the only other case Dr. Villadsen relied upon as suggesting it had some commonality with the Stipulation is Aqua Ill., Inc., Docket No. 14-0419, Order (March 25, 2015). Nicor Ex. 40.0 at 7, fn 19. Yet, in the 2014 Aqua case, the Commission used the average of Aqua's DCF and Staff's DCF analysis, along with Aqua's CAPM and Staff's CAPM analysis, in forming a basis to determine the ROE. IIEC-CUB asserts that 2014 Aqua case is not comparable to the Stipulation methodology where ROEs (Nicor Gas') are double counted, and where one of the values (Nicor Gas' ROE) relies on faulty adjustments to the DCF and CAPM results.

In many of the cases above, IIEC-CUB contends, the Commission has relied upon the parties' CAPM and DCF results in some manner. The Stipulation, much differently, relies on a double counting of Nicor Gas' ROE. In short, according to IIEC-CUB the Stipulation methodology is nothing like the manner by which the Commission has recently decided ROE awards.

Mr. Gorman compared the manner by which Dr. Villadsen conducted her ROE analyses to what Nicor Gas did in its more recent 2004 and 2008 rate cases. The 2008 rate case was Nicor Gas' last rate case, and both cases show how Nicor has deviated from the CAPM and DCF results in determining an ROE to now an ROE proposal with adders and other alleged deficiencies.

In the 2008 Rate Case, the Commission used Staff's and CUB's DCF returns to produce one average, and then used the Company's and Staff's CAPM returns for a second average. The midpoint of the two averages produced an ROE that ultimately served as the basis for the authorized ROE in that proceeding. 2008 Rate Case Order at 72. Notably the Commission explained "While we do not wish to ignore past practices, which appear to have served utilities and ratepayers for many years, neither do we wish to engage in cost of equity estimation in a manner that might be viewed as random or arbitrary." Id. at 67-68.

Mr. Gorman explained in great detail how Nicor Gas' witness in the 2008 rate case relied on CAPM and DCF studies and did not adjust the results of his DCF by using an ATWACC adder or other like adjustment. IIEC-CUB Ex. 5.0 at 10. Mr. Gorman also testified to the differences in Dr. Villadsen's CAPM analysis in this case as compared to the CAPM analysis performed by the Nicor witness in the 2008 case. In the Nicor Gas 2008 rate case, the Commission observed Nicor Gas witness Dr. Makhholm's CAPM return estimate was based on "published and adjusted Value Line betas," along with estimates of market risk premium and risk-free rates. The 2008 Rate Case Order also reported that Nicor had offered the same type of CAPM analysis as it did in its 2004 rate case.

In contrast to the last Nicor rate case and without justification for deviating from its past practice, IIEC-CUB argues Dr. Villadsen in this case proposed a Hamada financial risk adjustment to the published *Value Line* betas. IIEC-CUB Ex. 1.0 at 90: Table 16. In the 2008 rate case, Nicor Gas witness Dr. Makhholm did not make

adjustments to published betas. Nicor Gas' CAPM analyses in the 2008 and 2004 rate cases were based on "published adjusted Value Line betas," in the same manner Mr. Gorman conducted his CAPM study in this case. In this case Dr. Villadsen offered an ECAPM study using Value Line adjusted betas which IIEC-CUB believe to double count the increase in the CAPM return estimates for companies with betas less than 1, which reflects her proxy group and Nicor in this case. IIEC-CUB Ex. 5.0 at 13.

IIEC-CUB submits that, had Nicor Gas used the traditional DCF and CAPM approach similar to those it used in its 2008 rate case, and used the results of Staff's and Mr. Gorman's DCF and CAPM return estimates in the stipulated averaging, it would support an ROE in this case of 9.2%. IIEC-CUB Ex. 5.0 at 16-17.

d. AG's Position

The AG argues that a careful, evidence-based examination of a utility's allowed ROE is a key component in the determination of the overall return on the capital used to finance rate base, and thus integral to the Commission's revenue requirement calculation and determination of customer rates. Seminal state and federal case law on what constitutes a reasonable rate of return provides that the utility is entitled to ask a fair return upon the value of that which it employs for public convenience, but, on the other hand, the public is entitled to demand that no more be exacted from it than the services rendered are reasonably worth. State Public Utilities Commission ex rel. City of Springfield v. Springfield Gas & Electric Co ("Springfield Gas"), 291 Ill. 209, 217 (1920); citing Springfield Gas Smyth v. Ames, 169 U. S. 466, 18 Sup. Ct. 418, 42 L. Ed. 819 (other citations omitted). Because the property of the public utility is devoted to the public use, there shall not be an exorbitant charge for the service rendered. Springfield Gas, 291 Ill. at 217-218.

Illinois courts have held that "[t]he Commission has the responsibility of balancing the right of the utility's investors to a fair rate of return against the right of the public that it pay no more than the reasonable value of the utility's services. While the rates allowed can never be so low as to be confiscatory, within this outer boundary, if the rightful expectations of the investor are not compatible with those of the consuming public, it is the latter which must prevail." Camelot Utilities, Inc. v. Ill. Commerce Comm'n, 51 Ill.App.3d 5, 10; Citizens Utility Bd. v. Ill. Commerce Comm'n, 276 Ill.App.3d 730, 658 N.E.2d 1194 (1995).

The AG states that setting the equity component of the ROR is an exercise that should ensure that ratepayers are not arbitrarily and inequitably subsidizing utility shareholders. The level that at which the ROE is set directly – and significantly -- impacts the overall return Nicor Gas customers will pay on the Company's rate base investment. The higher the ROE, the higher the overall ROR and the higher the utility's revenue requirement.

In the instant docket, as part of her proposed 10.7% ROE, Nicor witness Villadsen included a 10-basis point adjustment for flotation costs. Nicor Gas Ex. 11.0 at 60-62. While the AG disagrees with that adjustment, as discussed in detail below, the fact is Dr. Villadsen believed that not reflecting that 10-point adjustment would render the ROE proposals unreasonable. Id. Likewise, Mr. Gorman and Ms. Phipps rejected the alleged need for that specific 10-point adjustment. See IIEC-CUB Ex. 1.0 at 106;

IIEC-CUB Ex. 3.0R at 30-31; Staff Ex. 3.0 at 17-21; Staff Ex. 8.0 at 19-23. The derivation of the Stipulation, which can be calculated by an arbitrary double-counting and three-step averaging of Nicor Gas and Staff's ROE numbers, contradicts the need for greater precision.

The evidence in the record shows that the Stipulation would trigger significant increases in the revenue requirement recommendations of Staff and other parties. Specifically, Staff filed testimony showing that the Staff-recommended revenue requirement increased from \$127 million (Staff Ex. 9.1) to \$137 million (Staff Ex. 11.1) following Staff's adoption of the higher 9.8% ROE figure and 7.26% ROR figures proposed in the Stipulation, as compared to Ms. Phipps' recommended 9.16% ROE and 6.80% ROR increase. Staff Ex. 8.0, 45; Appendix A, Schedule 1.

The impact of adoption of the stipulated ROR/ROE on the AG-proposed revenue requirement is likewise noteworthy. If the Stipulated ROR/ROE is incorporated in the AG- proposed revenue requirement, the AG recommended revenue requirement would be increased by \$16,566,000 to \$125,104,000 from its recommendation that rates be increased no higher than \$108,854,000.

The Commission should recognize that continued use of any kind of averaging invites the parties to manipulate ROE analyses to inflate or understate recommendations. As pointed out by Mr. Gorman, the Company's testimony and the resultant Stipulation in this case appears to have been offered in recognition that an average methodology may be used to derive an ROE recommendation. IIEC-CUB Ex. 5.0 at 17. The Company offered such an averaging methodology in the Stipulation submitted. As noted by IIEC witness Gorman, the Stipulation ROE used the midpoint of three averages: (1) an average of the Company's, Staff's and IIEC-CUB's recommended ROE of 9.67%; and (2) an average of only Nicor Gas' and Staff's ROE recommendations, producing a second average of 9.93%; and (3) the midpoint of these two averages, or 9.80%. IIEC-CUB Ex. 5.0 at 4. As IIEC-CUB witness Gorman explained, the Stipulation ROE gives excessive weight to Nicor Gas' recommended ROE of 10.7% and Staff's previously recommended ROE of 9.15% in producing the average ROE.

Mr. Gorman believes that double-counting the original Nicor Gas-recommended ROE is a particularly unreliable method for computing a reasonable Nicor Gas ROE because the Company's figure includes: (1) flawed, unreliable ROE adders to traditional DCF and CAPM returns that inflate the figure; (2) a CAPM return not based on published *Value Line* betas that have no acceptance in prior Commission decisions or academic literature; (3) a risk premium return that the Commission consistently rejected as unreliable in other rate cases; and (4) a flotation cost adder of 10 points that is not based on actual Nicor common stock flotation costs and, therefore, is not a reasonable adjustment to the calculated ROE. IIEC-CUB Ex. 5.0 at 5. However, Mr. Gorman does concede that Dr. Villadsen's Risk Premium study could be modified to produce a reasonable ROE for the Company of 9.8%. IIEC-CUB Ex. 1.0 at 100.

Illinois law requires that non-unanimous settlement agreements, like the Stipulated ROR/ROE agreement at issue here, be both lawful and based on record evidence. A non-unanimous settlement of a case can be reversed by a court if the

terms of the agreement violate the Act or if the terms are not supported by substantial evidence in the record. BPI I at 280. The AG claims that the instant Stipulation fails the BPI I requirements.

Illinois courts have held that summary assessment of ROE findings that do not include sufficient explanation or justification will be reversed by a Court. In Citizens Utility Bd. v. Ill. Commerce Com'n, 291 Ill.App.3d 300 (1997), the Court reversed and remanded a Commission order for failure to provide sufficient evidence in support of the Commission's ROE findings, as well as a 54-point ROE adder. In the case, the Commission had rejected the intervenor witnesses' ROE presentation, in part, because "all three [fail] to recognize the greater risks facing [Commonwealth] Edison [Company ("Edison")] as compared to their various 'sample' groups of companies." *Id.*, 291 Ill.App.3d at 308 (*citing* the Commission's Order in Docket No. 94-0065). The Court held that "[t]he Commission's order does not explain what 'greater risks' are facing Edison or how the three witnesses' presentations failed to account for those greater risks. Nor does the Commission explain the nature of the 'untimely data.'" *Id.* at 308. The Court noted that the "Commission's findings here contain no reference to the evidence adduced and its argument on appeal, therefore, cannot provide evidentiary support." *Id.* at 309. In all, the Court held that the decision left the Court without an informed basis for judicial review. *Id.* at 309-310.

The AG argues that no witness has provided evidence that the ROE established in the Stipulation is based on evidentiary support. Nicor Gas Ex. 39.0R at 1. Nonetheless, the AG argues that Dr. Villadsen's after-the-fact blessing that "the Stipulation reflects a way in which the Commission could evaluate and synthesize the conclusions reached by the various witnesses rather than choose the results recommended by one witness" and that the 9.8% ROE stipulated to "falls within" what she believes to be the reasonable range of results" does not satisfy either the BPI-I or Citizens Utility Board evidentiary standards and the proposal should be rejected by the Commission.

As outlined by Mr. Gorman (and Staff witness Phipps), there are many alleged flaws in the original 10.7% number that make its double-counting in the Stipulation-derived 9.8% figure the AG argues is unreasonable and arbitrary. First, Nicor Gas' 10.7% ROE incorporates Dr. Villadsen's reliance on a risk premium analysis, a methodology that has consistently been rejected as unreliable by the Commission. Dr. Villadsen's risk premium analysis resulted in ROEs of 10.25% and 10.07%, which were incorporated in her final recommendation. IIEC-CUB Ex. 1.0 at 83.

Second, Nicor Gas' DCF result includes an ATWACC ROE adder that adjusts the DCF ROE to reflect perceived differences in financial risk measured on book value versus market value. Staff witness Phipps refers to the ATWACC as a "leverage" adjustment to the return estimate. Staff Ex. 3.0 at 9-15. Mr. Gorman pointed out that Staff also outlined where the Commission rejected leverage adjustments proposed in prior rate cases. *Id.* at 14-15. Importantly, Mr. Gorman testified that he was not aware that this ATWACC (or leverage) methodology has ever been accepted by any utility regulatory commission in the United States generally, including the Commission.

As support for the ATWACC adder, Nicor Gas witness Villadsen references an Alabama Commission decision, which states that it recognized that the ATWACC analysis is not a prevalent methodology in the United States. Nicor Gas Ex. 25.0 at 35. Though Dr. Villadsen suggested that other non-utility rate-setting commissions may consider it for various purposes, she never described those purposes, and the record lacks proof that the ATWACC methodology has been used by any utility regulatory body to set regulated utility rates. Id. Furthermore, Mr. Gorman testified that he has not identified nor been aware of a FERC decision ever relying on an ATWACC methodology to award an ROE for a regulated utility company. IIEC-CUB Ex. 5.0 at 8.

Mr. Gorman further noted that not only is he not aware of public utility commissions adopting the ATWACC, certain commissions have affirmatively rejected it as being a flawed methodology that produces an excessive ROE. In each of those instances, those commissions found that the ATWACC adjustment was not based on credible evidence, inflated the ROE unjustifiably, or was not reliable for setting rates. The AG argues that Dr. Villadsen's repeatedly rejected ATWACC ROE adder must be removed from the Company's 10.7% ROE if Nicor Gas' return on equity is used in any averaging approach, to ensure consistency with past Commission decisions, and similar decisions reached by other regulatory commissions. IIEC-CUB Ex. 5.0 at 8-9.

There are other problems identified by Mr. Gorman in using Nicor Gas' CAPM return estimate in the averaging methodology for developing the stipulated ROE, as previously identified in testimonies. IIEC-CUB Ex. 1.0 at 90-96; IIEC-CUB Ex. 3.0R at 20-29. They include Dr. Villadsen's incorporation of the ATWACC adder of 1.5% and 1.6% for the CAPM and ECAPM analyses, respectively. Nicor Gas also makes adjustments to the published beta used in the traditional CAPM return estimate which further inflates the CAPM return. See IIEC-CUB Ex. 1.0 at 90: Table 9. Mr. Gorman testified that these adjustments are flawed and lack academic support when used in the manner proposed by Dr. Villadsen. IIEC-CUB Ex. 5.0 at 9.

Recounting other flawed adjustments, Mr. Gorman testified that Dr. Villadsen improperly adjusted the "published *Value Line* betas" for the proxy groups in a traditional CAPM, and then erroneously adjusts the published *Value Line* betas in an ECAPM. The effect of Dr. Villadsen's adjustment to published *Value Line* betas, and flawed development of an ECAPM study, produced a CAPM return that is significantly inflated for utilities with betas less than 1. See IIEC-CUB Ex. 3.0R at 20-26. Importantly, excluding these beta adjustments to Dr. Villadsen's CAPM return produces significantly different results: the Company's CAPM would have supported a return of 9.0% to 9.4%. See IIEC-CUB Ex. 1.0 at 83; IIEC-CUB Ex. 5.0 at 9.

Finally, Nicor Gas' inclusion of a 10-point adder for flotation costs is unsupported in the record, yet included within the Nicor Gas ROE used in the Stipulation. See IIEC-CUB Ex. 1.0 at 106; IIEC-CUB Ex. 3.0R at 30-31; Staff Ex. 3.0 at 17-21; Staff Ex. 8.0 at 19-23. As noted by Mr. Gorman, the Company must demonstrate what its *actual* flotation costs are, and then prove they are reasonable. It is not appropriate to approximate flotation costs and build those approximated costs into a utility's cost of service. Costs should be known and measurable and should be verifiable and most importantly, should be shown to be reasonable before they are included in cost of

service. Mr. Gorman testified that this is not possible if a utility's flotation costs are approximated, as Dr. Villadsen has done. IIEC-CUB Ex. 1.0 at 106.

Moreover, Mr. Gorman pointed out that Nicor Gas is not publicly traded, so its source of revenues can come from retained earnings, which do not incur flotation costs. Its other source of revenue can come from an equity infusion from its parent, where again flotation costs are not incurred. Thus, Mr. Gorman explained that Nicor has not incurred these costs in its cost of service and they should not be allowed for recovery in rates. IIEC-CUB Ex. 1.0 at 106. The flotation costs identified by Nicor Gas represented costs incurred to sell stock to the public that was subsequently acquired by The Southern Company when it acquired Nicor Gas. Therefore, there is no evidence that Nicor Gas has any flotation cost on its existing common stock. IIEC-CUB Ex. 1.0 at 105-106; IIEC-CUB Ex. 3.0R at 30-32.

The AG states that the record evidence shows that Nicor Gas' new ROE methodologies offered in this case have never been accepted by the ICC or any other regulatory commission in the United States. *Id.* at 6. As noted by Mr. Gorman, in the 2008 rate case, the Commission awarded an ROE using an averaging methodology applied to DCF returns and CAPM returns, a narrower scope of averaging than that of the ROE produced through the Stipulation. There, the Commission used the Staff's and CUB's DCF returns to produce one average, and then used the Company's and Staff's CAPM returns for a second average. The midpoint of the two averages produced an ROE that ultimately served as the basis for the authorized ROE in that proceeding. IIEC-CUB Ex. 5.0 at 10, *citing* 2008 Rate Case Order at 72.

In arriving at the averaging methodology, in response to parties' arguments about appropriate methodologies, the Commission found that: "While we do not wish to ignore past practices, which appear to have served utilities and ratepayers for many years, neither do we wish to engage in cost of equity estimation in a manner that might be viewed as random or arbitrary." *Id.* at 67-68. Also, in rebuttal to Staff in that case, the Company opined that market-based models should be shown to reasonably reflect regulatory and academic support for the reasonableness of the recommended return. *Id.* at 54. Mr. Gorman testified that the Commission's finding and the position advocated by Nicor, serve as important parameters for determining whether a party's recommended ROE should be used or considered in developing an ROE based on record averages. IIEC-CUB Ex. 5.0 at 10-11.

In contrast, Nicor Gas' DCF and CAPM methodologies employed in this case are *not* reasonably consistent with accepted regulatory practices for developing these models. Specifically, in the 2008 Rate Case Order the Commission summarized Nicor Gas witness Dr. Makholm's DCF study and CAPM studies, saying Nicor Gas' DCF and CAPM methodologies in the 2008 rate case were similar to those it offered in its 2004 rate case. 2008 Nicor Gas Rate Case Order at 52-53. Dr. Makholm's DCF and CAPM studies in Nicor Gas' last two rate cases are not comparable to Dr. Villadsen's methods in this case, Mr. Gorman testified. The 2008 Nicor Gas Rate Case Order states that in performing his DCF analyses, Dr. Makholm's only dispute with the Staff concerned the use of a multi-stage growth DCF methodology. In the 2008 case, unlike Dr. Villadsen here, Nicor Gas witness Dr. Makholm did not adjust the results of his DCF study for an ATWACC financial risk or leverage ROE adder. IIEC-CUB Ex. 5.0 at 11.

In significant contrast to Nicor Gas' last rate case, in this case Dr. Villadsen performed a market-based DCF study like the Company did in its last two rate cases, but then added an ATWACC (*i.e.*, leverage) ROE adder to the results of her DCF studies. IIEC/CUB Ex. 5.0 at 11-12. Dr. Villadsen's inclusion of an ATWACC or leverage DCF adder was a point of significant dispute between the parties in this case, (Staff Ex. 3.0 at 11-13; IIEC-CUB Ex. 10 at 83-89), and the ROE adder significantly inflated Nicor Gas' DCF return recommendation.

The AG emphasizes that Staff was particularly critical of this adder approach, as detailed in the testimony of Staff witness Phipps: "Dr. Villadsen addresses the perceived differences in financial risk through two types of adjustments. The first, a market-to-book ('M/B') adjustment, is intended to account for the difference in the market value capital structures of the Gas Sample companies and the book value capital structure of Nicor Gas, which Dr. Villadsen contends is a source of risk. Staff Ex. 3.0 at 10. Staff went on to state Dr. Villadsen's "... argument is without merit, since she confused the measurement tool – the common equity ratio – with the phenomenon to be measured – financial risk. . . ." Staff concluded that a company's actual financial risk is a product of its contractually required debt service payments, not how that debt is measured. As noted above, IIEC-CUB also outlined material flaws in the application and bias created by including an ATWACC ROE adder to the DCF return. IIEC-CUB Ex. 5.0 at 12.

The AG states that the Stipulation's double-counting of the Nicor Gas ROE artificially inflates the agreed-to ROE in other ways. The 2008 Order noted that Nicor offered the same CAPM analysis as it did in its previous rate case. *Id.* at 53 and 54; IIEC-CUB Ex. 5.0 at 12-13.

Mr. Gorman noted that Dr. Villadsen's CAPM return estimate in this proceeding, however, is arrived at very differently than that which the Company proposed in its last two rate cases. In this case Dr. Villadsen, proposed a Hamada financial risk adjustment to the published *Value Line* betas, as noted in Mr. Gorman's testimony in this case. IIEC-CUB Ex. 1.0 at 90. In the 2008 Nicor Rate Case, however, Nicor Gas' witness Dr. Makhholm did not make adjustments to published betas in Nicor's last rate case. 2008 Nicor gas Rate Case Order at 53 and 54. Rather, Nicor's CAPM in the 2008 and 2004 rate cases were based on "published adjusted *Value Line* betas," in the same manner that Mr. Gorman used in his CAPM study in this case. IIEC-CUB Ex. 5.0 at 13.

Also, in this case, as noted above, Dr. Villadsen offered an ECAPM study using *Value Line* adjusted betas. Mr. Gorman explained that the ECAPM analysis double-counts the increase in the CAPM return estimates for companies with betas less than 1, which includes Dr. Villadsen's proxy group and Nicor Gas in this case. Importantly, the 2008 Rate Case Order does not include a description of this model as being presented by Nicor Gas in its last rate case. 2008 Nicor Gas Rate Case Order at 53-55; IIEC-CUB Ex. 5.0 at 12.

Mr. Gorman identified other differences in the methodology employed in previous cases and Dr. Villadsen's approach in this case. Mr. Gorman pointed out that the record evidence shows that the way Dr. Villadsen implemented a Hamada beta adjustment, and her use of adjusted betas in the ECAPM analysis, are not supported by

regulatory or academic practitioners. See IIEC-CUB Ex. 3.0R at 21-26. Nicor Gas' CAPM in this case adjusted the published *Value Line* betas before applying them in a traditional CAPM study, and also applied adjusted betas in an ECAPM study, methodologies that have never been supported by the Commission or any other regulatory commission. IIEC-CUB Ex. 5.0 at 13-14.

As support for the stipulated ROE/ROR figures, Dr. Villadsen referenced Commission decisions in other recent rate cases that utilized results from different witnesses testifying concerning ROE in arriving at a Commission-allowed reasonable ROE. Nicor Gas Ex. 39.0R at 2; Nicor Gas Ex. 40.0 at 7, 8 and 15. Those "recent cases" were identified in Nicor Gas' response to IIEC Data Request 11.02 and page 3 of AG Cross Ex. 1 on Reopening: Ill.-American Water Co., Docket No. 16-0093, (Dec. 13, 2016); Liberty Utilities (Midstates Natural Gas) Corp. d/b/a Liberty Utilities, Docket No. 14-0371, (Feb. 11, 2015); Ameren Ill. Co. d/b/a Ameren Ill., Docket No. 13-0192, (Dec. 18, 2013); Ameren Ill. Co. d/b/a Ameren Ill., Docket No. 11-0282, (Jan. 10, 2012); Aqua Ill., Inc., Docket No. 10-0194, (Dec. 2, 2010); and Aqua Ill., Inc., Docket No. 14-0419, (Mar. 25, 2015). IIEC-CUB Ex. 5.0 at 14. In fact, in three of the cases, the Commission decided on the utility ROE by some averaging of the parties' DCF and CAPM results, unlike the three-part averaging ROE proposed in the Stipulation. Id. at 14-15.

In the Docket No. 16-0093, the Commission determined the ROE by taking a simple average of the recommendations offered by IAWC and the recommendations offered by intervenors Illinois Industrial Water Consumers, Federal Executive Agencies and CUB which the Commission claimed resulted in a reasonable ROE (and found that the Staff ROE was so low as to be an outlier that should be excluded). Docket No. 16-0093, Order at 66-67. No double-counting of any single ROE was incorporated in the final ROE. Moreover, if the Commission is to follow the logic applied in the IAWC case, it is the Company's original proposed ROE of 10.7%, as compared with Mr. Gorman's proposed 9.15% and Ms. Phipps's proposed 9.16% that is the outlier. Yet, not only does the Stipulation not exclude the clear outlier proposal, it gives it a double-weighting, again without a word of explanation as to its reasonableness.

In Docket No. 14-0371, the Commission determined the ROE by taking an average of the Staff and Liberty DCF average and the Staff and Liberty Utilities CAPM average. The Commission specifically found, too, that a Staff estimate of additional risk of 32 basis points was reasonably calculated. Docket No. 14-0371, Order at 66-67.

In the 2013 Ameren case, the Commission determined the ROE by taking an average of the average of the DCF proposed by Staff, the IIEC and the Company; and the CAPM proposed by Staff. Docket No. 13-0192, Order at 166.

In the 2011 Ameren case, the Commission averaged the DCF results of Ameren, Staff, Illinois Industrial Electric Consumers, and Governmental and Consumer Intervenors, concluded that the Staff CAPM analysis was the most reasonable, and rejected the risk premium methodology all-together, as promoted by the Company's witness, and included a reduction to Ameren's cost of equity by 16.25 basis points to reflect the reduction in risk associated with the existence of the uncollectibles riders.. Docket No. 11-0282, Order at 123, 125 and 126. This result is not analogous to the stipulated ROR/ROE at issue here.

In the 2010 Aqua case, the utility agreed with the Staff ROE with a slight modification, based on the weighting of samples utilized in the Staff analysis. While a stipulation between Staff and the Company was adopted (which the AG opposed) in the Aqua case, the stipulation included a specific derivation for the deviation from Staff's original ROE number. The stipulation in the Aqua case stated:

Aqua and Staff agree and stipulate that the cost of common equity estimates for smaller samples are prone to more measurement error. Given this fact, Aqua and Staff agree to use Staff's proposed ROE analysis, subject to revising the weighting of Staff's Water Sample Group and Utility Sample Group to the following: 1/3 weighting to Staff's Water Sample and 2/3 weighting to Staff's Utility sample. This weighting results in a ROE of 10.03% for Aqua.

Docket No. 10-0194, Order at 19, 20, 22.

In the 2014 Aqua case, the Commission rejected the Company's suggested use of a risk premium analysis and took an average of Aqua's and Staff's DCF and CAPM results. Docket No. 14-0419, Order at 43-44. Here, this averaging methodology employed no double-counting of any party's proposed ROE figures, unlike the stipulated ROE at issue in the instant case.

The AG states that if the Commission chooses to incorporate an "average" ROE in the utility's cost of capital calculation, several adjustments to Nicor Gas witness Villadsen's proposed ROE must be made to ensure that (1) the DCF and CAPM approaches are consistent with the Commission's past Nicor orders; and (2) customer rates are not arbitrarily and unreasonably inflated. Failure to make these adjustments produces an "averaging" approach that is flawed and arbitrary, Mr. Gorman testified. Id. at 16.

The AG argues that with these adjustments, using DCF and CAPM returns that were calculated using the methods the Company advocated for in its last two rate cases, and the results of Staff's and Mr. Gorman's DCF and CAPM return estimates produces a range for an ROE in this case of approximately 9.2% based on both the DCF and CAPM studies. Using the evidence in this case consistent with the Commission decisions in Nicor Gas' last two rate cases, produces an average ROE of 9.2%:

Any averaging methodology is only as good as the components being averaged. If a numeric value is artificially inflated, as the substantial evidence in the record demonstrates, the "average" quotient will be inflated. As detailed in both Mr. Gorman's and Staff's testimony, eliminating the financial risk ROE adders proposed by the Company (in the range of 1.4% to 1.9%) would have the effect of reducing the Company's inflated 10.7% ROE recommendation, to an ROE in the range of 9.0% to 9.4% using the DCF and CAPM methodologies normally relied on by the Commission. IIEC-CUB Ex. 1.0 at 83. Averaging these ROE results would support an ROE of about 9.2% in this proceeding based on methodologies offered by the Company if corrected, Staff (9.16%), and IIEC-CUB (9.15%), according to Mr. Gorman.

e. Commission Analysis and Conclusion

The Commission adopts an ROE of 9.80% as recommended by the Stipulation between the Company and Staff for reasons set forth below.

The Commission recognizes that estimating the cost of common equity is perhaps one of the most challenging aspects of a rate case proceeding. In fact, all parties in the instant case understand that determining a reasonable ROE is an inexact science and requires subjective decisionmaking. All parties recognize that there are many reasonable ways to compute an ROE. Each party arrived at their recommendation by generating a range of outcomes using various models with different assumptions, then either averaging the results of such models or selecting a specific ROE from within the range of results. Nicor Gas Ex. 11.0 at 3-4, 6-32, 54-63, 66-67; Staff Ex. 3.0 at 21- 27-45; IIEC-CUB Ex. 1.0 at 13-14, 47-77.

In estimating the cost of common equity, the Commission must consider not only the outputs of the financial models, but whether the authorized ROE satisfies the standards set forth in Bluefield Water Works & 398 Improvement Co. v. Public Service Commission of West Virginia, 262 U.S. 679 (1923) and Federal Power Commission v. Hope Natural Gas Co., 320 U.S. 591 (1944). These decisions establish that a regulatory body such as the Commission must consider whether the authorized return will allow a return that is sufficient to maintain the utility's financial integrity and to attract capital at reasonable terms, while ensuring that customers do not pay an excessive or unreasonable return on those rates. Bluefield, 262 U.S. at 692-93; Hope, 320 U.S. 591 at 603. The Company must be able to provide safe, reliable service at just and reasonable rates. Bluefield, 262 U.S. at 693; Hope, 320 U.S. 591 at 603. The return should be commensurate with returns investors could earn by investing in other companies of comparable risk. Bluefield, 262 U.S. at 692; Hope, 320 U.S. 591 at 603.

Determining the appropriate cost of common equity is particularly challenging in the instant case because prior to the Stipulation none of the parties recommended a reasonable ROE. If the Commission accepted IIEC/CUB's recommendation in its context, it would result in the lowest allowed return on Nicor Gas' common equity in the last nearly five decades. Nicor In. at 74-75. The Commission agrees with Nicor that such a low ROE would not allow Nicor to recover its cost of service and significantly harm Nicor's ability to reasonably compete for capital and harm ratepayers and investors alike. Nicor BOE. at 23-24. In the same vein, if the Commission were to adopt Nicor's recommendations, it would have been the highest equity award to Nicor in the past 23 years. IIEC/CUB RBOE. at 15. The Commission agrees with Staff that such a high ROE would generate a windfall for Nicor's common stock shareholders. Staff RBOE. at 12.

An ROE of 9.8% set forth in the Stipulation is a sensible mid-point between the extreme positions. The Stipulated ROE of 9.8%, falls between the range established by the lowest ROE, 9.15%, recommended by IIEC/CUB and the highest ROE, 10.70%, recommended by Nicor. Nicor Gas Ex. 39.1 at 4. Dr. Villadsen stated that 9.80% is a reasonable ROE and falls within the range of ROE estimates she obtained and considered in her own analysis. Nicor Gas Ex. 40.0 at 3. The Commission agrees with Nicor that those parties who oppose the Stipulation offered limited evidence. Only

IIEC/CUB submitted testimony opposing the Stipulation. Nicor BOE. at 15. However, IIEC/CUB's witness, Mr. Gorman, offered testimony that was inconsistent. While he initially testified that several of the Company's models, if adjusted as he described, would support an ROE of 9.80%, he later testified that the Stipulation's recommended ROE of 9.80% is not reasonable because it gives weight to the Company's initial 10.7% ROE recommendation in its averaging methodology. IIEC-CUB Ex. 1.0 at 83-84, 100; IIEC-CUB Ex. 5.0 at 4-5. Moreover, the ROE recommended by the Stipulation is the only proposal that is near the national average of utility companies in the United States. See Nicor Ex. 25.1 at 2. The average ROE for all utilities in the entire United States awarded over the past 24 months (a total of 246 cases) was 9.64%. Although the Commission does not rely on national averages to make its decisions, they can be useful benchmarks when evaluating parties' recommendations.

Lastly, we could also arrive at an ROE of 9.8% by taking a weighted average of the parties' recommendations. This approach avoids giving certain arguments more weight simply because more parties advocated for it. Determining the weight of evidence is within the broad discretion of the Commission as the trier of fact. Illinois Bell Tel. Co. v. Illinois Commerce Comm'n, 327 Ill. App. 3d 768, 777, 762 N.E.2d 1117, 1124 (2002). "The credibility of expert witnesses and the weight to be given their testimony are matters for the Commission as the trier of fact. (internal citation omitted)" Id. In the instant case, the Commission found it reasonable to weigh Staff and Nicor's original recommendations more heavily in the averaging as they represent the two sides of this dispute. The use of averages to resolve difficult disputes is an established practice at the Commission. See Illinois-American Water Co. Proposed Rate Increases for Water and Sewer Service, ICC Docket No. 16-0093 (Order, December 13, 2016); Aqua Illinois, Inc. Proposed General Increase in Water Rates for the Kankakee Service Area, ICC Docket No. 14-0419 (Order, March 25, 2015); Liberty Utilities (Midstates Natural Gas) Corp. d/b/a Liberty Utilities Proposed General Increase in Natural Gas Rates, ICC Docket No. 14-0371 (Order, February 11, 2015); Ameren Illinois Co. d/b/a Ameren Illinois Proposed general increase in gas rates, ICC Docket No. 13-0192 (Order, December 18, 2013); Ameren Illinois Co. d/b/a Ameren Illinois Proposed general increase in natural gas rates, ICC Docket No. 11-0282 (Order, January 10, 2012); Aqua Illinois, Inc. Proposed general increase in water rates for the Kankakee Water Division, ICC Docket No. 10-0194 (Order, December 2, 2010). Furthermore, it is important to note that the Commission, as the fact-finder, has discretion in constructing its averaging methodology that is not limited to past practices only. "[The Commission has the] power to deal freely with each situation as it comes before it, regardless of how it may have dealt with a similar or even the same situation in a previous proceeding." Citizens Utility Bd. V. Illinois Commerce Commission, 291 Ill.App.3d 300, 307 (1997).

For reasons stated above, the Commission concludes that Nicor Gas' cost of common equity is 9.80%, as recommended by the Stipulation. The Commission finds that this ROE strikes a fair balance between the competing interests, is supported by the record, and satisfies the governing legal standard. BPI I at 217. "Substantial evidence means more than a mere scintilla; however, it does not have to rise to the level of a preponderance of the evidence." Commonwealth Edison Co. v. Illinois Commerce Comm'n, 398 Ill.App.3d 510, 514 (Ill.App.2d, 2009) (internal quotations

omitted) (citing Citizens Utility Board v. Illinois Commerce Comm'n, 291 Ill.App.3d 300, 304 (1997)).

The Commission's analysis in this case is not indicative of how the Commission will review and decide upon ROE in future rate cases, nor shall this decision obligate the Commission to apply the same or similar analysis in future proceedings.

5. Flotation Cost Adjustment

a. Nicor Gas' Position

Nicor Gas argues that it should be able to recover its unrecovered issuance costs for stock issuances going back to 1961. Nicor Gas argues that to deny recovery of these costs is to effectively deny recovery forever, which will mean that Nicor Gas' investors are permanently denied a return on these costs. Nicor Gas Ex. 2.0 at 19.

Nicor Gas disagrees with Staff's position that recovery of these costs must be denied because they were denied in past Nicor Gas rate cases, including the 2004 rate case. 2004 Rate Case Order at 94 (Sep. 20, 2004). Nicor Gas argues that this is not correct because, in addition to the Commission not being bound by prior decisions even absent a change in the law, the rules of evidence have changed to allow for a party to affirmatively prove the nonexistence of something by establishing the absence of a business record. Nicor Gas asserts that, had these costs been recovered, the recovery would be recorded in the Company's books and records kept in the ordinary course of business. Nicor Gas asserts that it has reviewed the Company's complete books and records, and they reveal no line item or accounting entry documenting recovery of these costs. The absence of such line item or accounting entry, and the fact that these costs remain unrecovered on the Company's books, establishes that these costs were not recovered. Nicor Gas argues that the change in the rules of evidence since these costs were last considered in 2004 allows the Commission to look at the sworn testimony in this proceeding based on the witnesses' review of Nicor Gas' audited books and records, original equity issuance documents, rate filings made with the Commission, annual reports to the Commission, and the Commission's own rate orders showing the absence of a record of recovery of these costs and make an affirmative finding that these costs have not been recovered.

Nicor Gas also argues that some of the evidence presented in the 2004 Rate Case was not entered in to the record, while all the evidence presented here has been entered into the record. Nicor Gas contends that it has provided all the information required by Part 285 and all the information it has to support recovery of these costs.

Nicor Gas also disagrees with Staff's argument that the proceeds of the two issuances which were issued by Nicor Gas' then-holding company, Nicor, Inc., were not used solely to benefit Nicor Gas' rate base. While Nicor Gas maintains that all of these equity issuances funded Nicor Gas and its corporate predecessor in connection with the issuance of equity to support its utility operations, Nicor Gas points out that this argument applies only to those issuances by Nicor, Inc. and not to those issued by the utility itself.

Nicor Gas proposes to recover these costs through a 10 basis point adder to its ROE. Nicor Gas witness Dr. Villadsen calculated this by implementing a straightforward

adjustment to the single-stage DCF model. Nicor Gas argues that this calculation uses accepted methodologies, and it properly provides for sufficient prospective return both of and on the portion of the capital provided by investors that was lost to flotation costs at the time of the equity issuances. Nicor Gas disagrees with IIEC-CUB's contention that these costs were approximated. Nicor Gas argues that its witness Dr. Villadsen performed her calculations by using the known and verifiable costs of the issuances, then used the average of those costs to determine the total issuance cost. Nicor Gas Ex. 11.0 at 61.

Nicor Gas disagrees with Staff's proposed recovery mechanism, which increases the ROE by a percentage equal to documented dollar flotation costs divided by Nicor Gas' book value common equity balance. Nicor Gas Ex. 11.0 at 61. Nicor Gas contends that this methodology dramatically reduces the ROE adjustment and does not properly account for the time value of money and the return on this capital that was lost to investors.

b. Staff's Position

Staff states that Nicor Gas has failed to demonstrate that it has unrecovered common equity issuance costs (also referred to as "flotation costs"); therefore, the Company's proposed 10 basis points adjustment (0.10%) to the ROE for flotation costs should be rejected. The Company has reported \$478,277 in stock issuance expense in Account 214 (Capital Stock Expense) since 1978; Nicor Gas relies on this number to support its claim that issuance costs remain unrecovered. However, the mere existence of an amount registered in Account 214 is, by itself, insufficient to demonstrate the Company has not previously recovered flotation costs from ratepayers. Staff Ex. 3.0 at 18.

In prior dockets, the Commission has rejected the argument that any amount registered in Account 214 is an incurred but unrecovered flotation cost. In Docket No. 99-0354, the Commission rejected MidAmerican Energy Company's proposed common equity flotation cost adjustment, even though that company had flotation costs recorded in Account 214. Noting that Commission rules did not require utilities to amortize common stock expenses that were recovered through rates until December 31, 1993, the Commission stated it could not conclude that all of the issuance expense recorded in Account 214 remained unrecovered. The Commission further stated that, "[T]he existence of this figure in the FERC Form 1 does not necessarily require that it be reflected in rates." MidAmerican Energy Co., Docket No. 99-0534, Order at 35-36 (Jul. 11, 2000).

The Commission has considered and declined to approve repeated requests by Nicor Gas to recover flotation costs as an upward adjustment to its authorized cost of common equity, most recently in Docket No. 04-0779. 2004 Rate Case Order at 92-94; N. Ill. Gas Co. d/b/a Nicor Gas Co., Docket No. 95-0219, Order at 41, 46 (Apr. 3, 1996). The Commission found that Nicor Gas failed to demonstrate that it has incurred, for the benefit of Nicor Gas ratepayers, but not yet recovered, the fees upon which its flotation cost adjustment is based. 2004 Rate Case Order at 92-94 (Sep. 20, 2005). Recovery of flotation costs is to be allowed only if a utility can verify both that: 1) it incurred the specific amount of flotation costs for which it seeks compensation; and 2) that those

costs have not been previously recovered through rates. The Company has done neither in this proceeding. In the 2004 rate case, the Commission determined that Nicor Gas did not establish that issuance costs remain unrecovered. In this case, Nicor Gas did not present any additional evidence to supplement the documentation it provided - and which the Commission determined to be insufficient - to support its claim for unrecovered flotation costs in the 2004 rate case. This is significant because the Company has not issued any new equity since that case, which means no new issuance costs have been incurred and the same costs that were at issue in the 2004 rate case are at issue here. Since the Company presented the same evidence regarding flotation costs in this proceeding that it presented in the 2004 rate case, the Commission's review of that information and decision on this issue should similarly be the same.

The only evidence in this record that these costs were incurred is testimony and a spreadsheet (Nicor Gas Schedule D-5) presumably created by the Company in preparation for this proceeding and thus of questionable evidentiary value. Since Nicor Gas has failed to offer any new information or documents to support the argument that the costs were incurred but remain uncollected, there is no basis for the Commission to revisit its decision in the 2004 case rejecting recovery of these costs. This issue has been litigated and decided, and the Company offers nothing to support an argument that the Commission should not only revisit the issue of flotation costs but that it should reverse its prior decision.

In Docket No. 94-0065, the Commission articulates a general view on flotation cost adjustments and traditionally approved such adjustments when a utility anticipates issuing stock in the test year or when it has been demonstrated that costs incurred prior to the test year have not been recovered previously through rates. Commonwealth Edison Co., Docket No. 94-0065, Order at 93-94 (Jan. 9, 1995).

The finding in the Docket No. 94-0065 is not unique. There are numerous cases in which the Commission has rejected proposed flotation cost adjustments as inappropriate because a utility has been unable to show that it has incurred common equity issuance costs that have not previously been recovered through rates. See, e.g., MidAmerican Energy Co., Docket No. 14-0666, Order at 49 (Nov. 6, 2014); N. Shore Gas Co./ The Peoples Gas Light & Coke Co., Docket Nos. 07-0241/0242 (Cons.), Order at 101-102 (Feb. 5, 2008); Central Ill. Pub. Serv. Co. and Union Electric Co., Docket Nos. 02-0798/03-0008/03-0009 (Cons.), Order at 87 (Oct. 22, 2003); MidAmerican Energy Co., Docket No. 01-0696, Order at 24 (Sep. 11, 2002); Central Ill. Light Co., Docket No. 01-0465/0530/0637 (Cons.), Order at 79 (Mar. 28, 2002); Illinois-American Water Co., Docket No. 95-0076, Order at 69 (Dec. 20, 1995).

Not only has Nicor Gas failed to demonstrate it has uncollected issuance costs, it is also asking for relief that is possibly contrary to statute. In this case, as in Nicor Gas' previous cases including the 2004 rate case, Nicor Gas requests recovery of flotation costs for 1979 and 1980 common equity issuances made by its previous parent company, Nicor, Inc. Nicor Gas Ex. 15.0 at 20. Allowing recovery of the flotation costs incurred by Nicor, Inc. would violate Section 9-230 of the Act absent a showing by the Company that proceeds of the Nicor, Inc. equity issuance were used to fund Nicor Gas' rate base. Staff Ex. 8.0 at 22. Specifically, Section 9-230 of the Act states:

In determining a reasonable rate of return upon investment for any public utility in any proceeding to establish rates or charges, the Commission shall not include any (i) incremental risk, (ii) increased cost of capital ... which is the direct or indirect result of the public utility's affiliation with unregulated or nonutility companies.

220 ILCS 5/9-230.

In its order in the 2004 rate case, the Commission rejected arguments from the Company similar to those raised in this proceeding and specifically addressed Section 9-230 of the Act, as follows:

Nicor concedes on the record that two specific issuances at issue were made by Nicor Inc., yet it is Nicor Gas that seeks their recovery. According to Nicor, the fact that the two issuances were made by Nicor Gas' parent is "immaterial" since Nicor Gas is only seeking to recover the percentage of flotation cost applicable to Nicor Gas' equity capital. We disagree. Section 9-230 of the Public Utilities Act is clear in its proscription of calculating a rate of return where financial involvement with non-utility or unregulated companies is possible intermingled with flotation costs at issue as is the case here.

2004 Rate Case Order at 93.

Nicor Gas has not demonstrated that it has issuance costs that have not been collected and which were associated with an equity issuance that specifically benefited the Company. Nevertheless, assuming for the sake of argument that the Commission is inclined to approve a flotation cost adjustment in this docket, the Company is not entitled to a 10 basis points adjustment. Instead, Staff recommends that any cost issuance be calculated using a formula the Commission has previously accepted. Staff Ex. 3.0 at 21, See, e.g., Central Ill. Light Co. d/b/a AmerenCILCO, Central Ill. Pub. Serv. Co. d/b/a AmerenCIPS, Ill. Power Co. d/b/a Ameren IP, Docket Nos. 06-0070/0071/0072 (Cons.), Order at 148 (Nov. 21, 2006); Central Ill. Light Co., Docket No. 02-0837, Order at 40 (Oct. 17, 2003); MidAmerican Energy Co., Docket No. 01-0444, Order at 15-16 (Mar. 27, 2002); MidAmerican Energy Co., Docket Nos. 99-0122/99-0130 (Cons.), Order at 10 (Aug. 25, 1999); Iowa-Illinois Gas and Electric Co., Docket Nos. 92-0292/92-0357 (Cons.), Order at 60-65 (Jul. 21, 1993). Application of that formula in this proceeding, using the consensus ROE recommendation, would result in a common equity issuance cost adjustment of 0.003%. Thus, if the Commission authorizes an ROE of 9.15% for the Company prior to a flotation cost adjustment, the resulting ROE with a flotation cost adjustment would be 9.153%. Staff Ex. 3.0 at 21. This same formula should be used to calculate any actual flotation cost adjustment using the final Commission-approved ROE in this docket.

Instead, the Company suggests the Illinois Rules of Evidence have changed materially and that Rule 803(7) now allows for the admission of what is essentially negative evidence to prove the nonexistence of a matter. Simply stated, this rule allows

a party to argue that if the occurrence of a matter would normally be reflected in records kept in the ordinary course of business, the absence of such document can be used to demonstrate it did not occur. This change in rule is irrelevant in this docket, where the Company has not provided documentation other than witness testimony.

First, the change in the rule is not a change at all, negative evidence having been admissible in Illinois since at least 1945. See, Berg v. New York Central R.R. Co., 391 Ill. 52, 60-62 (1945). Indeed, it has been the rule in Illinois since at least 1921 that, if an event usually happens in the ordinary course of business, it is presumed to have happened in a particular case unless contrary evidence is adduced. Paden v. Rickford Palace Furniture Co., 220 Ill. App. 534 at 543 (2d Dist. 1921). The fact that Nicor Gas asserts that its books do not reflect it having recovered the flotation costs is a fact that the Commission appears to have already considered, and the codification of a hearsay exception, which is what the change to the Rule 803(7) accomplishes, adds no additional value to that evidence, especially where the law itself has not changed.

In the 2004 Rate Case, the Commission noted it was “perplexed” as to why Nicor Gas failed to produce the documents it references when it states its witnesses’ own sworn testimony “is based on the witnesses’ review of Nicor Gas’s audited books and records, original equity issuance documents...etc.” 2004 Rate Case Order at 93. That lack of documentation is even more perplexing in this proceeding, when the Company argues that the change in the Rules of Evidence require the Commission to reach evidentiary conclusions favorable to Nicor Gas based on the nonexistence of books, records, equity issuance documents, and similar documents that Nicor Gas’ witnesses in this proceeding and in a prior proceeding claimed to have reviewed.

In fact, Staff notes that the documentation the Company offers does not demonstrate that Nicor Gas has incurred but not recovered issuance costs. Nicor Gas points to witness testimony as supporting this claim but, as noted, the Commission has previously found this evidence to be deficient. Additionally, while the Company states that Nicor Gas Exhibit 15.2 supports its claim, in fact it does no such thing. Nicor Gas Ex. 29.0R at 25. Nicor Gas Exhibit 15.2 shows the various prospectuses for five stock offerings; not one of these shows issuance expenses incurred by the Company or its parent, Nicor, Inc. Rather, each prospectus shows the amount of money expected to be received by the respective issuer, (i.e., gross proceeds minus underwriting discounts and commissions) as well as the estimated issuances expenses. Nicor Gas Ex. 15.2. The estimates are simply that – estimates. The prospectuses do not demonstrate that: (1) those estimated costs were incurred by Nicor Gas or Nicor Inc.; (2) the actual proceeds equaled the estimated proceeds and were used exclusively by Nicor Gas for utility purposes; or (3) any issuance related expenses remain unrecovered in whole or in part.

Staff states that Nicor Gas seeks to recover flotation costs on the theory that (a) they must have been incurred, although Nicor Gas has produced no record of this; and (b) they must not have been recovered, because Nicor Gas cannot produce any record that they were. In other words, Nicor Gas seeks an adjustment to ROE based upon the apparent nonexistence of Company records that would show whether it was entitled to such an adjustment. If the Commission elects to rely on an evidentiary presumption, it might be well advised to consider the long-standing rule that “[w]here a party alone

possesses information concerning a disputed issue of fact and fails to bring forward that information, and it is shown that it can be produced by him alone, a presumption arises in favor of his adversary's claim of fact." In re Storment, 203 Ill. 2d 378, 394-5 (2002), quoting Belding v. Belding, 358 Ill. 216, 220-21 (1934).

Staff points out that the Commission has rejected identical evidence and arguments in the past, but Nicor Gas suggests those previous decisions have no precedential value. On the contrary, while Commission decisions are not *res judicata*, it is well settled that Commission decisions are entitled to a great deal of deference unless they depart drastically from past practices. Citizens Utility Bd. v. Ill. Commerce Com'n, 166 Ill.2d 111 (1995); Lakehead Pipeline Co. v. Ill. Commerce Com'n, 296 Ill.App.3d 942 (3rd Dist. 1998). To allow recovery of issuance costs when Nicor Gas has failed to prove that these costs were incurred but not recovered would be a drastic departure from past practice. See, e.g. MidAmerican Energy Co., Docket No. 14-0066, Order at 49 (Nov. 6, 2014); Ameren Ill. Co. d/b/a Ameren Ill., Docket No. 13-0192, Order at 165-166 (Dec. 18, 2013); Ameren Ill. Co. d/b/a Ameren Ill., Docket No. 11-0282, Order at 126 (Jan. 10, 2012); Ill.-American Water Company, Docket No. 95-0076, Order at 69 (Dec. 20, 1995); Commonwealth Edison Co., Docket No. 94-0065, Order at 92-93 (Jan. 9, 1995); North Shore Gas Co./ The Peoples Gas Light and Coke Co., Docket Nos. 07-0241/0242 (Cons.), Order at 101-102 (Feb. 5, 2008).

Finally, to support its claim for recovery of flotation costs, Nicor Gas argues "Nicor Gas has provided all of the data required by Part 285 (in addition to its sworn testimony) and the data supporting these costs has been admitted into the record as evidence." The Commission should reject Nicor Gas' argument. Nicor Gas fails to recognize that, pursuant to Part 285, "[the] standard information requirements do not bind the Commission to a decision based solely on data provided pursuant to this Part, and parties and Commission Staff may seek additional information through discovery." 83 Ill. Adm. Code 285.110(b). Providing information required by Part 285 does not mean that Nicor Gas has met its burden of proof.

Staff states that Nicor Gas has failed to meet its burden of proof with respect to flotation costs, as it similarly failed in previous dockets, and its arguments for an increase to ROE should be rejected. However, assuming for the sake of argument that the Company has demonstrated to the Commission's satisfaction that some issuance costs remain unrecovered, the Company has failed to demonstrate it is entitled to a 10 basis point increase to its ROE to account for these costs. Nicor Gas essentially asks for a significant perpetual return on a series of one-time costs. As Staff demonstrated, using the Commission's approved formula, any actual ROE adjustment is equal to .004%. Staff Ex. 3.0 at 21.

c. IIEC-CUB's Position

IIEC-CUB point out that Dr. Villadsen estimated that a 10-basis point adder represents a reasonable adjustment to account for flotation costs and took this into consideration when determining where the Company's return on equity falls within the range of her results. Nicor Gas Ex. 11.0 at 61.

IIEC-CUB argue that flotation costs should only be included in the development of cost of service under two conditions. IIEC-CUB claim first, the Company must

demonstrate what its *actual* flotation costs are, and then prove they are reasonable. According to IIEC-CUB, it is not appropriate to approximate flotation costs and build those approximated costs into a utility's cost of service: costs should be known and measurable and should be verifiable and most importantly, should be shown to be reasonable before they are included in cost of service. IIEC-CUB conclude that this is not possible if a utility's flotation costs are approximated, as Dr. Villadsen has done. IIEC-CUB Ex. 1.0 at 106.

IIEC-CUB state that as Nicor Gas is not publicly traded, its source of revenues can come from retained earnings, which do not incur flotation costs. IIEC-CUB claim that its other source of revenue can come from an equity infusion from its parent, where again flotation costs are not incurred. Thus, IIEC-CUB maintains that Nicor Gas has not incurred these costs in its cost of service and they should not be allowed for recovery in rates. Id.

According to IIEC-CUB, Nicor Gas argues it has incurred costs of issuing equity that have not previously been recovered in rates, and that these costs are identified in the record and substantiated. The Company also asserts it is legally entitled to recover these costs, claiming that it has found absolutely no evidence in the Company's books that these costs have been recovered. IIEC-CUB argue that the Company's claims should be rejected because it is not based on known and measurable costs for Nicor Gas. IIEC-CUB maintain that the Company's flotation cost adder is based on other companies and public stock issuances that may or may not reflect costs that are appropriate for ratepayers to pay to Nicor Gas. IIEC-CUB Ex.3.0R at 30-31. According to IIEC-CUB, these costs have not been "recovered" in Nicor Gas' words, because they have not been incurred.

IIEC-CUB maintain that there *is* evidence to the contrary. IIEC-CUB state that the historical Nicor Gas flotation cost reflected a period prior to Nicor Gas being acquired by Southern Company, and therefore, the public stock issuance cost identified by Nicor Gas in this proceeding reflects stock that is no longer traded to the market. IIEC-CUB Ex. 3.0R at 32. That stock was purchased by The Southern Company when it acquired Nicor Gas. As such, IIEC-CUB observe that the current common stock is owned by The Southern Company, and there is no proof that any flotation cost was ever incurred in order to allow The Southern Company to acquire all the common stock of Nicor Gas. For this reason, IIEC-CUB conclude that Nicor Gas has not identified any actual flotation costs incurred to support equity capital investment in Nicor Gas. Thus, a flotation cost is not justified. Id.

IIEC-CUB argue that the Company also failed to recognize that Nicor Gas can build up common equity without incurring public stock issuance costs because Nicor Gas can increase common equity through retained earnings, or from equity infusions from its parent company. According to IIEC-CUB, neither of these sources of equity capital would result in Nicor Gas incurring public stock flotation expenses. For these reasons, IIEC-CUB conclude that the Commission should not assume, without proof, that Nicor Gas has incurred public stock flotation costs, and adjust a return on equity based on costs which are not known and measurable. Id. at 31. Thus, IIEC-CUB recommend the Commission should reject Nicor Gas flotation cost adjustment.

d. Commission Analysis and Conclusion

Nicor Gas claims that it has produced sufficient evidence to show that there is no record of recovery of the public stock flotation expenses costs on the Company's books, which are kept as records of regularly conducted business activities, and that if these costs had been recovered there would be an entry on the Company's books. Nicor Gas' evidence included testimony and a spreadsheet created for this docket to attempt to show that this cost has not been recovered. As the Commission found previously in the 2004 Rate Case Order, the burden is on the Company to prove that this cost has not been recovered previously through rates. The Commission is not convinced that the evidence presented by the Company entitles it to the recovery it seeks. The Commission finds that Nicor Gas' evidence is still lacking and fails to establish that these costs were not previously recovered through rates. Therefore, the Company's flotation cost adjustment for past issuance expenses is rejected.

C. Recommended Rate of Return on Rate Base

The Commission finds that the Stipulation presented by Nicor Gas and Staff is substantially supported by the record and is not otherwise unlawful. The component values set forth in the Stipulation are either values recommended by a party in this proceeding or are within the range of values presented by the parties. Therefore, the Commission finds a 7.256% ROR to be reasonable.

The only value that IIEC/CUB and AG contest in the Stipulation is the ROE. As discussed above, the Stipulated ROE is reasonable and supported by substantial evidence.

In adopting the Stipulation, the Commission is aware that it may create a perverse incentive for parties to recommend extreme numbers. The Commission does not however find the issue to be especially concerning because the Commission can adjust the weights of the parties' recommendations based on the quality of evidence presented, as we did in the instant case. The Commission nevertheless strongly discourages such gamesmanship as it will only increase the contention between parties and add complications to an already difficult and expensive proceeding.

Having considered the conclusions above concerning Nicor Gas' capital structure and costs of debt and equity, the Commission finds that the Company should be authorized to earn a rate of return of 7.256%, which incorporates an ROE of 9.80%. The authorized rate of return is based on the full record in this proceeding, and represents the reasonable values agreed to by Nicor Gas and Staff in their Stipulation. It is summarized as follows:

CAPITAL COMPONENT	Weight	Cost	Weighted Cost
Short-term Debt	0.586%	1.33%	0.008%
Long-term Debt	47.414%	4.49%	2.129%

Common Equity	52.000%	9.80%	5.096%
Credit Facility Fees			0.023%
Total			7.256%

VII. COST OF SERVICE AND ALLOCATION ISSUES

A. Contested Issues

1. Embedded Cost of Service Study

a. Customer Component of Mains/Minimum-Size Analysis

(i) Nicor Gas' Position

Nicor Gas asserts that its proposed ECOSSE reproduces the same cost classification and allocation methodology that the Commission authorized in the 2008 Rate Case. Each of Nicor Gas' rate base and expense accounts is classified consistent with the manner in which the associated costs are incurred. Nicor Gas Ex. 9.0 at 2. Costs that are associated with serving peak design day requirements on the system are classified as demand-related, and costs that are associated with providing customers' access to and active status on the distribution system are classified as customer-related. Nicor Gas Ex. 9.0 at 6-7. Customer-related costs are incurred regardless of the amount of gas a customer consumes in any given period and include the costs of services, meters and regulators, and meter reading and billing expenses. Nicor Gas Ex. 9.0 at 9.

Nicor Gas explains that the division of distribution mains investment costs between the demand- and customer-related components is commonly determined through a minimum-size study or a zero intercept study. Id. at 10. The minimum-size study evaluates the cost of replacing the existing distribution mains of the system under two different sets of assumptions. The first determines the replacement cost, assuming that the entire system is replaced with two-inch diameter plastic pipe, which is the smallest, least-expensive size and type of pipe presently being installed. The second determines the cost of replacing existing distribution mains with the same diameter and lengths of pipe as is currently installed. The customer component of distribution mains is equal to the ratio of the replacement cost using the smallest size pipe to the replacement cost using the installed sizes of pipe. Nicor Gas asserts that based on the results of this study, 48 percent of Nicor Gas' distribution mains investment would be classified as customer-related. Nicor Gas Ex. 9.0 at 11.

Nicor Gas disagrees with the AG's proposal to classify 100% of distribution mains as demand-related because, as set forth above, 48 percent of Nicor Gas' distribution mains investment should be classified as customer-related, and the ECOSSE retains the same allocation of distribution mains for both the demand and customer component of distribution mains as was used in the 2008 Rate Case. Nicor Gas Ex.

24.0 at 4. This approach eliminates any impact on allocation of costs to rate classes. Moreover, Nicor Gas asserts that comparing the allocation of total revenue requirements with and without the customer component of distribution mains using the Company's ECOSS demonstrates that the use of a customer component of distribution mains does not affect the allocation of revenue requirements among customer class. Nicor Gas Ex. 36.0 at 36.

Nicor Gas also contested IIEC's proposal to allocate the customer component of distribution mains on the basis of the number of customers within each class. Nicor Gas Ex. 24.0 at 6-7. Nicor Gas maintains that this approach ignores the Commission's preference for the use of an Average and Peak ("A&P") general demand factor. Id. Nicor Gas argues that given the Commission's preference, both the demand and customer components should be allocated among customer classes using the Modified Distribution Mains ("MDM") study with the average and peak allocator. This approach ensures that the classification of a portion of distribution mains costs as customer-related does not shift revenue requirement responsibility among rate classes in the ECOSS. Id.

(ii) Staff's Position

Staff presented the direct testimony Cheri Harden on the Cost of Service ("COS") study utilized for rate design. Ms. Harden testifies that a COS study allocates costs among all customer rate classes to determine each class' respective responsibility for the costs imposed upon the utility. Staff Ex. 4.0 at 3. Ms. Harden states that the results of a COS study are summarized in rates of return for customer classes. Id. As Ms. Harden explains, if the return generated is above average, the class is paying more than its share of the utility's revenue requirement, while below-average returns indicate that the class pays less than its share. Id. It is efficient and equitable to base rate design on cost, because the rates that consumer's pay directly reflect the utility's cost of providing service. The determination of each class' responsibility is therefore an essential step in designing cost-based rates, which is the predominant goal and objective of rate design. However, this is not the only factor that the Commission may or should consider in designing rates.

Ms. Harden reviewed the COS study submitted by Nicor Gas, which shows by customer class the distribution of revenue responsibility necessary to achieve equalized rates of return on investment at the Company's proposed revenue requirement. Id. at 4. Ms. Harden opines that the COS study offered by the Company is consistent with the requirements established by the Commission in Nicor Gas' last rate case proceeding, blending both the average and peak allocation factors to derive each class' responsibility for demand-related fixed costs. Id. at 4.

In the 2008 Rate Case, the Company agreed to evaluate the allocator for gas service lines that reflects the level of service investment by customer class. 2008 Rate Case Order at 73. Ms. Harden found that the Company completed this evaluation, as described in the direct testimony of Nicor Gas witness Yardley. Staff Ex. 4.0 at 5. Ms. Harden testifies that the analysis conducted by Nicor Gas considered the pipe material and length of services connecting customers of each rate class to the Company's gas distribution system. Id. Ms. Harden also notes that the change in the services allocator

to services from meters is reflected on Nicor Gas Schedule E-6. Part 285 Filing, Sched. E-6, 24. Ms. Harden agrees with the changes to the services allocator for gas services lines shown in the COS study.

Ms. Harden supports the use of the COS study presented by the Company. Staff Ex. 4.0 at 5. Ms. Harden explains that the Company utilized the A&P allocation factor to prepare its COS study, which was approved for use in the last Nicor Gas rate case. Id. Ms. Harden also testifies that the Company's summary of the COS study results demonstrates that the largest increases are appropriate for the residential and large volume transportation classes. Id. Accordingly, Staff recommends that the Commission approve the COS study presented by the Company in this proceeding.

(iii) AG's Position

AG witness Rubin testified that Nicor Gas classified its distribution mains as being related to: (1) the number of customers served; and (2) the demands of those customers for gas. Mr. Rubin explains that the Company used what it calls its minimum-size analysis to conclude that 48% of the costs of distribution mains are customer-related and the other 52% of the costs of mains are demand-related. AG Ex. 2.0 at 4.

According to the AG, although a minimum-size analysis is a recognized method for classifying distribution costs, the method is considered controversial, and the AG is not aware that the Commission has ever used this approach. The AG states that to support his testimony, Mr. Rubin pointed out that in 1989, the National Association of Regulatory Utility Commissioners ("NARUC") published its most recent version of its Gas Distribution Rate Design Manual ("NARUC Gas Manual"). The Manual states, that "[a] portion of customer costs associated with the distribution system may be included as customer costs. However, the inclusion of such costs can be controversial." Id. at 4-5, *quoting* NARUC Gas Manual at 22. The NARUC Gas Manual further states although a minimum-size analysis could estimate a customer-related portion of the distribution system, "[t]he contra argument to the inclusion of certain distribution costs as customer costs is that mains and services are installed to serve demands of the consumers and should be allocated to that function." Id. at 109-113, *quoting* NARUC Manual at 23.

The AG adds that the Commission rejected a minimum-size approach to classifying distribution mains in Ameren's rate case in Docket No. 13-0192. The AG recommends that the Commission follow its past decisions rejecting the idea that a portion of distribution mains are directly related to the number of customers on the system.

The AG claims that it is Nicor Gas that misstates the Commission Order in Docket No. 13-0192. The AG notes that the Commission made clear in its Order in that case that IIEC had not provided an adequate basis to deviate from decisions in previous cases where the Commission rejected proposals to allocate the cost of mains on a customer component. Ameren III. Co. d/b/a Ameren III., Docket No. 13-0192, Order at 179-180 (Dec. 18, 2013). The AG argues that in the Commission's order in the Ameren case, the Commission firmly stated that it routinely concluded that it is not proper to allocate the cost of mains based on the number of customers. AG Ex. 2.0 at 5-6.

The AG states that if the Commission were to deviate from its past decisions rejecting a minimum-size analysis approach, it should reject Nicor Gas' analysis because it is not consistent with the NARUC Gas Manual. The AG claims that the Company's analysis deviated from the NARUC procedure in two important respects. First, Nicor Gas did not use the historic unit cost of the smallest main in the system, instead opting for a trended unit cost which greatly inflates the cost of mains installed decades ago. By trending the cost, Nicor Gas ends up with mains valued in excess of \$7 billion, compared to the book cost of mains (at year-end 2015) of \$2.1 billion. The historic cost by size of main taken from Nicor Gas' workpapers is included in the second column of AG Exhibit 2.01. Id. at 7; AG Ex. 2.01.

Nicor Gas' second error, according to the AG, is that the utility did not use the smallest main installed in the system. Nicor Gas used a 2-inch plastic main as the supposed "minimum size" on its system when Nicor Gas' records show that Nicor Gas currently has 7.3 million feet of distribution mains that are smaller than 2" in diameter. In the third column of AG Exhibit 2.01, Mr. Rubin reproduced the portion of Nicor Gas' workpapers showing the length of each main size in service as of year-end 2015. Mr. Rubin's analysis shows that the Company has a total of approximately 180.9 million feet of main, so these mains smaller than 2" represent approximately 4% of all mains on the system. Id. at 7; AG Ex. 2.01.

The AG states that AG Exhibit 2.01 shows that the smallest main in service at year-end 2015 was 0.75 inches. The last column of AG Ex. 2.01 shows Mr. Rubin's calculation of the unit cost for each size of main. Mr. Rubin's calculations shows that the unit cost of 0.75-inch main is \$1.38 per foot as of the end of 2015. Id. at 7-8.

The AG argues that if the Commission were to sanction a minimum-size analysis, a properly-performed analysis would result in 11.94% of costs related to distribution mains being classified as customer-related and the remaining 88.06% of mains' costs would be classified as demand-related. This result contrasts from Nicor Gas' faulty analysis showing 48% of the costs of distribution mains being customer-related and the remaining 52% being demand-related.

The AG notes that under Mr. Rubin's revisions to Nicor Gas' ECOSS, the residential class' responsibility of the Company's proposed revenue requirement would be \$590,014,000, or 70.1% of the proposed revenue requirement of \$841,690,000, which is significantly closer to the residential class' share of total system costs in the Company's 2004 rate case than what Nicor Gas is proposing here. AG Ex. 4.0 at 2.

The AG concludes that ignoring the demand-serving capability of the minimum-sized system – especially when a system as large as 2" mains is used – results in a serious distortion in Nicor Gas' ECOSS. In particular, too much demand-related cost is allocated to the residential and small commercial classes, and too little demand is allocated to classes serving large gas users. Id. at 4.

The AG states that IIEC essentially summarized Nicor Gas' testimony on this issue and stated that it agrees with the utility's approach. Among the statements IIEC makes is that it "agrees with the classification of a portion of Nicor Gas' main costs as customer related because it appropriately reflects cost causation." IIEC Ex. 1.0 at 8. The AG claims that this statement is interesting in two respects. First it directly

contradicts the Commission's conclusion in Docket No. 13-0192 that there is no causation between the number of customers and distribution main costs. Ameren Ill. Co. d/b/a Ameren Ill., Docket No. 13-0192, Order at 179-180 (Dec. 18, 2013). Second, IIEC's point contradicts Nicor Gas' assertion that its approach does not shift cost responsibility among customer classes.

In conclusion, the AG urges that the Commission, as it has done in past cases, should continue to reject a minimum-size analysis to classify main-related costs between the customer and demand classifications. However, if the Commission were to deviate from its historic practice, the AG recommended that it should find that no more than 11.94% of Nicor Gas' mains costs are customer-related.

(iv) IIEC's Position

IIEC states that Nicor Gas testified that the single largest plant investment on Nicor Gas' books is the investment in distribution mains, representing approximately 31% of net plant investment. Nicor Gas Ex. 9.0 at 10. Nicor Gas notes the classification of distribution mains reflects two distinct cost causative factors that drive Nicor investments in these facilities: (i) the coincident design demand on the system; and (ii) the number of customers on the system. Id. IIEC notes utility distribution mains are designed to deliver the maximum quantities of gas required during a peak period from Nicor Gas' transmission pipelines or interstate pipeline interconnects to the interconnection with each individual customer. Id. IIEC further notes distribution mains are also designed to deliver supplies in a reasonable proximity to customers in order to minimize the length of pipe used to serve all customers in an efficient manner. Id.

The division of distribution mains investment costs between the demand and customer-related components is typically determined through a minimum-size study or zero-intercept study. Id.

IIEC asserts the minimum-size studies evaluate the cost of replacing existing distribution mains on the system under two different sets of assumptions. Nicor Gas notes in testimony the first assumption in the Company's study determines replacement cost assuming the entire system is replaced with two-inch diameter plastic pipe. Id. Nicor Gas further notes the second assumption determines the cost of replacing existing distribution mains by using the same diameter and lengths of pipe currently installed on the system. Id. at 11. Based on the results of Nicor Gas' study, 48% of Nicor Gas' distribution mains investment would be classified as customer-related. Id. IIEC agrees with the classification of a portion of Nicor Gas' distribution main costs as customer related because it appropriately reflects cost causation.

IIEC notes the Company's recognition that "[t]ypically, the customer component of distribution mains is allocated on the basis of the number of customers in each rate class." Id. at 13. IIEC observes again, despite Company recognition of the correct application, the Company has applied its A&P allocation factor to the customer classified component of mains in both of its ECOSS studies, Proposed and Alternative. The Company argues its chosen method, which it concedes is not the typical method, preserves the underlying allocation approach adopted by the Commission in Nicor Gas' last base rate case. Id. IIEC argues preservation of a prior approach, despite

admission of a more cost based approach, is not appropriate and inconsistent with the intent of the Act. See, 220 ILCS 5/1-102(d)(iii).

IIEC states that the Company has applied the A&P allocation factor to both the demand and customer-classified components of distribution main costs in order to allocate these costs to customer classes. IIEC argues this does not reflect cost causation because it fails to recognize the customer related portion of the distribution mains. IIEC observes applying the A&P factor to both the demand component and customer component of distribution mains defeats the purpose of appropriately classifying a portion of mains as customer related. IIEC argues, consistent with principals of cost causation, the customer component of mains, which represents 48% of the Company's investment in distribution mains, should be allocated based on the number of customers. IIEC Ex. 1.0 at 8.

(v) Commission Analysis and Conclusion

The AG proposes that the Commission find that 100% of distribution mains should be classified as distribution because the proposed ECOSS retains the same allocations of distribution mains as were used in the 2008 study. The AG also relies on the 2013 Ameren rate case which the Commission finds is not related to this proceeding. Nicor Gas is not proposing to shift the cost responsibilities among the classes.

Staff evaluated the ECOSS prepared by the Company and supports the findings of the Study. Staff found that the Study evaluates the allocator for gas service lines that reflects the level of service investment by customer class as required by the Commission in the 2008 Rate Case. Staff further agreed that the Commission should approve the ECOSS.

The Commission disagrees with IIEC that the alternative ECOSS, which replaces the allocation of the demand component of distribution mains costs to reflect the traditional MDM study applied to the peak component and a new annual MDM study for the average component, represents a superior methodology to the Commission's established approach.

Moreover, as Nicor Gas demonstrated, comparing the allocation of total revenue requirements with and without the customer component of distribution mains using the proposed ECOSS demonstrates that the use of a customer component of distribution mains does not affect the allocation of revenue requirements among customer class. The Company's study utilized the A&P allocations approved in Nicor Gas' last rate case. Therefore, the Commission approves the Company's ECOSS, and it should be used to set rates.

b. Application of the MDM Analysis in the ECOSS

(i) Nicor Gas' Position

Nicor Gas states that the MDM study utilizes the same methodology as in the 2008 Rate Case, with the exception that the Company significantly expanded the analysis to capture a larger number of customers. Nicor Gas notes that the MDM study assesses the design use of distribution mains by different customers taking service on the system. Nicor Gas 9.0 at 13. The study serves to assign mains costs to customers

based on their relative design utilization of different types of distribution mains. Id. at 18. Nicor Gas performed an MDM study, or a similar study, as the basis for assigning distribution mains costs in each of its last three base rate cases. Id. at 13.

Nicor Gas explains that the MDM study examines the main size that connects individual customers to the Nicor Gas distribution system. In addition to the size of main, information concerning the customer's rate class and estimated design day use is collected. For each diameter of main, the aggregate design day load for each rate class is relied upon to allocate the associated book cost of main. This process is repeated for each size main, assuming that the design use of a given size main consists of the design use of all customers connected to that size main plus the design use of all customers connected to all smaller diameter mains. Nicor Gas 9.0 at 13.

Nicor Gas states that fixed demand-related distribution mains costs are allocated to rate classes on the basis of a blended allocation factor. In this instance, the blended factor is based on the results of the MDM study and a factor that is based on average use. Typically, the customer component of distribution mains is allocated on the basis of the number of customers in each rate class. However, Nicor Gas asserts that it applied the blended MDM and average allocation factor to the customer component of distribution mains as well to reserve the underlying allocation approach adopted by the Commission in Nicor Gas' 2008 Rate Case, while clarifying the classification of distribution mains among fixed cost categories of demand-related and customer-related. Id.

Nicor Gas asserts that IIEC's proposal to use the Company's alternative ECOSS, which replaces the allocation of the demand component of distribution mains costs to reflect the traditional MDM study applied to the peak component and a new annual MDM study for the average component, unnecessarily shifts approximately \$9.3 million of revenue requirement responsibility from non-residential classes to the residential class. Nicor Gas further maintains that an MDM study that takes into consideration customers' annual use does not represent a superior methodology and is inconsistent with the Commission's directive from the 2008 Rate Case. Id. at 18-19.

Nicor Gas asserts that the AG's proposal to replace the allocation of distribution mains based on the MDM study with an allocation that only utilizes an A&P methodology fails to recognize that the MDM study is unique to Nicor Gas and that the Commission recognized it as the appropriate basis for allocating the peak component of the peak and average allocator for Nicor Gas distribution mains costs. Nicor Gas Ex. 24.0 at 5. The AG's proposal leads to a wide variance in cost responsibility among customer classes and shifts \$24.0 million of cost responsibility from residential customers to non-residential customers. Id. The magnitude of the cost shift, together with the Commission's directive in the 2008 Rate Case and previous rate cases approving the use of the MDM study, in conjunction with an A&P allocation to customer classes, warrants rejection of the AG's proposal.

(ii) AG's Position

The AG explains that after classifying main-related costs, Nicor Gas allocated both the customer-related portion of mains and the demand portion of mains using the same allocation factor, MDM-Average. Mr. Rubin objected to the Company's approach,

saying that “allocating both demand-related and customer-related costs using the same factor makes the classification of costs irrelevant.” AG Ex. 2.0 at 9. The AG adds that if there is a customer-related component to distribution mains (as Nicor Gas claims, but the Commission has consistently rejected), the customer-related costs should be allocated based on the number of customers in each class, and demand-related costs should be allocated based on a measure of demand. In addition, if the minimum-size system approach is used, the AG asserts that Mr. Rubin showed that the Company’s minimum-size system has some demand-serving capability. These demand-serving capabilities of the minimum system must be taken into account in allocating the remaining (demand-related) portion of mains. Id. at 9-10.

The AG adds that Nicor Gas’ minimum-size analysis does not recognize that the minimum-size system has the ability to serve some demand, which results in double-counting the demand-related costs of serving customer classes that rely primarily on smaller mains, such as the residential class. If the Commission reverses course from its past decisions to use a minimum-system analysis, revised demand allocation factors would need to be developed. Id. at 10.

The AG argues that the MDM Average allocator is not a proper measure of demand for allocating distribution mains. The AG adds that on many occasions, the Commission has used the A&P allocator for gas distribution mains. The Commission endorsed the use of the A&P allocator in Ameren’s 2015 gas rate case (and in other cases). In the Ameren case, the Commission stated:

The record supports the continued use of AIC’s peak and average methodology to allocate demand-related T&D costs. This is the same method used and approved consistently by the Commission, including in AIC’s recent gas rate cases, Docket Nos. 13-0192 and 11-0282. It is also consistent with industry practice as it is recognized by NARUC as an appropriate allocation methodology. Moreover, the evidence demonstrates that the peak and average method recommended by AIC is reflective of cost causation principles, produces fair and reasonable results, and properly emphasizes the role of year-round demands in shaping T&D investments.

Ameren Ill. Co. d/b/a Ameren Ill., Docket No. 15-0142, Order at 103 (Dec. 9, 2015).

Consistent with the Commission’s decision in Docket No. 15-0142, the AG explains that Mr. Rubin revised Nicor Gas’ ECOSS to classify all costs related to distribution mains as demand-related and to use the A&P allocator to allocate those costs to customer classes. Mr. Rubin’s revisions to the ECOSS are included in AG Ex. 2.03.

The AG argues that consistent with the Commission’s historic practice, the ECOSS should be performed classifying all mains costs as demand-related, and that the demand component of mains should be allocated to customer classes using the

A&P allocator. Doing so, reduces the allocation to the Residential (Rate 1) class by more than \$23.3 million. AG Ex. 2.04.

(iii) IIEC's Position

Nicor Gas employs the MDM study to assess design use of distribution mains by different customers taking service on the Nicor Gas system. Nicor Gas 9.0 at 13. The MDM study serves to assign main costs to customer classes in the ECOSS based on relative design utilization of different sizes of distribution mains. Id. IIEC notes the Nicor Gas' MDM study utilizes the same methodology as in the previous rate case proceeding. Id. However, IIEC notes at the behest of the Commission, Nicor Gas expanded the analysis to capture a significantly greater number of customers. Id. The previous Nicor Gas MDM study relied upon a sample of approximately 700 customers, in this proceeding Nicor Gas utilized the information of approximately 2.1 million customers, which IIEC believes improves the study, lending further support for its application to both the peak and the average components of the A&P mains allocation method. Id. at 13-14.

In the Company's last base rate case, IIEC advocated utilizing the MDM study in the derivation of both the peak and the average component of the A&P allocation of distribution mains. Id. at 18. Nicor Gas testimony notes the Commission directed the Company to perform an alternative analysis, which was to provide a cost allocation study with the MDM adjustment applied to both the peak and the average components of the A&P cost allocation factor, in this proceeding. Id. IIEC observes the Company complied by performing the Alternative ECOSS but ignores the results and continues to urge the Commission to adopt its proposed ECOSS. Nicor Gas Ex. 24.0 at 5.

IIEC notes that for the Company's Proposed ECOSS, the MDM study is only used in the derivation of the peak component of the mains allocation. IIEC argues utilizing the MDM study only in the derivation of the peak component of the mains allocation does not correctly reflect cost causation. IIEC asserts Nicor Gas' system of mains is akin to the branches of a tree - the gas flows from the largest diameter mains into successively smaller-sized branches. IIEC argues it is undisputed that the largest volume customers cannot be served by the smaller diameter mains because the small mains do not have sufficient capacity. IIEC believes the MDM study captures and quantifies this physical fact.

IIEC believe the MDM study results should be applied to both components of the A&P allocator in the Company's ECOSS. IIEC notes the MDM study recognizes the Nicor Gas system of mains is configured such that not all customer classes use all main sizes to receive gas supply. Distinguishing the size of mains more accurately allocates the demand-related portion of distribution mains to customer classes. IIEC Ex. 1.0 at 5-6. IIEC believes that very same principle also holds true for the average component or volume-related portion of distribution mains. To illustrate, IIEC observes that if all customers in a class do not use a particular size of main for receiving gas service, then clearly those same customers do not use that particular main size on either a peak day or any other day. IIEC Ex. 1.0 at 6. IIEC asserts that Nicor Gas' use of annual volumes without distinguishing main sizes on the volume-related portion of mains completely ignores the engineering reality that Nicor Gas does not use one configuration of mains

on the peak day, and a different configuration of mains on all the other days. IIEC argues that just as the accuracy of the allocation of the demand-related portion of mains is improved by recognizing the MDM study, the accuracy of the average or volume-related portion of mains is improved by recognizing the fact that not all customer classes use all sizes of mains.

IIEC states that despite the information available to the Company it continues to support the use of the proposed ECOSS as opposed to the Alternative ECOSS. IIEC notes the Company attempts to tarnish the results of the Alternative ECOSS by labeling a correction in the revenue requirement responsibility, based on cost of service, as a “shift” of revenue requirement responsibility to the residential class. Nicor Gas Ex. 9.0 at 19. IIEC concedes there is a correction in revenue requirement responsibility in the amount of \$9.3 million dollars. Id. However, IIEC clarifies this correction properly assigns \$9.3 million of subsidies paid by other customers to the actual cost causers. IIEC asserts what has been characterized as a “shift” in the revenue requirement responsibility is in fact an appropriate recognition that the relevant customer classes should no longer be assigned costs for portions of the system they do not use and those costs are properly allocated to the customer classes who do in fact use them. Thus, IIEC observes the difference in allocated revenue requirements among the customer classes is not the result of an unwarranted “shift” in revenue requirement responsibility, but is the result of more accurately reflecting each classes’ respective cost of service in the Company’s ECOSS. IIEC notes, when an ECOSS uses a more appropriate allocation factor, better reflecting cost causation, there will be differences in the costs allocated to the various customer classes. IIEC argues basing opposition to the Alternative ECOSS, in essence, on the fact that it correctly allocates costs is an illogical argument and negates cost causation, or accurate identification of cost of service responsibility and allocation of those costs of service to those classes that actually cause the costs to be incurred.

IIEC continues to recommend that the Company’s Alternative ECOSS be used to guide class revenue allocation. The Alternative ECOSS reflects application of Nicor Gas’ MDM studies to both the average and peak components of the A&P allocator, modified by IIEC’s proposal to allocate the customer classified component of distribution mains on the basis of the number of customers within each class.

IIEC notes the AG took exception to the Company’s approach regarding the allocation of distribution main costs. AG Ex. 2.0 at 6. AG witness Rubin recommended replacing the allocation of distribution main costs based on the A&P method with the application of the MDM study with an allocation of distribution main costs that utilizes the A&P method without any application of the Company’s MDM study. IIEC argues the AG approach would completely ignore the principle of cost causation. IIEC observes MDM studies appropriately recognize that certain classes do not utilize certain sizes of mains for delivery of gas service and appropriately reflects costs causation. Therefore, IIEC finds the AG’s proposal should be rejected since it does not properly reflect cost causation.

(iv) Commission Analysis and Conclusion

The Commission finds that the evidence does not support deviating from prior directives concerning the use of the MDM study. The MDM study is unique to Nicor Gas and is the appropriate basis for allocating the peak component of the average and peak allocator for Nicor Gas' distribution mains costs. The Commission is not convinced that the AG's proposal to disregard the MDM study or IIEC's proposal to utilize the alternative ECOSS, which reflects application of Nicor Gas' MDM studies to both the average and peak components of the A&P allocator modified by IIEC's proposal to allocate the customer classified component of distribution mains on the basis of the number of customers within each class, would be beneficial to customers. The Commission therefore approves the use of the MDM analysis in Nicor Gas' proposed ECOSS.

c. Class Revenue Allocation

(i) Nicor Gas' Position

Nicor Gas proposes to base the revenue responsibility allocated to each rate class upon the results of the ECOSS with two modifications. Nicor Gas Ex. 9.0 at 23-24. The first adjustment reallocated the rate change indicated for Rate 17 and Rate 19 customers whose rates are not revised in a base rate proceeding, which is shown in Column G of Nicor Gas Exhibit 9.3. Id. at 24. The second adjustment relates to rate classes for which a revenue decrease is indicated by the comparison of existing base revenues plus QIP revenues to the ECOSS revenue requirements. Specifically, Nicor Gas proposes to hold the revenues for these rate classes level and utilize the resulting benefit to mitigate the revenue increase to the classes that would otherwise receive the greatest revenue increase, which are the Residential Rate 1 and Large Volume Transportation Rate 77 Rate Schedules. Id.

(ii) AG's Position

With respect to allocating costs among the classes, the AG notes that Mr. Rubin did not allocate revenue requirements according to the results of his ECOSS. The AG explained that although the ECOSS is an important factor in allocating costs, it also is important to moderate the effects of significant rate increases and to ensure that rates are fair to all customers through use of concepts such as gradualism, rate continuity, and fairness. AG Ex. 2.0 at 11.

The AG points out that it is common for rate analysts representing different interests (e.g., utilities, large energy users, residential customers, public utility commission staffs) to suggest limits on the variance between the revenue increase to any customer class and the system-average increase. AG witness Rubin said that he has seen limits as low as 120% of the average increase (that is, if the system-average increase is 10%, a 120% limit would mean no class would receive an increase of more than 12%) to as high as 200% in very rare cases in which the overall increase is quite small. In Mr. Rubin's experience, the most common limitation is that no class should receive an increase that is more than 150% of the system-average increase. Id.

The AG observes that setting limits on increases to any customer class serves several important purposes. First, it promotes fairness by distributing any revenue

increase among the customer classes. Second, it avoids extreme rate changes to any particular group of customers while moving each class closer to paying its COS. Third, reasonable rate increase limits recognizes that COS studies are estimates based on numerous assumptions that may change over time. The AG adds that cost studies provide important information, but are not perfect representations of the cost of serving different types of customers. Setting limits on the increase to any customer class recognizes these inherent limitations in cost studies. Id. at 12-13.

The AG proposes that the Commission limit the revenue increase to any customer class to no more than 150% of the system-average percentage increase and that no class should receive a rate decrease. Nicor Gas' proposed rate increase, including the effect of rolling the QIP surcharge into base rates, is 15.6%. The AG recommends that no customer class should receive an increase that is more than 150% of that amount, or 23.3%. The AG also recommends no customer class should receive a rate decrease while other customer classes receive substantial rate increases. Id. at 13.

The AG notes that the Commission adopted a similar limitation for Ameren's electric rates in Docket No. 09-0306. In placing limits on rate increases in that case, the Commission stated: It is a widely held ratemaking policy that rates should be designed to reflect cost causation, maintain gradualism, and avoid rate shock. Ameren Ill. Co. d/b/a Ameren Ill., Docket No. 09-0306, Order at 295 (Apr. 29, 2010). The AG points out that the Commission also concluded that no class should receive a revenue increase in excess of 150% of the system-average percentage increase in Ameren electric rate design cases in Docket No. 13-0476 and Docket No. 16-0387. Ameren Ill. Co. d/b/a Ameren Ill., Docket No. 13-0476, Order at 62-63 (Mar. 19, 2014); Ameren Ill. Co. d/b/a Ameren Ill., Docket No. 16-0387, Order at 9-10 (Feb. 23, 2017).

To implement the AG's recommendation, Mr. Rubin took the results of his ECOSS and determined the classes that are well below cost (e.g., those classes that require an increase greater than 150% of the system-average increase). Under his revised ECOSS, Rates 76 and 77, as well as contract customers, all have revenues so far below their respective costs of service that an increase of more than 23.3% would be required to bring those revenues up to the class cost of service. Mr. Rubin recommended that these classes' respective rate increases be limited to 150% of system-average. AG Ex. 1.0 at 14. The AG's proposal provides for no change in rates for those classes whose current revenues exceed the cost of service; the Rate 4, 5, and 75 classes. The remaining revenue requirement is then spread among the other customer classes in proportion to each class' cost of service. Mr. Rubin's calculations in support of his recommended class allocations are shown in AG Exhibit 2.05. Id. at 14-15; AG Ex. 2.05.

With respect to the residential class, the AG states that after applying mitigation, the net effect is a revenue allocation class that is only about \$8 million less than the amount Nicor Gas proposes. This is so even after correcting for Nicor Gas' overstating the residential cost of service by more than \$23 million. Nicor Gas proposes that residential customers provide revenues of \$605,482,000 (a 22.1% increase), while the AG recommended that the class should provide revenues of \$597,212,000 (a 20.4%

increase) under Nicor Gas' proposed revenue requirement. The effects on other customer classes are shown on AG Exhibit 2.05. Id. at 15; AG Ex. 2.05.

The AG added that these calculations are based on Nicor Gas' requested revenue requirement in its direct case. If the Commission reduces the revenue requirement level, the percentage increases described above would be reduced.

(iii) IIEC's Position

IIEC described above the issues it has with use of the Proposed ECOSS and the failure to better allocate costs in accordance with cost causation. IIEC also described its recommendation to use the Alternative ECOSS to guide class revenue allocation. See, IIEC Ex. 1.2 at 2. IIEC bases its proposed class revenue allocation on the Company's requested revenue requirement. IIEC notes to the extent the Commission approves a different revenue requirement for Nicor Gas, the class revenue allocation would be adjusted accordingly.

IIEC used the results of the Alternative ECOSS, adjusted for the allocation of the customer-classified component of distribution mains exclusively on the basis of the number of customers, to guide class revenue allocation. IIEC Ex. 1.0 at 9. As Nicor Gas did in its revenue allocation, IIEC held the Contract Service class rates at current rates and spread the difference in the calculated cost of service for contract customers to other classes based on those classes' proportion of total revenues. Id. In addition, all classes that would have received decreases IIEC held at current rates, as in the case of the Company proposed ECOSS. Id. at 9-10. IIEC observes the revenue associated with holding these classes at current rates has been used to mitigate the Residential class cost of service based increase due to the magnitude of the increase relative to the system average increase. Id. at 10. IIEC notes that the primary difference in IIEC's proposed class revenue allocation as compared to the Company's proposal is that Rate 76 is held at current rates as compared to receiving an increase under the Company's proposal for class revenue allocation in this case.

The AG bases its class revenue allocation on its proposed ECOSS. IIEC argues that because the AG's proposed ECOSS does not reflect cost causation, its recommended class revenue allocation should also be rejected.

(iv) Commission Analysis and Conclusion

The Commission finds that the proposed class revenue allocations as presented by Nicor Gas are reasonable and ease the revenue increase to the classes that would otherwise receive the greatest revenue increase.

Nicor Gas proposes to hold the revenues for these rate classes level and utilize the resulting benefit to mitigate the revenue increase to the classes that would otherwise receive the greatest revenue increase, which are the Residential Rate 1 and Large Volume Transportation Rate 77 Rate Schedules. Therefore, the Commission approves the class revenue allocations as presented by the Company.

The Commission rejects the AG's proposal to classify 100% distribution mains as demand-related because 48% of Nicor Gas' distribution mains investment should be classified as customer-related, and the ECOSS retains the same allocation of

distribution mains for both the demand and customer component of distribution mains as was used in the 2008 Rate Case.

The Commission also rejects ILEC's proposal to allocate the customer component of distribution mains on the basis of the number of customers within each class because, as Nicor Gas points out, this approach ignores the Commission's preference for the use of an A&P general demand factor.

2. Allocation of Certain Customer Care Costs

a. Nicor Gas' Position

Nicor Gas argues that neither the facts nor the law support RESA's proposal to remove \$12.7 million in Customer Care costs from delivery base rates, credit that amount to the bills of customers who take supply from a third-party supplier, and add an additional charge to the bills of customers who take supply from Nicor Gas. Nicor Gas Ex. 22.0 at 4. The Company explained that it incurs Customer Care costs to serve all customers, and that these costs include information technology, call center, rates, billing and collections, gas transportation and control, and other administrative and general services (collectively, "Customer Care costs"). Id. at 3. Nicor Gas observes that Staff recommends the Commission reject RESA's proposal and notes no party has contested the level of Customer Care Costs included in the proposed revenue requirement. Staff Ex. 10.0R at 9-10.

The Company explains that the Customer Select program allows Nicor Gas customers to choose to purchase their gas from a third-party supplier. Nicor Gas Ex. 22.0 at 5. If a customer does not choose a third-party supplier, Nicor Gas retains the obligation to provide supply services to the customer. Id. at 6. In addition, Nicor Gas continues to provide delivery services to all customers, even those who take supply from a third party. The Company presented evidence showing that it voluntarily proposed to initiate the Customer Select program, make it available to all customers and support it over the course of nearly 20 years. Id. at 3.

The Company notes that RESA's proposal is premised on the claim that such reallocation is necessary to maintain "competitive parity" between Nicor Gas and third-party suppliers, and to ensure that delivery rates are "composed of comparable rate structures offered by alternative gas suppliers." RESA Ex. 1.0R at 4-6. The Company argues that RESA's proposal should be rejected for several reasons.

First, Nicor Gas contends that alternative gas suppliers previously recognized that Nicor Gas' Customer Care costs support services for all Nicor Gas customers and are properly recovered from all customers. In accordance with an agreement reached with alternative gas suppliers in the 2008 Rate Case, Nicor Gas explains that it recovers the cost of providing customer care to all of its customers by including these costs in the delivery rates paid by both customers who take supply from the Company and those who take supply from third parties. In that case, the Company explains, the alternative gas suppliers agreed that the costs of caring for Customer Select customers are usual and customer functions that facilitate offering customer choice to [Nicor Gas] customers, and, these activities are designed to provide the benefit of choice to all Nicor Gas' residential and small commercial customers. The alternative suppliers concluded that

Customer Care costs should be included in base rates as a normal cost of doing business. Nicor Gas agreed and the Commission approved this treatment. 2008 Rate Case Order at 127-128.

Nicor Gas states that this method of cost recovery is reasonable. Since all Nicor Gas customers have the option to enroll in Customer Select, the Company contends these costs are appropriately allocated to all customers who take service from the Company. Nicor Gas Ex. 22.0 at 10. In addition, Nicor Gas explains, it is not practical to segregate Customer Care costs associated with Customer Select customers from the costs associated with providing delivery service, given the manner in which these customer care services are typically provided. Id.

Second, Nicor Gas argues that RESA's competitive parity argument presents the wrong issue for Commission consideration. Nicor Gas states the theory that underlies RESA's proposal is that the categories of costs incorporated in third-party suppliers' charges to their customers should be the same as the categories of costs incorporated in Nicor Gas' charges to its supply customers. Nicor Gas points out that the provision of competitive gas supply and the costs it entails are entirely different from the operations of a local gas distribution utility and its corresponding costs. Nicor Gas states there is no reason to expect or require that the cost structures of these two businesses will be identical, and RESA has not articulated one.

Instead of starting the inquiry by considering what costs are incorporated in the charges of entities that are *not* rate-regulated public utilities, Nicor Gas maintains the Commission should begin its inquiry by considering the costs that the regulated entity – Nicor Gas – incurs in providing service to its customers. Nicor Gas explains that the principle of cost causation requires that the cost of supplying public utility services is allocated to those who cause the costs to be incurred. Nicor Gas explains it incurs costs related to Customer Select, both in the provision of delivery services to the Customer Select customers, and in the process of making the program available to all Nicor Gas customers. The Company explains a substantial proportion of its Customer Care costs are fixed costs associated with the capability to provide all Nicor Gas' customer care functions. So long as the Company retains the obligation to serve all customers, Nicor Gas states it will not shed these costs, regardless of the number of customers who participate in Customer Select.

Third, Nicor Gas states RESA's reliance on a Commission Order regarding ComEd in Docket No. 14-0312 is misplaced. Nicor Gas notes that it voluntarily proposed to offer the Customer Select program and make it available to all customers. In contrast, the Company explains, the Act expressly establishes that electric utilities, such as ComEd, must allow the provision of competitive supply of electricity in their service territories, and distinguishes between electric utilities' supply and delivery functions. Nicor Gas explains that no such legal distinction exists with respect to the supply and delivery functions of gas utilities such as Nicor Gas. Nicor Gas Ex.36.0 at 11-12.

In addition, the Company argues the fact that a bright-line distinction has been drawn between electric utilities' supply and delivery functions does not dictate that the same distinction does, or should, apply to gas utilities. As just one example, electric

utilities do not maintain storage facilities on the scale that Nicor Gas does. Nicor Gas contends RESA's attempt to force the electric utility paradigm on a gas utility, and its failure to consider the potential impacts of its proposal on Nicor Gas' aquifer storage field operations, is undermined completely by the fact that RESA's witness has no experience in operating such storage facilities, or in gas distribution operations generally. In contrast, the Nicor Gas witness who addressed the issue has more than 25 years of experience in system operations. Nicor Ex. 21.0 at 1-10.

Further, Nicor Gas explains that RESA ignores the Commission's prior related order in Docket No. 13-0387, which required ComEd to conduct a study of the portions of customer care costs attributable to supply and delivery customers, respectively. Nicor Gas notes that it has not been ordered to conduct such a study and maintains that it should not be required to undertake such a study. Nicor Gas Ex. 24.0 at 20. The Company notes that Staff witness Rearden stated it appears unlikely that requiring Nicor Gas to engage in a study of the relative costs to serve sales and transportation customers will lead to a substantially more equitable set of rates. Staff Ex. 10.0R at 7.

Fourth, Nicor Gas asserts RESA's proposal could negatively impact the Company's storage assets, to the detriment of all Company customers. Nicor Gas Ex. 21.0 at 10. Nicor Gas explains that it owns and manages eight underground aquifer storage reservoirs, which it uses to serve winter load, meet high demand-day delivery needs, serve as an alternative to interstate firm transportation, and balance weather-driven differences from day-ahead supply plans for all of its customers – Customer Select participants included. Nicor Gas states that the functionality of the Company's storage facilities impacts the cost of delivery service, since the Company must replace any lost deliverability with additional firm transportation, which may be difficult to obtain, or costly. Id. at 4. Nicor Gas states that Customer Select suppliers and Transportation customers typically contract for more storage capacity than they use, and historically they do not withdraw gas to the level required to meet inventory targets that protect the functionality of the storage system. If the volume of Customer Select customers grows, Nicor Gas states it will have to balance the gas for that growing volume of customers over a smaller number of customers taking supply from the Company, presenting additional challenges. Id. at 7.

Nicor Gas further explains that, if RESA's proposal led customers to migrate away from Company supply service, and if Customer Select suppliers continue to use on-system storage as they have in the past, such switching may exacerbate existing problems in cycling gas in Nicor Gas' storage fields resulting from the actions of Transportation customers. Id. at 10. Therefore, Nicor Gas proposes that a study should be conducted to assess whether, and to what extent, storage allocations and related tariff terms and conditions for Transportation and Customer Select customers should be modified to protect the operational integrity of the Company's storage facilities. Nicor Gas explains this study of storage allocations should be conducted, and any necessary modifications implemented, before RESA's proposed cost-reallocation proposal is imposed, to ensure that charges to Customer Select customers reflect all of the costs they cause. Id. at 11.

Nicor Gas contends the Commission should reject RESA's proposed reallocation of Customer Care costs for all the reasons described above. But if the Commission is

inclined to consider any study of the impacts of the Customer Select program on Nicor Gas, Nicor Gas argues it must begin with a study of the impacts on the Company's storage facilities. Because Nicor Gas' storage fields are integral to its operations, and degradation of the fields will directly impact the costs to all customers, the Company maintains it is imperative that the impact of Customer Select customers on the fields be understood before any proposals that may increase the volume of Customer Select customers are adopted.

b. Staff's Position

Staff witness Dr. Rearden testified that: (1) Mr. Olikier has not demonstrated that the current allocations are unfair, or that his proposed allocations are a more equitable result than Nicor Gas' current rates; (2) his claim that Administrative and General Salaries are misallocated is unsupported, and his assertion is not obviously true; and (3) the revenue allocator that he proposes is not reasonable, because his measure of customer care costs does not have any reliable or predictable relationship to relative revenues. Staff Ex. 10.0R at 9.

Regarding the issue of storage, in response to Mr. Olikier, Nicor Gas witness Wassell discussed the link between how transportation customers use storage, with cost allocations in general. In particular, he posited that transportation customers generally contract for more storage capacity than they use, and only fill that capacity to the minimum amount required to retain their maximum withdrawal rights. In his view, this behavior puts the operational integrity of Nicor Gas' aquifer storage fields at risk, since aquifer fields need to be fully cycled to retain optimal characteristics. Nicor Gas Ex. 21.0 at 7-9. He recommends that the Commission reject Mr. Olikier's proposals until Nicor Gas studies how it should allocate its storage. Id. at 11.

With regard to the issue of storage, Dr. Rearden testified that storage use by transportation customers is a controversial topic in many gas utility rate cases. It appears that Nicor Gas is rightly concerned with maintaining operational integrity of its aquifer storage fields. When transportation customers do not use their storage with Nicor Gas in the same way that Nicor Gas uses storage for its customers, Nicor Gas needs to take actions to compensate for those differences when injecting and withdrawing gas from its storage fields. This can add additional constraints on how Nicor Gas manages its system. Thus, Dr. Rearden agreed with Nicor Gas' recommendation for a more in-depth study of storage allocations, regardless of how Nicor Gas allocates other costs. In particular, a reliable estimate of the costs Nicor Gas incurs to provide those storage services to transportation customers would be useful to establish how much Nicor Gas should charge for those services. Staff Ex. 10.0R at 7. Dr. Rearden recommended that Nicor Gas investigate storage allocation issues and present the results to interested parties prior to filing its next rate case. Id. at 9.

c. AG's Position

The AG states that RESA argues that \$12.7 million in Customer Care costs should be removed from the delivery rates Nicor Gas charges to customers who take gas supply from a third-party. RESA would then add that \$12.7 million to the delivery rates of customers who take gas supply from Nicor Gas.

The AG agrees with Nicor Gas and Staff. RESA's proposal to shift \$12.7 million in Customer Care Costs to the delivery rates of customers taking gas supply from the Company has no support in the record. The AG recommends that RESA's proposal be rejected.

d. RESA's Position

RESA recommends that the Commission direct that Nicor Gas unbundle customer care costs similar to the manner it has done with ComEd on the electric side. In the alternative, RESA recommends that the Commission order Nicor Gas to conduct a study to determine an appropriate allocation of customer care costs between the distribution and supply functions. To be clear, RESA is not recommending that Nicor Gas be prohibited from collecting these costs; rather, RESA is proposing that they be appropriately allocated to default service customers, customers who buy their supply from Nicor Gas, consistent with principles of cost causation.

Mr. Oliker described the competitive market in Nicor Gas' service territory. All of Nicor Gas' customers take distribution service from Nicor Gas. In Nicor Gas' service territory, customers have the right to select commodity service from an alternative gas supplier or to remain on default service and receive commodity service from Nicor Gas. Nicor Gas' "competitive choice" options are known as the Large Volume Transportation ("LVT") and Customer Select. Customers participating in these programs continue to pay Nicor for the cost of distribution through base distribution rates. RESA Ex. 1.0R at 3-4.

Mr. Oliker explained that all customers benefit from having a competitive natural gas market. First, competitive markets offer choices and control to customers beyond the standard variable default rate product. Second, having a diverse range of suppliers serving customers in Nicor Gas' service territory creates liquidity in the market which puts price pressure on wholesale natural gas prices, ultimately leading to lower retail natural gas prices for all customers including default service and transportation customers. Third, having multiple entities transacting business in Illinois creates jobs in the state and improves the state economy. Fourth, competition drives innovation and efficiencies that leak out into the market, not only to other suppliers in the market, but also to the utility as well. In short, competition greatly benefits all customers (including default customers) and that is why competitive markets are generally the favored means to deliver goods and services to customers in our society. Id. at 4.

According to RESA, to have a competitive market, both regulated and non-regulated products must be treated equally. Competitive parity is vital in any competitive market for products and services. Without competitive parity, innovation that is created by competitive forces in the market is severely restricted. All else being equal, if one product is granted favorable legal or regulatory treatment, customers will be more likely to purchase or enroll in that product. In that circumstance, the favored product has less incentive or pressure to innovate. Moreover, products that do not receive the same level of favoritism may be pushed out of the market. Id. at 4-5.

RESA contends that the current regulatory construct does not create competitive parity for all products and services in Nicor Gas' service territory. There are a number of actual costs, recovered through distribution rates that are utilized to support the

default rate product—such as customer care costs—but suppliers' products do not receive that same support and must recover their costs through competitive rates and charges under the current regulatory construct. Nicor Gas' similarly incurred costs are recovered through distribution charges which a customer cannot avoid. Consequently, the current paradigm leads to a non-comparable and discriminatory default rate product. The current rate structure discriminates against customers electing to take competitive service from a supplier, requiring such customers to pay for costs twice, once through distribution rates for service they are not receiving and again through rates charged by a supplier. Id. at 5-6.

According to RESA, allowing a utility to recover default service-related costs through distribution rates has two consequences. First, it tilts the playing field against competition by artificially deflating the utility default service price. Second, it discourages customers from selecting a supplier because it requires them to pay twice for those same services—once through its utility distribution charges and a second time through its competitive charges from a supplier. RESA's recommendation is simply a matter of assuring that costs are recovered through the correct "buckets". Id. at 6.

At RESA's request, Nicor Gas produced additional discovery identifying a portion of the customer care-related costs that it incurs. Specifically, within ICC Accounts 903 and 920, Nicor Gas has identified that it forecasts to incur \$21,897,489 in payroll expense related to the provision of customer care in these two accounts alone. Utilizing the allocation factor (58%) developed in Mr. Oliker's Direct Testimony, these costs alone would allocate approximately \$12,700,544 to default service. RESA argues that this amount is the minimum amount that the Commission should allocate to default service in this proceeding, and the Commission should direct Nicor Gas to provide a further study regarding the cost of providing default service for consideration in a future rate case or revenue neutral proceeding. Applying the allocation methodology proposed in Mr. Oliker's direct testimony to the \$21,897,489 customer care expense Nicor Gas forecasted would allocate \$0.00605 per therm for residential customers and \$0.001752 per therm to commercial and industrial default service customers. RESA Ex. 2.0R at 3.

RESA points out that its proposal for Nicor Gas in this proceeding is similar to its proposal that was accepted by the Commission in Docket No. 14-0312, a ComEd formula rate increase proceeding. In the Commission's final order, it directed ComEd to unbundle customer care costs that were historically collected through distribution rates. Commonwealth Edison Co., Docket No. 14-0312, Order at 104 (Dec. 10, 2014).

While Nicor Gas witness Yardley attempted to distinguish the Commission's treatment of customer care costs in the ComEd proceeding from RESA's proposed treatment in the instant proceeding, RESA contends that that attempt was without merit. First, Mr. Yardley claimed that the Nicor Gas Customer Select Program is offered on a voluntary basis, whereas ComEd is required by statute to allow customers to purchase supply from Retail Electric Suppliers. RESA responds that this is a distinction without a difference. The Commission's order in the ComEd case did not rely on the fact that ComEd is mandated to allow its customers to shop. Instead, the order eliminates a subsidy that supply customers provided to default customers. The same type of subsidy exists in Nicor Gas' rates.

Second, Mr. Yardley states that pursuant to an agreement between Nicor and certain suppliers in its last rate case, some costs of the Customer Select Program are recovered from all customers, rather than just Customer Select customers. However, RESA states that the record shows that there is no relationship between the costs that were the subject of that settlement agreement and the costs at issue here.

Third, Mr. Yardley claims that, in Docket No. 14-0312, the Commission did not reject the use of an avoided cost study. However, according to RESA, Nicor Gas Exhibit 36.1 shows that the Commission rejected ComEd's Switching Study, which was ComEd's avoided cost study prepared for that proceeding.

Mr. Yardley's testimony is misleading and mischaracterizes RESA's proposal. Mr. Oliker never claimed that Nicor Gas does not provide any call center services to Customer Select and transportation customers. Had that been his position, he would have recommended that all of Nicor Gas' call center cost be allocated to default service. Instead, he developed an allocation factor for the purpose of allocating a portion of Nicor's customer care costs to default service consistent with principles of cost causation. RESA Ex. 2.0R at 4.

Moreover, RESA contends that Mr. Oliker's proposal is consistent with Mr. Yardley's professed principles for ratemaking. As Mr. Yardley has stated in prior testimony and in discovery in this case, among other things, fairness, non-discrimination, and simplicity are key principles to guide utility ratemaking. Mr. Oliker stated that his proposal meets all of those principles. RESA Ex. 2.0R at 5.

Nicor Gas witness Grzenia also opposes RESA's recommendation. However, according to RESA, Ms. Grzenia's criticism of RESA's proposal is based on a number of misunderstandings or misrepresentations of that proposal. First, she claims that RESA is proposing to "allocate the total cost of providing customer care costs to only that portion of its customers that take supply service from Nicor Gas, rather than across all customers." Nicor Gas Ex. 22.0 at 3. In fact, as discussed above, RESA proposes to allocate to default service only the portion of customer care costs associated with providing that service. RESA Ex. 2.0R at 9, 11.

Second, RESA argues that Ms. Grzenia is also mistaken when she claims that RESA's cost allocation proposal is inconsistent with the treatment of "similar costs" proposed by alternative gas suppliers in Nicor Gas' last rate case. Nicor Gas Ex. 22.0 at 3-4. Ms. Grzenia is referring to costs associated with implementing the Customer Select program. Similar to Nicor Gas' default supply program, these costs are collected from all customers. Recovering the costs from all customers eligible for Customer Select was the right decision then and remains the right decision today. All customers who are eligible for the Customer Select Program benefit from its availability and, therefore, its costs should be socialized among all eligible customers. RESA's recommendation in this proceeding is directed at identifying customer care costs that relate to default service and ensuring those costs are appropriately allocated to that service. RESA Ex. 2.0R at 9-10.

Third, RESA contends that Ms. Grzenia is incorrect in claiming that Nicor Gas' current treatment of customer care costs is the result of an agreement with alternative gas suppliers. Nicor Gas Ex. 22.0 at 5. Again, that agreement, which was not with

RESA, was entered into between Nicor Gas and a group of alternative gas suppliers nearly ten years ago related to a customer account charge. That charge was discriminatory and unfair; therefore, its elimination was a positive outcome for purposes of moving the market forward. RESA Ex. 2.0R at 10.

Nicor Gas witness Wassell takes the position that before the Commission accepts RESA's recommendation, the "Commission should direct Nicor Gas to conduct a study examining the allocation of storage volumes to Transportation customers and Customer Select suppliers to determine whether an adjustment to such allocations is appropriate." Nicor Gas Ex. 21.0 at 3. However, according to RESA, there is no relationship between Mr. Wassell's proposal for a study of Nicor Gas' storage operations and RESA's proposal to allocate customer care costs associated with procuring and providing default service. RESA Ex. 2.0 at 13.

RESA states that Mr. Wassell attempts to create a nexus where none exists by claiming that the apparent goal of RESA's proposal is to "increase the number of customers choosing to participate in the Customer Select program" and that an increase in the number of customers in Customer Select would create problems for Nicor Gas' operation of its storage fields. Nicor Ex. 21.0 at 3. According to RESA, Mr. Wassell is wrong on both counts.

First, the goal of RESA's proposal is to improve the functioning of the competitive retail natural gas market in the Nicor Gas service territory through a more fair and equitable allocation of costs to the default service. There are many customers that are already participating in the Customer Select program that are paying Nicor Gas for services that are more appropriately assigned to default service customers. RESA Ex. 2.0R at 13. Second, Mr. Wassell's claim is inaccurate that if the number of Customer Select customers grows, Nicor Gas will be faced with "growing operational challenges in managing its on-system storage, especially under the existing terms and conditions of Nicor Gas' provision of those services." Nicor Gas Ex. 21 at 3. Initially, there is no cap on Nicor Gas' Customer Select program now and RESA has not seen a justification for a cap. In fact, Nicor Gas made a filing with the Commission in 2000 to remove the cap it had imposed for the Customer Select Program. Specifically, Nicor Gas filed revisions to its Schedule of Rates in August 2000 to extend the availability of the Customer Select Program to all customers. The Commission approved this expansion in its Order in Docket Nos. 00-0620/00-0621 (Cons.). Citizens Utility Bd./N. Ill. Gas Co. d/b/a Nicor Gas Co., Docket Nos. 00-0620/00-0621 (Cons.), Order at 13 (Jul. 5, 2001) ("Choice Expansion Order").

RESA also notes that the Commission's Choice Expansion Order makes it clear that the Commission has the authority to order Nicor Gas to allocate an appropriate amount of customer care costs to Nicor Gas' default customers. First, as identified above, the Commission specifically noted that the purpose of providing a customer choice program is to "facilitate gas service unbundling and foster competition." Id. at 13.

Moreover, the record shows that even a large amount of Customer Select migration away from default service would have minimal impact on Nicor Gas' ability to manage storage and balance its system. RESA Ex. 2.0 at 14. Nicor Gas requires suppliers to withdraw their storage balances related to the Customer Select program

below 35% by the end of winter. Mr. Wassel's own workpapers show that Suppliers have withdrawn storage down below 19% at the end of every winter since 2010, meaning they have utilized storage well within the end of winter target requirements. RESA Ex. 2.0R at 14-15.

If the Commission does not adopt RESA's recommended cost allocation, RESA recommends that the Commission order Nicor Gas to perform a study regarding the embedded distribution costs that relate to providing default service and to file an application in a revenue neutral rate design proceeding to appropriately allocate costs to default service. RESA Ex. 1.0R at 16-17.

RESA concludes that the Commission should accept RESA's recommendation and allocate \$12.7 million of customer care costs to Nicor Gas' default function. The Commission should also order Nicor Gas to conduct a study of its customer care costs for presentation in a revenue neutral rate proceeding or rate increase proceeding. However, if the Commission decides not to allocate customer care costs to Nicor Gas' default function in this proceeding, it should, at a minimum, still order the customer care cost study for use in a subsequent revenue neutral rate proceeding or rate increase proceeding.

e. Commission Analysis and Conclusion

According to Staff, RESA has failed to demonstrate that the current allocations are unfair, or that the proposed allocations are a more equitable result than Nicor Gas' current rates. The Commission agrees with Staff, the AG and the Company and finds that RESA's cost allocation proposal is not reasonable.

The Commission notes that the Company has an obligation to serve all customers for both supply and delivery service; therefore, it is necessary for Nicor Gas to properly allocate these costs. The Commission is troubled by RESA's allocators and the impacts on the Company's system. The Commission notes that there are both the operational and legal differences between the Nicor Gas system and what was determined in the ComEd case. The Company expresses concern about the impacts that may occur to the Company's storage fields should RESA's proposal be adopted. While RESA attempts to dismiss such concerns, it appears that more information as to the effects is needed. Staff agrees that additional information is needed to determine how the Company should allocate its storage. The Commission must be convinced that the storage fields are not subject to operational risk. In making this determination, the Commission agrees with Staff's proposal that the Company should prepare a study to assess the implications of how Transportation Customers use the Company's storage assets under the current terms and conditions of service. Accordingly, Nicor Gas is directed to prepare such a study and present its results in the Company's next rate case. Therefore, the Commission rejects the proposals of RESA.

VIII. RATE DESIGN

A. Uncontested Issues

1. Revisions to Transportation Charges

a. Gas Supply Cost Multiplier

Nicor Gas proposes to adjust the Gas Supply Cost Multiplier in Rates 6 and 7 from 0.47 to 0.49 due to a corresponding proposed change in the number of Maximum Daily Contract Quantity ("MDCQ") days of Storage Banking Service ("SBS") Capacity available to customers. Nicor Gas Ex. 8.0 at 3-4. No party challenged the proposed adjustment. The Commission approves Nicor Gas' proposed adjustment to the Gas Supply Cost Multiplier.

b. Individual and Group Administrative Charge in Rates 74 and 75

Nicor Gas proposes to increase the Administrative Charge to individual accounts on Rates 74 and 75 from \$23.00 per account to \$39.00 per account. Nicor Gas Ex. 8.0 at 4. Nicor Gas also proposes increasing the Administrative Charge to group accounts from \$33.00 per account to \$47.00 per account, and decreasing the monthly account charge from \$10.00 per account per month to \$8.00 per account per month. Id. No party challenged these proposed revisions. The Commission approves these adjustments.

c. Recording Device Charges for Rates 74 and 75

Nicor Gas proposes a single monthly Recording Device Charge for Rates 74 and 75 of \$16.00 per month for diaphragm and non-diaphragm meters. Nicor Gas Ex. 8.0 at 5. No party challenged these proposed revisions. The Commission approves these adjustments.

2. Revisions to Existing Rates

a. Rate 21 – Intrastate Transportation and Storage Services

Nicor Gas proposes to update its charges under its interstate tariff for its FERC-approved Operating Statement. Nicor Gas Ex. 8.0 at 6. The proposed change to Rate 21 aligns the charges with the rates approved by FERC in Docket No. PR 15-39-000. No party challenged the proposed revision. The Commission approves Nicor Gas' proposed revision to Rate 21.

3. Revisions to Existing Riders

a. Rider 6 – Gas Supply Cost

Nicor Gas proposes that an Uncollectible Factor of 1.34% be applied to the monthly Gas Cost in the recovery of Supply-related Uncollectible Expense. Nicor Gas Ex. 8.0 at 7. No party challenged the proposed revision. The Commission approves Nicor Gas' proposed adjustment to Rider 6.

b. Rider 25 – Firm Transportation Service

The proposed changes to the Gas Supply Cost Multiplier, Individual and Group Administrative Charge, and Recording Device Charges also appear in Nicor Gas' Rider 25. Nicor Gas Ex. 8.0 at 5. Nicor Gas proposes to update Rider 25 to reflect these changes. Id. No party challenged the proposed revisions. The Commission approves Nicor Gas' proposed adjustment to Rider 25.

c. Rider 26 – Uncollectible Expense Adjustment

The Commission's Order approving Rider 26 in the 2008 Rate Case required Nicor Gas, in its next general rate case, to segregate the Supply-related uncollectible expense component from Delivery-related uncollectible expense component, and to reconcile separately the recovery of Supply- and Delivery-related uncollectible expenses. Nicor Gas Ex. 8.0 at 7. Because the Supply-related Uncollectible Expense is addressed through the proposed revision to Rider 6, Rider 26 also must be amended to address only the Delivery-related Uncollectible Expense. Id. at 8.

Staff recommended defining the actual uncollectible expense to be based on the net write-offs of uncollectible accounts. Staff Ex. 1.0 at 23. In an effort to narrow the issues in this proceeding, Nicor Gas accepted Staff's proposal. No other party challenged the agreed-to revision to Rider 26. The Commission approves Nicor Gas' proposed adjustment to Rider 26.

d. Rider 34 – Supplier Firm Transportation Service

The proposed changes to the Gas Supply Cost Multiplier also appear in Nicor Gas' Rider 34. Nicor Gas proposes to update Rider 34 to reflect the change to the Gas Supply Cost Multiplier. Nicor Gas Ex. 8.0 at 5. No party challenged this proposed revision. The Commission approves Nicor Gas' proposed adjustment to Rider 34.

4. Other Tariff Revisions**a. Companion Rates**

The Company's proposed ECOSSE includes the following eight customer groups: Residential (Rate 1), General Gas Service (Rate 4), Seasonal Use Service (Rate 5), General Transportation Service (Rate 74), Seasonal Use Transportation Service (Rate 75), Large General Transportation (Rate 76), Large Volume Transportation Service (Rate 77), and Contract Service, which includes both Contract Service (Rate 17) and Contract Service for Electric Generation (Rate 19). Nicor Gas Ex. 9.0 at 7. There are presently no customers taking service on the Large General Service (Rate 6) or Large Volume Service (Rate 7) tariff rate schedules, which are sales services that are companion rate schedules to Rate 76 and Rate 77 respectively. Because there are no customers presently taking service under Rate 6 or Rate 7 rate schedules, they are not included in the ECOSSE. No party challenged Nicor Gas' companion rates, which are consistent with its last rate case. The Commission approves Nicor Gas' companion rates.

(i) Rate Schedules 4 and 74

Nicor Gas proposes to reflect the base rate change in the monthly customer charges for Rate 4 and Rate 74 customers due to the inclusion of the associated QIP in

rate base and reduction in the QIP surcharge percentage to zero with the effectiveness of new base rates as provided for in the terms of Rider QIP. No party challenged these proposed revisions. The Commission approves the revisions to Rate Schedules 4 and 74.

(ii) Rate Schedules 5 and 75

Nicor Gas proposes to increase the base revenues rates for Rate Schedules 5 and 75 to reflect the elimination of QIP revenues. Nicor Gas Ex. 9.0 at 28. Nicor Gas also proposes to increase the winter period charge for Rate 5 to equal the talk block charge for Rate 4. No party challenged these proposed revisions. The Commission approves Nicor Gas' proposed revisions to Rate Schedules 5 and 75.

(iii) Rate Schedules 6 and 76

Nicor Gas proposes to increase the customer charge for Rate 76 to \$2,000 to reflect the results of the ECOSS, and to set the Rate 6 rates equal to the Rate 76 rates, with the exception that the delivery charge was increased to reflect the unit cost of storage for Rate 76. Nicor Gas Ex. 9.0 at 29. No party challenged these proposed revisions. The Commission approves Nicor Gas' proposed revisions to Rate Schedules 6 and 76.

(iv) Rate Schedules 7 and 77

Nicor Gas proposes to increase the monthly fixed customer and demand charges applicable to Rate 77 to increase the proportion of fixed costs recovered through fixed charges, and set the rates for Rate 7 equal to Rate 77, with the exception that the delivery charge was increased to reflect the unit cost of storage for Rate 77. Nicor Gas Ex. 9.0 at 29. No party challenged these proposed revisions. The Commission approves Nicor Gas' proposed revisions to Rate Schedules 7 and 77.

b. Meter Class Capacity Designations Rate 4, 5, 74 and 75

The Company proposes to clarify the meter class capacity designations for various meters that relate to the Monthly Customer Charge for Rates 4, 5, 74, and 75. Nicor Gas Ex. 8.0 at 11. No party challenged these proposed revisions. The Commission approves Nicor Gas' proposed revisions to meter class capacity designations.

c. Service Reconnection Charge Increase

Nicor Gas proposes to increase the Service Reconnection Charge from \$42.00 to \$74.00 per reconnection. Nicor Gas Ex. 8.0 at 10. Nicor Gas also proposes to clarify language related to the monthly charges applicable to Rider 1, 2, 7, 26, and 32. No party challenged these proposed revisions. The Commission approves Nicor Gas' proposed revisions.

d. Gas Service Pipe Installation Charge Increase

Nicor Gas proposes to update and modify the charge per foot for installation of various types and diameters of gas service pipe for residential and small commercial customers. Nicor Gas Ex. 8.0 at 10. No party challenged these proposed revisions. The Commission approves Nicor Gas' proposed revisions.

e. Bill Insert Delivery

Nicor Gas proposes to clarify the method in which it delivers bill inserts to customers who have elected to receive monthly bill statements electronically. Nicor Gas Ex. 8.0 at 11. No party challenged the proposed revisions. The Commission approves Nicor Gas' proposed revisions.

f. Excess Flow Valve Installation

Nicor Gas proposes to add new language related to the installation of an EFV for existing gas service line when such installation is made at the customer's request. Nicor Gas Ex. 8.0 at 12. No party has challenged the proposed revisions. The Commission approves Nicor Gas' proposed revisions.

g. Requirement for Working Telephone Line

Nicor Gas proposes to continue the requirement for customers to have and maintain a working telephone line as a condition of service for tariff rates requiring a daily telemetry for gas metering. The proposed change would affect Rates 6 and 7, and Rates 74 through 77. Nicor Gas Ex. 8.0 at 11. No party challenged the proposed revision. The Commission approves Nicor Gas' proposed revisions.

h. SBS Capacity

Nicor Gas proposes to adjust the number of days to SBS Capacity available to customers based on a change in its design day forecast sendout. The proposed adjustment applies to Transportation and Customer Select customers. Nicor Gas Ex. 8.0 at 11. No party challenged the proposed revisions. The Commission approves Nicor Gas' proposed revisions.

i. Service Disconnection and Reconnection Charges

Nicor Gas proposes to clarify the current practice and cost recovery related to Service Disconnection and Reconnection charges when the Company disconnects service for cause. Nicor Gas Ex. 8.0 at 12. No party challenged the proposed revisions. The Commission approves Nicor Gas' proposed revisions.

j. Housekeeping Details

Nicor Gas proposes a variety of "housekeeping" changes to Sheet Nos. 35, 35.5, 37.2, 38.1, 40, 41, 42, 42.1, 42.2, 43, 44, 46, 47, 48, 49, 50, 50.1, 51, 52, 53, and 54 that clarify, update, or remove outdated format, content, or language. Nicor Gas Ex. 8.0 at 10-12. No party challenged the proposed revisions. The Commission approves Nicor Gas' proposed tariff revisions.

B. Contested Issues

1. Residential Customer Charge [Rate]

a. Nicor Gas' Position

Nicor Gas proposes to increase the Monthly Customer Charge for residential customers from \$13.55 to \$18.00, which is consistent with the results of its proposed ECOSS. Nicor Gas Ex. 9.0 at 25. Nicor Gas maintains that its proposal will provide customers with an important price signal concerning the impact of connecting to Nicor

Gas' distribution system, promote intra-class fairness because it limits potential subsidies by reflecting the underlying cost, promote revenue stability for customers and the Company associated with fixed costs, and moderate the potential impacts on all residential customers by maintaining approximately the same percentage revenue recovery through the customer and distribution charges as underlying current rates. Id. at 25-26. Additionally, Nicor Gas states that its bill impacts study confirms the reasonableness of the proposed revenue allocation and rate proposal. Nicor Gas points out that Staff concurs with Nicor Gas regarding the methodology applied to develop the Rate 1 Monthly Customer Charge proposal and that the resulting bill impacts are manageable. Staff Ex. 4.0 at 8.

Nicor Gas performed a Rate 1 subsidy study that compared the cost of serving Rate 1 customers across various levels of usage to the corresponding revenues at each usage level using the proposed rates. Nicor Gas maintains that the results of the Rate 1 subsidy study demonstrate that subsidies among Rate 1 customers are limited, ranging between 1.5 percent and 2.3 percent for the middle 50 percent of customers within the Rate 1 usage profile. Nicor Gas Ex. 9.0 at 30-31.

The AG claims that neither Nicor Gas nor Staff responded to Mr. Rubin's direct testimony regarding the customer charge for residential customers in their respective rebuttal testimony. However, Nicor Gas witness Yardley responded to the AG's suggested modifications to the Company's proposed ECOS, which invariably flow through to the Monthly Customer Charge. Nicor Gas Ex. 24.0 at 4-12.

Nicor Gas asserts that its proposed \$18.00 Monthly Customer Charge is reasonable in comparison to the charges approved by the Commission for other Illinois LDCs. A comparison of current monthly customer charges for other Illinois LDCs indicates that Nicor Gas' proposed Monthly Customer Charge would remain lower than Ameren, North Shore Gas, and Peoples Gas. Id. at 26-30.

b. Staff's Position

Staff states that Nicor Gas proposes to increase the Rate 1 monthly customer charge for the residential class from \$13.55 to \$18.50 (36.5%) and the flat distribution charge from \$0.0485 per therm to \$0.0705 (45%). Part 285 Filing, Sched. E-2 at 7. The average residential bill of 100 therms gas usage would increase \$4.96 or just above an 8% increase. Part 285 Filing, Sched. E-9 at 1. Ms. Harden testifies that the COS study summary demonstrates the largest increases are appropriate for the residential and large volume transportation classes. Staff Ex. 4.0 at 7. Ms. Harden explains that the monthly bill comparisons at proposed rates provided by Nicor indicate that a residential customer with low usage of 10 therms/month would have a 17% increase, which is higher than the requested revenue increase of 10%; however, an average use customer of 100 therms/month would have an increase of less than 5%, which is lower than the requested revenue increase of 10%. Id. at 7-8. Ms. Harden agreed with the proposed rate increase for residential customers, testifying that the proposal reflects manageable increases. Id. at 8. Staff recommends the Commission approve the Company's proposal for Rate 1 residential customers; however, the final rates should be adjusted based upon the revenue requirement ultimately approved by the Commission.

c. AG's Position

The AG recommends that Rate 1 rates be designed so that the customer charge is no more than the customer-related costs identified in its ECOSS. AG Exhibit 2.06 shows that this cost is \$15.68 per month under Nicor Gas' proposed revenue requirement. Setting the customer charge at this level would represent a 15.7% increase over the current customer charge of \$13.55 per month. The \$15.68 customer charge is the maximum amount that would be consistent with the ECOSS. AG Ex. 2.0 at 15.

The AG explains that a \$15.68 residential customer charge would authorize Nicor Gas to collect approximately 64% of residential base revenues through the customer charge under the utility's proposed revenue requirement. The 64% figure is consistent with Mr. Rubin's ECOSS results which show that customer-related costs account for approximately 64% of the residential cost of service. Id. at 15-16. AG Exhibit 2.03, lines 38 and 40, show Rate 1 customer-related costs of \$392,297,000 out of total Rate 1 costs of \$609,703,000.

The AG points out that Nicor Gas' existing customer charge is \$13.55 per month, which recovers 80% of residential revenues through the customer charge. The AG states that in several cases decided after Nicor Gas' most recent rate case, the Commission has recognized that it erred in setting the customer charge so high that it included the recovery of demand-related costs. In recent years, the Commission has held that an appropriate customer charge would collect no more than the utility's customer-related costs. For example, in Ameren's most recent rate case, the Commission found that because high fixed customer charges remove the price signal from increased gas usage, the appropriate direction for this rate design split to move is for less costs to be recovered through fixed rates. Ameren III. Company, d/b/a Ameren III., Docket No. 15-0142, Order at 108-109 (Dec. 9, 2015).

The AG also notes that Nicor Gas faces diminished risk of revenue recovery and, correspondingly, a diminished need for high residential customer charges. Nicor Gas now recovers, through a monthly revenue adjustment mechanism called Rider 32, a return on, and Depreciation Expense related to, the Company's investment in QIP under Section 9-220.3 of the Act. 220 ILCS 5/9-220.5. This rider ensures that Nicor Gas' costs for new, qualifying distribution facilities, such as main and associated infrastructure as defined under Section 9-220.3 of the Act, are collected from customers as the facilities are completed, rather than having to wait for the filing and completion of a new distribution rate case.

In addition, the AG points out that Nicor Gas is assured of current recovery of gas storage service costs through its Rider 5, which applies to all customer classes utilizing Nicor Gas' gas supplies. Rider 5 essentially ensures that Nicor Gas will collect its storage-related costs, not only by adjusting for actual versus projected payments for storage within the residential customer class, but even permitting the shifting of costs among classes for differences in storage utilization.

The Company is essentially guaranteed a designated level of revenues for uncollectible accounts through Rider 26, Uncollectibles Expense Adjustment. This rider

provides for monthly adjustments to customers' bills for any over- or under-collections of Nicor Gas' actual uncollectible accounts expense.

The AG argues that the existence of all of these ratemaking mechanisms are important because they remove many concerns Nicor Gas otherwise may have with revenue stability. There simply is no need to have high customer charges to enhance annual revenue stability when all of these riders provide the Company with assurances of expense recovery for the various expenses covered by the riders on an as-experienced basis.

The AG adds that other policy implications should be considered by the Commission when examining the customer charge issue in this case. The Illinois General Assembly, in its passage of Section 8-104 of the Act, made clear its interest in reducing the amount of natural gas delivered to utility customers and reducing the cost of utility bills that customers pay. Specifically, Section 8-104(c) requires specific reductions in the use of natural gas on an annual basis. Retaining a high Residential customer charge undermines this public policy objective by reducing the amount of the customer bills that can be reduced through conservation and energy efficiency.

The AG further notes that in the Commission's August 30, 2013 report to the General Assembly entitled, Report to the Illinois General Assembly Concerning Coordination Between Gas and Electric Utility Energy Efficiency Programs and Spending Limits for Gas Utility Energy Efficiency Programs ("ICC Report"), the Commission recognized that reducing the customer charge while increasing variable charges could reduce overall natural gas usage and assist in the achievement of statutory natural gas usage reduction goals in a cost-effective manner. ICC Report at 24.

Thus, the Commission agreed that enabling customers to have more control over their natural gas bills serves the statutory goal of reducing natural gas consumption in a cost-effective manner. According to the AG, adoption of Mr. Rubin's customer charge recommendation best serves this Commission-stated goal.

The AG states that neither Nicor Gas nor Staff responded to Mr. Rubin's direct testimony regarding the customer charge for residential customers in their respective rebuttal testimony.

If the Commission determines that the revenue requirement is less than Nicor Gas requested, the AG proposes two options as to how the residential customer charge be determined. If the Commission requires Nicor Gas to re-run the ECOSS to reflect all adjustments and changes found reasonable by the Commission, then the ECOSS results will show the customer-related costs for the residential (Rate 1) class. This revised customer-related cost is then divided by the number of residential bills to determine the maximum customer charge.

Alternatively, if Nicor Gas is not required to prepare a revised ECOSS, the AG states that a simple ratio can be used. As discussed above, the AG's proposed customer charge represents a 15.7% increase over the existing customer charge. Nicor Gas' proposed overall rate increase of 15.6% is nearly the identical percentage. So the Commission could simply take the overall increase in revenue requirement it finds to be

reasonable, as a percentage of existing revenues including the QIP, and apply that same percentage increase to the current residential customer charge of \$13.55 per month. AG Ex. 2.0 at 17.

d. CUB's Position

CUB supports Mr. Rubin's calculated Residential customer charge of \$15.68 per month. AG Ex. 2.06. CUB points out that setting the customer charge at this level would represent a 15.7% increase over the existing customer charge of \$13.55 per month, and would authorize Nicor Gas to collect approximately 64% of residential base revenues through the customer charge at its initially-proposed revenue requirement. AG Ex. 2.0 at 15. CUB agrees with the AG that this would be the maximum customer charge that is consistent with Mr. Rubin's proposed ECOSS, which shows that customer-related costs account for approximately 64% of the residential cost of service, and is aligned with traditional principles of cost causation. Id. at 15-16. CUB notes that Nicor Gas did not rebut Mr. Rubin's testimony regarding the residential customer charge.

CUB observes that in Nicor Gas' last rate case, an existing customer charge of \$13.55 per month was set to recover 80% of residential revenues through the customer charge. 2008 Rate Case Order at 88-90. In several cases decided after that time, CUB understands that the Commission has recognized that it erred in setting the customer charge so high that it included the recovery of demand-related costs. AG Ex. 2.0 at 16.

Here, CUB believes the Commission can confidently conclude that a cost-based customer charge can be achieved under Mr. Rubin's proposal. CUB supports Mr. Rubin's recommended 15.7% increase at least in part because it is nearly identical to the system-average increase in revenues proposed by Nicor Gas of 15.6%. Id. at 16. Mr. Rubin's proposal would correctly reduce the amount of fixed cost recovery through the customer charge from the 80% approved in 2009, to 64%, which is in line with the trend the Commission has set into motion in recent years and comports more closely with setting cost-based rates.

CUB states that the ultimately approved revenue requirement will be less than Nicor Gas initially proposed, since Nicor Gas accepted several adjustments of Commission Staff, the AG, and CUB-IIEC, which reduced its requested increase, and other recommended adjustments may be adopted by the Commission in its final order. As a result, Mr. Rubin recommends that one of two alternative calculations be performed to produce the applicable residential customer charge, either of which CUB supports as reasonable for calculating the final residential customer charge.

e. Commission Analysis and Conclusion

The Commission has previously concluded that the Company's proposed ECOSS is consistent with the directives of the 2008 rate case. Staff has agreed with the proposed rate increase for residential customers, finding that the proposal reflects manageable increases. The proposals of the AG and IIEC-CUB are based on the values of each party's approach to the Company's ECOSS. The Commission determines that this case can be distinguished from the Ameren case cited by the AG. The Ameren case included a rider with the rate design. Staff agrees with the Company

and recommends that the Commission approve the Company's proposal for Rate 1 residential customers.

Based on the evidence provided, the Commission determines that the Company's proposed rate design, and corresponding residential Monthly Customer Charge, is just and reasonable.

2. Residential Billing Determinants

a. Nicor Gas' Position

The forecasted level of residential customer demand for the test year (number of therms sold during a year) is used to develop the per unit cost for a therm of gas. Nicor Gas explains that it developed the 2018 test year residential billing determinants for its residential rate design based upon historical data which shows decreasing residential usage. Nicor Gas Ex. 24.0 at 25-26. The expected decline in total residential use of 0.92% annually from 2016 to 2018 is reasonable when focusing on the totality of the information presented. Id. at 27. Moreover, since 1997, Nicor Gas' average residential use per customer has declined by slightly more than 1% per year, which is consistent with the expected annual decline of 0.92% from 2016 to 2018. Id. at 28. Additionally, the total residential consumption for the first six months of 2017 is 2.1% below the same period for 2016. If the trend for the first half of 2017 remains level in the second half of 2017, weather-normalized throughput for 2017 will be below the test period forecast. Id. at 29.

An examination of the trending statistics demonstrates that rates of change in normalized residential throughput vary year-to-year. It is unreasonable to conclude from the historical data that a downward trend in residential use does not exist. Such a conclusion, as the AG proposes, would require ignoring both the decline of 3.72% from 2014 to 2015 and the average annual decline of 1.91 percent over the two-year period from 2014 to 2016. Id. at 27. Additionally, the AG's comparison of the 2010 and 2016 residential use levels does not provide an accurate estimate because there is no consistent degree base in that analysis. Id. at 28. The normalized degree days for the 2010 test year were 5,600 as compared to the 5,869 degree days underlying the 2016 normalized level, thereby explaining the perceived increase in residential throughput. Id.

b. AG's Position

The AG argues that the Commission should adopt the adjustment proposed by AG witness Effron to increase the forecast of 2018 test year residential sales by 41.154 million therms to a more reasonable level of 2.236 billion therms. Mr. Effron used the actual weather-normalized 2016 as the basis for 2018 residential sales. AG Ex. 1.0 at 25-26.

The AG states that Nicor Gas forecasted residential sales of 2.195 billion therms for the 2018 test year (including transportation). Nicor Gas Schedule C-3, col (Q), Line 1 + Line 5. The weather-normalized residential sales in 2016 were approximately 2.236 billion therms (including transportation). Nicor Gas' response to Data Request AG 6.02 Exhibit 1, col (M), Line 1 + Line 5. The Company's 2018 residential test year forecast represents a decrease of approximately 41 million therms, or nearly 2%, from 2016.

Nicor Gas argued that sales decrease is related to the continuing trend of lower base use and historical use per degree day factors partially offset by continued customer additions. AG Ex. 1.0 at 24. The AG asserts that Nicor Gas did not establish any clearly defined trend of declining use per residential customer and the available data does not indicate the existence of such a trend.

The AG argues that available data indicate that the weather normalized sales in 2016 approximated the weather normalized sales in 2015. Further, when comparing the weather normalized 2016 residential sales to the test year residential sales in the 2009 test year of the Company's 2008 rate case, the weather normalized 2016 residential sales of 2.236 billion therms represents an increase of approximately 4%. The 4% increase in residential sales is greater than the percentage increase in the number of customers from 2009 through 2016. Thus, the usage per residential customer also increased during that period. Id. at 25.

Nicor Gas argued that there was a downward trend in residential usage based on the decline in residential usage of 3.72% from 2014 to 2015 and the average annual decline of 1.91% over the two-year period from 2014 to 2016. Nicor Gas Ex. 24.0 at 27. However, the AG responded that the Company's arguments are based on comparisons to the usage in 2014, which was the highest weather normalized sales level in recent years. Usage in 2015 and 2016 were higher than any of the years prior to 2014.

The AG observes that if the Company had chosen any of the years 2010 – 2013 as the starting point in the trend analysis, not only would there have been no downward trend, there would actually have been an *upward* trend. AG Ex. 3.0 at 7-8.

The AG claims that Mr. Effron's proposal to use the actual weather-normalized residential sales in 2016 as the forecast of 2018 test year residential sales is not only reasonable, it is conservative. The AG urges the Commission to adopt the AG's adjustment to increase 2018 test year residential sales by 41,154,000 therms. This results in an increase of \$1,996,000 to pro forma test year residential revenues under present rates AG Exhibit 1.1, Schedule C-1.

c. CUB's Position

CUB cites to AG witness Effron's testimony in support of increasing the billing determinants used to determine residential sales for purposes of setting the residential sales. AG Ex. 1.0 at 25-26. The Company is forecasting a decrease in residential sales of 41 million therms, or nearly 2% from 2016 to the 2018, for the 2018 test year. AG Ex. 1.0 at 24. Mr. Effron testified that the data he reviewed does not justify the significant downward adjustment to residential sales proposed by Nicor Gas. Id. He concluded that, while the weather-normalized residential sales did decrease from 2014 to 2015, the sales in 2016 were approximately the same as in 2015. Id. In fact, Mr. Effron noted that the weather-normalized 2016 residential sales of 2.236 billion therms represents an increase of approximately 4% from the test year residential sales established in the Company's 2008 rate case, in which the test year residential sales for the 2009 test year were 2.150 billion therms. Id. at 25. Mr. Effron further pointed out that this was actually greater than the percentage increase in residential customers over the same period. Thus, says CUB, not only did residential sales actually increase over this period, the use per residential customer also increased. Id.

CUB notes that Nicor Gas witness Yardley claimed that the decline in residential use of 3.72% from 2014 to 2015, and the average annual decline of 1.91% over the two-year period from 2014 to 2016 is evidence of a downward trend in residential use. Nicor Gas Ex. 24.0 at 27. As the data provided by the AG shows, however, the Company has not established any clearly defined trend of declining use per residential customer, and the available data does not indicate the existence of such a trend. AG Ex. 1.0 at 25. CUB points out that this table shows that the year 2014 is an outlier: the use in 2015 and 2016 was higher than the use in any of the years prior to 2014. As Mr. Effron testified, if Mr. Yardley had chosen any of the years 2010-2013 as the starting point in his trend analysis, not only would there have been no downward trend, there would actually have been an upward trend. AG Ex. 3.0 at 8. Furthermore, CUB maintains that this data does not support Mr. Yardley's claim that there has been a long-term downward trend in average customer use. Nicor Gas Ex. 36.0 at 15.

Based on the record data, Mr. Effron recommended that the actual weather-normalized residential sales in 2016 be used as the forecast of 2018 test year residential sales, as a reasonably conservative basis for estimating residential sales in the 2018 test year. AG Ex. 1.0 at 25. Adopting Mr. Effron's proposal would increase 2018 test year residential sales by 41,154,000 therms, which results in an increase of \$1,996,000 to pro forma test year residential revenues under present rates. AG Ex. 1.1, Schedule C-1.

CUB avers that Nicor Gas focuses on a supposed steady decline in usage over recent years. According to CUB, however, the evidence demonstrates that Nicor Gas' projections of declined usage are out of line with actual usage patterns. CUB points to AG witness Effron's testimony that, while the weather-normalized residential sales did decrease from 2014 to 2015, the sales in 2016 were approximately the same as in 2015. Thus, CUB recommends that the Commission adopt the modified forecasted level of residential customer demand proposed by AG witness Effron. AG Ex. 1.0 at 25.

d. Commission Analysis and Conclusion

The Commission bases its findings on a reliable sales forecast to set rates so the Company can recover its approved revenue requirement. The Commission agrees with Nicor Gas that the period of 2016-2018 would be a more reasonable period to base the residential use per customer. The AG is focused on a single year period that may or may not reflect an accurate forecast. Further, the AG's broader analysis comparing the 2016 levels to 2010 levels failed to account for fewer degree days in 2010. Therefore, the Commission determines that the forecast of residential throughput developed by the Company for the 2018 test period is reasonable.

3. Bill Credits

This issue is addressed in Section VII.B.2, above.

4. Proposed Rider 35 – Payment Fee Adjustment

a. Nicor Gas' Position

Nicor Gas proposes Rider 35 to respond to the effects of over- or under-recoveries of the Company's actual Payment Fee Costs, as described more fully in Section IV.B.3. Nicor Gas Ex. 8.0 at 9. Nicor Gas argues that, contrary to Staff's

assertion, Rider 35 is an appropriate rider mechanism pursuant to the recent decision of the Illinois Supreme Court in The People ex rel. Madigan v. Ill. Commerce Comm'n, 2015 IL 116005, ¶ 33 (“Madigan”), wherein the Court affirmed the Commission’s authority to approve riders that are “just and reasonable.” The Court also firmly rejected the argument that the Commission may exercise its discretion to approve riders only in “exceptional circumstances” as such argument “has no tether to our case law[.]” Madigan at ¶¶ 24-25. The Court further affirmed that a rider “merely facilitates direct recovery of a particular cost, without direct impact on the utility’s rate of return.” Madigan at ¶ 39 (quoting Citizens Util. Bd. v. Ill. Commerce Comm’n, 166 Ill. 2d 111, 137-138 (1995)). Thus, a rider need not recover only expenses that are volatile, but also may facilitate a utility’s recovery of a particular cost without impact to the utility’s rate of return so long as it is just and reasonable. Nicor Gas further maintains that Rider 35 is appropriate because it will not distort the Company’s proposed revenue requirement, rather the Company’s revenue requirement will be established independent of Rider 35.

Nicor Gas also disputes the AG’s proposal that Rider 35 should be rejected because it has not taken account of any offsetting cost savings. The AG’s proposal conflates the costs represented by the Payment Fee Cost with the manner in which Nicor Gas processes a bill payment. The Payment Fee Costs and the Company’s bill-processing costs are unrelated, and the AG presented no evidence to the contrary. Furthermore, even if such a comparison were appropriate, the AG failed to offer a proposal that would reasonably link a specific reduction in bill-processing costs to increased Payment Fee Costs. Rather, the AG simply speculates that any bill-processing cost reduction must be associated to the Payment Fee Costs. The AG’s recommendation is based on speculation and is not supported by any evidence.

b. Staff’s Position

Staff recommends that Rider 35 as proposed by the Company be rejected by the Commission. The Rider will be unnecessary if the Commission does not allow Nicor Gas’ pro forma adjustment for payment fees. In the event the Commission determines that the fees paid to third-party vendors by some customers should be socialized across all customers and that such costs meet the criteria for rider recovery, Staff then recommends that certain changes be reflected in the proposed tariff language such that the full amount of the payment fees paid by Nicor Gas be recovered through the Rider, rather than only the incremental portion not already included in delivery rates. Staff Ex. 6.0 at 11-12; Attach. A.

Staff states that while Rider 35 would be unnecessary given Staff’s proposal to disallow recovery of the payment fees in operating expenses, Staff does not believe the costs at issue warrant rider recovery. While the customer’s decision to pay its utility bills through a third-party vendor may be outside the Company’s control, it is well within the Company’s control to choose to assume such costs and to directly charge customers for those third-party fees the Company would incur.

Staff argues that Madigan dealt with a gas company’s revenue decoupling rider, which Rider 35 is nothing like, the Illinois Supreme Court stated that riders can be useful in “alleviating the burden imposed upon a utility in meeting volatile expenses.” Id. at

¶38. In determining whether the Commission had authority to approve the rider, the Illinois Supreme Court considered whether the rider impacted and distorted the ratemaking process. Id. at ¶ 40 (“...if the rider has no impact on the revenue requirement, it poses no risk of distorting the ratemaking process.”)

Staff argues that there should be no dispute that Nicor Gas’ proposed new Rider 35 does not recover costs which are volatile. The costs are not volatile as Nicor Gas would be negotiating set costs for the payment transactions with the third-party payment vendors. Staff Ex. 1.0, Attach. H. Also, based on past experience the Company is presumably able to provide a reasonable estimate of an annual amount to include in base rates. Most importantly, however, Rider 35 will impact the revenue requirement that is ultimately approved in this matter. The Company proposes to recover through Rider 35 any credit payment fees in excess of or under recovered through a base amount included in base rates. Nicor Gas Ex. 8.0 at 8-9. Rider 35 would distort the ratemaking process given that the Company is choosing rider recovery for a single cost element out of its approved revenue requirement and is ignoring all the other cost elements going into that revenue requirement which can vary as well. Because Rider 35 would not recover costs which are volatile or outside the Company’s control, and would lead to a distortion of the revenue requirement ultimately approved in this docket, the Commission should not approve Rider 35. Unlike the gas decoupling rider in Madigan, the impact of Rider 35 is that the rider would not accept the revenue requirement ultimately approved by the Commission and would distort the ratemaking process. Madigan at ¶40.

c. AG’s Position

AG witness Effron testified that if the Commission approves Rider 35, then the cost of fee-free payments should be reduced by any savings that occur. If the Commission approves the Company’s proposed Rider 35, then the Commission should adopt the proposal by AG witness Effron to offset the cost of fee-free payments by any savings that occur.

The AG points out that, based on the Company’s response to discovery, in 2016 there were 7.9 million check payments by mail. The AG alleges that if customers migrate to fee-free payment and the cost of processing the fee-free payments is less than the cost of processing checks, Nicor Gas will realize savings. In addition, Nicor Gas also stated that “the Company and the Commission have fielded customer complaints relating to the payment convenience fees.” The AG added that to the extent that the Company reduces the number of such complaints that will have to be addressed, there will be cost savings. The Company further noted that “[b]y making it easier for customers to pay their bills, more customers may be able to make more timely payments.” More timely payments will reduce the revenue lag and CWC requirement. AG Ex. 3.0 at 9-10.

d. CUB’s Position

As discussed above in Section IV.B.3, CUB supports the AG and Staff in recommending that Nicor Gas’ request to include Payment Fee Costs, and associated approval of Rider 35, be rejected by the Commission.

e. Commission Analysis and Conclusion

Nicor Gas seeks a new rider “to respond to the effects of over- or under-recoveries of the Company’s actual Payment Fee Costs.” Staff opposes the rider because Payment Fee Costs are not volatile, and the Company’s proposed rider would amount to single-issue ratemaking. The AG and CUB also oppose Rider 35.

A rider is a cost recovery method that generally alters an otherwise applicable rate and recovers a specific cost under particular circumstances and often includes a reconciliation formula, designed to match revenue recovery with actual costs. Citizens Utility Bd, 166 Ill.2d at 133. For purposes of public utility ratemaking, the Commission has discretion to approve a utility’s proposed rider mechanism to recover a particular cost if: (1) the cost is imposed upon the utility by an external circumstance over which the utility has no control; and (2) the cost does not affect the utility’s revenue requirement. Commonwealth Edison Co., 405 Ill. App. 3d 389 (1st Dist. 2010). In the case of proposed Rider 35, neither element is true. These costs are also not out of Nicor Gas’ control. Nicor Gas has chosen to allow a third-party vendor to collect fees from customers who pay in a certain manner, and has opted to pass those fees on to customers. The costs do affect the revenue requirement.

The Commission agrees with Staff that proposed Rider 35 costs are not variable. The rider addressed in Madigan, Rider VBA, was very different from the riders addressed in previous cases that were rejected by the courts. Rider VBA was designed to consider not only revenue recovery but also revenue disgorgement. The intent of Rider VBA was to prevent under-recovery of fixed distribution costs, as well as over-recovery, by decoupling the revenue for those costs that the companies receive from the volume of gas that they delivered. Unlike a traditional rider, which usually focused on recovery of one specific set of costs, Rider VBA addressed the entire revenue requirement and rate design aspects. As shown above, Payment Fee Costs are simply one small component of Nicor Gas’ operating expenses.

Nicor Gas improperly claims that Madigan holds that “a rider need not recover only expenses that are volatile.” Madigan, rather, emphasizes that the decoupling rider at issue in that case “reduced reliance on forecasts which were inevitably incorrect each year” and “stabilized revenues.” Madigan at ¶ 11. The Company does not contend that Payment Fee Costs are variable or incorrect; on the contrary, the Company predicts specific estimates of what the 2018 test year costs would be, based on actuals from previous years.

Commonwealth Edison Co. held that riders are by nature methods of single-issue ratemaking, so they are unlawful absent a showing of exceptional circumstances. Commonwealth Edison Co., 405 Ill.App.3d at 411, citing A. Finkl & Sons Co. v. Ill. Commerce Comm’n, 250 Ill.App.3d 317, 327 (1993). Madigan, however, reemphasized that revenue decoupling is a different rate design from traditional ratemaking, so Rider VBA is unlike the riders discussed in Commonwealth Edison Co. Madigan declined “to categorically find that Rider VBA is a method of single-issue ratemaking” because it does not isolate or provide for the recovery of any specific cost. *Id.* Instead, the rider in Madigan accounted for only those costs approved by the Commission as part of its calculation of the *entire* revenue requirement. Madigan at ¶ 16 (emphasis added). In

this case, as stated above, Rider 35 would provide specialized recovery for only *one* of a set of numerous costs that is part of the revenue requirement. As Commonwealth Edison Co. held, that would be impermissible single-issue ratemaking.

The Commission declines to adopt Nicor Gas' proposed Rider 35.

IX. GROSS REVENUE CONVERSION FACTOR

Nicor Gas presented evidence that the major factors in calculating its gross revenue conversion factor ("GRCF") are uncollectible accounts and federal and state income taxes. The Company's revised GRCF is 1.721127.

A. Uncontested Issues

1. Invested Capital Tax Adjustment

Staff witness Ebrey proposed adjusting the GRCF to exclude the component for ICT and base uncollectible accounts expense on average historic net write-offs. Staff Ex. 1.0 at 6. Nicor Gas accepted Ms. Ebrey's proposed adjustment and revised its GRCF accordingly. Nicor Gas Ex. 16.0 at 33. This adjustment is not contested and is approved.

2. Impact of Increase in State Corporate Tax Rate

The Illinois state corporate tax rate increased from 7.75% to 9.5% after the Company submitted its direct testimony, which included the Company's initial proposed GRCF. Nicor Gas presented evidence that it revised the GRCF in the Company's rebuttal testimony to reflect the change in the corporate tax rate. Nicor Gas Ex. 16.0 at 33. No Staff or Intervenor witness disputes this assertion. This adjustment is approved.

X. FINDINGS AND ORDERING PARAGRAPHS

The Commission, having considered the entire record herein and being fully advised in the premises, is of the opinion and finds that:

- (1) Northern Illinois Gas Company d/b/a Nicor Gas Company is an Illinois corporation engaged in the storage, transmission, distribution, and sale of natural gas to the public in the State of Illinois and, as such, is a "public utility" as defined in Section 3-105 of the Public Utilities Act;
- (2) the Commission has jurisdiction over the parties hereto and of the subject matter herein;
- (3) the findings and conclusions stated in the prefatory portion of this Order are supported by the evidence of record and are hereby adopted as findings of fact; the Appendix attached hereto provide supporting calculations for various conclusions in this Order;
- (4) the test year for the determination of the rates herein found to be just and reasonable should be the 12 months ending December 31, 2018; such test year is appropriate for purposes of this proceeding;
- (5) for the test year ending December 31, 2018, and for the purposes of this proceeding, the Company's rate base is \$2,422,250,000;

- (6) Northern Illinois Gas Company d/b/a Nicor Gas Company's December 31, 2016 plant balance of \$6,072,988,000, as reflected on the Company's Schedule B-5, is approved for purposes of an original cost determination;
- (7) a just and reasonable return which Northern Illinois Gas Company d/b/a Nicor Gas Company should be allowed to earn on its net original cost rate base is 7.256%; this rate of return incorporates a return on common equity of 9.80%, on long-term debt of 4.49%, and on short-term debt of 1.33%;
- (8) the rate of return set forth in Finding (7) results in base rate operating revenues of \$770,472,000 and net annual operating income of \$175,758,000 based on the test year approved herein;
- (9) Northern Illinois Gas Company d/b/a Nicor Gas Company's rates which are presently in effect are insufficient to generate the operating income necessary to permit Northern Illinois Gas Company d/b/a Nicor Gas Company the opportunity to earn a fair and reasonable return on net original cost rate base; these rates should be permanently canceled and annulled;
- (10) the specific rates proposed by Northern Illinois Gas Company d/b/a Nicor Gas Company in its initial filing do not reflect various determinations made in this Order; Northern Illinois Gas Company d/b/a Nicor Gas Company's proposed rates should be permanently canceled and annulled consistent with the findings herein;
- (11) Northern Illinois Gas Company d/b/a Nicor Gas Company should be authorized to place into effect tariff sheets designed to produce annual base rate revenues of \$770,472,000 which represents a gross increase of \$137,096,000; such revenues will provide Nicor Gas with an opportunity to earn the rate of return set forth in Finding (7) above; based on the record in this proceeding, this return is just and reasonable;
- (12) the determinations regarding cost of service and rate design contained in the prefatory portion of this Order are reasonable for purposes of this proceeding; the tariffs filed by Northern Illinois Gas Company d/b/a Nicor Gas Company should incorporate the rates and rate design set forth and referred to herein;
- (13) the new tariff sheets authorized to be filed by this Order shall reflect an effective date not less than five working days after the date of filing, with the tariff sheets to be corrected within that time period if necessary, except as is otherwise required by Section 9-201(b) of the Act as amended;
- (14) the 2017 QIP amounts included in base rates are comprised of Gross Plant of \$717,097,000, related accumulated depreciation of \$133,908,942 (increase to Gross Plant), related accumulated deferred income taxes of \$156,705,580 (decrease to Gross Plant), and \$15,209,816 for annualized depreciation expense less annualized depreciation expense applicable to the plant being retired;

- (15) the Company's 2016 and 2017 QIP costs included in rate base in this proceeding are subject to review in the annual QIP reconciliations proceedings and costs related to such 2016 and 2017 QIP are subject to refund for prudence and reasonableness adjustments in annual QIP reconciliation and future rate base proceedings;
- (16) the Company shall prepare a study to assess the implications of how Transportation Customers use the Company's storage assets under the current terms and conditions of service and present its results in the Company's next rate case proceeding; and
- (17) Northern Illinois Gas Company d/b/a Nicor Gas Company has satisfied Condition 8 of the Commission's Final Order in Docket No. 15-0558 by filing a study analyzing the impact, if any, of Nicor Gas' affiliation with The Southern Company and its other subsidiaries on the cost of capital of Nicor Gas.

IT IS THEREFORE ORDERED by the Illinois Commerce Commission that the tariff sheets presently in effect rendered by Northern Illinois Gas Company d/b/a Nicor Gas Company are hereby permanently canceled and annulled, effective at such time as the new tariff sheets approved herein become effective by virtue of this Order.

IT IS FURTHER ORDERED that the proposed tariffs seeking a general rate increase, filed by Northern Illinois Gas Company d/b/a Nicor Gas Company on March 10, 2017, are permanently cancelled and annulled.

IT IS FURTHER ORDERED that Northern Illinois Gas Company is authorized to file new tariff sheets with supporting workpapers in accordance with Findings (11), (12) and (13) of this Order, applicable to service furnished on and after the effective date of said tariff sheets.

IT IS FURTHER ORDERED that the \$6,072,988,000 original cost of plant for Northern Illinois Gas Company d/b/a Nicor Gas Company at December 31, 2016, as presented in Staff Exhibit 2.0, is unconditionally approved as the original cost of plant.

IT IS FURTHER ORDERED that Northern Illinois Gas Company d/b/a Nicor Gas Company is directed to prepare a study to assess the implications of how Transportation Customers use the Company's storage assets under the current terms and conditions of service and present its results in the Company's next rate case proceeding.

IT IS FURTHER ORDERED that any motions, petitions, objections, and other matters in this proceeding that remain unresolved are disposed of consistent with the conclusions herein.

IT IS FURTHER ORDERED that, subject to the provisions of Section 10-113 of the Public Utilities Act and 83 Ill. Adm. Code 200.880, this Order is final; it is not subject to the Administrative Review Law.

By Order of the Commission this 31st day of January, 2018.

(SIGNED) BRIEN SHEAHAN
Chairman

Line No.	Description	Company Pro Forma Present (Co. Ex. 30.1R)	Adjustments (Schedule 2)	Pro Forma Present (Cols. b+c)	Company Proposed Increase (Co. Ex. 30.1R)	Gross Revenue Conversion Factor	Proposed Rates With Adjustments (Cols. d+e+f)	Adjustment To Proposed Increase	Pro Forma Proposed (Cols. g+h)
	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)
1	Base Rate Revenues	\$ 633,376	\$ -	\$ 633,376	\$ 184,489	\$ 1	\$ 817,866	\$ (47,394)	\$ 770,472
2	Other Revenues	20,713	-	20,713	-	-	20,713	-	20,713
3	Total Operating Revenue	654,089	-	654,089	184,489	\$ 1	838,579	(47,394)	791,185
4	Uncollectible Accounts	8,027	-	8,027	2,269	-	10,296	(583)	9,713
5	Storage	19,633	-	19,633	-	-	19,633	-	19,633
6	Transmission	9,023	-	9,023	-	-	9,023	-	9,023
7	Distribution	69,045	-	69,045	-	-	69,045	-	69,045
8	Customer Accounts	53,930	(8,406)	45,524	-	-	45,524	-	45,524
9	Customer Service and Info. Expenses	1,023	-	1,023	-	-	1,023	-	1,023
10	Sales	726	-	726	-	-	726	-	726
11	Administrative and General	132,924	-	132,924	-	-	132,924	-	132,924
12	Depreciation Expense	207,768	-	207,768	-	-	207,768	-	207,768
13	Taxes Other Than Income	34,851	(206)	34,645	-	-	34,645	-	34,645
14	Total Operating Expense								
15	Before Income Taxes	536,950	(8,612)	528,338	2,269	-	530,607	(583)	530,024
16	State Income Tax	(5,483)	770	(4,713)	17,311	-	12,598	(4,447)	8,151
17	Federal Income Tax	(65,342)	2,564	(62,778)	57,718	-	(5,060)	(14,827)	(19,887)
18	Deferred Taxes and ITCs Net	97,139	-	97,139	-	-	97,139	-	97,139
19	Total Operating Expenses	563,264	(5,278)	557,986	77,298	-	635,284	(19,857)	615,427
20	NET OPERATING INCOME	\$ 90,825	\$ 5,278	\$ 96,103	\$ 107,191	\$ 1	\$ 203,295	\$ (27,537)	\$ 175,758
21	Rate Base (Schedule 3, Column (d))								\$ 2,422,250
22	Overall Rate of Return (Per Order)								7.256%
23	Revenue Change (Col. (i) Line 3 minus Col. (d), Line 3)								\$ 137,096
24	Percentage Revenue Change (Col. (i), Line 23 divided by Col. (d), Line 3)								20.96%

Nicor Gas Company
Adjustments to Operating Income
For the Test Year Ending December 31, 2018
(In Thousands)

Line No.	Description	Interest Synchronization (Schedule 6)	(Source)	(Source)	(Source)	(Source)	Fee Free Customer Pmts (Sched. 6.08)	Invested Capital Tax (Schedule 8)	Total Operating Statement Adjustments
	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)
1	Base Rate Revenues	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -
2	Other Revenues	-	-	-	-	-	-	-	-
3	Total Operating Revenue	-	-	-	-	-	-	-	-
4	Uncollectible Accounts	-	-	-	-	-	-	-	-
5	Storage	-	-	-	-	-	-	-	-
6	Transmission	-	-	-	-	-	-	-	-
7	Distribution	-	-	-	-	-	-	-	-
8	Customer Accounts	-	-	-	-	-	(8,406)	-	(8,406)
9	Customer Service and Info. Expenses	-	-	-	-	-	-	-	-
10	Sales	-	-	-	-	-	-	-	-
11	Administrative and General	-	-	-	-	-	-	-	-
12	Depreciation Expense	-	-	-	-	-	-	-	-
13	Taxes Other Than Income	-	-	-	-	-	-	(206)	(206)
14	Total Operating Expense	-	-	-	-	-	-	-	-
15	Before Income Taxes	-	-	-	-	-	(8,406)	(206)	(8,612)
16	State Income Tax	(49)	-	-	-	-	799	20	770
17	Federal Income Tax	(164)	-	-	-	-	2,663	65	2,564
18	Deferred Taxes and ITCs Net	-	-	-	-	-	-	-	-
19	Total Operating Expenses	(213)	-	-	-	-	(4,944)	(121)	(5,278)
20	NET OPERATING INCOME	\$ 213	\$ -	\$ -	\$ -	\$ -	\$ 4,944	\$ 121	\$ 5,278

Nicor Gas Company
Rate Base
For the Test Year Ending December 31, 2018
(In Thousands)

Line No.	Description	Company Pro Forma Rate Base (Co. Ex. 30.1R)	Adjustments (Schedule 4)	Pro Forma Rate Base (Col. b+c)
	(a)	(b)	(c)	(d)
1	Gross Utility Plant	\$ 6,726,997	\$ -	\$ 6,726,997
2	Accumulated Depreciation	(3,574,109)	-	(3,574,109)
3		-	-	-
4	Net Plant	3,152,888	-	3,152,888
5	Additions to Rate Base			
6	Cash Working Capital	70,943	(2,275)	68,668
7	Materials and Supplies	11,225	-	11,225
8	Gas in Storage	56,075	-	56,075
9		-	-	-
10		-	-	-
11		-	-	-
12		-	-	-
13		-	-	-
14		-	-	-
15		-	-	-
16	Deductions From Rate Base:			
17	Construction Work in Progress	(6,878)	-	(6,878)
18	Accumulated Deferred Income Taxes	(664,082)	59,730	(604,352)
19	Customer Deposits	(31,118)	-	(31,118)
20	Budget Payment Plan Balances	(21,276)	-	(21,276)
21	Retirement Benefits, Net	(14,864)	(151,898)	(166,762)
22	Regulatory Tax Liability	(13,067)	-	(13,067)
23	Investment Tax Credits	(10,436)	-	(10,436)
24	Reserve for Injuries and Damages	(181)	-	(181)
25	Customer Advances for Construction	(12,536)	-	(12,536)
26	Rate Base	\$ 2,516,693	\$ (94,443)	\$ 2,422,250

Nicor Gas Company
Adjustments to Rate Base
For the Test Year Ending December 31, 2018
(In Thousands)

Line No.	Description	Cash Working Capital (Schedule 9)	(Source)	Pension Asset (Sched 7.02)	(Source)	(Source)	(Source)	(Source)	Total Rate Base Adjustments
	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)
1	Gross Utility Plant	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -
2	Accumulated Depreciation	-	-	-	-	-	-	-	-
3		-	-	-	-	-	-	-	-
4	Net Plant	-	-	-	-	-	-	-	-
5	Additions to Rate Base								-
6	Cash Working Capital	(2,275)	-	-	-	-	-	-	(2,275)
7	Materials and Supplies	-	-	-	-	-	-	-	-
8	Gas in Storage	-	-	-	-	-	-	-	-
9		-	-	-	-	-	-	-	-
10		-	-	-	-	-	-	-	-
11		-	-	-	-	-	-	-	-
12		-	-	-	-	-	-	-	-
13		-	-	-	-	-	-	-	-
14		-	-	-	-	-	-	-	-
15		-	-	-	-	-	-	-	-
16	Deductions From Rate Base:	-	-	-	-	-	-	-	-
17	Construction Work in Progress	-	-	-	-	-	-	-	-
18	Accumulated Deferred Income Taxes	-	-	59,730	-	-	-	-	59,730
19	Customer Deposits	-	-	-	-	-	-	-	-
20	Budget Payment Plan Balances	-	-	-	-	-	-	-	-
21	Retirement Benefits, Net	-	-	(151,898)	-	-	-	-	(151,898)
22	Regulatory Tax Liability	-	-	-	-	-	-	-	-
23	Investment Tax Credits	-	-	-	-	-	-	-	-
24	Reserve for Injuries and Damages	-	-	-	-	-	-	-	-
25	Customer Advances for Construction	-	-	-	-	-	-	-	-
26	Rate Base	<u>\$ (2,275)</u>	<u>\$ -</u>	<u>\$ (92,168)</u>	<u>\$ -</u>	<u>\$ -</u>	<u>\$ -</u>	<u>\$ -</u>	<u>\$ (94,443)</u>

Docket No.17-0124
Appendix
Schedule 5

Nicor Gas Company
Revenue Effect of Adjustments
For the Test Year Ending December 31, 2018
(In Thousands)

Line No.	Description	Per Company	Adjustments	Per Order
	(a)	(b)	(c)	(d)
1	Present Revenues	\$ 654,089 ⁽¹⁾	\$ -	\$ 654,089 ⁽²⁾
2	Proposed Increase	184,489 ⁽³⁾	(47,393) ⁽⁴⁾	137,096 ⁽⁵⁾
3	Proposed Revenues	<u>\$ 838,578</u>	<u>\$ (47,393)</u>	<u>\$ 791,185</u>
4	% Increase	28.21%		20.96%
5	Adjustments:			
6	Rate of Return (Applied to Company Rate Base)		(26,514)	
7	Pension Asset		(10,115)	
8	Fee Free Customer Payments		(8,509)	
9	Interest Synchronization		(1,797)	
10	Cash Working Capital		(250)	
11	Invested Capital Tax		(208)	
12			-	
13			-	
14			-	
15			-	
16			-	
17			-	
18			-	
19			-	
20			-	
21			-	
22	Gross Revenue Conversion Factor		1	
23	Rounding		(1)	
24	Total Revenue Effect of Adjustments		<u>\$ (47,393)</u>	

Sources:

- (1) Schedule 1, column (b), line 3
- (2) Schedule 1, column (d), line 3
- (3) Schedule 1, column (e), line 3
- (4) Schedule 1, columns (f) + (h), line 3
- (5) Schedule 1, column (i), line 24

Nicor Gas Company
Interest Synchronization Adjustment
For the Test Year Ending December 31, 2018
(In Thousands)

Line No.	Description	Amount
	(a)	(b)
1	Rate Base	\$ 2,422,250 (1)
2	Weighted Cost of Debt	2.14% (2)
3	Synchronized Interest	51,763
4	Company Interest Expense	<u>51,245 (3)</u>
5	Increase (Decrease) in Interest Expense	<u>518</u>
6	Increase (Decrease) in State Income Tax Expense	
7	at 9.500%	<u>\$ (49)</u>
8	Increase (Decrease) in Federal Income Tax Expense	
9	at 35.000%	<u>\$ (164)</u>

(1) Source: Schedule 3, Column (d).

(2) Source: Per Order

(3) Source: Company Ex. 30.1R

Nicor Gas Company
Gross Revenue Conversion Factor
For the Test Year Ending December 31, 2018
(In Thousands)

Line No.	Description	Rate	With Bad Debts	Without Bad Debts
	(a)	(b)	(c)	(d)
1	Revenues		1.000000	1.000000
	State Invested Capital Tax		0.000000	0.000000
2	Uncollectibles	1.2300%	<u>0.012300</u>	
3	State Taxable Income		0.987700	1.000000
4	State Income Tax	9.5000%	<u>0.093832</u>	<u>0.095000</u>
5	Federal Taxable Income		0.893868	0.905000
6	Federal Income Tax	35.0000%	<u>0.312854</u>	<u>0.316750</u>
7	Operating Income		<u>0.581014</u>	<u>0.588250</u>
8	Gross Revenue Conversion Factor		<u>1.721129</u>	<u>1.699958</u>

Docket No. 17-0124
Appendix
Schedule 8

Nicor Gas Company
Invested Capital Tax Adjustment
For the Test Year Ending December 31, 2018
(In Thousands)

Line No.	Description	Amount	Source
(A)	(B)	(C)	(D)
1	Rate Base	2,422,250	Schedule 3, Column (d), line 26
2	Rate of Return	7.26%	Per Order
3	Operating Income Required	175,758	Line 1 times line 2
4	Pro Forma Income at Present Rates before ICT Adjustment	<u>94,305</u>	Schedule 1, Column (d), line 20
5	Additional Operating Income Allowed	81,453	Line 3 minus line 4
6	Invested Capital Tax Rate	<u>0.80%</u>	Company Schedule A-2.1, line 2
7	Incremental Invested Capital Tax Impact per Order	652	Line 5 times line 6
8	Incremental Invested Capital Tax Impact per Company	<u>858</u>	Company Ex. 30.1R
9	Adjustment to Invested Capital Tax	<u><u>(206)</u></u>	Line 7 minus line 8

Nicor Gas Company
Cash Working Capital Adjustment
For the Test Year Ending December 31, 2018
(In Thousands)

Line No. (A)	Item (B)	Amount ⁽¹⁾ (C)	Average Daily Amount (C)/365 (D)	Expense (Lead)/Lag ⁽²⁾ (E)	Cash Requirement (D)*(E) (F)	Source (G)
1	Revenues	\$ 1,289,020	\$ 3,532	57.40	\$ 202,712	Schedule 9, p. 2, line 7
2	IL Public Utilities Tax	1,720	5	57.40	271	
3	Other Pass Through Taxes	211,423	579	0.00	-	
4	Net Revenues/Total Receipts	<u>\$ 1,502,163</u>			\$ 202,982	
5	Natural Gas Purchases	\$ 935,893	2,564	(39.41)	(101,051)	
6	Employee Benefits	16,367	45	(17.56)	(787)	
7	Pension	6,242	17	(45.09)	(771)	Nicor Gas Ex. 16.0, 23
8	OPEB	9,578	26	-	-	
9	Payroll and withholdings	103,475	283	(13.97)	(3,960)	
10	Incentive Compensation	1,293	4	(246.50)	(873)	
11	Intercompany Billings	61,671	169	(45.09)	(7,618)	
12	Retailers Occupation and Use Tax	276	1	(23.03)	(17)	
13	Other Operation and Maintenance Expense	78,641	215	(45.82)	(9,872)	Schedule 9, p. 2
14	Federal Insurance Contributions (FICA)	7,889	22	(13.97)	(302)	
15	Federal Unemployment Tax	66	0	(76.38)	(14)	
16	State Unemployment Tax	464	1	(76.38)	(97)	
17	Invested Capital Tax	20,691	57	(30.13)	(1,708)	Schedule 9, p. 3
18	Corporation Franchise Tax	337	1	(160.82)	(148)	
19	Property/Real Estate Tax	3,265	9	(349.39)	(3,126)	
20	Interest Expense - Long Term debt	51,570	141	(91.25)	(12,892)	Schedule 9, p. 2
21	Interest Expense - Short Term debt	194	1	-	-	Schedule 9, p. 2
22	Federal Income Tax	(19,887)	(54)	(37.88)	2,064	
23	State Income Tax	8,151	22	(37.88)	(846)	
24	Illinois Public Utility Tax	1,720	5	41.01	193	
25	Energy Assistance/Renewable Energy	25,741	71	(0.97)	(68)	
26	Gross Receipts/Municipal Utility Tax	85,185	233	(3.29)	(768)	
27	Illinois Gas Use Tax	31,595	87	29.44	2,548	
28	Illinois Gas Revenue Tax	71,747	197	29.51	5,801	
					<u>-</u>	
29	Total Outlays	<u>\$ 1,502,163</u>	-		(134,314)	Sum of lines 5 through 28
30	Total Cash Working Capital Requirement				<u>\$ 68,668</u>	Sum of lines 4 and 29
31	Cash Working Capital per Order (Rounded to nearest \$1,000)	\$ 68,668				Line 30
32	Cash Working Capital per Company	<u>70,943</u>				
33	Adjustment per Order	<u>\$ (2,275)</u>				

Source:

(1) Schedule 1, except where noted.

(2) Nicor Gas Ex. 30.1 R, Schedule B-8 Revised, except where noted.

Nicor Gas Company
Cash Working Capital Adjustment
For the Test Year Ending December 31, 2018
(In Thousands)

Line No.	Item	Amount	Source (1)
(A)	(B)	(C)	(D)
1	Total Operating Revenues	\$ 791,185	Schedule 1, p. 1, line 3, column (i)
2	PGA Revenue	935,893	
3	Uncollectible Accounts	(9,713)	Schedule 1, p. 1, line 4, column (i)
4	Depreciation	(207,768)	Schedule 1, p. 1, line 12, column (i)
5	Deferred Taxes and ITCs, net	(97,139)	Schedule 1, p. 1, line 18, column (i)
6	Return on Common Equity	(123,438)	Line 10
7	Total Revenues for CWC Calculation	<u>\$ 1,289,020</u>	Sum of lines 1 through 6
8	Total Rate Base	\$ 2,422,250	Schedule 3, line 26, column (d)
9	Weighted Cost of Equity	5.0960%	Per Order
10	Return on equity deduction from revenue	<u>\$ 123,438</u>	Line 8 * Line 9
11	Other O&M Expenses	287,611	Sch. 1 col. (i), sum of lines 4 through 11
12	Payroll and Withholdings	(103,475)	
13	Incentive Pay	(1,924)	
14	Inter-Company Billings	(61,671)	
15	Pension	(6,242)	
16	OPEB	(9,578)	
17	Other Benefits	(16,367)	
18	Uncollectible Accounts	(9,713)	
19			
20	Other Operations & Maintenance (net)	<u>\$ 78,641</u>	
21	Total Rate Base	\$ 2,422,250	Line 8
22	Weighted Cost of Long-term Debt	<u>2.13%</u>	Per Order
23	Interest on Long-term Debt	<u>51,570</u>	
24	Total Rate Base	2,422,250	Line 8
25	Weighted Cost of Short-term Debt	<u>0.01%</u>	Per Order
26	Interest on Short-term Debt	<u>194</u>	

(1) Nicor Gas Ex. 30.1 R, Schedule B-8 Revised, except where noted.

Nicor Gas Company
Cash Working Capital Adjustment
For the Test Year Ending December 31, 2018
(In Thousands)

Line No.	Item	Amount	Source (1)
(A)	(B)	(C)	(D)
1	Invested Capital Tax per Company	\$ 20,897	Nicor Gas Ex. 30.1 R, Sch 3.01 ICT, line 5
2	Invested Capital Tax Adjustment	(206)	Schedule 8, line 9
3	Invested Capital Tax per Order	<u>\$ 20,691</u>	Line 1 + line 2

1991 WL 501801 (Hawai'i P.U.C.), 120 P.U.R.4th 427, Util. L. Rep. P 26,044

Re Hawaii Electric Light Company, Inc.

Docket No. 6432

Decision & Order No. 10993

Hawaii Public Utilities Commission

March 6, 1991

Before Naito, chairman, and DuPont and Young, commissioners.

By the COMMISSION:

DECISION AND ORDER

I.

INTRODUCTION

On May 3, 1989, pursuant to rule 8-1 of the commission's Rules of Practice and Procedure (General Order No. 1), the Hawaii Electric Light Company, Inc. (HELCO), filed a notice of intent to apply for a general rate increase. On July 19, 1989, HELCO filed such an application. It filed the application in accordance with [Hawaii Revised Statutes \(HRS\) § 269-16](#).

HELCO initially requested that the commission approve rate increases that would produce \$13,843,000 in additional revenues, or 16.9 per cent more than at present rates, for a 1990 test year. The requested rate increases reflect an estimated 10.9 per cent rate of return on a year-end rate base for the 1990 test year. Through rebuttal testimony at the evidentiary hearing, HELCO revised its request. As revised, HELCO seeks rate increases that will produce \$9,865,000 in additional revenues, or 11.35 per cent more than at present rates, for the test year 1990. The revised request reflects a 10.86 per cent rate of return on a year-end rate base for the 1990 test year.

As required by rule 8-3(9) of the commission's Rules of Practice and Procedure, simultaneously with the filing of its application, HELCO filed written direct testimonies and exhibits in support of the application. Pursuant to rule 8-6 of the commission's Rules of Practice and Procedure, HELCO served copies of its application on the Division of Consumer Advocacy (CA), Department of Commerce and Consumer Affairs, and on the Mayor of the County of Hawaii. By a letter dated July 26, 1989, the CA notified the commission that it had no objection to the completeness of the application within the meaning of [HRS § 269-16](#) and rule 8-3 of the commission's Rules of Practice and Procedure.

As required by rule 6-60-7 (3) of the commission's Standards for Electric and Gas Utility Service in the State of Hawaii, HELCO notified its customers of its application for rate increases. Pursuant to [HRS § 269-16](#), notices of public hearings were published in the Hawaii Tribune-Herald and in the West Hawaii Today. Public hearings on HELCO's application were held on September 11, 1989, at the Hawaii Electric Light Company Auditorium, Hilo, Hawaii, and on September 12, 1989, at the Kahakai Elementary School Cafeteria, Kailua-Kona, Hawaii.

On September 21, 1989, the Hamakua Sugar Company, Inc. (HSC), the Hilo Coast Processing Company (HCPC), and the Hawaiian Sugar Planters' Association (HSPA) jointly filed a motion to intervene. On September 22, 1989, the Mauna Kea Power Company, Inc. (MKPC), filed a petition to intervene. HELCO objected to the motion to intervene and the petition to intervene and filed a memorandum in opposition to each on October 2, 1989.

On September 25, 1989, the Puna Community Council (PCC) filed an application to intervene. HELCO filed a memorandum in opposition to PCC's application on September 29, 1989. The commission, by Order No. 10357, filed on October 3, 1989, found PCC's application to be deficient and not in compliance with rule 4 of the commission's Rules of Practice and Procedure. The commission directed PCC to file an amended application in conformity with the commission's rules within seven days of the issuance of Order No. 10357. On October 11, 1989, PCC filed an amended application to intervene. HELCO filed a memorandum in opposition to PCC's amended application on October 23, 1989.

On October 16, 1989, HELCO submitted a stipulated prehearing order, signed by HELCO and the CA, outlining the issues and the procedures and a schedule to be followed in the docket. On October 30, 1989, MKPC filed a motion in opposition to the stipulated prehearing order. On November 3, 1989, HSC, HCPC, and HSPA jointly filed a memorandum in opposition to the stipulated prehearing order.

On November 6, 1989, the commission held a hearing on HSC's, HCPC's and HSPA's joint motion to intervene, MKPC's petition to intervene, PCC's amended application to intervene, and MKPC's, HSC's, HCPC's and HSPA's opposition to the stipulated prehearing order. By Order No. 10399, filed on November 24, 1989, the commission admitted HSC, HCPC, HSPA, and MKPC as participants in this docket. The commission, however, limited their participation solely to the question of the reasonableness of HELCO's proposal to revise its schedule Q and its avoided cost heat rates and avoided operating and maintenance costs used in computing its avoided energy costs. The commission directed HELCO, the CA, HSC, HCPC, HSPA, and MKPC to meet informally to formulate the issues and set the procedural schedule for this proceeding. On December 13, 1989, HELCO, the CA, HSC, HCPC, HSPA, and MKPC submitted a stipulated prehearing order. The commission approved the stipulated order as Prehearing Order No. 10421. The prehearing order covers the entire spectrum of this docket, including the issue on which HSC, HCPC, HSPA, and MKPC are participants.

By Order No. 10399, the commission denied PCC's application and amended application to intervene. However, the commission granted participant status to PCC, limited specifically to the impact of HELCO's proposed rate structure on the ratepayers of the Puna district who are in the lower income brackets. The commission directed PCC to participate in the proceedings through the CA. By a letter, dated November 28, 1989, PCC took exception to Order No. 10399 and declined to participate further in this docket. By Order No. 10432, filed on December 21, 1989, the commission approved PCC's withdrawal as a participant and rescinded that portion of Order No. 10399 that granted PCC participant status in this docket.

Hearings on HELCO's application began on March 7, 1990, and were completed on March 19, 1990. On May 21, 1990, as requested by HELCO in its application and pursuant to [HRS § 269-16\(d\)](#), the commission granted HELCO interim rate increases, pending the issuance of a final decision in this docket. The interim rate increases granted by Decision and Order No. 10633 reflect the position of the CA on rate of return, rate base, and test year results-of-operation. The increases produce \$3,466,000 in additional revenues, or 4.05 per cent more than at present rates, for the test year 1990.

HELCO and the CA filed their respective opening briefs on May 21, 1990, and reply briefs on June 6, 1990. On the issue on which HSC, HCPC, HSPA, and MKPC are participants, the parties filed their respective opening briefs on May 23, 1990, and reply briefs on June 6, 1990.

On September 14, 1990, HELCO filed a motion for approval of a stipulation entered into by HELCO and the CA to modify, on an interim basis pending a final decision in this docket, the fuel clause established in Docket No. 4833 (HELCO's last rate case). HELCO sought the modification to avoid a substantial underrecovery that would otherwise result due to an 'anomaly' in the fuel clause. By Decision and Order No. 10770, issued on September 26, 1990, the commission approved the stipulation, subject to the condition that any revenue collected under the modification in excess of that which HELCO would be entitled to collect under the fuel clause finally determined by the commission to be just and reasonable would be refunded to HELCO's customers, with interest.

On November 19, 1990, HELCO filed a motion for approval of a stipulation entered into by HELCO and the CA concerning the undrawn proceeds of certain special purpose revenue bonds. By this stipulation, the parties agreed that: (1) the issuance of up to \$10 million in special purpose revenue bonds on HELCO's behalf before the end of 1990 would not result in the reopening of this rate case; (2) neither the issuance of such bonds nor the existence of undrawn proceeds resulting from such issuance would be considered in any way in calculating HELCO's revenue requirements for the normalized 1990 test year in this rate case; and (3) this stipulation would apply solely to this proceeding. The purposes of the stipulation are solely to simplify and expedite this proceeding and to facilitate, for the benefit of HELCO's customers, the use of a portion of the aggregate amount of special purpose revenue bonds, otherwise expiring in 1990, that may be issued by the State. By Order No. 10895, issued on December 21, 1990, the commission approved the stipulation.

II.

ISSUES

A.

All parties agree that the appropriate test year is calendar year 1990. The ultimate issue in this docket is whether HELCO's proposed rate increases are just and reasonable, and, if not, what increases, if any, may be granted pursuant to [HRS § 269-16](#). HELCO requests that the commission authorize rate increases that would produce \$9,865,000 in additional revenues (an 11.35 per cent increase over the revenues produced at present rates) and that would reflect a 10.86 per cent rate of return on HELCO's year-end rate base for the 1990 test year. The CA proposes rate increases that would produce \$3,466,000 in additional revenues and that would reflect a 10.28 per cent rate of return on HELCO's average rate base for the 1990 test year.

The difference in the proposals arises from differences concerning, among other things, estimated expenses for the test year, the treatment to be accorded employee benefits, the method of calculating depreciation of plant assets, the method of determining the rate base, the elements to be included in the rate base, the cost of common equity, the rate design, changes in HELCO's rules, and HELCO's service reliability. Each of these differences is identified, discussed, and disposed of in the sections that follow.

B.

On the matter on which HSC, HCPC, HSPA, and MKPC are participants in this proceeding, the issue is whether HELCO's calculation of avoided energy costs and the schedule Q rate is just and reasonable and in accordance with applicable statutes and administrative rules. The schedule Q rate is available to qualifying facilities with a design capacity of 100 kilowatts or less for energy delivered to HELCO.

HELCO proposes to amend various components of the proxy method of calculating avoided energy costs and the schedule Q rate that HELCO asserts was adopted by the commission in *Windpower Association of Hawaii v. Hawaiian Electric Co.*, Docket No. 4569, Decision and Order No. 8298 (Mar. 18, 1985). HSC, HCPC, HSPA, and MKPC would have the commission hold that the proxy method is unlawful and adopt a different methodology for the calculation of avoided energy costs and the schedule Q rate. The CA sides with HELCO in opposing what HELCO and the CA consider to be a change in methodology from that adopted by the commission in Docket No. 4569 and in favor of a separate generic docket, if the commission chooses to explore possible changes in the methodology.

III.

REVENUES

A. Sales

Revenue projections, whether at present rates or at proposed rates, depend on anticipated sales during the test year. HELCO's initial forecast of test year kilowatthour (kwh) sales was 702,300,000 kwh. The CA's initial forecast was 712,418,200 kwh.

HELCO used mathematical modeling and trending techniques in forecasting sales for rate schedules R, G, H, and F. These techniques employ mathematical relationships, based on historical data and other related information, to estimate kwh sales and the number of customers in the test year. For schedule P, on account of the meager number of large power customers in this schedule, HELCO used market analysis on an individual customer basis to forecast sales.

The CA also used mathematical trending techniques in forecasting kwh sales, but only for rate schedules R, G, and H. Moreover, the CA, unlike HELCO, made separate forecasts for the average number of customers and the average use per customer. The CA multiplied the two components to obtain the kwh sales for each rate schedule. For schedules P and F, the CA evaluated each customer's account to arrive at the total estimated consumption.

In rebuttal, HELCO accepted the CA's methodology and revised its estimate upward to 710,218,200 kwh (an increase of 7,918,200 kwh). As a result of the change, the difference between the parties is now 2,200,000 kwh. The following schedule compares HELCO's revised forecast and the CA's projections of average number of customers, average use per customer, and total sales for each schedule.

<i>Rate Schedule</i>		<i>HELCO</i>	<i>CA</i>	<i>Difference</i>	
		<i>(Revised)</i>			
<i>Number of Average Annual Customers</i>					
R	Residential service		40,300	40,300	0
G	General service		7,351	7,350	1
H	Commercial cooking, heating,				
	AC and refrig. service		860	860	0
P	Large power service		62	63	(1)
F	Public street lighting		27	27	0
Total			48,600	48,600	0
<i>Average Annual Consumption Per Customer (kwh)</i>					
R	Residential service		6,790	6,790	0
G	General service		25,365	25,365	0
H	Commercial cooking, heating				
	AC and refrig. service		53,460	53,460	0

120 P.U.R.4th 427, Util. L. Rep. P 26,044

P	Large power service		3,225,396	3,225,396	0
F	Public street lighting		117,625	117,625	0
<i>Total Sales (megawatthours (mwh))</i>					
R	Residential service	273,637	273,637		0
G	General service	186,730	186,430		300
H	Commercial cooking, heating				
	AC and refrig. service	45,976	45,976		0
P	Large power service	200,700	203,200		(2,500)
F	Public street lighting	3,176	3,176		0
Total		710,218	712,418		(2,200)

The difference of 2,200,000 kwh is due to the inclusion by the CA of 2,500,000 kwh in schedule P for the Kona Lagoon Hotel. HELCO excluded all but 300,000 kwh for the Kona Lagoon Hotel, because the hotel will not be completed until the fall of 1991. HELCO included the 300,000 kwh in schedule G for lighting, security, and maintenance purposes. After confirming that the hotel's completion date will be outside the test year, the CA accepted HELCO's estimate of 300,000 kwh for the Kona Lagoon Hotel in schedule G. Thus, the parties agree that the total estimated sales is 710,218,000 kwh. We conclude that this estimate is reasonable.

B. Revenue

The revised estimate of sales and number of customers required HELCO to revise its initial revenue projections. HELCO's revised test year electric sales revenue projection, at present rates, is \$86,644,000, and its revised other operating revenue estimate, at present rates, is \$301,000. HELCO's revised total revenue estimate, at present rates, is \$86,945,000. The CA's revised electric sales revenue forecast is \$85,330,000, and its revised other operating revenue estimate is \$301,000. The CA's revised total revenue estimate is \$85,631,000.

The difference of \$1,314,000 in the electric sales revenue forecast of HELCO and that of the CA is due to the inclusion by HELCO and the exclusion by the CA of the firm capacity surcharge revenues for the firm capacity payments of \$1,200,000 that HELCO asserts it must make to the Puna Geothermal Venture (PGV), and related revenue taxes. The inclusion of the firm capacity surcharge on account of PGV results in a capacity surcharge rate of 0.00678 cent per kwh. Its exclusion results in a capacity surcharge rate of 0.00492 cent per kwh. In later sections (see 'Fuel Oil Expense' and 'Purchased Power Expense' in part IV), we discuss the CA's exclusion of the PGV capacity surcharge. For the reasons stated there, we conclude that HELCO's test year electric sales revenue projection of \$86,644,000, at present rates, and also its other operating revenue estimate of \$301,000 are reasonable for the test year. The following shows HELCO's total sales and operating revenue for the test year:

Rate Schedule

Revenue At Present Rates

R	\$35,360,700
G	9,297,500

J	16,183,900
H	5,439,900
P	19,984,700
F	376,900
Total electric sales revenue	86,644,000
Other operating revenue	301,000
Total operating revenue	\$86,945,000

IV.

EXPENSES**A. Fuel Oil Expense**

The estimate of the fuel oil expense is the product of the estimated fuel oil consumption in the test year and the price of fuel. The consumption estimate depends on the amount of energy or power that HELCO is expected to produce in the test year. HELCO used a computer simulation model to determine the amount of fuel likely to be consumed by its generating units to produce the power anticipated for the test year. Initially, HELCO estimated its net power generation at 341.3 gigawatthours (gwh) and its fuel oil consumption at 746,142 barrels (728,931 barrels of industrial oil and 17,211 barrels of diesel oil). By using the April 1, 1989, fuel prices: (\$12.0184 per barrel (bbl) for no. 6 fuel oil and \$26.356 per bbl for diesel oil), HELCO estimated its fuel oil expense, including certain transportation costs, for the test year at \$9,323,000.

On rebuttal, HELCO revised its estimate of net power generation and its estimate of fuel oil consumption and adopted the January 1, 1990, fuel oil prices, as suggested by the CA. As revised, the net power generation is 505.4 gwh (an increase of 164.1 gwh). The revised net power generation takes into account: (1) the above-mentioned increase of 7.9 gwh in HELCO's forecast of sales; (2) a reduction in the estimate of the amount of energy to be purchased by HELCO from PGV in the test year from 219 gwh to 62 gwh; and (3) an increase in the estimate of the amount of power to be produced by a hydroelectric power source to 16.6 gwh, as advocated by the CA. A comparison of HELCO's initial position and its position on rebuttal on its test year net generation is shown below:

	HELCO	HELCO	Increase
	(Direct)	(Rebuttal)	
	(gwh)	(gwh)	(gwh)
Sales	702.3	710.2	7.9
+ Company use	1.3	1.3	0
Sales + no charge	703.6	711.5	7.9
Losses	73.0	73.8	.8

Net system input	776.6	785.3	8.7
- Purchased energy	420.3	263.3	(157.0)
Net HELCO system	356.3	522.0	165.7
- HELCO hydroelectric	15.0	16.6	1.6
Net HELCO generation	341.3	505.4	164.1

The increase in HELCO's net generation to 164.1 gwh results in an increase in the estimate of fuel oil consumption by 268,683 barrels for industrial oil and 99,848 barrels for diesel oil. The following shows HELCO's estimates of the fuel oil consumption, fuel price, and fuel expense for each of its power plants:

<i>Plant</i>	<i>Consumption</i> (bbls)	<i>Price</i> (\$/ bbl)	<i>Expenses</i> (\$000)
<i>(1) Industrial Oil:</i>			
Hill	576,689	17.7870	10,258
Shipman	192,417	17.7870	3,423
Puna	228,508	18.4345	4,212
Subtotal	997,614		17,893
<i>(2) Diesel Oil:</i>			
Keahole	50,749	31.6533	1,606
Waimea	31,819	30.9314	984
Hilo	34,491	30.4501	1,050
Subtotal	117,059		3,640
Total	1,114,673		21,533

The CA made an initial fuel oil expense forecast of \$15,927,000 for the test year. The CA subsequently withdrew this estimate and accepted HELCO's revised test year fuel oil expense estimate of \$21,533,000. We conclude that this estimate is reasonable.

B. Purchased Power Expense

1. At present rates

HELCO's initial estimate of purchased power expense, at present rates, was \$31,310,000. In rebuttal, HELCO revised its estimate to \$20,121,000. The revision is the result of a change in the estimate of the amount of energy and firm capacity HELCO expects to receive from PGV. HELCO lowered its estimate for energy from 219 gwh to 62 gwh and for firm

capacity from 25 mw to 7.5 mw. The new purchased power expense consists of \$15,408,000 in purchased energy payments and \$4,713,000 in firm capacity payments.

The CA's estimate of purchased power expense for the test year is \$18,921,000. This is \$1,200,000 lower than HELCO's revised test year estimate. The difference results from the CA's refusal to include in purchased power expense any payment to PGV in the test year. The CA expresses concern that PGV may not come on line in the test year and that, if in fact this occurs, the inclusion of the payments to PGV in purchased power expense would cause HELCO's customers to pay for capacity not received. The CA proposes that HELCO recover PGV's firm capacity expense through a firm capacity surcharge when PGV actually comes on line.

HELCO asserts that the CA is inconsistent in its treatment of the PGV contract. The CA would exclude the firm capacity payments to PGV from the purchased power expense, even though it has accepted HELCO's inclusion of 62 gwh of energy (based on 7.5 megawatts (mw) of capacity) from PGV in calculating the estimate for fuel oil expense. HELCO, however, agrees that its customers should not have to pay for PGV capacity until PGV actually comes on line and, thus, accepts the CA's recommendation to recover the PGV firm capacity cost through a firm capacity surcharge.

The CA is indeed inconsistent, as asserted by HELCO, in its treatment of the PGV purchased power contract. Energy cannot be produced, if the capacity is not available, and 7.5 mw of capacity will either be available or not available from PGV in the test year. HELCO's approach is consistent and appropriate. Thus, notwithstanding HELCO's agreement with the CA's recommendation, we conclude that HELCO's estimate of \$20,121,000 for purchased power expense at *present rates* is reasonable.

2. At proposed rates

HELCO's estimated purchased power expense at *proposed rates* is \$19,654,000. It is lower than under the present rates because HELCO proposes to revise downward its schedule Q rate and avoided energy costs from what they are at present rates. HELCO's schedule Q rate and avoided energy costs are the basis for many of its purchased power contracts. The proposed revisions to schedule Q rate and avoided energy costs affect those energy producers whose contracts with HELCO either (1) do not have minimum floor prices or (2) have minimum prices that are lower than the proposed avoided energy rates. HSC and Hawaiian Electric Renewable Systems, Inc., fall within the first category, and HCPC falls within the second category.

The schedule Q rate applies to qualifying facilities with capacities equal to or under 100 kw; HELCO's avoided energy rates apply to qualifying facilities with capacities greater than 100 kw. The interplay between the schedule Q rate and HELCO's avoided energy costs is that the schedule Q rate is based on the composite of the on-peak and off-peak avoided energy cost rates, adjusted by on-peak and off-peak power factors. HELCO's revised estimates of its avoided energy costs (including the operations and maintenance (O&M) component) at present rates are 5.23 cents per kwh for on-peak hours and 4.36 cents per kwh for off-peak hours. At proposed rates (with revised heat rates and with the O&M component reduced to zero), the avoided energy costs are 4.89 cents per kwh for on-peak hours and 3.84 cents per kwh for off-peak hours. The schedule Q rate under HELCO's proposed rates is reduced to 4.26 cents per kwh from 4.68 cents per kwh.

The CA accepts HELCO's calculation of the avoided energy costs and the schedule Q rate. However, the intervenors (HSC, HCPC, HSPA, and MKPC) dispute the appropriateness of HELCO's calculation. We shall discuss in detail later in a separate decision and order in this docket the differing perspectives of the parties on this issue. For present purposes, we elect not to alter the manner in which avoided energy costs are calculated. We therefore accept the estimated purchased power expense of \$20,121,000 at proposed rates as being reasonable.

C. Fuel Adjustment Factor

HELCO's fuel adjustment factor at present rates is -1.143 cents per kwh. The fuel adjustment factor is based on the test year fuel prices, the estimated test year fuel consumption, the estimated test year purchased energy expense, and the test year fuel efficiency. The CA accepts HELCO's fuel adjustment factor at present rates.

HELCO initially proposed to set the fuel adjustment factor at zero under its proposed rates. It also proposed to set the base purchased power cost equal to the base fuel cost, even though the test year composite purchased power cost is higher than the base fuel cost. In effect, it proposed to set both the base fuel cost and the purchased power cost at the test year average cost of oil and purchased power. This proposal is to avoid an overrecovery or an underrecovery of the fuel cost as the mix of purchased power and company generation changes over time from the test year mix. HELCO's proposal is a deviation from the prior method of calculating the fuel adjustment factor. HELCO argues that, under the previously determined method of calculating the fuel adjustment factor, it will experience underrecovery of its purchased energy costs in the 1990 test year.

The CA questions whether HELCO ever undercollected under the current fuel adjustment clause. Nevertheless, it asserts that basing both the base fuel cost and the base purchased power cost on the average cost of oil and purchased power is improper and suggests that there is a more direct method of addressing the 'anomaly' in the present method. The CA proposes that the base purchased energy cost be weighted by the proportion of the test year purchased energy to total system net energy and that the base company generation cost be weighted by the proportion of the test year company generation to total system energy.

On September 14, 1990, HELCO and the CA entered into a stipulation to effectuate a fuel adjustment clause on an interim basis, pending the final disposition of this docket. The stipulated interim fuel adjustment clause incorporates the CA's proposal in calculating the fuel adjustment factor. HELCO acknowledges that the CA's proposed method corrects the anomaly. The stipulation is based on a test year purchased energy percentage of the total system net energy of approximately 34 per cent. The commission approved the stipulation by Decision and Order No. 10770, filed on September 26, 1990. The order made the stipulated fuel adjustment clause effective on October 1, 1990.¹

The CA's method of calculating the fuel adjustment factor is reasonable and should, as acknowledged by HELCO, correct the 'anomaly' that may otherwise result by the use of the method used in the last HELCO rate case in 1984.

D. Other Production Expenses

HELCO's estimate of other production expenses for the test year is \$6,447,000. The CA's forecast is \$6,369,000. At the time of the hearing, HELCO's estimate was \$6,402,000, based on the assumption that PGV would provide 25 mw of power during the test year, and, therefore, the Puna power plant's three operator shifts would be reduced to two shifts. HELCO anticipated a savings of \$45,000 as a result and deducted that amount from its test year forecast. As already noted, PGV will not be providing 25 mw of power in the test year, and, thus, HELCO will need to maintain three shifts at the Puna power plant throughout 1990 and into 1991. The CA in its calculation recognized this and added the \$45,000 (which HELCO had anticipated saving) back into other production expenses.

The major divisions of the other production expense category are (1) operations and (2) maintenance. The difference in the estimates between HELCO and the CA is due to the exclusion by the CA of (1) \$54,000 in labor expense associated with a boiler operator at the Hawaii Geothermal Project-Abbott (HGP-A) facility and (2) \$24,000 in normalized painting expense. The issue with respect to the HGP-A boiler operator arises from the closing of the HGP-A facility in December 1989.

The CA asserts that, with the closing of the HGP-A plant, the cost of the HGP-A boiler operator should be excluded in computing the production operations labor expense, since the operator's position is no longer in existence. HELCO maintains that the operator will be utilized by HELCO for normal team operation activities. HELCO points out that, when it originally supplied an operator to the HGP-A facility, the operator was not replaced, and, thus, in effect, the operator will be returning to his former position, and HELCO will be returning to the more normal staffing level. This, HELCO argues, will better enable HELCO to handle situations of normal operator turnover and to reduce some overtime. The CA is not convinced that the operator will be utilized to reduce overtime expense. It believes that HELCO intends to keep the operator and use him later in the year to fill the position of one of three employees projected to transfer out of the production department. This alone, the CA asserts, establishes that the operator is not of present use to HELCO.

We agree with the CA that the sum of \$54,000 on account of the HGP-A boiler operator should be excluded from other production expense. This determination should not result in the discharge of the operator. HELCO has asserted that its production operation suffers from a high rate of employee turnover. It states that historically, on the average, production operation has had one turnover every four months. The causes of the turnover are promotion, transfer to other positions, retirement, and voluntary termination of employment. This being so, it would appear that the HGP-A boiler operator could and probably would replace other operators who leave for other positions, retire, or quit in the normal course of production operation. Indeed, HELCO states that it expects one transfer from the production department to the transmission and distribution department in the 1990 test year.

The \$24,000 normalized painting cost is included in HELCO's production maintenance expense. This cost represents what HELCO considers as the 1990 amortized portion of the total cost of \$141,000 for the painting of smokestacks and fuel tanks. The amortization is over six years, the service life of an industrial coating in severe service. The CA objects to the inclusion of this cost, since HELCO has no plans to do any painting in 1990. The CA asserts that normalizing painting expense would not be inappropriate if HELCO, in fact, maintained any semblance of a regular schedule over which the painting activity could be normalized. The CA points out that HELCO has not established a practice of painting its smokestacks and fuel tanks on a regular basis. It notes, for instance, that a number of tanks had not been painted in over 25 years.

We agree with the CA. By HELCO's own admission, no painting expenses are planned for the test year. In HELCO's last rate case, the commission disallowed proposed maintenance expenses that will not be incurred in the test year. See *In re Hawaii Elec. Light Co.*, Docket No. 4833, Decision and Order No. 8179 (Nov. 23, 1984). HELCO has presented no new arguments to cause us to deviate from that decision.

Except for these adjustments (\$54,000 for the HGP-A boiler operator and \$24,000 in amortized painting cost), the CA accepts HELCO's other production expenses. We conclude that the CA's projection of \$6,369,000 for other production expenses is reasonable.

E. Transmission and Distribution Expense

HELCO's estimated transmission and distribution (T&D) expense for the test year is \$2,957,000. The CA accepts this amount. Based on the record, we conclude that this amount is reasonable.

Although the CA accepts HELCO's estimate, it is highly critical of the reliability of HELCO's system. The CA points to HELCO's 1989 experience. In 1989, HELCO experienced an inordinate amount of power outages, and HELCO's system reliability dropped below its goals. HELCO currently assesses its system reliability by three measures. The first measure is the average system availability index (ASAI). The ASAI is calculated by dividing the customer hours of available service by the customer hours demanded. The second measure is the customer average interruption duration (CAID). The CAID is calculated by dividing the sum of customer interruption durations by the total number of customers. The

third measure is the system average interruption frequency (SAIF). The SAIF is calculated by dividing the total number of customer interruptions by the total number of customers served. HELCO's goals, as measured by these indices, are:

ASAI	99.98 per cent or better;
CAID	45 minutes or less; and
SAIF	1.85 or less.

In 1989, the ASAI dropped to 99.9254 per cent, the lowest in the last 15 years; the CAID increased to 98.13 minutes; and the SAIF increased to 3.99. The ASAI value reflects a 0.06 per cent decline from HELCO's established goal. This translates into a 1989 average system outage time that is 6 hours longer than what it was in 1988.

The CA recommends that a part of any rate increase that the commission may grant be made subject to refund, if HELCO's reliability performance in 1990 fails to meet HELCO's reliability standards² and that HELCO measure reliability performance by smaller service districts — for example, by circuits or substations. The CA also recommends that the existing reliability standards and goals be maintained. In making these recommendations, the CA expresses particular concern that HELCO has taken no steps to mitigate major causes of outages 'specifically as a consequence of the 1989 experience.'

HELCO agrees that it needs to minimize the number and duration of outages and otherwise ensure system reliability; but it disagrees with the CA's recommendations. It strongly denies that it has taken no action to mitigate major causes of outages 'specifically as a consequence of the 1989 experience.' It points to HELCO's stepped up tree trimming activities, HELCO's correction of faulty installation of protective relays, and HELCO's actions to add to its reserve margin. HELCO asserts that 1989 was an unusual year, with many outages occurring from weather-related causes beyond the control of HELCO. At the time of the hearing, HELCO also expressed doubts about the efficacy of measuring system reliability by the existing HELCO goals. It described the goals as 'unattainable.' Finally, HELCO doubts that calculating reliability indices by smaller service districts (as contrasted from calculating on an island-wide basis) would be meaningful, because of the 'many variables involved in service reliability.' It contends that customers who choose to live in an isolated, remote part of the island cannot expect the same level of service reliability as customers who live in more densely populated areas.

The commission agrees with the CA that HELCO's system reliability needs to be improved. The number of outages in 1989 was too high. The data indicate that outages in 1989 were caused, not only by foul weather and falling tree branches, but also by equipment failure. Indeed, the hours of customer outages caused by equipment failure in 1989 were the highest in the last six years. Equipment performance is generally within HELCO's control. Frequent outages cause disruptions of businesses, inconvenience, aggravation, and loss of revenues to customers. We recognize that HELCO has the largest service territory in the State and a relatively small (although growing) customer base. Nevertheless, HELCO has an obligation to maintain a reliable system.

Several issues are raised by the CA's recommendations: (1) what HELCO needs to do to ensure system reliability; (2) whether system reliability should be measured by smaller service districts, in addition to measuring on an island-wide basis; and (3) by what standards system reliability should be measured. With respect to the first of these issues, we believe that HELCO needs to increase its activities to ensure reliability of its system. The record reveals that HELCO increased its transmission and distribution facilities by 67 per cent and its expenditures for transmission and distribution operations and maintenance by 36 per cent in the period 1984 to 1987. However, from 1988 to 1989, HELCO increased its expenditures for transmission and distribution operations and maintenance by only a marginal amount, and the proposed increase for test year 1990 is not much more than the increase in 1989. HELCO's kwh sales have been increasing at rather healthy rates: 8 per cent in 1986, 5 per cent in 1987, 6.9 per cent in 1988, and 8.4 per cent in 1989. With this ever

increasing electric demand that requires HELCO to expand its transmission and distribution facilities, HELCO needs to increase its operations and maintenance efforts commensurate with the expansion of its transmission and distribution facilities.

On the second issue, we believe, as the CA does, that system reliability should be measured, not only on an island-wide basis, but also by smaller districts. We do not agree that measurement by smaller districts would not serve a meaningful purpose. Although it is not reasonable to expect service that is totally free of interruptions, those who live in less populated and remote areas should not have to endure an inordinate amount of service interruptions. Electric service is essential to all segments of the community. Thus, customers, wherever situated, have a right to expect that their electric service will be provided at a reasonable level of reliability.

Measurement of reliability on an island-wide basis provides information that is relevant to the island as a whole, but may fail to disclose serious service problems that exist in certain specific locales on the island. Reliability measurements by smaller service districts or substations will enable HELCO to detect these localized problems and correct them rapidly.

Concerning the third issue, during the course of the hearing, HELCO promised to return to the commission with more realistic goals at a later date. On January 16, 1991, it filed with the commission two reports: one, a special report on service reliability levels, and, second, a study report on the methodology for determining reliability indices. The study on the methodology for determining reliability indices is the result of a joint effort by the Hawaiian Electric Company, Inc. (HECO), and its subsidiaries, HELCO and the Maui Electric Company, Limited (MECO). The special report on service reliability levels is specific to HELCO and is based on the methodology study.

Both reports conclude that the reliability indices ASAI, SAIF, and CAID are the best available for measuring service reliability and that the indices should be calculated for outages with durations greater than one minute rather than five minutes as is the case under existing practices. The reports also conclude that a reasonable range of reliability indices should be determined by analyzing six years of historical annual reliability indices and removing any abnormal outages. Six-year historical data are to be normalized and an average calculated with a band of one standard deviation.

The HELCO-specific report contains data for the various measures for the years 1985 to 1990. The report states that these historical data indicate the reasonable ranges of service reliability for HELCO to be an ASAI between 99.923 per cent and 99.978 per cent, an SAIF between 2.124 and 6.463, and a CAID between 44.87 and 80.35 minutes. It concludes that '[d]ue to the random probability of service interruptions, plus or minus one standard deviation around the average represents a reasonable range of service reliability.'

The commission has not had an opportunity to fully evaluate the reports. Thus, we are not prepared at this time to accept reliability standards based simply on past experiences as being sufficient. The commission considers system reliability to be an important issue that commands attention greater than that which can be given in this docket. We will, therefore, institute an examination of this issue in a separate docket shortly after the issuance of this decision and order. HECO, MECO, and the Kauai Electric Division of Citizens Utilities Company, in addition to HELCO, will be parties to the docket.

In that examination, we will study the reports submitted by the utilities on January 16, 1991, review service problem areas, evaluate the utilities' efforts to ensure system reliability, and explore procedures by which continuing system reliability may be assured. We will consider making annual reviews of service quality, in conjunction with the commission's review of the utilities' capital expenditure plans, a part of the procedure to ensure continuing system reliability. In preparation for the docket on system reliability, HELCO shall provide the commission and the CA with copies of its 'Annual Service Reliability Report' and its 'Annual Circuit Report'.

In light of the commission's intentions, we do not find it necessary to adopt the CA's recommendations at this time. Whether or not a rate reduction should be ordered because of HELCO's system reliability problems, as suggested by the CA, may be considered upon completion of the examination of the system reliability issues in the separate docket.

F. Customer Accounts Expense

HELCO's projection of customer accounts expense under present rates is \$1,715,000. The CA's projection is \$1,550,000. The difference under present rates is \$165,000. Of this difference, \$32,000 is in the uncollectibles account. This difference of \$32,000 is due to the use by HELCO and the CA of different uncollectible factors applied to their differing revenue projections. The remaining difference of \$133,000 is in the various other accounts that make up the customer accounts expense and is due in part to the use by the parties of different forecasting methods.

1. Uncollectibles expense

HELCO's projection of uncollectibles expense under present rates is \$132,000. The CA's projection is \$100,000. The uncollectibles expense is determined by multiplying the projected sales revenue by an uncollectible factor. HELCO used an uncollectible factor of 0.152 per cent, and the CA used an uncollectible factor of 0.1177 per cent. HELCO derived its uncollectible factor by dividing the total net write-offs for the latest 12 months by the total electric sales revenue for the same 12-month period. HELCO's uncollectible factor is, in effect, a net write-off percentage. The latest 12-month period on which HELCO calculated its uncollectible factor covers 1989.³ The CA, on the other hand, derived its uncollectible factor by dividing the total uncollectibles expense for the latest 12 month period by total revenues projected for the same period. The latest 12-month period on which the CA calculated its uncollectible factor is December 1, 1988, to November 30, 1989.

The parties refer to HELCO's method of calculating its uncollectible factor or net write-off percentage as the 'percentage of electric sales revenue' methodology. The CA criticizes the use of this methodology as resulting in HELCO regularly overestimating its uncollectibles expense. It asserts that actual experience has shown little correlation between HELCO's calculation of uncollectibles expense and bad debt. It recommends that the commission adopt the CA's methodology. In the alternative, it suggests that the commission adopt the methodology purportedly used in some other jurisdictions, such as Massachusetts, Connecticut, and Illinois. These other jurisdictions purportedly maintain the mismatch between write-offs and uncollectibles but minimize the effect by averaging net uncollectible write-offs over a period of years, as a percentage of revenues.

HELCO, in objecting to the CA's method, points out that this process lags uncollectibles expense instead of making it current as HELCO's method does. HELCO argues that the factor calculated by the CA may be applicable to test year *collected* revenues, but rates are based on test year *billed* revenues, and uncollectibles should also be calculated based on billed revenues. It further contends that HELCO has not consistently overestimated its uncollectibles expense as asserted by the CA. It points to the recorded uncollectibles expense of \$195,000 for 1988 and \$88,000 for 1989, when the forecast for both years was \$96,000.

HELCO's methodology is the methodology approved by the commission in HELCO's last rate case in 1984. See *In re Hawaii Elec. Light Co.*, Docket No. 4833, Decision and Order No. 8179 (Nov. 23, 1984). We hold that HELCO's methodology in calculating the uncollectible factor is reasonable. HELCO's method is reasonable, because it is based upon actual net write-offs. We see no reason to deviate from our earlier decision and adopt HELCO's uncollectible factor. Since we earlier accepted HELCO's revenue projection, we accept HELCO's uncollectibles expense of \$132,000.

2. Other customer accounts expense

The remaining difference of \$133,000 between HELCO's projected customer accounts expense and that of the CA reflects differences in labor and nonlabor expenses for supervision, meter reading, and records and collection. The CA's forecast of labor expense is less than HELCO's by \$2,000 for supervision, \$15,000 for meter reading, and \$48,000 for records and collection. These differences result, generally, from the application of different methodologies in estimating labor costs. Specifically for meter reading and records and collection, the difference results from the differing treatments of vacant positions.

With respect to methodology, the CA based its calculation on 11 months of actual and one month of estimated 1989 expense. HELCO based its estimate on expected hours of work and standard hourly wage rates, including anticipated increases in rates. We conclude that HELCO's forecasting method is appropriate and, accordingly, we accept the utility's projection for supervision labor expense as reasonable.

For meter reading and records and collection, HELCO included in its calculation the meter reading positions that were vacant in 1989. In 1989, there were six meter reading position vacancies caused by transfers to other positions. HELCO asserts that the vacancies, time taken to fill the vacancies, and the training of new meter readers caused the 1989 actual labor expense to be far below forecast. The major impact of the meter reader vacancies was on the records and collection expense, since employees from records and collection were reassigned temporarily to meter reading until the vacancies were filled. HELCO contends that the CA unjustifiably excluded the vacant meter reading positions in calculating its labor expense.

We conclude that HELCO's inclusion of the meter reading positions that were vacant in 1989 in estimating the labor segment of customer accounts expense is reasonable. HELCO needs to maintain proper manning levels in meter reading. Meter reading is an integral part of HELCO's billing process.

The CA's forecast of nonlabor expense is less than HELCO's by \$5,000 for meter reading, \$62,000 for records and collection, and \$1,000 for miscellaneous. The CA's estimate, as in the case of its estimate of labor expense, is based on 1989 data. HELCO contends that the CA failed to adjust the 1989 data to reflect various items that will be needed in the test year.

We accept as reasonable HELCO's forecast of nonlabor expense for meter reading and miscellaneous. However, we adopt the CA's forecast of nonlabor expense for records and collection. HELCO's forecast of records and collection nonlabor expense includes anticipated increased expenditures for vehicles, bulk mail, uniforms, technical and support services, meter reading devices, and telephone service. HELCO's projection for records and collection nonlabor expense is about 16.5 per cent greater than those experienced in 1989. HELCO has not provided sufficient evidence to justify the entire increase.

3. Summary

In summary, for the customer accounts expense, we conclude that the sum of \$1,653,000 is reasonable. This sum consists of \$79,000 for supervision, \$375,000 for meter reading, \$1,059,000 for records and collection, \$8,000 for miscellaneous, and \$132,000 for uncollectibles.

G. Customer Service Expense

Both HELCO and the CA agree on a test year forecast of \$217,000 for this account. This sum consists of \$21,000 for supervision, \$148,000 for customer assistance, and \$48,000 for information advertising. This category of expense is primarily to provide, as a part of the customer service division's function, information and assistance to customers on

safe, efficient, and economic use of electric services. Activities include the distribution of information on alternate energy and energy-related issues.

The expense related to supervision includes the allocated labor charges of the manager of the administrative department and the director of customer and consumer services for time spent in providing consultation and supervision in customer service activities. The customer assistance expense is primarily the salaries of a staff of three people who plan and execute energy-related programs and classes for residential consumers, teachers, youth groups, and the general public. The programs include ways in which appliances may be used more efficiently. The informational advertising expense is for (1) local media conservation and informational advertising, including advertising on safe operation of appliances and emergency preparedness, and (2) producing and printing 'Consumer Lines,' an insert included in the monthly billings mailed to customers. 'Consumer Lines' is actually produced and printed by HECO, HELCO's parent company. HELCO shares in the cost of its production and printing. 'Consumer Lines' contains energy-related issues such as safety and conservation. We conclude that the sum of \$217,000 for customer service expense, as agreed to by HELCO and the CA, is reasonable.

H. Administrative and General Expenses

HELCO's projection of administrative and general (A&G) expenses is \$7,071,000. That figure represents HELCO's third and latest forecast. The CA's estimate is \$5,256,000. For the reasons stated below, we will allow \$5,120,000 as a reasonable projection of A&G expenses.

HELCO and the CA agree on the projections of A&G expenses for the following categories of accounts:

<i>Account</i>	<i>Amount</i> (in thousands)
Transfer to construction	\$ (252) *
Transfer to other	(23) *
Outside other services	17
Property insurance	211
Injuries — employees	416
Injuries — public	237
Pensions — nonfunded	3
Pensions — funded	1,700
Research & development	165
Preferred stock & long-term debt	166
Board of directors fees	15
Maintenance of general plant	31

The asterisked (*) amounts represent the results of the application of a transfer ratio of 18.78 to the 'transfer to construction' category and a transfer ratio of 1.71 to the 'transfer to other' category of expenses. These transfer ratios are based on HELCO's test year estimates, and we adopt them for the purposes of this docket. However, based on these ratios and our approved test year expenses for the A&G salaries and office supplies categories as specified below, the 'transfer to construction' amount should be \$254,000. There is no change in the 'transfer to other' amount. With the revision of the 'transfer to construction' amount, we accept the amounts enumerated above as reasonable for their respective categories of A&G expenses.

HELCO and the CA disagree as to projections for the other categories of A&G expenses. We describe the disagreement and dispose of the differences by the various categories of expenses in the paragraphs that follow.

1. A&G salaries

HELCO's forecast of A&G salaries is \$ 1,170,000. The CA's estimate is \$1,182,000. HELCO and the CA differ by \$12,000, because the CA refuses to recognize HELCO's transfer of labor cost from this account category to the regulatory commission expense account category. The \$12,000 represents the cost of the time devoted by A&G personnel to this rate case docket. The CA argues that rate case work is a part of the relevant employee's 'normal duties and responsibilities,' and, thus, the cost of the time spent on the rate case should remain in the A&G salaries account. HELCO reasons that the transfer best captures the nature of the expense.

We disagree with HELCO. The transfer of \$12,000 to the regulatory commission expense account is not in accordance with the Uniform System of Accounts (USOA) of the National Association of Regulatory Utility Commissioners (NARUC). The USOA provides that the regulatory commission expense account 'shall include all expenses (*except pay of regular employees only incidentally engaged in such work*) properly includible in utility operating expenses, incurred by the utility in connection with formal cases before regulatory commissions, or other regulatory bodies . . . ' (Emphasis added.) The record indicates that the HELCO employees who were witnesses and participated in this rate case were only incidentally engaged in the case. Their primary responsibility is other than involvement in rate cases. Their participation in rate cases, when they do arise, occurs as a part of their normal duties and responsibilities and is confined to issues and matters within their usual, assigned area of work. Thus, the CA's 1990 test year estimate for A&G salaries of \$1,182,000 is just and reasonable.

2. Office supplies and expense

HELCO's test year estimate of office supplies and expense is \$172,000. The CA's estimate is \$158,000. The estimates differ, because the parties used different forecasting methods and the CA excluded as expense the amounts projected for gifts and donations.

The CA's estimate is derived by taking recorded 1989 expenses through October 31, 1989, subtracting \$1,100 of 'gifts and donations' and then annualizing the balance by dividing it by 10 months and multiplying by 12 months.⁴ HELCO argues, first, that the exclusion of gifts and donations is unreasonable. It maintains that HELCO is a part of the Big Island community and that the sum is intended to be used to support local community groups, such as a judo school, the Hawaii Youth Baseball, the East Hawaii Special Olympics, and the Big Island Nutrition Council; it is not intended for Aloha United Way contributions. HELCO, then, argues that the CA's forecasting method fails to recognize that the expenses in this area fluctuate from year to year and complains that the CA's forecast excludes any form of escalation for cost increases and is no more than an estimate of 1989 expenses.

The CA is correct in disallowing gifts and donations. Gifts and donations to local community groups are no different from other charitable gifts. This commission has long taken the position that gifts and donations should not be allowed as

operating expenses for ratemaking purposes. They are to be given at the company's cost, not the ratepayers'. Expenditures for gifts and donations are not necessary to HELCO's primary responsibility of providing safe, reliable, and reasonably priced service to its customers, and ratepayers should not be burdened with the choice exercised by HELCO as to objects of charitable contributions. We recognize that the amount involved here is small, but ratepayers will derive no direct benefit by the gifts and donations contemplated by HELCO.

We agree with HELCO, however, that the CA's forecasting method fails to take into account the fluctuating needs of HELCO and escalating costs. The CA's calculation of 1989 actual expenses of \$158,000 is not much lower than HELCO's projection of \$172,000. We conclude that HELCO's expense amount of \$172,000, less \$1,000 on account of gifts and donations, or \$171,000, is reasonable for office supplies and expense.

3. Outside legal services

For the test year, HELCO projects \$53,000 in expenses for outside legal services. The CA's estimate is \$20,000. The difference in the estimates results from the application of different calculating methodologies. The CA calculated its estimate by (1) totaling HELCO's recorded legal expenses for 1986, 1987, and 1988, (2) deducting from the sum, all legal expenses associated with HELCO's acquisition of the Puna plant and with proceedings on account of the 1986 Tax Reform Act, and (3) dividing the net sum by three to derive an average for the three years. The CA deducted the legal expenses associated with the acquisition of the Puna plant and the proceedings on account of the 1986 Tax Reform Act, because they were extraordinary and nonrecurring expenses.

HELCO responds that the CA's calculation (1) does not recognize that legal expenses generally relate to nonrecurring matters and that HELCO will incur legal expenses in 1990 for matters that did not exist in the 1986-1988 period, (2) assumes that the cost of legal services has not increased since 1987, and (3) fails to consider the legal services that HELCO will require in 1990.

HELCO and the CA are both partially correct. The legal services that HELCO requires and the extent to which it requires them need not necessarily be the same year after year, and the cost of such services has been increasing over the years. However, the historical costs of irregular, unusual, or otherwise nonrecurring legal services should not be considered in projecting future legal expenses. Whether legal costs are of an irregular, unusual, or nonrecurring nature needs to be determined on a case by case basis.

In this docket, we agree with neither HELCO's nor the CA's estimate of the expense for outside legal services. We do not view the legal services rendered in the acquisition of the Puna plant or in the proceedings related to the 1986 Tax Reform Act to be unusual, irregular, or nonrecurring. We believe, however, that a fairer assessment of test year expenses for outside legal services can be had by viewing HELCO's 1984 to 1989 six-year historical experience. The expenses during this six-year period ranged from a low of \$14,000 to a high of \$52,000. We conclude that the average of this six-year period of \$33,000 is a reasonable estimate of expenses for outside legal services for the test year.

4. Affiliated services

This account category includes expenses that are payments by HELCO to its affiliates for services rendered to HELCO. HELCO's test year forecast for this account is \$963,000. The CA's estimate is \$954,000. The difference of \$9,000 arises from: the parties' use of differing bases to calculate the amount of membership dues that HELCO is required to pay to the Edison Electric Institute (EEI); the deduction by the CA of 49.58 per cent of the amount payable on account of the EEI dues, which percentage the CA considers as representing payment for lobbying activities by EEI; and the disallowance by the CA of amounts that it considers to be duplications of costs for accrued vacation and nonproductive wages.

a.

With respect to the EEI dues, HELCO's projection is \$20,000. HELCO's parent, HECO, pays EEI dues on a company-wide basis and allocates the cost among itself and its subsidiaries. The allocation is based on a formula that takes into account each company's kwh sales and number of customers. The estimate of the 1990 EEI dues was allocated on the basis of the actual 1988 kwh sales and number of customers.

The CA's projection of HELCO's share of the cost for the 1990 EEI dues is \$13,000. The CA used the same methodology to calculate HELCO's share, but based its calculation on the 1990 test year's projection of kwh sales and number of customers, rather than on the actual 1988 sales and customer data. The result was \$25,057. However, the CA went further and deducted 49.58 per cent of the \$25,057, or \$12,423, on the ground that this amount represents payment by HELCO to support EEI's government lobbying and mass media advertising activities.

The CA argues that such activities provide no particular benefit to HELCO's ratepayers and are of benefit largely to the utility. Lobbying activities seek to influence legislative or executive actions that favor the utility; mass media advertising activities are intended to encourage the use of electricity and to improve the utility's public image. The CA points out that this commission in prior rate cases has disallowed the inclusion in utilities' operating expenses those portions of EEI dues that represent payments for EEI government lobbying activities, on the ground that such activities provide no particular benefits to ratepayers.

The CA is correct. We have in the past disallowed as operating expenses those portions of the EEI dues that represent payment to support government lobbying and mass media advertising activities by EEI. See, for instance, *In re Hawaiian Elec. Co.*, Docket No. 4536, Decision and Order No. 7678 (Sept. 16, 1983). We reaffirm our former decisions. Accordingly, we will allow as affiliated services expense \$13,000 of the total portion of the EEI dues allocated to HELCO.

b.

On the matter of the inclusion in the affiliated services account of expenses for accrued vacation leave and nonproductive wages arising from certain affiliated services, HELCO admits that these are duplicate charges. By the CA's calculation, these duplicate charges amount to \$500 for accrued vacation leave and \$1,900 for nonproductive wages. We, thus, reduce HELCO's test year estimate of the expense for affiliated services by \$2,400.

c.

There are other HECO-allocated expenses in the account. Initially, the CA proposed to disallow \$324,000 of these other allocated charges. Subsequently the CA accepted HELCO's estimates without any explanation. The various other allocated expenses, HELCO's estimates of which the CA accepted, are as follows: (i) \$266,000 for services provided by HECO's rate and regulatory affairs department; (ii) \$83,500 for services in the compensation and benefit area provided by HECO's human resources and industrial relations departments; (iii) \$34,000 in audit fees for services provided by HECO's internal audit group; and (iv) \$139,000 in overhead charges for all other billings from HECO and HEI.

Initially, the CA proposed that \$102,000 of HECO's rate and regulatory affairs department charges, \$58,000 of compensation and benefit charges, \$34,000 in audit fees, and \$139,000 in overhead charges be disallowed on the ground that these amounts are duplicative of the amounts included in other accounts. It also initially proposed that \$83,500 of the charges of HECO's human resources and industrial relations departments be disallowed on the ground that it should be amortized over a three-year period.

Although the CA agrees that \$954,000 of HELCO's estimated \$963,000 is reasonable for the affiliated services account, the commission does not agree. Our reasons are stated in subsection d below.

d.

We find that both HELCO's and the CA's overall projections for affiliated services are too high. HELCO's records indicate that in the years 1986, 1987, and 1988, the actual expenses for affiliated services were \$681,000, \$481,000, and \$516,000, respectively. For 1989, HELCO's forecast was \$699,000 — \$183,000, or 35 per cent, over actual 1988 expenses. HELCO's test year forecast is \$264,000, or 38 per cent, more than the 1989 forecast. The 1990 test year forecast is \$447,000, or 87 per cent, more than the actual expenses for 1988. The increase in the test year estimate is due mostly to the increase in the amount forecasted to be payable for services (other than in rate cases) rendered by HECO's rate and regulatory affairs department. The forecasted increase for these services is \$190,000 more than that forecasted for 1989. In the years before the test year, the charges for services rendered by HECO's rate and regulatory affairs department averaged \$71,000 per year.

HELCO gives two reasons for the higher estimated charges for HECO's rate and regulatory affairs department services in the test year than in the years past: (i) effective 1990, HECO's managers and directors are charging the subsidiaries directly for their nonsupervisory time, unlike in years past, and (ii) HECO's rate and regulatory affairs department is now doing more work for HELCO than in the past. HELCO points to activities related to Big Island geothermal development and the class load research studies on the island as examples of the kind of additional work the HECO rate and regulatory affairs staff are performing for HELCO.

There is insufficient evidence to substantiate the reasons given by HELCO for the dramatic projected increase in affiliated service expense. It does not appear reasonable that the practice of directly charging the costs of the nonsupervisory time of HECO's managers and directors to the subsidiaries and the involvement of HECO's rate and regulatory affairs staff in the kinds of activities described should result in such a large increase in the test year. Moreover, we believe that it is the duty and responsibility of HECO's rate and regulatory affairs staff to provide advice and assistance to its subsidiaries. Such advice and assistance are intended to aid HELCO in maximizing its profits and, thus, enure to the benefit of HECO. Accordingly, HECO should be willing to absorb some of the costs of the services that HECO's staff provides to HELCO.

The 1989 forecast of \$699,000 is more indicative of the level of expenses HELCO can expect to incur for affiliated services in the test year. Although this sum is \$183,000, or 35 per cent, higher than actual 1988 expenses, it incorporates the normalized charges of HECO's rate and regulatory affairs department, HECO's initiation of a new payroll system, and moderate increases for other services. We conclude that \$699,000 is reasonable for test year 1990.

5. Dental plan

HELCO's projected dental plan expense is \$197,000. However, HELCO has transferred \$47,000 of the \$197,000 to its proposed postretirement benefits account, leaving \$150,000 in the dental plan account. The CA's estimate of dental plan expense is \$197,000. The CA does not agree with the creation of a postretirement benefits account. Thus, the CA keeps the total estimated \$197,000 in the dental plan account.

We discuss later in this decision and order HELCO's proposal to create a postretirement benefits account. Since we will not allow the accrual of postretirement benefits at this time, \$47,000 should not be deducted from the projected \$197,000. The sum of \$197,000 for dental plan expense is reasonable.

6. Group life insurance

HELCO's initial estimate of expense for group life insurance for the test year was \$141,000. Its revised estimate is \$111,000. The revised estimate accounts for the transfer of \$30,000 of the original \$141,000 to HELCO's proposed postretirement benefits account. The CA's estimate is \$128,000. HELCO's revised estimate and the CA's estimate differ by \$17,000. The difference is due to the CA's objection to the transfer of \$30,000 to the postretirement benefits account and the exclusion by the CA of \$13,000 for executive life insurance premiums.

Since we will not allow the accrual of postretirement benefits at this time, the CA is correct that the sum of \$30,000 should not be deducted from HELCO's initially projected \$141,000. The CA would exclude \$13,000 in executive life insurance premiums from the projected \$141,000 for the reason that the Internal Revenue Code does not recognize this expense as a deductible item for federal income tax purposes. Further, the CA contends that the beneficiaries of executive life insurance policies are not ratepayers but the stockholders or the family members of the executives whose lives are covered by the policies. If the family members benefit, the executive life insurance policies constitute a form of additional compensation.

HELCO's position is that the beneficiary of the executive life insurance policies is the company, since the proceeds of the policies fund death benefits for the families of the executives covered by the policies. HELCO also contends that the tax consequences under the Internal Revenue Code should not be the determining factor in the treatment to be given to executive life insurance premiums for ratemaking purposes.

The commission's view is that the cost of the premiums for executive life insurance policies should be borne by HELCO and its stockholder. They are the beneficiaries of the policies, whether or not the proceeds of the policies are used to extend death benefits to the families of the executives covered by the policies. No benefit accrues to ratepayers. We will disallow the expense of \$13,000 for executive life insurance policy premiums, and we conclude that the CA's estimate of \$128,000 is reasonable.

7. Group medical and hospital insurance

HELCO's estimate for this account is \$795,000. The CA's test year estimate is \$1,001,000. The difference of \$206,000 is due to HELCO's transfer of this amount to its proposed postretirement benefit fund. Since we are disallowing the accrual of postretirement benefits for this docket, we will accept the CA's estimate of \$1,001,000 as reasonable for the test year.

8. Other employee benefits

HELCO's test year forecast of other employee benefits expense is \$204,000. The CA's projection is \$56,000. The difference of \$148,000 is due to the CA's exclusion of (a) \$12,700 for employee athletic activities and award banquets, and (b) \$135,000 for HELCO's management incentive plan. We accept the CA's projection of \$56,000 as being reasonable.

a.

HELCO acknowledges that athletic activities and banquet expenses are not directly related to production, transmission, and distribution of power. It argues, however, that they are essential to maintaining a work force that interacts as a team. It, further, notes that the Internal Revenue Code allows a deduction of these expenses for income tax purposes.

The CA excludes \$12,700 for athletic activities and award banquets, because it does not believe that expenditures for such purposes are necessary to accomplish the company's primary purpose of providing safe, adequate, reliable, and reasonably priced service to its customers. The CA points to this commission's decision in *In re Hawaii Electric Light Co.*, Docket No. 2993, Decision and Order No. 5261 (Aug. 28, 1978). In that decision we held that employee membership in the Volcano Golf and Country Club and employee activities of bowling, softball, and Christmas parties do not contribute

to any of the functions of the utility nor benefit electric consumers. We regarded such activities to be primarily for the entertainment and amusement of employees and disallowed proposed expenditures for those purposes.

We reaffirm our decision in Docket No. 2993, just as we did in several cases decided since 1978, but before this docket.⁵ We are not persuaded that expenditures for employee athletic activities and award banquets should be considered for ratemaking purposes. We, thus, disallow the projected expenditure of \$12,700.

b.

The CA contends that expenditures for management bonus and incentive programs should not be allowed for ratemaking purposes, because such expenditures do not benefit the ratepayers. The CA maintains that management personnel should fulfill their corporate responsibilities, regardless of any incentive compensation. It contends that incentive compensation is, in effect, duplicative of salaries and wages.

HELCO urges that the management incentive program is intended to recognize and reinforce performance beyond the employee's job description and the normal responsibilities for which an employee is paid. Without the plan, management's only means of rewarding exemplary behavior would be through permanent pay raises, which are very difficult to rescind once granted. Furthermore, ratepayers are the direct beneficiaries of the employee performance that the company rewards.

As the CA points out in its brief, this commission has time and again disallowed expenditures for bonuses, incentives, and profit sharing for purposes of ratemaking.⁶ We see no reason to deviate from our prior decisions. Thus, we disallow \$135,000 in expenses projected for the management incentive program.

9. Vision plan

HELCO's test year projection for the vision plan is \$24,000. The CA's estimate is \$30,000. The difference of \$6,000 in the parties' estimates is due to HELCO's transfer of the \$6,000 to the proposed postretirement benefits account. Since we are disallowing the accrual of postretirement benefits, the \$6,000 should be added back to the vision plan account. The projected \$30,000 expense for the vision plan is reasonable.

10. Postretirement benefits

HELCO proposes to account for the cost of employees' postretirement benefits on an accrual basis beginning in the test year. Its estimate of the amount to be accrued in the test year is \$2,483,000. The CA opposes accruing the cost of postretirement benefits and would disallow the estimated \$2,483,000.

Postretirement benefits include medical insurance, reimbursement of Medicare Part B premiums, vision care, dental care, and life insurance.⁷ HELCO's current practice (the practice that prevailed in the years before the test year) is to account for postretirement benefits other than pension expenses on a 'pay-as-you-go' basis. HELCO's estimate of the cash outlay for postretirement benefit payments for the 1990 test year is \$289,000.

HELCO gives two primary reasons for accruing the cost of these postretirement benefits. First, the current cost of providing service (a part of the cost being the cost of the postretirement benefits) should be borne by the customers receiving that service. Second, it would be to the benefit of HELCO's customers for HELCO to build a fund to pay the cost of postretirement benefits, because such a fund will reduce the cost for all customers to the extent that there are earnings on the fund.

HELCO's proposal to accrue the cost of postretirement benefits is spurred by the issuance of a new rule by the Federal Accounting Standards Board (FASB), requiring the accrual of the cost of postretirement benefits, effective for the fiscal years beginning after December 15, 1992. At the time of the hearings in this docket, the rule was in the form of an 'exposure draft'. At the writing of this decision and order, the rule is in final form.

The FASB rule was triggered by rapid increases in health care costs over the past years. Accounting for the cost of postretirement benefits on a cash basis presented no particular problem when the difference between cash accounting and accrual accounting was not considered material. However, with increases in health care costs, companies throughout the country have accumulated significant obligations to pay postretirement benefits. These obligations remain unrecognized on the books under the cash method of accounting. The FASB rule, in effect, compels disclosure of significant corporate obligations that affect a company's financial status.

HELCO's estimate of postretirement expenses for 1990 was calculated for the company by The Wyatt Company, an actuarial firm. It was calculated in accordance with the FASB rule and reflects all of the components required to be included by the rule, including the test year's portion of the amortized 'transition obligation.'⁸ The 'transition obligation' is the amount of the unfunded accumulated postretirement benefit obligation for all participants determined as of the date the FASB rule is initially applied. HELCO proposes that this date be the beginning of the test year — January 1, 1990. The transition obligation in HELCO's case has been amortized over 16-1/2 years (the average remaining service period of active postretirement benefits plan participants). The transition obligation includes the cost of building up a fund sufficient to satisfy the future needs of the company's current retirees and employees. After 16-1/2 years, HELCO will be in a position to collect only that amount associated with the future benefits anticipated to be paid to then current employees.

The CA objects to accruing the cost of postretirement benefits on a number of grounds. First, the CA argues that the effects of employing the accrual method of accounting are disastrous to current ratepayers. The proposed accrual of \$2,483,000 is an increase of almost \$2.2 million over \$289,000, the amount that is payable under the pay-as-you-go method; it constitutes almost 25 per cent of HELCO's requested increase in revenue requirements.

Second, the CA notes that the actuarial assumptions upon which the cost to be accrued is predicated are subject to uncertainties and significant variations. Assumptions need to be made about the ages of the company's retiring employees, the interest discount rate, the medical expense inflation rate, the medicare payment inflation rate, and medical usage. The CA argues that HELCO cannot determine in advance the effects of altering the assumptions upon which The Wyatt Company's projections are based.

Finally, the CA urges that, due to the uncertainties in forecasting the costs to be accrued and in light of the fact that no employee is endangered by the present method of having ratepayers undertake the responsibility to pay for current retirees as their expenses are incurred, the pay-as-you-go method be retained until some body of experience accumulates on the accrual method of accounting for the cost of postretirement benefits.

We are in agreement with HELCO that the accrual method of accounting for the cost of postretirement benefits properly places the burden of paying for the cost on the ratepayers who receive the benefits of the service that triggers the cost. Even the CA admits that the pay-as-you-go method does result in current ratepayers paying for the expenses of former employees. However, the change from the pay-as-you-go basis to the accrual basis impacts heavily on ratepayers. At this time, we are not inclined to ask ratepayers to foot the additional expense that will be entailed in the changeover.

We are aware that deferring recognition of postretirement benefits expenses on an accrual basis will not make those expenses go away and that the problem will be even larger in the future if it is deferred, as asserted by HELCO. However, the FASB rule does not become effective until the fiscal year after December 31, 1992. This provides the commission,

as well as NARUC and the Federal Energy Regulatory Commission, if they are so inclined, time to study more fully the impact of the new FASB rule and the means of attaining the ends sought by the rule without unduly burdening ratepayers. The commission anticipates a separate generic docket on the rule. We, therefore, will not allow HELCO to accrue the cost of postretirement benefits. Accordingly, HELCO shall continue the current pay-as-you-go method to account for the cost of these benefits.

11. Employee benefits transferred to construction and others

HELCO's projection of the costs of employee benefits to be transferred out of the A&G account to construction is \$1,905,000. Its projection of the costs of employee benefits transferred to others is \$56,000. The CA's estimate of these costs is \$1,141,000 and \$33,000, respectively. These transfers are credit amounts, since the result of the transfers is to reduce A&G expense. The difference between the parties with respect to both transfers is due in part to (as noted above) the parties' differing projections for dental plan, group life insurance, group medical and hospital insurance, other employee benefits, vision plan, and postretirement benefits. The difference is also due to the parties' use of different transfer ratios to determine the portion of the costs of the various employee benefits to be transferred.

We conclude that the transfer ratios of 34.83 to calculate the amount to be transferred to construction and 1.02 to calculate the amount to be transferred to other accounts are reasonable for the test year. Applying these ratios to the projected amounts that we accept as expenses for the various benefits, we conclude that the amount of \$1,085,000 for transfer to the construction account and the amount of \$32,000 for transfer to the others account are reasonable.

12. Regulatory commission expense

HELCO's estimate of its total expense for the rate case in this docket is \$580,000. This total, amortized over a three-year period, results in a test year expense of \$193,000. The CA's test year estimate is \$14,000. The difference is \$179,000. The difference results from the CA deducting from HELCO's projected total expense of \$580,000 the amounts noted below and applying a five-year amortization period, rather than HELCO's three-year period.

The deductions made by the CA from HELCO's total estimated cost and the reasons for the deductions are as follows: (a) \$149,000, representing the labor cost of HELCO's employees, because this cost is duplicative of the labor charges included in the projected affiliated services expense; (b) \$286,000, representing the labor cost of HECO's employees, because this cost is for services that HECO already provides and is collected through the management fee charged by HECO to HELCO and is included in HELCO's projected outside services-associated expense; (c) \$4,000, representing HECO's nonlabor costs (such as airfare, lodging, and meals), since this cost is associated with the labor cost of HECO's employees, which the CA disallows; (d) a reduction of 50 per cent of the \$141,00 that results after the deductions enumerated in (a), (b), and (c) above, on the reasoning that HELCO's stockholder (HECO) benefits directly from the rate case through the opportunity to earn increased returns on common equity and should, thus, bear one-half of the cost of this ratemaking proceeding.

After these deductions, the projected cost to HELCO for this ratemaking proceeding is \$70,500. An amortization of this amount over a five-year period results in a test year expense of \$14,000. HELCO's response to each of the deductions proposed by the CA and our disposition of the proposals follow.

a.

HELCO denies that the \$149,000 deducted by the CA is duplicative of any cost included in the expense for affiliated services. HELCO asserts that the labor costs related to this docket were transferred from other accounts. HELCO notes

that HELCO's total labor cost is higher in this docket than in previous rate cases, because in this rate case HELCO, for the first time, has included nonlabor costs in its estimate of total labor cost.

We accept the CA's adjustment and disallow \$149,000 in rate case expense. Earlier, in discussing the expenses for A&G salaries, we reaffirmed our previous holding that labor costs associated with a rate case should remain in the source or original account, because the work performed by HELCO's permanent employees in a rate case is only incidental to their usual duties. Moreover, in this docket, no exhibit or worksheet was presented, reflecting a reduction of labor and nonlabor costs associated with this docket from each of the source or original accounts.

b.

HELCO also denies that \$286,000 on account of HECO's labor cost is duplicative of the amounts included in the projected outside services-associated expense. HELCO asserts that \$139,000 of the \$286,000 was taken out of the outside services-associated expense and included in rate case expense, and \$147,000 of the \$286,000 was added as a rate case expense, because HELCO had failed to include this amount in its original estimate. HELCO states that the reason HECO's costs are higher in this case than in previous rate cases is that in prior cases HECO charged HELCO directly for only the cost of the services of HECO staff below the director's level and charged HELCO for the costs of the services of directors and above only as part of HECO's overhead charges. Beginning with this rate case, HELCO is to be billed directly for the costs of the services of HECO's directors and managers.

We accept the CA's adjustment of \$286,000. The record contains no evidence that \$139,000 was deducted from the outside services-associated expense. The record is also devoid of any explanation as to how the amount of \$286,000 was developed. Although HECO may have changed its policy and now bills HELCO directly for the costs of the services of HECO's directors and managers, we find that the cost of \$286,000 is unreasonably high for HECO's services to HELCO in this rate case. In past cases, HECO's charges to HELCO were approximately \$125,000 for the services rendered by HECO's staff below the directors' level. The record does not show why direct billing of the costs of the services of HECO's directors and managers should almost double HECO's charges to HELCO. Further, we find no reason for HELCO to depend so heavily on HECO to provide the expertise necessary in a rate case. HELCO's personnel appear to possess the skills and experience required for a rate case.

c.

HELCO objects to the CA's exclusion of HECO's nonlabor charges associated with HELCO's rate case. It contends that such exclusion is unreasonable. It argues that nonlabor costs, such as airfares, meals, and lodging, are legitimate costs incurred by HECO in HELCO's rate case. However, we will accept the CA's adjustment. The \$4,000 nonlabor charge deducted by the CA is associated with and incidental to HECO's labor cost of \$286,000, which we have disallowed.

d.

HELCO's position with respect to the CA's allocation of 50 per cent of HELCO's rate case cost to HELCO's stockholder (HECO) is that such an allocation is unreasonable. HELCO maintains that the cost of a rate case is a necessary and proper cost of doing business. In the past, the commission refused to allocate any part of a utility's rate case cost to the utility's stockholders. See *In re Hawaiian Elec. Co.*, Docket No. 2781, Decision and Order No. 4802 (Aug. 18, 1977); *In re Hawaii Elec. Light Co.*, Docket No. 2993, Decision and Order No. 5261 (Aug. 28, 1978); *In re Hawaii Elec. Light Co.* 54 PUR4th 83 (1983); *In re Hawaii Elec. Light Co.*, Docket No. 4833, Decision and Order No. 8179 (Nov. 23, 1984). We reaffirm our past decisions and will not allocate any portion of HELCO's rate case cost to its stockholder.

e.

HELCO disagrees with the CA's use of a five-year amortization period. HELCO states that it would require additional rate relief in possibly three years due to the addition of a new generation unit and numerous system developments. Based on historical data and HELCO's future system requirements, we agree with HELCO that a three-year amortization period is reasonable. Based on a three-year amortization period and the CA's estimated total rate base expense of \$141,000, the reasonable test year regulatory Commission expense is \$47,000.

13. Institutional and goodwill advertising

HELCO's test year estimate of institutional and goodwill advertising expense is \$2,000. The \$2,000 is intended for informational radio and television advertising and for decorating HELCO's offices during the Christmas season. The CA would disallow the expenditure of money for such purposes, on the ground that such expenditure serves primarily to improve the company's public image.

We find that institutional advertising and decorating HELCO's offices during the Christmas season are part of the company's continuing effort to promote good community relations. The amount of \$2,000 for this purpose is reasonable.

14. Community service activities

HELCO's test year projection of the expense for community service activities is \$14,000. The CA's estimate is \$1,200. HELCO represents that its estimate includes the cost of news film for distribution to schools, support of the Junior Achievement program, and assistance to various nonprofit community clubs, organizations, and associations.

The CA's estimate is \$12,800 less than HELCO's, because the CA recommends the disallowance of HELCO's entire test year estimate, except \$1,200 to cover the cost of an annual subscription to the Science Screen Report. The CA contends that HELCO's estimate for the test year 1990 is unreasonable and not supported by historical data. The CA notes that the company's actual recorded expenditures were \$3,000 in 1985, \$2,000 in 1986, \$3,000 in 1987, and \$5,000 in 1988.

The commission's view is that HELCO should continue to provide community services. However, we find its projection for the test year to be extremely high when compared to actual expenditures made in previous years. We conclude that the sum of \$4,000 (which is the high average of the amounts actually expended in prior years) is reasonable.

15. Company membership expense

HELCO's 1990 test year forecast of its membership expense is \$12,000. Membership expense consists of fees for membership in industrial, service, trade, and technical organizations. The CA's test year estimate is \$3,400. The CA's estimate consists of fees for membership in the Hawaii Visitors Bureau, the Hawaii Island Chamber of Commerce, the Kona Chamber of Commerce, and the Japanese Chamber of Commerce. The CA notes that its proposal is consistent with the commission's decision in *In re Hawaii Electric Light Co.*, Docket No. 4833, Decision and Order No. 8179 (Nov. 23, 1984).

HELCO's estimate is questionable. The record notes that, for the entire 12 months of 1988, HELCO expended \$13,790 in membership expense and for the first eight months of 1989 it expended \$5,737. No reason is given for the difference in amounts of \$8,100. Recognizing that four months of 1989 are not accounted for, we are unable to ascertain a reason for such a large difference. In any event, in the absence of further evidence, we will follow our decision in Docket No. 4833, cited by the CA, and limit HELCO's membership expense to the fees for membership in the Hawaii Visitors Bureau,

the Hawaii Island Chamber of Commerce, the Kona Chamber of Commerce, and the Japanese Chamber of Commerce. The CA's estimate of \$3,400 is reasonable.

16. Summary of A&G expenses

The following summarizes the A&G expenses that we will allow as reasonable for the test year.

<i>Account</i>	<i>Amount</i> (\$000)
A&G salaries	1,182
Office supplies	171
Transfer to construction	(254)
Transfer to other	(23)
Outside legal services	33
Outside other services	17
Outside services associated	699
Property insurance	211
Injuries - employees	416
Injuries - public	237
Employee benefits - flex credits	0
Pensions - nonfunded	3
Dental insurance	197
Pensions - funded	1,700
Group life insurance	128
Group medical & hospital	1,001
Other employee benefits	56
Vision plan	30
Long-term disability	0
Postretirement	0
Employee benefits transferred to construction	(1,085)

Employee benefits transferred to	
other	(32)
Regulatory commission expense	47
Institution/goodwill advertising	2
Community service	4
Company membership	3
Research & development	165
preferred stock & long-term debt	166
Board of directors fees	15
Rents	0
Maintenance of general plant	31
Total A&G expenses	<u>\$ 5,120</u>

I. Accrued Vacation and Nonproductive Wage Expenses

Accrued vacation expense represents the cost of employee vacation, which is earned proportionately by each employee for each day of work. This expense is recorded by HELCO as vacation time is earned. Nonproductive wage expense represents paid time off for such occasions as holidays, sickness, deaths in an employee's family, and physical examinations required by the company.

For the test year, HELCO proposes \$478,00 of accrued vacation expense and \$381,000 of nonproductive wage expense. The CA initially recommended disallowance of both expense amounts.⁹ However, during the evidentiary hearing, the CA reversed its position without explanation. It now proposes to allow the utility's estimates for accrued vacation and nonproductive wage expenses.

Although the CA has reversed its position, we elect to adopt its original stance, and we disallow HELCO's expenses for accrued vacation and nonproductive wage payments. We are not convinced that HELCO has avoided duplicating expenses that are already accounted for in total wages. These costs are not additional expenses above normal wages. They may be appropriate expenses in those instances when payments are made to terminating employees for their accrued vacation time or when paid replacements are necessary for regular employees who are on nonproductive time off. HELCO has not shown that its estimates include only such appropriate expenses.

J. Wage Rollback

Wage rollback normalizes O&M labor costs. This calculation adjusts the O&M labor expense used in setting electric rates by annualizing wage increases received during the year. By rolling back wages, O&M labor expense reflects wage increases as if they were in effect for the entire test year.

HELCO estimates a wage rollback of \$174,000. The CA projects a wage rollback of \$154,000. The difference of \$20,000 is due to the CA's exclusion of accrued vacation expense, nonproductive wages, and a production adjustment made by

HELCO. HELCO's wage rollback reflects nonunion raises, effective May 1, 1990, and union raises, effective November 1, 1990. Without this rollback, electric rates would account for only seven months of nonunion and two months of union salary increase. According to the utility, this rollback adjusts for O&M labor costs and related payroll taxes, but not for related employee benefits.

We find the methodology utilized by HELCO in computing the wage rollback to be reasonable. However, based on our decision to disallow accrued vacation and nonproductive wage expenses (see section I above), we accept the CA's estimate of \$154,000 as reasonable.

K. Depreciation Expense

HELCO's test year estimate of depreciation expense is \$8,860,000. The CA's forecast is \$7,976,000. The following shows the difference between the parties:

	<i>HELCO</i>	<i>CA</i>	<i>DIFFERENCE</i>
	(\$000)	(\$000)	(\$000)
Depreciation accrual	10,308	9,387	921
Less:			
Depreciation of Vehicles	244	207	37
Amortization of			
contributions in aid of			
construction	1,204	1,204	0
Depreciation expense	8,860	7,976	884

The difference of \$884,000 is due to the parties' use of different methods to calculate depreciation accrual. HELCO proposes to adopt an average monthly balance method of calculating depreciation and to normalize the 1990 depreciation accrual by annualizing the depreciation accrual on 1990 plant additions. This method considers the 1990 test year depreciable plant additions in the calculation of depreciation accrual. The CA's estimate is based on the beginning-of-year balance of depreciable plant to which the depreciation rates are applied. This is the method that HELCO uses for book purposes and currently uses to calculate depreciation accrual. HELCO's use of the average monthly balance method is a departure from its current method.

HELCO believes that its proposed method better matches recovery of investment in an asset (through depreciation) with the asset's service life. The proposed method would start depreciating an asset when it goes into service, rather than delay the start of depreciation to the beginning of the next year, which is the case under the current method. HELCO argues that the average monthly balance method is more consistent with generally accepted accounting principles (GAAP) and is more proper for ratemaking. HELCO mentions that the GTE Hawaiian Telephone Company has been using the average monthly balance method, as seen in Docket No. 5114.

The CA agrees in principle with HELCO's proposed method. However, the CA believes that HELCO should stay with the current method, because (1) the current method is also consistent with GAAP and HELCO's most recent depreciation study, (2) HELCO has conducted no studies to consider, and offered no testimony concerning, the wide-ranging effects

that HELCO's proposed method would have, and (3) HELCO has not provided a 'compelling' reason for a change now to a different method of calculating depreciation accrual. The CA recommends that, before any change in the method is adopted, the commission should await the results of the next depreciation study, which should include an examination of the issue of changing to HELCO's proposed method.

Our review of HELCO's application of the proposed methodology to estimate the amount of the test year depreciation accrual¹⁰ indicates that HELCO calculated its estimate by applying the depreciation rates to the sum of the beginning 1990 depreciable plant balance *and* the estimated 1990 test year plant additions. This method does not conform to the average *monthly* plant balance method. The operation of the average monthly balance method is clearly described in the testimony submitted by the GTE Hawaiian Telephone Company in Docket No. 5114. The testimony is: 'On a monthly basis, depreciation charges are computed by multiplying one-twelfth of the annual rate by the average monthly book balance for each class of depreciable plant.'¹¹ Generally, utility plant additions are not completed all at one time. The additions increase gradually each month from the beginning of the year, with most of the additions being completed at the end of the year.

HELCO's application of the average monthly balance method overstates the estimate for test year 1990. HELCO's calculation is the result that would be obtained by using the 'current' method to derive the depreciation expense for the year 1991. We agree with the CA that HELCO's proposed methodology and its application should be carefully examined in HELCO's next depreciation study. HELCO's proposed depreciation expense is unacceptable. The CA's depreciation expense of \$7,976,000 is reasonable.

L. Taxes

There are four categories of tax-related expenses. Taxes other than income taxes and income taxes are expense items reflected in the results of operation; deferred income taxes and unamortized investment tax credits are items related to the rate base. Much of the differences between HELCO and the CA are in the latter two categories. The differences and our disposition of the differences follow.

1. Taxes other than income taxes

HELCO pays six types of taxes other than income taxes. Three are payroll-related. The other three taxes are the public service company tax, the public utilities commission fee, and the franchise tax. Both HELCO and the CA used the same method and rates in calculating projected obligations for taxes other than income taxes. The difference in their respective estimates is due to the use of different revenue projections in estimating the public service company tax, the public utilities commission fee, and the franchise tax.

The commission finds the method and rates used in making the projections for taxes other than income taxes to be reasonable and consistent with our prior decisions. Since we have earlier accepted HELCO's revenue projections, we adopt HELCO's projected amounts to be paid in public service company tax, public utilities commission fee, and franchise tax. HELCO and the CA agree on the estimate of the amounts to be paid in payroll-related taxes. The total projections for taxes other than income taxes are \$7,983,000 at present rates and \$8,377,000 at proposed rates.

2. Deferred income taxes and unamortized investment tax credits

Deferred income taxes and unamortized investment tax credits (ITC) are items that are deducted from the rate base and, thus, reduce the rate base. HELCO's projection for the test year is \$6,299,000 in accumulated deferred income taxes

and \$863,000 in unamortized ITC. The CA agrees with HELCO's projection of unamortized ITC. However, the CA's estimate of accumulated deferred income taxes is \$14,796,000.

The principal reason for the difference of \$8,497,000 in the estimates of accumulated deferred income taxes is the exclusion by the CA of negative deferred taxes in the amount of \$8,385,000 from HELCO's projection. These negative deferred taxes are the result of income taxes paid by HELCO on contributions in aid of construction (CIAC) and customer advances received by HELCO after 1986.

Before 1986, receipts of CIAC and customer advances were not taxable as income, and assets paid for by CIAC were not depreciable for tax purposes. In 1986, the United States Congress enacted a tax reform act. Under the Tax Reform Act of 1986 (1986 TRA), the receipts of CIAC and customer advances received after 1986 are taxable as income, the assets purchased with CIAC are depreciable, and the refund of customer advances are deductible as an expense in computing income taxes.

Following the enactment of the 1986 TRA, HELCO did not seek to recover the amount of the taxes associated with CIAC and customer advances from those making the contributions and advances—the contributors and customers. HELCO paid the taxes on these contributions and advances from funds available to it. However, it treated the taxes as prepayment of future taxes and recorded it on its books as negative deferred income taxes. HELCO, in its projection of deferred income taxes for the test year, proposes to add the amount of the negative deferred income taxes generated by the payment of taxes on the contributions and advances to the rate base as an offset against deferred income taxes, thereby increasing the rate base.

The CA argues that ratepayers should not have to bear the burden of the cost of additional income taxes payable on account of CIAC and customer advances. It maintains that the cost causers of these additional taxes—the contributors and customers—should pay the taxes. It contends that, since HELCO chose not to require the contributors and customers to pay the taxes, HELCO, and not its ratepayers, should bear the income tax cost. It recommends that HELCO adopt the full 'gross-up' method with respect to CIAC and customer advances. Under this method, contributors and customers would be required to pay an amount, over and above the amounts of CIAC and customer advances, sufficient to pay the taxes attributable to the contributions and advances.

HELCO argues that the CA is unreasonable in excluding the negative deferred taxes in calculating its deferred income taxes. HELCO defends its practice of not charging those making CIAC and customer advances on several grounds. First, it believes that there is only a small impact on ratepayers, if the taxes are spread over the general ratepayer base rather than collected from the cost causers. Second, HELCO believes that the law requiring the taxation of the receipts of CIAC and customer advances is a temporary aberration and is likely to be repealed by the Congress, in light of the concerns raised by utilities and others nationwide.

Third, HELCO suggests that collecting for taxes associated with CIAC and customer advances from the contributors and customers, particularly the contributors, will present administrative difficulties for HELCO. If amounts for taxes are collected from contributors and customers, in fairness, the amounts would need to be refunded to the contributors and customers as HELCO derives tax savings from the depreciation and deductions it is allowed to take for income tax purposes for the facilities constructed by the contributions and advances. HELCO would need to keep continuous track of the whereabouts of the contributors and customers until the depreciation and deductions are exhausted.

Fourth, HELCO contends that placing the burden of paying the taxes associated with CIAC and customer advances on contributors and customers, who in many cases are developers of real property, will detrimentally affect economic development and the State policy of encouraging energy and affordable housing. This argument is premised on HELCO's belief that developers would not accept the notion that they must pay a tax on their contributions or advances. Fifth,

HELCO notes that it is merely following its tariff in not charging those making the contributions or advances for the taxes attributable to the contributions or advances.

Finally, HELCO asserts that, if the negative deferred taxes on account of CIAC and customer advances are not recognized for ratemaking purposes, HELCO may be deemed to be in violation of the normalization rules under the Internal Revenue Code, potentially resulting in a disallowance of any accelerated depreciation by HELCO. The ability of HELCO to take accelerated depreciation benefits HELCO's customers through the creation of positive deferred taxes, which results in a deduction from rate base.

The commission has in past cases subscribed to the position that the cost causer should bear the burden of the cost of providing the appropriate service. We believe this to be a reasonable principle. The CA's argument that HELCO should have grossed up the CIAC and customer advances and its proposal that the commission require HELCO to gross up all future CIAC and customer advances are in accord with this principle. However, for the reasons stated below, the commission will not exclude negative deferred taxes associated with receipts of CIAC and customer advances in calculating HELCO's deferred income taxes and will not in this docket require HELCO to gross up future CIAC and customer advances.

With respect to CIAC and customer advances received since the 1986 TRA, I.R.S. Notice 87-82, 1987-2 C.B. 389, and Letter Ruling 90-35-056 (Sept. 10, 1990), both issued by the Internal Revenue Service, appear to deter any commission action to exclude negative deferred taxes associated with receipts of CIAC and customer advances in computing deferred income taxes. Notice 87-82, issued shortly after the passage of the 1986 TRA, requires utilities to use the normalization method of accounting with respect to CIAC property in accordance with the normalization rules under Internal Revenue Code (I.R.C.) §§ 167 and 168. The basis of the notice is that the treatment of CIAC property as depreciable assets under the 1986 TRA creates book and tax timing differences.

Notice 87-82 makes an exception to the use of the normalization method. It provides that the normalization rules need not be applied if (1) the CIAC is included in the utility's taxable income for tax purposes; (2) the utility uses the noninclusion method of accounting for CIAC¹²; (3) the federal income tax attributable to the receipt of the CIAC is not taken into account in determining cost of service; and (4) the contributor pays the utility an additional amount that is reasonably intended to indemnify or reimburse the utility for the prepayment of tax resulting from receipt of the CIAC (i.e., if the CIAC is grossed up). As required by Notice 87-82, HELCO has normalized its receipts of CIAC and customer advances.

Letter Ruling 90-35-056 declares that reversing negative deferred taxes and thereby decreasing the rate base of a utility would constitute a violation of the normalization requirements of I.R.C. § 168(f)(2). A violation of the normalization requirements means, at least, an inability to take advantage of and to benefit from the accelerated depreciation provisions of the Code. The Service issued the letter ruling upon the request of an electric utility for the Services' assurances that a reversal of negative deferred taxes in compliance with an order of its governing commission does not constitute a violation of the normalization rules as set out in the Service's Notice 87-82.

The electric utility (as in the case of HELCO in this docket) had not collected from contributors the taxes associated with CIAC received after the 1986 TRA. It also had not treated the taxes associated with the receipt of the CIAC as a current expense. Rather, it had treated the tax as a prepayment of future taxes and had reduced its reserve for deferred taxes. In 1988, the utility sought a rate increase and proposed an increase in its rate base to annualize the retroactive adjustment to reflect normalization accounting (the reduction of its deferred tax reserve) for the CIAC book and tax timing differences on all CIAC received after 1986. The commission ruled that the utility should have collected the associated taxes from the contributors and refused to include an amount in the rate base to reflect the negative deferred taxes; it ordered the reversal of the accounting entries previously recorded by the utility.

In holding that the rate order compelling the utility to reverse the negative deferred taxes with respect to contributions that were not grossed up would violate [Notice 87-82](#), the Service stated:

The firm has adopted a normalization method that actually reflects the character of the contributions and is in accordance with [Notice 87-82](#). Accordingly, in this case, post-1986 CIACs, that were not grossed up and consequently are normalized as set out in the notice, cannot be treated as grossed up when the utility did not actually receive the taxes associated with CIACs from contributors.

In light of the requirements of [Notice 87-82](#) and the declaration in [Letter Ruling 90-35-056](#), the commission is constrained from requiring HELCO to exclude negative deferred taxes on account of CIAC and customer advances received in the past without being grossed up. HELCO (and ultimately its ratepayers) should not be placed in jeopardy by a finding of violation of [Notice 87-82](#) as a result of the commission's actions.

With respect to future receipts of CIAC and customer advances, there appears to be some merit in the CA's argument that HELCO should be required to gross up the contributions and advances to include the income taxes associated with such receipts. We are, however, uncertain as to the full ramifications of such a requirement. Requiring a gross-up does not appear to cause a utility to violate any rules of the Service or the Internal Revenue Code. However, we are not certain of the benefits to HELCO and to its ratepayers that may be foregone by such a requirement and the appropriate scope of the application of such a requirement. Given such uncertainties, the commission believes that the issue of whether utilities should be required to gross up contributions and advances should be subject to intensive examination in a separate, generic docket, in which all utilities would be parties. We will, shortly after the issuance of this decision and order, commence such a docket.

In the docket to explore the gross-up issue, we will also examine whether, if a gross-up is ordered, a utility may adopt the Missouri approach to alleviate the problem advanced by HELCO that such a gross-up requirement will impose undue administrative burden on the utility. As noted above, HELCO expresses concern about the difficulties in keeping track of the whereabouts of contributors and customers for the purpose of refunding to them the amounts of the taxes collected on account of CIAC and customer advances as depreciation is taken on the facilities constructed by the CIAC and as advances are returned. Such refunds may be stretched over extended periods.

The [Missouri approach](#), as set forth in [In re St. Louis County Water Co.](#), 79 PUR4th 581 (1986), permits the utility to deduct from the grossed-up amount the estimated present value of the future tax savings that the utility may realize as a result of the contributions and advances. In the Missouri case, the Missouri Public Service Commission allowed each of the utilities to calculate the present value at a discount rate equal to the overall rate of return allowed in the utility's latest rate case. This Missouri approach allows for a one time calculation which will discount the amount to be paid to the utility by contributors and customers. Obviously, such an approach will not be completely accurate, and there may be some residual impact on ratepayers under such discount methodology. Nevertheless, such an approach is worthy of exploration in the generic docket to meet such administrative problems that the utilities may encounter under a gross-up requirement.

Based on the foregoing, we accept HELCO's projections of \$6,299,000 in accumulated deferred income taxes and \$863,000 in unamortized ITC for the test year.

3. Income taxes

The parties agree on the method and tax rate used to calculate the test year income tax expense. The expense is computed by applying a composite federal and state income tax rate of 37.9699 per cent to the taxable income for the test year. HELCO's estimate of income taxes for the test year is \$5,253,000. The CA's estimate is \$9,037,000. The difference is principally in the parties' differing estimates of operating income and expenses, which are discussed elsewhere in this

decision and order. The parties, however, also differ in the amounts of certain specific adjustments that need to be made to operating income before computing the income tax expense.

a.

One specific adjustment on which the parties initially differed was the amount of interest on debt to be deducted from operating income in computing income taxes. However, on rebuttal, HELCO accepted the CA's method and amount. The CA's estimate is \$4,973,000. However, this amount is based on an end-of-test year debt structure. The use of an end-of-test year debt structure is inconsistent with the CA's use of an average test year rate base, although it is consistent with HELCO's proposal to use an end-of-test year rate base. As will be noted later, the commission approves the CA's average rate base. In light of our decision to utilize an average test year rate base, the CA's estimate of \$4,973,000 needs to be modified to reflect an average interest for the test year. We use the data that the CA used in deriving this average interest.

The CA's year-end figure of \$4,973,000 is calculated as follows: \$5,129,429 (cost of long-term debt), less \$186,000 (debt portion of allowance for funds used during construction) plus \$30,000 (interest on customer deposits). The resulting \$4,973,429 is rounded to \$4,973,000. We calculate the average interest cost for the test year thus: \$4,259,609 (interest on long-term debt at the beginning of the test year) plus \$5,129,429 (current cost of long-term debt) divided by two; from the resulting \$4,694,519, subtract \$186,000 (debt portion of allowance for funds used during construction) plus \$30,000 (interest on customer deposits). The result is \$4,538,519. Round this figure to \$4,539,000. We conclude that this sum of \$4,539,000 is the proper interest expense deduction in calculating the company's income tax amount.

b.

The more serious difference between HELCO and the CA in computing income taxes for ratemaking purposes is the amount by which book depreciation should be adjusted (i.e., reduced) to arrive at a depreciation amount that is deductible from operating income. The effect of the adjustment is to increase operating income, which, in turn, increases taxable income.

There are two basic components in this adjustment. One involves capitalized employee benefits, payroll taxes, and use taxes incurred in the construction of assets; the other involves capitalized allowance for funds used during construction (AFUDC). HELCO's adjustment is \$250,000 for employee benefits, payroll taxes, and use taxes and \$286,000 for AFUDC, for a total of \$536,000. The CA's adjustment is \$46,000 for employee benefits, payroll taxes, and use taxes and \$141,000 for AFUDC, for a total of \$187,000.

(i)

The sum of \$204,000 separates HELCO and the CA in the computation of the tax depreciation adjustment for capitalized employee benefits, payroll taxes, and use taxes. This is nearly all of HELCO's proposed adjustment of \$250,000. The difference arises from the CA's limiting the adjustment to those employee benefits, payroll taxes, and use tax amounts capitalized in the test years of HELCO's last three rate cases (Dockets No. 2186, No. 2595, and No. 2993). The CA limits the adjustment to these amounts because, it asserts, it was only in the test years of those three rate cases that the costs of employee benefits, payroll taxes, and use taxes associated with construction were both capitalized for ratemaking purposes and expensed in the company's income tax computation. The CA asserts that no such double deductions occurred for costs associated with capital construction in the years between rate cases.

HELCO objects to the CA's use of only the sum of the flow-throughs in prior rate case test years. It contends that, contrary to the implication inherent in the CA's position, the flow-throughs of tax benefits associated with the capitalized items do not occur only in the rate case test years. It occurs in the years between rate cases as well. By flowing through

the tax benefit in a rate case, the electric rates are lower than they would otherwise be, and these rates continue to be lower, to the benefit of ratepayers, in the years between rate cases. Moreover, HELCO asserts, the use of prior rate case test year estimates are not appropriate in succeeding rate proceedings. In each succeeding rate case, the estimates are updated for actual balances and new and better estimates are made, based on current information.

Both HELCO and the CA cite our Decision and Order No. 9049, issued on January 30, 1987, in Docket No. 5658 (*In re Hawaiian Electric Co.*, [82 PUR4th 218]). Docket No. 5658 was a generic docket, in which HELCO, HECO, MECO, GASCO, the Kauai Electric Division of Citizens Utilities Company, and the GTE Hawaiian Telephone Company were parties. The issue in the docket was whether the book depreciation expenses used in the calculation of income taxes for ratemaking purposes should be adjusted (that is, reduced) by the depreciation amounts associated with (1) employee benefits, payroll taxes, and use taxes (incurred in the construction of assets) which are capitalized on the books but also expensed for income tax purposes in the year incurred and (2) allowance for funds used during construction (AFUDC).

By Decision and Order No. 9049, the commission recognized and ordered that a depreciation adjustment for these items, if just and reasonable, 'can be utilized in the calculation of income taxes for ratemaking purposes.' However, it left to future rate cases the issue of the amount and calculation of the depreciation adjustment. The difference between HELCO and the CA is in the calculation of the adjustment and in the interpretation and application of Decision and Order No. 9049.

The thrust of Decision and Order No. 9049 is the elimination of a double deduction that occurs when an expense is capitalized on the books but also expensed for income tax purposes. We do not agree with the CA that such double deduction occurred only in the test years of the past three rate cases. The commission agrees with HELCO's position regarding the calculation of the effect of employee benefits, payroll taxes, and use taxes on the depreciation adjustment. The commission believes that the adjustment should include all the appropriate figures from 1967 to 1981. The CA has limited the adjustment to only those depreciation expenses contained in the last three rate cases. HELCO has made its calculation on the basis of the 1967 to 1981 figures. The figure for the employee benefits, payroll tax and use tax portion of the depreciation adjustment is therefore \$250,000.

(ii)

The difference between HELCO and the CA in the computation of the adjustment for AFUDC is the result of HELCO including in the computation both the debt and the equity components of AFUDC, and the CA including only the debt component, and not the equity component. AFUDC is a concept of capitalizing the costs of funds used in the construction of work in progress. In computing the AFUDC amount, HELCO assumed that funds used for construction are drawn proportionately from each component of HELCO's capital structure. The rates applied in computing are (1) for the common equity component, the rate found by the commission to be fair and reasonable in the most recent rate decision for the company, and (2) for the debt component, the embedded cost.

The CA excluded the equity component in computing the adjustment for AFUDC, because, it asserts, the equity component is a pre-tax amount—i.e., it has not been flowed through in computing the company's income tax. It agrees that the debt component of AFUDC is included within interest expense, and thus, has been flowed through and is, thus, an after-tax (net-of-tax) amount and should be included in the adjustment for AFUDC.

HELCO asserts that, by Decision and Order No. 9049 in Docket No. 5658, the commission recognized that both the equity portion of AFUDC and the after-tax debt component of AFUDC give rise to permanent book and tax differences that must be taken into account in the depreciation adjustment. It claims that the CA does not understand the tax depreciation adjustment relating to the equity portion of AFUDC and that the CA only confuses the issue by its discussion of whether the equity component of AFUDC is pre-tax or after-tax. HELCO maintains that the tax depreciation adjustment with respect to the equity component of AFUDC does not arise out of the prior flow-through of

an associated tax benefit. It concludes that the depreciation expense related to capitalized AFUDC should be excluded from the income tax computation for ratemaking purposes because the entire amount of AFUDC is a permanent book and tax difference which has no income tax impact.

HELCO is correct in its reading of Decision and Order No. 9049. In that decision, the commission concluded that '[AFUDC] should not be part of the basis upon which income tax depreciation is calculated and should not be included as part of total depreciable expenses in computing the depreciation deduction for income taxes.' We did not qualify our conclusion in any way and did not distinguish between the equity component and the debt component of AFUDC. The fact that one component amount is a pre-tax and the other an after-tax amount is not germane. We need to distinguish between the purpose of adjusting for capitalized employee benefits, payroll taxes, and use taxes and the purpose of adjusting for AFUDC.

For capitalized employee benefits, payroll taxes, and use taxes, the purpose is to obviate a double deduction. For AFUDC, the purpose is to recognize that AFUDC is not deductible in computing income tax. We made this plain in our decision and order when we stated that the purpose of the depreciation adjustment is 'to recognize that expenses once taken as income tax deductions cannot be taken again as deductions for income tax purposes *and* to recognize that AFUDC is not allowable as an income tax deduction.' (Emphasis added.) We, thus, conclude that the depreciation amount in computing income tax for this docket's ratemaking purposes should be reduced by \$256,000 on account of AFUDC.

The resulting proposed depreciation adjustment of \$536,000 is reasonable: \$250,000 on account of capitalized employee benefits, payroll taxes, and use taxes and \$286,000 on account of AFUDC.

c.

There are other relatively minor differences between HELCO and the CA in the calculation of income taxes for the test year. These differences include HELCO's proposal to deduct \$13,000 for meals and entertainment and \$6,000 for keyman insurance premiums in determining taxable income. The CA would allow none of them. There is also a difference between HELCO and the CA on the amount of State investment tax credit. HELCO claims \$22,000, while the CA proposes \$17,000. The commission accepts HELCO's position on these items. HELCO's position is reasonable and in agreement with the existing tax laws.

In summary, we conclude that the income tax amounts of \$3,267,000 under present rates and \$4,846,000 under proposed rates are reasonable.

v.

RATE BASE

HELCO's estimate of its 1990 test year rate base is \$129,819,000 at proposed rates. The CA's estimate is \$115,756,000. There is a difference in excess of \$14,000,000.

The parties agree on the amounts to be included in the rate base for (1) property held for future use (\$1,000 at year-end 1990), (2) materials and supplies inventory (\$1,961,000 at year-end 1990), and (3) fuel oil inventory (\$1,476,000). The materials and supplies inventory includes production material inventory (\$420,000 at year-end 1990) and transmission and distribution inventory (\$1,541,000 at year-end 1990).

The difference of \$14,000,000 between HELCO's estimate and the CA's estimate of the 1990 test year rate base arises from (1) HELCO's use of a year-end rate base and the CA's use of an average year rate base, (2) the parties' different

estimates of depreciated plant-in-service, working cash (capital), and operating cash balance to be included in the rate base, and (3) the parties' differing estimates of accumulated deferred income taxes that are to be deducted from the rate base. The parties agree on the amounts to be included in the rate base for property held for future use, material and supplies inventory, and fuel oil inventory. They also agree on the amounts for contributions in aid of construction, customer advances, customer deposits, and unamortized investment tax credits, all of which are to be deducted from the rate base. A discussion of the parties' positions on each of these items follows.

A. The Base

HELCO proposes that its revenue requirements in this rate case be determined on the basis of a year-end rate base. It asserts that the use of a year-end rate base will combat the effects of attrition. It alleges that HELCO is suffering and will continue to suffer from the effects of attrition. It claims that HELCO's rate base has been increasing faster than sales and that it has not earned its allowed rate of return on rate base since at least 1980. It asserts that its rate of return has dropped dramatically in 1988 due to attrition. HELCO represents that it will continue to suffer from the effects of attrition even after the rates approved by the commission in this docket go into effect. It estimates that the kwh sales in the test year will be about 4.9 per cent higher than sales in 1989, and the rate base at the end of the year will be about 5.6 per cent greater than that at the beginning of the test year.

The CA's position is that we should stay with the average year rate base adopted by the commission in past rate cases. It asserts that a year-end rate base is inconsistent with the use of average revenues and expenses in determining revenue requirements. The CA notes that a year-end rate base has been used by the commission only in instances of high inflation and rising costs.

The CA challenges HELCO's claim of the need to adopt a year-end rate base to combat attrition. The CA believes that the solution to a falling rate of return, when it occurs, is an application for a rate increase and not preemption in the present docket of anticipated future attrition by raising the company's revenue requirements above that to which it is otherwise entitled. The CA contends that the employment of a future test year and the various adjustments traditionally approved by the commission satisfactorily address whatever attrition problem there may be that cannot be addressed by more frequent rate filings. The CA warns that the use of a year-end rate base, in addition to the use of a future test year and various adjustments, would almost certainly result in significant excess recovery to the company, to the detriment of ratepayers.

We see no reason to depart in this docket from our traditional practice of using the average test year rate base. The causes of attrition are many and varied. HELCO has made no attrition study. It has presented little evidence on the causes and effects of expected attrition, and it has presented no alternatives to counter attrition, other than a change to a year-end rate base. The commission believes that the interim rate increases granted on May 21, 1990, and the rate increases granted by this order should minimize any attrition problem. Finally, as the CA points out, HELCO has the option of filing for further rate increases should earnings deteriorate in the future.

B. Depreciated Plant-In-Service

HELCO's estimate of plant-in-service is \$171,942,000. The CA's forecast is \$171,689,000. The difference of \$253,000 is due to differing estimates of plant additions and accumulated depreciation, as follows:

<i>HELCO</i>	<i>CA</i>	<i>Difference</i>
(\$000)	(\$000)	(\$000)

Beg. 1990 plant-in-service	236,346	236,339	7
Add:			
1990 plant additions	23,423	22,256	1,167
Less:			
1990 plant retirements	2,299	2,299	0
End 1990 plant-in-service	257,470	256,296	1,174
Less: acc. depreciation	85,528	84,607	(921)
Net plant-in-service	171,942	171,689	253

1. Plant-in-service

The CA has accepted HELCO's estimate of the amount of plant-in-service at the beginning of the test year and the amount of 1991 plant retirements. However, the CA's estimate of 1990 plant additions is \$1,167,000 less than that estimated by HELCO. The CA's estimate of plant additions is based on HELCO's representations made in its rebuttal testimony concerning the amount of capital projects carried over from 1989 to 1990 and the amount of projects initially intended for 1990 being deferred to 1991. HELCO represented that \$1,791,500 worth of 1989 projects was carried over to 1990, and \$2,958,600 worth of 1990 projects will be deferred to 1991 due to financial constraints.

Based on these representations, the CA's estimates of 1990 plant additions of \$22,256,000 and year-end plant-in-service of \$256,296,000 would be correct. Despite its representations, HELCO has chosen not to alter its 1990 plant additions estimate, because, it asserts, the estimate represents a normalized level of additions. HELCO states that the projects deferred from 1990 to 1991 could be reinstated as 1990 projects, if HELCO's financial condition improves.

Our review of the record reveals several discrepancies in the amount of projects represented by HELCO as having been carried over from 1989 to 1990¹³ and in the amount of projects deferred from 1990 to 1991.¹⁴ Based on the record, we have revised the amount of 1989 projects carried over to 1990 to \$862,800, and the amount of 1990 projects deferred to 1991 to \$2,937,600.

When the revised figures are taken into account, the estimated 1990 plant additions should be \$21,348,000, and the estimated amount of plant-in-service by year-end 1990 should be \$255,388,000. The revised estimate of \$21,348,000 in 1990 plant additions is 9 per cent lower than HELCO's forecasted amount. This is in line with HELCO's 1989 plant addition experience. The 1989 plant additions were 9 per cent below HELCO's forecast. Based on our analysis, we find the adjusted 1990 plant addition estimate of \$21,348,000 to be reasonable. We also find reasonable HELCO's plant retirement estimate of \$2,299,000.

2. Accumulated depreciation

For accumulated depreciation, the CA accepts HELCO's calculation, except in one respect. It disagrees with HELCO's estimate of depreciation accrual. HELCO's estimate is \$10,308,000, and the CA's estimate is \$9,387,000. The following table highlights the difference in each party's calculation of accumulated depreciation.

	<i>HELCO</i>	<i>CA</i>
	(\$000)	(\$000)
Beg. 1990 acc. depr.	77,055	77,055
Depreciation accrual	10,308	9,387
Salvage	134	134
Less:		
Retirements	(1,413)	(1,413)
Cost of removals	(556)	(556)
End 1990 acc. depr.	85,528	84,607

We previously held HELCO's estimate of depreciation accrual to be unacceptable and accepted the CA's estimate of \$9,387,000. Thus, we adopt the CA's estimate of accumulated depreciation of \$84,607,000. The resulting net plant-in-service of \$170,781,000 is reasonable.

C. Property Held For Future Use

The CA accepts HELCO's forecast of \$1,000 for the test year amount of property held for future use. We find the amount to be reasonable.

D. Materials and Supplies

The CA accepts HELCO's estimates for materials and supplies of \$1,878,000 at the beginning of the test year and \$1,961,000 at the end of the test year. These estimates are reasonable.

E. Fuel Oil Inventory

HELCO's recorded fuel oil inventory for 1989 was \$1,792,000. The CA has no quarrels with this figure, and we accept it for the purposes of this docket.

HELCO's estimate of the test year fuel oil inventory is \$1,476,000. The CA agrees with this estimate. HELCO's initial forecast was \$1,365,000. The initial forecast was computed on the basis of the estimated amount of fuel oil inventory required for each of HELCO's generating units. In revising its estimate, HELCO accepted the CA's method of forecasting fuel oil inventory. The CA utilized a computer production simulation model to estimate the total barrels of fuel oil

required in the test year. The CA also used the January 1, 1990, fuel oil prices and a 24-day inventory for no. 6 fuel oil. The CA accepted HELCO's 30-day inventory for no. 2 diesel oil. The forecast of \$1,476,000 is reasonable.

F. Working Cash

Working cash (or cash working capital) is the amount of money provided by HELCO's investors, over and above the investment in plant and other specifically identified rate base items, to bridge the gap between the time expenditures are required to be made to provide service and the time collections (revenues) are received for that service. HELCO's estimate of working cash for the 1990 test year is \$1,945,000 at present rates and \$1,995,000 at proposed rates. The CA's figures are \$716,000 at present rates and a negative \$215,000 at proposed rates.

The working cash requirements for the various items for which cash from investors is required to bridge the time between expenditures and collections are calculated by (1) determining the average number of days between paying for the item and collecting revenues to cover that payment (net collection lag), (2) calculating the average expenditures per day, and (3) multiplying the net collection lag by the average expenditures per day. The net collection lag is equal to the revenue collection lag minus the payment lag.

The parties agree on most of the items for which working cash requirements should be calculated, but disagree on a few. On the items they agree, they also agree on revenue collection lag and payment lag. The items that the parties agree should be included in the calculation of working cash and the revenue collection lag and the payment lag for these items are as follows.

	<i>Collection Lag Days</i>	<i>Payment Lag Days</i>
Expenses Requiring Cash:		
Fuel Oil Purchases	39	20
Purchased Power	39	28
O&M Labor	39	11
O&M Nonlabor	39	24
Expenses Providing Cash:		
Revenue Taxes	39	91
Income Taxes	39	84

The parties disagree on the inclusion of cash requirements for depreciation expenses, deferred taxes, and return on common equity. HELCO proposes to include and the CA proposes to exclude the requirements for these items. The parties also disagree on the inclusion of interest expense and preferred dividends in the calculation of working cash. HELCO would exclude these items, while the CA would include them in the calculation. The inclusion of interest expense and preferred dividends in the calculation of working cash operates, in the same manner as the inclusion of revenue taxes and income taxes, to reduce the amount of working cash required.

1. Depreciation expenses, deferred income taxes

The CA excludes depreciation expenses and deferred income taxes because neither is a cash payment for which the company must look to investors to fund. Investors are not required to supply cash for these expenses in advance of the collection of revenues. By definition, the CA urges that working cash requirements must be determined on a cash, not an accrual, basis. The CA cites the commission's Decision and Order No. 8570, issued on December 12, 1985, in Docket No. 5081 (*In re Hawaiian Electric Co.*). In that decision and order, the commission agreed with the CA that depreciation expenses and deferred taxes do not require cash outlays and disallowed the inclusion of these items in calculating working cash.

HELCO urges that depreciation expenses and deferred taxes be included in the computation of working cash, because these two balances are deducted from the assets serving customers before all of the funds represented by the balances are actually received from the customers. Depreciation expenses and deferred taxes are deducted from the assets immediately as they are recognized; however, the funds represented by depreciation expenses and deferred taxes are not actually received through revenue collections until an average of 39 days after each expense is recognized. HELCO asserts that noninclusion of depreciation expenses and deferred taxes results in an understatement of the company's total cash investment. Unless included, the 39-day lag in revenue collection would result in investors losing the opportunity to earn a return on that investment.

For the reasons stated by the CA and in our Decision and Order No. 8570, we exclude depreciation expenses and deferred taxes in the computation of working cash. We adhere to our rationale that the purpose of working cash allowance is to compensate investors for the use value of their money where the company is required to pay expenses by *the outlay of cash* before receiving from ratepayers the revenues associated with the expenses. Depreciation expenses and deferred taxes are noncash expenses; they do not require the outlay of cash.

2. Common equity

The CA excludes return on common equity in the computation of working cash, because it is a residual income account, and there is no cash working capital requirement associated with it. It argues that allowing the inclusion of return on common equity in the computation results in ratepayers paying a return on the shareholder's interest through both the rate of return and the cash working capital allowance. The CA again cites our Decision and Order No. 8570 in Docket No. 5081. There, we did not allow the inclusion of return on common equity in the computation of working cash, because, as the CA argued in that docket, 'the return on common equity is the responsibility of the utility and . . . it is not an expense incurred in providing the service to which the revenue relates.'

HELCO denies that customers would be paying a return on the shareholder's interest through both the rate of return and cash working capital allowance if return on common equity is included in computing working cash. HELCO asserts that, by including return on common equity in the working cash computation, customers will be paying only an amount sufficient to provide investors with the opportunity to earn the allowed rate of return. It argues that, if the CA's proposal is followed, it is tantamount to promising investors an opportunity to earn a given rate of return, but making them wait 39 days to collect that return. The lag results in the investors not earning the allowed rate of return.

We are not persuaded that we should depart from Decision and Order No. 8570. HELCO presents no arguments not already considered in Docket No. 5081. Return on common equity does not represent any expense incurred in providing service to which any revenue relates. Thus, return on common equity is excluded from consideration in computing working cash.

3. Interest expense, preferred dividends

The CA includes in the computation of working cash interest expense and preferred dividends, because each is precollected from ratepayers and the obligation to pay them is known and certain as to the quantity and time of payment. During the period of time between the company's collection of these funds from ratepayers and the disbursement of the dividend, the funds are at the company's disposal and may be used for any corporate purpose.

HELCO argues that the CA is inconsistent in insisting on the exclusion of return on common equity but on the inclusion of interest expense and preferred dividends in computing working cash. It contends that in *In re Hawaiian Telephone Co.*, Docket No. 4588, Decision and Order No. 8042 (Aug. 14, 1984), the commission agreed with the Hawaiian Telephone Company that the cash working capital requirements for interest expense, preferred dividends, and return on common equity should be collectively included or excluded from rate base calculation. HELCO represents that these items could be excluded if they offset each other.

HELCO claims, however, that in this docket, the working cash requirement of the return on common equity is significantly higher than the cash working capital provided by interest expense and preferred dividends. Hence, if interest expense and preferred dividends are to be included in computing working cash, so should return on common equity, and vice-versa. HELCO also notes that the CA's 'one-sided approach' of including interest expense and preferred dividends but not return on common equity was rejected by the commission in *In re Hawaiian Electric Co.*, 56 PUR4th 398 (1983).

HELCO is correct in its reading of Decision and Order No. 8042. Return on common equity, interest expense, and preferred dividends should be dealt with collectively and included or excluded as a whole in computing working cash. However, we disagree with HELCO that these items should be included if return on common equity, on one hand, and interest expense and preferred dividends, on the other, do not offset each other. Just as return on common equity is excluded from computing working cash because it is not an expense incurred in providing service to which revenues may relate, the receipts on account of interest expense and preferred dividends are not revenues to which the expense of providing service may relate. The fact that the receipts may consist of cash is not relevant. Furthermore, with respect to preferred dividends, preferred equity (as well as common equity) belongs to the company, and, therefore, we cannot expect the company to use the related revenues as working cash. Thus, we exclude interest expense and preferred dividends in the computation of working cash.

4. Conclusion

There are other differences between HELCO's calculation and the CA's calculation of working cash, but these other differences relate to differences in the amounts for O&M labor and O&M nonlabor expenses and differences in revenue taxes arising from the use of different revenue figures. These differences were discussed earlier in this decision and order.

We exclude depreciation expenses, deferred taxes, return on common equity, interest expense, and preferred dividends in computing working cash. We conclude that the amount of working cash at present rates is \$1,088,000 and at HELCO's proposed rates is \$838,000.

G. Operating Cash Balance

HELCO's estimate of operating cash balance is \$500,000 for the test year. The CA recommends that no operating cash balance be recognized as an item in the calculation of the rate base. HELCO maintains that an operating cash balance is needed to ensure smooth and economical operation of the company. It contends that the company must maintain certain balances just to handle the unpredictability of cash needs and cash inflows. With an operating cash balance, HELCO represents that paying of bills can be better planned and the administrative burden of more frequent borrowings of funds to meet cash needs can be eliminated. It says that an operating cash balance will provide the company with essential operating flexibility.

The CA's principal objection to the inclusion of operating cash balance as a rate base item is that there is no evidence to suggest that HELCO's operating cash balance is provided by its investors. It argues that ratepayers should not have to pay a return on money that cannot be shown to be provided by the company's investors. HELCO's response to this argument is that it is not necessary to prove that the specific dollars represented by operating cash balance come from HELCO's investors. It argues that in a rate base determination, when all funds supplied by noninvestors (except the 1971 and subsequent unamortized investment tax credit balances) are deducted from the total investment in assets serving customers, the remainder can only be funds supplied by investors (and the 1971 and subsequent unamortized ITC balances). This net investment, HELCO claims, should be allowed to earn a return.

We are in agreement with the CA and will disallow the inclusion of operating cash balance as an item in the rate base. There is no assurance that the operating cash balance is investor-supplied funds. As the CA points out, it is impossible to subtract 'all funds supplied by noninvestors' to arrive at an amount that can be said to be supplied by investors. Our denial of the inclusion of operating cash balance as a rate base item is in consonant with our prior decisions in the cases cited by the CA. See *In re Maui Elec. Co.*, Docket No. 4691, Decision and Order No. 8048 (Aug. 20, 1984); *In re Hawaiian Elec. Co.*, 56 PUR4th 398 (1983); and *In re Hawaii Elec. Light Co.*, Docket No. 4833, Decision and Order No. 8179 (Nov. 23, 1984). In all those cases we denied the inclusion of operating cash balances (referred to in the cases as compensating bank balance) as a rate base item.

H. Unamortized Contributions in Aid of Construction

Contributions in aid of construction (CIAC) are nonrefundable funds paid to the company by customers to defray the costs of installing facilities (generally underground line extension facilities) needed to provide service to them. The facilities constructed with these contributions are not financed by the company with debt or equity; thus, ratepayers should not have to pay a return on these plant investments. The contributions must, therefore, be deducted from the rate base.

The CA agrees with HELCO's estimate of the amount of unamortized CIAC. The unamortized CIAC balances are projected at \$23,095,000 for 1989 and \$29,890,000 for the test year 1990. The amounts appear reasonable, in light of the number of forecasted projects. The commission accepts these numbers.

I. Customer Advances

Customer advances, like CIAC, are funds paid to the company by customers to defray the costs of installing facilities (generally overhead line facilities) needed to provide service to them. They differ from CIAC, however, in that they are refundable. They constitute an obligation on the part of the company. However, like in the case of CIAC, the plant constructed with customer advances are not financed by the utility with debt or equity, and, thus, ratepayers should not have to pay a return on these plant investments. Customer advances, like CIAC, must be deducted from the rate base.

The CA projects customer advances at \$11,749,000 for 1989. HELCO and the CA both forecast customer advances at \$10,504,000 for the test year 1990. We find these figures to be reasonable.

J. Accumulated Deferred Income Taxes

Accumulated deferred income taxes, like unamortized CIAC and customer advances, are deducted from the company's rate base. HELCO's estimate for accumulated deferred income taxes as of year-end 1990 is \$6,299,000. The actual balance as of December 31, 1989, was \$6,157,000. The CA's estimate for accumulated deferred income taxes as of year-end 1990 is \$14,159,000. Its calculation of the actual balance as of December 31, 1989, is \$13,530,000. The CA's estimate as of

year-end 1990 and its calculation as of December 31, 1989, are higher than HELCO's, because the CA has excluded the negative deferred income taxes associated with CIAC and customer advances. The propriety of this exclusion was discussed earlier in this decision and order.

In accordance with our decision concerning the CA's exclusion of negative deferred income taxes, our conclusion is that the proper and reasonable estimate of the accumulated deferred income taxes is \$6,157,000 for year-end 1989 and \$6,299,000 for year-end 1990.

K. Customer Deposits

Customer deposits are moneys collected from customers who do not meet HELCO's criteria for establishing credit at the time they start service under rule 5 of the utility's tariff. The deposits are held until the customers have one year of prompt payment experience or until they close their accounts or their customer status is terminated for nonpayment. Customer deposits are not funds supplied by HELCO's investors and are, therefore, deducted from the rate base. The CA accepts HELCO's projection of customer deposits of \$500,000 at year-end 1990 and \$460,000 at year-end 1989. These estimates are reasonable for purposes of this docket.

L. Unamortized Investment Tax Credits

HELCO's estimate of the unamortized investment tax credit balance is \$863,000 at the end of 1990 and \$754,000 at the end of 1989. The CA accepts HELCO's estimates.

The unamortized investment tax credits taken under the Revenue Act of 1962 and the State investment tax credits are subtracted from assets serving customers, pursuant to Decision and Order No. 8179 in Docket No. 4833. However, federal investment tax credits taken in 1971 and in the years following are not deducted in the rate base calculation; they are, rather, amortized as a credit in determining operating income over 30 years. Under the 1971 Revenue Act, HELCO is required to share the benefits of the federal investment tax credits with its customers. The act provides an option to the company to accomplish this sharing by amortizing the credits to customers over the life of the assets. HELCO elected the option, with the approval of this commission. As a result, since 1971 the unamortized balance of federal investment tax credits is not deducted in the rate base calculation.

The commission accepts HELCO's estimate of the balance of unamortized investment tax credits as reasonable estimates.

M. Conclusion

Based on our analysis, we find a 1990 test year rate base of \$124,298,000 to be reasonable. The following table summarizes the calculation for this rate base.

	<i>12/31/89</i>	<i>12/31/90</i>
	(\$000)	(\$000)
Plant-in-service	236,339	255,388
Less: Acc. depreciation	77,055	84,607
Net plant-in-service	159,284	170,781

Add: Property held for

future use	1	1
------------	---	---

Materials & supplies	1,878	1,961
----------------------	-------	-------

Fuel oil inventory	1,792	1,476
--------------------	-------	-------

Total	162,955	174,219
-------	---------	---------

Less: Unamortized CIAC	23,095	29,890
------------------------	--------	--------

Customer advance	11,749	10,504
------------------	--------	--------

Acc. Def. Inc. Tax	6,157	6,299
--------------------	-------	-------

Customer deposit	460	500
------------------	-----	-----

Unamortized tax cr.	754	863
---------------------	-----	-----

Total	120,740	126,163
-------	---------	---------

Average		123,452
---------	--	---------

Add: Working cash		1,088
-------------------	--	-------

Rate base - Present Rates (1989)		124,540
----------------------------------	--	---------

Less change in working cash		(250)
-----------------------------	--	-------

Rate base - proposed rates (1990)		124,290
-----------------------------------	--	---------

VI.

RATE OF RETURN

HELCO submits that the range for a fair rate of return is 10.52 per cent to 10.74 per cent and proposes that the rate of return on its rate base for the normalized 1990 test year be 10.86 per cent. The CA puts forth that 10.28 per cent to 10.42 per cent constitutes the range for a fair rate of return and suggests that the commission adopt 10.28 per cent as the fair rate of return for HELCO.

At the outset, the commission reaffirms its ruling in prior decisions to adhere to the guidelines set forth in *Bluefield Waterworks and Improvement Co. v. Public Service Commission*, 262 U.S. 679, 1923D 11, 67 L.Ed. 1176, 43 S.Ct. 675 (1923), and *Federal Power Commission v. Hope Natural Gas Co.*, 320 U.S. 591, 51 PUR NS 193, 88 L.Ed. 333, 64 S.Ct. 281 (1944). In essence, the guidelines are threefold. A fair return must:

- (a) Be commensurate with returns on investment in other enterprises having corresponding risks and uncertainties;
- (b) Provide a return sufficient to cover the capital costs of the business, including service on the debt and dividends on the stock; and

(c) Provide a return sufficient to assure confidence in the financial integrity of the enterprises to maintain its credit and capital-attracting ability.

Both HELCO and the CA agree that a fair rate of return should be at least equal to HELCO's composite cost of capital, because the composite cost of capital represents the carrying cost of money received from investors to finance the net rate base. The composite cost of capital is composed of the earnings requirements on the elements of HELCO's capital structure, which include (1) short-term borrowing, (2) long-term debt, (3) preferred stock, and (4) common equity. The composite cost of capital is the sum of the weighted earnings requirements for each element of the capital structure. HELCO and the CA agree on the capital structure (i.e., the relative proportions of the elements making up the capital structure) and on the costs of debt and preferred stock, but disagree on the cost of common equity. We examine the agreements and disagreements in the sections that follow.

A. Capital Structure

HELCO's projected capital structure for year-end 1990 is:

	<i>Capitalization</i>	
	<i>Amount</i>	<i>Percent of</i>
	<i>in Thousands</i>	<i>Total</i>
Short-term debt	\$ 2,000	1.46%
Long-term debt	62,268	45.30%
Preferred stock	13,100	9.53%
Common equity	60,081	43.71%
Total	\$ 137,449	100.00%

HELCO and the CA agree that this projected capital structure is reasonable for ratemaking purposes, that it represents a balanced structure that is consistent with the company's goals of maintaining financial integrity and minimizing the cost of capital, and that the ratios of the elements in the structure are within the range of capitalization ratios for comparable electric utilities. The commission also concludes that the projected capital structure is reasonable.

We note that included in the projected capital structure are the entire principal amounts of the special purpose revenue bond series 1990A and 1990B, issued in January and July of 1990, respectively. However, the undrawn proceeds of the special purpose revenue bond series 1990C, issued in December 1990, are not included. They were excluded by an agreement of the parties, which agreement was approved by the commission in Order No. 10895, filed in this docket on December 21, 1990. The usual practice of the commission in rate cases is to include the undrawn proceeds from the sale of special purpose revenue bonds in the company's capital structure. However, in this instance, the commission concluded that it is reasonable not to include the undrawn proceeds from the 1990C issuance in HELCO's capital structure.

B. Cost of Short-Term Debt

HELCO's estimate of the cost of its projected \$2,000,000 short-term debt at year-end 1990 is 8 per cent. HELCO'S short-term borrowing represents short-term funds borrowed from HECO at commercial paper borrowing rates. The rate of

8 per cent represents HELCO's conservative estimate of the commercial paper borrowing rate for the test year 1990. HELCO estimated the commercial paper borrowing rate by adding the spread between the 1989 3-month commercial paper rate and the 3-month United States Treasury bill rate to the yield on futures contracts on 3-month United States Treasury bills scheduled for issuance in late 1989 and early 1990. The CA raised no objection to this cost calculation. We conclude that this cost is reasonable.

C. Cost of Long-Term Debt

HELCO's estimate of the cost of its projected \$62,268,000 of long-term debt at year-end 1990 is 8.2 per cent. This is the embedded composite interest rate for HELCO's long-term debt. The composite cost of 8.2 per cent includes the annual cost to amortize the debt premium and the expenses of issuance over the life of the various debt issues. It also includes the annual amortization of \$22,000 for the differential between interest earned and the sum of interest expenses and issuance costs related to special purpose revenue bonds held in trust before being drawn down. The CA's calculation of the cost of long-term debt is also 8.2 per cent. The long-term debt cost of 8.2 per cent is reasonable.

HELCO's original estimate of the cost of its projected long-term debt was 8.26 per cent. The estimate was reduced, because of events that occurred after the filing of its application in this docket. The company refinanced its series 1984 special purpose revenue bonds at an interest rate of 7.2 per cent and its series 1988 special purpose revenue bonds at an interest rate of 7.625 per cent. These refinancings were done by converting the bonds from a variable to a fixed rate. Also, HELCO had initially planned to issue \$13,000,000 of series 1989 special purpose revenue bonds at an estimated interest rate of 8 per cent. Instead, HELCO issued \$3,000,000 of series 1990A special purpose revenue bonds in early 1990 at an interest rate of 7.35 per cent. HELCO still planned, at the time of the filing of its brief, to issue an additional \$10,000,000 of series 1990B special purpose revenue bond later in 1990 at an estimated rate of 8 per cent.

D. Cost of Preferred Stock

HELCO's estimate of the cost of its projected \$13,100,000 of preferred stock at year-end 1990 is 9.48 per cent. The CA's estimate is also 9.48 per cent. HELCO's preferred stock cost of 9.48 per cent is reasonable.

HELCO issued its series F preferred stock in December 1989 at a dividend rate of 8.50 per cent. The annual cost rate for the series B-F preferred stock includes the annual dividend cost and the annual amortization of the issue expenses over the lives of each issue. The sinking fund requirements have been taken into account so that the issuance costs amortized in any one year are weighted to account for the balance outstanding in that year.

HELCO's original estimated cost of projected preferred stock was reduced from 9.64 per cent, because of a decrease in the actual from the estimated dividend rate for series F preferred stock issued in December 1989.

E. Cost of Common Equity

HELCO submits that the fair rate of return on the company's projected common equity of \$60,081,000 at year-end 1990, which includes a projected sale of \$9,000,000 of common stock to HECO, should be 14 per cent. The CA proposes 12.7 per cent as the fair rate of return.

HELCO and the CA agree that the cost of common equity should be derived from market information. HELCO and the CA also agree that multiple methods should be employed to determine a market-based return on common equity, because of the judgment and limitations inherent in all methods. HELCO and the CA further agree that the methods employed should be expectational, forward-looking, and long-term in view. Based on this approach, HELCO and the CA used a number of similar market-based estimation models. The difference in the recommended rates of return results

from the use of different groups of proxy companies to derive market-based return on common equity for HELCO, the use of market data from different times, and differences in judgment.

1. The proxies used

Both HELCO and the CA used proxy companies to develop a market-based cost of HELCO's common equity, because HELCO's common equity is not publicly traded. Under this methodology, it is assumed that the rate of return on common equity for these proxy companies is the return necessary for HELCO. Judgmental adjustments are made when the fit of the proxy companies' financial, operating, and business profiles to those of HELCO is incomplete.

HELCO used Hawaiian Electric Industries (HEI) as a proxy. HELCO argues that the use of HEI as a proxy is appropriate, because HEI, through HECO, owns all of HELCO's common stock, and HEI is viewed by the market essentially as an electric utility. HELCO also analyzed a group of eleven 'barometer' companies, but only to check on the reasonableness of the HEI-derived cost of common equity.

The CA analyzed a group of nine proxy or 'comparable' companies to develop a market-based cost of HELCO's common equity. Five of the companies in the CA's group of comparable companies were also in HELCO's group of barometer companies. The CA argues that the expected return on HEI stock is an inappropriate proxy for HELCO's cost of common equity. It is inappropriate, because HEI, as a holding company, includes diversified companies representing industries with higher market risks, and because HEI satisfies neither HELCO's nor the CA's selection criteria for 'barometer' or 'comparable' companies.

2. The methodologies applied

HELCO used three methods for developing an estimate of HELCO's return on common equity—the constant growth discounted cash flow (DCF) method, the capital asset pricing model (CAPM), and the risk premium (RP) method. HELCO also initially used a modified DCF method, but later abandoned it. The CA used two methods—the constant growth DCF method and the CAPM. All of the methods used by HELCO and the CA are market-based and expectational in nature and provide a quantitative basis for judging the rate of return on HELCO's common equity.

The constant growth DCF method is a stock valuation approach to estimating the cost of common equity. In this method, the required rate of return is the sum of: (1) the current dividend yield, represented by the ratio of expected next-period dividends to current stock price and (2) the expected constant dividend growth rate. The theory underlying the constant growth DCF approach is that the market price an investor pays for a share of stock represents the present value of expected future dividend yields, grown at a constant rate. The future flow of dividend yields is discounted at a rate reflecting investor preference for current income and investor assessment of dividend realization risk. The rate of return on common equity capital under the DCF model is, thus, that rate which compensates investors for risk and time, assuming that the security is efficiently priced. Estimation of the DCF rate of return requires estimates of the current dividend yield and the dividend growth rate.

Under the CAPM, the required rate of return is the sum of: (1) a risk-free rate of return, which represents a floor on expected returns and is generally measured by the return on riskless securities, such as United States Treasury securities, and (2) a risk premium, which represents an additional return over the riskless rate required to compensate investors for bearing additional risk. The risk premium is proportional to the 'nondiversifiable' (or 'systematic') risk of the security in question—that is, the security-specific risk that cannot be eliminated through diversification. The nondiversifiable risk is obtained by the application of a beta to the amount by which the average market rate of return exceeds the risk-free rate of return. A beta is a measure of the relative risk of a security compared to the risk of the average market stock. The beta for the market is set equal to 1. A stock with a beta greater than 1 is riskier than the average market stock, and a

stock with a beta less than 1 is less risky than the average market stock. Use of the CAPM to determine the rate of return on common equity requires estimates of the risk-free rate, the stock's beta, and the market rate of return.

The CA's expert describes the CAPM as a risk premium approach to estimating the cost of common equity. Under the RP method, the required rate of return is the sum of: (1) the cost of long-term debt, and (2) a risk premium for the additional risk borne by stockholders, as opposed to bondholders, arising from stockholders' residual claim to assets and earnings. The use of this RP method requires estimates of the cost of long-term debt and the premium for stockholders' additional risk.

3. The parties' analyses

HELCO's estimate of the rate of return on its common equity is based on the calculations made by its expert witness, Joseph F. Brennan. Mr. Brennan first estimated the rate of return on common equity for HEI and for the group of barometer companies. He estimated the rate for each by averaging: (1) the average of the DCF, CAPM, and RP results, with the DCF result weighted twice as heavily as each of the CAPM and RP results and (2) the average of the DCF, CAPM, and RP results, each weighted equally. The use of the average-of-averages approach resulted in heavier weight being given to the estimates derived from the use of the CAPM and the RP method than to the estimate derived from the use of the DCF method.¹⁵ The computations produced a rate of return on common equity for HEI of 13.25 per cent and for the group of barometer companies of 12.9 per cent. Mr. Brennan then estimated the rate of return on common equity for HELCO, based on the results for HEI and the group of barometer companies. Asserting that a higher rate of return is justified for HELCO, because its risk is higher than that of HEI or of the group of barometer companies, Mr. Brennan concluded that a rate of return in the range of 13.25 per cent to 13.75 per cent is reasonable for HELCO.

Based on Mr. Brennan's conclusion, which HELCO characterizes as extremely conservative, HELCO proposes a 14 per cent rate of return on common equity. It argues that a longer-term view should be taken in establishing a return on common equity and that the rate of 14 per cent is justified in light of HELCO's risk, HELCO's need to construct new facilities, and HELCO's need to issue additional securities to construct these new facilities.

The CA's proposal on the rate of return on common equity is based on the calculations made by its expert witness, J. Robert Malko. Dr. Malko first computed the rate of return for his group of comparable companies by averaging the DCF and CAPM results, each weighted equally. The computation produced a rate of return of 13.02 per cent. Based on the results for his group of comparable companies, Dr. Malko concluded that the rate of return on common equity for HELCO should be in the range of 12.7 per cent to 13 per cent. In deriving this range, Dr. Malko allowed for a projected declining trend in interest rates and for HELCO's larger business risks attributable to its planned construction program, its geographic isolation, and its small size.

4. Discussion

Mr. Brennan (for HELCO) and Dr. Malko (for the CA) both used the constant growth DCF method and the CAPM in estimating the cost of common equity for their respective groups of sample companies. They differed, however, in (1) the companies included in their respective groups of sample companies; (2) the method of estimating the current dividend yield for the DCF approach; (2) the estimate of the interest rate to reflect rate volatility in the CAPM; and (3) the selection of the adjusted beta values for the CAPM. Despite these differences, the results of their computations of the cost of common equity for their respective groups of sample companies are nearly the same. Mr. Brennan's resulting estimate is 12.9 per cent, and Dr. Malko's resulting estimate is 13.02 per cent.

However, the recommendations on the cost of HELCO's common equity differ more widely than the difference in the estimates of the cost of common equity for Mr. Brennan's group of sample companies and Dr. Malko's group of sample

companies, because of HELCO's use of HEI as a proxy, in addition to the group of barometer companies. Thus, the primary issue in the development of a market-based estimate of the rate of return on HELCO's common equity is whether the use of HEI as a proxy is appropriate.

The test to determine appropriateness is multiple. The proxy company or companies should be similar to HELCO in terms of industry type, size, operations, business environment, and capital attraction characteristics. Thus, a proxy company should first have almost all of its revenues derived from electric operations. As primarily an electric utility, the proxy company should (by HELCO's own criteria) have tradeable common stock, and its stock rating should be similar to that of HELCO. The proxy company should be small and be substantially a regulated company. It should have no major generating plants under construction, not be a holding company with more than one subsidiary, have a common equity ratio of approximately 35 per cent to 50 per cent, and have a bond rating similar to that of HELCO.

When measured against these criteria, HEI is not an appropriate proxy. The evidence does not support the use of HEI's market-derived common equity cost rate in determining HELCO's cost of common equity. HEI is a diversified holding company with subsidiaries in the electric, savings and loan, insurance, maritime freight transportation, real estate, and investment industries. As of December 1988, HEI derived 25 per cent of its operating revenues from nonelectric operations. This percentage does not reflect the full year impact of its savings and loan acquisition in mid-1988.

Despite HELCO's claim that the stock market views HEI as an electric utility, the company presented little direct evidence in support of this claim, other than a similarity of HEI's beta coefficients with those of the electric industries. However, identical beta values do not imply identical industries. Moreover, HEI's beta, as an econometric estimate using historical data, simply reflects HEI's past electric history. HEI's diversification is a relatively recent occurrence. There is no evidence that HEI's risk, relative to that of a sample of electric utilities, will remain stable over time. Companies engaged in electric utility operations to the same extent as HELCO are, therefore, the more appropriate proxies in developing a market-derived common equity cost rate for HELCO.

HELCO argues that HEI's consolidated cost of common equity would not overstate HELCO's cost of common equity. It points to HELCO's market-to-book ratio as evidence of this. However, the posture of HELCO's market-to-book ratio is insufficient to prove HELCO's claim. HELCO infers that a return, equal or higher than that for HEI, is required from the fact that the derived relative market price for HEI electric utilities is less than that for HEI, consolidated.

There are two problems with this approach. First, the derived market-to-book ratio for the electric utilities is based on the average of market-to-book ratios of the nonutility industries represented by HEI's diversified businesses, rather than on specific company ratios. The market-to-book ratio of the electric utilities can be above or below that of HEI, depending on the actual market-to-book ratios of HEI's nonutility subsidiaries.

Second, market price is a positive function of expected income and a negative function of risk. Thus, the lower relative electric utility price could be the result of lower expected income rather than higher risk. Indeed, a lower relative electric utility price could result from both lower expected income and lower risk, if the negative effects of lower income outweigh the positive effects of lower risk. That the utilities have lower expected income growth is a point raised by HELCO. Thus, the fact that the derived relative market price for electric utilities is lower than for HEI, consolidated, is not sufficient to conclude that HELCO has a higher risk than HEI and requires a higher return. Accordingly, HELCO's use of HEI's cost of common equity does not provide an appropriate basis to estimate HELCO's cost of common equity.

While the use of HEI as a proxy for HELCO is not appropriate, the spread between the return on common equity for HEI and that of the barometer and comparable companies provides an upper bound measure for the additional return required to reflect HELCO's unique risks, relative to the barometer or comparable companies. HELCO's analysis indicates that the estimated cost of common equity is higher for HEI than it is for the group of barometer companies.

The CA's analysis corroborates this finding. The results of the CA's analysis of its comparable companies are similar to those of HELCO's analysis of its barometer companies. The higher cost of common equity for HEI than for the group of comparable companies may be the result of higher investment risk, but there is insufficient evidence to determine the source of the risk. The evidence is unclear as to the risks contributed by HEI's diversification into industries that are typically riskier than electric utilities and the risks resulting from other factors unrelated to industry type, such as business location and regional supply and demand conditions. HELCO provided no direct evidence on the risk-return profile of each of its acquisitions and the portfolio risk-return impact of diversification away from electric utility operations.

As noted above, HELCO estimated the cost of common equity for barometer companies by averaging the results derived from the application of the DCF method, the CAPM, and the RP method, with heavier weight given to the results obtained under the CAPM and the RP method. We note Mr. Brennan's testimony that the DCF method tends to underestimate the cost of common equity when current earnings do not reflect the expected growth reflected in market price. However, we also note Dr. Malko's testimony that the CAPM and the risk premium method employed by Mr. Brennan are just two different types of risk premium estimations. Accordingly, we find that equal weight should be assigned to: (i) the DCF method and (ii) the CAPM and the RP method.

In setting rates for a regulated company, it is important to consider the kind of economic conditions under which the company will be operating. As of the hearing date, the rate of inflation for 1990 was expected to be 4 per cent, with moderate GNP expansion. This denoted a stable condition, suitable for the use of market-based rate of return models.¹⁶

The determination of a reasonable cost of equity is ultimately a matter of informed judgment. Due consideration needs to be given to HELCO's business risks arising from its small size, large planned construction program, oil dependence, and narrow economic base, although these risks are somewhat mitigated by the larger than average residential component in its demand mix and the projected declining interest rates. It is reasonable to base the rate of return on HELCO's common equity on the market data of comparable proxy companies, with some allowance for HELCO's business risks. Given HELCO's larger business risks and the attendant investment risk, it is also reasonable to establish a rate of return on HELCO's common equity that tends to minimize deterioration in its financial profile. Based on the record, we conclude that a rate of return on common equity of 13.1 per cent is reasonable for HELCO.

F. Cost of Capital

As a result of our conclusions regarding the cost of the various component parts of HELCO's capital structure, the overall weighted cost of capital for HELCO for the test year 1990 is 10.46 per cent.

			<i>Cost</i>	<i>Weighted Capital Cost</i>
	<i>Capitalization</i>		<i>Rate</i>	
	<i>(\$000s)</i>			
Short-term debt	\$ 2,000	1.46%	8.00%	.12%
Long-term debt	62,268	45.30%	8.20%	3.71%
Preferred stock	13,100	9.53%	9.48%	.90%
Common equity	60,081	43.71%	13.10%	5.73%

Total

\$ 137,449

100.00%

10.46%

The commission finds, upon weighing all the evidence in this proceeding, that a fair and reasonable return to HELCO for its properties actually used and useful for public utility purposes is 10.46 per cent for the test year 1990. This return, in the commission's opinion, satisfies the guidelines set forth in *Bluefield* and *Hope*.

VII.

COST OF SERVICE AND RATE DESIGN

Such level of annual revenue requirements as may be authorized in this rate case must be translated into actual service rates. Both HELCO and the CA agree that rates should be based on costs. All classes of customers should pay their share of the costs in providing service to them. The parties differ, however, on the basic approach to allocating the total cost of service to the various classes of customers. HELCO advocates the embedded cost of service approach; the CA proposes that the allocation be based on marginal cost principles. HELCO and the CA also disagree on HELCO's proposal to increase the customer charge for the residential class of customers (schedule R).

In addition to the change in the customer charge for the residential class of customers, HELCO proposes to revise its customer charges for other classes of customers (schedules G, J, H, P, and F) and to revise the demand charges (where applicable) and energy charges for each class of customers. HELCO also proposes to separate schedule G and option J of schedule G into two separate rate schedules, G and J. The CA does not object to these proposals.

A. Cost of Service Studies

1. HELCO's approach

HELCO performed an embedded cost of service study, the results of which were used to allocate the company's total system cost among the various classes of customers to aid in determining each class' responsibility for the proposed increases in the company's revenue requirements. It also performed a marginal cost study, the results of which were used as a check in designing its proposed rates.

In performing the cost of service study, HELCO first categorized costs by the production, transmission, and distribution functions. It then classified the functionalized costs into three cost components—energy, demand, and customer costs. The energy, demand, and customer costs are the bases for the customer charges, demand charges, and energy charges included in the class rate schedules. HELCO based the functionalization into the three cost components on the Electric Utility Cost Allocation Manual published by NARUC. Following the NARUC cost allocation manual, HELCO classified the production function costs into the demand and energy components, the transmission function costs into the demand component, and the distribution function costs into the demand and customer components. The final step in performing the cost of service study was the allocation of the cost components to the different rate (customer) classes.

HELCO allocated the customer cost component on the basis of the number of customers, weighted to reflect differences in service phase and voltage level, metering requirements, and the complexity of the meter reading, billing, and accounting activities required by the customer classes. HELCO allocated the demand costs differently for the distribution component and for the production and transmission components. It allocated the distribution demand costs on class peak demands at various distribution voltage levels. It allocated the production and transmission demand costs by the average and excess demand (AED) method.

The AED method is distinguished from the two other commonly used methods to allocate demand costs—the peak responsibility method and the noncoincidental peak demand method. These other two methods consider only one demand parameter in allocating demand costs.¹⁷ The AED method, however, considers other cost-related factors, such as the extent of the use of utility facilities by each customer class. It takes into account the system load factor, the class peak demand, and the diversity of demand. It allocates demand cost on the basis of each class' average demand (kwh divided by the number of hours) and excess demand (noncoincident demand minus the average demand). HELCO asserts that the allocation approach it took is in accord with the approach previously approved by the commission.

Of its proposed total additional revenue requirements of \$9,865,000, HELCO designated \$196,000 as miscellaneous or other operating revenues and allocated the remaining \$9,669,000 to the various rate classes. HELCO represents that it allocated this remainder to the various rate classes with the following as primary considerations: (1) the rate of return generated from each rate class (as determined by the cost of service study) relative to the system average rate of return and (2) the relationship of the percentage increase in revenues for each class relative to the total system revenue increase. HELCO's objective was to move toward equal rates of return for all of the rate classes by allocating different revenue increases to the various classes.

However, HELCO also sought to avoid drastic and sudden rate increases for certain classes of customers (particularly the residential customers) and to hold the rate increases for these rate classes at a reasonable level. Thus, HELCO allocated the total proposed revenue increases to the various rate classes in such a manner that the rate of return produced by each rate class as well as the class' per cent revenue increase fell within 'reasonable ranges' relative to the respective system averages. The result is that HELCO's allocation of its proposed revenue requirements does not reflect equal rates of return for all rate classes, but, nevertheless, manifests a gradual movement toward equality. The following table displays the results of HELCO's allocation of the total system revenue requirements:

<i>Rate Class *</i>	<i>Present</i>	<i>Proposed</i>	<i>Rate of Return</i>	<i>Proposed Increases</i>
<i>(Rate Schedule)</i>				
			<i>(\$000)</i>	<i>(%)</i>
R	2.28%	6.33%	4,597.0	13.00%
G	12.34	16.23	916.0	9.85
J	11.95	16.96	1,618.0	10.00
H	6.69	12.28	707.0	13.00
P	11.75	17.66	1,782.0	8.92
F	1.43	7.47	49.0	13.00
Total	6.34	10.86	9,669.0	11.16

Customer classes R, H, and F are allocated more of the proposed increases in revenue requirements than the other classes, because they currently provide a lower rate of return than the average system rate of return. Customer class P is allocated the least of the proposed increases in revenue requirements, because it currently provides a rate of return more than the system average rate of return.

2. The CA's approach

The CA recommends that the commission use the long-run marginal cost approach, rather than the embedded cost of service approach taken by HELCO, in determining each customer class' responsibility for proposed increases in system revenue requirements. Under the marginal cost approach, the focus is on the cost of providing an additional unit of service. The CA contends that the long-run marginal cost approach recognizes that present consumption influences construction requirements and, as such, future system costs. It concludes that, by reflecting these costs, rates based on long-run marginal costs will ensure that the correct amount of new capital investment is devoted to expanding HELCO's electric resources.

A principal thrust of the CA's recommendation is that the marginal cost approach promotes efficient energy use and energy conservation. It argues that HELCO's approach sends a wrong signal to consumers—that increased energy consumption is appropriate—and, thus, will induce them to consume more, not less, energy. The CA asserts that HELCO's approach operates in this fashion because the embedded cost of service approach addresses the cost of the company's installed capacity and, unlike the marginal cost approach, does not explore the incremental aspects of demand. The CA contends that the embedded cost of service approach understates the cost of energy. It warns that the use of the embedded cost of service approach could sabotage the commission's efforts in pending Docket No. 6617 on integrated resource planning.

The CA readily admits that use of the marginal cost approach is not without problems. It recognizes that, since revenue requirements are based on accounting costs, marginal costs may not equal revenue requirements. In times of rising utility costs, the marginal cost of the next unit of service is likely to be greater than the embedded cost associated with a unit of capacity; conversely, in times of declining utility costs, the marginal cost of the next unit of service would likely be less than the embedded cost. To resolve this problem, the CA suggests that marginal costs be reconciled with revenue requirements by setting marginal costs equal to the embedded revenue requirements.

In accordance with its preferred approach, the CA conducted a cost of service study based on marginal costs. In its determination of marginal costs, the CA focused primarily on the bulk power production function, which includes generation (production) and high voltage transmission, and, with respect to generation, on the capacity to meet peak demand. It measured the marginal cost of meeting peak demand by the annual carrying cost of additional capacity that must be added only for the purpose of meeting additional demand. Assuming an efficient system, in which case the cost would not exceed the carrying cost of a generating unit with the lowest fixed cost per kilowatt of capacity, the CA concluded that the cost of a combustion turbine peaking unit was appropriate in measuring marginal cost of meeting peak demand.

For the purposes of its study, in determining the marginal costs associated with providing additional bulk power production, the CA calculated the marginal cost of generation capacity required to meet an additional kilowatt of demand. It also calculated the associated marginal transmission cost and the marginal cost of providing additional energy. The CA concluded in its study that the marginal energy cost of bulk power supply on the HELCO system is in the range of 4.6228 cents to 6.1801 cents per kilowatthour. It also concluded that the marginal cost of capacity on the HELCO system is \$97.20 per kilowatt year.

The CA determined the costs of providing the other functional elements of electric service besides bulk power production—that is, lower level transmission, distribution, and customer service costs—by utilizing HELCO's embedded costs contained in its cost of service study as approximations of long-run marginal costs. However, the CA disagreed with HELCO in the allocation of portions of distribution plant investments and related expenses to customer classes.

The CA's analysis, with marginal cost substituting for embedded cost of bulk power supply (production and transmission), resulted in collected revenues exceeding revenue requirements. To meet the required revenue level, the CA reduced all of the bulk power cost components proportionately. This involved the application of a factor of 1.16513 to the bulk power marginal cost levels related to the company's revenues.

After obtaining the costs of the functional elements, the CA allocated the total of each functional component to the customer classes on the basis of allocation factors that reflect each class' responsibility for that functional component. For instance, for the bulk power capacity total cost, the CA developed allocation factors based on each class' contribution to peak demand; for the peak and off-peak energy total cost, the CA developed allocation factors based on each class' energy at generation level.

In this connection, the CA is critical of HELCO's use, in its embedded cost of service study, of the AED method in allocating bulk power (production and transmission) costs. The AED method weighs all fixed bulk power costs by the annual system load factor to determine the portion attributable to energy usage; all costs in excess are deemed to be demand-related. The CA claims that this method ignores the importance of marginal demand and energy costs in arriving at the appropriate breakdown between energy-related costs and demand-related costs. It notes that, under HELCO's embedded cost of service study, the demand-related bulk power costs account for 40 per cent of HELCO's bulk power revenue requirement, while under the CA's study, the marginal demand-related bulk power costs account for only 22 per cent of the bulk power marginal costs.

The CA also criticizes HELCO's allocation of the demand-related costs on the basis of class noncoincident demands, rather than coincident demands. The CA contends that allocation on the basis of class noncoincident demands would cause an excessive portion of the bulk power costs to be allocated to lower load factor customer classes (such as residential) and to customers who do not make significant contributions to peak demands and would result in commercial and industrial customers with demands coincident with the system peak to be subsidized.

The CA's coincident peak demand approach in allocating functional costs resulted in the following differences between each class' allocated costs and its portion of HELCO's revenue requirements at present rates:

<i>CA's</i>	<i>HELCO's</i>		
<i>Allocated Costs</i>	<i>Present Rev.</i>		<i>Difference</i>
<i>(\$000)</i>	<i>(\$000)</i>		<i>(\$000)</i>
<i>Schedule</i>			
R	39,520	34,853	4,674
G	7,687	9,192	(1,506)
J	14,896	15,942	(1,049)
H	5,545	5,354	190
P	20,556	19,617	937
F	395	371	24

Class revenue levels do not deviate significantly from long-run marginal costs for schedules H and P, but there is some deviation for the other classes. In light of this fact, the CA proposed to adjust class revenue levels as follows: (1) for

schedules H and P, increase the revenue levels by assigning to these classes roughly 3.8 per cent of the total revenue increase; (2) for schedules R and F, increase the revenue levels by assigning to these classes about 4.25 per cent of the total revenue increase; and (3) assign the remaining revenue increase to schedules G and J in proportion to present revenues.

3. Discussion

As noted by HELCO in its testimony and brief, the use of long-run marginal cost in allocating system cost and assigning revenue requirement responsibility to the various customer classes was debated many times in past cases. See, for instance, *In re Hawaiian Elec. Co.*, Docket No. 2793, *In re Hawaiian Elec. Co.*, Docket No. 3705, and *In re Hawaiian Elec. Co.*, Docket No. 3874. In each case, the commission rejected the use of the marginal cost methodology for ratemaking purposes. The arguments presented in this docket for and against the use of the methodology are not new. Nevertheless, we have given renewed consideration to the use of the long-run marginal cost approach for purposes of ratemaking. For the reasons already stated in the earlier dockets and reiterated in some respects in this decision and order, we decline to adopt the long-run marginal cost approach.

We have no disagreement with the theoretical basis for the use of marginal cost in designing rates. The use of marginal cost in pricing electricity is advocated by some respected authorities. The promotion of economic efficiency and the conveyance of proper price signals to encourage conservation and shift in customer use of electricity to nonpeak periods are laudable objectives. There are, however, difficulties in the use of marginal cost in rate design. Even those who advocate the use of marginal cost admit there are limitations in the use of this approach in ratemaking. Further, there are particular difficulties in the way the CA applies marginal cost in this docket. We do not see how any of the objectives intended by the use of marginal cost are achieved by the CA's approach.

A major difficulty in the use of the marginal cost approach in setting rates is that the revenue requirements determined by the use of this approach are not directly translatable into rates. This is because marginal cost will not equal revenue requirements determined by the use of accounting cost, except under very unusual circumstances.¹⁸ Thus, the use of marginal cost in rate setting requires care, not only in the performance of the mechanics in marginal cost analysis, such as the selection of a proper time horizon, but also in the adjustment of the results of marginal cost analysis to reflect revenue requirements based on embedded cost. We acknowledge the efforts made by the CA in this respect. However, the process followed and the results achieved by the CA do not justify our placing confidence in the analysis performed by the CA. In the following paragraphs, we discuss the problems with the CA's marginal cost analysis.

a.

The CA (and so also HELCO in its marginal cost study) followed the method developed by the National Economic Research Associates (i.e., the annualized average cost per kilowatt of a peaking unit) to calculate generation marginal cost and the associated incremental transmission investment cost. However, the CA calculated marginal cost only for the bulk power function (production and high voltage transmission). For the other functional categories, it utilized HELCO's embedded cost as an 'approximation' of marginal cost.

The CA's reasons for limiting marginal costing to the bulk power function are: (1) the most important marginal cost variations occur during the performance of bulk power production (which includes the provision of capacity to meet peak demand and the production of energy), and (2) generally, marginal cost pricing attains the rate design objectives of efficiency, conservation, and equity only at the bulk power level.

By way of an explanation of the second ground, the CA represents that a price equal to the marginal cost of extending the distribution grid or adding a new service drop (while relevant to the new customer) would not reflect the cost of providing such service to existing customers, and it would not encourage an optimal reallocation of resources among

existing customers so as to improve efficiency or conservation. Notwithstanding these reasons, the purpose for the use of marginal cost pricing appears to be compromised by the use of marginal cost for some elements but not for others. The CA's marginal cost study is not a true marginal cost analysis.

b.

The CA's resulting total long-run marginal cost of \$79,058,000 does not equal revenue requirements (based on embedded cost) for the test year, as calculated by the CA, of \$85,631,000 at present rates¹⁹ and \$89,096,000 at the CA's proposed rates. The difference between revenue requirements, based on embedded cost, and the long-run marginal cost is solely on account of the marginal cost for the bulk power function. For the bulk power function, the long-run marginal cost is \$59,970,000 and revenue requirements, based on embedded cost and the CA's proposed rates, are \$70,008,000. The long-run marginal cost for the other functions is the same as the embedded cost, since the CA used embedded cost as a substitute for marginal cost for these other functions.

Since marginal cost does not equal revenue requirements (embedded cost), the CA reconciled marginal cost to embedded cost through the 'equal percent of marginal cost' approach. The use of this approach required the application of a factor of 1.16513 to the marginal cost of each component of the bulk power function. This factor is the ratio of total embedded cost (\$70,008,000) to total marginal cost (\$59,970,000). The following summarizes the CA's calculation of long-run marginal cost and embedded cost at the CA's proposed rates for the bulk power function and its reconciliation of marginal cost to embedded cost.

<i>Item</i>	<i>Total</i>	<i>Production Dem.</i>	<i>Energy</i>	<i>Transm. Dem.</i>
	<i>(\$000)</i>	<i>(\$000)</i>	<i>(\$000)</i>	<i>(\$000)</i>
Embedded cost	70,008	21,597	40,688	7,723
Unrecon. marg. cost	59,970	12,030	46,575	1,365
Recon. marg. cost	70,008	14,044	54,371	1,593

As shown in the table above, total unreconciled marginal cost is lower than total embedded cost; the unreconciled marginal cost of the production demand and transmission demand components are lower than their respective embedded cost by 44.3 per cent and 82.3 per cent; the unreconciled marginal cost of the energy component is about 14.5 per cent higher than its embedded cost. The reconciliation lessened the difference between embedded cost and marginal cost for each of the production demand and the transmission demand components; however, it widened the gap between embedded cost and marginal cost for the energy component. The reconciled marginal cost for the production demand component is 34.98 per cent less than embedded cost; the reconciled marginal cost for the transmission demand component is 79.4 per cent less than embedded cost; and the reconciled marginal cost for the energy component is 33.6 per cent more than embedded cost.

The high energy cost should ultimately be reflected in all rate schedules, if the cost is spread uniformly among the schedules. The schedule for the residential class (schedule R) should be particularly affected, since unlike other schedules, it does not have a demand cost component. Except for a small segment of customer charge, the rest of schedule R is energy cost.

Generally, higher energy rates should encourage conservation. However, the achievement of that goal cannot be fairly concluded in this docket. By the CA's approach, the energy cost is overstated. The CA overstated the energy cost, first, when it excluded from the transmission demand cost component of the bulk power function the demand cost of certain

transmission-related investments and expenses not associated with the addition of peak capacity, and included them in the energy component. As a consequence, the unreconciled marginal energy cost far exceeded the embedded energy cost.

The application of the 'equal percent of marginal cost' methodology exacerbated the problem. The reconciliation effectively shifted production demand embedded cost of \$7,553,000 and transmission demand embedded cost of \$6,130,000 (totaling \$13,683,000) to the energy component. The energy cost, therefore, includes (1) the initial allocation of transmission-related demand cost not associated with peak capacity addition and (2) that portion of the production and transmission demand cost shifted by the application of the 'equal percent of marginal cost' methodology and is, thus, inflated.

c.

HELCO and the CA allocated the functionalized costs to the various customer schedules in essentially the same manner, except for the allocation of the bulk power demand cost. HELCO used the average excess demand (AED) method and the CA used the '12 coincidental peak' (12 CP) method to allocate the bulk power demand cost. This commission has in the past approved the use of the AED allocation method. We reaffirm our earlier decisions.

The 12 CP method assumes that demand-related cost should be allocated according to the proportion each rate class uses energy at the time of system peak. We share HELCO's concern that this method places too much reliance upon a single demand characteristic—the customer group's contribution to the system peak load. Under this method, cost responsibility may shift from one customer class to another as peak load patterns change, resulting in rate shock and rate instability. Indeed, indications are that such changes in peak load patterns may already be occurring. HELCO's information suggests that its system day peaks have been growing at a faster rate than its system evening peaks. The AED method, on the other hand, takes into account a variety of cost-related factors, including class peak load, system load, and diversity of demand.

Despite the use of differing methods, both parties reach results that are fairly close in the allocation of production and transmission demand-related cost to the various rate classes. The following table illustrates this.

	<i>HELCO</i>	<i>CA</i>
Schedule R	45.75%	45.15%
Schedule G	8.02%	6.95%
Schedule J	18.31%	15.86%
Schedule H	6.73%	6.09%
Schedule P	20.70%	25.46%
Schedule F	0.49%	0.49%
Total	100.00%	100.00%

B. Rate Changes

1. HELCO's proposals

In the design of its rates, HELCO proposes a number of changes to its rules, schedules, and rate schedule charges. HELCO represents that these changes take into account generally accepted rate design objectives, including (1) recovering revenue requirements, (2) moving toward cost of service, (3) improving revenue stability, (4) providing interclass fairness, (5) improving intraclass fairness, (6) maintaining rate continuity, (7) encouraging efficient use of utility plant and improving load factor, (8) improving understandability of rate schedules and rules, (9) facilitating tariff administration, (10) encouraging load management, and (10) improving marketability of load management riders.

a.

HELCO proposes to separate option J currently in schedule G and create a new schedule J. It proposes modifications in customer charges, demand charges, and energy charges in each of its rate schedules R, G, J, H, P, and F as follows.

(1) *Schedule R (residential)*. HELCO proposes to (a) increase the customer charge from \$7 per month to \$10 per month; (b) increase the nonfuel charge from 5.591 cents per kwh to 7.939 cents per kwh; (c) reduce the fuel base of the energy charge from 6.739 cents per kwh to 5.624 cents per kwh; (d) increase the minimum charge from \$15 per month to \$17 per month; (e) increase the multifamily dwelling charge from \$2.60 per additional unit to \$2.75 per additional unit; and (f) increase the apartment house collection arrangement maximum discount from \$5.25 per month to \$5.50 per month.

(2) *Schedule G (general service, nondemand)*. HELCO proposes to (a) increase the customer charge from \$20 per month to \$25 per month for single-phase customers and from \$30 per month to \$35 per month for three-phase customers; (b) increase the energy charge from 13.984 cents per kwh to 14.123 cents per kwh; and (c) increase the minimum charge to an amount equal to the customer charge from \$20 per month to \$25 per month for single-phase customers and from \$30 per month to \$35 per month for three-phase customers.

(3) *Schedule J (general service, demand)*. HELCO proposes to (a) increase the customer charge from \$20 per month to \$25 per month for single-phase customers and from \$30 per month to \$35 per month for three-phase customers; (b) increase the demand charge from \$3 per kw to \$3.50 per kw and apply the charge as a demand charge, rather than limiting its application to a determination of the minimum charge; (c) increase the billing demand ratchet from 75 per cent to 100 per cent; (d) decrease the energy charge in the first load factor block from 13.984 cents per kwh to 12.763 cents per kwh, in the second load factor block from 10.719 cents per kwh to 9.5 cents per kwh, and in the third load factor block from 9.719 cents per kwh to 8.1 cents per kwh; (e) increase the minimum charge from \$75 per month to the sum of the customer charge and the demand charge; and (f) add a power factor adjustment.

(4) *Schedule H (commercial heating, cooking, and air conditioning)*. HELCO seeks to (a) increase the customer charge from \$20 per month to \$25 per month for single-phase customers and from \$30 per month to \$40 for three-phase customers; (b) increase the demand charge from \$3.50 per kw to \$4.50 per kw; and (c) increase the energy charge from 10.514 cents per kwh to 10.721 cents per kwh.

(5) *Schedule P (large power)*. HELCO proposes to (a) increase the customer charge from \$300 per month to \$325 per month; (b) increase the demand charge from \$8 per kw to \$10 per kw for the first 500 kw of billing demand and from \$7.50 per kw to \$9 per kw for over 500 kw of billing demand; and (c) increase the energy charge from 10.266 cents per kwh to 10.607 cents per kwh in the first load factor block, decrease the energy charge from 8.943 cents per kwh to 8.6 cents per kwh in the second load factor block, and decrease the energy charge from 7.943 cents per kwh to 6.2 cents per kwh in the third load factor block.

(6) *Schedule F (street lighting service)*. HELCO proposes to (a) increase the energy charge from 15.794 cents per kwh to 17.017 cents per kwh in the first load factor block and from 9.724 cents per kwh to 10 cents per kwh in the second load factor block; and (b) increase the minimum charge from \$20 per month to \$35 per month.

b.

HELCO proposes to add a new schedule U, eliminate schedule O, and modify riders M and T, as follows.

(1) *Schedule U*. The proposed schedule U (time of use service) is a stand alone, time of day rate schedule that would be available to any customer with a demand of 25 kw or more. It is intended to encourage off-peak energy use and to discourage on-peak demand without penalizing on-peak energy use. It is a load management schedule and is an alternative to rider T (which is added to either schedule J or schedule P). It replaces to some extent schedule O (off-peak service), which HELCO proposes to eliminate.

The proposed demand charge for this schedule is equal to the weighted average of the demand cost for schedule J and schedule P, rounded to the nearest \$10. The proposed customer charge for the schedule is equal to the weighted average of the customer cost of schedule J and schedule P, rounded to the nearest \$10, plus \$10 for the additional cost for a time of day meter. The proposed minimum charge is the sum of the customer charge and the demand charge. The proposed on-peak energy charge is equal to the weighted average of the energy charge for the first load factor block of schedules J and P, rounded to the nearest cent. The proposed off-peak energy charge is equal to the weighted average of the energy charge for the third load factor block of schedules J and P. The demand, customer, and energy charges are derived from the demand, customer, and energy charges of schedules J and P, because most of the potential customers of schedule U are those who are now taking service under schedules J and P.

(2) *Schedule O*. HELCO proposes to eliminate schedule O (off-peak service), because the terms and provisions of the schedule are so inflexible as to make the schedule difficult, if not impossible, to market. There are currently no subscribers to this service.

(3) *Rider M*. HELCO proposes to modify rider M (off-peak and curtailable service) to be the same as HECO's rider M. At present, HELCO has no rider M customers.

(4) *Rider T*. HELCO proposes to modify rider T to make it easier to administer and more understandable. HELCO would eliminate the excess off-peak demand charge and modify the minimum energy charge by excluding surcharges and credits.

c.

HELCO proposes to change its rules in the following respects.

(1) *Service establishment charge*. HELCO proposes to move the service establishment charge from schedule B to rule 7 and eliminate schedule B. HELCO considers it more appropriate to include the charge in a rule rather than in a rate schedule since it is a one-time charge that applies to all of HELCO's rate schedules. HELCO also proposes to increase the amount of the charge from \$10 to \$15. HELCO states that the proposed \$15 charge is closer to HELCO's cost of service.

(2) *Late payment charge*. HELCO proposes to move the late payment charge from each separate rate schedule to rule 8. HELCO asserts that this change will simplify its rate schedules.

(3) *Returned check charge*. HELCO proposes to increase the amount of the returned check charge from \$10 to \$15. It claims that the \$15 is closer to its cost of service.

(4) *Field collection charge*. HELCO proposes no changes in the amount of the field collection charge. However, it seeks to modify the circumstances under which the charge may be collected. It proposes to assess the charge whenever a field

collection call is made, regardless of whether the unpaid bill is successfully collected or not. HELCO asserts that the cost responsibility should be assigned to the customer who causes HELCO to incur the cost. Otherwise, HELCO's customers who pay on time will be subsidizing those who do not pay their bills on time and cause HELCO to make field calls.

(5) *Master metering*. HELCO proposes to move the master metering provision from rate schedules G, J, and P to rule 10.F. This change is to simplify the individual rate schedules by consolidating the master metering provisions in one rule.

(6) *Fuel adjustment clause*. HELCO proposes to move the fuel adjustment clause from each separate rate schedule into one common rate sheet. This is to simplify the individual rate schedules. HELCO also proposes to make some changes in its fuel adjustment clause. These proposed changes are addressed in a separate decision and order.

2. The CA's position

From the CA's perspective, how rates are designed and structured influences energy use and demand patterns and customer behavior. The CA's general observation is that HELCO's rate structure proposals encourage consumption. It believes that, instead of encouraging consumption, HELCO's rate design should encourage conservation. It is concerned that HELCO's proposals would adversely impact the development of demand-side options and the commission's docket on integrated resource planning.

The CA is particularly critical of the higher increases in fixed charges (e.g., customer charges and demand charges) than in energy charges that resulted from HELCO's approach. The CA claims that HELCO's proposals offer little incentive for customers to conserve or otherwise use energy efficiently. The CA is also critical of HELCO's failure to consider strategic conservation and peak clipping in its rate design. Strategic conservation is a program initiated by the utility to promote a targeted reduction in energy consumption, and peak load clipping is a program to reduce the system peak loads. The CA professes that strategic conservation and peak clipping are two of the most important demand-side management programs that require consideration in rate design. The CA acknowledges that HELCO's proposals concerning schedule U and rider T contain aspects of demand-side management options, but it asserts that both schedule U and rider T are designed essentially to either promote increased energy sales during targeted time periods or shift sales from one time period to another, without reducing energy consumption.

Despite these general objections, the CA has proposed no specific rate design scheme; it has offered no specific comments on any of HELCO's proposals to modify schedules or rules, except on that proposal to increase schedule R's customer charge from \$7 per month to \$10 per month. The CA objects to the 42 per cent increase in customer charge as unwarranted. It asserts that the customer charge should reflect the costs that are avoided if customers leave the system, which costs are primarily those associated with the operation and maintenance of specific customer service facilities, meter reading, and billing functions. The CA calculates the annual avoidable residential customer costs at \$3.77 per customer per month and argues that the existing \$7 per customer per month charge is more than adequate to cover that amount.

The CA further asserts that the \$7 per customer per month charge is more consistent with the commission's interest in promoting conservation and economic efficiency. It claims that burdening the fixed charge by increasing it adversely affects low use customers, as it forces them to bear a disproportionate share of the revenue collection responsibility to the benefit of the high use customers. Finally, the CA accuses HELCO of raising the fixed residential service charge as a gameplan to recover as much of its costs through nonreviewable automatic recovery provisions as it can.

3. Discussion

On a general note, we share the CA's concern that HELCO seems to assign more of the increases in revenue requirements to fixed charges than to charges associated with energy use. However, with some exceptions, we agree with HELCO's proposals in the design of its rates. We outline our exceptions below. Some of these exceptions address what appears to be the assignment of a greater burden of the increases in revenue requirements on fixed charges.

a.

We are equally concerned with the CA that HELCO's proposal to increase schedule R's customer charge from \$7 to \$10 per month represents a hefty 42.85 per cent increase. It is too large an increase to be implemented at once. The customer charge is a sensitive issue, particularly with residential customers. As we stated before, an increase in customer charge should be on a gradual basis, since it has a direct financial impact on low income customers. See *In re Hawaiian Elec. Co.*, 43 PUR4th 361 (1981).

However, the commission appreciates HELCO's desire to move customer charge closer to customer cost as determined by HELCO's cost of service study. Thus, we do not agree with the CA that the customer charge should be kept at \$7 per month. Customer cost has increased since the last rate case. A moderate increase of \$1 per month is appropriate. This modest increase should not unduly burden residential customers.

b.

Although the CA has not commented at all and raised no objections with respect to these matters, we find the following HELCO proposals to be unreasonable.

1. *Schedule J demand ratchet.* HELCO proposes to increase the demand ratchet in schedule J from 75 per cent to 100 per cent. Increasing the demand ratchet would discourage consumers from reducing demand. We note at this juncture that HELCO's estimated marginal demand cost of \$32.99 per kw is substantially higher than its estimated embedded cost of \$13.46 per kw. It is, thus, particularly critical that rate design not encourage increased consumption that may necessitate the installation of additional capacity.

2. *Schedule P energy rates.* HELCO's proposal to decrease the energy rates for the second and third blocks in schedule P is without justification. From the record, we gather that the customer charge is slightly below cost and the demand charges of \$10 per kw per month for under 500 kw and \$9 per kw per month for over 500 kw are considerably lower than the embedded demand cost of \$24.95 per kw per month. As the CA has argued throughout this docket, we need to be concerned with designing rates that do not discourage energy conservation.

3. *Field collection charge.* HELCO proposes to assess a field collection charge regardless of whether an overdue payment has been successfully collected. The assessment of field collection charges has been repeatedly addressed by this commission in several rate cases. See *In re Maui Elec. Co.*, Docket No. 4691, Decision and Order No. 8048 (Aug. 20, 1984), and *In re Hawaii Elec. Light Co.*, Docket No. 4833, Decision and Order No. 8179 (Nov. 23, 1984). The commission decided in these cases that an assessment of a field collection charge should not be allowed in cases where collection is not successful. HELCO has not offered any reason in this docket for the commission to alter its position on this matter. Therefore, HELCO's proposal to assess a field collection charge regardless of success in collection is denied.

C. Integrated Resource Planning Cost Recovery

1. HELCO's proposal

[i] HELCO proposes to include an integrated resource plan cost recovery provision (IRP clause) in its rates. The IRP clause is intended as a mechanism by which HELCO may recover, without having to go through a rate case, its expenses to develop an integrated resource plan and to implement specific programs recommended by the integrated resource plan. HELCO intends the IRP clause to operate similarly to its fuel adjustment clause and its firm capacity surcharge. The expenses incurred by HELCO to develop its integrated resource plan and to implement integrated resource programs would be recovered through a surcharge in HELCO's bills.

The expenses to be included in the clause would be subject to prior commission review and approval. The amount of the surcharge would be determined by the commission and would be based on the expenses for integrated resource planning that are incurred by HELCO, the period of time over which the expenses would be recovered, and the number of kilowatthours that are forecasted over that time period. A quarterly reconciliation to actual cost recovery would be made. HELCO has not included any additional expenses or rate base additions in test year 1990 for integrated resource planning beyond HELCO's ongoing activities that relate to generation planning, demand-side management, sales and peak forecasting, and load research.

HELCO asserts that developing an integrated resource plan and implementing recommended programs will be expensive and some cost recovery mechanism must be instituted. It contends that, if an IRP clause is not approved by the commission, the commission should allow the rate basing of integrated resource planning expenses. Rate basing the expenses would permit HELCO to recover its integrated resource planning expenses over the life of the programs that are implemented.

2. The CA's position

The CA is willing to support HELCO's surcharge proposal in return for HELCO entering immediately into a pilot demand-side management program. The CA believes that it is important that HELCO 'hit the ground running' on demand-side management programs as a lead-in, initial phase of the integrated resource planning docket now pending before the commission. The CA suggests that a 2 per cent energy use reduction goal be established for HELCO's pilot demand-side management program as an incentive to uncover the areas of potential savings. However, the CA would not tie the recovery of HELCO's expenses for integrated resource planning to the achievement of the 2 per cent goal, but rather to the commission's later determination that HELCO has made a full and good faith effort to do so.

The CA would further condition the allowance of the surcharge on the following. First, it would require a balancing account to be established for the recovery of all expenses associated with the integrated resource planning process on an automatic recovery basis. Second, it would require the establishment of meaningful checks and balances to ensure the reasonableness and prudence of HELCO's expenditures against the account.

Specifically, the CA would require that a detailed procedure be established for advance review and approval by the commission of proposed integrated resource planning projects and expenditures. It would also require that all expenditures be subject to later prudence review. The CA suggests that projects be approved on a project-by-project basis and that HELCO be required to provide detailed, analytic information on each project, including a statement of the need for and the objectives of the project, the timetable for the implementation of the project, and the full costs of the project. It also suggests that integrated resource projects be approved on a 'not to exceed' basis. The CA would have itself and other interested parties involved in the approval process and suggests that a final report be required, outlining accomplishments and other pertinent information, to be filed upon the conclusion of the project. It recommends that the IRP clause be approved for a period of two years.

HELCO objects to conditioning the allowance of an IRP clause as suggested by the CA. HELCO contends that proposals for pilot demand-side management programs should be considered in the commission's integrated resource planning docket (Docket No. 6617). HELCO agrees that meaningful checks and balances are warranted, but strongly objects to

later prudence review. While not specifically objecting to the 2 per cent energy use reduction goal proposed by the CA, HELCO suggests that goals should be established on a rational basis, rather than arbitrarily or on the basis of mainland experience.

3. Discussion

As asserted by the CA, automatic adjustment clauses, or balancing accounts, are generally appropriate only for expenses that are substantial, volatile, and beyond the control of the utilities. HELCO's proposed IRP clause does not meet these criteria. However, since integrated resource planning is a new, complex, and likely costly undertaking, we believe it is appropriate to provide HELCO with a cost recovery mechanism to remove impediments to proceeding with that planning process. HELCO, along with other utilities, are parties to the integrated resource planning Docket No. 6617.²⁰

We appreciate the CA's concerns about the growth in demand for energy and the high costs of generation expansion, which motivate the CA to propose that the surcharge be conditioned on HELCO embarking immediately on a pilot demand-side management program. However, we do not believe that it is appropriate to require HELCO to pursue a pilot demand-side management program at this time or in this docket. In this docket, we are concerned simply with whether HELCO should be allowed an IRP clause, which HELCO claims (and we agree) is necessary for HELCO to engage in integrated resource planning as required by this commission in Docket No. 6617.

Whether HELCO should undertake 'immediately' a pilot demand-side management program is an issue that should be addressed in Docket No. 6617. Indeed, in our prehearing order in Docket No. 6617, we pose as an issue whether the utilities should undertake immediate demand-side management programs, pending the full development of integrated resource plans. Docket No. 6617 is proceeding as scheduled, and we see no need in this docket to mandate HELCO to implement a demand-side management program as a condition to the allowance of an IRP clause.

We are in accord with the CA, however, that there is a need for checks and balances to ensure the reasonableness and prudence of HELCO's expenditures against the balancing account. An IRP clause is a new undertaking, and given the nature of the expenses of integrated resource planning, the clause requires greater monitoring than a fuel adjustment clause. Integrated resource planning costs appear to fall into at least two major categories: (1) the costs of planning and (2) the costs of implementing particular options. The costs of planning include those associated with the development of the framework for planning and those associated with the planning process. Included in these costs are the costs of data gathering, development of models, and research and development of options in meeting the demand for energy. The costs of implementing particular options include the costs of particular programs or projects selected to satisfy the demand for energy.

With respect to the first category of costs, we will require that HELCO develop an annual budget of the costs it proposes to include in the IRP clause for approval by the commission and furnish the commission with an accounting of expenditures and a report on the variance between the budget and actual expenditures before inclusion of any cost in the IRP clause. With respect to the second category of costs, we will require HELCO to present to the commission for prior approval its proposed program or project, together with information concerning the expenses expected to be incurred, in much the same manner as it is now required to submit to the commission for prior approval its proposed capital expenditures.

Although we approve the establishment of an IRP clause, we reserve our authority to determine whether any particular cost or expense may be recovered through the clause. It is not entirely clear at this point as to what integrated resource planning costs are appropriately recoverable through the IRP clause. Particularly with respect to program or project costs, questions may legitimately be raised as to whether such costs should be recovered through the IRP clause or whether they should be rate-based. The commission reserves the authority to make that determination on a case by case basis.

D. Employee Discount

HELCO provides in schedule E residential service rates for HELCO's employees that are one-third less than the rates for nonemployee residents under schedule R. HELCO is required to provide the employee discount to its union employees and retirees pursuant to the collective bargaining agreement between HELCO and the International Brotherhood of Electrical Workers, Local 1260, AFL-CIO. The employee discount has been in effect for at least 20 years.

The CA suggests that the commission disallow employee discount or impute to HELCO the revenues that the company would have received but for the discount. The CA contends that the employee discount is contrary to sound public policy, because it runs counter to the State policy, set forth in [HRS § 226-18\(c\)\(3\)](#), of encouraging energy conservation. The CA asserts that HELCO's employee discount encourages inefficient use of electricity by its employees. The CA notes that an average employee usage of electricity is 40 per cent higher than that of a nonemployee residential customer.

HELCO, however, defends the employee discount as follows: (1) the employee discount is a contractual obligation between the company and the union, and the CA's proposal constitutes an unwarranted interference with the collective bargaining process between HELCO and its employees; (2) the employee discount is a mechanism by which the company can compensate its employees without making that compensation subject to various taxes; and (3) it would cost from \$1.50 to \$1.70 in additional salary or benefit costs to replace a \$1 discount on an employee's electric bill.

Employee discount has been an issue many times before. The commission has repeatedly rejected its elimination. We will adhere to our past decisions and reject its elimination in this docket. The employee discount has been negotiated in good faith between HELCO and its employees. We are constrained from interfering with that agreement, although there is nothing that legally requires us to recognize the discount.

We think, however, that the CA makes a point when it notes that the average HELCO employee usage is 40 per cent higher than that of a nonemployee residential consumer. It appears that higher employee usage is the norm among all electric utilities in the State. It is true, as pointed out by HELCO, that the CA did not show the demographics of HELCO's employees to show how they compare with nonemployees in terms of family size, age, and types of residences. We do not believe that differences in demographics alone, even if such differences could be shown, are sufficient explanations for the higher usage by HELCO employees. We agree with the CA that a wrong energy conservation impression is conveyed to the public by the employee discount. High energy consumption appears to be subsidized by the general ratepayers. Employee discount should be discontinued. We urge HELCO to consider other compensation alternatives to replace employee discount.

VIII.

ULTIMATE FINDINGS AND CONCLUSIONS

1. The operating revenues, operating expenses, and operating income for the test year, as set forth in Exhibit A, are reasonable.
2. The use of an average test year rate base is reasonable.
3. The test year average depreciated rate base under present rates is \$124,540,000. The test year average depreciated rate base under proposed rates is \$124,290,000. See Exhibit B.
4. Under existing rates, HELCO's income for the test year would provide a rate of return of 8.37 per cent on the average rate base.

5. The capital structure for the test year is as follows: short-term debt, 1.46 per cent; long-term debt, 45.3 per cent; preferred stock, 9.53 per cent; and common equity, 43.71 per cent. The costs of capital are 8 per cent, 8.2 per cent, 9.48 per cent, and 13.1 per cent, respectively. The fair rate of return for the test year is 10.46 per cent.
6. HELCO is granted a rate increase that will produce an annual revenue increase of \$4,553,000.
7. The interim increase of \$3,466,000 granted under Decision and Order No. 10633 was necessary, just, and reasonable, and no refunds are required.
8. An additional increase of \$1,087,000 over and above the interim increase is necessary, just, and reasonable.
9. The interim fuel adjustment clause approved by Decision and Order No. 10770 was necessary, just, and reasonable, and no refund is required.
10. A provision to recover costs associated with integrated resource planning and with the implementation of particular IRP options is necessary, just, and reasonable.

IX.

IT IS ORDERED:

1. HELCO is granted a rate increase that will produce an annual sales revenue increase of \$4,553,000, as shown on Exhibit A, or a rate of return of 10.46 per cent on the rate base for the test year. The effective date of the rate increase shall be March 15, 1991.
2. HELCO shall provide to the commission revised rate schedules and appropriate work papers reflecting the increases authorized in this decision and order. The revised rate schedules and work papers shall be served on the parties and shall be filed with the commission by March 15, 1991.
3. HELCO may place into effect on a permanent basis, the fuel adjustment clause made effective on an interim basis by Decision and Order No. 10770.
4. HELCO may place into effect a cost recovery provision (IRP clause) in its rates to recover its costs associated with integrated resource planning and with the implementation of particular IRP options. The recovery of costs through the IRP clause shall be subject to the conditions and reservations set forth in this decision and order.
5. HELCO's firm capacity surcharge associated with the purchased power contracts with the Hamakua Sugar Company, Inc., and the Hilo Coast Processing Company shall be terminated upon the effective date of the revised rates approved by this decision and order. Any overcollection of the firm capacity surcharge shall be refunded to HELCO's ratepayers.

**EXHIBIT A, DOCKET NO. 6432, HAWAII ELECTRIC
LIGHT CO., INC., RESULTS OF OPERATIONS, pp. 496-499.**

TABULAR OR GRAPHIC MATERIAL SET FORTH AT THIS POINT IS NOT DISPLAYABLE

**EXHIBIT B, DOCKET NO. 6432, HAWAII ELECTRIC LIGHT CO.,
INC., COMPUTATION OF WORKING CASH ITEMS, pp. 499-500.**

TABULAR OR GRAPHIC MATERIAL SET FORTH AT THIS POINT IS NOT DISPLAYABLE

Footnotes

- 1 The same issue of the potential undercollection or overcollection of revenues under the current method of calculating the fuel adjustment factor and how to correct this 'anomaly' surfaced in the currently pending Hawaiian Electric Company, Inc.'s rate case in Docket No. 6531. As in this docket, the utility and the CA entered into a stipulation to effectuate on an interim basis a fuel adjustment clause calculated on the method proposed by the CA.
- 2 The CA initially recommended that the commission withhold a portion of any rate increase until HELCO demonstrates to the commission's satisfaction that it has taken actions to minimize the number of system outages. At the conclusion of the hearing, the CA revised its position.
- 3 A different time period is specified in HELCO's opening brief, which we attribute to a typographical error.
- 4 The CA's initial estimate of office supplies and expense was \$142,000. This sum was derived by subtracting 20 per cent for business meals and entertainment expense as well as \$1,100 in gifts and donations from the 1989 actual expenses to October 31, 1989, and then annualizing the difference. The CA revised its estimate to \$158,000, after determining that it had improperly attributed meals and entertainment expense to the office supplies and expense category.
- 5 See *In re Hawaiian Elec. Co.*, 56 PUR4th 398 (1983); *In re Hawaii Elec. Light Co.*, Docket No. 4833, Decision and Order No. 8179 (Nov. 23, 1984); and *In re Hawaiian Tel. Co.*, Docket No. 5114, Decision and Order No. 8711 (Apr. 4, 1986).
- 6 See, for example, *In re Hawaiian Tel. Co.*, Docket No. 5114, Decision and Order No. 8711 (Apr. 4, 1986); *In re Kauai Elec. Div. of Citizens Util. Co.*, Docket No. 4125, Decision and Order No. 6832 (Oct. 28, 1981); and *In re Young Bros.*, Docket No. 3216, Decision and Order No. 5104 (May 8, 1978). These cases are cited in the CA's brief.
- 7 Although it is a postretirement benefit, the accrual cost of life insurance is not included in the test year estimate due to miscommunication between the actuary and the company.
- 8 Under the FASB rule, the following components comprise the net period cost of postretirement benefits: (1) service cost, (2) interest cost, (3) actual return on plan assets, (4) prior service costs, (5) unrecognized gains and losses, and (6) amortization of the transition obligation (if the employer chooses to amortize, rather than immediately recognize the transition obligation).
- 9 The CA cited two decisions in which the commission disallowed accrued vacation expense. See *In re Hawaiian Tel. Co.*, Docket No. 4306, Decision and Order No. 7412 (Jan. 26, 1983), and *In re Hawaiian Tel. Co.*, Docket No. 4588, Decision and Order No. 8042, (Aug. 14, 1984).
- 10 HELCO's application of the proposed methodology is outlined in HELCO-WP-903.
- 11 *In re Hawaiian Tel. Co.*, Docket No. 5114, HTC T-48 at 28, lines 14 to 17.
- 12 The noninclusion method is the practice of excluding the receipt of CIAC on a utility's books of account and not including the CIAC or CIAC property in income, cost of service, or rate base. If a utility uses the noninclusion method, the Internal Revenue Service says that this is equivalent to including the CIAC in income in the year of receipt and depreciating the related CIAC property in its entirety in the same year. Notice 87-82 states that a utility using the noninclusion method of accounting for CIAC will be treated for purposes of the normalization rules as if it computed its tax expense for rate purposes by depreciating the related CIAC property in its entirety in the year in which the CIAC is received.
- 13 Compare HELCO-R-1018 and HELCO-WP-1002 (pages 1, 2, 3, 4, and 7). Note, for example, project no. P1-3159-Kanoelehua Sound Wall. Note, also, the omission of eight projects on HELCO-WP-1002. The commission deleted these omitted projects from the carryover list.
- 14 See HELCO-R-1017. The commission noted three discrepancies, requiring the commission to revise the estimated amount of projects deferred from 1990 to 1991.
- 15 We calculate that the estimates derived from the use of the CAPM and the RP method were given heavier weight than the estimates derived from the use of the DCF method by a proportion of 0.58 to 0.42.
- 16 Most analysts predict that Hawaii will continue to have modest economic expansion of 2-3 per cent in 1991. The national inflation rate, the relevant one for interest rates, is projected to continue at 4 per cent. These forecasts, however, have a significant element of uncertainty because of the conflict in the Persian Gulf.
- 17 The peak responsibility method allocates demand costs using the class demand at the time of the system peak. The system peak for HELCO usually occurs in the evening, between November and December. The assumption is that the capacity requirement of the utility system is determined by the peak load(s) and, thus, demand-related costs should be allocated in accordance with each rate class' respective contributions to the system peak.

The noncoincident peak demand method allocates demand costs using the maximum demands of the rate classes during the year regardless of when they occur. The assumption is that each customer class, if served independently, would require facilities that would meet the class' maximum demand.

*

R = residential

G = general service-nondemand

J = general service-demand

H = commercial cooking, heating, air conditioning, refrigeration

P = large power service

F = public street lighting

- 18 Pricing at marginal cost is optimal, if followed uniformly throughout the economy. However, as a practical matter, price often diverges from marginal cost in some sectors for a variety of reasons (e.g., diseconomies of scale, disproportionately heavy taxation). The use of marginal cost pricing in a sector may worsen, rather than improve, the allocation of resources when price diverges from marginal cost in other sectors, particularly where the sectors are strongly interdependent. It has been suggested that, where it is not possible to equate price to marginal cost, the 'second-best' solution might be to keep price greater than marginal cost by the same degree in all sectors. J. Bronbright, A. Danielsen & D. Kamerschen, *Principles of Public Utility Rates* at 430 (2d ed. 1988).
- 19 The CA's calculation of revenue requirements at present rates is the same as HELCO's, except for the CA's exclusion of firm capacity surcharge revenues of \$1,200,000 plus related revenue taxes of \$114,000. HELCO's figure is \$86,945,000. \$86,945,000 minus \$1,314,000 (\$1,200,000 + \$114,000) equals \$85,631,000.
- 20 Also parties to the docket are various public interest groups, state and federal agencies, and the counties.

End of Document

© 2018 Thomson Reuters. No claim to original U.S. Government Works.

KANSAS GAS SERVICE, A DIVISION OF ONEOK, INC.

Working Capital

Cash Working Capital

Test Year Ended December 31, 2005

Section 6
Schedule 6-H
Page 1 of 1

Line No.	Category	Col. 1	Revenue Lag	Col. 2	Expense Lead	Col. 3	Net Lead/Lag	Col. 4	% of Total Year	Col. 5	Expense	Col. 6	Cash Working Capital Requirement	Col. 7
1	Labor		43.41		10.82		32.586		8.9216%		\$42,988,622		\$3,835,254	
2	Labor Attends		43.41		119.64		-76.227		-20.8698%		13,533,629		(2,824,437)	
3	Purchased Gas Expense		43.41		31.26		12.149		3.3262%		741,847,600		24,675,365	
4	Payables		43.41		32.39		11.020		3.0171%		28,725,740		866,685	
5	Supplies and Expenses		43.41		72.30		-28.888		-7.9091%		12,519,872		(990,209)	
6	General Taxes		43.41		197.74		-154.325		-42.2520%		19,018,612		(8,035,742)	
7	Income Taxes		43.41		37.38		6.035		1.6523%		24,471,069		404,334	
8	Interest on Long Term Debt		43.41		75.26		-31.855		-8.7214%		23,263,028		(2,028,864)	
9											<u>\$906,368,173</u>		<u>\$15,902,385</u>	
10													(\$534,795)	
11													(1,745,662)	
12													(2,297,253)	
13													<u>\$11,324,676</u>	

Less: Sales and Use Tax Payables Offset

Less: Franchise Fee Payables Offset

Less: Legal Contingency and Workers Compensation Reserves

Cash Working Capital in Rate Base (WC 5)