filed electronically in docket office on 07/20/18

IN THE TENNESSEE PUBLIC UTILITY COMMISSION
AT NASHVILLE, TENNESSEE

IN RE:	)	
	)	
CHATTANOOGA GAS COMPANY	)	
PETITION FOR APPROVAL OF AN	)	**DOCKET NO. 18-00017**
ADJUSTMENT IN RATES AND	)	
TARIFF; THE TERMINATION OF THE	)	
AUA MECHANISM AND THE	)	
RELATED TARIFF CHANGES AND	)	
REVENUE DEFICIENCY RECOVERY;	)	
AND AN ANNUAL RATE REVIEW	)	
MECHANISM	)	

CONSUMER PROTECTION AND ADVOCATE DIVISION'S
RESPONSES TO FIRST DISCOVERY REQUESTS
OF CHATTANOOGA GAS COMPANY

The Consumer Protection and Advocate Division of the Office of the Tennessee Attorney General (Consumer Advocate), pursuant to Rules 26, 33, and 34 of the Tennessee Rules of Civil Procedure, Tennessee Public Utility Commission (TPUC) 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 Request of Chattanooga Gas Company (CGC or the Company) to the Consumer Advocate, filed on July 15, 2018.

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:

DISCOVERY REQUEST NO. 1:

On Page 20, Lines 1-3, of Mr. Novak's Direct Testimony, Mr. Novak states, "The Commission has a long-established policy of only allowing rate recovery of the minimum required contribution for pension and other post-employee benefits (OPEB) expense." This testimony in Footnote 29 then references one docket, Commission Docket 92-14631, Investigation of Proper Regulatory Treatment of Other Post-Employment Benefits for Utilities Regulated by the Tennessee Public Service Commission. Please provide the following information:

a. Is it Mr. Novak's position that the Commission has allowed only the rate recovery of the minimum required contribution for pension and OPEB expense in every Tennessee rate case before the TPUC or its predecessor agencies since 1992 and thereafter? Please explain your response.

b. Identify all Tennessee utility rate case decisions regarding OPEB expenses since 1992 and thereafter. For purposes of responding to this request, for each rate case identify the docket number, name of the utility, type of utility (natural gas, electric, telephone, water), date of the applicable rate case order, state "Minimum Only" or "Other" whereby the TPUC or predecessor agency allowed recovery of only the minimum contribution for pension and OPEBs (i.e., "Minimum Only") or allowed something other than the minimum ("Other"), and identify the page number of the order reflecting such decision. Further, please provide a complete copy of each of the rate case orders identified in response to this request if such order is not currently available on the TPUC website.

Response:

The Consumer Advocate objects to this request on the grounds that it is overly broad and unduly burdensome, as the request seeks information relating to every Tennessee rate case since 1992 and appears to require the Consumer Advocate to perform research that could be conducted by the Company. Further, this request seeks information that is inadmissible or not reasonably calculated to lead to the discovery of admissible evidence as much of this information may relate to various types of utilities or to fact patterns distinguishable from this Docket. Without waiving these objections, the Consumer Advocate would answer as follows:

a. Mr. Novak has not researched every decision regarding pension and OPEB expense in every rate case brought before TPUC. However, it is his general understanding that TPUC has, by means of its decisions and orders, adopted a general policy in which the Commission only recognizes the current minimum pension and OPEB expense as determined by the utility's actuary as an appropriate amount to consider for setting rates.

b. The Consumer Advocate does not have access to all of the documents that would be required to provide the information requested by the Company. Further, many of these prior rate cases brought before the TPUC were resolved through settlement agreements that do not explicitly address pension or OPEB expense, thereby making the factual scenarios presented by the requested cases potentially ambiguous or irrelevant as they relate to this proceeding. Again, without waiving the objections above, the Consumer Advocate would submit the following table concerning the treatment of pension and OPEB expense in the following dockets, which represent the last rate cases for each of these utilities.

Utility/Docket	Pension & OPEB Expense Resolution
Tennessee-American Water Company Docket No. 12-00049	Settlement Agreement. No mention of Pension or OPEB Expense in the Settlement

	Agreement. No Pension or OPEB assets included in the Rate Base calculation shown as Attachment A, Schedule 2 to the Settlement Agreement.
Kingsport Power Company Docket No. 16-00001	Settlement Agreement. No mention of Pension or OPEB Expense in the Settlement Agreement. No Pension or OPEB assets included in the Rate Base calculation shown as Attachment A, Schedule 2 to the Settlement Agreement.
Atmos Energy Corporation Docket No. 14-00146	Settlement Agreement. Page 22 of the Commission's Order states the following with respect to Deferred Pension Regulatory Asset Balance: "The Company shall include in rate base the average unamortized portion of the regulatory asset related to FAS 87 which it was authorized to establish in the Final Order from Docket No. 12-00064. The regulatory asset will be fully amortized on May 31, 2017. No further regulatory asset for FAS 87 shall be established unless so established by the TRA, and until the TRA adopts new ratemaking methodologies thereto."
Piedmont Natural Gas Company Docket No. 11-00144	Settlement Agreement. Page 5 of the Commission's Order states the following with respect to Pension Expense: "That for purposes of future defined benefit pension expense and environmental clean-up expense incurred by Piedmont, the deferral mechanisms established pursuant to Authority Order dated June 9, 1997 in Docket No. 96-00977 and Tennessee Public Service Commission Order dated December 21, 1992 in Docket No. 92-116160 should remain in effect."

Responsible Witness: Mr. Novak.

DISCOVERY REQUEST NO. 2:

Provide a back-cast going back to January of 2010 illustrating the performance accuracy of the regressions utilized by Mr. Novak to project volumes for the CPAD attrition year for R-1, C-1, and C-2, similar to that provided by Chattanooga Gas Company in response to CPAD-1-247.

Response:

The requested information is included in Mr. Novak's workpapers that have already been supplied to the Company, and were provided in the following locations:

Rate Schedule R-1, see CPAD Revenue Workpapers R-10-5.00 to R-10-5.12;
Rate Schedule C-1, see CPAD Revenue Workpapers R-20-5.00 to R-20-5.12; and
Rate Schedule C-2, see CPAD Revenue Workpapers R-21-5.00 to R-21-5.12.

Responsible Witness: Mr. Novak.

DISCOVERY REQUEST NO. 3:

Please label the statistical measures on the "Parameters2" tab labeled as "Weather Normalization Regression Statistics" and "Annual Usage Regression Statistics" in the following work-papers provided by witness Novak:

a. R-1 Residential Revenues
b. R-4 Multi-Family Revenues
c. C-1 Commercial Revenues
d. C-2 Commercial Revenues

Response:

a. The statistics referred to by the Company make use of certain array functions within Microsoft Excel. Specifically, the "LINEST" and the "LOGEST" functions calculate the regression statistics by using the "least squares method" that best fits the data and then return an array of the calculated statistics. The calculated statistics included on the "Parameter2" of the Consumer Advocate's revenue workpapers referred to above are laid out as follows:

Slope Value	Constant Value
Standard Error Values of the Coefficient.	Standard Error Values of the Constant.
Coefficient of Determination (Correlation).	Standard Error of the Y Estimate.
F Statistic.	Degrees of Freedom.
Regression Sum of Squares.	Residual Sum of Squares.

Note that not all of the statistics returned from the "LINEST" and the "LOGEST" functions are used in the Consumer Advocate's weather normalization workpapers. In order to view these workpapers, to see which statistics are used in the workpapers, and how the workpapers are labeled, refer to the "Regression Output" section on the "1 Variable" tab.

b. See response to Item 3a above.
c. See response to Item 3a above.
d. See response to Item 3a above.

Responsible Witness: Mr. Novak.

DISCOVERY REQUEST NO. 4:

Provide copies of Mr. Novak's prior testimony that are identified on Attachment WHN-1 addressing natural gas cost allocation and rate design matters including, but not limited to, the following cases (there were no links for these as was indicated on the exhibit):

a. Atmos Energy Corporation, Tennessee Docket No. 07-00105.
b. Piedmont Natural Gas, Tennessee Docket No. 11-00144.
c. Atmos Energy Corporation, Tennessee Docket No. 14-00146.
d. B&W Gas Company, Tennessee Docket No. 15-00042.
e. Vectren Energy Delivery, Ohio Docket No. 07-1080-GA-AIR.
f. CenterPoint Energy, Texas Docket No. GUD 9902.

Response:

The Consumer Advocate objects to this request on the grounds that it is unduly burdensome, as the request appears to require the Consumer Advocate to perform research that could be conducted by the Company. Further, this request seeks information that is inadmissible or not reasonably calculated to lead to the discovery of admissible evidence as this information relates to other cases outside the scope of this Docket. In addition, Tennessee Rule of Civil Procedure 26.02(4)(A)(i) provides in pertinent part, "upon request in an interrogatory, the party shall disclose . . . a list of all other cases in which, *during the previous four years*, the witness testified as an expert . . . ." (Emphasis added.) The Company's request clearly seeks information beyond the four-year limit. Without waiving these objections, the Consumer Advocate would answer as follows:

See the attached exhibits:

a. See Attachment CGC-1-4a;
b. See Attachment CGC-1-4b;
c. See Attachment CGC-1-4c;
d. See Attachment CGC-1-4d;
e. See Attachment CGC-1-4e; and
f. See Attachment CGC-1-4f.

Responsible Witness: Mr. Novak.

DISCOVERY REQUEST NO. 5:

On Page 9, Lines 9-12, of Dr. Klein's Direct Testimony filed on July 3, 2018, Dr. Klein states that, "The Tennessee regulators have applied the double-leverage approach to capital structures for regulated subsidiaries of parent companies to take into account the parent-subsidiary relationship. This approach has been applied to all regulated public utility industries since at least the 1970s." Please provide the following:

a. Is it Dr. Klein's position that the double leverage approach has been applied by Tennessee regulators in every rate case since the 1970s where the regulated utility was a subsidiary of a parent company? Please explain your response.

b. Identify all Tennessee rate case decisions where the capital structure was at issue for a utility that was a subsidiary of a parent entity and whether the double-leverage approach was or was not applied (including cases where double-leverage could have been raised but was not; this request also includes stipulated capital structures). For purposes of responding to this request, for each rate case identify the docket number, name of the utility, type of utility (natural gas, electric, telephone, water), date of the applicable rate case order, state "Yes" or "No" whether the TPUC or predecessor agency applied the double-leverage approach to the capital structure to take into account the parent-subsidiary relationship ("Yes") or did not ("No"), and identify the page number of the order whereby the double-leverage approach was or was not applied. Further, please provide a complete copy of each of the rate case orders identified in response to this request if such order is not currently available on the TPUC website.

Response:

The Consumer Advocate objects to this request on the grounds that it is overly broad and unduly burdensome, as the request seeks information relating to *every* general rate case before the TPUC and its predecessor agencies since 1970 and appears to require the Consumer Advocate to perform research that could be conducted by the Company. Further, this request seeks information that is inadmissible or not reasonably calculated to lead to the discovery of admissible evidence as much of this information would relate to types of utilities or contain facts that would be clearly distinguishable from the subject matter of this Docket. Without waiving these objections, the Consumer Advocate would answer as follows:

a. To the Consumer Advocate's knowledge, Tennessee regulators have applied double-leverage in every rate case involving Tennessee-American Water Company (a subsidiary of the American Water Works Company), Kingsport Power Company (a subsidiary of American Electric Power), and major telecommunications companies (Bellsouth, GTE, United Inter-mountain) prior to their election of relaxed regulation. To the knowledge of Dr. Klein, who was hired by the Tennessee Public Service Commission (TPSC) in 1986, the application of the double leverage approach in this context extends at least to back to that year. Additionally, Tennessee court decisions involving appeals of the TPSC's adoption of double-leverage capital structures indicate that this practice was followed at least as far back as the late 1970s (*see United Inter-mountain Telephone Company and Raytheon Company v. Tennessee Public Service Commission, et al.*, (Davidson County Chancery Court, October 25, 1978) (included as Attachment 1-5). While the Consumer Advocate has not undertaken to research every rate case since the 1970s where the regulated utility was a subsidiary of a parent company, for regulated companies in Tennessee other than those listed above that are subsidiaries of parent companies, double-leverage as well as other methods have been used to recognize the parent-subsidiary relationship, such as use of the consolidated capital structure of the parent.

b. See response to Item 5a above.

Responsible Witness: Dr. Klein

DISCOVERY REQUEST NO. 6:

On Page 18, Line 24-25, and p. 19, Lines 1-2, of Mr. Dittemore's Direct Testimony, Mr. Dittemore states, "The Commission adopted a Stipulation and Agreement in Docket No. 12-00049, a Tennessee American Water Company rate case that excluded Return on Equity costs from the calculation of Daily Operating Expenses, and therefore it was completely excluded from determination of CWC [cash working capital] in that case." Please respond to the following:

a. It is Mr. Dittemore's position that the TPUC and predecessor agencies have always excluded return on equity costs from the calculation of Daily Operating Expenses, and therefore from cash working cash? Please explain your answer.

b. Identify all Tennessee rate case decisions since 2010 and thereafter where cash working capital was at issue for a utility and whether return on equity was excluded or included from the calculation of daily operating expenses. For purposes of responding to this request, for each rate case identify the docket number, name of the utility, type of utility (natural gas, electric, telephone, water), date of the applicable rate case order, state "Yes" or "No" whether the TPUC or predecessor agency excluded return on equity ("Yes") or did not ("No"), and identify the page number of the order reflecting such decision. Further, please provide a complete copy of each of the rate case orders identified in response to this request if such order is not currently available on the TPUC website.

Response:

The Consumer Advocate objects to this request on the grounds that it is overly broad and unduly burdensome, as the request seeks information relating to all previous dockets before TPUC and its predecessor agencies and appears to require the Consumer Advocate to perform research that could be conducted by the Company. The Company's request also mischaracterizes the Consumer Advocate witness' testimony insofar as it avers that Mr. Dittemore was using an entirely historical basis for making his recommendation. Further, this request seeks information that is inadmissible or not reasonably calculated to lead to the discovery of admissible evidence as much of this information may relate to other types of utilities or contain fact patterns distinguishable from the subject of this Docket. Without waiving these objections, the Consumer Advocate would answer as follows:

a. With respect to all Tennessee rate case decisions where cash working capital was at issue for a utility and whether return on equity was excluded or included from the calculation of daily operating expenses, the Consumer Advocate responds that it has not performed a search and the related analysis of all previous dockets before TPUC and its predecessor agencies on the subject matter of this request since such a search would be beyond the scope of reasonable discovery in this Docket. The Consumer Advocate would point out that Mr. Dittemore's testimony provides a clear example in which the TPUC excluded Return on Equity costs from the calculation of Daily Operating Expenses, thereby removing Return on Equity from the Cash Working Capital calculation.

b. See the response to Item 6a above.

Responsible Witness: Mr. Dittemore

DISCOVERY REQUEST NO. 7:

On Page 26, Lines 9-15, of Mr. Dittemore's Direct Testimony filed on July 3, 2018, Mr. Dittemore states that, "CGC proposes to amortize its balance of "Unprotected" ADIT to the cost of service over a five-year period.... I propose using a three-year amortization period .... Further, the three-year period is consistent with the period used to amortize rate case costs." Please provide the following:

a. Is there any applicable statute, rule, order, or other regulatory requirement that requires a three-year amortization instead of a five-year amortization? If so, please identify such requirements.

b. Is there any applicable statute, rule, order, or other regulatory requirement that requires that the amortization period for the unprotected ADIT must be the same as the rate case amortization period? If so, please identify such requirements.

Response:

The Consumer Advocate objects to this request (both subparts) on the grounds that it is vague, ambiguous, overly broad, and unduly burdensome, as the request seeks information relating to all statutes, rules, orders, or regulations, as well as all previous dockets before TPUC and its predecessor agencies on the subject matter of the request and appears to require the Consumer Advocate to perform research and analysis that could be conducted by the Company. To require the Consumer Advocate to perform research and the related analysis of all statutes, rules, orders, or regulations, as well as all previous dockets before TPUC and its predecessor agencies on the subject matter of this request is beyond the scope of reasonable discovery in this Docket.

Responsible Witness: Objection provided by Counsel.

DISCOVERY REQUEST NO. 8:

On Page 32, Lines 18-19, Mr. Dittemore states, "The purpose of a CAM [cost allocation manual] for a regulated entity is two-fold. First, it provides formal specific guidance to employees on the procedures to follow in tracking costs and allocating such costs to the appropriate organization.

The existence of the manual, along with periodic training and reinforcement, signifies that compliance with documented procedures is a priority. Secondly, the CAM should be used to support the reasonableness of such allocation methodologies and processes before the state regulators. The lack of a CAM raises questions as to whether either of these objectives is a priority within SCG." On Page 33, Lines 3-4, Mr. Dittemore further states, "I recommend TPUC require future CGC cost allocations to be supported by a fully transparent and documented CAM." Please provide the following:

a. Is there any currently applicable statute, rule, order, or other regulatory requirement that requires a natural gas utility to have a cost allocation manual? If so, please identify such specific authority.

b. Can the Commission in this rate case docket require CGC to utilize a CAM for any future rate cases? If so, please identify such authority by statute or rule. If not, by what authority can the TPUC require CGC to file a CAM? Please explain your answer.

c. Can the Commission in this rate case docket require CGC to utilize a CAM for any future annual rate review CGC may seek under § 65-5-103(6)(A)? Please explain your answer. In explaining your answer, please expressly discuss how a CAM that does not exist can be a "methodology adopted in its most recent rate case"?

d. Has the Commission previously required a regulated utility to create, file, or have an approved CAM? If so, please identify all such instances by docket number, name of the utility, type of utility (natural gas, electric, telephone, water), the date of the applicable order, and the page of the order whereby such an obligation was required.

e. Provide a complete copy of all orders identified in response to this request if such order is not currently available on the TPUC website.

Response:

The Consumer Advocate objects to this request (all subparts) on the grounds that it is vague, ambiguous, overly broad, and unduly burdensome, as the request seeks information relating to all statutes, rules, orders, or regulations, as well as all previous dockets before TPUC and its predecessor agencies on the subject matter of the request and appears to require the Consumer Advocate to perform research and analysis that could be conducted by the Company. To require the Consumer Advocate to perform research and the related analysis of all statutes, rules, orders, or regulations, as well as all previous dockets before TPUC and its predecessor agencies on the subject matter of this request is unduly burdensome and beyond the scope of reasonable discovery in this Docket. Additionally, the Consumer Advocate objects on the ground that a response to the request would require, in part, certain legal analysis and conclusions that are not proper in the context of the discovery process, but would only be proper in the context of legal briefs and related analysis and argument. Further, this request seeks information that is inadmissible or not reasonably calculated to lead to the discovery of admissible evidence as much of this information would relate to types of utilities or contain facts that clearly distinguishes those matters from the subject matter of this Docket. With respect to the specific subparts, the Consumer Advocate would answer as follows:

a. Objection as noted above.

b. Objection as noted above.

c. Objection as noted above.

d. Without waiving the above objections, the Consumer Advocate would note the Public Service Commission's Order in the matter *In Re: Application of Bellsouth, BSE, Inc. for a Certificate of Convenience and Necessity to Provide Intrastate Telecommunications Services* (2000 WL 36322979, Docket No. 98-00879 (Tenn. P.S.C. February 14, 2000)) in which the Commission opined:

> Another factor in considering BSE's Application is that BSE failed to submit a viable business plan and a cost allocation manual. The Authority has routinely examined the business plans of CLEC applicants when determining whether such applications meet the requirements of Tenn. Code Ann. § 65-4-201(c). In considering BSE's application the review of a cost allocation manual is essential when the Authority must determine whether the grant of certification to a BellSouth affiliate such as BSE will foster competition and promote the public interest. More specifically, the filing of a cost allocation manual aids the Authority in determining whether the appropriate safeguards are in place to prevent cross-subsidies between regulated and non-regulated services. The lack of a business plan and cost allocation manual prevents the Authority from determining the extent to which BSE intends to operate, and whether such operation and the provisioning of telecommunications services on an expanded level is compatible with the public interest.

e. Objection as noted above.

Responsible Witness: Mr. Dittemore. Objection provided by Counsel.

DISCOVERY REQUEST NO. 9:

Provide Attachment WHN-7, CGC Excess Revenue Calculations 2011-2016 in Excel format including without limitation the functionality of working cells and formula.

Response:

See Attachment CGC-1-9.

Responsible Witness: Mr. Novak

DISCOVERY REQUEST NO. 10:

Provide copies of all documents referenced in Mr. Novak's testimony.

Response:

The Consumer Advocate believes that all documents referenced in Mr. Novak's testimony have either already been supplied or are included within the record for this Docket. To the extent the Consumer Advocate discovers additional responsive information, it will provide the information in a supplemental response pursuant to the Tennessee Rules of Civil Procedure.

Responsible Witness: Mr. Novak

DISCOVERY REQUEST NO. 11:

Provide copies of all documents, analysis, and studies relied on by Mr. Novak in preparing his testimony that have not been previously provided.

Response:

To the Consumer Advocate's knowledge, all documents, analysis, and studies relied upon by Mr. Novak in preparing his testimony have already been provided. To the extent the Consumer Advocate discovers additional responsive information, it will provide the information in a supplemental response pursuant to the Tennessee Rules of Civil Procedure.

Responsible Witness: Mr. Novak

DISCOVERY REQUEST NO. 12:

Provide the backup and other support for the fixed compensation benefit rate as provided in Consumer Advocate Schedule No. 4-3.

Response:

See the Attachment provided in response to Consumer Advocate Discovery Request 1-139.

Responsible Witness: Mr. Dittemore

DISCOVERY REQUEST NO. 13:

For the period 2010 to date, for each TPUC or predecessor agency base rate case docket identify by utility the total number of data requests submitted by CPAD to each such utility. Specifically, this request includes, but is not limited to, Tennessee Docket Nos. 11-00144, 14-00146, and 16- 0000.

Response:

The Consumer Advocate objects to this request on the grounds that it is vague, ambiguous, overly broad, and unduly burdensome. The request asks the Consumer Advocate to locate, identify, make assumptions about, sort through, and count separate discovery requests for every docket in which the Consumer Advocate has been a party, including both general rate cases and potentially certain alternative regulation cases. To require the Consumer Advocate to research and the related analysis of all previous dockets before TPUC and its predecessor agencies on the subject matter of this request is unduly burdensome and beyond the scope of reasonable discovery in this Docket. Further, the request is not calculated to lead to the discovery of admissible evidence. The number of requests in prior cases does nothing to contribute to the merits of the current Docket.

Responsible Witness: Objection provided by Counsel.

RESPECTFULLY SUBMITTED,

DPWhitaker, III

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CERTIFICATE OF SERVICE

I hereby certify that a true and correct copy of the foregoing was served via U.S. Mail or electronic mail upon:

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This the 20th day of July, 2018.

D P Whitaker, III
Daniel P. Whitaker, III

ATTACHMENT

1-4a

BEFORE THE TENNESSEE REGULATORY AUTHORITY
NASHVILLE, TENNESSEE

August 21, 2007

In re: Petition of Atmos Energy Corporation	)	
for Approval of Adjustment of Its Rates and	)	
Revised Tariff	)	Docket No. 07-00105

PRE-FILED DIRECT TESTIMONY

OF

WILLIAM H. NOVAK

Q. Would you state your name, business address and occupation for the record, please?

A. My name is William H. Novak. My business address is 19 Morning Arbor Place, The Woodlands, TX, 77381. I am the owner of WHN Consulting, a utility consulting and expert witness services company.

Q. Please provide a summary of your background and professional experience.

A. I have both a Bachelors degree in Business Administration with a major in Accounting, and a Masters degree in Business Administration from Middle Tennessee State University. I am also licensed to practice as a Certified Public Accountant in Tennessee.

My work experience has centered around regulated utilities for over 25 years. Before establishing WHN Consulting, I was Chief of the Energy & Water Division of the Tennessee Regulatory Authority where I had either presented testimony or advised the Authority on a host of regulatory issues for over 19 years. In addition, I was previously the Director of Rates & Regulatory Analysis for two years with Atlanta Gas Light Company, a natural gas distribution utility with operations in Georgia and Tennessee. I also served for two years as the Vice President of Regulatory Compliance for Sequent Energy Management, a natural gas trading and optimization company in Texas.

Q. What is the purpose of your testimony in this proceeding?

A. The purpose of my testimony is to present Atmos Intervention Group's ("AIG's") recommended structural changes (other than rates) to the industrial tariffs of Atmos Energy Corporation ("Atmos" or "the Company") for the TRA's consideration. I have also prepared draft industrial tariff sheets that incorporate these recommendations as Exhibits AIG-1 through AIG-6.

Q. Are these the same tariff changes that you proposed in Docket 05-00258?

A. No. We have updated our proposals to reflect the TRA's industrial rate design for Chattanooga Gas Company in Docket 06-00175.

Q. Please summarize the tariff changes that you are recommending.

A. AIG proposes that the following changes be made to the Company's existing tariffs:

1. A revision to the Company's existing Small Commercial/Industrial Gas Service tariffs (Rate Schedule 220) as shown on Exhibit AIG-1;
2. A revision to the Company's existing Large Commercial/Industrial Gas Service tariffs (Rate Schedule 230) as shown on Exhibit AIG-2;
3. Consolidation and revision of the Company's existing Demand/Commodity Gas Service and Optional Gas Service (Rate Schedules 240 and 250) as shown on Exhibit AIG-3;
4. A new gas Transportation Storage Option (Rate Schedule 255) tariff, offered to Transportation Customers as shown on Exhibit AIG-4;
5. New language for the Company's existing Transportation (Rate Schedule 260) tariff as shown on Exhibit AIG-5; and
6. Introduction of a new Low Volume Transportation with Firm Backup (Rate Schedule 265) tariff as shown on Exhibit AIG-6 that will allow more customers access to purchase their own gas supplies and also encourage competition among gas suppliers.

Q. Please describe your recommended changes to the Company's Commercial & Industrial (Rate Schedules 220 and 230) tariffs as shown on Exhibits AIG-1 and AIG-2.

A. We recommend that Rate Schedule 220 be revised to include service to only smaller commercial/industrial customers with annual gas consumption of less than 4,000 Ccf per year. We further recommend that Rate Schedule 230 be revised to reflect commodity service to medium sized commercial and industrial customers whose annual gas usage exceeds 4,000 Ccf per year. Currently, the Company requires annual gas consumption in excess of 135,000 Ccf per year to distinguish between these two tariff sheets. In addition, we would also recommend that Rate Schedule 230 be further changed to implement a three tier declining step block structure consisting of monthly consumption at 3000 Ccf, 4000 Ccf and 5000 Ccf. For the third tier, we are recommending that the commodity rate be set at 50% of the 1st tier rate.

Q. Have other gas utilities adopted rate designs similar to what you are now proposing here?

A. Yes. This rate design structure is consistent with the structure approved by the TRA for small and medium sized commercial/industrial customers of Chattanooga Gas Company in Docket 06-00175.

Q. Why have you modeled Chattanooga Gas Company's rates in this testimony?

A. These commercial and industrial tariff sheets were based on the results of a class cost of service study that was performed by Chattanooga Gas Company with input from the Chattanooga Manufacturer's Association. In addition, it's our position that declining block steps represent an equitable rate structure for both smaller and larger commercial/industrial customers in that it reflects the fact that a gas utility's costs of service declines as its sales volumes increase.

Q. Please describe your recommended changes to the Company's Large Commercial & Industrial (Rate Schedules 240 and 250) tariff as shown on Exhibit AIG-3.

A. We recommend that Rate Schedules 240 and Rate 250 be consolidated into one rate schedule, with both fixed and variable components in the Customer Base Use Charge, along with a modification of the existing Demand Charge. We also recommend that the existing rate steps be changed to reflect the same tier structure approved by the TRA in Chattanooga Gas Company's last rate case.

Q. Why are you proposing that the rate structure be modified into a fixed demand charge and commodity rate for all customers on this tariff?

A. This rate structure closely reflects the straight fixed variable rates that are charged to gas utilities from their interstate pipelines for capacity charges. This type of rate structure recovers a portion of capacity costs through a demand charge which is independent of the total volumetric throughput and rewards those customers that have higher load factors.

Q. Please explain how a customer will opt for firm or interruptible service under this rate schedule. ?

A. Customers will contract for firm entitlement and pay a demand charge allocation to be credited to the purchased gas adjustment. For those customers contracting 100% firm, the firm contract entitlement will be billed at the billing demand.

Q. Won't this change produce a higher total customer charge for the existing interruptible customers presently served under Rate Schedule 250?

A. Yes. For the interruptible customers presently being served under the Company's existing Rate Schedule 250, this change will produce an increase in their monthly customer charge. These customers receive a higher value of service relative to the Company's other customers. For example, the existing Rate 250 customers make no contribution to the Company's interstate pipeline demand costs, yet they have use of this demand capacity for almost the entire year with very few interruptions. In addition, these customers have "no-notice" capabilities, which allows them to "swing" or move back and forth between the Company's sales and transportation rate schedules with the Company bearing the burden of assuming their gas scheduling and nominations. Finally, the Company assumes a singificanly greater credit risk for these customers. For these reasons, we are recommending that the monthly customer charges to this class be increased to reflect a more accurate cost of providing this service.

Q. Please describe your recommended proposal for a Transportation Storage Option (Rate Schedule 255) as shown on Exhibit AIG-4.

A. Over the past twelve years, there has been an exodus of large commercial/industrial customers that were previously served through the Company's bundled sales rate schedules that are now buying gas through a gas marketer. Subsequently, many of the storage assets that were needed to serve the Company's customers are stranded, and could provide better value through a Transportation Storage rate that would assist transportation customers with mitigating gas volatility risks and exposure in the marketplace. Furthermore, since transportation customers do make a contribution to the Company's base rates, including the Company's return on storage inventory, a pro-rata amount of storage should be made available to transportation customers.

Q. Would this Storage Tariff Option compromise reliability of service to the Company's other rate classes?

A. No. This service would be recallable by the Company if their other customers have any gas supply risks. However, this situation would only occur when the Company has a gas supply shortage and is unable to buy gas on the market.

Q. How would the Storage Tariff Option be implemented?

A. Under our proposed tariff, the Company would calculate the Excess Storage Volumes which are based on the Company's unutilized storage volumes for the past year. This volume would be reviewed by the TRA and posted on August 1 under this program.

Q. How does the Transportation Storage Option benefit the Company's transportation customers?

A. The Transportation Storage Option provides transportation customers with some ability to mitigate potential spikes in natural gas pricing. Given the price volatility of natural gas, transportation customers today are actually paying more just to get price stability. To the extent that the Company has excess storage capacity available, their asset manager is currently profiting from selling this same storage and then sharing it with the Company. This change ensures that the value of this storage flows directly to the Company's customers, and is not diverted to the Company's asset manager.

Q. How will this Transportation Storage Option benefit the Company's other bundled sales customers?

A. Revenues from this service will reflect true market prices of this service, and 100% of these revenues will then be credited to the Purchased Gas Adjustment which will reduce the gas costs for the Company's other bundled sales customers. This service allows the full market value of these storage assets to be realized with all of the proceeds flowing to the Company's customers instead of the existing sharing formula with the Company's asset manager.

Q. How will the minimum bid amounts be calculated?

A. The minimum bid reflects only a nominal value for this service. The market will determine the final bid amounts.

Q. What happens to unused gas in storage?

A. Any unused gas will be returned to the Company's inventory on April 1 of the following year.

Q. Do other gas utilities offer this same type of storage service to their customers?

A. Yes. This same type of storage service is offered to industrial customers of Chattanooga Gas Company.

Q. Please describe your recommended changes to the Company's Interruptible Transportation (Rate Schedule 260) tariff as shown on Exhibit AIG-5.

A. We have numerous recommendations for the Company's Interruptible Transportation Rate Schedule 260 that we feel will encourage more competition and realign rates to a structure that is more cost based.

First, we are proposing a demand and commodity rate structure similar to the rates that were approved in Chattanooga Gas Company's last rate case. We feel this type of rate structure more closely reflects the straight fixed variable rate design and rewards those customers with better load factors.

Secondly, our proposed tariff clarifies some balancing language that we feel is necessary to align imbalance charges with the Company's actual costs. An imbalance occurs when a transportation customer either brings in more or less gas to the Company's system than they have used. The existing provisions of the Company's tariff related to balancing are based on the Company's connecting pipeline balancing costs. However, the Company is typically allowed to aggregate all of their delivery points in order to mitigate these imbalances. Furthermore, most interstate pipeline tariffs automatically use the Company's storage as a supply buffer to help manage their supply imbalances. Therefore, it is our position that applying the provisions of a pipeline's imbalance tariff to a specific transportation customer is not appropriate and unfair to the customer. Instead, our recommendations for balancing are intended to provide an incentive for customers to sustain a reasonable imbalance level with the Company while aligning these incentives with the Company's actual cost of maintaining imbalances.

We have also proposed new penalty language which mitigates some of the penalty exposure to large customers and allows the Company to waive penalties when they do not first incur penalties themselves. This language is intended to align the penalty charges with the Company's actual costs and associated risks.

This language has been modeled after the TRA's approved tariff for CGC's transportation customers.

Q. Will your proposed changes to Rate Schedule 260 result in these transportation customers paying a lower base rate than the sales customers on Rate Schedule 250?

A. Yes. The transportation customers on Rate Schedule 260 are required to arrange and manage their own gas commodity purchases. In addition, these customers may be making a contribution to the Company's demand costs depending on how the capacity release revenue is credited to the Company's firm customers. Finally, these customers allow the Company to reduce their carrying costs of purchasing gas and the associated credit risk of recovering this cost. Because the cost of providing service to these transportion customers is less than it is for sales customers, we have proposed a lower demand charge to reflect the lower value of this service.

Q. Please describe your recommended proposal for a Low Volume Transportation with Firm Backup (Rate Schedule 265) tariff as shown on Exhibit AIG-6.

A. We have proposed a Low Volume Transportion rate to give smaller customers the option of buying gas through a third party. This rate is similar to the Low Volume T-3 transportation rate that was recently approved by the TRA for Chattanooga Gas Company and it is our understanding that several commercial customers are already opting for this type of service.

This rate allows customers who use in excess of 4,000 Ccf per year the option of using a third party gas supplier. Similar to Chattanooga's T-3 Low Volume transportation rate, the Company would provide firm backup service under this rate schedule. However, customers that subscribe to this rate schedule would continue to contribute to the Company's cost of service, and pay a demand charge to be applied as a credit to the purchased gas adjustment.

Q. Please explain why the proposed Rate 265 Low Volume Transportion rate is more equitable for the Company's sales customers.

A. The Company has contracted for long term pipeline and storage assets in order to serve their firm customers. Presently, when firm customers opt for transportation service, they no longer contribute revenues for the cost of these assets which results in a cost shift to the Company's other sales customers. However, it is likely that the Company's asset manager, who serves approximately 90% of the Company's transportation customers, also provides service to other firm customers using these same managed assets. The end result is value creation for the Company's affiliate asset manager at the expense of the Company's sales customers. However, by allocating the costs of firm capacity to this rate schedule, and providing a firm swing service, an unfair shift in costs is avoided which is more equitable to all of the Company's customers.

Q. Please explain how this benefit is calculated as shown on Exhibit AIG-7.

A. Exhibit AIG 7 provides a hypothetical example of the economics from Rate Schedule 265. In this example, a new low volume transportation customer would continue to be allocated a portion of the overall demand costs incurred by the Company. This demand cost is then credited to the Company's PGA and results in a reduction of $18,000 per year in demand costs to the Company's other sales customers. Under the existing tariff, the Company's firm transportation customers no longer pay a contribution to the Company's demand costs.

Q. Are there any other benefits of the Low Volume Transportion rate?

A. Yes. The current asset management relationship has given the Company's affiliate a virtual monopoly in certain service areas where the Company has subscribed to 100% of the interstate pipeline capacity. Under our proposal, customers could contract for alternate gas supplies through competing gas marketers. By unbundling the control that the Company has over pipeline capacity assets, these customers will be able to reduce their costs and benefit from increased competition. The Company's smaller customers who do not transport their own gas, would also benefit since there would continue to be a contribution to pipeline demand costs from the customers electing this tariff.

Q. What are you recommendations for the costs of providing telemetering service for transportation customers?

A. We are proposing that the transportation customers pay the costs of telemetering, and that the Company provide them with an option to pay for these costs over a 24 month period.

Q. Mr. Novak, do you have any recommendations for the Company's other commercial and industrial tariffs?

A. Yes. The Company has other commercial and industrial tariffs that have either not been used at all, or just used sparingly. These tariffs include:

Rate Schedule 221, Experimental School Service;

Rate Schedule 280, Economic Development Gas Service;

Rate Schedule 291, Negotiated Gas Service;

Rate Schedule 292, Cogeration Service; and

Rate Schedule 293, Large tonnage Air Conditioning Gas Service.

At present, we see very little need for continuing these tariffs. As mentioned above, they have seen very little or no usage, and they have no counterparts in the tariffs approved by the TRA for other gas utilities. However, if they are continued, we would recommend that their rate structure be altered to fall in line with the recommendations that we have made for other commercial and industrial tariffs.

Q. Mr. Novak, do you have any recommendations for the Company's Special Contracts?

A. Yes. To our knowledge, the Company currently has the following six active Special Contracts that have been approved by the TRA:

Docket	Company
86-07410	Saturn Corporation
97-01443	Alumax Extrusions
98-00277	Middle Tennessee State University
00-01022	Superior Industries International
01-00138	Mountain Home Energy Center
03-00540	Goodyear Tire & Rubber Company

The components of these individual Special Contracts need to be reexamined after the TRA first determines the total rate adjustment necessary. It may well be that the rate advantages of these Special Contracts will now be obsolete and can be incorporated into the Company's regular tariff rates.

Q. Mr. Novak, are you proposing any specific rates for the commercial and industrial classes at this time?

A. No. Instead we have tried describe only how the rates should be structured within the individual commercial and industrial tariffs. Until the TRA first makes a decision as to the total rate adjustment amount necessary, it will be impossible to make a specific recommendation for any tariff rates. As a result, we have labeled the specific rates contained in our Exhibits as "TBD", meaning "to be determined".

For this rate case, we would first ask the TRA to apportion any rate change that it deems appropriate evenly across-the-board to all customer classes based on the existing gross margin in each rate class. We would then like to present the TRA through either supplemental testimony or post hearing briefs, with specific rate recommendations that will produce this new level of revenue.

Q. Do you have any other recommendations for the TRA to consider?

A. Yes. We would ask the TRA to require the Company to file a class cost of service study in their next rate case. Because of the accelerated pace of the previous rate case docket in 2006 along with the quick turn around to this rate case, there has not been enough time to prepare and present such a study for the TRA's consideration. Without such a study, it is impossible to know if the rates for a particular customer class are too high, thereby resulting in a subsidy to the other customer classes. A similar study was filed in the last rate case for Chattanooga Gas Company, and we feel that such a review is certainly warranted in the Company's next rate case.

Q. Does this conclude your testimony?

A. Yes, it does.

VERIFCATION

STATE OF TENNESSEE)

COUNTY OF DAVIDSON)

I, William H. Novak, being duly sworn state that I am authorized to make this verification on behalf of Atmos Intervention Group; that I have read the foregoing Testimony and Exhibits and know the content thereof; that the same are true and correct to the best of my knowledge, information and belief.

William H. Novak

Sworn and subscribed before me this 21st day of August, 2007.

Sue Arnett

Notary Public

My Commission Expires: ______

SUE ARNETT
STATE OF TENNESSEE NOTARY PUBLIC
DAVIDSON COUNTY, TENN.

My Commission Expires SEPT. 25, 2010

ATMOS ENERGY CORPORATION
SMALLCOMMERCIAL/INDUSTRIAL GAS SERVICE

Rate Schedule 220: All Service Areas

Availability

This service is available within the Company's service area to any commercial/industrial customer consistently using less than 4,000 Ccf per year for any purpose at the option of the Company, to the extent that gas is available. This schedule is not available to residences, apartment or federal housing projects.

Character of Service

Natural gas, with a heating value of approximately 1,000 Btu per cubic foot, supplied through a single delivery point and a single meter, at the delivery pressure of the distribution system in the area, or such higher delivery pressure as agreed upon by the Customer and Company.

Customer Charge

A monthly customer charge of **$<<TBD>>** is payable regardless of the usage of gas.

Monthly Rate

All Consumption, per Ccf **$<<TBD>>**

Minimum Bill

The minimum net monthly bill shall be the Customer Charge per meter as described above.

Payment

Each monthly bill for service is due and payable on the date it is issued. A charge of five percent (5%) may be added to the amount of any bill remaining unpaid at the close of the first business day after fifteen (15) days following such date of issue.

Gas Lights

For all metered gas light services under this tariff, the charge for such service shall be based on actual usage through a metered source at this tariff rate. It shall be within the Company's discretion whether a gas light should be metered, however if the gas light is unmetered, the Company may estimate and determine the appropriate consumption of the light and charge the applicable rate under this rate schedule.

Exhibit AIG-2
Schedule 1

ATMOS ENERGY CORPORATION
MEDIUM COMMERCIAL/INDUSTRIAL GAS SERVICE

Rate Schedule 230: All Service Areas

Availability

This service is available within the Company's service area to any commercial/industrial customer consistently using more than 4,000 Ccf per year for any purpose at the option of the Company, to the extent that gas is available.

Character of Service

Natural gas, with a heating value of approximately 1,000 Btu per cubic foot, supplied through a single delivery point and a single meter, at the delivery pressure of the distribution system in the area, or at such higher delivery pressure as agreed upon by the Customer and Company. Service under this rate schedule may be terminated by either party following twelve (12) months notice to the other party.

Customer Charge

A monthly customer charge of $<<TBD>> is payable regardless of the usage of gas.

Monthly Rate

	Net Rate
First 3,000 Ccf per Month	$<<TBD>> per Ccf
Next 2,000 Ccf per Month	$<<TBD>> per Ccf
Over 5,000 Ccf per Month	$<<50% of Tier 1>> per Ccf

Minimum Bill

The minimum net monthly bill shall be the Customer Charge per meter location as described above.

Payment

Each monthly bill for service is due and payable on the date it is issued. A charge of five percent (5%) may be added to the amount of any bill remaining unpaid at the close of the first business day after fifteen (15) days following such date of issue.

Gas Lights

For all metered gas light services under this tariff, the charge for such service shall be based on actual usage through a metered source at this tariff rate. It shall be within the Company's discretion whether a gas light should be metered, however if the gas light is unmetered, the Company may estimate and determine the appropriate consumption of the light and charge the applicable rate under this rate schedule.

ATMOS ENERGY CORPORATION
LARGE COMMERCIAL/INDUSTRIAL DEMAND/COMMODITY GAS SERVICE

Rate Schedule 240: All Service Areas

Availability

This service is available within the Company's service area to any commercial/industrial customers consistently using at least 270,000 Ccf per year or 1,000 Ccf per day during off peak periods for any purpose at the option of the Company, to the extent gas is available.

Character of Service

Natural gas, with a heating value of approximately 1,000 Btu per cubic foot, supplied through a single delivery point and a single meter, at a delivery pressure of the distribution system in the area, or at such higher delivery pressure as agreed upon by the Customer and Company. Service under this rate schedule may be terminated by either party following twelve (12) months notice to the other party.

Customer Charge

A monthly Customer Charge of $<<TBD>> is payable regardless of the usage of gas.

Monthly Rate

Demand Charge		
Per Unit of Billing Demand		$<<TBD>>
Commodity Charge		
First 1,500	Mcf Per Month	$<<TBD>>
Next 2,500	Mcf Per Month	$<<TBD>>
Next 11,000	Mcf Per Month	$<<TBD>>
Over 15,000	Mcf Per Month	$<<TBD>>

Firm Contract Entitlement

Customers may subscribe to firm, non-interruptible service under this Rate Schedule by opting for firm service under one of the following options:

A. The Firm Contract Entitlement is the same as the Billing Demand and the Customer is opting for 100% no-notice supply through the Company; or

B. The Firm Contract Entitlement is contracted at a firm level as specified in an annual contract with the Company. Any volumes in excess of the Firm Contract Entitlement are considered interruptible and subject to Limitations and Curtailment as specified in this rate schedule.

Minimum Bill

The minimum net monthly bill shall be the Customers Base Use Charge plus the Monthly Demand Charge as described above.

Payment

Each monthly bill for service is due and payable on the date it is issued. A charge of five percent (5%) may be added to the amount of the bill remaining unpaid at the close of the first business day after fifteen (15) days following date of issue.

ATMOS ENERGY CORPORATION
LARGE COMMERCIAL/INDUSTRIAL DEMAND/COMMODITY GAS SERVICE

Rate Schedule 240: All Service Areas (Continued)

Billing Demand

The Billing Demand for the current month shall be redetermined effective November 1 of each successive year. The Billing Demand is the highest demand day in any of the previous billing months November, December, January, February, and March.

Whenever a customer commences taking service under this Rate Schedule, the billing demand shall be either 6% of the monthly consumption in each month until redetermined as stated above, or the actual highest daily demand day recorded if electronic gas metering monitoring is installed.

Determination of Billing Demand

The Billing Demand shall be determined at the option of the Customer by one of the following methods:

1. By measuring the maximum volume of gas taken by the Customer in any one day through the use of Measurement Data Collection Equipment installed by the Company.

2. When gas is delivered to a Customer through a positive displacement meter without the use of daily recording and measuring equipment, the maximum volume of gas taken in any one day during the billing month shall be six percent (6%) of the total volume of gas used by the customer during such billing month.

Measurement Data Collection Equipment

Customers served by this Rate Schedule shall be required to install Data Collection Equipment for the purpose of measuring daily volumes of natural gas taken by the customers. Customer shall be responsible for providing telephone and power to the gas metering location, and paying associated monthly usage charges for providing these utilities to metering location. Customers will be responsible for the cost and installation of the Data Collection Equipment. Company will allow customers the option of paying for Data Collection Equipment over a repayment period of 24 months.

Gas Lights

For all metered gas light services under this tariff, the charge for such service shall be based on the actual usage through a metered source at this tariff rate. It shall be within the Company's discretion whether a gas light should be metered, however, if the gas light is unmetered, the Company may estimate and determine the appropriate consumption of the light and charge the applicable rate under this rate schedule.

Limiting and Curtailing Gas Service

This schedule is subject to interruption on one-half-hour's notice given by the Company by telephone or otherwise. The Company will curtail transportation gas service to the Customers under this schedule in order to prevent a shortage of gas for the use of Customers under the Company's other rate schedules.

Customer shall immediately discontinue the use of transported gas service, to the extent of curtailment ordered, when and as directed by the Company; and authorized representatives of the Company shall have at all times the right of ingress and egress to the Customer's premises. Upon determination by the Company that the necessity for curtailment has ceased the Company shall so notify the Customer by telephone or otherwise and the Customer shall not resume service until so notified.

ATMOS ENERGY CORPORATION
LARGE COMMERCIAL/INDUSTRIAL DEMAND/COMMODITY GAS SERVICE

Rate Schedule 240: All Service Areas (Continued)

In the event Customer takes daily gas deliveries in excess of Customer's daily firm contract entitlement where such consumption is measured and recorded on a daily basis, or in the event Customer does not comply with a curtailment order as directed by the Company and takes gas in excess of the daily volume allowed by the Company in the curtailment order, such gas taken in excess of Customer's daily firm contract entitlement or such daily volumes taken in excess of curtailment volumes shall be paid for by the Customer at the greater of the rate of $15.00 per Dth or the average daily index on curtailment days plus $5.00, and all applicable pipeline and/or gas supplier penalties and/or charges because of the Customer's failure to comply with a curtailment order as directed by the Company. This penalty rate will only apply to unauthorized volumes of gas used by Customer in excess of 50 Mcf over the Customer's firm contract entitlement and allocated volumes from authorized shipper. These additional charges shall be in addition to all other charges payable under this Rate Schedule.

If Customer can validate that a localized interstate pipeline restriction prohibited delivery of third party gas during a curtailment, and the Company incurred no penalties from the pipeline as a direct result of Customer's unauthorized usage of gas, then Company will agree to waive any penalties pursuant to this tariff.

The payment of a charge for unauthorized over-run shall not under any circumstances be considered as giving any such Customer the right to take unauthorized over-run volumes, nor shall such payment be considered as a substitute for any other remedies available to Company against Customer for failure to respect its obligations to adhere to the provisions of its contract with the Company.

The curtailment of interruptible transportation service deliveries in whole or in part under this schedule shall not be the basis for claims against the Company for any damages sustained by the Customers

Purchased Gas Cost Adjustment

Bills for service are subject to the cost of purchased gas in accordance with the Purchased Gas Adjustment (PGA) Rider approved by the Tennessee Regulatory Authority.

Firm Contract Entitlement will be billed based on the Company's allocated firm costs per Mcf of contract and credited to the Purchased Gas Adjustment. All Commodity gas will be billed per the Non-Firm GCA of the purchased gas adjustment.

Service Regulations

Gas service at these schedules will be furnished in accordance with the Company's General Rules and Regulations, copies of which for public reference during business hours at each of the Company's offices.

ATMOS ENERGY CORPORATION
TRANSPORTATION STORAGE OPTION

Rate Schedule 255: All Service Areas

Availability

This Transportation Storage Option (TSO) Rate Schedule is a bundled sales service available to those Customers served under the Company's Transportation Rate Schedules 260 and 265, to assist such Customers with mitigating the volatility of gas costs by providing the option of using storage volumes when such volumes can be made available by the Company.

Service under this Rate Schedule will be awarded to winning bidders for November 1 of the current year through March 31 of the following year (Heating Season). Service provided under this Rate Schedule may be interrupted on any given day provided that the Company interrupts this service only when alternate supplies cannot first be purchased by the Company.

Title to Gas

All gas dedicated to TSO annually shall remain the property of the Company. Title to said dedicated Gas shall pass from the Company to the Customer when Gas is delivered to the Customer pursuant to the terms of this Rate Schedule.

Excess Storage Volumes

Excess Storage Volumes (ESV) are the amount of storage inventory that was not utilized by Company's ratepayers in the previous withdrawal season. Such volumes are to be determined by the following formula less 50%:

ESV =(Total Storage Inventory – Total Winter Withdrawals + Total Winter Injections) x 50%

The Excess Storage Volumes will be confirmed annually with the TRA staff and posted for bidding on August 1.

Available Volumes

On August 1 of each year, the Company will post Excess Storage Volumes and daily deliverability to be made available for Customers under this Rate Schedule for the upcoming Heating Season. In addition the Company will post acceptable minimum seasonal Deliverability and Reservation rates specified below as well as the commodity rate that will be applied to the total aggregate Reserved Volumes upon delivery.

Customers eligible to receive service under TSO may submit bids to the Company on or before August 20. Bids must include the following: Customer's desired Maximum Daily Deliverability; the dollar value the Customer places on the requested Maximum Daily Deliverability Volume in the form of a monthly unit Maximum Daily Deliverability Rate; Customer's desired total Reserved Volume; and the dollar value the Customer places on the requested Reserved Volume during the Heating Season in the form of a monthly unit Reservation Rate On or before August 25 the Company will evaluate all bids and award the reserved Daily Deliverability and Reserved Volumes to the bid(s) that optimize the value of the storage asset. If a customer nominates TSO service for a given day and fails to take delivery of such amounts, then such volumes will be carried over to the subsequent day.

If two or more bids generate the same value and the requested volumes exceed the total Daily Deliverability or total Reserved Volume available for use under this Rate Schedule, the Daily Deliverability will be allocated to the winning bidders on a pro rata basis. On or before August 31, the winning bidders shall enter into a contract to purchase from the Company the requested and/or allocated Reserved Volume.

ATMOS ENERGY CORPORATION
TRANSPORTATION STORAGE OPTION

Rate Schedule 255: All Service Areas (Continued)

Deliverability

Service provided under this Rate Schedule on a daily basis is limited to the total remaining capacity of the Company after firm requirements are satisfied. In the event of a curtailment, TSO supply must be nominated and will be delivered as long as the Company's firm requirements are satisfied. If on any day, the Company is unable to meet the total TSO nominations because the demand for Gas to be delivered under this Rate Schedule exceeds the Company's ability to deliver Gas using the Company's existing capacity, nominations will be confirmed based on the highest unit rate bid for the monthly Deliverability Rate. In the event that multiple bids are the same, the volumes will be reduced prorata. In no event will a Customer's cumulative receipt of Gas under this Rate Schedule exceed the Customer's total Reserved Volume for the Heating Season.

Rates

These rates are in addition to the rates applicable to the Customer under Rate Schedules 260 and 265. The following charges shall be billed monthly during the Heating Season:

(a) Maximum Deliverability Rate - A charge per Dth applied to the Maximum Daily Deliverability that the Customer bid and the Company accepted. The minimum acceptable bid for the Maximum Deliverability Rate shall be $3.00. A one time charge per Dth of daily deliverability will be allocated to the Customer for the winter withdrawal season. All revenue collected from this charge shall be credited to the Deferred Gas Cost Account as recovered Demand Cost under the Purchase Gas Adjustment (PGA) provisions of the Company's tariff.

(b) Reservation Rate - A charge per Dth applied to the Reserved Volume that the Customer bid and the Company accepted. The minimum acceptable bid for the Reservation Rate shall be $.10/dekatherm. All revenue collected from this charge shall be credited to the Deferred Gas Cost Account as recovered Demand Cost under the Purchase Gas Adjustment (PGA) provisions of the Company's tariff.

(c) Commodity Rate - The rate to be applied to the Reservation Volumes will be posted on August 1 of any given year. The Commodity rate will represent a projection of the storage gas delivered to the city gate to include all variable charges including the cost of storage gas, storage commodity and withdrawal costs, and Company's FT commodity and pipeline fuel charges. Revenues collected from this charge shall be credited to the Deferred Gas Cost Account as recovered Commodity Cost under the Purchased Gas Adjustment (PGA) provisions of the Company's tariff.

Payment for the Maximum Daily Deliverability Charge and the Reservation Charge, shall be in five equal monthly payments due on the first of the month beginning November 1. All other charges shall be due upon presentation. Payments received after the due date shall be for an amount which shall be greater by five percent (5%) than the net billing.

Notification by Customers

Qualifying Customers that have been approved for TSO volumes will notify the Company by fax or e-mail by 12:00 Noon prior to the effective Gas Day that they desire to use volumes available under this Rate Schedule. Customers will be notified via e-mail or fax when demand for gas volumes under this Rate Schedule are terminated or allocated due to deliverability limitations pursuant to the availability provisions of this Rate Schedule. Provision of Gas under this Rate Schedule will automatically end when the Customer has utilized the Customer's Reserved Volume for the applicable Heating Season.

ATMOS ENERGY CORPORATION
TRANSPORTATION STORAGE OPTION

Rate Schedule 255: All Service Areas (Continued)

Gas Volume Remaining at March 31

If a Customer does not utilize the Customer's total Reserved Volume awarded by the Company, the remaining volume as of April 1 will be transferred to the Company's system inventory (excluding Company LNG).

Exhibit AIG-5
Schedule 1

ATMOS ENERGY CORPORATION
LARGE COMMERCIAL/INDUSTRIAL TRANSPORTATION
Interruptible Transportation

Rate Schedule 260: All Service Areas

Availability

This rate schedule provides for the transportation of gas received by the Company from the Connecting Pipeline Company for the Customer's account to that Customer's facilities Service under this rate schedule is available to commercial and industrial customers using either 270,000 Ccf or more per year or 1,000 Ccf per day during off-peak periods. Qualifying customers must install and maintain adequate standby facilities and alternate fuel supply in case gas deliveries are interrupted at any time.

Definitions

For purposes hereof:

i. "Connecting Pipeline Company" means a pipeline supplier to the Company whose facilities in the sole judgment of the Company can be utilized to transport gas to the Company for delivery by the Company to the Customer under this rate schedule.

ii. "Transportation Imbalance" occurs when more gas is received by the Company from the Connecting Pipeline Company for the Customer's account, less the unaccounted for gas adjustment, than is delivered to that customer's facilities for the month.

iii. "PGA Rider" means the Company's Purchased Gas Adjustment Rider, as amended and approved by the Tennessee Regulatory Authority from time to time.

Customer Charge

A monthly Customer Charge of $<<TBD>> is payable regardless of the usage of gas.

Monthly Rate

Demand Charge		
Per Unit of Billing Demand		$<<TBD>>
Commodity Charge		
First 1,500	Mcf Per Month	$<<TBD>>
Next 2,500	Mcf Per Month	$<<TBD>>
Next 11,000	Mcf Per Month	$<<TBD>>
Over 15,000	Mcf Per Month	$<<TBD>>

Firm Contract Entitlement

Customers may subscribe to firm, non-interruptible service under this Rate Schedule by opting for a specified volume of firm contract. A Purchased Gas Adjustment Demand Component will be applied to each unit of Billing demand based on the Company's allocated firm costs per Mcf of contract and credited to the Purchased Gas Adjustment.

ATMOS ENERGY CORPORATION
LARGE COMMERCIAL/INDUSTRIAL TRANSPORTATION
Interruptible Transportation

Rate Schedule 260: All Service Areas (Continued)

Billing Demand

The Billing Demand for the current month shall be redetermined effective November 1 of each successive year. The Billing Demand is the highest demand day in any of the previous billing months November, December, January, February, and March.

Whenever a customer commences taking service under this Rate Schedule, the billing demand shall be either 6% of the monthly consumption in each month until redetermined as stated above, or the actual highest daily demand day recorded if electronic gas metering monitoring is installed.

Determination of Billing Demand

The Billing Demand shall be determined at the option of the Customer by one of the following methods:

1. By measuring the maximum volume of gas taken by the Customer in any one day through the use of Measurement Data Collection Equipment installed by the Company.

2. When gas is delivered to a Customer through a positive displacement meter without the use of daily recording and measuring equipment, the maximum volume of gas taken in any one day during the billing month shall be six percent (6%) of the total volume of gas used by the customer during such billing month.

Terms and Provisions of Service under this Rate Schedule

i. Except as expressly modified by the provisions of this rate schedule, all of the terms, provisions, and conditions of the rate schedule (as made effective by the Tennessee Regulatory Authority from time to time) applicable to Customers shall also apply to service by the Company to Customer under this rate schedule.

ii. Receipts and deliveries of gas hereunder shall be at uniform rates of flow with no significant fluctuations or imbalance. Any imbalances shall be corrected by the customers, insofar as practicable, during the month in which they occur. Customers may adjust its daily nominations during the month in order to correct accumulated imbalance, subject to the limitations of the Company.

iii. Customer shall notify Company in advance of authorized shippers to transport gas for the Customers usage. Such notification shall be by fax or email confirmation to Company's Gas Control department. The quantity of gas delivered to Customer shall be based on total nominated volume of gas delivered by Customer to Company less any adjustments made by Connecting pipeline during the month.

iv. The Customer is responsible for making all arrangements for transporting the gas from its source of supply to the Company's interconnection with the Connecting Pipeline Company unless other arrangements have been made between the Customer and the Company.

v. If rendition of service to Customer under this rate schedule causes the Company to incur additional charges from the Connecting Pipeline Company, Customer shall reimburse Company for all charges.

vi. Once a customer elects and has qualified for service under this rate schedule, all services will be provided under the terms and conditions of this rate schedule for a term of no less than 12 months. At any time following the first six months of service under this rate schedule, service may be terminated by either party following at least 30 days written notice to the other party.

ATMOS ENERGY CORPORATION
LARGE COMMERCIAL/INDUSTRIAL TRANSPORTATION
Interruptible Transportation

Rate Schedule 260: All Service Areas (Continued)

Balancing Provisions:

Any difference between the quantities delivered to the Company's city gate facilities for the account of the Customer for the month, and the quantities consumed by the Customer as metered for the month, shall be the monthly imbalance. This imbalance shall be resolved monthly by "cashing out" the imbalance as it is known at that time.

If the Customer consumes more gas than it has delivered to the Company, the Customer will be deemed to be "short" by the amount of the deficiency and will buy an amount of gas equal to the deficiency from the Company. The Customer shall pay a price equal to the highest Average Weekly Cost of Gas, as determined from the "Daily Price Survey" set forth in *Gas Daily* published by Platts, in the first issue of such publication following the date of the transaction plus the Ft commodity rate, applicable surcharges and fuel on the relevant pipeline times the premium percentage corresponding to the percentage of the deficiency listed in the table below.

If the Customer consumes less gas than it has delivered to the Company, the Customer will be deemed to be "long" by the amount of the surplus, and the Company will buy the amount of the surplus by paying the Customer a price equal to the lowest Weekly Average Index Cost of Gas, as determined from the "Daily Price Survey" set forth in *Gas Daily* published by Platts, in the first issue of such publication following the date of the transaction, Ft commodity rate, applicable surcharges and fuel on the relevant pipeline times the discount percentage corresponding to the percentage of the deficiency listed in the table below:

Percentage of the Imbalance	Short Premium	Long Discount
Equal to or less than 20%	100%	100%
Over 20%	120%	80%

The Daily Index Cost of Gas shall be derived from the prices published in *Gas Daily* in the Daily Price Survey, per Atmos WACOG source of natural gas from pipelines, and adjusted for each service area.

	+	
Interstate Pipeline A Index	A	WA%
	+	
Interstate Pipeline B Index	B	WA%
	+	

Where Interstate (A..X) represents interstate pipeline index serving an Atmos service area and WA% represents the percentage gas sourced from this receipt source, and A represents the highest Average Weekly Daily pricing for the applicable interstate pipeline or source point.

Agency Authorization

A customer may authorize an agent to act on its behalf with respect to the nominations, imbalance resolution, and/or billing under this rate schedule by executing an Agency Authorization From provided by the Company. To the extent that the Agent appointed by the customer is common to other customers on the Company, the Company will permit such Agent to aggregate all such qualifying customers' transportation quantities for purposes of administering service to such Agent. Once a customer has designated an agent, the agent is then authorized to act on behalf of the customer and as such, the agent can be considered in all references contained within this rate schedule. The customer may not change agents within the calendar month without permission of the Company.

ATMOS ENERGY CORPORATION
LARGE COMMERCIAL/INDUSTRIAL TRANSPORTATION
Interruptible Transportation

Rate Schedule 260: All Service Areas (Continued)

Limiting and Curtailing Gas Service

This schedule is subject to interruption on one-half-hour's notice given by the Company by telephone or otherwise. The Company will curtail transportation gas service to the Customers under this schedule in order to prevent a shortage of gas for the use of Customers under the Company's other rate schedules.

Customer shall immediately discontinue the use of transported gas service, to the extent of curtailment ordered, when and as directed by the Company; and authorized representatives of the Company shall have at all times the right of ingress and egress to the Customer's premises. Upon determination by the Company that the necessity for curtailment has ceased, the Company shall so notify the Customer by telephone or otherwise and the Customer shall not resume service until so notified.

In the event Customer takes daily gas deliveries in excess of Customer's daily firm contract entitlement and allocated volume from a third party supplier where such consumption is measured and recorded on a daily basis, or in the event Customer does not comply with a curtailment order as directed by the Company and takes gas in excess of the daily volume allowed by the Company in the curtailment order, such gas taken in excess of Customer's daily contract entitlement or such daily volumes taken in excess of curtailment volumes and/or shall be paid for by the Customer at the greater of the rate of $15.00 per Dth or the average daily index on curtailment days plus $5.00, and all applicable pipeline and/or gas supplier penalties and/or charges because of the Customer's failure to comply with a curtailment order as directed by the Company. This penalty rate will only apply to unauthorized volumes of gas used by Customer in excess of 50 Mcf over the Customer's contract entitlement or allocated volumes from authorized shipper. These additional charges shall be in addition to all other charges payable under this Rate Schedule.

If Customer can validate that a localized interstate pipeline restriction prohibited delivery of third party gas during a curtailment, and the Company incurred no penalties from the pipeline as a direct result of Customer's unauthorized usage of gas, then Company will agree to waive any penalties pursuant to this tariff.

The payment of a charge for unauthorized over-run gas shall not under any circumstances be considered as giving any such Customer the right to take unauthorized over-run volumes, nor shall such payment be considered as a substitute for any other remedies available to Company against Customer for failure to respect its obligations to adhere to the provisions of its contract with the Company.

The curtailment of interruptible transportation service deliveries in whole or in part under this schedule shall not be the basis for claims against the Company for any damages sustained by the Customer.

Measurement Data Collection Equipment

Customers served by this Rate Schedule shall be required to install Data Collection Equipment for the purpose of measuring daily volumes of natural gas taken by the customers. Customer shall be responsible for providing telephone and power to the gas metering location, and paying associated monthly usage charges for providing these utilities to metering location. Customers will be responsible for the cost and installation of the Data Collection Equipment. Company will allow customers the option of paying for Data Collection Equipment over a repayment period of 24 months.

ATMOS ENERGY CORPORATION
LARGE COMMERCIAL/INDUSTRIAL TRANSPORTATION
Interruptible Transportation

Rate Schedule 260: All Service Areas (Continued)

Gas Lights

For all metered gas light services under this tariff, the charge for such service shall be based on the actual usage through a metered source at this tariff rate. It shall be within the Company's discretion whether a gas light should be metered, however, if the gas light is unmetered, the Company may estimate and determine the appropriate consumption of the light and charge the applicable rate under this rate schedule.

Terms and Provisions of Service Under This Rate Schedule

The Company will collect gross receipt tax on the incremental gross gas related charges.

The Purchased gas Adjustment computed in accordance with TRA Administrative Rule 1220-4-7 shall not apply. Other adjustments, charges/or credits as determined in accordance with the Tennessee Regulatory Authority's Rules and Regulations and applicable taxes shall be added to the above rates.

Except as expressly modified by the provisions of this rate schedule, all of the terms, provisions, and conditions of the rate schedule (as made effective by the Tennessee Regulatory Authority from time to time) applicable to Customer shall also apply to service by the Company to Customer under this rate schedule.

ATMOS ENERGY CORPORATION
LARGE COMMERCIAL/INDUSTRIAL TRANSPORTATION
Interruptible Transportation

Rate Schedule 260: All Service Areas (Continued)

Gas Lights

For all metered gas light services under this tariff, the charge for such service shall be based on the actual usage through a metered source at this tariff rate. It shall be within the Company's discretion whether a gas light should be metered, however, if the gas light is unmetered, the Company may estimate and determine the appropriate consumption of the light and charge the applicable rate under this rate schedule.

Terms and Provisions of Service Under This Rate Schedule

The Company will collect gross receipt tax on the incremental gross gas related charges.

The Purchased gas Adjustment computed in accordance with TRA Administrative Rule 1220-4-7 shall not apply. Other adjustments, charges/or credits as determined in accordance with the Tennessee Regulatory Authority's Rules and Regulations and applicable taxes shall be added to the above rates.

Except as expressly modified by the provisions of this rate schedule, all of the terms, provisions, and conditions of the rate schedule (as made effective by the Tennessee Regulatory Authority from time to time) applicable to Customer shall also apply to service by the Company to Customer under this rate schedule.

Exhibit AIG-6
Schedule 1

ATMOS ENERGY CORPORATION
LOW VOLUME TRANSPORTATION WITH FIRM BACKUP

Rate Schedule 265: All Service Areas

Availability

This rate schedule provides for the transportation of gas received by the Company from the Connecting Pipeline Company for the Customer's account to that Customer's facilities. Service under this rate schedule is available to commercial and industrial customers using 4,000 Ccf or more per year. This rate schedule is offered as a companion to the customers existing sales rate schedule.

Definitions

For purposes hereof:

i. "Connecting Pipeline Company" means a pipeline supplier to the Company whose facilities in the sole judgment of the Company can be utilized to transport gas to the Company for delivery by the Company to the Customer under this rate schedule.

ii. "Transportation Imbalance" occurs when more gas is received by the Company from the Connecting Pipeline Company for the Customer's account, less the unaccounted for gas adjustment, than is delivered to that customer's facilities for the month.

iii. "PGA Rider" means the Company's Purchased Gas Adjustment Rider, as amended and approved by the Tennessee Regulatory Authority from time to time.

Customer Charge

A monthly Customer Charge of $<<TBD>> is payable regardless of the usage of gas.

Monthly Rate

First 3,000	Ccf Per Month	$<<TBD>>
Next 2,000	Ccf Per Month	$<<TBD>>
Over 5,000	Ccf Per Month	$<<TBD>>

Purchased Gas Cost Adjustment

A Purchased Gas Adjustment Demand Component will be apply to each unit of Billing demand based on the Company's allocated firm costs per Mcf of contract and credited to the Purchased Gas Adjustment.

Billing Demand

The Billing Demand for the current month shall be redetermined effective November 1 of each successive year. The Billing Demand is the highest demand day in any of the previous billing months November, December, January, February, and March.

Whenever a customer commences taking service under this Rate Schedule, the billing demand shall be either 6% of the monthly consumption in each month until redetermined as stated above, or the actual highest daily demand day recorded if electronic gas metering monitoring is installed.

Terms and Provisions of Service under this Rate Schedule

i. Except as expressly modified by the provisions of this rate schedule, all of the terms, provisions, and conditions of the rate schedule (as made effective by the Tennessee Regulatory Authority from time to time) applicable to Customers shall also apply to service by the Company to Customer under this rate schedule.

ATMOS ENERGY CORPORATION
LOW VOLUME TRANSPORTATION WITH FIRM BACKUP

Rate Schedule 265: All Service Areas (Continued)

ii. Receipts and deliveries of gas hereunder shall be at uniform rates of flow with no significant fluctuations or imbalance. Any imbalances shall be corrected by the customers, insofar as practicable, during the month in which they occur. Customers may adjust its daily nominations during the month in order to correct accumulated imbalance, subject to the limitations of the Company.

iii. Customer shall notify Company in advance of authorized shippers to transport gas for the Customers usage. Such notification shall be by fax or email confirmation to Company's Gas Control department. The quantity of gas delivered to Customer shall be based on total nominated volume of gas delivered by Customer to Company less any adjustments made by Connecting pipeline during the month.

iv. The Customer is responsible for making all arrangements for transporting the gas from its source of supply to the Company's interconnection with the Connecting Pipeline Company unless other arrangements have been made between the Customer and the Company.

v. If rendition of service to Customer under this rate schedule causes the Company to incur additional charges from the Connecting Pipeline Company, Customer shall reimburse Company for all charges.

vi. Once a customer elects and has qualified for service under this rate schedule, all services will be provided under the terms and conditions of this rate schedule for a term of no less than 12 months. At any time following the first six months of service under this rate schedule, service may be terminated by either party following at least 30 days written notice to the other party.

Balancing Provisions:

Any difference between the quantities delivered to the Company's city gate facilities for the account of the Customer for the month, and the quantities consumed by the Customer as metered for the month, shall be the monthly imbalance. This imbalance shall be resolved monthly by "cashing out" the imbalance as it is known at that time.

If the Customer consumes more gas than it has delivered to the Company, the Customer will be deemed to be "short" by the amount of the deficiency and will buy an amount of gas equal to the deficiency from the Company. The Customer shall pay a price equal to the firm GCA of the Rate Schedule 230.

If the Customer consumes less gas than it has delivered to the Company, the Customer will be deemed to be "long" by the amount of the surplus, and the Company will buy the amount of the surplus by paying the Customer a price equal to the lowest Weekly Average Index Cost of Gas, as determined from the "Daily Price Survey" set forth in *Gas Daily* published by Platts, in the first issue of such publication following the date of the transaction, Ft commodity rate, applicable surcharges and fuel on the relevant pipeline times the discount percentage corresponding to the percentage of the deficiency listed in the table below:

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	+	
Interstate Pipeline A Index	A	WA%
	+	
Interstate Pipeline B Index	B	WA%
	+	

ATMOS ENERGY CORPORATION
LOW VOLUME TRANSPORTATION WITH FIRM BACKUP

Rate Schedule 265: All Service Areas (Continued)

Where Interstate (A, X) represents interstate pipeline index serving an Atmos service area and WA% represents the percentage gas sourced from this receipt source, and A represents the highest Average Weekly Daily pricing for the applicable interstate pipeline or source point.

Agency Authorization

A customer may authorize an agent to act on its behalf with respect to the nominations, imbalance resolution, and/or billing under this rate schedule by executing an Agency Authorization From provided by the Company. To the extent that the Agent appointed by the customer is common to other customers on the Company, the Company will permit such Agent to aggregate all such qualifying customers' transportation quantities for purposes of administering service to such Agent. Once a customer has designated an agent, the agent is then authorized to act on behalf of the customer and as such, the agent can be considered in all references contained within this rate schedule. The customer may not change agents within the calendar month without permission of the Company.

Measurement Data Collection Equipment

Customers served by this Rate Schedule shall be required to install Data Collection Equipment for the purpose of measuring daily volumes of natural gas taken by the customers. Customer shall be responsible for providing telephone and power to the gas metering location, and paying associated monthly usage charges for providing these utilities to metering location. Customers will be responsible for the cost and installation of the Data Collection Equipment. Company will allow customers the option of paying for Data Collection Equipment over a repayment period of 24 months.

Gas Lights

For all metered gas light services under this tariff, the charge for such service shall be based on the actual usage through a metered source at this tariff rate. It shall be within the Company's discretion whether a gas light should be metered, however, if the gas light is unmetered, the Company may estimate and determine the appropriate consumption of the light and charge the applicable rate under this rate schedule.

Terms and Provisions of Service Under This Rate Schedule

The Company will collect gross receipt tax on the incremental gross gas related charges.

Except as expressly modified by the provisions of this rate schedule, all of the terms, provisions, and conditions of the rate schedule (as made effective by the Tennessee Regulatory Authority from time to time) applicable to Customer shall also apply to service by the Company to Customer under this rate schedule.

HYPOTHETICAL EXAMPLE OF RATE 265 SAVINGS

In this example, an existing Rate 230 firm sales customer opts to convert to transportation service under Rate 265.

Sample Firm Customer with the following characteristics:

Annual consumption of 150,000 therms.
Billing demand of 150 dekatherms.
PGA Allocations of $10.00 per dekatherm per month.
Billing rate contribution to billing demand is $0.15 per therm.

Current Scenario:

- Customer elects transportation service under the Company's existing transportation tariff;
- Customer opts for gas service from the Company's marketing affiliate;
- The existing billing demand contribution of $22,500 (150,000 therms * $0.15 contribution rate) is lost and must be made up through higher PGA rates to other sales customers;
- The Company's marketing affiliate uses this same capacity (now idle) to deliver gas to the transportation customer.

New Scenario under AIG Proposed Rate 265:

- Customer continues to pay contribution towards the Firm PGA and Company provides firm backup service;
- Customer provides $18,000 (150 billing demand * $10.00 PGA Allocation *12 months) in billing demand contribution;
- Customer purchases gas from the most competitive third party;
- Control over the Company's pipeline assets are unbundled resulting in a competitive market.

CERTIFICATE OF SERVICE

I hereby certify that a copy of the foregoing is being forwarded via U.S. mail, postage prepaid, to:

William T. Ramsey
Neal & Harwell
150 4th Avenue North
Suite 2000
Nashville, TN 37219

Robert E. Cooper
Vance Broemel
Office of the Attorney General
Consumer Advocate and Protection Division
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D. Billye Sanders
Waller Landsen Dortch & Davis, LLP
511 Union Street, Ste. 2700
Nashville, TN 37216

on this the 21st day of August 2007.

Henry M. Walker

ATTACHMENT

1-4b

filed electronically in docket office on 12/19/11

STATE OF TENNESSEE

Office of the Attorney General

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December 19, 2011

Dr. Kenneth Hill
Chairman
Tennessee Regulatory Authority
460 James Robertson Pkwy.
Nashville, TN 37243-0505

Re: *Petition of Piedmont Natural Gas Company, Inc, For Adjustment to its Rates*
Docket No. 11-00144

Dear Chairman:

Please accept for filing the attached pre-filed Direct Testimony of the Consumer Advocate in the above-referenced docket. This information was previously filed under seal out of an abundance of caution due to the large volume of financial information Piedmont Natural Gas Company, Inc. ("Piedmont", "Company") deemed "confidential" under the protective order entered in this docket.

The Consumer Advocate and the Company have worked together to ensure that this information be made public, with the exception of one footnote (no. 5) in the Direct Testimony of William H. Novak and all workpapers related to Dave Peters' Direct Testimony, which will remain under seal.

Sincerely,

Ryan McGehee
Assistant Attorney General
(615) 532-5512

cc: all parties of record in Docket 11-00144

BEFORE
THE TENNESSEE REGULATORY AUTHORITY

Petition of Piedmont Natural Gas Company, Inc. for an Adjustment to its Rates, Approval of Changes to its Rate Design, Amortization of Certain Deferred Assets, Approval of New Depreciation Rates, Approval of Revised Tariffs and Service Regulations, and Approval of a New Energy Efficiency Program and GTI Funding	)))))))))	Docket No. 11-00144

DIRECT TESTIMONY
of
WILLIAM H. NOVAK

ON BEHALF OF
THE CONSUMER ADVOCATE AND PROTECTION DIVISION
OF THE
TENNESSEE ATTORNEY GENERAL'S OFFICE

December 6, 2011

TABLE OF CONTENTS

ATTACHMENTS

Q1. PLEASE STATE YOUR NAME, BUSINESS ADDRESS AND OCCUPATION FOR THE RECORD.

A1. My name is William H. Novak. My business address is 19 Morning Arbor Place, The Woodlands, TX, 77381. I am the President of WHN Consulting, a utility consulting and expert witness services company.[1]

Q2. PLEASE PROVIDE A SUMMARY OF YOUR BACKGROUND AND PROFESSIONAL EXPERIENCE.

A2. A detailed description of my educational and professional background is provided in Attachment WHN-1 to my testimony. Briefly, I have both a Bachelors degree in Business Administration with a major in Accounting, and a Masters degree in Business Administration from Middle Tennessee State University. I am a Certified Management Accountant, and am also licensed to practice as a Certified Public Accountant.

My work experience has centered on regulated utilities for over 25 years. Before establishing WHN Consulting, I was Chief of the Energy & Water Division of the Tennessee Regulatory Authority where I had either presented testimony or advised the Authority on a host of regulatory issues for over 19 years. In addition, I was previously the Director of Rates & Regulatory Analysis for two years with Atlanta Gas Light Company, a natural gas distribution utility with operations in Georgia and Tennessee. I also served for two years as the Vice President of Regulatory Compliance for Sequent Energy Management, a natural

[1] State of Tennessee, Registered Accounting Firm ID 3682.

gas trading and optimization entity in Texas, where I was responsible for ensuring the firm's compliance with state and federal regulatory requirements.

Q3. ON WHOSE BEHALF ARE YOU TESTIFYING?

A3. I am testifying on behalf of the Consumer Advocate & Protection Division ("CAPD" or "the Consumer Advocate") of the Tennessee Attorney General's Office.

Q4. HAVE YOU PRESENTED TESTIMONY IN ANY PREVIOUS PIEDMONT RATE CASES?

A4. Yes. I presented testimony in Dockets U-85-7355, U-87-7499, 89-10491, and 91-02636 concerning either Nashville Gas Company or Piedmont Natural Gas Company ("Piedmont" or "the Company") rate cases as well as other generic tariff and rulemaking dockets. In addition, I advised the TRA Directors in the Company's last rate case (Docket 03-00313) on issues where I did not present testimony.

Q5. WHAT IS THE PURPOSE OF YOUR TESTIMONY IN THIS PROCEEDING?

A5. My testimony will support and address the CAPD's positions and concerns with respect to the Company's Petition. Specifically, I will address the following:

i. CAPD's proposed attrition period revenue and gas cost calculations;

ii. CAPD's position on Piedmont's proposed Cost of Service Study;

iii. CAPD's proposed rate design;

iv. CAPD's position on Piedmont's proposed cost recovery proposals for an Energy Efficiency Program and GTI Funding; and

v. CAPD's position on certain aspects of Piedmont's proposed tariff revisions.

Q6. WHAT DOCUMENTS HAVE YOU REVIEWED IN PREPARATION OF YOUR TESTIMONY?

A6. I have reviewed the Company's Rate Case Application as filed on September 2, 2011, along with the testimony and exhibits presented with their filing. In addition, I have reviewed the Company's workpapers supporting their attrition period revenues and cost of service study. I have also reviewed the Company's responses to the relevant data requests submitted by the TRA as well the Company's responses to CAPD's discovery requests in these same areas.

I. ATTRITION PERIOD REVENUES & GAS COST

Q7. MR. NOVAK, PLEASE DESCRIBE THE MAJOR AREAS OF DIFFERENCE BETWEEN THE COMPANY'S AND CAPD'S CALCULATION OF ATTRITION PERIOD BILLING DETERMINANTS.

A7. The primary differences are due to different forecasts for normal weather, annualized customer usage and customer growth. As shown in detail on Attachment WHN-2, Schedule 1 and summarized below in Table 1, the CAPD first began with the Company's test period sales and transportation volumes of

296,047,022 therms, 1,988,976 bills and 277,186 billing demand units.[2] We then adjusted for normal weather, annualized customer usage and customer growth to arrive at attrition billing determinants of 288,167,934 therms, 2,021,045 bills and 219,672 billing demand units.

Table 1 – Summary of CAPD Attrition Period Billing Determinants

	Test Period	Weather Adjustment	Customer Growth	Attrition Period
Bills	1,988,976	0	32,069	2,021,045
Billing Demand	277,186	0	-57,514	219,672
Therms	296,047,022	-5,269,571	-2,609,517	288,167,934

I have also included a detailed comparison with the Company's attrition period billing determinants on Attachment WHN-2, Schedule 2. This comparison is summarized below on Table 2.

Table 2 – Comparison of Company and CAPD Attrition Period Billing Determinants

	Company	CAPD	Difference
Bills	2,008,767	2,021,045	12,278
Billing Demand	219,672	219,672	0
Therms	287,155,030	288,167,934	1,012,904

Q8. WHY IS THE CAPD'S WEATHER ADJUSTMENT DIFFERENT FROM THE COMPANY'S?

A8. The CAPD's weather adjustment for the residential and commercial customer classes is different from the Company's for two reasons. First, there were errors in the Company's calculation of normal weather and test period weather.[3] In addition, the Company chose to separately weather normalize the residential and

[2] Billing Demand Units refers to peak day capacity subscribed to by the Company's firm industrial customers on Rate Schedules 303 and 313.

[3] The Company incorrectly calculated normal cycle heating degree days for March as 534 instead of 518. In addition, the Company also incorrectly calculated the cycle heating degree days for May 2011 as 115 instead of 113.

commercial standard and value designations that it now proposes to eliminate whereas the CAPD consolidated these tariff designations in its weather normalization calculation.

Furthermore, with the elimination of the value and standard designations the CAPD believes that the SGS and MGS tariffs[4] need to be combined for weather normalization purposes as they were prior to the Company's 2003 rate case. The CAPD therefore performed separate weather normalization studies for the entire residential and commercial customer classes.

The combination of these two errors results in the entire difference between the Company and CAPD's weather normalization adjustments. In addition, I have also prepared a weather normalization factor summary that is included on Attachment WHN-3 for Weather Normalization Adjustment ("WNA") tracking purposes that implements the CAPD's proposals to consolidate the residential and commercial tariffs.

Q9. HOW HAS THE CAPD ADJUSTED THE ATTRITION PERIOD BILLING DETERMINANTS FOR EXISTING CUSTOMER USAGE?

A9. The CAPD adjusted industrial customer usage by individually analyzing the sales volumes of the Company's 25 largest customers. These 25 customers represented over 72% of the Company's test period volumes to the industrial class. Where we felt that it was necessary, such as a large swing in gas usage or a material tariff

[4] Small General Service and Medium General Service tariffs that comprise the Commercial customer class.

transfer, we adjusted the test period usage to take these changes into account. We then compared our own adjustments with those proposed by the Company. For the most part, we felt that the Company had properly adjusted for any test period anomalies and tariff transfers within the industrial customer group. However, we did find evidence where a large customer's usage was curtailed due to flooding during the test period that the Company didn't include in their filing.[5] As a result, we have made an adjustment of 818,070 therms to properly reflect this customer's going level consumption in the attrition period.[6]

Q10. HOW WERE SALES VOLUMES FOR ADDED CUSTOMERS COMPUTED?

A10. A historical average of added customers to normal plant additions was first calculated. This average was then applied to the CAPD's forecast of attrition period normal plant additions giving residential and commercial "customers to be added" during the attrition year. More simply stated though, the CAPD has increased the number of residential and commercial customers based upon an average historical ratio of customer additions to normal plant additions. These forecasted customer additions were then multiplied by an average usage volume per customer giving additional attrition period sales volumes for the residential and commercial rate classes.

---

[5] [redacted]

[6] CAPD Workpaper R-7-I-2.02.

While other witnesses will testify more fully on the CAPD's forecast of plant in service, I would like to point out that if the TRA should decide to adjust the CAPD's forecasted plant in service, then a corresponding adjustment should also be made to revenues.

Q11. HOW WERE THE ATTRITION PERIOD BILLING DETERMINANTS TRANSLATED INTO REVENUES?

A11. The attrition period billing determinants as shown on Attachment WHN-2 were multiplied by the existing base tariff rates and the PGA rate based upon the Company's demand and commodity gas costs at April 1, 2011. This gives total attrition period gas sales and transportation revenues of $94,603,962 as shown on Attachment WHN-4 and summarized below in Table 3.

Table 3 – Comparison of Company and CAPD Attrition Period Gross Margin under Current Rates			
	Company	**CAPD**	**Difference**
Residential	$54,662,151	$55,025,059	$362,908
Commercial	28,683,304	28,803,370	120,066
Industrial	8,315,092	8,428,238	113,146
Special Contract	624,617	434,249	-190,368
Sales for Resale	28,481	28,481	0
Other Revenue	2,005,089	1,884,565	-120,524
Total	**$94,318,734**	**$94,603,962**	**$285,228**

Q12. HOW DID THE CAPD COMPUTE OTHER REVENUES?

A12. Other revenues primarily consist of forfeited discounts, reconnection charges, bad check charges and rental income from utility property. To compute forfeited discounts, the CAPD took the historical ratio of forfeited discounts to residential and commercial revenues, since these are ordinarily the customers who generate forfeited discounts. This ratio was then multiplied by the attrition period residential and commercial revenues. To compute the other items for this category, I analyzed the test period amounts and adjusted for growth where appropriate. This produced $1,884,565 in Other Revenues as shown on Attachment WHN-4.

Q13. HOW WAS THE CAPD'S COST OF GAS COMPUTED?

A13. We began with the attrition period throughput volumes and billing demand discussed above. These determinants were then priced out at the April 1, 2010 PGA rates. This produced $94,601,622 in gas cost as shown on Attachment WHN-5.

II. COST OF SERVICE STUDY

Q14. PLEASE BRIEFLY EXPLAIN THE PURPOSE OF THE ALLOCATION PROCESS IN THE COMPANY'S COST OF SERVICE STUDY.

A14. The purpose of any Cost of Service Study ("COSS") is to arrive at the cost of serving each customer class and present a systematic approach to allocating this cost (or total revenue requirement) to the different classes of customers. The COSS then provides a measure of guidance for the TRA to consider how to best adjust individual rates for each customer class to produce the total revenue requirement.

Q15. HAVE YOU REVIEWED THE COMPANY'S PROPOSED COST OF SERVICE STUDY IN THIS CASE?

A15. Yes. The Company has developed a COSS that first classifies each element of rate base and income into three categories for demand costs, customer costs and commodity costs. The Company then allocates these classified costs using 40 separate allocation factors.[7] The result of the Company's COSS is to allocate 98% of the operating expenses to residential and commercial customers and allocating the remaining 2% to industrial customers.[8]

Q16. DO YOU AGREE WITH THE COMPANY'S COSS METHODOLOGY IN THIS CASE?

A16. No. There are mathematical errors in the Company's study that need to be corrected.[9] These errors cascade down through the Company's COSS, resulting in errors to other allocation factors that depend upon them.

In addition, the assignment of 40 individual allocation factors to each element of the Company's cost of service is inherently judgmental, and the Company has not introduced any evidence to fully explain their rationale for each individual allocation assignment. For example, the Company has allocated a significant portion of their costs based upon peak day consumption, meaning that almost all of these costs will be allocated to residential and commercial customers without

[7] Direct testimony and exhibits of Company witness Yardley.
[8] Company Exhibit DPY-5, Page 8.
[9] The Company incorrectly calculates the Plant in Service classification by omitting $557,644 in commodity costs. In addition, the Company incorrectly calculates the distribution services classification by omitting $25,937,975 in meter costs.

any discussion or evidence as to why such an allocation is appropriate. I could easily justify allocating many of these same costs based upon the total throughput of each customer class which would then allocate a majority of the costs to industrial customers. Since the Company has not provided any rationale for its individual allocation choices it is impossible to determine their rationale for cost allocation.

Finally, other factors beyond just the cost of service need to also be considered in allocating costs. These other factors include value of service, product marketability, encouragement of efficient use of facilities, broad availability of service functions, and a fair distribution of charges among users. Since it is impossible to properly consider each of these other factors, it follows that no mechanical or mathematical formula can ever be applied to the cost of service that would translate it directly into rates.

Q17. HOW DOES THE CONSUMER ADVOCATE PROPOSE THAT THE TRA ALLOCATE THE COMPANY'S REVENUE REQUIREMENTS TO EACH CUSTOMER CLASS?

A17. The CAPD recommends that its proposed revenue deficiency of $9,863,394 be allocated evenly across-the-board to all customer classes, including special contract customers, based upon the ratio of each customer class' attrition period margin to total attrition period margin. The CAPD's complete revenue deficiency allocation is presented on Exhibit WHN-6 and summarized below on Table 4.

Table 4 – Comparison of Company and CAPD Attrition Period Revenue Deficiency Allocation			
	Current Margin	**CAPD Allocation**	**Company Allocation**
Residential	$55,025,058	59.34%	65.95%
Commercial	28,803,371	31.07%	28.17%
Industrial	8,428,238	9.09%	5.85%
Special Contract & Sale for Resale	462,730	0.50%	0.03%
Other Revenue	1,884,565	- N/A -	- N/A -
Total	**$94,603,962**	**100.00%**	**100.00%**

To summarize the results of Table 4, the CAPD would allocate 59.34% of any revenue increase to residential customers based upon an across-the-board distribution of attrition period margin under current rates. Alternatively, the Company would allocate 65.95% of any revenue increase to residential customers based upon their COSS. The CAPD believes that an across-the-board increase to all customer classes more equitably spreads the burden of any increase in rates and is preferable to the Company's COSS results.

III. RATE DESIGN

Q18. HAVE YOU REVIEWED THE COMPANY'S PROPOSED RATE DESIGN?

A18. Yes. The Company's proposed rate design realigns "…rates within each [customer] class to recover a greater proportion of fixed revenue requirements through fixed charges."[10] Stated more simply, the Company is proposing to reduce its existing base rate commodity charge for all tariffs while increasing the fixed monthly customer charges to make up for the difference. The primary

[10] Direct testimony of Company witness Yardley, page 15, lines 15 – 16.

driver behind this proposal is the continuing decline in sales volumes for new customers. The result of the Company's proposal is a substantial increase of as much as 120% in monthly customer charges.

Q19. DO YOU AGREE WITH THE COMPANY'S RATE DESIGN PROPOSAL?

A19. No. While I do agree that the Company has experienced declines in customer usage due to efficiency and technology gains in gas appliances, I believe that the changes proposed by the Company are too radical to implement in a single rate case.

Q20. WHAT RATE DESIGN DOES THE CAPD PROPOSE?

A20. The CAPD recognizes that the decline in customer usage has impaired the gas utilities ability to earn a fair rate of return. For that reason, we are proposing a gradual shift towards placing more margin on customer charges than through volumetric charges. However, we believe that this revenue shift must occur gradually rather than through an immediate change to a new rate structure. We are therefore proposing that the entire revenue deficiency in this case be recovered through increased customer charges only. In other words, we are proposing that the existing base rate commodity charges remain at their current levels. We feel that this proposal shifts more of the Company's revenue recovery towards fixed charges but avoids a radical change of existing commodity rates. The CAPD's complete rate design is contained on Exhibit WHN-6 and summarized below on Table 5.

Table 5 – CAPD Proposed Rate Design			
Tariff	**Current Rates**	**Company Proposed**	**CAPD Proposed**
Residential			
Summer Bills per Month	$10.00	$17.00	$12.84
Winter Bills per Month	13.00	22.00	16.69
Summer Usage/Therm	0.2700	0.2214	0.2700
Winter Usage/Therm	0.3200	0.2714	0.3200
Commercial			
Small Customer Charges[11]	$29.00	$40.00	$41.31
Medium Customers Charges[12]	75.00	125.00	197.22
Small Summer Usage/Therm	0.3030	0.3277	0.3030
Small Winter Usage/Therm	0.3540	0.3787	0.3540
Medium Summer Usage/Therm	0.3030	0.3398	0.3030
Medium Winter Usage/Therm	0.3540	0.3908	0.3540
Industrial			
Customer Charges per Month	$300.00	$450.00	$710.97
Billing Demand Charges/Therm	0.80	1.00	8.00
Usage – Step 1/Therm	0.09742	0.09948	0.09742
Usage – Step 2/Therm	0.08953	0.09159	0.08953
Usage – Step 3/Therm	0.06450	0.06656	0.06450
Usage – Step 4/Therm	0.02764	0.02970	0.02764
Special Contract	$434,249	$434,249	$480,071
Sales for Resale			
Customer Charges per Month	$0.00	$0.00	$96.95
Billing Demand Charges/Therm	0.80	1.00	0.80
Usage/Therm	0.09000	0.09870	0.09

IV. COST RECOVERY PROPOSALS

Q21. HAS PIEDMONT PROPOSED ANY PARTICULAR PROGRAMS IN THIS RATE CASE WHERE IT SEEKS COST RECOVERY?

[11] Small usage customers are those whose average consumption is less than 200 therms per day.

[12] Medium usage customers are those whose average consumption is greater than or equal to 200 therms per day.

A21. Yes. The Company has proposed what it calls an "Energy Efficiency Program" wherein it would spend $500,000 for educational activities in public schools to promote energy efficiency. The Company has also proposed a $150,000 contribution to the Gas Technology Institute ("GTI") to fund research and development activities. The Company is then asking to recover the $650,000 total cost of both programs through increased rates.

Q22. DOES THE CAPD SUPPORT THE COMPANY'S PROPOSED COST RECOVERY FOR THESE PROGRAMS?

A22. No. The CAPD is opposed to cost recovery for both of the Company's proposed programs. Both of these programs would result in an involuntary tax on gas consumers for funding since neither program is necessary in order to provide utility service. Furthermore, in the case of the Company's proposed "Energy Efficiency Program" there has been no evidence presented that Nashville area schools would allow a private entity to make such a presentation to its students. Finally, the program violates the state's conservation policy on "cost effective, measurable and verifiable savings"[13] since it requires all of the Company's 170,000 customers to pay for the benefits received by as few as 6,800 customers[14].

In the case of GTI funding, the benefits are illusory at best since any successful research would ultimately be marketed to manufacturers in the distant future. The

[13] Section 53 of Public Chapter 531.
[14] Testimony of Company witness Powers, Page 15.

CAPD therefore asks the TRA to reject both of the Company's proposals for cost recovery.

V. TARIFF CHANGES

Q23. MR. NOVAK, HAVE YOU REVIEWED THE TARIFF CHANGES PROPOSED BY THE COMPANY?

A23. Yes. In this case, the Company has proposed the following rate changes to its existing tariff:[15]

- The elimination of the standard/value designations for residential, small general service and medium general service tariffs;
- The elimination of step rates of 20,000 therms/month and 50,000 therms/month respectively for small and medium general service tariffs;
- A two month expansion of the WNA period from November – March to October – April;
- The establishment of a natural gas vehicle rate schedule;
- An update to the weighted average pipeline percentages included in rate schedules 307 and 313; and
- A proposal to retain the current allocation of fixed gas costs by rate class.

[15] Other non-rate changes to the Company's tariff are discussed by other CAPD witnesses.

Q24. What is the CAPD's position with respect to the Company's proposal to remove the standard/value designations for residential, small general service and medium general service tariffs?

A24. These designations were implemented in the Company's last rate case in 2003. However, from the customer's point of view, the designations were meaningless since the rates were the same for both the standard and the value designations. Removing these designations probably makes it easier for these customers to understand their bill. Therefore, the CAPD supports this change.

Q25. What is the CAPD's position with respect to the Company's proposal for eliminating the step rates of 20,000 therms/month and 50,000 therms/month respectively for small and medium general service tariffs?

A25. These step rates were also implemented in the Company's last rate case in 2003. Again however, the steps were meaningless from the customer's point of view since the rates were identical for consumption above and below the step. Removing these steps probably makes it easier for these customers to understand their bill. Therefore, the CAPD supports this change.

Q26. What is the CAPD's position with respect to the Company's proposal to implement a two month expansion of the WNA period?

A26. The CAPD is opposed to the Company's proposal to change the WNA recovery period. Since both the Company and the CAPD are now advocating a shift in revenue recovery towards customer charges and away from commodity charges, it would appear ill-timed to now implement a change in the WNA recovery period. In addition, since the WNA only addresses commodity charges, this change would impact a smaller portion of the Company's total revenues. The CAPD therefore proposes that the existing WNA period of November – March remain in effect.

Q27. What is the CAPD's position with respect to the Company's proposal to implement a natural gas vehicle tariff?

A27. The Company has proposed a new Rate Schedule 342 for Natural Gas Vehicle Fuel. The Company has also proposed a monthly customer charge of $40 and a consumption charge of $0.23109 per therm. The CAPD believes that the prospects for the natural gas fuel market are good and that this customer group may eventually develop and contribute to the recovery of the Company's common costs. The CAPD therefore supports the Company's initial proposal for this rate schedule until the next rate case.

Q28. What is the CAPD's position with respect to the Company's update to the weighted average pipeline percentages included in rate schedules 307 and 313?

A28. Rate Schedule 307 (Balancing, Cash-Out and Agency Authorization) and Rate Schedule 313 (Firm Transportation Service) both contain identical provisions that reflect the weighted average ratio of winter capacity from delivering pipelines. These percentages remain in effect until the Company's next rate case. The current and Company proposed values for these percentages are shown below in Table 6.

Table 6 – Pipeline Percentages		
Pipeline	**Current**	**Proposed**
TEXAS (SOUTH/EAST), Tenn Zone 1 Zone 0: South	28.36%	30.28%
GULF COAST, Tenn 500 So La Z1 Louisiana	65.32%	38.06%
GULF COAST, Tenn 800 So La Z1	6.32%	31.66%
Total	**100.00%**	**100.00%**

The CAPD has reviewed the Company's proposed calculations of the test period pipeline percentages and supports their inclusion in the tariff for Rate Schedules 307 and 313.

Q29. What is the CAPD's position with respect to the Company's position to retain the current allocation of fixed gas costs by rate class?

A29. The CAPD is opposed to the Company's position on this issue. In the Company's last rate case, the TRA approved a new mechanism whereby the Company was allowed to recover different amounts of pipeline demand charges from different customer classes. A copy of these fixed gas costs are included in Company Exhibits DRC-4 and PKP-1. Currently, no other gas utility has such a mechanism that allows for variable fixed gas rate recovery from different customer classes. Instead, these fixed gas costs are recovered through the PGA process and typically included in the commodity PGA for most customers.[16]

[16] Industrial Rate 303 and 313 customers have unique demand billing attributes assigned to them.

The sole purpose for the implementation of variable demand charges in the last rate case was to place a higher charge for demand recovery from "standard rate" customers than from "value rate" customers. In fact, except for the demand recovery rates, the current value/standard designations for residential and commercial customers are identical. Now, with the elimination of the standard/value designations, the use of variable demand charges serves no purpose. The CAPD therefore recommends that all variable demand charges be eliminated and that the Company revert to filing for its fixed cost recovery through the PGA.

Q30. DOES THIS COMPLETE YOUR TESTIMONY?

A30. Yes it does. However I reserve the right to incorporate any new information that may subsequently become available.

IN THE TENNESSEE REGULATORY AUTHORITY
AT NASHVILLE, TENNESSEE

IN RE:	)	
	)	
Petition of Piedmont Natural Gas	)	
Company, Inc. for an Adjustment to its	)	
Rates, Approval of Changes to its Rate	)	Docket No. 11-00144
Design, Amortization of Certain Deferred	)	
Assets, Approval of New Depreciation	)	
Rates, Approval of Revised Tariffs and	)	
Service Regulations, and Approval of a	)	
New Energy Efficiency Program and GTI	)	
Funding	)	

AFFIDAVIT

I, William H. Novak, CPA, on behalf of the Consumer Advocate Division of the Attorney General's Office, hereby certify that the attached Direct Testimony represents my opinion in the above-referenced case and the opinion of the Consumer Advocate Division.

WILLIAM H. NOVAK

Sworn to and subscribed before me
this 28 **day of** NOV**, 2011.**

NOTARY PUBLIC

My commission expires: 2-24-15

TAMMY L. JONES
Notary Public
STATE OF TEXAS
My Comm. Exp. 02-24-15

ATTACHMENT WHN-1

William H. Novak Vitae

William H. Novak

19 Morning Arbor Place
The Woodlands, TX 77381

Phone: 713-298-1760
Email: halnovak@whnconsulting.com

Areas of Specialization

Over twenty-five years of experience in regulatory affairs and forecasting of financial information in the rate setting process for electric, gas, water and wastewater utilities. Presented testimony and analysis for state commissions on regulatory issues in four states and has presented testimony before the FERC on electric issues.

Relevant Experience

WHN Consulting – September 2004 to Present

In 2004, established WHN Consulting to provide utility consulting and expert testimony for energy and water utilities. Complete needs consultant to provide the regulatory and financial expertise that enabled a number of small gas and water utilities to obtain their Certificate of Public Convenience and Necessity (CCN) that included forecasting the utility investment and income. Also provided the complete analysis and testimony for utility rate cases including revenues, operating expenses, taxes, rate base, rate of return and rate design for utilities in Tennessee. Assisted American Water Works Company in preparing rate cases in Ohio and Iowa. Provided commercial and industrial tariff analysis and testimony for an industrial intervenor group in a large gas utility rate case. Industry spokesman for water utilities dealing with utility commission rulemaking. Consultant for the North Carolina and Illinois Public Utility Commissions in carrying out their oversight functions of Duke Energy and Peoples Gas Light and Coke Company through focused management audits. Also provide continual utility accounting services and preparation of utility commission annual reports for water and gas utilities.

Sequent Energy Management – February 2001 to July 2003

Vice-President of Regulatory Compliance for approximately two years with Sequent Energy Management, a gas trading and optimization affiliate of AGL Resources. In that capacity, directed the duties of the regulatory compliance department, and reviewed and analyzed all regulatory filings and controls to ensure compliance with federal and state regulatory guidelines. Engaged and oversaw the work of a number of regulatory consultants and attorneys in various states where Sequent has operations. Identified asset management opportunities and regulatory issues for Sequent in various states. Presented regulatory proposals and testimony to eliminate wholesale gas rate fluctuations through hedging of all wholesale gas purchases for utilities. Also prepared testimony to allow gas marketers to compete with utilities for the transportation of wholesale gas to industrial users.

Atlanta Gas Light Company – April 1999 to February 2001

Director of Rates and Regulatory Analysis for approximately two years with AGL Resources, a public utility holding company serving approximately 1.9 million customers in Georgia, Tennessee, and Virginia. In that capacity, was instrumental in leading Atlanta Gas Light Company through the most complete and comprehensive gas deregulation process in the country that involved terminating the utility's traditional gas recovery mechanism and instead allowing all 1.5 million AGL Resources customers in Georgia to choose their own gas marketer. Also responsible for all gas deregulation filings, as well as preparing and defending gas cost recovery and rate filings. Initiated a weather normalization adjustment in Virginia to track adjustments to company's revenues based on departures from normal weather. Analyzed the regulatory impacts of potential acquisition targets.

Tennessee Regulatory Authority – Aug. 1982 to Apr 1999; Jul 2003 to Sep 2004

Employed by the Tennessee Regulatory Authority (formerly the Tennessee Public Service Commission) for approximately 19 years, culminating as Chief of the Energy and Water Division. Responsible for directing the division's compliance and rate setting process for all gas, electric, and water utilities. Either presented analysis and testimony or advised the Commissioners/Directors on policy setting issues, including utility rate cases, electric and gas deregulation, gas cost recovery, weather normalization recovery, and various accounting related issues. Responsible for leading and supervising the purchased gas adjustment (PGA) and gas cost recovery calculation for all gas utilities. Responsible for overseeing the work of all energy and water consultants hired by the TRA for management audits of gas, electric and water utilities. Implemented a weather normalization process for water utilities that was adopted by the Commission and adopted by American Water Works Company in regulatory proceedings outside of Tennessee.

Education

B.A, Accounting, Middle Tennessee State University, 1981
MBA, Middle Tennessee State University, 1997

Professional

Certified Public Accountant (CPA), Tennessee Certificate # 7388
Certified Management Accountant (CMA), Certificate # 7880
Former Vice-Chairman of National Association of Regulatory Utility Commission's Subcommittee on Natural Gas

ATTACHMENT WHN-2
CAPD Pro Forma Billing Determinants

Piedmont-Nashville
CAPD Pro Forma Billing Determinants

Attachment WHN-2
Schedule 1

Line No.	Tariff	Test Period	Weather Adjustment	Customer Growth	Attrition Period
	Residential				
1	Bills - Winter	749,069		10,972	760,041
2	Bills - Summer	1,036,462		19,388	1,055,850
3	**Total Bills**	**1,785,531**		**30,360**	**1,815,891**
4	Therms - Winter	90,323,919	-5,078,068	5,443,127	90,688,978
5	Therms - Summer	22,684,308	1,511,077	-3,582,230	20,613,155
6	**Total Volumes**	**113,008,227**	**-3,566,991**	**1,860,897**	**111,302,133**
	Commercial (SGS and MGS):				
7	Bills - Winter	84,677		596	85,273
8	Bills - Summer	116,550		1,124	117,674
9	**Total Bills**	**201,227**		**1,720**	**202,947**
10	Therms - Winter	48,785,794	-2,413,430	2,580,102	48,952,466
11	Therms - Summer	19,001,521	710,850	-2,015,236	17,697,135
12	**Total Volumes**	**67,787,315**	**-1,702,580**	**564,866**	**66,649,601**
	Industrial Sales & Transportation:				
13	Bills	2,162		2	2,164
14	Demand	277,186		-57,514	219,672
15	First 15,000 Therms	23,059,400		132,180	23,191,580
16	Next 25,000 Therms	16,334,970		250,000	16,584,970
17	Next 50,000 Therms	12,550,840		578,340	13,129,180
18	Over 90,000 Therms	40,188,720		11,571,500	51,760,220
19	**Total Volumes**	**92,133,930**		**12,532,020**	**104,665,950**
	Special Contract:				
20	Bills	25		-13	12
21	Therms	23,014,430		-17,567,300	5,447,130
	Sale for Resale:				
22	Bills	31		0	31
23	Demand	16,800		-14,400	2,400
24	Therms	103,120		0	103,120
25	**Total Bills**	**1,988,976**	**0**	**32,069**	**2,021,045**
26	**Total Demand**	**277,186**	**0**	**-57,514**	**219,672**
27	**Total Therms**	**296,047,022**	**-5,269,571**	**-2,609,517**	**288,167,934**

SOURCE: CAPD Revenue Workpaper R-13.01.

Piedmont-Nashville
Comparison of Company and CAPD Pro Forma Billing Determinants

Attachment WHN-2
Schedule 2

Line No.	Consumer Advocate	Company A/	CAPD B/	Difference
	Residential			
1	Bills - Winter	758,266	760,041	1,775
2	Bills - Summer	1,047,658	1,055,850	8,192
3	**Total Bills**	**1,805,924**	**1,815,891**	**9,967**
4	Therms - Winter	88,586,380	90,688,978	2,102,598
5	Therms - Summer	22,149,900	20,613,155	-1,536,745
6	**Total Volumes**	**110,736,280**	**111,302,133**	**565,853**
	Commercial (SGS and MGS):			
7	Bills - Winter	84,670	85,273	603
8	Bills - Summer	115,954	117,674	1,720
9	**Total Bills**	**200,624**	**202,947**	**2,323**
10	Therms - Winter	47,577,320	48,952,466	1,375,146
11	Therms - Summer	19,142,250	17,697,135	-1,445,115
12	**Total Volumes**	**66,719,570**	**66,649,601**	**-69,969**
	Industrial Sales & Transportation:			
13	Bills	2,152	2,164	12
14	Demand	219,672	219,672	0
15	First 15,000 Therms	23,194,400	23,191,580	-2,820
16	Next 25,000 Therms	16,559,970	16,584,970	25,000
17	Next 50,000 Therms	13,000,840	13,129,180	128,340
18	Over 90,000 Therms	48,167,520	51,760,220	3,592,700
19	**Total Volumes**	**100,922,730**	**104,665,950**	**3,743,220**
	Special Contract:			
20	Bills	36	12	-24
21	Therms	8,673,330	5,447,130	-3,226,200
	Sale for Resale:			
22	Bills	31	31	0
23	Demand	2,400	2,400	0
24	Therms	103,120	103,120	0
25	**Total Bills**	**2,008,767**	**2,021,045**	**12,278**
26	**Total Demand**	**219,672**	**219,672**	**0**
27	**Total Therms**	**287,155,030**	**288,167,934**	**1,012,904**

A/ Company Exhibit DRC-1.
B/ CAPD Attachment WHN-2, Schedule 1.

ATTACHMENT WHN-3

WNA Factors

Piedmont-Nashville
Summary of WNA Factors

Attachment WHN-3
Schedule 1

Tariff	"R" Value ($/Therm)	Heat Factor (Therms/DDD)	Base Factor (Therms/Mo.)
Residential	TBD	0.17945	7.91318
Commercial (SGS & MGS)	TBD	0.74873	104.85079

Piedmont-Residential
Cycle Weather Normalization
Nashville Heating Degree Days

Attachment WHN-3
Schedule 2

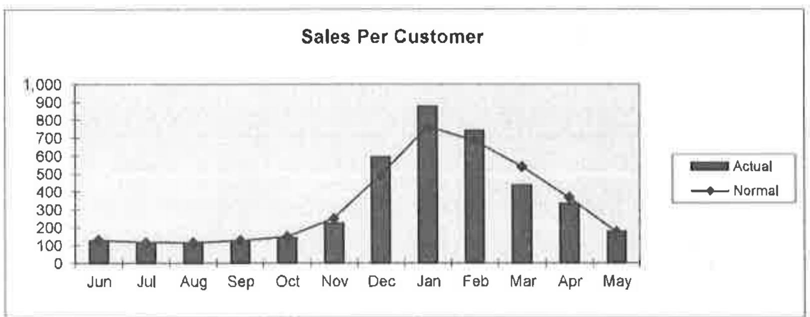
For the 12 Months Ended May 31, 2011

MONTH	SALES	CUSTOMERS	SALES PER CUSTOMER	ACTUAL WEATHER	NORMAL WEATHER
June	1,986,500	147,976	13.4245	10	16
July	1,603,102	147,825	10.8446	0	0
August	1,514,414	147,449	10.2708	0	0
September	1,613,034	146,860	10.9835	0	1
October	2,222,777	146,626	15.1595	69	77
November	5,296,044	147,737	35.8478	274	311
December	17,168,174	149,341	114.9595	715	579
January	29,307,299	150,511	194.7187	949	798
February	24,595,687	150,767	163.1371	881	806
March	13,956,715	150,713	92.6046	381	518
April	9,923,668	150,258	66.0442	278	324
May	3,820,813	149,468	25.5627	113	108
TOTAL	113,008,227	1,785,531	753.5574	3,670	3,538

MONTH	WEATHER DEVIATION	PER CUST ADJUSTMENT	NORMAL SALE/CUST	NORMAL SALES	WEATHER ADJUSTMENT
June	5.9400	1.0660	14.4905	2,144,242	157,742
July	0.0600	0.0108	10.8554	1,604,699	1,597
August	0.1000	0.0179	10.2887	1,517,053	2,639
September	0.7200	0.1292	11.1127	1,632,008	18,974
October	8.1200	1.4572	16.6167	2,436,440	213,663
November	37.0700	6.6524	42.5002	6,278,850	982,806
December	-136.2800	-24.4561	90.5034	13,515,876	-3,652,298
January	-151.0900	-27.1138	167.6049	25,226,374	-4,080,925
February	-75.3900	-13.5291	149.6080	22,555,945	-2,039,742
March	137.2500	24.6302	117.2348	17,668,806	3,712,091
April	46.1500	8.2818	74.3260	11,168,075	1,244,407
May	-4.7700	-0.8560	24.7067	3,692,868	-127,945
TOTAL	-132.1200	-23.7095	729.8479	109,441,236	-3,566,991

Regression Output:

Constant	7.91317500
Std Err of Y Est	12.60424070
R Squared	0.96550403
X Coefficient	0.17945485
Std Err of Coef.	0.01072661



Piedmont-Commercial
Cycle Weather Normalization
Nashville Heating Degree Days

Attachment WHN-3
Schedule 3

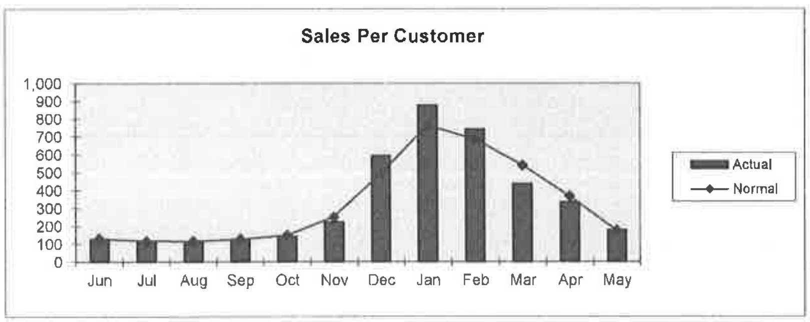
For the 12 Months Ended May 31, 2011

MONTH	SALES	CUSTOMERS	SALES PER CUSTOMER	ACTUAL WEATHER	NORMAL WEATHER
June	2,109,703	16,731	126.0955	10	16
July	1,935,453	16,655	116.2085	0	0
August	1,895,701	16,581	114.3297	0	0
September	2,084,668	16,448	126.7429	0	1
October	2,343,194	16,390	142.9649	69	77
November	3,678,624	16,535	222.4750	274	311
December	10,022,339	16,902	592.9676	715	579
January	14,973,464	17,093	875.9998	949	798
February	12,675,291	17,104	741.0717	881	806
March	7,436,076	17,043	436.3126	381	518
April	5,626,926	16,956	331.8546	278	324
May	3,005,876	16,789	179.0384	113	108
TOTAL	67,787,315	201,227	4,006.0612	3,670	3,538

MONTH	WEATHER DEVIATION	PER CUST ADJUSTMENT	NORMAL SALE/CUST	NORMAL SALES	WEATHER ADJUSTMENT
June	5.9400	4.4475	130.5430	2,184,114	74,411
July	0.0600	0.0449	116.2534	1,936,201	748
August	0.1000	0.0749	114.4046	1,896,943	1,242
September	0.7200	0.5391	127.2820	2,093,535	8,867
October	8.1200	6.0797	149.0446	2,442,840	99,646
November	37.0700	27.7555	250.2305	4,137,561	458,937
December	-136.2800	-102.0374	490.9302	8,297,703	-1,724,636
January	-151.0900	-113.1261	762.8737	13,039,800	-1,933,664
February	-75.3900	-56.4470	684.6247	11,709,822	-965,469
March	137.2500	102.7637	539.0763	9,187,478	1,751,402
April	46.1500	34.5540	366.4086	6,212,824	585,898
May	-4.7700	-3.5715	175.4669	2,945,914	-59,962
TOTAL	-132.1200	-98.9227	3,907.1385	66,084,735	-1,702,580

Regression Output:

Constant	104.85079190
Std Err of Y Est	42.16793515
R Squared	0.97754372
X Coefficient	0.74873344
Std Err of Coef.	0.03588624



Piedmont-Nashville
Nashville 30 Year Daily Normal Heating Degree Days

DAY	JAN	FEB	MAR	APR	MAY	JUN	JUL	AUG	SEP	OCT	NOV	DEC
1	25.57	22.67	19.40	11.23	2.77	0.30	0.00	0.00	0.00	2.33	7.67	20.77
2	24.30	22.67	17.57	8.73	2.63	0.13	0.00	0.00	0.00	2.77	9.80	21.10
3	24.20	24.20	19.03	8.47	4.27	0.13	0.00	0.00	0.00	3.20	11.60	20.00
4	24.43	26.30	16.40	10.00	4.47	0.13	0.00	0.00	0.00	2.73	12.10	21.37
5	25.93	27.10	16.70	11.03	2.97	0.07	0.00	0.00	0.03	3.07	12.70	23.37
6	24.60	26.67	16.77	10.70	2.27	0.10	0.00	0.00	0.13	3.50	14.80	24.47
7	25.73	26.47	17.13	9.33	1.73	0.10	0.00	0.00	0.03	4.77	13.43	23.63
8	27.50	25.47	16.33	8.37	1.87	0.00	0.00	0.00	0.00	4.33	12.70	21.77
9	26.37	25.30	17.53	10.13	1.63	0.00	0.00	0.00	0.00	3.67	11.50	21.50
10	26.77	25.30	18.87	9.03	1.73	0.07	0.00	0.00	0.00	3.73	13.27	22.53
11	28.20	24.33	17.17	8.40	1.47	0.00	0.00	0.00	0.00	4.33	13.80	22.60
12	25.37	25.50	15.63	8.47	1.20	0.03	0.00	0.00	0.00	4.27	15.60	23.63
13	25.73	24.70	14.67	6.63	1.70	0.17	0.00	0.10	0.10	4.43	15.40	23.17
14	27.57	21.77	15.03	5.50	1.63	0.00	0.00	0.00	0.23	5.33	14.50	22.40
15	28.57	21.57	13.63	7.10	1.70	0.00	0.00	0.00	0.10	4.93	14.67	22.30
16	28.30	21.63	13.93	7.47	2.20	0.00	0.00	0.00	0.33	5.87	15.97	23.80
17	27.90	22.50	12.77	7.50	1.77	0.00	0.00	0.00	0.47	5.77	16.83	23.30
18	28.43	21.13	11.53	6.03	1.57	0.00	0.00	0.00	0.33	5.80	15.37	25.20
19	29.43	20.53	12.63	4.93	1.33	0.00	0.00	0.00	0.60	7.50	12.83	26.23
20	29.30	17.83	12.57	4.60	1.17	0.00	0.00	0.00	0.53	7.73	14.47	26.80
21	29.07	16.47	14.97	5.13	1.30	0.03	0.00	0.00	1.27	6.17	16.77	25.30
22	26.70	19.50	14.70	4.53	1.20	0.03	0.00	0.00	1.53	6.70	17.57	24.70
23	26.30	19.37	12.80	5.20	0.43	0.00	0.00	0.00	1.80	7.47	16.67	26.00
24	26.00	20.33	12.00	4.93	0.27	0.00	0.00	0.00	1.80	8.53	17.57	28.43
25	27.93	21.10	11.27	3.97	0.63	0.00	0.00	0.00	1.27	8.10	15.93	31.37
26	29.00	20.57	11.37	4.07	0.27	0.00	0.00	0.00	1.80	7.70	15.03	28.70
27	27.97	19.70	11.03	4.70	0.47	0.00	0.00	0.00	2.07	9.03	14.60	23.33
28	25.70	20.80	10.33	4.63	0.47	0.00	0.00	0.03	1.83	9.50	17.30	22.77
29	23.83	4.93	10.90	3.80	0.67	0.00	0.00	0.07	2.10	8.53	18.30	24.47
30	24.33		11.33	2.70	0.53	0.00	0.00	0.00	2.20	7.10	18.90	24.17
31	25.40		10.90		0.43		0.00	0.00		6.03		22.50
Calendar Total	826	636	447	203	49	1	0	0	20	175	438	742
Cycle Total	798	806	518	324	108	16	0	0	1	77	311	579

NON-LEAP YEAR TOTAL	3,538
LEAP YEAR TOTAL	3,553

Note: Degree Days for February 29 must be multiplied by 4 to arrive at the true DDD for this day.
NOTE: AVERAGE IS FOR THE 30 YEAR PERIOD ENDED: May, 2011.

ATTACHMENT WHN-4

Revenue Comparison

Piedmont-Nashville
Attrition Period Revenue Summary Comparison

Attachment WHN-4
Schedule 1

Line No.	Consumer Advocate	Demand Units	Bills	Sales Volumes	Gross Margin A/
1	**Residential**		1,815,891	111,302,133	$55,025,059
	Commercial				
2	Small General Service		198,023	50,982,004	$23,099,911
3	Medium General Service		4,924	15,667,597	5,703,459
4	**Total Commercial**		**202,947**	**66,649,601**	**$28,803,370**
	Industrial				
5	Firm Sales	61,947	475	5,628,480	1,154,835
6	Interruptible Sales		15	19,280	6,378
7	Firm Transportation	157,725	1,021	18,057,200	3,223,277
8	Interruptible Transportation		653	80,960,990	4,043,748
9	**Total Industrial**	**219,672**	**2,164**	**104,665,950**	**$8,428,238**
10	**Special Contract**		12	5,447,130	434,249
11	**Sales for Resale**	2,400	31	103,120	28,481
12	**Total Sales & Transportation**	**222,072**	**2,021,045**	**288,167,934**	**$92,719,397**
13	Other Revenues				1,884,565
14	**Total Revenues**				**$94,603,962**

Line No.	Company	Demand Units	Bills	Sales Volumes	Gross Margin B/
15	**Residential**		1,805,924	110,736,270	$54,662,151
	Commercial				
16	Small General Service		195,782	51,281,220	$23,081,065
17	Medium General Service		4,842	15,438,360	5,602,239
18	**Total Commercial**		**200,624**	**66,719,580**	**$28,683,304**
	Industrial				
19	Firm Sales	61,947	475	5,628,480	1,154,835
20	Interruptible Sales		15	19,280	6,378
21	Firm Transportation	157,725	1,021	18,057,200	3,223,275
22	Interruptible Transportation		641	77,217,770	3,930,604
23	**Total Industrial**	**219,672**	**2,152**	**100,922,730**	**$8,315,092**
24	**Special Contract**		36	8,673,330	624,617
25	**Sales for Resale**	2,400	31	103,120	28,481
26	**Total Sales & Transportation**	**222,072**	**2,008,767**	**287,155,030**	**$92,313,645**
27	Other Revenues				2,005,089
28	**Total Revenues**				**$94,318,734**

A/ CAPD Revenue Workpaper R-13.00.
B/ Company Exhibits DRC-1 and PKP-1.

ATTACHMENT WHN-5

Gas Cost Calculation

Piedmont-Nashville
Gas Cost Calculation

Attachment WHN-5
Schedule 1

Line No.	Consumer Advocate	Revenue	Margin	Gas Cost A/
1	Residential (301)	$111,860,380	$55,025,059	$56,835,321
	Commercial			
2	Small General Service (302)	$49,080,850	$23,099,911	$25,980,939
3	Medium General Service (352)	13,423,825	5,703,459	7,720,366
4	**Total Commercial**	**$62,504,675**	**$28,803,370**	**$33,701,305**
	Industrial			
5	Firm Sales (303)	$4,160,219	$1,154,835	$3,005,384
6	Interruptible Sales (304)	16,210	6,378	9,831
7	Firm Transportation (313)	4,039,490	3,223,277	816,213
8	Interruptible Transportation (314)	4,098,048	4,043,748	54,300
9	**Total Industrial**	**$12,313,966**	**$8,428,238**	**$3,885,728**
10	Special Contract	552,454	434,249	118,205
11	Sales for Resale (310)	89,544	28,481	61,063
12	**Total Sales & Transportation**	**$187,321,019**	**$92,719,397**	**$94,601,622**

Line No.	Company	Revenue	Margin	Gas Cost B/
13	Residential (301)	$111,208,831	$54,662,151	$56,546,680
	Commercial			
14	Small General Service (302)	$49,214,518	$23,081,065	$26,133,453
15	Medium General Service (352)	13,209,710	5,602,239	7,607,471
16	**Total Commercial**	**$62,424,228**	**$28,683,304**	**$33,740,924**
	Industrial			
17	Firm Sales (303)	$4,160,218	$1,154,835	$3,005,383
18	Interruptible Sales (304)	16,210	6,378	9,832
19	Firm Transportation (313)	4,039,484	3,223,275	816,209
20	Interruptible Transportation (314)	3,984,729	3,930,604	54,125
21	**Total Industrial**	**$12,200,641**	**$8,315,092**	**$3,885,549**
22	Special Contract	742,822	624,617	118,205
23	Sales for Resale (310)	89,544	28,481	61,063
24	**Total Sales & Transportation**	**$186,666,066**	**$92,313,645**	**$94,352,421**

A/ CAPD Revenue Workpapers R-13.02.
B/ Company Exhibit DRC-1.

ATTACHMENT WHN-6
CAPD Proposed Rate Design

Piedmont-Nashville
CAPD Proposed Rate Design

Attachment WHN-6
Schedule 1

Tariff	Billing Determinants	Current Base Rates	Current Margin	Revenue Deficiency	Proposed Margin	Proposed Base Rates	Percent Increase
Residential							
Customer Charges							
Summer	1,055,850	$10 00	$10,558,498	$2,999,415	$13,557,913	$12 84	28.41%
Winter	760 041	$13 00	9 880 535	2 806 822	12 687 357	$16 69	28.41%
Total Customer Charge Margin	1,815,891		$20,439,033	$5,806,238	$26,245,271		28.41%
Commodity Charges							
Summer Therms	20,613,155	$0.27000	$5,565,552	$0	$5,565,552	$0 27000	0 00%
Winter Therms	90,688,978	0.32000	29,020,473	0	29,020,473	0 32000	0 00%
Total Commodity Charge Margin	111,302,133		$34,586,025	$0	$34,586,025		0.00%
Total Residential		1	$55,025,058	$5,806,238	$60,831,296		10.55%
				$5,806,238	$60,831,296		
Commercial							
Small General Service							
Customer Charges							
Summer	114,819	$29 00	$3,329,743	$1,413,323	$4,743,066	$41 31	42.45%
Winter	83 204	$29 00	2 412 926	1 024 177	3 437 103	$41 31	42.45%
Total Customer Charge Margin	198,023		$5,742,669	$2,437,500	$8,180,169		42.45%
Commodity Charges							
Summer Therms	13,536,997	$0.30300	$4,101,710	$0	$4,101,710	$0 30300	0 00%
Winter Therms	37 445 007	0.35400	13 255 533	0	13 255 533	0 35400	0 00%
Total Commodity Charge Margin	50,982,004		$17,357,243	$0	$17,357,243		0.00%
Total Small General Service			$23,099,912	$2,437,500	$25,537,412		10.55%
Medium General Service							
Customer Charges							
Summer	2,855	$75 00	$214,128	$348,956	$563,084	$197 22	162 97%
Winter	2,069	$75 00	155,169	252,873	408,042	$197 22	162 97%
Total Customer Charge Margin	4,924		$369,297	$601,828	$971,125		162.97%
Commodity Charges							
Summer Therms	4,160,139	$0.30300	$1,260,522	$0	$1,260,522	$0 30300	0 00%
Winter Therms	11,507,458	0.35400	4,073,640	0	4,073,640	0 35400	0 00%
Total Commodity Charge Margin	15,667,597		$5,334,162	$0	$5,334,162		0.00%
Total Medium General Service			$5,703,459	$601,828	$6,305,287		10.55%
Total Commercial		0.310650974	$28,803,371	$3,039,328	$31,842,699		10.55%
				$3,039,328	$31,842,699		
Industrial							
Customer Charges	2,164	$300.00000	$649,200	$889,347	$1,538,547	$710 97	136.99%
Volumetric Charges							
Step 1 - 0 to 15,000 Therms per Month	23,191,580	$0.09742	$2,259,324	$0	$2,259,324	$0 09742	0 00%
Step 2 - 15,001 to 40,000 Therms per Month	16,584,970	0.08953	1,484,852	0	1,484,852	0 08953	0 00%
Step 3 - 40,001 to 90,000 Therms per Month	13,129,180	0.06450	846,832	0	846,832	0 06450	0 00%
Step 4 - Over 90,000 Therms per Month	51,760,220	0.02764	1,430,652	0	1,430,652	0 02764	0 00%
Total Volumetric Charges	104,665,950		$6,021,660	$0	$6,021,660		0.00%
Demand Charges	219,672	$8.00000	$1,757,378	$0	$1,757,378		0.00%
Total Industrial		0.09090	$8,428,238	$889,347	$9,317,585		10.55%
				$889,347	$9,317,585		
Other							
Special Contracts			$434,249	$45,822	$480,071	Proprietary	10.55%
Sales for Resale							
Customer Charges	31	$0 00	$0	$3,005	$3,005	$96 95	100%
Demand Charges	2,400	8.00000	19,200	0	19,200	8 00000	0%
Volumetric Charges	103,120	0.09000	9 281	0	9 281	0 09000	0%
Total Sales for Resale			$28,481	$3,005	$31,486		10.55%
Total Other		0	$462,730	$48,827	$511,557		10.55%
				$48,827	$511,557		
Miscellaneous Service Revenue							
Forfeited Discounts			$1,564,421	$79,654	1,644,075		5 09%
Bad Check Charges			51,090	0	51,090		0 00%
Reconnect Charges			241,448	0	241,448		0 00%
Other Miscellaneous Items			27,606	0	27,606		0 00%
Total Miscellaneous Service Revenue			$1,884,565	$79,654	$1,964,219		4.23%
				$79,654	$1,964,219		
Total Base Rate Margin			$94,603,962	$9,863,394	$104,467,356		10.43%
				9,863,394	104,467,356		

SOURCE CAPD Workpaper R-14 00.

ATTACHMENT

1-4d

BEFORE
THE TENNESSEE REGULATORY AUTHORITY

	)	
	)	
	)	
PETITION OF B&W PIPELINE, LLC	)	
FOR AN INCREASE IN ITS RATES	)	Docket No. 15-
AND CHARGES	)	
	)	
	)	
	)	

DIRECT TESTIMONY
of
WILLIAM H. NOVAK

ON BEHALF OF
B&W PIPELINE, LLC

April 2, 2015

Q1. PLEASE STATE YOUR NAME, BUSINESS ADDRESS AND OCCUPATION FOR THE RECORD.

A1. My name is William H. Novak. My business address is 19 Morning Arbor Place, The Woodlands, TX, 77381. I am the President of WHN Consulting, a utility consulting and expert witness services company.[1]

Q2. PLEASE PROVIDE A SUMMARY OF YOUR BACKGROUND AND PROFESSIONAL EXPERIENCE.

A2. A detailed description of my educational and professional background is provided in Attachment WHN-1 to my testimony. Briefly, I have both a Bachelors degree in Business Administration with a major in Accounting, and a Masters degree in Business Administration from Middle Tennessee State University. I am a Certified Management Accountant, and am also licensed to practice as a Certified Public Accountant.

My work experience has centered on regulated utilities for over 30 years. Before establishing WHN Consulting, I was Chief of the Energy & Water Division of the Tennessee Regulatory Authority where I had either presented testimony or advised the Authority on a host of regulatory issues for over 19 years. In addition, I was previously the Director of Rates & Regulatory Analysis for two years with Atlanta Gas Light Company, a natural gas distribution utility with operations in Georgia and Tennessee. I also served for two years as the Vice

[1] State of Tennessee, Registered Accounting Firm ID 3682.

President of Regulatory Compliance for Sequent Energy Management, a natural gas trading and optimization entity in Texas, where I was responsible for ensuring the firm's compliance with state and federal regulatory requirements.

In 2004, I established WHN Consulting as a utility consulting and expert witness services company. Since 2004 WHN Consulting has provided testimony or consulting services to state public utility commissions and state consumer advocates in at least ten state jurisdictions as shown in Attachment WHN-1.

Q3. ON WHOSE BEHALF ARE YOU TESTIFYING?

A3. I am testifying on behalf of B&W Pipeline, LLC ("B&W Pipeline" or "the Company").

Q4. WHAT IS THE PURPOSE OF YOUR TESTIMONY IN THIS PROCEEDING?

A4. The purpose of my testimony is to present to the TRA the underlying methodology used by B&W Pipeline in the calculation of its attrition period adjustments to rate base and income as shown on Company Exhibits, Schedules 2 and 3. In addition, I am responsible for presenting the Company's fair rate of return used to arrive at the revenue deficiency as shown on Company Exhibit, Schedule 1. Finally, I am responsible for the calculation of the new initial proposed rates that will begin providing the Company with the opportunity to recover its reasonable operating expenses and provide a fair return on its investment.

Q5. WHAT HISTORIC TEST PERIOD AND ATTRITION PERIOD HAS THE COMPANY PROPOSED IN ITS FILING?

A5. We have used the twelve months ended December 31, 2014 as our historic test period with adjustments through the twelve months ending December 31, 2016. The twelve months ended December 31, 2014 was chosen as our test period because it was the latest calendar year available as the Company was putting its case together. The twelve months ending December 31, 2016 was chosen as our attrition period because it represented the first twelve-month period that any new rates approved by the TRA would be in effect.

Q6. PLEASE EXPLAIN THE COMPANY'S RATE BASE CALCULATION.

A6. The attrition period rate base of $2,575,326 shown on Company Exhibit, Schedule 2 represents the total projected investment by the owner of B&W Pipeline at June 30, 2016, which is the midpoint of the attrition year. This amount also represents the investment on which the Company should be allowed the opportunity to earn a fair rate of return during the attrition period. The individual components of Rate Base are taken from the Company's books and records and are the same amounts reported on the Company's annual report to the TRA. The individual components of Rate Base are further explained below.

Line 5, Total Plant in Service; $3,154,842.

Utility Plant in Service largely represents the mains and supporting equipment already in place that is used to provide gas transportation service. This amount represents the original cost paid for the system by B&W Pipeline along with subsequent improvements to the system.

Line 6, Accumulated Depreciation; $633,516.

This item represents the amount of depreciation which has accumulated over the life of the various plant items included in utility plant in service. The Company has current depreciation rates of 3.33% on utility plant. The attrition period adjustment of $177,984 represents the monthly depreciation on existing and new plant through June 30, 2016, which is the midpoint of the attrition year.

Line 8, Deferred Rate Case Expense; $54,000.

This item represents the unamortized balance of the Company's cost of preparing, presenting and defending this rate case filing before the TRA. The Company is expecting the total cost of this filing to be $60,000 and we are asking the TRA to allow us to amortize this cost over a five-year period. The $54,000 unamortized amount reflects the expected balance at June 30, 2016, which is the midpoint of the attrition year.

Q7 MR. NOVAK, HAVE YOU PROVIDED SUPPORTING WORK PAPERS FOR THE PRO FORMA RATE BASE CALCULATIONS DESCRIBED ABOVE THAT WERE MADE TO THE TEST PERIOD AND ATTRITION period?

A7. Yes. The Company has included its supporting rate base workpapers in its filing.

Q8. PLEASE EXPLAIN THE COMPANY'S NET OPERATING INCOME/LOSS CALCULATION.

A8. The attrition period net operating loss of $-265,111 represents the projected operating loss by B&W Pipeline, at presently approved rates, for the twelve months ending December 31, 2016. The calculation of this net operating loss is shown on column 5 of Company Exhibit, Schedule 3. The individual components of Net Operating Income are first taken from the Company's books and records and are the same amounts reported on the Company's annual report to the TRA. The individual components of Net Operating Income/Loss are further explained below.

Lines 1-2, Transportation Revenue; $101,917.

This amount represents the projected gas transportation revenues the Company expects to realize for the twelve months ended December 31, 2016 under current rates. The details of this projection are further shown on Company Exhibit, Schedule 4. To forecast transportation revenue, we first increased the adjusted test period amount of revenues for added customers and then priced out the anticipated usage of these new customers at the existing tariff rates. Navitas has informed the Company of the addition of two new customers that they have already connected to their system. In addition, the Company expects to add volumes from gas transportation to its affiliate that uses gas for oil extraction from local wells in the area.

Lines 3 – 12, Operation Expense; $243,692.

This amount represents the projected expenses necessary for B&W Pipeline to operate the utility. The individual components of Operation Expense are presented on Company Exhibit, Schedule 2. To project the attrition year Operation Expense, the Company made two adjustments to Operator Fees and Professional Services.

The Operator Fees represent charges from Enrema, the Company's service affiliate to operate the pipeline. Because B&W Pipeline has no employees of its own, it depends on Enrema to provide these services. These services include oversight of the day-to day operations, monitoring the daily work provided by subcontractors, preparation and review of all regulatory reports and filings, and providing the utility with an emergency contact person on a 24 hour basis. The historic test period amount of Operator Fees of $273,000 was reduced by 50% to reflect amounts that are allocated to the Non-Utility Operations discussed below. The remaining attrition period amount of $136,500 reflects front office and back office costs of operating the pipeline.

An attrition period adjustment of $12,000 was made to Professional Services. The Company anticipates that the total legal, regulatory and accounting costs of making, presenting and defending this rate case filing to be $60,000. The Company is asking the Authority to allow it to amortize these costs over a five-year period beginning January 1, 2016. As shown on Company Exhibit, Schedule 5, the $12,000 increase in this projected expense represents the first year of this amortization.

Lines 13 – 17, Maintenance Expense; $4,148.

This amount represents the projected expenses necessary for B&W Pipeline to maintain the utility plant and pipeline. The individual components of Operation

Expense are presented on Company Exhibit, Schedule 2. The historic maintenance expense for the test period of $4,148 was used as the anticipated attrition period maintenance expense.

Line 18, Depreciation Expense; $118,656.

This item represents the annual systematic depreciation on the Company's plant in service. As mentioned above, the Company's currently approved depreciation rates are 3.33% on its utility plant. The historic depreciation expense for the test period of $118,656 was used as the anticipated attrition period depreciation expense.

Line 19, Taxes Other Than Income; $532.

This item largely represents the Company's property taxes, franchise taxes and TRA Inspection Fees. The historic expense for the test period of $532 was used as the anticipated attrition period amount.

Q9. MR. NOVAK, HAVE YOU PROVIDED SUPPORTING WORK PAPERS FOR THE PRO FORMA NET OPERATING INCOME CALCULATIONS DESCRIBED ABOVE THAT WERE MADE TO THE TEST PERIOD AND ATTRITION PERIOD?

A9. Yes. The Company has included its supporting revenue and expense workpapers in its filing.

Q10. PLEASE EXPLAIN HOW THE COMPANY'S REVENUE DEFICIENCY WAS COMPUTED.

A10. As shown on Company Exhibit, Schedule 1, the attrition period net operating loss of $-265,111 was divided by the average attrition period average rate base of

$2,575,326 to get a rate of return under existing rates of -10.29%. The attrition period rate base was then applied to the Company's requested fair rate of return of 10.12% resulting in a required operating income of $260,537. This means that the Company's current net operating income needs to be increased from $-265,111 to $260,537 or by $525,648 in order to achieve this required operating income. Since the Company is a single member limited liability company, all income flows directly to the owner's tax return. Therefore, the revenue conversion factor is equal to 1.00 and no adjustment for income taxes is necessary. This means that the revenue deficiency is equal to the operating income deficiency of $525,648.

Q11. HOW DID YOU DETERMINE THE COMPANY'S FAIR RATE OF RETURN OF 10.12%?

A11. I first examined the Company's capital structure. The Company is a single member limited liability company without any debt. Therefore all of the funding has been provided by the owner's equity. To determine a cost of equity, I examined the previous decisions of the TRA in the last 3 rate cases for natural gas utilities as shown on Company Exhibit, Schedule 6. The average return on equity for these three utilities equaled 10.12% which is what the Company is requesting in this case.

Q12. HAS THE COMPANY PREPARED A PROPOSED RATE DESIGN TO RECOVER ITS REVENUE DEFICIENCY?

A12. Under the current rate design structure, the Company's rates would need to be increased from $0.60 per Mcf to $3.69 per Mcf in order for B&W Pipeline to recover its revenue deficiency as shown below.

Item	Amount
Attrition Period Revenue at Current Rates	$101,917
Projected Revenue Deficiency	525,648
Attrition Period Revenue at Proposed Rates	**$627,565**
Attrition Period Sales Volumes (Mcf)	169,861
Attrition Period Rate per Mcf	**$3.69**

However, the Company is currently negotiating with Navitas for a traditional pipeline rate design based upon peak day usage that is acceptable to both parties. We expect to have a final rate design to present to the TRA before this matter is scheduled for hearing.

Q13. DOES THIS COMPLETE YOUR TESTIMONY?

A13. Yes it does. However I reserve the right to incorporate any new information that may subsequently become available.

ATTACHMENT

1-4e

FILE

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OCC EXHIBIT NO ________

BEFORE
THE PUBLIC UTILITIES COMMISSION OF OHIO

In the Matter of the Application of Vectren Energy Delivery of Ohio, Inc., for Authority to Amend its Filed Tariffs to Increase the Rates and Charges for Gas Services and Related Matters.	)	Case No. 07-1080-GA-AIR
In the Matter of the Application of Vectren Energy Delivery of Ohio, Inc., for Approval of An Alternative Rate Plan for a Distribution Replacement Rider to Recover the Costs of a Program for the Accelerated Replacement of Cast Iron Mains and Bare Steel Mains and Service Lines, a Sales Reconciliation Rider to Collect Difference Between Actual and Approved Revenues, and Inclusion in Operating Expense of the Costs of Certain Reliability Programs.	)	Case No. 07-1081-GA-ALT

DIRECT TESTIMONY
Of
WILLIAM H. NOVAK

ON BEHALF OF THE
OFFICE OF THE OHIO CONSUMERS' COUNSEL
10 West Broad Street, Suite 1800
Columbus, Ohio 43215

July 23, 2008

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SCHEDULES

ATTACHMENTS

I. INTRODUCTION

Q1. PLEASE STATE YOUR NAME, BUSINESS ADDRESS AND OCCUPATION FOR THE RECORD, PLEASE.

A1. My name is William H. Novak. My business address is 19 Morning Arbor Place, The Woodlands, TX, 77381. I am the President of WHN Consulting, a utility consulting and expert witness services company.

Q2. PLEASE PROVIDE A SUMMARY OF YOUR BACKGROUND AND PROFESSIONAL EXPERIENCE.

A2. A detailed description of my educational and professional background is provided in Attachment WHN-1 to my testimony. Briefly, I have both a Bachelors degree in Business Administration with a major in Accounting, and a Masters degree in Business Administration from Middle Tennessee State University. I am a Certified Management Accountant, and am also licensed to practice as a Certified Public Accountant.

My work experience has centered on regulated utilities for over 25 years. Before establishing WHN Consulting, I was Chief of the Energy & Water Division of the Tennessee Regulatory Authority where I had either presented testimony or advised the Authority on a host of regulatory issues for over 19 years. In addition, I was previously the Director of Rates & Regulatory Analysis for two years with Atlanta Gas Light Company, a natural gas distribution utility with operations in Georgia and Tennessee, where I was responsible for defending the utility's gas cost recovery and rate filings at a time when it was completely exiting the gas merchant function in Georgia, and employing a straight fixed variable ("SFV") rate design for each of its individual customers. I also served for two years as the Vice President of Regulatory Compliance for Sequent Energy Management, a natural gas trading and optimization company in Texas, where I was responsible for ensuring the firm's compliance with state and federal regulatory requirements.

Q3. ON WHOSE BEHALF ARE YOU TESTIFYING?

A3. I am testifying on behalf of the Office of the Ohio Consumers' Counsel ("OCC").

Q4. WHAT IS THE PURPOSE OF YOUR TESTIMONY IN THIS PROCEEDING?

A4. My testimony will support certain OCC Objections to the Staff Report and address issues raised by those objections. Specifically I will address the following aspects of the Company's case:

- The process used to normalize test period sales for weather;
- The forecast of revenues under current rates for all customer classes;
- The allocation of the proposed rate increase to different customer classes;
- The rate design for the residential customer class;
- The Distribution Rate Rider ("DRR"); and
- The Sales Reconciliation Rider ("SRR").

Q5. WHAT DOCUMENTS HAVE YOU REVIEWED IN PREPARATION OF YOUR TESTIMONY?

A5. I have reviewed the Vectren Energy Delivery of Ohio ("Vectren" or "the Company") Rate Case Application, along with the testimony and exhibits presented with their filing. In addition, I have reviewed the Company's workpapers related to the cost of service and revenue calculations supporting their filings. I have also reviewed the Company's responses to the data requests submitted by the Staff and Eagle Energy, as well as the OCC in these same areas. Finally, I have reviewed the Staff Report and the Eagle Report along with workpapers provided to the OCC in support of their conclusions.

II. WEATHER NORMALIZATION

Q6. PLEASE EXPLAIN THE PROCESS OF WEATHER NORMALIZATION.

A6. Generally speaking, gas sales to the residential and small commercial customer classes are highly dependent upon changes in weather. In addition, weather normalization can often be appropriate to individual industrial customers that use natural gas solely for heating load as opposed to a process load.

To the extent that any of these customer classes use gas for heating, then the severity of weather impacts their demand for gas. That is to say that during colder than normal periods, the Company will generally increase their sales to the residential and small commercial customer classes. Likewise in periods of warmer than normal weather, the Company's sales will generally decrease to the same customer classes.

Weather normalization in a rate case represents an adjustment to the actual historical gas sales volumes to account for the impacts of the differences between actual and normal weather. In other words, the historical values of the residential and small commercial customer classes are adjusted to what they ***would have been*** if normal weather had occurred. This adjustment to "normal" is necessary because we don't know precisely what any future years' weather will be; therefore we assume in a rate case that weather will be normal and we adjust accordingly.

Q7. ***HOW IS NORMAL WEATHER DETERMINED?***

A7. In the United States, the most widely relied upon source of weather data is from the National Oceanic and Atmospheric Administration ("NOAA"). To my knowledge, NOAA has always calculated normal weather as a 30 year average of the actual daily weather observed. NOAA recalculates this normal weather average every 10 years, with the last calculation taking place for the 30 year period ended December 31, 2000. The NOAA calculation of normal weather has traditionally been accepted and utilized by public utility commissions in gas distribution rate cases.

Q8. HAS THE COMPANY ADOPTED A 30 YEAR AVERAGE AS NORMAL IN ITS RATE CASE?

A8. No. Instead of the 30 year average, the Company has proposed using a 10 year average of actual weather as a proxy for normal weather. NOAA has calculated the 30 year average of weather to be 5,690 heating degree days ("HDD") whereas the Company has adopted a 10 year average of 5,388 HDD for a difference of 302 HDD or 5.3%. The impact of this change in computing normal weather from 30 years to 10 years results in an increase in the Company's revenue requirements of approximately $1.7 million.

As shown on Schedule WHN-1, during the 10 year period used by the Company to calculate normal weather, the deviation of actual heating degree days experienced from normal weather for both 10 year and 30 year averages produced the following results:

	10 Year Average	**30 Year Average**
Years Warmer Than Normal	4	7
Years Colder Than Normal	6	3

As expected, both the 10 year average and the 30 year average produced results that were on both sides of the normal average. As a result, there appears to be very little evidence in support of the Company's conclusions that 30 year weather is no longer appropriate since the evidence shows that during the last 10 years the actual weather experienced was both warmer and colder than the 30 year average. It therefore appears that Vectren has elected to use a 10 year average of weather in order to increase the Company's revenue requirement. I doubt that such an action would be requested if the actual weather experienced had been materially colder than the normal during this 10 year period.

Q9. WHAT IS THE COMPANY'S BASIS FOR USING A 10 YEAR AVERAGE FOR NORMAL WEATHER?

A9. The Company's sole basis for adopting a 10 year average for normal weather appears to be contained within the four page testimony of Company witness Michael F. Gorman who states very clearly that his analysis "* * * is purely statistical and in no way either climatological or meterological in nature."[1] However, the source weather data used by Mr. Gorman as the basis for his analysis is completely climatological. Mr. Gorman then concludes in his analysis that "* * * from a statistical perspective, a 30 year weather history provided less accuracy (and therefore greater bias) than shorter historical periods."[2] This conclusion appears to be the Company's complete rationale for adopting a 10 year average of weather as normal.

[1] Gorman Prefiled Direct Testimony at 2.

[2] Id. at 3.

Q10. IS MR. GORMAN'S CONCLUSION THAT 30 YEAR WEATHER IS LESS ACCURATE THAN A 10 YEAR PERIOD CORRECT?

A10. From a strictly statistical point of view a shorter time period may be more accurate than a longer period. However, Mr. Gorman's analysis is simply a self-fulfilling prophecy. If one calculates the average weather for a 10 year period, one would expect that 10 year average to be closer to the most recent weather actually realized than a 30 year average of weather. Under this logic, a five year, three year or even one year average would be more "accurate" than the 30 year average. However, this does not mean that there is any "predictive" value in using a shorter average. Weather is not something that is readily predicted from the results of the previous year or even the most recent 10 years. While we can make observations based on historic periods that take into account both recent and long term trends, it would not be reasonable to focus too much on either the most recent or the long term past. Instead, some form of combination is necessary. The NOAA 30 year average provides that combination because it reflects the recent past while at the same time recognizing any recent anomalies that need to be mitigated. Otherwise a stretch of 2 or 3 years of extremely cold or warm weather could seriously skew the analysis. The best method for determining what is "normal" is to use a longer term average as NOAA does, since this longer period takes into account many of the anomalies that a shorter period would miss. In fact, the Company actually puts their sales budget together using a 30-year average of weather. The NOAA 30-year average is far less volatile than the Company's choice of the most recent

10-year average, which appears to have been chosen for the sole purpose of increasing the Company's revenue requirement.

Q11. DID THE STAFF ADOPT A 30 YEAR AVERAGE FOR NORMAL WEATHER?

A11. No. The Staff recommended the adoption of the Company's 10 year average for normal weather. Page 8 the Staff Report states that Staff "* * * agree[s] with normalizing test year sales volumes to recognize the average use per customer ("AUPC") based on a ten year actual heating degree day average." This is a policy departure from past practice of the Staff, and there is no further mention in the Staff Report as to how they reached this conclusion.

I have reviewed other recent Staff Reports in gas distribution rate cases with respect to weather normalization and noted that in the following cases weather normalization was not even addressed, and I am therefore assuming that a 30 year average was used:

Case	Company
94-0987	Columbia Gas of Ohio
95-0488	Eastern Natural Gas Company
95-0656	Cincinnati Gas & Electric
97-1724	Northeast Ohio Gas Company
07-0194	Waterville Gas Company
07-0689	Suburban Gas Company

However, weather normalization was specifically mentioned in the Staff Report for these other recent cases with recommendations as noted:

Case	**Company**
01-1228	Cincinnati Gas & Electric *Staff recommended a10 year average*
03-2170	Northeast Ohio Gas Company *Staff recommended a 30 year average*
07-0829	East Ohio Gas Company *Considered as part of a decoupling mechanism*

Of special interest, the only time that the Staff recommended a 10 year average for normal weather, in the 2001 CG&E rate case noted above, the case was ultimately settled by the parties through a stipulation presented to and accepted by the Commission. Therefore the Commission has not previously made a specific decision on the policy issue of using a 10 year average for normal weather.

However, the method and analysis utilized by the Staff to calculate VEDO's normal residential sales volumes and average sales per customer are in error. I believe that these errors contributed to the Staff's recommendation that the Commission adopt the Company's proposed 10-year average for normal weather.

Q12. PLEASE IDENTIFY THE ERRORS CONTAINED IN THE STAFF'S CALCULATION.

A12. On page 33 of the Staff Report, a presentation is made of residential weather normalized use per customer and weather normalized sales since 1990. I was able to obtain the Staff's workpapers supporting this calculation, which I have included in Attachment WHN-2 to my testimony, and discovered two errors in the Staff's analysis.

First, as shown on pages 1 – 4 of Attachment WHN-2, although the Staff obtained the correct 30 year monthly normal heating degree days from NOAA, they were incorrectly totaled to 5,388 normal degree days instead of 5,690 per the NOAA report. This error produced a 5.5% error in the Staff's calculation of normal use per customer.[3]

The second error involved the Staff's methodology for the calculation of normal sales. The Staff began by taking the percentage difference between the annual actual heating degree days and the incorrectly calculated normal heating degree days of 5,388. The Staff then applied this percentage change in heating degree days to the actual sales and actual sales per customer to get the normalized use per customer and normalized sales contained on page 33 of the Staff Report.

[3] While 5,388 heating degree days equals the 10 year average used by the Company, the individual monthly amounts used by the Staff in their analysis do not total to this amount.

Q13. IS THE STAFF'S METHODOLOGY OF COMPUTING THE NORMAL SALES PRESENTED ON PAGE 33 OF THE STAFF REPORT CORRECT?

A13. No. The Staff's methodology assumes a one-to-one relationship between the percentage change in weather to the percentage change in residential sales. Since other anomalies can and do impact residential sales (conservation, smaller houses, etc.) this one-to-one relationship rarely occurs. In my opinion, weather normalization is best calculated by using linear regression on the monthly sales per customer with the actual weather experienced over multiple 12-month periods. An equation from this regression analysis can then be applied to normal monthly weather. This type of analysis also provides a coefficient of correlation statistic that measures the change in sales per customer that can be explained by changes in weather.

Q14. HAVE YOU PERFORMED SUCH A REGRESSION ANALYSIS?

A14. Yes. The summary results of my weather normalization using linear regression are presented on Schedule WHN-2. As can be seen from this data, over the latest six year period from 2002 – 2007, residential weather normalized use per customer has actually increased.

The results of the weather normalization for commercial customers have not been finished, due to a delay in data previously requested from the Company and provided to the OCC on July 18. The results from the analysis of this information will be presented to the Commission in supplemental testimony.

Q15. WHAT CONCLUSIONS DO YOU MAKE FROM THIS ANALYSIS?

A15. I conclude that the apparent basis for the Staff's support of the Company's proposal to adopt a ten year average for normal weather based on declining normalized usage per customer is in error. As a result, there is no independently valid basis for the Staff's acceptance of the Company's ten year proposal. I certainly don't oppose a change in policy when new data indicate a change should be made, however there is no corroborating data in this case to suggest that a change from a 30 year average of weather to a 10 year average should be made.

Q16. DO YOU EXPECT WEATHER NORMALIZED RESIDENTIAL SALES PER CUSTOMER TO REMAIN CLOSE TO THE LEVELS CALCULATED HERE IN THE FUTURE?

A16. At least for the short term future, (representing the first 12 to 18 months that any rates set by the Commission would be in effect), I do expect the residential weather normalized sales per customer to remain close to the levels presented above. As shown by the data in Schedule WHN-1, the residential normal sales per bill over the last six years has only varied minimally from the test period with a low of 0.0070 MMcf per bill in 2006 to a high of 0.0079 per MMcf per bill in 2004.

However, over longer periods of time, normal residential sales per customer may well decline. Erosion of average sales per customer is nothing new, and has been experienced by gas utilities since long before current concerns about weather. Because natural gas is a scarce commodity, simple economics dictate that better technology will always be deployed to make its use more efficient. We've seen this in the past with better insulated homes and more efficient energy appliances. However, these changes have very little to do with weather, since approximately 99%[4] of total residential sales can be explained by changes in weather.

Another consideration that can cause erosion of average sales per customer is the Company's annual expansion of plant in service. This is especially true when the average use per customer from new customers is less than the embedded average use from the existing customers. However, for the last four years the Company's addition to plant in service has averaged $20.7 million while its average depreciation expense has been over $26.4 million during this same period.[5] This means that the Company has limited its plant expansion to only a portion of those dollars provided from internally generated funds.

Q17. WHAT DO YOU RECOMMEND THE COMMISSION ADOPT FOR PURPOSES OF CALCULATING NORMALIZED TEST YEAR VOLUMES IN THIS CASE?

[4] Regression correlation factors from Schedule WHN-1.

[5] Company filing, Schedule C-11.1, Line 6 and Schedule C-11.2, Line 6.

A17. I recommend that the Commission reject the 10 year average for normal weather proposed by the Company and accepted by the Staff, and instead continue to utilize a 30 year average for normal weather as calculated by NOAA since it provides a more reasonable basis for analyzing the Company's normal sales per customer. I therefore recommend that the Commission adopt the test period weather normalized sales per bill of 0.0074 MMcf per bill for the residential customer class as shown on Schedule WHN-2. A recommendation for weather normalized sales per bill for the commercial customer class will be made available in supplemental testimony.

III. REVENUE FORECAST

Q18. HAVE YOU REVIEWED THE COMPANY'S REVENUE CALCULATION?

A18. Yes. The Company began its revenue calculation from its revenue budget. However, starting the revenue calculation from the Company's budget requires an acceptance of the Company's budgeting process -- and the assumptions that underlie that process -- which I find to be unreasonable. I conclude this because the individual components making up the Company's complete operating budget have not been identified and verified. As a result, I experienced significant delays in obtaining historical sales and customer data needed to enable me to put together my own analysis.[6]

[6] This same dilemma was also noted on page 31 of the Eagle Energy Report which states as follows: "While there seems to be adequate budget documentation for capital and operating expenses, similar documentation does not appear to exist for the revenue or margin budgeting process."

For the residential and commercial customer classes, my approach was to first normalize the actual test period volumes for 30-year average weather as previously noted, in order to compute the normal sales per customer. I then increased the test period number of customers by the four year annual average increase in customers actually experienced. The adjusted test period sales volumes and customers were then priced out at current rates to arrive at the revenues under present rates.

For the industrial customer class, I began with the actual test period sales volumes and bills, and then made adjustments for known changes. These known changes typically included the new customers and closings that were specifically identified by the Company. Again, the adjusted test period sales volumes and customers were then priced out at current rates to arrive at the revenues under present rates.

The result of my revenue forecast is shown on Schedule WHN-3. In addition, a comparison of the OCC's revenue forecast with the Company and the PUCO Staff can be found on Schedule WHN-4. At this time, only the results of the revenue forecast for the residential customer class has been completed. The revenue forecast for commercial and industrial customers has not been finished, due to a delay in data previously requested from the Company and later provided to the OCC on July 18. The results from the analysis of this information for commercial and industrial customers will be presented to the Commission in supplemental testimony.

IV. RATE INCREASE ALLOCATION

Q19. HAVE YOU REVIEWED THE COMPANY'S PROPOSED RATE INCREASE ALLOCATION?

A19. Yes. The residential customer class currently provided 64.27%[7] of the Company's base rate revenue during the test period. The Company has proposed that 84.68% of their proposed increase be allocated to the residential customer class consisting of the sales, transportation and dual fuel tariffs. As derived from Table 1a of the Staff Report and presented on Schedule WHN-5, the Staff has proposed that 62.03% of their proposed rate increase be allocated to the residential customer class.

Q20. DO YOU AGREE WITH THE STAFF RECOMMENDATION?

A20. While I don't agree with the Staff's methodology for the rate increase allocation, I do agree with the end results produced by it for the residential customer class. Generally, I believe that any increase in revenue requirements approved by the Commission should be allocated equally to <u>all</u> customer classes based on the test period gross margin. When such an adjustment is made, it results in roughly the same rate increase allocation as the Staff has proposed. I therefore support the Staff's recommendation of the rate increase allocation for this case.

[7] Excluding miscellaneous revenues.

V. RESIDENTIAL RATE DESIGN

Q21. HAVE YOU REVIEWED THE COMPANY'S PROPOSED CHANGES TO ITS RESIDENTIAL (RATE 310 AND 315) TARIFFS?

A21. Yes. The Company has asked to recover its entire base rate increase allocated to the residential customer class through an increase in the fixed monthly customer charge. This type of rate design is generally known as a straight fixed variable ("SFV") rate design. Under the Company's proposal, the residential monthly customer charge would initially be increased from its present fixed rate of $7.00 per customer per month to $10.00 per customer per month during the summer months (from May to October) and from $7.00 per customer per month to $16.75 per customer per month during the winter heating season (from November to April). The Company then went further, and proposed a second stage (revenue neutral) increase in the fixed residential monthly customer charge from $10.00 per customer per month to $11.96 per customer per month during the summer months and from $16.75 per customer per month to $20.04 per customer per month during the winter heating season that would take place on November 1, 2010. Finally, the Company proposes to move to complete recovery of costs allocated to the residential class through a fixed monthly customer charge (with no volumetric rate) in its next rate case.

Q22. DOES THE STAFF AGREE WITH THE COMPANY'S PROPOSAL FOR THIS CHANGE IN THE RESIDENTIAL MONTHLY CUSTOMER CHARGE?

A22. Yes, the Staff appears to accept the SFV rate design. Staff, however, has proposed a lower volumetric charge that reflects their adjustment to the Company's case. The Staff is basically proposing the same changes to the residential customer's monthly customer charge, as proposed by the Company.

Q23. WHAT RATIONALE DOES THE STAFF AND COMPANY CITE FOR THIS CHANGE IN THE MONTHLY RESIDENTIAL CUSTOMER CHARGE?

A23. Both the Staff[8] and Company[9] point to the continuing decline in sales per customer as the biggest reason for the change. The Staff goes on to further point out that the Company "* * * has seen the recovery of distribution costs deteriorate as the volume of gas used by residential customers has decreased."[10] The Staff also points out that recovery of allocated residential costs through a fixed charge will levelize the distribution component of a customers' bill providing rate certainty.

Q24. DO YOU AGREE WITH THE STAFF'S RATIONALE FOR THIS CHANGE?

[8] Staff Report at 30.

[9] Benkert Direct Testimony at 9.

[10] Staff Report at 30.

A24. No. As pointed out in Section I of my testimony, the Staff's analysis of declining weather normalized use per customer for the residential customer class is in error. While actual sales per customer have declined, the average weather normalized residential usage per customer has held steady between 7 to 8 Mcf per bill for the last six years. It is important to distinguish between actual and weather normalized usage since rates are set on weather normalized sales volumes. There is simply no corroborating evidence in the record for this rate case supporting a decline in residential weather normalized use per customer. In fact, as shown on Schedule WHN-2, just the opposite has occurred; weather normalized residential average use per customer has actually increased during the test period from the preceding year.

In addition, the Staff's point that a flat monthly distribution charge for residential customers will somehow provide customers with price certainty is also faulty. The distribution charge is relatively minor in comparison to a customer's total bill that includes gas costs which fluctuate monthly and other surcharges. I doubt if any residential customers would perceive an added benefit to price certainty from a fixed monthly distribution charge.

Q25. ARE THERE OTHER REASONS THAT YOU OPPOSE THE MOVE TO A FIXED MONTHLY CUSTOMER CHARGE?

A25. Yes. First, I have never witnessed any residential customers requesting a change in their rate structure to a flat monthly distribution charge. For better or for worse, residential customers are accustomed to paying for gas service as gas is consumed. Such a significant change in residential rate design is likely to cause customer confusion as well as a negative reaction, especially during periods of low usage in the summer months.

Second, adoption of a flat monthly distribution charge for residential service removes an important future rate design tool from the Commission's discretion. A typical change to volumetric rates is more akin to "fine tuning" a rate change while a change to the monthly customer charge is similar to rate design by sledge hammer. It may well be that future costs are better recovered through volumetric rates, but only if they are blended with other existing costs.

Third, it is inappropriate that the move towards a fixed monthly distribution charge is only applied to residential and small general service customers. Other gas utilities have applied separate demand charges to recover their fixed costs from industrial customers with a corresponding offset to the volumetric rate. However, no such rate design has been suggested for the industrial customer class by either the Staff or the Company. From a policy perspective, it appears inappropriate to apply the cost recovery principles of SFV to one class without applying it to all other customer classes.

Fourth, the immediate adoption of SFV rate design adversely impacts low income, non-Percentage of income Payment Plan ("PIPP"), customers with the largest percentage increase in rates. It also transfers costs from higher volume customers to these same lower volume customers. These are the very customers who can least afford this change in rate design policy. A rate increase of any kind always presents an undue hardship for these customers. However, a change to SFV rate design presents non-PIPP, low income customers with a second rate increase on top of an increase in revenue requirements.

Finally, from a policy perspective, SFV rate design sends inaccurate pricing signals to the customer and negatively impacts conservation efforts by reducing the volumetric rates, which then lengthens the payback period of conservation investments. In this case, the Company has proposed spending an additional $2.9 million annually on conservation programs.[11] The full benefits of these conservation programs will be diluted by a rate design that fails to recognize or reward customers for conservation – which is a state policy objective.

Q26. ARE YOU AWARE OF THE OHIO COMMISSION'S RECENT DECISION REGARDING FIXED MONTHLY DISTRIBUTION CHARGES FOR

[11] Direct Prefiled Testimony of Company witness Rose at14 and Staff Report at 48.

RESIDENTIAL CUSTOMERS IN THE DUKE ENERGY OHIO RATE CASE?[12]

A26. Yes. In that case, the Commission adopted a fixed monthly distribution charge for residential customers based largely on the evidence presented showing a declining use per residential customer. However, the Commission must make a decision in this case based on the specific facts and information presented in the record. Here, unlike in the Duke case, there is no corroborating evidence presented showing that the average weather normalized customer usage is declining. Having said that however, even if there was corroborating evidence presented demonstrating that the average weather normalized customer usage had declined, that would not have been in and of itself a sufficient reason to alter the rate design in such a radical manner.

Q27. WHAT TYPE OF RATE DESIGN DO YOU PROPOSE FOR RESIDENTIAL CUSTOMERS?

A27. I recommend limiting any increase in the existing fixed monthly customer charge from $7.00 per customer per month to $10.00 per customer per month. This change equals the monthly customer charge adjustment ($7.00 - $4.00) approved in the Company's last rate case.[13] This change also equals the monthly charge

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[12] PUCO Case No. 07-589-GA-AIR.

[13] Case 04-0571-GA-AIR.

($10.00) that the Company has proposed for the summer months. I would then propose that the balance of the increase allocated to the residential customer class be placed on a single volumetric rate of $0.08046/Ccf as shown on Schedule WHN-5. A single volumetric rate should help create greater conservation incentives for more residential customers than the existing two-tier declining block rate structure. Schedule WHN-5 provides an illustration of my recommended rate design for residential customers.

Q28. WHAT ARE THE ADVANTAGES OF YOUR RATE DESIGN?

A28. First, it is a rate design structure that the Company's residential customers are already familiar with. As a result, there should not be the same type of confusion with this rate design as would be seen with the Company's proposed shift to an SFV rate design. Secondly, the increase from this rate design to individual customers likely meets their expectations based on how their bill has changed from past rate cases. In addition, this rate design also preserves volumetric rates to allow for fine tuning of any future cost recovery by the Commission. Finally, it is a rate design that sends more accurate price signals to the customer and encourages conservation.

Q29. DO YOU HAVE ANY COMMENTS TO MAKE IF THE COMMISSION SHOULD ELECT TO ADOPT SFV RATE DESIGN IN SPITE OF YOUR ARGUMENTS?

A29. Yes. If the Commission is committed to the policy concept of an SFV rate design, which the OCC does not support, then I would urge it to gradually implement its impact over several periods instead of all at once in a single rate case. The Company has proposed to partially implement SFV immediately and then proposed a second revenue neutral rate change on November 1, 2010, which would increase the current monthly residential customer charge from $7.00 per customer per month to $20.04 per customer per month. This change is simply too large to consider in a single rate case.

Instead of this rapid pace, I would recommend that the Commission consider limiting an annual change of no more than $1.00 to $2.00 every year until the Company's next rate case. Slowly changing the current rate design from volumetric cost recovery to a fixed cost recovery would allow the Commission to gauge the customer's reaction to SFV implementation and make adjustments accordingly. However, I want to emphasize that this level of increase in the customer charge is not supportable and from a policy perspective is not a good direction to take. I would urge the Commission to hold the line on keeping customer charges low and retaining the volumetric charge.

VI. DISTRIBUTION RATE RIDER

Q30. DO YOU SUPPORT CONTINUING THE COMPANY'S PROPOSED DISTRIBUTION RATE RIDER ("DRR")?

A30. No. While I do recognize the safety concerns expressed by the Commission Staff regarding the need for accelerated bare steel and cast iron main replacement, the DRR has effectively become a single issue ratemaking mechanism. The DRR also represents by far the single biggest rider ever proposed by the Company. According to the Staff Report, the cost of the DRR will be approximately $338 million[14] over 20 years which is significantly larger than the Company's existing rate base of approximately $228 million.[15] The annual revenue requirements from such an increase would be approximately $42 million, and spread out over 20 years the DRR will result in an average increase in rates of approximately $2.1 million each year. I have been advised by OCC Counsel that single issue ratemaking is inconsistent with Ohio's general ratemaking provisions of Chapter 4909 of the Revised Code.

Additionally, I have concerns with certain other aspects of the DRR program that center on the approval process for a substantial and material rate increase outside of the normal rate case process. This accelerated process that is proposed to implement DRR rates cuts short the time that any stakeholder would normally have to scrutinize the changes if made within the rate case process. Moreover the

[14] Staff Report at 41.
[15] OCC Exhibit RCS-1.

DRR examines only one distinct expense item without considering whether there are separate and offsetting adjustments negating the need for the rider, either in part or in whole.

Notwithstanding my previously stated concerns, if the Commission stands ready to approve the DRR, which I am not recommending, I would support in part the Commission Staff's recommendations with certain modifications.

The Staff's first recommendation extends the DRR for eight years, or until a subsequent rate case, whichever occurs first. However, I recommend that any extension be limited to four years, since this is typically the length of time between rates cases for the Company. This modification gives me some assurance that the DRR won't become a "runaway train" without the ability to modify its terms or eliminate it entirely. For example, the DRR could have an impact on other areas of the Company's income statement that have not yet been contemplated. It is impossible for these changes to be considered in base rates outside of the normal rate case process. A four-year time limit on the DRR extension will give intervening parties an opportunity to timely examine the progress and impact of the DRR on all phases of the Company's operations.

The Staff's second recommendation caps the DRR charge, including riser replacements at $0.90 per month. I support the concept of a limit on any DRR charge. This cap provides the OCC with assurance that the total DRR charge won't get out of control, and provides customers with a known upper bound of base charges that can be applied to them.

VII. SALES RECONCILIATION RIDER

Q31. HAVE YOU REVIEWED THE SALES RECONCILIATION RIDER ("SRR") PROPOSAL CONTAINED IN THE ALT REG PLAN APPLICATION?

A31. Yes. The Company's existing SRR-A was approved in Case No. 05-1444-GA-UNC. The intended use of the SRR-A which was developed in that proceeding, was to decouple the link between gas consumption and the utility's opportunity to earn a fair return on the basis that this linkage was counterproductive to energy efficiency. In that proceeding, the Commission found "it is in the public interest, **in order to promote energy efficiency,** to decouple the link between gas consumption and the Company's ability to meet its revenue requirements."[16] In the present proceeding, the Company has proposed to implement SRR-A on the rate effective date, followed by a second SRR-B in order to "* * * track changes in base revenue recovery resulting from abnormal weather as well as other causes such as declining use per customer."[17]

[16] Opinion and Order at 18, Case No. 05-1444-GA-UNC.
[17] Direct testimony of Company witness Ulrey, at 10.

SRR-A was designed to protect the Company from the effects of declining use per customer. SRR-B as proposed by the Company, goes one step further and also protects the Company from changes in sales volumes caused by abnormal weather in addition to the effects of declining use per customer not directly attributable to weather. In other words, SRR-B provides a ***guarantee*** (as opposed to the opportunity) for the Company to fully recover the revenues approved by the Commission.

Q32. WHAT RECOMMENDATION HAS BEEN MADE BY THE STAFF WITH REGARD TO SRR-A AND SRR-B?

A32. Staff appears to support the implementation of SRR-A, and concurs with the Company proposal to collect SRR-A deferrals over a one year period beginning with the rate effective date in this order. The Staff proposes to eliminate the SRR-B in favor of SFV rate design.[18]

Q33. WHAT IS YOUR POSITION WITH RESPECT TO SRR-A?

A33. My position is that the SRR-A is unreasonable and unlawful as a result of the process used to implement the rider and the lack of sufficient Demand Side Management (DSM) required for its implementation. As a result, the $5,152,213 in deferrals that the Company is now seeking to collect through the SRR-A are

[18] Staff Report at 34.

unreasonable and unlawful based upon this same reasoning. My position reflects the OCC position taken in Case No. 05-1444-GA-UNC.

However, notwithstanding these objections to the contrary, if the Commission should decide to adopt the SRR-A, I would recommend that the deferrals created be recovered over a two year period, as opposed to the one year recovery supported by the Staff and the Company. Since the SRR-A deferrals were originally developed over a two year period, it only seems reasonable that they should be recovered over this same period of time.

Q34. WHAT ISYOUR POSITION WITH RESPECT TO SRR-B?

A34. While I do not agree with the Company's proposed changes to implement SRR-B, I do agree that the impact of SRR-B is preferable to the implementation of SFV rate design. I understand that decoupling is a measure that should only be adopted when appropriate procedures are followed (within the context of a full rate proceeding under R.C. 4929.05) and when comprehensive DSM is being proposed. I also understand that appropriate procedures have been followed in this proceeding related to the filing of the SRR-B proposal, and that the commitment to DSM by the Company in this case may warrant the use of this regulatory mechanism.

However, I disagree with the Company's proposal to add the effect of weather recovery to SRR-B. Abnormal weather in the gas distribution industry represents just one of the risks of doing business. Under the Company's proposal, the risk is shifted to Vectren's customers. I understand that the Company makes no adjustment to the equity return to account for this. Therefore, absent any adjustment to the Company's equity return, there should be no need for adjustment of the SRR to include the impact of abnormal weather.

Q35. DOES THIS CONCLUDE YOUR TESTIMONY?

A35. Yes it does. However I reserve the right to incorporate any new information that may subsequently become available. I also reserve the right to supplement my testimony in the event that the PUCO Staff fails to support the recommendations made in the Staff Report and /or changes in any position in the Staff Report.

ATTACHMENT

1-4f

GAS UTILITIES DOCKET NO. 9902

STATEMENT OF THE INTENT OF CENTERPOINT ENERGY RESOURCES CORP., D/B/A CENTERPOINT ENERGY ENTEX AND CENTERPOINT ENERGY TEXAS GAS TO INCREASE RATES ON A DIVISION WIDE BASIS IN THE HOUSTON DIVISION	§ § § § § §	BEFORE THE RAILROAD COMMISSION OF TEXAS

THE ATTORNEY GENERAL ★ TEXAS ★

DIRECT TESTIMONY OF

WILLIAM H. NOVAK

ON BEHALF OF

THE STATE OF TEXAS

October 19, 2009

STATE'S EXHIBIT
2

012185

GAS UTILITIES DOCKET NO. 9902

STATEMENT OF THE INTENT OF CENTERPOINT ENERGY RESOURCES CORP., D/B/A CENTERPOINT ENERGY ENTEX AND CENTERPOINT ENERGY TEXAS GAS TO INCREASE RATES ON A DIVISION WIDE BASIS IN THE HOUSTON DIVISION	§ § § § § §	BEFORE THE RAILROAD COMMISSION OF TEXAS

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WILLIAM H. NOVAK

ON BEHALF OF

THE STATE OF TEXAS

October 19, 2009

D121866

DIRECT TESTIMONY OF WILLIAM H. NOVAK
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Q. ***PLEASE STATE YOUR NAME, BUSINESS ADDRESS AND OCCUPATION FOR THE RECORD, PLEASE.***

A. My name is William H. Novak. My business address is 19 Morning Arbor Place, The Woodlands, TX, 77381. I am the President of WHN Consulting, a CPA firm that also provides utility consulting and expert witness services.

Q. ***PLEASE PROVIDE A SUMMARY OF YOUR BACKGROUND AND PROFESSIONAL EXPERIENCE.***

A. A detailed description of my educational and professional background is provided in Attachment WHN-1 to my testimony. Briefly, I have both a Bachelors degree in Business Administration with a major in Accounting, and a Masters degree in Business Administration from Middle Tennessee State University. I am licensed to practice as a Certified Public Accountant ("CPA") and am also a Certified Management Accountant ("CMA").

My work experience has centered on regulated utilities for over 25 years. Before establishing WHN Consulting, I was Chief of the Energy & Water Division of the Tennessee Regulatory Authority where I had either presented testimony or advised the Authority on a host of regulatory issues for over 19 years. In addition, I was previously the Director of Rates & Regulatory Analysis for two years with Atlanta Gas Light Company, a natural gas distribution utility with operations in Georgia and Tennessee, where I was responsible for defending the

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utility's gas cost recovery and rate filings at a time when it was completely exiting the gas merchant function in Georgia. I also served for two years as the Vice President of Regulatory Compliance for Sequent Energy Management, a natural gas trading and optimization company in Texas, where I was responsible for ensuring the firm's compliance with state and federal regulatory requirements.

Q. ON WHOSE BEHALF ARE YOU TESTIFYING?

A. I am testifying on behalf of the State of Texas ("the State").

Q. WHAT IS THE PURPOSE OF YOUR TESTIMONY IN THIS PROCEEDING?

A. My testimony will address the following issues raised by CenterPoint Energy Resources Corp., d/b/a CenterPoint Energy Entex and CenterPoint Energy Texas Gas ("CenterPoint's" or "the Company's") filing:

- The proposed Cost of Service Adjustment ("COSA");
- The proposed Pension Cost Recovery ("PCR") adjustment;
- The proposed Integrity Assessment & Management ("IAM") adjustment;
- The proposed changes to the Purchased Gas Adjustment ("PGA"); and
- The methodology used by the Company to calculate its Class Cost of Service Study.

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Q. WHAT DOCUMENTS HAVE YOU REVIEWED IN PREPARATION OF YOUR TESTIMONY?

A. I have reviewed the Company's Statement of Intent, along with the testimony and exhibits presented with their filing. In addition, I have reviewed the Company's workpapers related to the cost of service and revenue calculation supporting their filings. I have also reviewed the Company's responses to the relevant data requests submitted by the intervening parties and the Examiner.

I. COST OF SERVICE ADJUSTMENT

Q. HAVE YOU REVIEWED THE COMPANY'S PROPOSED COST OF SERVICE ADJUSTMENT?

A. Yes. The proposed Cost of Service Adjustment ("COSA") allows the Company to implement new rates on an annual basis without going through the normal rate case process. This is the first of several mechanisms that the Company has proposed in order to reduce its risk as a gas utility.

Q. WHAT IS THE COMPANY'S RATIONALE FOR REQUESTING THE COSA?

A. The Company claims that it is expecting to experience changing levels of expense over the next several years, and that in order to minimize its regulatory expense it

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has filed this COSA tariff to allow it to adjust its rates to the cost of service that is actually experienced.[1]

Q. DOES THE GAS UTILITY REGULATORY ACT ("GURA") CONTEMPLATE AN AUTOMATIC RATE ADJUSTMENT SUCH AS COSA?

A. No. GURA Chapter 104, "Rates and Services," addresses rate changes initiated by a gas utility in Subchapters C and G. In Subchapter C, entitled "Rate Changes Proposed by a Utility," a rate change is authorized subject to a formal statement of intent rate case that includes a comprehensive cost of service rate review. In Subchapter G, entitled "Interim Rate Adjustment," an interim rate change is authorized through the Gas Reliability Infrastructure Project ("GRIP") Statute to recover the cost of changes for investment in service. Because the COSA proposed by the Company in this proceeding satisfies neither of these two provisions, it cannot be considered as a methodology required by GURA for a change in rates. The COSA proposed by the Company is neither an Interim Rate Adjustment per Subchapter G nor the result of a formal statement of intent per Subchapter C.

[1] Direct testimony of Richard Zapalac, Page 11, Lines 3-12.

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Q. HOW WILL THE PROPOSED COSA TARIFF BE IMPLEMENTED?

A. According to the Company's proposed COSA Tariff,[2] the Company will make an annual filing with the Commission no later than May 1st. The Commission will then have 90 days to review the Company's filing before rates go into effect on August 1st. If the Commission disagrees with the Company's filing, then the Company has the right to appeal this decision and place new COSA rates into effect subject to refund.

Q. IS THE PROPOSED COSA TARIFF IN THIS CASE THE SAME AS THAT ALREADY APPROVED FOR THE TEXAS COAST DIVISION?

A. No. The Texas Coast COSA ("COSA-3") specifically limits the annual COSA surcharge to five percent (5%) of the customer charge.[3] In this proceeding, there is no cap on the annual COSA surcharge. In addition, the Texas Coast COSA provides for total funding of $250,000 to assist with the annual regulatory rate review of COSA. In this proceeding, the funding for the annual regulatory rate review of COSA is limited to $100,000.

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[2] Exhibit A to the Company's Statement of Intent, Page 10.

[3] See Tex. R.R. Comm'n, *Statement of Intent of CenterPoint Energy Resources Corp., d/b/a CenterPoint Energy Entex and CenterPoint Energy Texas Gas to Increase Rates In The Unincorporated Areas of CenterPoint's Texas Coast Division and All Consolidated Dockets*, Docket No. 9791 (Gas Util. Div. March 6, 2008) (Cost of Service Adjustment).

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Q. WHAT IS THE IMPACT FROM THE REMOVAL OF THE 5% ANNUAL COSA SURCHARGE CAP?

A. Removal of the 5% annual COSA surcharge cap could potentially end all future rate cases, since the COSA would allow recovery on an annual basis of all costs without a rate case filing or a hearing to set rates. It would also eliminate customer participation through the intervention process, since rate cases would be eliminated, and intervenors are apparently not encouraged to participate in the annual COSA review.

Q. BUT WOULDN'T THE COSA ALSO ELIMINATE THE COMPANY'S RATE CASE COSTS WITH THIS SAVINGS PASSED ON TO CUSTOMERS?

A. Certainly. Since rate cases would now be replaced with an annual automatic adjustment mechanism, the Company would not incur any rate case costs. However, as a regulatory enticement, the Company has proposed to reimburse its regulators up to $100,000 for their annual costs to investigate COSA. Since this "regulatory candy" ultimately increases the COSA surcharge, it is unclear what the net impact would be on the Company's rate case costs.

Q. DO YOU AGREE WITH THE COMPANY'S REQUEST FOR THE COSA?

A. No. The COSA represents an attempt by the Company to minimize regulatory oversight and to reduce its rate recovery risk. In addition, the Company has offered no proof in its filing that the cause for this tariff is material and its timing

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is imminent. Instead, we are only told through testimony that Company is "anticipating significant cost increases."[4] However, nothing is mentioned by the Company of any expected costs decreases that may either mitigate or offset any increase to its future cost of service.

Q. WHAT IS THE COMPANY'S RECOURSE IF IT DOES EXPERIENCE AN INCREASE TO ITS COST OF SERVICE?

A. The Company is certainly free to file a new rate case anytime that it feels it is justified. While a tariff such as the COSA may well reduce future rate case expenses through the use of automatic adjustment clauses, it also degrades the ability of regulatory authorities to properly review all other aspects of the Company's filings including any concerns that are raised by intervenors. In addition, automatic adjustment clauses such as the COSA can encourage wasteful and imprudent spending since these costs are automatically recovered from customers without the same scrutiny that takes place during a formal rate case.

Q. YOU MENTIONED THAT THE COSA WAS AN ATTEMPT BY THE COMPANY TO REDUCE ITS RISK WITHOUT A CORRESPONDING ADJUSTMENT TO ITS EQUITY RETURN. WHAT WOULD BE THE APPROPRIATE RETURN ON EQUITY FOR A GAS UTILITY WITH A COSA SIMILAR TO WHAT HAS BEEN PROPOSED HERE?

[4] Direct testimony of Richard Zapalac, Page 11, Line 6.

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A. I'm not a cost of capital witness, and I'll certainly defer to the State's expert witness in this area. However, since the Company has proposed to reduce most of its revenue recovery risk through an automatic adjustment clause like COSA without a cap to limit its impact, it appears to me that the return on equity should be substantially reduced if the Company's proposed COSA is adopted.

Q. WHAT IS YOUR FINAL RECOMMENDATION ON THE COMPANY'S PROPOSED COSA?

A. I recommend that the Company's proposed COSA be rejected and that the cost of service continue to be reviewed and considered only within the structure of a properly filed rate case as required by GURA.

II. PENSION COST RECOVERY ADJUSTMENT & INTEGRITY ASSESSMENT AND MANAGEMENT ADJUSTMENT

Q. HAVE YOU REVIEWED THE COMPANY'S PROPOSED PENSION COST RECOVERY ADJUSTMENT & INTEGRITY ASSESSMENT AND MANAGEMENT ADJUSTMENT MECHANISMS?

A. Yes. The Company has proposed these two adjustments as an alternative if the Commission chooses to reject its proposed COSA. The Company's proposed Pension Cost Recovery ("PCR") Adjustment Rate Schedule allows for an annual adjustment to the Company's tariff rates for its most current pension expense.

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The Company's proposed Integrity Assessment and Management ("IAM") Adjustment Rate Schedule allows for an annual adjustment to the Company's tariff rates for recovery of its most current costs incurred from changes to existing rules and regulations by a regulatory body.[5]

Q. WHAT IS THE COMPANY'S RATIONALE FOR REQUESTING THE PCR AND IAM?

A. The Company claims that it is expecting to experience changing levels of expense in this area over the next several years, and that in order to minimize its regulatory expense it has filed this tariff to allow it to annually reset its rates to recover the cost that is actually experienced.[6]

Q. DO YOU AGREE WITH THE COMPANY'S REQUEST FOR THE PCR AND IAM?

A. No. Like the COSA, the PCR and IAM represent attempts by the Company to reduce its revenue recovery risk. In addition, the Company has offered no proof in its filing that the reasons for these two tariffs are material and their timing is imminent. Instead, we are only told through testimony that the Company is "expecting" changes to its cost in these two areas. However, nothing is mentioned by the Company of any expected cost decreases that may either mitigate or offset these expected increases.

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[5] Company's Statement of Intent, Exhibit A, Pages 18 and 19.
[6] Direct testimony of Matthew Troxle, Page 18, Lines 6-13.

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Q. WHAT IS THE COMPANY'S RECOURSE IF IT DOES EXPERIENCE THE INCREASE TO PENSION EXPENSE AND INTEGRITY ASSESSMENT AND MANAGEMENT COSTS THAT IT EXPECTS?

A. The Company is certainly free to file a new rate case anytime that it feels it is necessary. While a tariff such as the PCR and IAM may well reduce future rate case expenses through the use of automatic adjustment clauses, it also degrades the ability of regulatory bodies to properly review all other aspects of the Company's filing including new concerns that are voiced by customers. In addition, automatic adjustment clauses such as the PCR and IAM can encourage wasteful and imprudent spending since these costs are automatically recovered from customers, without the scrutiny that takes place during a formal rate case.

Q. DO YOU HAVE ANY FURTHER COMMENTS WITH RESPECT TO THE PCR AND IAM ADJUSTMENTS?

A. Yes. A review of the Company's proposed PCR tariff[7] reveals that only the Railroad Commission Staff is allowed to dispute or question the calculation of the Company's annual PCR filing. This provision eliminates all intervenors, including the State, from reviewing or commenting on the Company's PCR adjustment. I strongly disagree with this provision since the intervenors currently have the right to dispute pension expense within the structure of a rate case.

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[7] Exhibit A to the Company's Statement of Intent, Page 19.

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Likewise, an examination of the Company's proposed IAM tariff[8] reveals that there is no process contemplated for the review of the Company's annual IAM filing by either the regulatory authorities or intervenors. Therefore, as presently written, the IAM tariff allows new rates to go into effect without review or notice to customers. In addition, the proposed tariff does not specify how disputes regarding recorded costs are to be resolved. I strongly disagree with this provision of the IAM since all tariff filings should undergo adequate review by the regulatory authority and allow for the opportunity to intervene and comment by interested parties.

Q. WHAT IS YOUR FINAL RECOMMENDATION ON THE COMPANY'S PROPOSED PCR AND IAM ADJUSTMENTS?

A. I recommend that the Company's proposed PCR and IAM be rejected and that the Company's pension expense and regulatory costs continue to be reviewed and considered only within the structure of a properly filed rate case as required by GURA.

III. PURCHASED GAS ADJUSTMENT CHANGES

Q. HAVE YOU REVIEWED THE COMPANY'S PROPOSED CHANGES TO ITS PURCHASED GAS ADJUSTMENT ("PGA")?

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[8] Exhibit A to the Company's Statement of Intent, Page 18.

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A. Yes. The Company has proposed two separate modifications to its current PGA rate schedule. The first modification would allow the Company to pass through the carrying charges on any changes to gas inventory via the PGA. The second modification would allow the Company to pass through the gas cost portion of uncollectible expense via the PGA.

Q. WHAT IS THE COMPANY'S RATIONALE FOR REQUESTING THESE CHANGES TO THE PGA?

A. The Company claims that the volatility of wholesale gas cost has made the recovery of uncollected gas cost through base rates "inefficient and less accurate."[9] The Company provided no testimony supporting its proposed change to the PGA for recovering the carrying cost of gas in storage.

Q. DO YOU AGREE WITH THE COMPANY'S PROPOSED CHANGES TO ITS PGA RATE SCHEDULE?

A. No. Like the COSA, PCR and IAM proposed changes discussed earlier, the proposed changes to the PGA rate schedule represent further attempts by the Company to reduce its business risk without a corresponding adjustment to its return on equity. In addition, the Company has offered no proof in its filing that its reason for the change to the PGA rate schedules are material and their timing is imminent.

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[9] Direct testimony of Matthew Troxle, Page 16, Line 23.

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Q. DO YOU HAVE ANY FURTHER COMMENTS WITH RESPECT TO THE COMPANY'S PROPOSED CHANGES TO ITS PGA RATE SCHEDULE?

A. Yes. The changes sought by the Company to its PGA Rate Schedule involve policy issues that may need to be considered in a separate rulemaking docket for all regulated gas utilities outside of a rate case. Implementation of the PGA should be industry-wide and not just apply to a single company as is being proposed here. Whether the carrying costs of gas storage inventory should be recovered through base rates or through the PGA is a question of industry-wide interest and impact that is best answered outside of this rate case.

In addition, the Company has not yet proven that it has the ability to provide the adequate reporting necessary for regulatory authorities to properly segregate its gas costs from each of its uncollectible accounts. Currently, these amounts are only reported in total along with the base rate portion of uncollectible expense. To segregate the accurate gas cost from each uncollectible account requires the ability to accurately identify the PGA rate that was applied on a cycle basis to each customer for multiple billing periods. In addition, provisions need to be made to flow subsequent customer payments back into the PGA when these amounts are collected. Until the Company can adequately demonstrate its ability to properly segregate, account for, and report these components of uncollected PGA costs, then any request to flow these costs through the PGA should be denied.

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Q. WHAT IS YOUR FINAL RECOMMENDATION ON THE COMPANY'S PROPOSED CHANGES TO ITS PGA RATE SCHEDULE?

A. I recommend that the Company's proposed PGA Rate Schedule changes be rejected.

IV. COST OF SERVICE STUDY

Q. HAVE YOU REVIEWED THE COMPANY'S COST OF SERVICE STUDY?

A. Yes. I agree in principle with the methodology utilized by the Company to complete their Cost of Service Study. Based upon my review, the Company's Cost of Service Study did not appear to favor any particular customer group.

Q. DOES THIS COMPLETE YOUR TESTIMONY?

A. Yes it does. However I reserve the right to incorporate any new information that may subsequently become available. In addition, to the extent that I have not addressed a particular issue, method, procedure, etc. it should not be assumed that I am in agreement with the Company's treatment of that item.

ATTACHMENT

1-5

UNITED INTER-MOUNTAIN TELEPHONE COMPANY Plaintiff and RAYTHEON COMPANY Intervenor VS. NO. 78-759-I TENNESSEE PUBLIC SERVICE COMMISSION, ET AL Defendants	IN THE CHANCERY COURT, PART I, AT NASHVILLE

RECEIVED
OCT 25 1978
TENNESSEE PUBLIC SERVICE COMM.
GENERAL COUNSEL'S OFFICE

MEMORANDUM

This is an action to review the March 21, 1978 order of the Tennessee Public Service Commission dealing with the petition of United Inter-Mountain Telephone Company for an increase in rates. The company claims that the decision of the Commission is arbitrary, capricious, confiscatory and otherwise contrary to law. The Raytehon Company has intervened to challenge the increase allowed on its obselete private branch exchange (PBX) equipment.

On September 21, 1977 the company filed its petition with the Commission seeking authority to increase its rates and change its rate structure to produce $4,849,062.00 in additional revenues. The result would have been a 10.59% return on the rate base and approximately 13.05% on the common equity portion of its capital structure. The Commission suspended the effective date of the increased rates and ordered an exhaustive study by the Commission staff of the books and records of the company and its parent United Telecommunications, Inc.

The Commission ordered a public hearing for February 27, 1978 in Johnson City, Tennessee, at which time the scheduled witnesses were heard and cross-examined and seven public witnesses testified concerning the company's service and rates. The Commission's order of March 21, 1978 adopted and approved a 9.57% rate of return on the company's rate base allowing an increase in total revenue of $2,036,243.00; the order rejected a proposed change in the rate structure to separate the local service rates into two components, flat rate and extended area coverage (EAS). In addition the order made two minor accounting adjustments: (1) It disallowed the deduction for free service given to management employees (concessions) over that given to other employees, and (2) disallowed the cost of prior appellate litigation as an expense. In the order the Commission directed the company to file for approval a proposed tariff to produce the additional annual gross revenue of $2,036,243.00 and mandated a rate design which would minimize the increase in the basic local exchange rates.

On March 23, 1978 the revised tariff was mailed to the Commission and by order of March 30, 1978 the Commission approved the increase to take effect April 1, 1978. In keeping with the mandate of the Commission, the revised tariff increased local residential service about 5%, businesses about 7%, and the PBX charges approximately 130%. It is this large increase in the PBX charges that is attacked by the intervenor, Raytheon. The increased cost of its equipment, labeled "obselete" by the company is the same as it was in the initial filing, while the other rate increases were cut substantially to lower the additional revenue to the Commission approved level of $2,036,243.00.

A. <u>THE RATE OF RETURN</u>

The company assigns as error the Commission's finding with respect to the rate of return. Proof with respect to that issued was offered by three witnesses, two witnesses testified on behalf of the company and recommended a rate of return of 10.59% on the rate base, and 13.7% on common equity. The Commission witness recommended a 9.5% rate of return on the rate base and in working up to that recommendation assumed a 13.20% to 13.6% return on common equity. The differences, as discussed in the Commission's order, result from the use by the Commission witness of the technique called "double leverage" which considers the effect of the parent company's financial structure on the company's common stock. The company is wholly owned by United Telecommunications, Inc., and the common equity of the company is financed by issues of short term and long term debt, preferred stock and common stock, all at the parent level. Therefore, the Commission's witness adopted the parent company's capital structure. An analysis of the values used and the results obtained reveals that this is the major difference in the testimony of the three witnesses. The result of the double leverage technique is a reduction in the revenues required to produce the required return.

The company attacks the Commission's adoption of the analysis by its witness and cites references to the record where his credibility may be questioned. The Court is of the opinion however that the Commission was free to adopt the analysis presented by its witness and that the alleged oversights in his testimony do not render it unreliable. The double leverage analysis has been used in the majority of recent cases involving subsidiaries of holding companies and the Court is of the opinion that it is proper to consider the effect of the parent-subsidiary relationship on the capital structure of the subsididary. In order to give proper weight to the risk involved in the venture, the fact that it is owned by a larger company is important. Therefore, the assignment with respect to this issue should be overruled.

B. RATE DESIGN

The company proposed in its petition before the Commission a change in the way charges are made for local service. The proposed change included an extended area service "adder", which would apply equally to residential and business service. The Commission rejected this proposal in its order and stated its reasons therefor on page 25 of the March 21, 1978 order. In contrast, the order of the Commission adopted the rate design presently in effect for local exchange service.

The Court is of the opinion that the company failed to show how this action of the Commission is erroneous. While the company contends that the EAS adder will more equitably distribute the cost of EAS benefit, the rate design in effect is the one in use for many years and the burden is on the company to show how it is prejudiced by the rejection of the proposed rate design. The record does not reveal a basis on which the Commission's order should be overturned for this reason.

Included in this assignment is the now familiar complaint about the effect of "attrition" on the company's earnings. Where the rates are fixed and the cost of operation will inevitably rise due to the effects of inflation, a decline in the rate of return must follow. The company argues that the record shows that it has not been able to earn the rate of return granted in the past due to this phenomenon. Therefore, the argument goes, the present rate order is inadequate because it does not deal with this problem. The Court is of the opinion that the record does not support a specific conclusion respecting the effect of attrition on the company's earnings in the future. The company's witness, in his prepared testimony, did indicate his figures included a 1% before tax provision for the effect of attrition based on the company's experience in past years. There is no evidence in the record of a positive nature to show what the effect will be in future years. Because the company has not earned the allowed rate of return in past years does not allow the Court to speculate on the results in the future. Therefore, the challenge to the Commission's order based on the rate design should be overruled.

C. ADJUDGMENTS TO OPERATING INCOME

The company grants free local service to certain of its management and supervisory personnel, the service at a 50% reduction to certain other non-bargaining personnel, and a 40% reduction to employees covered by collective bargaining. The Commission's order adopted the staff's adjustment to income which disallowed the effect of the unequal treatment of the various classes of employees by showing an increase in revenue equal to the charges that would be collected if all classes of employees were given only a 40% discount on local service. The order stated: ". . .management employees should not be treated any differently than non-management employees with regard to concessions on telephone service."

There are two arguments with respect to this item. On one hand, the company contends that this action by the Commission is an arbitrary and unjustified interference with the management decisions of the company; the concessions are valid employee benefits and would be borne by the rate payers if another benefit in the form of a salary adjustment were substituted therefor.

On the other hand, experts in the field of utility regulation frown on such concessions as being bad policy.

> "Absent a statutory expression of policy, it is difficult to understand why a regulatory agency should authorize free or reduced rate service to the employees of

> a utility. If compensation is inadequate, it should be adjusted in the usual way, employees remaining acutely aware of the impact of rates paid by the general public." A.J.G. Priest, Principles of Public Utility Regulation, p. 281.

While the parties have not briefed the question of the Commission's power to disallow such concessions completely, and there are no regulations in the record dealing with the Commission's policy, the Court is persuaded that Mr. Priest's position is a preferable one and employees of a regulated utility should be aware of the "impact of rates paid by the general public." If the Commission has the power to disallow the concessions completely, it has the power to allow a 40% discount applied evenly to all classes of employees and to impute to the company the revenue which would be generated by such even-handed treatment.

The other adjustment adopted by the Commission disallowed an expense item for the cost of appealing the prior rate case through the courts. There appears to be a split of authority on this question, with some cases turning on the success, or lack thereof, of the appeal. The Commission adopted that approach in this case:

> "We, therefore, conclude that a consistent regulatory policy of disallowing unsuccessful appellate costs is a reasonable approach to balancing the equities between the shareholders and rate payers on appeals undertaken by a utility to increase its revenues and

profits over and beyond what the Commission finds reasonable."

While it would be useful to the Courts and to regulated companies for the Commission to adopt regulations, or rules, with respect to itèm such as these, there is no evidence in the record that the rule adopted by the Commission in this case has been arbitrarily applied. The Court is of the opinion, therefore, that the dissallowance of the expenses of appeal of the prior case under the circumstances of this case was within the discretion of the Commission under its statutory authority.

D. THE INTERVENOR'S COMPLAINT

The initial tariffs filed with the petition for an increase in rates in this case included an increase of $813,919.00 on the private branch exchange equipment charges, which effects the petitioner, Raytheon Company. That amounted to approximately 130% increase on the equipment which is now termed "obselete" because it is no longer offered to customers of the company. While the Commission ordered the increase requested by the company to be reduced by approximately 60%, the rates applicable to the PBX equipment were maintained at the level of the original request. Raytheon alleges that the effect of the increase is to shift the rate increase

($813,919.00 out of a total increase of $2,036,243) to obsolete equipment.

While the increase attributed to PBX equipment may be unusual and on the surface shocking to the intervenor, there is evidence in the record of a substantial nature to support the change. The company's witness testified that "it was apparent that a revenue deficiency existed in our large PBX accounts. We believe that this service should be self-supporting and therefore propose the increase as shown in my exhibits to Section XI." (Witness Spinks, Vol. 1, p. 175). The studies on which his opinion was based are in the record and they show the increase necessary to recover the costs associated with providing PBX service. Although other evidence of the necessary charges to support the initial filing was discounted, or ignored, by the Commission, since this evidence suppports the action of the Commission the Court cannot say that the Commission's action was arbitrary, capricious, or illegal. Therefore, the Court concludes that the intervening petition should be dismissed.

From all of the above, the Court is of the opinion that the petition for review and the intervening petition should be dismissed at the cost of the petitioners.

Mr. Midyett will prepare the order.

Ben H. Cantrell

BEN H. CANTRELL, CHANCELLOR

October 24, 1978

cc: Mr. John R. Hoffman, Bristol, Tenn.
Mr. Eugene W. Ward
Mr. T. E. Midyett, Jr.

ATTACHMENT

1-9

A/ 2011	From Rate Case Order	Jan-11	Feb-11	Mar-11	Apr-11	May-11	Jun-11	Jul-11	Aug-11	Sep-11	Oct-11	Nov-11	Dec-11	**12 mo. YTD**	
Average Rate Base	in 09-00183	[redacted]												91,309,566	Over/(Under) Recovery
Average 12 month-to-date rate base	$ 93,818,504														
monthly adjusted net operating income		1,414,613	1,284,959	773,798	528,289	287,452	179,083	200,207	532,672	181,024	752,895	946,497	772,738	**7,854,227**	**1,115,548**
12 month-to-date adjusted net operating income	$ 6,923,840														
monthly rate of return		[redacted]													
12 month-to-date rate of return	7.38%													8.602%	

B/ 2012	From Rate Case Order	Jan-12	Feb-12	Mar-12	Apr-12	May-12	Jun-12	Jul-12	Aug-12	Sep-12	Oct-12	Nov-12	Dec-12	**12 mo. YTD**	
Average Rate Base	in 09-00183	$ 91,393,152	88,475,776	85,921,568	85,832,843	87,099,020	86,790,228	87,776,023	89,045,103	90,060,472	91,049,644	91,305,842	90,347,427	88,758,092	Over/(Under) Recovery
Average 12 month-to-date rate base	$ 93,818,504	$ 91,740,071	91,591,363	91,240,043	91,230,395	91,267,165	90,557,479	90,418,381	90,185,876	89,805,650	89,519,864	89,099,823	88,407,565		
monthly adjusted net operating income		$ 1,387,152	1,320,658	890,527	382,076	232,924	175,771	91,164	155,391	147,778	317,310	968,169	1,025,841	**7,094,761**	**544,381**
12 month-to-date adjusted net operating income	$ 6,923,840	$ 7,826,863	7,711,764	7,799,215	7,742,642	7,727,930	7,713,545	7,699,756	7,326,149	7,538,595	7,275,131	7,368,400	7,154,170		
monthly rate of return		18.44%	17.91%	12.44%	5.34%	3.21%	2.43%	1.25%	2.09%	1.97%	4.18%	12.72%	13.63%		
12 month-to-date rate of return	7.38%	8.42%	8.42%	8.55%	8.49%	8.47%	8.52%	8.52%	8.12%	8.39%	8.13%	8.27%	8.09%	7.993%	

B/ 2013	From Rate Case Order	Jan-13	Feb-13	Mar-13	Apr-13	May-13	Jun-13	Jul-13	Aug-13	Sep-13	Oct-13	Nov-13	Dec-13	**12 mo. YTD**	
Average Rate Base	in 09-00183	$ 88,347,054	85,290,970	82,973,042	82,779,023	84,351,526	86,143,248	88,401,080	90,736,044	93,372,464	95,669,119	96,362,926	95,564,787	89,165,940	Over/(Under) Recovery
Average 12 month-to-date rate base	$ 93,818,504	$ 88,014,111	87,605,436	87,365,980	87,356,786	87,370,379	87,211,910	87,619,542	87,912,170	88,219,925	88,700,582	89,109,229	89,408,406		
monthly adjusted net operating income		$ 1,543,395	1,243,605	878,699	477,022	303,603	196,844	102,502	134,852	164,267	397,030	994,998	1,132,593	**7,569,410**	**988,931**
12 month-to-date adjusted net operating income	$ 6,923,840	$ 7,369,975	7,287,312	7,190,107	7,316,093	7,377,333	7,370,610	7,547,128	7,521,518	7,524,784	7,581,216	7,598,663	7,642,112		
monthly rate of return		20.96%	17.50%	12.71%	6.92%	4.32%	2.74%	1.39%	1.78%	2.11%	4.98%	12.39%	14.22%		
12 month-to-date rate of return	7.38%	8.37%	8.32%	8.23%	8.37%	8.44%	8.45%	8.61%	8.56%	8.53%	8.55%	8.53%	8.55%	8.489%	

B/ 2014	From Rate Case Order	Jan-14	Feb-14	Mar-14	Apr-14	May-14	Jun-14	Jul-14	Aug-14	Sep-14	Oct-14	Nov-14	Dec-14	**12 mo. YTD**	
Average Rate Base	in 09-00183	$ 92,879,391	90,202,182	89,910,842	90,735,182	93,073,391	98,533,678	105,372,270	110,373,277	112,710,487	117,162,434	118,692,371	118,559,975	103,183,790	Over/(Under) Recovery
Average 12 month-to-date rate base	$ 93,818,504	$ 89,525,187	89,792,177	90,264,095	90,974,309	91,834,817	93,097,614	94,690,319	96,489,317	96,810,040	100,221,278	101,942,153	104,062,352		
monthly adjusted net operating income		$ 1,454,386	1,251,303	897,801	680,877	317,239	340,375	212,468	182,920	259,301	438,809	961,895	1,240,960	**8,238,334**	**623,332**
12 month-to-date adjusted net operating income	$ 6,923,840	$ 7,583,901	7,580,515	7,591,859	7,741,375	7,748,414	7,882,786	8,013,173	8,059,147	8,137,011	8,195,336	8,158,128	8,266,557		
monthly rate of return		18.79%	16.65%	11.98%	9.00%	4.09%	4.15%	2.42%	1.99%	2.76%	4.49%	9.72%	12.56%		
12 month-to-date rate of return	7.38%	8.47%	8.44%	8.41%	8.51%	8.44%	8.47%	8.46%	8.35%	8.41%	8.18%	8.00%	7.94%	7.984%	

B/ 2015	From Rate Case Order	Jan-15	Feb-15	Mar-15	Apr-15	May-15	Jun-15	Jul-15	Aug-15	Sep-15	Oct-15	Nov-15	Dec-15	**12 mo. YTD**	
Average Rate Base	in 09-00183	$ 116,794,756	114,062,126	111,346,719	111,552,107	113,628,253	115,689,308	117,796,251	119,572,892	120,882,192	121,804,993	122,238,855	120,206,264	117,131,226	Over/(Under) Recovery
Average 12 month-to-date rate base	$ 93,818,504	$ 105,584,430	107,221,976	108,787,527	110,479,495	112,207,982	113,955,851	115,155,057	115,724,025	116,376,086	116,832,516	117,033,892	116,778,799		
monthly adjusted net operating income		$ 1,452,212	1,398,596	1,005,356	571,959	283,506	118,101	190,984	270,876	164,609	388,805	963,259	993,610	**7,801,873**	**(842,454)**
12 month-to-date adjusted net operating income	$ 6,923,840	$ 8,258,352	8,430,385	8,498,121	8,389,604	8,355,918	8,146,944	8,126,970	8,212,673	8,130,578	8,080,115	8,080,538	7,208,230		
monthly rate of return		14.92%	14.71%	10.83%	6.15%	2.99%	1.23%	1.95%	2.72%	1.63%	3.83%	9.46%	11.34%		
12 month-to-date rate of return	7.38%	7.82%	7.86%	7.81%	7.59%	7.45%	7.15%	7.06%	7.10%	6.99%	6.92%	6.90%	6.83%	6.661%	

B/ 2016	From Rate Case Order	Jan-16	Feb-16	Mar-16	Apr-16	May-16	Jun-16	Jul-16	Aug-16	Sep-16	Oct-16	Nov-16	Dec-16	**12 mo. YTD**	
Average Rate Base	in 09-00183	$ 116,946,771	114,414,387	112,826,542	112,942,309	114,342,688	114,822,831	114,855,826	116,658,069	118,689,389	120,236,157	121,127,788	119,787,884	116,470,887	Over/(Under) Recovery
Average 12 month-to-date rate base	$ 93,818,504	$ 116,622,673	116,403,021	116,420,387	116,704,543	116,966,383	117,153,113	117,131,976	117,146,703	117,054,368	116,964,112	116,894,804	116,483,867		
monthly adjusted net operating income		$ 1,619,472	1,182,858	902,348	585,115	205,142	105,443	187,178	165,380	255,343	465,155	633,391	1,115,480	**7,422,305**	**(1,173,289)**
12 month-to-date adjusted net operating income	$ 6,923,840	$ 8,136,628	7,916,851	7,808,972	7,823,928	7,737,018	7,725,834	7,724,715	7,622,023	7,700,082	7,777,183	7,447,518	7,422,213		
monthly rate of return		16.62%	12.41%	9.60%	6.22%	2.15%	1.10%	1.95%	1.70%	2.58%	4.64%	6.27%	11.17%		
12 month-to-date rate of return	7.38%	6.98%	6.80%	6.71%	6.70%	6.61%	6.59%	6.59%	6.51%	6.58%	6.65%	6.37%	6.37%	6.373%	

B/ 2017	From Rate Case Order	Jan-17	Feb-17	Mar-17	Apr-17	May-17	Jun-17	Jul-17	Aug-17	Sep-17	Oct-17	Nov-17	Dec-17	**12 mo. YTD**	
Average Rate Base	in 09-00183	$ 117,909,057	116,683,393	116,577,908	117,026,179									117,049,134	Over/(Under) Recovery
Average 12 month-to-date rate base	$ 93,818,504	$ 116,411,742	116,468,988	116,731,329	116,987,150										
monthly adjusted net operating income		$ 1,447,211	1,201,015	847,691	490,063									**3,985,980**	
12 month-to-date adjusted net operating income	$ 6,923,840	$ 6,787,163	6,810,696	6,763,966	668,571										
monthly rate of return		14.73%	12.35%	8.73%	5.03%										
12 month-to-date rate of return	7.38%	5.83%	5.85%	5.79%	5.70%									3.405%	

[redacted] Denotes Information sourced from Confidential Monthly filing

A/ Monthly Rate Base data for 2011 is sourced from "Rate Base Page 15 ROR Caculation Reports.xlsx" (filed with 2012 monthly reports) taken from "Rate of Return By Month" tab; Net Operating Income is taken from Monthly Report of Tennessee Revenues, Expenses, and investments filed by CGC monthly

B/ Monthly Data from January 2012 forward sourced from Monthly Reports of Rate of Return Computed in Accordance with TRA Order Docket 09-00183.