BEFORE THE TENNESSEE PUBLIC UTILITY COMMISSION
NASHVILLE, TENNESSEE

February 15, 2018

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

DIRECT TESTIMONY OF

DANIEL P. YARDLEY

ON BEHALF OF

CHATTANOOGA GAS COMPANY

I. INTRODUCTION

Q. Please state your name, affiliation and business address.

A. My name is Daniel P. Yardley. I am Principal, Yardley & Associates and my business address is 2409 Providence Hills Drive, Matthews, North Carolina 28105.

Q. On whose behalf are you testifying?

A. I am testifying on behalf Chattanooga Gas Company ("CGC" or the "Company").

Q. Please provide a brief outline of your professional and educational background.

A. I have been employed as a consultant to the natural gas industry for over 25 years. During this period, I have directed or participated in numerous consulting assignments on behalf of local distribution companies ("LDCs"). A number of these assignments involved the development of gas distribution company cost allocation, pricing, service unbundling, revenue decoupling and other tariff analyses. In addition to this work, I have performed interstate pipeline cost of service and rate design analyses, gas supply and capacity planning analyses, and financial evaluation analyses. I received a Bachelor of Science Degree in Electrical Engineering from the Massachusetts Institute of Technology in 1988.

Q. Have you previously testified before the Tennessee Public Utility Commission ("TPUC"), or as it was formerly known, the Tennessee Regulatory Authority ("TRA"), and other regulatory bodies concerning rate and regulatory matters?

A. Yes. I testified in CGC's last rate case before the TRA in Docket No. 09-00183. I have also testified on numerous occasions before other state utility commissions, the Federal Energy Regulatory Commission, and the National Energy Board of Canada on a variety of rate and regulatory topics. The subject matters addressed in these proceedings include cost allocation, service design, rate design, revenue decoupling, cost recovery mechanisms and tariff design. A list of my previous expert testimony is provided as Exhibit DPY-3 to my direct testimony.

Q. What is the purpose of your direct testimony?

A. I have been asked by CGC to evaluate the manner in which it recovers its base distribution revenue requirements from customers and to propose changes that are consistent with the nature of the services it provides as well as important rate design objectives. In this regard, my testimony addresses two topics. First, I will describe the Company's rate design goals, which appropriately reflect important public policy and industry developments. Second, I will support the derivation of specific rates and charges for distribution services that fairly apportion the Company's revenue requirement among customer classes. The new charges are based on appropriate rate design considerations including the results of an allocated cost of service study ("ACOSS") performed in a consistent manner with other elements of the Company's filing.

Q. Please summarize your findings.

A. The following four findings and recommendations are supported through my direct testimony:

(1) **The CGC ACOSS establishes an important means of assessing the reasonableness of its existing and proposed base rates:** The ACOSS employs sound allocation methods reflecting principles of cost causation. The results of the ACOSS provide an indication of the relative rates of return by rate class and the proportion of fixed customer-related costs recovered through existing fixed charges.

(2) **The results of the ACOSS indicate that interclass subsidies exist within the current rate structure**: The results of the ACOSS indicate that the class-specific rates of return for the Residential (Rate Schedule R-1), Multi-Family (Rate Schedule R-4) and Small Commercial (Rate Schedule C-1) customers are lower than that of the remaining customer groups. Reducing the existing level of interclass subsidization is an important consideration to achieve a fair rate structure.

(3) **The proposed class-specific base revenue requirements reasonably apportion the Company's requested revenue increase among rate classes:** By applying a larger proportion of the revenue increase to the Residential, Multi-Family and Small Commercial rate classes, the proposed class-specific revenue requirements promote fairness. At the same time, rate increases applied to other rate classes mitigate the increase to residential and small commercial customers to balance rate moderation concerns with fairness.

(4) **The current residential and small commercial customer charges are below the cost-based level:** The below-cost customer charges result in intra-class subsidies as substantial customer-related costs are recovered through variable charges applied to customer usage. This shifts a disproportionate share of customer-related costs to larger customers within a class. Increases to the seasonal residential and small commercial customer charges yield rates that are closer to cost-based levels and contribute to lower intra-class subsidies.

Q. Are you sponsoring any exhibits that accompany your prepared direct testimony?

A. Yes. I am sponsoring the following exhibits, which will be explained later in my testimony:

Exhibit DPY-1:	Allocated Cost of Service Study.
Exhibit DPY-2:	Summary of Existing and Proposed Rates and Revenues.
Exhibit DPY-3:	Prior Testimony.

II. DEVELOPMENT OF CGC'S RATE DESIGN GOALS

Q. What relationship exists between energy policy objectives and a utility's rate design?

A. From a public policy perspective, rate design is a critically important tool for achieving specific energy policy goals that influence the quality of life for the citizens of Tennessee and the State's competitive position. Policy goals affected by rate design include end-use fuel mix, energy efficiency and the resulting environmental and cost impacts of energy consumption. Therefore, the form of a utility's rate structure is an important building block that can contribute to achieving important energy policy goals.

The nexus between rate design and energy policy objectives continues to receive attention throughout the U.S., due in large part to the growth in domestic natural gas production enabled by new drilling techniques and to the prevalence of throughput-based rate designs for distribution service. Throughput-based rate designs recover a substantial portion of LDC fixed-cost revenue requirements through volumetric charges applied to the amount of natural gas consumed by customers. The inherent operating incentives under this form of rate structure are for the LDC to add new customers and to promote increased consumption by its existing customers.

While growing natural gas loads through the addition of new customers is consistent with public policy favoring the direct and most efficient use of clean-burning natural gas, the incentive to increase consumption by current customers is at odds with other public policy goals that favor energy conservation and reductions in customer energy bills. Adopting a form of rate design that promotes appropriate policy goals aligns the economic interests of an LDC and the customers that it serves.

Q. Do CGC's rates reflect a traditional throughput-based rate design?

A. Yes. The Company's rate structure for the majority of customers follows the traditional model. While the rates for customers include a combination of fixed monthly charges and throughput-based or variable charges, typically, a significant proportion of base distribution revenues are derived from the variable charge components and are directly linked to customer usage patterns. Base distribution revenues, sometimes referred to as margin revenues, are revenues received through base rates that recover a utility's cost of service, excluding purchased gas or other tracked costs. Under current rates, base revenues from variable charges account for nearly 30 percent of existing residential base revenue recoveries and 40 percent of small commercial base revenue recoveries. Further reductions in the proportion of fixed costs recovered through variable prices is appropriate at the present time.

Q. What common approaches have been implemented to address the throughput incentive associated with traditional LDC rate designs?

A. Regulators in many individual jurisdictions have approved various types of rate design changes that address the shortcomings associated with traditional rate designs that lead to an LDC's dependence on customer throughput in order to recover fixed costs. The changes include fixed-cost rate design approaches as well as revenue decoupling mechanisms.

Q. Did CGC propose a rate design approach that would have eliminated the throughput incentive in its last base rate proceeding?

A. Yes. CGC proposed the Alignment and Usage Adjustment ("AUA") tariff rider in Docket No. 09-00183. CGC's proposed AUA represented a form of revenue decoupling that would have eliminated the link between customer usage and margin recovery for residential and small commercial customers. The proposed AUA mechanism also replaced the Company's weather normalization adjustment ("WNA") mechanism as the AUA would encompass the margin impacts of all factors affecting customer usage, including weather. The TRA elected to approve the AUA, but with a significant modification that imposed a two percent margin revenue cap on revenues that could be recovered through the mechanism in a given year. The two percent recovery limitation reintroduces the link between throughput and margin recovery in a way that has limited CGC's ability to recover the impacts of warmer-than-normal weather in some years. Therefore, the Company is proposing to eliminate the AUA and reintroduce the weather normalization adjustment mechanism that was in place previously.

Q. Did the Company work with stakeholders on potential modifications to the AUA mechanism in order to address the shortcomings of the mechanism approved by the TRA?

A. Yes. The TRA approved the modified AUA on a three-year trial basis. CGC met with the parties to discuss potential modification of the mechanism that would allow the mechanism to be continued in a manner that offered benefits to the Company and its customers. All of CGC's concerns with the mechanism stem from the level of the revenue recovery cap given the recovery of weather impacts through the AUA that were previously recovered through a weather adjustment mechanism. As Mr. Hickerson discusses in more detail in his testimony, the AUA trial was continued after the initial three year term without adopting the modifications requested by CGC. More recently, CGC sought to terminate the AUA entirely and return the residential and small commercial customers back to the WNA. The prehearing officer suspended that request and the parties agreed to deal with the future applicability of the WNA in place of the AUA in this docket.

Q. What are the implications of the replacement of the AUA mechanism including the two percent cap with the prior weather normalization mechanism on the base rates proposed in this proceeding?

A. The elimination of the AUA mechanism heightens the importance of reducing the proportion of fixed base distribution costs recovered through variable charges. While the Company is not proposing to shift to a full fixed charge rate design, I am supporting increases to existing fixed charges that exceed the overall percentage increase in base rates sought by CGC in this proceeding.

Q. What principles guide the development of new rates for CGC in this proceeding?

A. The rate design approach I recommend seeks to achieve the following five goals:

(1) **Fairness** – Fairness is accomplished through pricing services based on the underlying cost. Fairness is important in many respects including, (i) between the Company and its customers, (ii) across rate classes served by CGC, and (iii) among customers taking service under a common rate schedule.

(2) **Not Discriminatory** – Avoiding undue discrimination requires rates that do not grant an unreasonable preference or subject an unreasonable disadvantage to any customer or group of customers.

(3) **Revenue Stability** – Revenue stability means that CGC's base rate revenues are more predictable in view of future uncertainties. As customer usage patterns have become less certain, improved revenue stability through rate design takes on greater importance as a way of mitigating the increased risks to customers and the Company associated with such unpredictable consumption patterns.

(4) **Moderation** – Moderation allows for the implementation of price changes over time to ensure that customers are not exposed to dramatic price changes all at once.

(5) **Simplicity** – Simplicity means a rate structure that is easy for customers to understand and straightforward to administer.

III. CGC DISTRIBUTION RATE DESIGN

Q. Please describe the Company's existing rate schedules.

A. CGC's existing rate schedules are segregated by sector, nature of service (firm or interruptible) and by customer size. Firm service is provided under six separate rate schedules; two applicable to residential customers and four applicable to commercial and industrial ("C&I") customers. The majority of residential customers take service under Rate Schedule R-1 (Residential General Service), while a limited number of multi-family housing locations are served under Rate Schedule R-4 (Residential Multi-Family Housing Service), which is closed to new customers. Firm C&I customers take service under separate size-based rate schedules. C&I customers with less than 4,000 annual therms taking sales service are served under Rate Schedule C-1 (Small C&I General Service). C&I customers with greater than 4,000 annual therms taking sales service are served under Rate Schedule C-2 (Medium C&I General Service). All C&I customers are eligible to take firm transportation service under Rate Schedule T-3 (Low Volume Transport), which mirrors the rate structure for Rate Schedule C-2. Lastly, large industrial customers with greater than 365,000 annual therms are eligible to take service under Rate Schedule F-1 (Large Volume Firm Service).

CGC provides interruptible service pursuant to three rate schedules that offer varying degrees of gas supply backup. Standard interruptible service is provided to sales customers pursuant to Rate Schedule I-1 (Interruptible Service) and to transportation customers pursuant to Rate Schedule T-1 (Interruptible Transportation Service). Additionally, customers may opt for partial or full gas supply backup under Rate Schedule T-2 (Interruptible Service with Firm Gas Supply Backup).

Lastly, CGC offers service under additional rate schedules targeted to specific market needs. These include natural gas vehicle service provided to commercial and industrial customers under Rate Schedule V-1 and to residential customers under Rate Schedule V-2. Additionally, the Company's tariff also includes economic development and special service rate options pursuant to Rate Schedule EDGS-1 and Rate Schedule SS-1, respectively. Rate Schedule EDGS-1 provides for a declining price discount over the initial four years of service to customers that satisfy economic development eligibility criteria. Rate Schedule SS-1 service is subject to price discounting in order to maintain loads on CGC's system that provide benefits that exceed the marginal costs of providing service.

Q. What rates and charges are incorporated into the Residential Service tariff, Rate Schedule R-1, and the Small C&I Service tariff, Rate Schedule C-1?

A. Approximately 97 percent of the Company's customers take service under these two rate schedules. The existing rate design for the two services is similar and includes two types of base rate charges that are intended to recover CGC's non-gas revenue requirements. The rates are seasonally differentiated between the winter months of November through April and the summer months of May through October. The residential base rates consist of a $16.00 monthly customer charge during the winter and a $13.00 monthly customer charge during the summer as well as a flat distribution or throughput charge of $0.11591 per therm applicable to all therms across both seasons. Under this rate structure, all residential customers pay a minimum amount to CGC equal to the customer charge, regardless of their monthly usage. The rate design also results in customers paying higher amounts as their consumption increases due to the per-therm distribution charge. The distribution charge is considered a variable charge because all of the associated revenues are linked to customer usage or throughput.

The existing rate design for Rate Schedule C-1 customers is similar to that for residential customers. The monthly customer charge for Rate Schedule C-1 is $29.00 during the winter and $25.00 during the summer. The distribution charge is seasonally differentiated and is $0.18581 per therm during the winter and $0.14589 per therm during the summer.

Q. Do the remaining rate schedules employ the same type of rate design?

A. The rate structures for larger commercial and industrial customers taking service under CGC's other rate schedules employ a rate structure that includes a fixed monthly demand charge in addition to monthly customer and distribution charges. The demand charge is an important means of recovering fixed peak-related costs from customers in an equitable manner. The distribution charges for these classes also decline across rate blocks applicable to customer usage within a single month.

Q. Are there separate charges for gas supply?

A. Yes. Sales customers that purchase their gas supply from CGC pay a volumetric Purchased Gas Adjustment ("PGA") rate[1] for gas supply. The PGA rate recovers the costs of purchased gas and upstream pipeline capacity and storage resources necessary to ensure firm delivery to customers throughout the year, and is adjusted periodically to track changes in the delivered cost of gas supply. The PGA rate may be adjusted periodically through filings with the TRA to reflect changes in gas costs or recoveries.

Many C&I customers are transportation-only customers, and pay CGC to deliver gas supply that they have purchased from various third-party gas suppliers ("TPS") that may offer competitive pricing or other terms. The gas supply price for a firm transportation customer is negotiated in a competitive marketplace

[1] The PGA rate includes the Gas Cost Adjustment, the Refund Adjustment and the Actual Cost Adjustment.

between the customer and the TPS. Gas supply charges (whether through the PGA or from TPSs) now represent 55 to 60 percent of the total natural gas bill for the vast majority of CGC's customers.

Q. Did you perform a traditional ACOSS to support your rate design recommendations?

A. Yes. I believe that an ACOSS provides an important means of assessing the reasonableness of existing prices and guiding the development of price changes. In particular, the ACOSS that I performed for CGC examines all of the Company's common costs reflected in its base rate petition, and through appropriate cost assignments and allocations, establishes measures of investments, expenses and income by customer class. The ACOSS is an important tool because many of the Company's costs are common and are incurred to serve many classes of customers collectively.

The ACOSS calculates the total investment and operating costs incurred to serve each customer class, thereby establishing class-specific total revenue requirements. The class-specific revenue requirements are compared to class revenues in order to establish class income and rate of return on investment. The class-specific rates of return are used to guide the apportionment of the revenue requirements among all of CGC's customer classes in conjunction with the development of proposed rates. The ACOSS also determines the classification of costs among demand, customer and volumetric components. The classification of costs within a rate classification is used to guide the development of the form of billing rates for that class. Although the ACOSS is not the only factor relied upon to design rates, it is an invaluable guide to ensuring that the process is fair and reasonable.

Q. Please describe the general costing methodology that is incorporated in the CGC COSS.

A. The most significant consideration in the development of an ACOSS is the methodological approach to allocating fixed demand costs. The ACOSS performed for CGC reflects a system design approach to the allocation of fixed demand costs that closely follows principles of cost causation.

Q. Please summarize the results of the ACOSS and how these results guided the development of proposed rates for CGC.

A. The primary results from the ACOSS are the rate of return by class, which guides the allocation of the Company's revenue requirement among classes and the unit customer and demand-related costs, which guide the intra-class rate design. The results of the ACOSS indicate that the rate of return for the Residential, Multi-Family, and Small Commercial rate classes are lower than the system-average rate of return at present rates of 4.61 percent. The rate of return for the Medium Commercial and Industrial rate classes are above the system-average, indicating that these other classes are subsidizing the prices for the remaining rate classes. Table 1 provides a summary of the rate of return by class and the required increase in base rates to yield the overall rate of return of 7.83 percent.

Table 1

CGC ACOSS
Rate of Return by Class and
Required Increase to Yield Equalized Rates of Return
($ million)

Rate Schedule	ACOSS Rate of Return	Unitized	Required Revenue Increase to Yield 7.83% Rate of Return
Residential R-1	(2.1%)	(0.5)	$12.2
Multi-Family R-4	1.2%	0.3	$0.0
Small Commercial C-1	0.6%	0.1	$1.8
Med. C&I C-2/T-3	28.2%	6.1	($4.1)
Industrial F-1/T-1 /T-2	50.2%	10.9	($2.8)
Overall	4.6%	1.0	$7.0

With respect to unit costs, the ACOSS indicates that the system-wide average monthly customer cost is $30.90, and the cost generally varies with the size of the customer. The lowest average customer cost of $17.03 per month is indicated for the Residential Multi-Family (R-4) class; however, this class actually reflects multiple billing units associated with customers served off of a shared service line, which reduces the unit cost. The highest average customer cost of $120.21 is associated with industrial customers taking service under Rate Schedules F-1 and T-2. The significant variance between monthly customer-related costs and customer charges is taken into consideration when designing the intra-class rate design. A comparison of existing customer costs to customer-related costs is presented in Table 2.

Table 2

CGC ACOSS
Comparison of Existing Customer Charges and Customer-Related Costs

Rate Schedule	ECOSS Customer-Related Cost	Existing Customer Charge Winter/Summer	Difference Winter/Summer
Residential R-1	$27.61	$16.00 / $13.00	$11.61 / $14.61
Multi-Family R-4	$17.03	$6.00 / $6.00	$11.03 / $11.03
Small Commercial C-1	$47.40	$29.00 / $25.00	$18.40 / $22.40
Med. C&I C-2/T-3	$73.41	$75.00 / $75.00	($1.59) / ($1.59)
Industrial F-1/T-2	$120.21	$300.00 / $300.00	($179.79) / ($179.79)

A full description of the CGC ACOSS as well as the input data and detailed results are presented in Exhibit DPY-1.

Q. What steps did you employ to establish the specific rates you are proposing?

A. First, I determined the class-by-class revenue requirements, which reflect the results of the ACOSS and other rate design principles. Next, I evaluated the existing level of customer charges and proposed increases, where appropriate, to recover a greater proportion of customer-related costs through customer charges. Lastly, I established the appropriate rate structure and rate levels to recover the remaining portion of class revenue requirements.

Q. How did you develop the class-by-class revenue requirements?

A. The revenue requirements by customer class are based upon the rates of return under the present rates as well as the required increase by class to achieve the overall rate of return of 7.83 percent. In particular, I am proposing to allocate a higher proportion of the revenue increase to the Residential, Multi-Family and Small Commercial rate classes. While these rate classes are the only ones that require any increase to yield the overall rate of return, I am proposing to allocate a portion of the overall increase to other classes as a means of moderating the increase to residential customers. Specifically, I am proposing to increase the base rates for Medium Commercial (C-2 and T-3) as well as all industrial customer classes by one-half of the average base revenue increase.

This approach yields revenue requirement increases of $4.5 million to the Residential R-1 rate class, $8,000 to the Residential Multi-Family (R-4) rate class and $1.1 million to the Small Commercial (C-1) rate class. The resulting increases to these classes, which in all cases are between 12 and 14 percent of total class revenues, achieve rate moderation objectives and promote fairness by reducing the existing variances in rate of return among customer classes. Disparate rates of return continue to exist at proposed rates because I am not proposing to lower the overall revenue requirements allocated to the Medium Commercial customers served under the C-2 and T-3 rate schedules and allocated to industrial customers served under the F-1 and T-2 rate schedules.

Q. Why is the level of the customer charge important?

A. The level of the monthly fixed customer charge is important for a variety of reasons that relate to the Company's rate design goals I described earlier. First, the monthly fixed customer charge provides customers with an important price signal concerning the impact of connecting to CGC's distribution system. Second, recovering customer-related costs through monthly fixed customer charges contributes to intra-class fairness. To the extent that a portion of customer-related costs are recovered through volumetric charges, intra-class subsidies are created as larger customers pay a disproportionate share of customer-related costs. Third, the fixed monthly customer charge provides revenue stability as fixed costs that are incurred to serve customers are recovered through a fixed charge.

Q. Please describe the customer charge you propose for Rate Schedule R-1 service and how you derived this amount.

A. I am proposing to increase the customer charge for residential customers to move the charge closer towards a level that reflects the underlying costs allocated to this class of service. Specifically, I propose to increase the monthly customer charge during the winter months of November through April from $16.00 to $21.00 and during the summer months of May through October from $13.00 to $18.50. Continuing the seasonally-differentiated monthly customer charges is an appropriate means of aligning the need to recover a greater proportion of fixed costs through fixed charges with customer expectations that natural gas service provides a higher value during the peak season. These new customer charges remain below cost-based levels. Even with the increase to the residential customer charge, approximately 27 percent of the target revenue requirements of the class are recovered through the delivery charge.

Q. What customer charges do you propose for customers taking service pursuant to other rate schedules?

A. I am proposing to increase the monthly customer charge for Multi-Family customers from $6.00 to $8.50 per month. I am also to increase the Small

Commercial monthly customer charges from $29.00 to $39.00 in the winter and from $25.00 to $35.00 in the summer. These increases yield monthly customer charges that are closer to cost-based levels and provide greater fixed charge recovery of CGC's fixed costs.

I am proposing to retain the monthly customer charges for all other rate classes given that the existing charges are either at or above cost-based levels. The monthly customer charge for Medium C&I customers is $75.00 while the monthly customer charge for industrial customers is $300.00.

Q. Please explain the next step in the rate design process.

A. Once the customer charges are established, the next step in the rate design process is to design the remaining rate elements for each class to recover the total target revenue requirements less the revenues recovered through the customer charge. For the residential class, the remaining revenue requirements are recovered through a volumetric charge of $0.13921 per therm. I am proposing to retain the existing seasonally-differentiated distribution charge for small commercial customers. The proposed winter distribution charge is $0.22678 per therm and the proposed summer distribution charge is $0.18686 per therm. I am proposing a similar increase to the Residential Multi-Family (R-4) seasonally-differentiated flat block charges as well. The proposed volumetric charges for this class are $0.26141 per therm during the winter and $0.23723 per therm during the summer.

Q. Are you proposing any base rate changes for CGC's remaining customer classes?

A. Yes. Although I am not proposing increases to the monthly customer charges for other rate classes, I am proposing to increase the fixed cost recovery through an increase to the monthly demand charge in order to better align prices with underlying costs of providing service. For the medium C&I customers served under Rate Schedules C-2 and T-3, I am proposing to increase the fixed monthly demand charge from $5.50 to $7.00 per dekatherm. In addition, I am proposing to increase the seasonally-differentiated declining block variable distribution charges by an equal $0.01093 per therm.

I am proposing similar changes to the demand charges for the larger industrial customers served under Rate Schedules F-1 and T-2. Specifically, I am proposing to increase the fixed monthly demand charge $5.50 to $7.00 per dekatherm. I am proposing a similar increase to the partial standby monthly demand charge from $1.35 to $1.75 per month. In addition, I am proposing to increase the declining block variable distribution charges by an equal $0.00022 per therm.

Q. Have you prepared a summary of the proposed rate changes?

A. Yes. The existing and proposed rates for each class are compared in Exhibit DPY-2. The revenue change and associated percentage impact is indicated for each rate schedule on this exhibit. In addition, Exhibit DPY-2 provides a proof of revenues demonstrating that the proposed charges yield the requested revenue requirements based on the Company's forecasts of sales and customers.

Q. Are your proposed rates consistent with the results of the ACOSS?

A. The proposed rates result in rates of return that are closer to the system-average rate of return than would be the case if the requested increase had been spread equally to all classes. The prices for residential and small commercial customers continue to be subsidized by remaining classes, but to a lesser degree than under the existing rate design.

Q. Does this conclude your direct testimony?

A. Yes, it does.

CHATTANOOGA GAS COMPANY
ALLOCATED COST OF SERVICE STUDY

I. PURPOSE AND GUIDING PRINCIPLES

Chattanooga Gas Company ("CGC") is proposing to change existing rates in connection with a proposed increase in base rate revenue requirements. An allocated cost of service study ("ACOSS") assesses the reasonableness of existing prices, and guides the development of price changes. In particular, the ACOSS examines all of a utility's common costs, and through appropriate cost assignments and allocations, establishes measures of investments, expenses and income by customer class. An ACOSS is necessary to determine the cost responsibility for each customer class because many of the Company's costs are common and are incurred to serve many classes of customers collectively.

The ACOSS calculates the total investment and operating costs incurred to serve each customer class, establishing class-specific total revenue requirements. The class-specific revenue requirements are compared to class revenues in order to establish class income and rate of return on investment. The class-specific rates of return are used to guide the apportionment of the base rate increase among all of CGC's customer classes in conjunction with the development of proposed rates. The ACOSS also determines the classification of costs among demand, customer and commodity components. The classification of costs within a rate classification is used to guide the development of the form of billing rates for that class. Although the ACOSS is not the only factor relied upon to design rates, it is an invaluable guide to ensuring that the process is fair and reasonable.

The primary principle that guides the ACOSS process is that of cost causation. Each step in the development of the ACOSS is consistent with the factors that drive or contribute to the incurrence of costs on the CGC system. For example, the principle of cost causation requires that the costs incurred by the Company for billing be apportioned to classes on the basis of the number of bills issued or customers in each class.

II. Specification of Chattanooga Gas Company ACOSS

A. Overview

The ACOSS follows a three-part process, which consists of the functionalization, classification and allocation of CGC's total cost of service. First, cost functionalization involves the segregation of costs into categories based on the function that each cost is incurred to provide. In the ACOSS, the functions are production, transmission, storage and distribution – the direct functions associated with costs incurred by the Company. Second, cost classification further separates costs according to the primary cost causative forces exhibited on CGC's system. The cost classifications used in the ACOSS relate to fixed costs required to serve peak requirements (demand-related), fixed costs associated with providing customers with access to and active status on the system (customer-related), and variable costs associated with system throughput (commodity-related). Finally, cost allocation takes each classification of cost for each function and apportions that cost to each of the Company's customer classes. Cost allocation utilizes a variety of factors to apportion the various types of costs among classes in a manner that is consistent with principles of cost causation.

B. Customer Classes

The ACOSS groups CGC customers into five groups based on rate schedules set forth in CGC's gas tariff. The ACOSS groups and associated rate schedules are: Residential (R-1), Residential Multi-Family (R-4), Small Commercial (C-1), Medium Commercial and Industrial (C-2 and T-3), and Industrial (F-1, T-1 and T-2). Rate Schedules that are grouped together within the ACOSS, e.g., C-2 and T-3, reflect common base rates even though other terms and conditions of service vary including differences between sales and transportation services.

B. Data Sources

The primary data sources fall in two general categories: data related to the establishment of the total cost of service, and data used as the basis for allocating the total cost of service among customer classes. The total cost of service or revenue requirement data utilized in the ACOSS are taken from schedules supporting CGC's base rate application in this proceeding. The Company's forecasts of sales, customers and revenues by class supporting the application, as adjusted for pro forma changes, are used as allocation bases for several categories of costs. The remaining allocation data are derived from special studies of facility or operating costs. All of the data utilized in the ACOSS correspond to a common time period of July 2018 through June 2019. This is the Attrition Period, which is the period for which rates are to be determined.

C. Cost Functionalization

The functionalization of costs refers to the segregation of costs among the primary functions provided by gas utilities to their retail customers. The chart of accounts prescribed by Tennessee Regulatory Authority separates the majority of costs into the following four functions:

- *Production:* The production function includes costs associated with the upstream commodity gas supply, interstate pipeline transportation capacity necessary to deliver the supply to CGC's system, and upstream storage facilities. Additionally, the costs of any production facilities and the administrative costs associated with procuring natural gas and transportation are categorized as production-related.

- *Storage:* The storage function includes costs associated with on-system facilities that are able to receive injected supplies or delivered liquid natural gas for later withdrawals.

- *Transmission:* The transmission function includes costs associated with large diameter, high pressure facilities that deliver gas to smaller distribution facilities. Transmission facilities include transmission mains and compressors.

- *Distribution:* The distribution function includes costs associated with delivering supplies within areas that are close in proximity to gas loads, such as distribution mains. The costs associated with connecting customers to the distribution system are also considered distribution-related, which include costs associated with services, meters and regulators.

The majority of CGC's non-gas supply costs are associated with the distribution function. Costs that do not directly fall into one of these primary functions, such as administrative and general expenses, are functionalized on the same basis as other related costs.

D. Cost Classification

Classification is the apportionment of costs among demand, customer and commodity categories. Each of CGC's rate base and expense accounts is classified consistent with the manner in which the associated costs are incurred. Costs that are associated with serving peak requirements on the system are classified as demand-related, e.g., costs associated with transmission accounts. Costs that are associated with providing customers access to and active status on the distribution system are classified as customer-related. Customer-related costs are incurred regardless of the amount of gas a customer consumes in any given period and include the costs of services, meters and regulators, and meter reading and billing expenses. Costs that are associated with the quantity of gas purchased or transported are classified as commodity-related. Examples of commodity-related costs are purchased gas costs. Demand and customer-related costs are considered fixed, while commodity-related costs are variable. Some categories of costs vary with more than one of the classifications described previously.

Lastly, some categories of costs are appropriately classified based on how other related costs are classified. For example, distribution operations supervision and engineering expenses are classified based on the classification of all other distribution operations accounts.

The Company's investment in distribution mains is its largest category of plant investment. The classification of distribution mains reflects the distinct cost causative factors that drive the Company's investments in these facilities. The first factor is the coincident peak demand on the system. Distribution mains are designed to deliver the maximum quantities that are required during a peak period from interstate pipeline interconnects to the interconnection with each individual customer service. The second factor is the number of customers on the system. Distribution mains are also designed to deliver supplies in reasonable proximity to customers in order to minimize the overall investment in pipe needed to collectively serve all customers.

The breakdown of distribution mains investment costs between the demand and customer-related components is determined through a minimum-size study. The premise underlying this study is that the size of distribution main installed in a given location is most affected by the peak load that will be served by the main, and that the length of distribution main is most affected by the number of customers that are served.

The minimum size study evaluates the cost of replacing the existing distribution mains of the system under two different sets of assumptions. The first determines the cost of replacing existing distribution mains with the same type, diameter and lengths of pipe as is currently installed. The second determines the replacement cost assuming that the entire system is replaced with two-inch diameter plastic pipe, which is the smallest, least-expensive size and type of pipe presently being installed. The customer component of distribution mains is equal to the ratio of the replacement cost using the smallest size pipe to the replacement cost using the installed sizes of pipe. Based on the results of this study, 62% of CGC's distribution mains investment is classified as customer-related.

E. Cost Allocation

Cost allocation is the apportionment of individual elements of the Company's classified cost of service among rate classes based on each class' responsibility for the cost being incurred. Cost allocation follows cost causation principles and requires the development of numerous allocation factors that reflect the different types of costs included in CGC's overall revenue requirements. Considerable effort is required to yield the set of allocation factors underlying the ACOSS.

The ACOSS follows system-design criteria in order to allocate costs on the basis of cost causation. The demand allocator used in the ACOSS is the coincident design day demand factor. Under this method, the allocation of demand costs reflects the manner in which the Company designs, plans and constructs its system to satisfy firm demands. Off-peak loads do not increase the Company's demand-related investments, and therefore, are not factored into the demand allocator in a system-design ACOSS.

The other allocation factors used in the ACOSS may be grouped into three categories as follows: (i) class summary statistics reflected in the base rate filing, such as the number of customers and throughput by class; (ii) special studies that examine the costs associated with a specific type of investment or expense; and (iii) internal allocation factors, which are composite factors determined on the basis of how related cost items are allocated. All of the various factors must be developed assuming a consistent time period for the ACOSS to be accurate.

Four special studies were performed related to significant capital investment and operations and maintenance ("O&M") expense accounts. The studies are as follows:

- *Meter Investment Study:* The meter investment study establishes the aggregate investment in meters and associated regulators based on the type and replacement cost of various meters installed to serve each class.

- *Service Investment Study:* The service investment study establishes the aggregate investment in services based on the type and replacement cost of various meters installed to serve each class.

- *Working Capital Study:* The working capital study examines the components of CGC's proposed working capital allowance. A composite allocator is derived from the allocation of each component within the ACOSS.

- *Labor Expense Study:* A study of the Company's payroll expense examines components of the Company's payroll costs. The labor study is used as the basis for allocating costs that vary with direct payroll costs, such as pensions and benefits costs.

Together, these special studies are utilized to allocate a substantial portion of the Company's total revenue requirements to customer classes.

III. Results

Detailed ACOSS results are provided in this exhibit. Specifically, pages eight and nine provide an income statement by class at existing and proposed rates, respectively. Pages ten, eleven and twelve contain summaries of allocated rate base, O&M expense and total revenue requirements by classification and rate class. Lastly, page thirteen provides a detailed analysis of the components of monthly customer-related costs.

The ACOSS demonstrates that the rates of return for the Residential (R-1), Residential Multi-Family (R-4) and Small Commercial (C-1) classes are far below the system-average rate of return of 4.61% at present rates. The Residential class is by far CGC's largest class. The rate of return for all other classes is well above the system-average, indicating that these classes are subsidizing the prices for residential and small commercial customers.

Monthly customer costs are derived from the costs that are classified as customer-related and the apportionment of these costs to CGC's various customer classes. The system-wide average monthly customer cost is $30.90, and the cost generally varies with the size of the customer. The lowest average customer cost of $17.03 per month is associated with serving the Multi-Family class.

The results of the ACOSS clearly indicate that class-differentiated base rate revenue increases are appropriate given the wide disparity in rates of return by customer class. In addition, the monthly customer-related costs should be taken into consideration in the development of proposed modifications to existing customer charges.

Chattanooga Gas Company
Income and Rate of Return at Present Rates

Line No.	Description	Total System	R-1 Residential	R-4 Multi-Family	C-1 Small Commercial	C-2 / T-3 Medium C&I	F-1 / T-1 /T-2 Industrial
	(A)	(B)	(C)	(D)	(E)	(F)	(G)
1	**REVENUES**						
2	Margin Revenues	$ 31,655,847	$ 14,332,359	$ 26,108	$ 3,543,596	$ 9,309,472	$ 4,444,312
3	AFUDC	900,355	631,971	980	121,945	108,955	36,505
4	Miscellaneous Revenues	789,142	543,976	860	103,912	106,477	33,917
5	**Total**	**$ 33,345,344**	**$ 15,508,305**	**$ 27,948**	**$ 3,769,453**	**$ 9,524,904**	**$ 4,514,734**
6	**OPERATING EXPENSES**						
7	Operations and Maintenance	$ 13,664,603	$9,259,286	$13,584	$1,924,807	$1,896,438	$570,488
8	Depreciation and Amortization	8,035,649	5,578,380	7,727	1,140,724	990,028	318,790
9	Taxes Other Than Income Taxes	3,523,948	2,449,073	3,799	475,746	449,658	145,671
10	**Total**	**$ 25,224,201**	**$ 17,286,740**	**$ 25,111**	**$ 3,541,277**	**$ 3,336,124**	**$ 1,034,949**
11	**OPERATING INCOME BEFORE TAXES**	**$ 8,121,143**	**$ (1,778,435)**	**$ 2,837**	**$ 228,176**	**$ 6,188,780**	**$ 3,479,785**
12	**INCOME TAXES**						
13	Federal Income Taxes	$ 457,767	$ 315,550	$ 499	$ 60,278	$ 61,765	$ 19,675
14	State Income Taxes	202,546	139,620	221	26,671	27,329	8,705
15	Deferred Income Taxes	-	-	-	-	-	-
16	**Total**	**$ 660,313**	**$ 455,170**	**$ 720**	**$ 86,948**	**$ 89,094**	**$ 28,380**
17	**RATEMAKING ADJUSTMENTS**	**$ (96,740)**	**($67,903)**	**($105)**	**($13,103)**	**($11,707)**	**($3,922)**
18	**NET INCOME**	**$ 7,364,090**	**$ (2,301,508)**	**$ 2,012**	**$ 128,125**	**$ 6,087,978**	**$ 3,447,483**
19	**RATE BASE**	**$ 159,856,708**	**$110,193,281**	**$174,188**	**$21,049,552**	**$21,569,055**	**$6,870,631**
20	**RATE OF RETURN AT PRESENT RATE**	**4.61%**	**-2.09%**	**1.16%**	**0.61%**	**28.23%**	**50.18%**

Chattanooga Gas Company
Income and Rate of Return at Proposed Rates

Line No.	Description	Total System	R-1 Residential	R-4 Multi-Family	C-1 Small Commercial	C-2 / T-3 Medium C&I	F-1 / T-1 /T-2 Industrial
	(A)	(B)	(C)	(D)	(E)	(F)	(G)
1	**REVENUES**						
2	Margin Revenues	$ 38,650,801	$ 18,831,300	$ 34,303	$ 4,655,973	$ 10,321,195	$ 4,808,030
3	AFUDC	900,355	631,971	980	121,945	108,955	36,505
4	Miscellaneous Revenues	816,005	562,493	889	107,450	110,101	35,072
5	**Total**	**$ 40,367,161**	**$ 20,025,763**	**$ 36,173**	**$ 4,885,367**	**$ 10,540,251**	**$ 4,879,606**
6	**OPERATING EXPENSES**						
7	Operations and Maintenance	$ 13,704,568	$9,286,835	$13,628	$1,930,069	$1,901,830	$572,206
8	Depreciation and Amortization	8,035,649	5,578,380	7,727	1,140,724	990,028	318,790
9	Taxes Other Than Income Taxes	3,523,948	2,449,073	3,799	475,746	449,658	145,671
10	**Total**	**$ 25,264,166**	**$ 17,314,289**	**$ 25,154**	**$ 3,546,539**	**$ 3,341,516**	**$ 1,036,667**
11	**OPERATING INCOME BEFORE TAXES**	**$ 15,102,995**	**$ 2,711,474**	**$ 11,018**	**$ 1,338,828**	**$ 7,198,735**	**$ 3,842,940**
12	**INCOME TAXES**						
13	Federal Income Taxes	$ 1,828,700	$ 1,260,569	$ 1,993	$ 240,799	$ 246,742	$ 78,597
14	State Income Taxes	656,382	452,461	715	86,431	88,564	28,211
15	Deferred Income Taxes	-	-	-	-	-	-
16	**Total**	**$ 2,485,082**	**$ 1,713,030**	**$ 2,708**	**$ 327,230**	**$ 335,306**	**$ 106,809**
17	**RATEMAKING ADJUSTMENTS**	**$ (96,740)**	**($67,903)**	**($105)**	**($13,103)**	**($11,707)**	**($3,922)**
18	**NET INCOME**	**$ 12,521,173**	**$ 930,541**	**$ 8,205**	**$ 998,495**	**$ 6,851,722**	**$ 3,732,209**
19	**RATE BASE**	**$ 159,856,708**	**$110,193,281**	**$174,188**	**$21,049,552**	**$21,569,055**	**$6,870,631**
20	**RATE OF RETURN AT PROPOSED RAT**	**7.83%**	**0.84%**	**4.71%**	**4.74%**	**31.77%**	**54.32%**

Chattanooga Gas Company
Rate Base

Line No.	Description	Total System	R-1 Residential	R-4 Multi-Family	C-1 Small Commercial	C-2 / T-3 Medium C&I	F-1 / T-1 /T-2 Industrial
	(A)	(B)	(C)	(D)	(E)	(F)	(G)
1	**I. PLANT IN SERVICE**						
2	Demand	$ 108,284,067	$ 59,030,589	$ 24,371	$11,988,517	$25,919,319	$11,321,270
3	Customer	193,130,958	152,536,462	303,798	28,835,277	10,555,840	899,580
4	Commodity	-	-	-	-	-	-
5		$ 301,415,025	$211,567,051	$328,170	$40,823,795	$36,475,159	$12,220,850
6	**II. ACCUMULATED RESERVE FOR DEPRECIATION**						
7	Demand	$ 41,634,717	$ 22,696,985	$ 9,371	$4,609,529	$9,965,857	$4,352,976
8	Customer	86,268,721	67,697,806	122,758	13,286,323	4,665,501	496,333
9	Commodity	-	-	-	-	-	-
10		$ 127,903,439	$90,394,792	$132,129	$17,895,852	$14,631,358	$4,849,309
11	**III. NET PLANT IN SERVICE**						
12	Demand	$ 66,649,350	$ 36,333,604	$ 15,001	$7,378,988	$15,953,462	$6,968,295
13	Customer	106,862,236	84,838,655	181,040	15,548,954	5,890,339	403,247
14	Commodity	-	-	-	-	-	-
15		$ 173,511,586	$121,172,259	$196,041	$22,927,943	$21,843,801	$7,371,542
16	**IV. RATE BASE ADDITIONS**						
17	Demand	$ 19,583,332	$ 10,792,750	$ 7,839	$2,207,020	$5,106,014	$1,469,708
18	Customer	14,905,832	11,414,750	22,765	2,254,450	1,115,341	98,526
19	Commodity	-	-	-	-	-	-
20		$ 34,489,164	$22,207,500	$30,604	$4,461,470	$6,221,355	$1,568,234
21	**V. RATE BASE DEDUCTIONS**						
22	Demand	$ (19,958,482)	$ (10,907,343)	$ (5,286)	($2,218,670)	($4,874,154)	($1,953,030)
23	Customer	(28,185,560)	(22,279,135)	(47,171)	(4,121,191)	(1,621,947)	(116,115)
24	Commodity	-	-	-	-	-	-
25		$ (48,144,042)	($33,186,478)	($52,457)	($6,339,861)	($6,496,102)	($2,069,145)
26	**VI. TOTAL RATE BASE**						
27	Demand	**$ 66,274,200**	**$ 36,219,011**	**$ 17,554**	**$7,367,339**	**$16,185,322**	**$6,484,974**
28	Customer	**93,582,509**	**73,974,270**	**156,634**	**13,682,213**	**5,383,733**	**385,658**
29	Commodity	**-**	**-**	**-**	**-**	**-**	**-**
30		**$ 159,856,708**	**$110,193,281**	**$174,188**	**$21,049,552**	**$21,569,055**	**$6,870,631**

Chattanooga Gas Company
O&M Expense

Line No.	Description	Total System	R-1 Residential	R-4 Multi-Family	C-1 Small Commercial	C-2 / T-3 Medium C&I	F-1 / T-1 /T-2 Industrial
	(A)	(B)	(C)	(D)	(E)	(F)	(G)
1	**I. PRODUCTION EXPENSE**						
2	Demand	$ -	$ -	$ -	$0	$0	$0
3	Customer	-	-	-	-	-	-
4	Commodity	-	-	-	-	-	-
5		$ -	$0	$0	$0	$0	$0
6	**II. STORAGE EXPENSE**						
7	Demand	$ 1,242,143	$ 677,149	$ 280	$ 137,522	$ 297,324	$ 129,868
8	Customer	-	-	-	-	-	-
9	Commodity	-	-	-	-	-	-
10		$ 1,242,143	$677,149	$280	$137,522	$297,324	$129,868
11	**III. TRANSMISSION EXPENSE**						
12	Demand	$ -	$ -	$ -	$ -	$ -	$ -
13	Customer	-	-	-	-	-	-
14	Commodity	-	-	-	-	-	-
15		$ -	$0	$0	$0	$0	$0
16	**IV. DISTRIBUTION EXPENSE**						
17	Demand	$ 800,261	$ 436,259	$ 180	$88,600	$191,554	$83,669
18	Customer	2,819,256	2,155,691	4,102	448,741	202,616	8,107
19	Commodity	-	-	-	-	-	-
20		$ 3,619,517	$2,591,949	$4,282	$537,341	$394,170	$91,775
21	**V. CUSTOMER ACCOUNTS EXPENSE**						
22	Demand	$ 101,189	$ 55,300	$ 27	$ 11,249	$ 24,712	$ 9,901
23	Customer	221,338	181,112	457	28,755	10,350	664
24	Commodity	-	-	-	-	-	-
25		$ 322,527	$236,412	$484	$40,004	$35,062	$10,566
26	**VI. CUSTOMER SERVICE AND SALES EXPENSE**						
27	Demand	$ -	$ -	$ -	$ -	$ -	$ -
28	Customer	97,852	85,020	272	9,809	2,657	94
29	Commodity	-	-	-	-	-	-
30		$ 97,852	$ 85,020	$ 272	$ 9,809	$ 2,657	$ 94
31	**VII. ADMINISTRATIVE AND GENERAL EXPENSE**						
32	Demand	$ 3,138,277	$ 1,710,818	$ 706	$347,450	$751,191	$328,111
33	Customer	5,284,252	3,985,487	7,604	857,944	421,425	11,792
34	Commodity	-	-	-	-	-	-
35		$ 8,422,529	$5,696,305	$8,311	$1,205,394	$1,172,617	$339,903
36	**VIII. TOTAL O&M EXPENSE**						
37	Demand	**$ 5,281,869**	**$ 2,879,526**	**$ 1,193**	**$ 584,820**	**$ 1,264,782**	**$ 551,549**
38	Customer	**8,422,699**	**6,407,310**	**12,435**	**1,345,249**	**637,049**	**20,657**
39	Commodity	**-**	**-**	**-**	**-**	**-**	**-**
40		**$ 13,704,568**	**$ 9,286,835**	**$ 13,628**	**$ 1,930,069**	**$ 1,901,830**	**$ 572,206**

Chattanooga Gas Company
Total Revenue Requirements

Line No.	Description	Total System	R-1 Residential	R-4 Multi-Family	C-1 Small Commercial	C-2 / T-3 Medium C&I	F-1 / T-1 /T-2 Industrial
	(A)	(B)	(C)	(D)	(E)	(F)	(G)
1	**I. O&M EXPENSE**						
2	Demand	$ 5,281,869	$ 2,879,526	$ 1,193	$ 584,820	$ 1,264,782	$ 551,549
3	Customer	8,422,699	6,407,310	12,435	1,345,249	637,049	20,657
4	Commodity	-	-	-	-	-	-
5		$ 13,704,568	$ 9,286,835	$ 13,628	$ 1,930,069	$ 1,901,830	$ 572,206
6	**II. DEPRECIATION**						
7	Demand	$ 2,801,185	$ 1,527,054	$ 630	$ 310,129	$ 670,503	$ 292,868
8	Customer	5,234,464	4,051,326	7,096	830,595	319,525	25,921
9	Commodity	-	-	-	-	-	-
10		$ 8,035,649	$ 5,578,380	$ 7,727	$ 1,140,724	$ 990,028	$ 318,790
11	**III. TAXES OTHER THAN INCOME**						
12	Demand	$ 1,336,090	$ 729,025	$ 320	$ 148,143	$ 322,179	$ 136,423
13	Customer	2,187,858	1,720,048	3,479	327,602	127,479	9,249
14	Commodity	-	-	-	-	-	-
15		$ 3,523,948	$2,449,073	$3,799	$475,746	$449,658	$145,671
16	**IV. DEFERRED INCOME TAXES**						
17	Demand	$ -	$ -	$ -	$ -	$ -	$ -
18	Customer	-	-	-	-	-	-
19	Commodity	-	-	-	-	-	-
20		$ -	$0	$0	$0	$0	$0
21	**V. RATEMAKING ADJUSTMENTS**						
22	Demand	$ 34,754	$ 18,946	$ 8	$ 3,848	$ 8,319	$ 3,634
23	Customer	61,986	48,957	98	9,255	3,388	289
24	Commodity	-	-	-	-	-	-
25		$ 96,740	$67,903	$105	$13,103	$11,707	$3,922
26	**VI. RETURN**						
27	Demand	$ 5,191,191	$ 2,836,999	$ 1,375	$ 577,076	$ 1,267,780	$ 507,961
28	Customer	7,330,223	5,794,330	12,269	1,071,714	421,702	30,208
29	Commodity	-	-	-	-	-	-
30		$ 12,521,414	$8,631,328	$13,644	$1,648,790	$1,689,482	$538,170
31	**VII. INCOME TAXES**						
32	Demand	$ 1,030,278	$ 563,049	$ 273	$ 114,530	$ 251,612	$ 100,813
33	Customer	1,454,804	1,149,981	2,435	212,699	83,694	5,995
34	Commodity	-	-	-	-	-	-
35		$ 2,485,082	$1,713,030	$2,708	$327,230	$335,306	$106,809
36	**VIII. TOTAL REVENUE REQUIREMENTS**						
37	Demand	**$ 15,675,368**	**$ 8,554,599**	**$ 3,799**	**$ 1,738,547**	**$ 3,785,174**	**$ 1,593,248**
38	Customer	**24,692,034**	**19,171,951**	**37,812**	**3,797,114**	**1,592,837**	**92,319**
39	Commodity	**-**	**-**	**-**	**-**	**-**	**-**
40		**$ 40,367,402**	**$27,726,550**	**$41,611**	**$5,535,662**	**$5,378,011**	**$1,685,567**

Chattanooga Gas Company
Monthly Customer Cost Detail

Line No.	Description		Total System		R-1 Residential		R-4 Multi-Family		C-1 Small Commercial		C-2 / T-3 Medium C&I		F-1 / T-1 /T-2 Industrial
	(A)		(B)		(C)		(D)		(E)		(F)		(G)
1	**I. AVERAGE CUSTOMER COSTS**												
2	Customer-Related Revenue Req.	$	24,692,034	$	19,171,951	$	37,812	$	3,797,114	$	1,592,837	$	92,319
3	Average Customers		66,593		57,861		185		6,676		1,808		64
4	**Average Monthly Customer Cost**	**$**	**30.90**	**$**	**27.61**	**$**	**17.03**	**$**	**47.40**	**$**	**73.41**	**$**	**120.21**
5	**II. MONTHLY CUSTOMER COST DETAIL**												
6	O&M Expense												
7	Mains and Services Expense	$	1.78	$	1.67	$	1.11	$	2.45	$	2.46	$	8.82
8	Meter & Regulator Expense		0.99		0.73		0.21		2.11		5.33		-
9	Meter Reading Expense		0.10		0.10		0.10		0.10		0.10		0.10
10	Customer Records and Collections		0.00		0.00		0.00		0.00		0.00		0.00
11	Uncollectible Accounts		0.18		0.16		0.11		0.26		0.38		0.77
12	All Other O&M		7.49		6.56		4.08		11.88		21.10		17.22
13	Total O&M	$	10.54	$	9.23	$	5.60	$	16.79	$	29.36	$	26.90
14	Depreciation												
15	Mains	$	2.28	$	2.28	$	2.28	$	2.28	$	2.28	$	2.28
16	Services		2.42		2.08		0.27		4.60		4.63		25.18
17	Meters and Meter Installations		0.90		0.66		0.19		1.91		4.83		4.17
18	Regulators		0.12		0.08		0.02		0.24		0.62		-
19	All Other Depreciation		0.83		0.72		0.43		1.34		2.37		2.12
20	Total Depreciation	$	6.55	$	5.83	$	3.20	$	10.37	$	14.73	$	33.75
21	Taxes Other Than Income Taxes	$	2.74	$	2.48	$	1.57	$	4.09	$	5.88	$	12.04
22	Deferred Income Taxes	$	-	$	-	$	-	$	-	$	-	$	-
23	Ratemaking Adjustments	$	0.08	$	0.07	$	0.04	$	0.12	$	0.16	$	0.38
24	Rate Base-Related (Return and Income Taxes)												
25	Mains	$	6.35	$	6.35	$	6.35	$	6.35	$	6.35	$	6.35
26	Services		3.29		2.83		0.37		6.24		6.29		34.19
27	Meters and Meter Installations		1.66		1.22		0.35		3.51		8.85		5.48
28	Regulators		0.29		0.21		0.06		0.61		1.55		-
29	All Other Rate Base-Related		(0.59)		(0.60)		(0.50)		(0.67)		0.26		1.12
30	Total Rate Base-Related	$	10.99	$	10.00	$	6.62	$	16.03	$	23.29	$	47.14
31	**Total Average Monthly Customer Cost**	**$**	**30.90**	**$**	**27.61**	**$**	**17.03**	**$**	**47.40**	**$**	**73.41**	**$**	**120.21**

Chattanooga Gas Company
Base Revenue and Total Revenue at Present and Proposed Rates

Line No.	Description	Post Test Year Billing Units Winter Nov-April	Summer May-Oct	Total	Present Winter Rates Nov - April Rate	Revenue	Present Summer Rates May - Oct Rate	Revenue	Present Total Revenue	Proposed Winter Rates Nov - April Rate	Revenue	Proposed Summer Rates May - Oct Rate	Revenue	Proposed Total Revenue
	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)	(l)	(m)	(n)
1	**Residential (R-1)**													
2	Number of Bills	350,374	343,953	694,327	$16.00	$5,605,991	$13.00	$4,471,386	$10,077,377	$21.00	$7,357,863	$18.50	$6,363,126	$13,720,989
3	Distribution Charges	32,061,265	4,648,096	36,709,361	$0.11591	$3,716,221	$0.11591	$538,761	$4,254,982	$0.13921	$4,463,249	$0.13921	$647,061	$5,110,310
4	**Total Residential Margin**					$9,322,212		$5,010,147	$14,332,359		$11,821,112		$7,010,188	$18,831,300
5	**PGA**					$18,009,301		$2,565,799	$20,575,100		$18,009,301		$2,565,799	$20,575,100
6	**Total Revenues**					$27,331,513		$7,575,946	$34,907,459		$29,830,413		$9,575,987	$39,406,400
7													**Increase**	**$4,498,941**
8													**Percent**	**12.9%**
9	**Residential (R-4)**													
10	Number of Bills	1,110	1,110	2,220	$6.00	$6,660	$6.00	$6,660	$13,320	$8.50	$9,435	$8.50	$9,435	$18,870
11	Distribution Charges	44,700	15,800	60,500	$0.21768	$9,730	$0.19350	$3,057	$12,788	$0.26141	$11,685	$0.23723	$3,748	$15,433
12	**Total Residential (R-4) Margin**					$16,390		$9,717	$26,108		$21,120		$13,183	$34,303
13	**PGA**					$25,101		$8,721	$33,823		$25,101		$8,721	$33,823
14	**Total Revenues**					$41,492		$18,439	$59,930		$46,221		$21,905	$68,126
													Increase	**$8,196**
													Percent	**13.7%**

Chattanooga Gas Company
Base Revenue and Total Revenue at Present and Proposed Rates

Line No.	Description	Post Test Year Billing Units Winter Nov-April	Summer May-Oct	Total	Present Winter Rates Nov - April Rate	Revenue	Present Summer Rates May - Oct Rate	Revenue	Present Total Revenue	Proposed Winter Rates Nov - April Rate	Revenue	Proposed Summer Rates May - Oct Rate	Revenue	Proposed Total Revenue
	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)	(l)	(m)	(n)
1	**Commercial (C-1)**													
2	Number of Bills	40,871	39,237	80,107	$29.00	$1,185,251	$25.00	$980,918	$2,166,169	$39.00	$1,593,959	$35.00	$1,373,286	$2,967,244
3	Distribution Charges	6,736,217	862,087	7,598,303	$0.18581	$1,251,656	$0.14589	$125,770	$1,377,426	$0.22678	$1,527,639	$0.18686	$161,090	$1,688,729
4	**Total Commercial (C-1) Margin**					$2,436,908		$1,106,688	$3,543,596		$3,121,598		$1,534,375	$4,655,973
5	**PGA**					$3,787,290		$475,930	$4,263,220		$3,787,290		$475,930	$4,263,220
6	**Total Revenues**					$6,224,198		$1,582,618	$7,806,816		$6,908,888		$2,010,305	$8,919,193
7													**Increase**	**$1,112,377**
8													**Percent**	**14.2%**
9	**Commercial (C-2)**													
10	Number of Bills	10,638	10,520	21,158	$75.00	$797,842	$75.00	$788,992	$1,586,835	$75.00	$797,842	$75.00	$788,992	$1,586,835
11	DDDC (Firm) Demand (C-2) in Dths	180,098	178,101	358,200	$5.50	$990,540	$5.50	$979,558	$1,970,098	$7.00	$1,260,687	$7.00	$1,246,710	$2,507,397
12	Distribution Charges													
13	0 - 3000 therms	14,275,855	5,380,306	19,656,160	$0.18744	$2,675,866	$0.14717	$791,820	$3,467,686	$0.19837	$2,831,901	$0.15810	$850,626	$3,682,528
14	3,001 - 5,000 therms	2,086,675	559,979	2,646,654	$0.17109	$357,009	$0.11683	$65,422	$422,432	$0.18202	$379,817	$0.12776	$71,543	$451,360
15	5,001 - 15,000 therms	2,488,428	738,226	3,226,654	$0.16666	$414,721	$0.10892	$80,408	$495,129	$0.17759	$441,920	$0.11985	$88,476	$530,396
16	over 15,000 therms	1,133,944	237,597	1,371,541	$0.08623	$97,780	$0.08623	$20,488	$118,268	$0.09716	$110,174	$0.09716	$23,085	$133,259
17	Revenue Adjustment					-$1,357		-$1,357	-$2,714		-$1,357		-$1,357	-$2,714
18	**Total Commercial (C-2) Margin**					$5,332,402		$2,725,331	$8,057,733		$5,820,985		$3,068,076	$8,889,061
19	**PGA**					$8,086,537		$3,647,025	$11,733,563		$8,086,537		$3,647,025	$11,733,563
20	**Total Revenues**					$13,418,940		$6,372,356	$19,791,296		$13,907,522		$6,715,101	$20,622,623
													Increase	**$831,327**
													Percent	**4.2%**

Chattanooga Gas Company
Base Revenue and Total Revenue at Present and Proposed Rates

Line No.	Description	Post Test Year Billing Units Winter Nov-April	Summer May-Oct	Total	Present Winter Rates Nov - April Rate	Revenue	Present Summer Rates May - Oct Rate	Revenue	Present Total Revenue	Proposed Winter Rates Nov - April Rate	Revenue	Proposed Summer Rates May - Oct Rate	Revenue	Proposed Total Revenue
	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)	(l)	(m)	(n)
1	**Commercial Transportation (T-3)**													
2	Number of Bills	270	270	540	$75.00	$20,250	$75.00	$20,250	$40,500	$75.00	$20,250	$75.00	$20,250	$40,500
3	DDDC (Firm) Demand (T-3) in Dths	39,654	39,654	79,309	$5.50	$218,099	$5.50	$218,099	$436,199	$7.00	$277,581	$7.00	$277,581	$555,162
4	Distribution Charges													
5	0 - 3000 therms	772,070	664,990	1,437,060	$0.18744	$144,717	$0.14717	$97,867	$242,583	$0.19837	$153,156	$0.15810	$105,135	$258,290
6	3,001 - 5,000 therms	422,440	302,720	725,160	$0.17109	$72,275	$0.11683	$35,367	$107,642	$0.18202	$76,893	$0.12776	$38,676	$115,568
7	5,001 - 15,000 therms	1,335,740	844,880	2,180,620	$0.16666	$222,614	$0.10892	$92,024	$314,639	$0.17759	$237,214	$0.11985	$101,259	$338,473
8	over 15,000 therms	969,420	308,280	1,277,700	$0.08623	$83,593	$0.08623	$26,583	$110,176	$0.09716	$94,189	$0.09716	$29,952	$124,141
9	Revenue Adjustment													$0
10	**Total Commercial Transportation (T-3) Margin**					$761,549		$490,190	$1,251,739		$859,282		$572,853	$1,432,135
11	**PGA**					$243,581		$243,582	$487,163		$243,581		$243,582	$487,163
12	**Total Revenues**					$1,005,130		$733,772	$1,738,902		$1,102,863		$816,434	$1,919,298
13													**Increase**	**$180,396**
14													**Percent**	**10.4%**
15	**Total Firm Revenues**													
16	Margin Revenues								$27,211,534					$33,842,771
17	PGA Revenues								$37,092,868					$37,092,868
18	**Total**								**$64,304,403**					**$70,935,639**

Chattanooga Gas Company
Base Revenue and Total Revenue at Present and Proposed Rates

Line No.	Description	Post Test Year Billing Units Winter Nov-April	Summer May-Oct	Total	Present Winter Rates Nov - April Rate	Revenue	Present Summer Rates May - Oct Rate	Revenue	Present Total Revenue	Proposed Winter Rates Nov - April Rate	Revenue	Proposed Summer Rates May - Oct Rate	Revenue	Proposed Total Revenue
	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)	(l)	(m)	(n)
1	**Industrial Transport with Full Standby (F-1/T-2)**													
2	Number of Bills	198	198	396	$300.00	$59,400	$300.00	$59,400	$118,800	$300.00	$59,400	$300.00	$59,400	$118,800
3	DDDC (Firm) Demand (T-2) in Dths	70,745	70,745	141,491	$5.50	$389,100	$5.50	$389,100	$778,199	$7.00	$495,218	$7.00	$495,218	$990,436
4	Distribution Charges													
5	0 - 15,000 therms	2,792,390	2,522,550	5,314,940	$0.08064	$225,178	$0.08064	$203,418	$428,597	$0.08086	$225,793	$0.08086	$203,973	$429,766
6	15,001 - 40,000 therms	3,242,150	2,753,070	5,995,220	$0.06891	$223,417	$0.06891	$189,714	$413,131	$0.06913	$224,130	$0.06913	$190,320	$414,450
7	40,001 - 150,000 therms	4,866,780	4,134,220	9,001,000	$0.03908	$190,194	$0.03908	$161,565	$351,759	$0.03930	$191,264	$0.03930	$162,475	$353,739
8	over 150,000 therms	1,141,360	1,062,530	2,203,890	$0.02402	$27,415	$0.02402	$25,522	$52,937	$0.02424	$27,667	$0.02424	$25,756	$53,422
9	Revenue Adjustment													$0
10	**Total Industrial Transport with Full Standby Margin**					$1,114,704		$1,028,719	$2,143,423		$1,223,471		$1,137,141	$2,360,613
11	**PGA**					$557,127		$557,127	$1,114,254		$557,127		$557,127	$1,114,254
12	**Total Revenues**					$1,671,831		$1,585,847	$3,257,677		$1,780,598		$1,694,269	$3,474,867
13													**Increase**	**$217,190**
14													**Percent**	**6.7%**
15	**Industrial Transport with Partial Standby (F-1/T-2+T-1)**													
16	Number of Bills	84	84	168	$300.00	$25,200	$300.00	$25,200	$50,400	$300.00	$25,200	$300.00	$25,200	$50,400
17	Demand in Dths													
	DDDC (Firm) Demand (T-2)	25,044	25,044	50,088	$5.50	$137,742	$5.50	$137,742	$275,484	$7.00	$175,308	$7.00	$175,308	$350,616
18	Capacity (Non-Firm) Demand (T-1)	25,794	25,794	51,588	$1.35	$34,822	$1.35	$34,822	$69,644	$1.75	$45,140	$1.75	$45,140	$90,279
19	Total Demand													
20	Distribution Charges													
21	0 - 15,000 therms	1,168,600	1,150,510	2,319,110	$0.08064	$94,236	$0.08064	$92,777	$187,013	$0.08086	$94,493	$0.08086	$93,030	$187,523
22	15,001 - 40,000 therms	1,649,470	1,493,390	3,142,860	$0.06891	$113,665	$0.06891	$102,910	$216,574	$0.06913	$114,028	$0.06913	$103,238	$217,266
23	40,001 - 150,000 therms	3,587,940	3,166,980	6,754,920	$0.03908	$140,217	$0.03908	$123,766	$263,982	$0.03930	$141,006	$0.03930	$124,462	$265,468
24	over 150,000 therms	3,025,290	2,725,510	5,750,800	$0.02402	$72,667	$0.02402	$65,467	$138,134	$0.02424	$73,333	$0.02424	$66,066	$139,399
25	Revenue Adjustment													$0
26	**sub-Total Industrial Transport with Partial StandbyMargin**					$618,549		$582,683	$1,201,232		$668,507		$632,444	$1,300,952
27	**PGA**					$197,224		$197,224	$394,448		$197,224		$197,224	$394,448
28	**Total Revenues**					$815,773		$779,907	$1,595,680		$865,731		$829,668	$1,695,400
29													**Increase**	**$99,720**
30													**Percent**	**6.2%**
31	**Total Transport with Standby Revenues**													
32	Margin Revenues								$3,344,655					$3,661,565
33	PGA Revenues								$1,508,702					$1,508,702
34	**Total**								**$4,853,357**					**$5,170,267**

Chattanooga Gas Company
Base Revenue and Total Revenue at Present and Proposed Rates

Line No.	Description	Post Test Year Billing Units Winter Nov-April	Summer May-Oct	Total	Present Winter Rates Nov - April Rate	Revenue	Present Summer Rates May - Oct Rate	Revenue	Present Total Revenue	Proposed Winter Rates Nov - April Rate	Revenue	Proposed Summer Rates May - Oct Rate	Revenue	Proposed Total Revenue
	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)	(l)	(m)	(n)
1	**Interruptible Sales (I-1)**													
2	Number of Bills	6	6	12	$300.00	$1,800	$300.00	$1,800	$3,600	$300.00	$1,800	$300.00	$1,800	$3,600
3	Distribution Charges													
4	0 - 15,000 therms	90,000	90,000	180,000	$0.08064	$7,258	$0.08064	$7,258	$14,515	$0.08086	$7,277	$0.08086	$7,277	$14,555
5	15,001 - 40,000 therms	109,240	140,930	250,170	$0.06891	$7,528	$0.06891	$9,711	$17,239	$0.06913	$7,552	$0.06913	$9,742	$17,294
6	40,001 - 150,000 therms	0	19,810	19,810	$0.03908	$0	$0.03908	$774	$774	$0.03930	$0	$0.03930	$779	$779
7	over 150,000 therms	0	0	0	$0.02402	$0	$0.02402	$0	$0	$0.02424	$0	$0.02424	$0	$0
8	Revenue Adjustment													$0
9	**Total Interruptible Sales (I-1) Margin**					$16,585		$19,543	$36,129		$16,629		$19,598	$36,228
10	**PGA**					$84,867		$102,070	$186,937		$84,867		$102,070	$186,937
11	**Total Revenues to Customer**					$101,452		$121,613	$223,065		$101,496		$121,668	$223,164
12													**Increase**	**$99**
13													**Percent**	**0.0%**
14	**Interruptible Industrial Transportation (T-1)**													
15	Number of Bills	102	102	204	$300.00	$30,600	$300.00	$30,600	$61,200	$300.00	$30,600	$300.00	$30,600	$61,200
16	Capacity (Non-Firm) Demand (T-1)	53,251	53,251	106,501	$1.35	$71,888	$1.35	$71,888	$143,777	$1.75	$93,189	$1.75	$93,189	$186,377
17	Distribution Charges													
18	0 - 15,000 therms	1,446,260	1,530,000	2,976,260	$0.08064	$116,626	$0.08064	$123,379	$240,006	$0.08086	$116,945	$0.08086	$123,716	$240,660
19	15,001 - 40,000 therms	1,976,690	2,139,540	4,116,230	$0.06891	$136,214	$0.06891	$147,436	$283,649	$0.06913	$136,649	$0.06913	$147,906	$284,555
20	40,001 - 150,000 therms	2,799,980	2,645,680	5,445,660	$0.03908	$109,423	$0.03908	$103,393	$212,816	$0.03930	$110,039	$0.03930	$103,975	$214,014
21	over 150,000 therms	3,257,050	3,329,510	6,586,560	$0.02402	$78,234	$0.02402	$79,975	$158,209	$0.02424	$78,951	$0.02424	$80,707	$159,658
22	Revenue Adjustment													
23	**sub-Total Interruptible Industrial Transport Margin**					$542,986		$556,671	$1,099,657		$566,372		$580,093	$1,146,465
24													**Increase**	**$46,808**
25													**Percent**	**4.3%**
26	**Total Interruptible Revenues**													
27	Margin Revenues								$1,135,786					$1,182,693
28	PGA Revenues								$186,937					$186,937
29	**Total**								**$1,322,723**					**$1,369,630**

Chattanooga Gas Company
Base Revenue and Total Revenue at Present and Proposed Rates

Line No.	Description	Post Test Year Billing Units Winter Nov-April	Summer May-Oct	Total	Present Winter Rates Nov - April Rate	Revenue	Present Summer Rates May - Oct Rate	Revenue	Present Total Revenue	Proposed Winter Rates Nov - April Rate	Revenue	Proposed Summer Rates May - Oct Rate	Revenue	Proposed Total Revenue
	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)	(l)	(m)	(n)
1	**Total All Classes**													
2	Margin Revenues								$31,691,975					$38,687,028
3	PGA Revenues								$38,788,507					$38,788,507
4	**Total**								**$70,480,482**					**$77,475,535**
5	**Other Revenues**													
6	Miscellaneous Revenues								$612,767					$639,630
7	Special Contract Revenues								$143,018					$143,018
8	**Total**								$755,785					$782,648
9	**TOTAL COMPANY**								**$71,236,267**					**$78,258,183**
10													**Total Increase**	**$7,021,916**

Prior Testimony of
Daniel P. Yardley

Jurisdiction	Sponsor	Year	Topics	Docket
Federal Energy Regulatory Commission	Northern Distributor Group	1992	Cost of Service and Cost Allocation	RP92-1
	Northern Distributor Group	1995	Cost of Service and Rate Design	RP95-185
	Atlanta Gas Light, et al.	2001	Storage Cost Allocation	RP01-245
	Bay State Gas and Northern Utilities	2002	Rate Design	RP02-13
Florida	Peoples Gas System	2008	Cost Allocation and Rate Design	Docket No. 080318-GU
Illinois	Nicor Gas	2017	Cost Allocation and Rate Design	Docket No. 17-00124
New Hampshire	Northern Utilities	2005	Jurisdictional Gas Cost Allocation	DG05-080
Massachusetts	Bay State Gas	1998	Capacity Assignment	D.T.E. 98-32
	Bay State Gas	2001	Contract Approval	D.T.E. 00-99
	Bay State Gas	2006	Declining Use Rate Adjustment	D.T.E. 06-77
	Bay State Gas	2007	Declining Use Rate Adjustment	D.P.U. 07-89
	Bay State Gas	2009	Revenue Decoupling	D.P.U. 09-30
National Energy Board of Canada	Alberta Northeast Gas, Ltd.	2012	TransCanada Pipeline Service Restructuring and Tolls	RH-3-2011
	Alberta Northeast Gas, Ltd.	2013	TransCanada Pipeline Shipper Renewal Rights	RH-1-2013
	Alberta Northeast Gas, Ltd.	2014	TransCanada Pipeline Service Service and Toll Design	RH-1-2014
New Jersey	New Jersey Natural Gas	1999	Rate Unbundling	Docket No. GO99030123
	Elizabethtown Gas, *et al.*	1999	Customer Account Services	Docket No. EX99090676
	Elizabethtown Gas	2002	Cost Allocation and Rate Design	Docket No. GR02040245
	South Jersey Gas Company	2003	Cost Allocation and Rate Design	Docket No. GR03080683
	South Jersey Gas Company	2004	Capacity Charge	Docket No. GR04060400
	New Jersey Natural Gas	2005	Revenue Decoupling	Docket No. GR0512020
	South Jersey Gas Company	2005	Revenue Decoupling	Docket No. GR0512019
	South Jersey Gas Company	2007	Annual Decoupling Adjustment	Docket No. GR07060354

Prior Testimony of
Daniel P. Yardley

Jurisdiction	Sponsor	Year	Topics	Docket
New Jersey *cont.*	New Jersey Natural Gas	2007	Cost Allocation and Rate Design	Docket No. GR07110889
	South Jersey Gas Company	2008	Annual Decoupling Adjustment	Docket No. GR08050367
	Elizabethtown Gas	2009	Revenue Decoupling, Cost Allocation and Rate Design	Docket No. GR09030195
	South Jersey Gas Company	2009	Annual Decoupling Adjustment	Docket No. GR09060340
	South Jersey Gas Company	2009	Cost Allocation and Rate Design	Docket No. GR10010035
	New Jersey Natural Gas	2010	Energy Efficiency Cost Recovery	Docket No. GR10030225
	South Jersey Gas Company	2011	Annual Decoupling Adjustment	Docket No. GR11060337
	New Jersey Natural Gas	2011	Energy Efficiency Cost Recovery	Docket No. GR11070425
	South Jersey Gas Company	2012	Annual Decoupling Adjustment	Docket No. GR12060475
	New Jersey Natural Gas	2012	Energy Efficiency Cost Recovery	Docket No. GR12070640
	New Jersey Natural Gas and South Jersey Gas Company	2013	Revenue Decoupling	Docket No. GR13030185
	South Jersey Gas Company	2013	Annual Decoupling Adjustment	Docket No. GR13050434
	South Jersey Gas Company	2013	Cost Allocation and Rate Design	Docket No. GR13111137
	South Jersey Gas Company	2014	Annual Decoupling Adjustment	Docket No. GR14050510
	New Jersey Natural Gas	2014	Energy Efficiency Cost Recovery	Docket No. GO14121412
	South Jersey Gas Company	2015	Annual Decoupling Adjustment	Docket No. GR15060642
	Elizabethtown Gas	2015	Infrastructure Cost Recovery	Docket No. GR15091090
	New Jersey Natural Gas	2015	Cost Allocation and Rate Design	Docket No. GR15111304
	South Jersey Gas Company	2016	Annual Decoupling Adjustment	Docket No. GR16060483
	Elizabethtown Gas	2016	Cost Allocation and Rate Design	Docket No. GR16090826
	South Jersey Gas Company	2017	Cost Allocation and Rate Design	Docket No. GR17010071
	South Jersey Gas Company	2016	Annual Decoupling Adjustment	Docket No. GR17060586
North Carolina	Piedmont Natural Gas Company	2011	Cost Allocation and Rate Design	Cocket No. G-9, Sub. 631

Prior Testimony of
Daniel P. Yardley

Jurisdiction	Sponsor	Year	Topics	Docket
Rhode Island	Providence Gas Company	1996	Cost Allocation and Rate Design	Docket No. 2076
Tennessee	Chattanooga Gas Company	2009	Revenue Decoupling, Cost Allocation and Rate Design	Docket No. 09-00183
	Piedmont Natural Gas Company	2011	Cost Allocation and Rate Design	Docket No. 11-00144
Wisconsin	Wisconsin Power and Light	2001	Cost Allocation and Rate Design	Docket No. 6680-UR-111