IN THE TENNESSEE PUBLIC UTILITY COMMISSION
AT NASHVILLE, TENNESSEE

IN RE:	)	
	)	
PETITION OF PIEDMONT NATURAL GAS COMPANY, INC. FOR APPROVAL OF ITS 2025 ANNUAL REVIEW OF RATES MECHANISM PURSUANT TO TENN. CODE ANN. § 65-5-103(d)(6)	)	**DOCKET NO. 25-00036**
	)	

DIRECT TESTIMONY

OF

CLARK D. KAML

August 6, 2025

Public Version

Table of Contents

I. INTRODUCTION

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

A1. My name is Clark Kaml. My business address is the Office of the Tennessee Attorney General, John Sevier State Office Building, 500 Dr. Martin L. King Jr. Blvd, Nashville, Tennessee 37243. I am a Financial Analyst employed by the Consumer Advocate Division in the Office of the Tennessee Attorney General ("Consumer Advocate").

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

A2. I received a Bachelor of Science Degree in Economics from the University of North Dakota in 1987 and a Master of Arts Degree in Economics from the University of North Dakota in 1988. I have more than 30 years of experience working in the regulated utilities industries including electric, natural gas, telephone, and water. I have worked for various agencies including the Public Service Commission of North Dakota, the Kansas Corporation Commission, the Minnesota Public Utilities Commission, the Minnesota Office of the Attorney General, and the Grant County Public Utility District. In addition, I have worked with private companies, municipalities, and served on a Rate Committee. I have served as Co-Chair of the National Association of State Utility Commissioners ("NARUC") Staff Subcommittee on Strategic Issues and as Co-Chair of the National Association of State Utility Consumer Advocates ("NASUCA") Gas Committee.

Q3. HAVE YOU PREVIOUSLY PROVIDED TESTIMONY BEFORE THE TENNESSEE PUBLIC UTILITY COMMISSION ("TPUC" OR THE "COMMISSION")?

A3. Yes. I filed testimony in the Tennessee-American Water Company's recent rate case, TPUC Docket No. 24-00032, the Limestone Water Utility Operating Company's recent rate case, TPUC Docket No. 24-00044, and Chattanooga Gas Company's Annual Rate Review, TPUC Docket No. 25-00028.

Q4. ON WHOSE BEHALF ARE YOU TESTIFYING?

A4. I am testifying on behalf of the Consumer Advocate Division.

Q5. WHAT IS THE SCOPE OF YOUR REVIEW IN THIS PROCEEDING?

A5. My testimony will discuss the following Consumer Advocate's review and recommendations with respect to the 2025 Annual Rate Review Mechanism Petition ("ARM" or the "Petition") filed by Piedmont Natural Gas Company, Inc. ("Piedmont" or the "Company") to adjust its rates and charges:

a. Operating and Expense Adjustments;
b. Intra-Class Rate Design:
c. Cost Studies and Cross Subsidies; and
d. Customer Bills.

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

A6. I have reviewed the Company's Pre-Filed Testimony along with the exhibits and workpapers filed with the Company's Petition. I have reviewed previous ARM Petitions, Commission Orders, and the Settlement Agreements in TPUC Docket

No. 21-00135. Additionally, I have reviewed the Company's discovery responses to the Consumer Advocate's discovery requests issued and filed in this Docket.

II. EXECUTIVE SUMMARYAND RECOMMENDATIONS

Q7. WHAT ARE YOUR RECOMMENDATIONS?

A7. I am recommending:

- Operating and maintenance expenses be adjusted by [redacted] to remove [redacted] associated with chamber of commerce fees and American Gas Association ("AGA") fees.
- Piedmont's assertion that its cost study demonstrates that the cross-subsidies exist be denied.
- In future filings, Piedmont:
    - Provide and discuss specifically in testimony all proposed rate structure changes, including intra-rate class allocations.
    - Provide a comparison of the rates approved in TPUC Docket No. 21-00135 and the pending ARM's proposed rates, and an analysis of the change(s) from TPUC Docket No. 21-00135 to the pending ARM's proposed rates and revenue requirement in the percentage of revenue contribution from each rate class.
- The Commission take note of the rate design changes that have occurred through the ARM.
- The Commission require Piedmont to provide more rate and price details on its bill, or in the alternative, to provide a direct link on the bill to a web page that will break down the customer's bill in detail.

Q8. CAN YOU PROVIDE A BRIEF DISCUSSION OF THE OVERALL PURPOSE OF AN ARM?

A8. In general, an alternative ratemaking mechanism is intended to provide a more streamlined option to traditional cost of service ratemaking processes while meeting traditional regulatory objectives of just and reasonable rates. In theory, alternative ratemaking mechanisms aim to be less burdensome and costly than traditional rate regulation and may enable a company to be more responsive to changing goals and needs of the company and the community.

Q9. WHAT IS THE ARGUMENT THAT PIEDMONT'S ARM MEETS THIS GOAL OF BEING LESS BURDENSOME AND COSTLY?

A9. Piedmont's ARM design was agreed to in a Stipulation and Settlement Agreement between the Consumer Advocate and the Company in TPUC Docket No. 21-00135.[1] As designed, the ARM allows the Company to annually adjust its revenue requirement and revenue recovery outside of a traditional rate case proceeding, subject to certain formulas and criteria based on the rulings established in the Company's last general rate case.

Whether an ARM is considered less burdensome and costly depends on perspective. ARM proceedings may streamline the revenue requirement process and reduce the regulatory lag for companies.

Q10. IS THERE AN ARGUMENT THAT ARMS ARE NOT LESS BURDENSOME AND COSTLY?

A10. Customers and consumer groups often argue that automatic adjustment mechanisms have negative impacts on consumers. It is argued that many ARMs shift risk to consumers or that consumers do not benefit from ARMs. As noted by the National Regulatory Research Institute:

> [R]atemaking is as much an art as a science, requiring regulators to impute their subjective values and judgment in decision making. Analysts can play an important role, however, by providing regulators with vital information on the inevitable tradeoffs among the various

[1] *Order Approving Amended Annual Review of Rates Mechanism, In re: Petition of Piedmont Natural Gas Company, Inc. to Adopt an Annual Review of Rates Mechanism Pursuant to Tenn. Code Ann. § 65-5-103(d)(6),* TPUC Docket No. 21-00135 (November 1, 2022).

> objectives that they assign to ratemaking.
>
> Some alternative rate mechanisms might result in all stakeholders being better off. At least in theory, if they result in a net efficiency gain, all parties can benefit, although in practice, politically and administratively, it may be difficult to prevent losers.[2]

III. O&M ADJUSTMENTS

Q11. HAVE YOU QUANTIFIED THE REVENUE REQUIREMENT IMPACTS OF THE O&M ADJUSTMENTS YOU ARE SPONSORING?

A11. Yes. The O&M adjustments that I am recommending are identified on Confidential Exhibit CDK-1. The total expense adjustment is $200,153 as shown on line 4.

Q12. YOUR FIRST TWO ADJUSTMENTS ARE FOR ORGANIZATIONAL DUES AND FEES. BRIEFLY EXPLAIN ORGANIZATIONAL DUES AND FEES.

A12. Organization dues are payments made to belong to a specific membership-based organization or association. The costs for membership in the organizations (along with donations made to the organization) are often disputed due to lack of transparency, concerns over the extent to which the funds are used for lobbying and political advocacy, and questions regarding evidence that the costs benefit customers.

Q13. HOW ARE THE ENTITIES IN THE FIRST TWO ADJUSTMENTS ORGANIZED?

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[2] Ken Costellow, NRRI: Alternative Rate Mechanisms and Their Compatibility with State Utility Commission Objectives, Report No. 14-03, at 83 (April 2014).

A13. The chamber of commerce[3] and the AGA[4] are classified as 501(c)(6) organizations under the Internal Revenue Code.[5] These entities are non-profit organizations with goals that include the promotion of business interests.[6]

Q14. WHAT IS YOUR FIRST RECOMMENDATION?

A14. O&M adjustment No. 1 removes [redacted] for fees and dues for Chambers of Commerce.

Q15. HOW DID YOU DETERMINE THE AMOUNT YOU ARE RECOMMENDING BE DISALLOWED?

A15. The expenses are provided in the Petition's File <Schedule 52Q_Miscellaneous O&M Adjustments_CONFIDENTIAL>, Tabs "52.Q.2.2024", and "52.Q.3.2024". The values were confirmed in the Company's Confidential Response to the Consumer Advocate's DR Nos. 1-47 and 1-48 (attached as Confidential Exhibit CDK-2 and Confidential Exhibit CDK-3.)

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[3] United States Internal Revenue Service, Exemption requirements: Business Leagues, https://www.irs.gov/charities-non-profits/other-non-profits/requirements-for-exemption-business-league (last visited August 4, 2025). "Chambers of commerce and boards of trades are of the same class as business leagues, but rather than promoting one or more lines of business, their efforts are directed to promoting the common economic interests of all commercial enterprises in a given trade community." *Id.*

[4] *Id.* "A business league is an association of persons having some common business interest, the purpose of which is to promote such common interest and not to engage in a regular business of a kind ordinarily carried on for profit. To be exempt as a business league, an organization's activities must be devoted to improving business conditions of one or more lines of business (as distinguished from performing particular services for individual persons). It must be shown that the conditions of a particular trade or the interests of the community will be advanced." *Id.*

[5] United States Internal Revenue Service, Tax Exempt Organization Search, https://apps.irs.gov/app/eos/ (last visited August 4, 2025).

[6] United States Internal Revenue Service, Business Leagues, https://www.irs.gov/charities-non-profits/other-non-profits/business-leagues#:~:text=Section%20501(c)(6,professional%20associations%20are%20business%20leagues. (last visited August 4, 2025). "Section 501(c)(6) of the Internal Revenue Code provides for the exemption of business leagues, chambers of commerce, real estate boards, boards of trade and professional football leagues, which are not organized for profit and no part of the net earnings of which inures to the benefit of any private shareholder or individual." *Id.*

Q16. WHY IS THIS ADJUSTMENT NECESSARY?

A16. Chamber of Commerce dues are a form of contribution to a non-profit organization that is not essential to the provision of natural gas services and does not directly benefit Piedmont's customers. The decision to belong to a chamber of commerce, and therefore the associated membership cost, is a discretionary decision by and for the corporation without a demonstrable benefit to ratepayers. These costs may serve corporate goals and initiatives but are not necessary in the provision of natural gas service. This point is noticeable in Piedmont's Response to the Consumer Advocate DR No. 1-47 that states:

[redacted]

[redacted]

The benefits listed above are benefits to the Company. To the extent that the membership and costs are beneficial to Piedmont's ratepayers, the decision to make such contributions should be made by the individual customers based on their individual preferences and values. Those contributions should not be made on behalf of captive customers without their input. The goals of shareholders and capital investors may not be aligned regarding legislation, regulation, and economics. Ratepayers should not be required to pay for costs designed to meet corporate goals or objectives that either support the interests of shareholders or are explicitly at odds with customers' interests.

There has been no demonstration that these costs are necessary to or directly benefit natural gas customers; therefore, they should not be recovered in rates from consumers.

Q17. IS YOUR ADJUSTMENT CONSISTENT WITH COMMISSION PRECEDENT REGARDING THE TEATMENT OF SUCH EXPENSES?

A17. Yes. The Commission has previously held with respect to Tennessee American Water Company ("TAWC"):

> The Commission voted unanimously to disallow the Chamber of Commerce and STEM donations totaling $45,000. The panel found that while these donations may have indirectly contributed to economic growth in the Company's service territory, these donations are not the type of "expansion of infrastructure" that is contemplated by the statute. Further, disallowance of these donations is consistent with the [Commission's] long-standing policy of disallowing charitable contributions and donations for ratemaking purposes as they do not satisfy the guiding principle of necessity and reasonableness, nor is it apparent that they provide a clear benefit to ratepayers. As a result of its decision regarding these donations, the panel voted unanimously that TAWC be required to file amended calculations and tariffs consistent with the panel's decision for the EDI Rider.[7]

In another docket, the Commission rejected a utility's proposed recovery of $37,540 in Miscellaneous Expenses for donations to the civic, community and charitable organizations of Chattanooga and Cleveland, Tennessee.[8] The Commission explained it is Order:

> A majority of the [Commissioners] found that accounting principles and standards under which regulated companies operate generally will not support charitable contributions in a rate case. The majority concluded that such a finding is consistent with the [Commission's] position in the Nashville Gas case although charitable contributions were voluntarily withdrawn. A majority of the Directors concluded that this was an inappropriate recovery, and adopted the Advocate's position in which

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[7] *Order Granting In Part, and Denying In Part, Petition*, 14-15, TRA Docket No. 14-00121 (February 1, 2016).

[8] *Order*, at 42-43, TRA Docket No. 97-00982 (October 7, 1998). This docket is no longer found on the TPUC Docket Page; therefore, a copy of the order is attached as *CA Attachment 1.*

Miscellaneous Expenses in the determination of Net Operating Income were excluded.[9]

Q18. WHAT IS YOUR SECOND ADJUSTMENT?

A18. Adjustment No. 2 is necessary to eliminate [redacted] in allocated American Gas Association ("AGA") membership fees. The invoice was originally recorded on two different schedules. In its Response, Piedmont stated that: [10]

[redacted]

Q19. WHY ARE YOU RECOMMENDING THAT THESE EXPENSES BE EXCLUDED?

A19. The AGA is a trade organization representing and advocating on behalf of energy companies. The AGA's membership categories are as follows:[11]

- U.S. Energy Utilities: U.S. natural gas distribution companies and their corporate parents.
- Transmission and Marketing Companies: U.S. natural gas transmission companies; Canadian and Mexican natural gas distribution and transmission companies; and natural gas marketers, brokers and gatherers.
- Exploration and Production Companies: Companies involved in the extracting and production of natural gas and liquified natural gas companies
- Products and Services Companies: Suppliers; consultants; professionals in the operating, financial, marketing and legal communities; and others who provide products or services to the natural gas industry.
- International Energy Companies and Affiliates: Utilities or other

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9 *Id.*

10 *Petition*, File <Schedule 52QMiscellaneous O&M Adjustments_CONFIDENTIAL.xlsx>, Tabs "52.A.2.2024" and "52.Q3.2024" and the Company's CONFIDENTIAL Response to Consumer Advocate DR No. 1-48.

11 American Gas Association, About AGA, Become An AGA Member, Membership, https://www.aga.org/about/me mbership/ (last visited August 4, 2025).

entities outside North America interested in international gas activities.

- Industry Associates – Associations or organizations affiliated with the natural gas industry.

Membership dues for natural gas utility companies are calculated based on operating income.[12]

Q20. IS THERE EVIDENCE THAT THE ORGANIZATION ENGAGES IN LOBBYING?

A20. Yes. The AGA's website affirms that it is an organization engaged in lobbying, legislation, and regulation at the state and federal level. Lobbying activity is confirmed in the Response to Consumer Advocate DR No. 1-48 Confidential Attachment (Confidential Exhibit CDK-4.) Regarding the specific importance of rate regulation, the AGA states:

> The State Affairs Committee is the association's committee responsible for analyzing industry rate issues and state economic regulatory trends. The committee develops information on matters pertaining to rate of return, rate base, rate design, revenue requirements, rate administration, rate case presentations, the impact of rates on load growth and financial results and the analysis of trends in innovative rate structures. The committee identifies current ratemaking concepts and helps member companies develop and share new strategies to influence change in state economic regulatory policies and programs.[13]

Additionally, the website states that membership works to "protect the interest of the natural gas industry."[14] The protection of only industry interests is compounded by the fact that access to much of the AGA's analysis and comments by non-

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[12] American Gas Association, About AGA, Become An AGA Member, Membership, Categories, U.S. Energy Utilities Membership (form), https://www.aga.org/wp-content/uploads/2025/01/Estimate-Application-for-U.S.-Energy-Utilitie_Larry-Douglas-1.pdf (last visited August 4, 2025).

[13] American Gas Association, Research & Policy, Policy: State, Rates and Regulatory, https://www.aga.org/research-policy/regulatory/ (last visited August 4, 2025).

[14] American Gas Association, About AGA, Become An AGA Member, Membership, https://www.aga.org/about/membership/ (last visited August 4, 2025).

members, such as the Company's customers, is limited. Allowing AGA membership costs would directly result in ratepayers subsidizing political and regulatory activities with which they may not agree and that may be contradictory to the consumers' interests because they protect industry interests.

Expenses recovered from consumers should have a clear benefit to customers and should be transparent.[15] In Response to the Consumer Advocate DR No. 1-48, which requested a copy of the AGA Budget for 2024 and for the percentage of AGA expenditures associated with the promotion of natural gas, Piedmont stated [redacted] therefore, it cannot reasonably assert that such fees have any clear benefit to consumers.

Q21. WHAT IS YOUR CONCLUSION AND RECOMMENDATION?

A21. Because the Company is unable to identify how the membership fees are utilized, it cannot say that such fees provide any cognizable benefit to its ratepayers. Additionally, consumers should not be forced to incur costs that potentially undermine consumer interests and goals. Therefore, these fees and dues should be excluded from rate recovery.

IV. INTRA-CLASS RATE DESIGN

Q22. IS THE ISSUE OF RATE DESIGN BEING ADDRESSED BY OTHER CONSUMER ADVOCATE WITNESSES?

[15] *Order Granting In Part, and Denying In Part, Petition*, 14-15, TRA Docket No. 14-00121 (February 1, 2016).

A22. Yes. Consumer Advocate witness William Novak is addressing the revenue requirement increase and allocation to the various customer classes.

Q23. WHAT ASPECTS OF RATE DESIGN DOES YOUR TESTIMONY ADDRESS?

A23. My testimony addresses intra-class revenue allocation and modifications to rates through the ARM result in changes to the rate design.

For purposes of transparence, and ease of customer understanding the rate changes resulting from the filing, those changes should be clearly identified and explained. Future applications should contain schedules, in the testimony, with line items for each rate, demonstrating the existing rate and the proposed rate.

Q24. WHAT IS RATE DESIGN?

A24. In a relatively recent publication NARUC provided the following comments on rate design within the context of electric rates:

> Rate design – the framework that utilities and regulators use to set prices for electricity services – is a fundamental element of a well-functioning electricity system. Rate design sits at the nexus between customers and utilities, determining the prices that customers pay for electricity and impacting the revenues that utilities raise to support commercial viability.[16]

While this definition is within the context of electric rates, the same basic concept applies to rate design across all utility types: that it is the determination of prices that customers pay for the good or service. For any given company, rate design

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16 *Primer on Rae Design for Cost-Reflective Tariffs,* National Association of Regulatory Utility Commissioners for review by the United States Agency for International Development, p. 6 (January 2021). A copy of this document is available at https://pubs.naruc.org/pub.cfm?id=7BFEF211-155D-0A36-31AA-F629ECB940DC.

represents the totality of the components of all charges and the prices that customers pay. Rate design is different from an individual customer's bill.

Q25. WHAT IS INTRA-CLASS RATE DESIGN?

A25. A fundamental question for a regulated utility is how to charge customers for service. This might include such components as monthly fixed charges, demand charges, energy or volumetric charges, block rates, and seasonal rates. In total, these components are considered the rate structure.

The establishment of the various components ("rate structure",) and charges that apply to each of these rates within a specific customer class are intra-class rate design. The two common components of rate structure are the monthly ("service") or ("customer") charge and the rate for the commodity, which is the price of the gas itself. The customer charge is usually a fixed cost, and the commodity charge is a volumetric, variable charge.

Q26. WHY IS THE ALLOCATION BETWEEN THE COMPONENTS AN IMPORTANT ISSUE?

A26. As explained above, the rate design is a determination of how the revenue requirement will be recovered. That has been, and continues to be, the focus of debate for decades due to numerous factors including policy, fairness, and risk. How the rates are set impacts a customer's ability to influence their monthly bill through behavior modification. Depending on individual needs, the rate design will impact customers differently.

The topics being addressed in this testimony are simply mathematical, and do not address socio-economic issues such as those mentioned above. The topics here are the allocation between fixed and variable costs, and impact on revenue requirement variation among classes.

Q27. GENERALLY, HOW ARE THE ALLOCATIONS OF RECOVERY FROM FIXED CHARGES AND THE RATE CHARGED TO VARIABLE CONSUMPTION IMPORTANT TO INDIVIDUAL CUSTOMERS?

A27. The method of how rates are set has a direct impact on the ability of the customer to control the bill, and thus, consumer behavior. If 100% of the revenue requirement for a class is spread equally over each customer, all customers would have the same monthly bill, regardless of use. The customer would not be able to change the bill and would have no incentive to monitor usage. Conversely, if 100% of the revenue requirement is recovered from rates applied to consumption, customers would have full control of the monthly bill. Those with little or no use would pay little or nothing. Customers have different rate design preferences based on various factors including ideology and lifestyle.

Q28. WHEN THE RATE INCREASE IS BEING ALLOCATED EQUALLY ACROSS ALL RATE CLASSES IN AN ARM FILING, WHY DOES ALLOCATION TO SPECIFIC RATE COMPONENTS REMAIN IMPORTANT?

A28. Rate design is the determination of how the revenue requirement will be recovered. While the allocation of a rate increases proportionately across all rate classes might be perceived as maintaining the existing rate design, that is not the case. If one component is modified at a different proportion than another, then the rate design has been altered. As a controversial topic, any modification should be a conscious decision and acknowledged.

Piedmont suggests that rate design is not being changed. In his testimony, Keith Goley states:[17]

> Piedmont is proposing the **same overall rate design, which includes fixed monthly charges, demand charges, and volumetric rates, for each rate schedule,** including step rates for Large General Service, which underlies its existing rates. This is the same rate design methodology that the TPUC approved in Piedmont's last general rate case proceeding and, in the Company's previous Annual ARM proceedings. (Emphasis added.)

Further, Mr. Goley states:[18]

> Piedmont proposes to allocate the margin revenue increase of $8,679,258 **evenly across all applicable Rate Schedules** such that the margin revenue **percentage increase is the same for all the customer classes**. **This approach aligns with Piedmont's rate design objectives** and a gradual move toward parity. (Emphasis added.)

These statements can easily be misinterpreted and be considered misleading. Mr. Goley later explains that the increase is being applied only to the volumetric portion of rates:[19]

> In order to effectuate the proposed increase of $8,679,258 for the Annual Base Rate Reset Revenue Requirement Deficiency, Piedmont proposes to change the base margin volumetric billing rates (the rates per therm) for each Applicable Rate Schedule, with the exception of Rate Schedule 310 – Resale Service (due to the absence of active customers on this Rate Schedule since February 2023).

Q29. WHY DO YOU CONSIDER THIS TESTIMONY MISLEADING?

A29. As stated, reading the testimony could reasonably believe that there would be

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17 *Direct Testimony of Keith Goley* at 6:13-18, TPUC Docket No. 25-00036 (May 20, 2025).

18 *Id.* at p. 8.

19 *Id.* at 6:20 – 7:2.

proportionate increases in all rates. An individual would need to have working knowledge of Piedmont's rate increases under its ARM, and a technical understanding of how rates have been changed, to understand that the following statements result only in an increase to variable rates:

- Piedmont is proposing the same overall rate design, which includes fixed monthly charges, demand charges, and volumetric rates, for each rate schedule,
- Piedmont proposes to allocate the margin revenue increase of $8,679,258 evenly across all applicable Rate Schedules,
- [The] revenue percentage increase is the same for all customer classes.

The rate design encompasses rates to recover the full revenue apportionment. This includes all rates, not select rates or components. While monthly rates remain the same, the volumetric component is changing. Thus, the rate modifies the rate design.

Piedmont's statements are technically correct. Understanding the implications of those statements is not clear. The practical implications should be emphasized.

Q30. WHY IS THIS DISTINCTION IMPORANT?

A30. A company's revenue requirement is a component of both fixed and variable costs. Each year, the change in the revenue requirement is some mix of the company's variable and fixed costs. The fixed, monthly service charge and the variable, volumetric rates charged to customers are not designed to specifically reflect the same fixed and variable costs experienced by the utility. These rates are designed with the goal of achieving the revenue requirement as a whole. To maintain the existing rate structure while achieving the goal of recovering the full revenue requirement, all revenue components, for all rate classes should be increased equally, ensuring equal revenue contribution increases.

Q31. HAS PIEDMONT EXPLAINED WHY THE RATE INCREASE IS APPLIED ONLY TO THE VOLUMETRIC COMPONENT?

A31. In Response to Consumer Advocate DR. No. 2-43 (Exhibit CDK-5) Piedmont stated:

> In compliance with Piedmont's TPUC-approved ARM Tariff (Service Schedule No. 318), the Base Margin Rates are defined as the volumetric rates per therm for each Applicable Rate Schedule (not the fixed monthly charges or other rate components for each Applicable Rate Schedule), and sets forth the Base Margin Rates as the appropriate rate components to be amended in accordance with the approved ABRR Revenue Requirement Deficiency (or Sufficiency) in each Annual ARM Filing. For this reason, Piedmont's proposed rate design for recovery of the entirety of the $8.679 million ABRR Revenue Requirement Deficiency is an adjustment to the Base Margin Rates per therm.

Q32. DO YOU HAVE ANY CONCERNS WITH THE COMPANY'S EXPLANATION?

A32. While Piedmont's Response to Consumer Advocate DR No. 2-43 explains why it applied the rate deficiency to the Base Margin Rates, it also states:

> Piedmont's proposed rate design for the ABRR Revenue Requirement Deficiency in this proceeding is fully in compliance with the requirements of the Company's TPUC-approved ARM Tariff (Service Schedule No. 318). It is also consistent with the rate design used for the ABRR Revenue Requirement Deficiency proposed by the Company, accepted by the CAD in settlement, and adopted by the TPUC in each of Piedmont's two prior Annual ARM proceedings. And it is consistent with the settled and approved rate design established in Piedmont's last general rate case.

The Consumer Advocate disagrees with Piedmont's representation. Existing rate design, and modifications to a rate design should not be confused. Each time that some rates have been changed, without all rates and charges being modified on a proportionate basis, there is a new rate design. Thus, the current rate design and the proposed rate design are not the same as that approved in TPUC Docket No. 21-00135.

Q33. ARE THERE OTHER POTENTIAL RATE DESIGN IMPACTS?

A33. Yes. Due to changes in customer mix and consumption patterns, each time rates are modified to reflect the revenue requirement, individual customer impacts may differ.

Q34. HOW CAN AN EQUAL PERCENTAGE INCREASE IN CUSTOMER CLASSES HAVE CUSTOMER IMPACTS?

A34. At the basic level, the total revenue requirement responsibility is "allocated" or "assigned" to specific rate classes or services. Those revenue requirement responsibilities are then converted to rates, subject to independent variables such as number of customers and expected consumption.

To the extent that actual independent variables differ from those used to set rates, the revenue will differ from the assigned revenue requirement. This creates a dynamic situation in an ARM filing, where the goal is to meet an overall target revenue requirement with variables changing. When this occurs, it is rarely possible to maintain the revenue requirement responsibility apportionment by class and the rate design.

This is demonstrated in the simple example below. Assume:

- A revenue requirement of $1,000;
- A Customer Class X, with 50 percent revenue apportionment

($500);

- 10 customers;
- An average of 100 units of consumption per customer; and
- A rate design with a fixed charge of $40 per month and a variable charge of $0.10 per unit.

It would look like the following:

		Cust	Rate	Revenue	Ratio
Class X					
Fixed		**10**	$ 40.00	$ 400	80%
Variable Rate			$ 0.10	$ 100	20%
Total Revenue				$ 500	

With these assumptions, 80 percent of the revenue from the class is being generated through the fixed charged. If one customer with the average consumption is lost, the revenue from that class would drop by $50 ($40 from the monthly charge and $10 from the variable rate), total contribution to revenue requirement would have decreased to 47.37 percent of total revenue as the total revenue for the company decreased to $950.

Class X		Cust	Rate	Revenue	Ratio
Fixed		**9**	$ 40	$ 360	80%
Variable Rate			$ 0.10	$90	20%
Total Revenue				$ 450	47.37%

The question is how to recover that lost revenue.

- If the revenue apportionment is maintained, with the contribution from Class X remaining at 50%, the rate design must be modified to apply rates that would generate an additional $50 in revenue. Even if the recovery within Class X is maintained, it will be modified with respect to other classes, as the fixed and/or variable cost must be increased. In the example below, the revenue targets for the rates is maintained at the original ratio:

Class X		Cust	Rate	Revenue	Ratio
Fixed		9	$ 44	$ 400	80%
Variable Rate			$ 0.11	$ 100	20%
Total Revenue				$ 500	50.00%

- If the shortage is recovered through an equal apportionment to all classes, then both revenue recovery would change for all classes and rates for the classes would need to be altered. The revenue deficit of $50 requires a 5.26% increase to meet the revenue requirement of $1,000. Applying 5.26% increase to the $450 current revenue from Class X, produces an increase of $24 for a total revenue of $474 from Class X. The customer class contribution remains at the lower 47.37%. There is an additional $26 deficiency that needs to be recovered from other customers. Maintaining the fixed rate has the following rate design and revenue generation:

Class X		Cust	Rate	Revenue	Ratio
5.25% Increase					
Fixed		9	$ 40	$ 360	76%
Variable Rate			$ 0.13	$ 114	24%
Total Revenue				$ 474	47.37%

Both class revenue apportionment and rate design can be changed in ARM proceedings. Modifications to rate design or revenue apportionment are policy considerations and are worth drawing overt attention to throughout the life of an alternative ratemaking mechanism.

Q35. THIS EXAMPLE IS DEPENDENT ON A CHANGE IN THE NUMBER OF CUSTOMERS. ARE CHANGES IN CUSTOMER COUNTS AND USAGE COMMON?

A35. Yes. As demonstrated in the Response to Consumer Advocate DR No. 1-43, customer counts and usage per class change frequently. In addition, the magnitudes of the changes fluctuate across customer classes. This is acknowledged by the Commission in TPUC Docket No. 21-00135, *Order Denying Proposed Annual*

Review of Rates Mechanism on p. 37, "Over time a utility's mix of customer between rate classes and associated cost of service may change necessitating the Commission to review how revenue is collected from the different customer classes."

Q36. ABSENT A CHANGE IN THE NUMBER OF CUSTOMERS OR USAGE PATTERNS, HOW CAN CHANGES IN THE RATE DESIGN FOR A CUSTOMER CLASS HAVE DIFFERING IMPACTS AMONG CUSTOMERS?

A36. Increasing a revenue apportionment for a class is not the same as spreading the revenue requirement increase equally to the individual component rates. Applying several revenue increases to one component can impact customers within the same rate class differently, depending on their usage patterns. The following is an example. Assume:

- Revenue allocation is based on a 50/50 rate apportionment between fixed and volumetric charges.
- There is an annual increase of 5% allocated only to the customer charge over a 5-year period.

[*Intentionally Blank, Table on Next Page*]

Years		5							
Increase/year		5%							
		Original		**Percent**		**Year 5**		**Percent**	**Percent**
		Rate/Unit	**Revenue**	**Revenue**		**Rate/Unit**	**Revenue**	**Increase**	**Revenue**
Fixed	**10**	$5.00	$50.00	61%	**10**	$7.76	$78	55%	61%
Volumetric	**100**	$0.50	$50.00	39%	**100**	$0.50	$50	0%	39%
Total Revenue			$100.00				$128	28%	
Customer 1: High Use				**Percent**				**Monthly Bill**	**Percent**
		Rate/Unit	**Revenue**	**Of Bill**		**Rate/Unit**	**Revenue**	**Increase**	**Of Bill**
Fixed	**1**	$5.00	$5.00	33%	**1**	$7.76	$7.76		44%
Volumetric	**20**	$0.50	$10.00	67%	**20**	$0.50	$10.00		56%
Total Revenue			$15.00				$17.76	18%	
Customer 2: Low Use				Percent					**Percent**
		Rate/Unit	**Revenue**	**Of Bill**		**Rate/Unit**	**Revenue**		**Of Bill**
Fixed	**1**	$5.00	$5.00	67%	**1**	$7.76	$7.76		61%
Volumetric	**5**	$0.50	$2.50	33%	**5**	$0.50	$2.50		39%
Total Revenue			$7.50				$10.26	37%	

At the end of the 5-year period:

- The average bill would have increased approximately 28%.
- The monthly rate for the customer charge would have increased approximately 55%.
- The percentage of revenue from the customer charge would have changed from 50% to approximately 61%.
- For a customer using double the average, the monthly bill increase would be approximately 18%.
- For a customer using half the normal consumption, the monthly bill would have increased approximately 37%.

These two examples demonstrate that seemingly small and proportionate rate changes impact customers differently.

Q37. WHAT ARE OTHER CONCERNS WITH PIEDMONT'S APPROACH TO MODIFYING RATE DESIGN AS PART OF THE ARM FILING?

A37. The rate design encompasses numerous policy issues and is often the subject of significant debate. In addition to recovering revenue, rates can be used to send price signals to modify consumer behavior and meet goals such as promoting efficiency and ensuring affordability. To use rates as a tool, any changes in the rate design should be deliberate and consciously made as well as effectively communicated.

As this Petition stands currently, Piedmont's rate design is being modified without a clear notification that rate design is being changed with no open discussion of the potential customer impact. Items that should be given more attention within this issue are:

- That residential monthly charges have remained the same since November of 2013. Exhibits CDK-6 and CDK-7 demonstrate that the monthly charge was $17.45 for November-March and $13.45 as of March 2012. [20]
- That monthly service charge is not explicitly provided on a residential customer's bill.
- That rate design is being changed within the ARM, without adequate customer notice of a rate design change.
- And that by applying the entire increase to the volumetric charge, to the extent that the rate increase is a result of changes in common costs and capital cost, a larger percentage of the fixed costs are being picked up by the volumetric charge. This may send incorrect price signals and has the potential for revenue recovery disparity within a customer class.

The last point above is a controversial issue in rate design proceedings due to the impact that it has on price signals and the potential rate increase disparity. However, each item above is highlighted to show the lack of transparency with customers, Consumer Advocate, and Commission Staff what is going on year over year in designing rates.

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[20] https://www.piedmontng.com/_/media/pdfs/png-rates/tn-rates-2013-11.pdf; https://www.piedmontng.com/_/media/pdfs/png-rates/tn-rates-2025-04.pdf (7/12/ 2025).

Q38. WHAT IS YOUR RECOMMENDATION?

A38. The recommendations below have no numerical impact on the current proposed rate design and recovery of revenue requirement. However, each recommendation is aimed at highlighting specific factors that are important considerations year over year in designing rates and should be explicitly noted in future filings. Therefore, I recommend that in future ARM proceedings, Piedmont should be required to provide testimony and attending schedules that specifically:

- Identify all rates for which charges are being proposed;
- Compare side by side, all current, existing rates and the proposed rates under the instant petition;
    - Provide the change to each rate as a dollar value and as a percentage of the previous rate;
- Compare all proposed rates, by class, with the rates contained in the Settlement Agreement in TPUC Docket No. 20-0086.
    - Provide the comparison in total and as a percent increase; and
- Compare the revenue contribution from each customer class approved in Docket 21-00135 with the proposed rates.
    - Provide the values by class as a dollar value and a percentage of total revenue requirement.

V. COST STUDIES AND CROSS SUBSIDIZATION

Q39. WHAT IS A COST STUDY?

A39. Generally, a cost study is the process of identifying expenses associated with the provision of a good or service. They are often used as analytical tools to enable more informed decision making. Of singular importance is the fact that there are numerous types of cost studies, employed for various purposes, and are dependent on the opinions, judgement, and decisions of those involved in developing the study. Thus, the output and usefulness of any cost study is dependent on how the study design and data are employed, and the understanding of the information resulting from the study.

As demonstrated below, definitions of profit, cost, and the type of cost studies are critical to understanding the discussions around cost studies.

Q40. WHAT IS CROSS-SUBSIDIZATION?

A40. It is the use of profits from a product or service to cover the costs of another business or service.

Q41. WHAT IS COST-OF-SERVICE RATEMAKING?

A41. In the most basic terms, cost-of-service ratemaking is when a regulatory body determines the revenue requirement "cost-of-service" that is necessary for a company to recover costs and earn a fair return. Rates for services are then set to meet the approved revenue requirement.

Q42. HOW DOES THIS DIFFER FROM RATES SET BY THE MARKET?

A42. In a competitive market, where multiple providers exist, and a consumer is able to easily choose from various providers, the market determines the price of goods and services. The profit of individual companies is the residual of revenues less costs, and providers are able to adjust output and prices in an effort to maximize prices.

Unlike companies in a free market, regulated utilities are required to provide the service and goods at the set prices and are not able to adjust prices or output to maximize profits.

Q43. WHAT ROLE DO COST STUDIES PLAY IN RATE SETTING?

A43. Once a revenue requirement is determined, there are questions about who should be responsible for meeting the revenue requirement, and how the rates for meeting the revenue requirement should be set. Cost-of-Service studies are frequently utilized to guide revenue requirement apportionment among various customer classes and provide direction for rate development within a class.

Q44. ARE THERE PARTICULAR COST STUDIES THAT ARE MORE CONTROVERSIAL THAN OTHERS?

A44. The use of any cost study to justify rate setting is subject to controversy. Regulators are faced with the goals of setting rates to recover costs and setting rates that are just and reasonable. With those goals in mind, there is a predisposition to rely on a "fully allocated cost study." Due to the frequency of their use, the conclusions drawn, and the nature of how they are developed, fully allocated cost studies are often at the center of cost study debates.

Q45. WHAT IS A FULLY ALLOCATED COST STUDY?

A45. A fully allocated cost study that assigns all costs, direct and indirect, for a period, to specific products and/or services. Even at this level, there is a fundamental question of how "cost" is being defined and measured.

Q46. DID PIEDMONT USE A COST STUDY IN THIS PETITION?

A46. Yes. Mr. Goley explained that Piedmont performed an "Allocated Cost of Service Study."[21]

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21 *Direct Testimony of Keith Goley* at 7:15 – 9:1, TPUC Docket No. 25-00036 (May 20, 2025).

Q47. DOES PIEDMONT UTILIZE THE COST STUDY TO DETERMINE RATES?

A47. Piedmont uses its cost study to influence rate determination. Mr. Goley stated that "Piedmont's main objectives are to design rates that compensate the utility for the cost of the services that it provides to all customer classes."[22]

He further discusses the goals of avoiding cross-subsidization. Mr. Goley claimed that the cost study shows that Piedmont's residential class rate schedule rate of return is below the overall system rate of return of 6.49%.[23]

Q48. WHAT IS THE IMPORTANCE OF THE 6.49% RATE OF RETURN?

A48. Piedmont's authorized rate of return is 6.49%. It represents the cost of capital for the rate base.

Q49. ARE THERE ISSUES WITH UTILIZING FULLY ALLOCATED COST STUDIES TO DETERMINE WHETHER THE RETURN FROM CUSTOMER CLASS IS SUFFICIENT?

A49. Yes. There are issues both with the use of a fully allocated cost study to establish rates and with the conclusions that Piedmont makes based on its cost study.

First, a fully allocated cost study produces specific results that are misunderstood. The values from a fully allocated cost study are dependent on subjective design and data input, assumptions, and bias. Unfortunately, these values are then often used to support inaccurate conclusions.

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22 *Id.* at 7:5-6.

23 *Id*. at 7:19-23.

Economists, William Baumol, Michael Koehn, and Robert Willig, clearly note that a full allocation cost of approach has been discredited by marginal and incremental cost analysis. They stated that the major purpose of the article was to: [24]

> [P]uncture the legend that a fully allocated cost calculation produces numbers approximately any substantive economic magnitudes. We will show that different and equally plausible allocation criteria yield shockingly different numerical results, so that by judicious choice of allocation criterion, the partisan calculation can make the process yield virtually any numbers he chooses (in advance) to obtain.

Relying on a study that is fundamentally based on arbitrary decisions will result in a similarly flawed decision.

Q50. IS THERE A REASON THAT FULLY ALLOCATED COST STUDIES ARE USED IN RATE REGULATED PROCEEDINGS?

A50. Regulatory rules often require cost studies to be included in rate proceedings. As noted by Baumol, *et al*:

> If regulatory rules nevertheless require the undefinable to be defined, [the] only option to those who must comply with the rules is to adopt some arbitrary device, usually dressed up to give an appearance of reasonableness – an arbitrary rule that divides up indivisible investment and costs. This of course, is what full allocation means.[25]

The authors go on to note that "there seems to be an impression that any such calculation, if carried out with sufficient care, will yield a reasonable approximation to some underlying true figure. That impression is totally unfounded.[26]

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[24] William Baumol, Michael Koehn, and Robert Willig, *How Arbitrary is 'Arbitrary'?- or, Toward the Deserved Demise of Full Cost Allocation*, Public Utilities Fortnightly, p.16 (September 3, 1987). A copy of this article is attached as CA Attachment 2.

[25] *Id.* at p. 17.

[26] *Id.*

Q51. HOW DOES THE FACT THAT FULLY ALLOCATED COST STUDIES ARE ARBITRARY AFFECT RATE PROCEEDINGS?

A51. With the understanding that such studies are arbitrary, we know that rates based on the fully allocated cost study are not more "cost" justified than many other rates that might be proposed using other measures. There is only a random probability that any rate would be the same as that resulting in a competitive market. In addition, a fully allocated cost study is unlikely to be able demonstrate that any good or service is subsidized by another good or service. The issue of subsidization will be addressed later in my testimony.

With this knowledge, caution is the best strategy when drawing conclusions or making absolute statements based on those studies.

Q52. HOW DOES PIEDMONT APPLY THE COST STUDY TO RATES?

A52. The Company relies on the cost study to suggest that there is cross-subsidization occurring in current rates and to mitigate the cross-subsidy by moving customer rates toward parity.[27] Mr. Goley claimed that Table 2 in his testimony demonstrates that the rates of return are moving closer to "parity" with their proposal.[28]

Q53. DO YOU HAVE ANY CONCERNS OR OBJECTIONS TO THE COMPANY'S APPROACH?

A53. Yes. There are several concerns. First, as noted above, a fully allocated cost study is dependent on choice and discretion in its development. Thus, a goal of adjusting rates to reach parity based on that study, and the resulting rates, are arbitrary. The

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27 *Direct Testimony of Keith Goley* at 7:12-15.

28 *Id*. at 9, Table 2.

cost study is not a sound basis of support for the reasonableness of the proposed rates.

Second, the Company indicated that by moving rates to meet its objectives, it is attempting to mitigate cross-subsidization. A fully allocated cost study does not prove the existence of cross-subsidies.

Third, although Piedmont is drawing conclusions from the cost study and using the results for rate design, the Company does not discuss the cost study results with respect to the actual rates being proposed.

In summary, the cost study used by the Company does not provide any information regarding marginal cost or cross-subsidization, and it does not discuss the desired price signals or customer price response.

Q54. DID PIEDMONT CONDUCT MARGINAL COST STUDIES OR INCREMENTAL COST STUDIES TO SUPPORT ITS CLAIMS?

A54. No. In responses to Consumer Advocate DR Nos. 1-40 and 1-41 (Exhibit CDK-8 and Exhibit CDK-9) the Company responded that it did not conduct a stand alone cost study for the individual customer classes and that it did not conduct a marginal cost study in this proceeding.

Q55. EXPLAIN WHY FULLY ALLOCATED COST STUDIES DO NOT PROVE THE EXISTANCE OF CROSS-SUBSIDIZATION.

A55. The definition of a subsidy is the provision of financial aid in some form to promote a given objective. Generally, this is viewed as reducing the cost of production or the consumer rate (price). The definition of a cross-subsidy is generally viewed as using profits from one product to offset losses or returns on another product.

From an economic perspective, profit is maximized where the marginal revenue equals marginal cost. Some important observations are:

- In most regions of operation, a lower output would result in a lower profit.
- Marginal cost does not include allocated costs, such as common costs or embedded costs, that would exist even without additional production.
- If marginal revenue from the additional output is meeting or exceeding the added cost of production, the goods or services are not being subsidized.
- At the point where marginal cost is equal to marginal revenue, the allocation of additional costs could create the perception that the marginal output was not meeting its costs. This might cause some to say that the output is being subsidized and possibly alter operations.

Because a fully allocated cost study assigns costs to output, it distorts the cost benefit analysis of goods and services. Without fully understanding the model, it can lead to inaccurate conclusions.

Q56. WHAT ARE THE CRITERIA FOR DETERMINING IF A CROSS-SUBSIDY EXISTS?

A56. Two conditions are necessary for a cross-subsidy to exist:

- One condition is that a customer (service, class, or group of customers (this is definition dependent), must be paying less than the marginal cost to service those customers.
- The other condition is that another customer or group of customers must be paying more than their stand-alone cost.

If a customer, or customer class, is paying rates that are more than the marginal cost to provide service, any revenue above the marginal cost contributes to overhead and makes the Company better off without additional increasing cost to other customers.

VI. CUSTOMER BILLS

Q57. WHAT ARE YOUR CONCERNS REGARDNG PIEDMONT'S CUSTOMER BILLS?

A57. A utility's customer bill is the invoice for the services provided and the primary communication between a utility and its customer. For utilities, there is a general expectation that the bill will outline the services provided along with the rates for the services and additional fees that make up the total bill.

In contrast to what might be expected to be on a standard customer bill, the cost information provided in Piedmont's residential customer bills is sparse. Piedmont provided a sample bill in Confidential Response to Consumer Advocate DR No. 1-34. A redacted, real Piedmont customer bill from its Tennessee jurisdiction is attached as Confidential Exhibit CDK-10. Both bills demonstrate that for current charges, Piedmont's bill provides only the total month's charges. It is lacking the individual components that make up the "current billing and other basic charges" and the ability to calculate, replicate, and verify the bill.

Q58. IS THIS A NEW ISSUE?

A58. It is not. The concern about the lack of information on Piedmont's bills has been raised by the Consumer Advocate in the past. The Company has acknowledged the limited detail on its bills and agreed to work with the Consumer Advocate to address this issue. This topic is discussed by the Commission in a previous Order:

> Consumer Advocate witness, Mr. Dittemore, did not object to the Company's method of calculating the rate design to reflect new ARM revenue calculations, but did recommend that the ARM rider

> rates be set forth separately on customer bills. Mr. Dittemore asserted that this separate rider will increase customer transparency and may result in customers gaining more knowledge about their natural gas bills, especially given the magnitude of current customer bills. The Company opposed Mr. Dittemore's suggestion that the ARM Rider Rate be billed separately on customers' bills. **Ms. Powers testified that Piedmont's current billing system provides only limited detail billing, but Piedmont intends to address this limitation with the development of its next generation billing system**. Ms. Powers disagreed that a separately billed rider rate will provide more clarity because the rates are likely to be a relatively small portion of the customers' total bills. With the filing of the New Petition, the Consumer Advocate withdrew its recommendation to require the ARM rider rates to be set forth separately on customer bills. **Alternatively, the parties agreed to address this issue in a future docket and work together for prospective implementation upon the establishment of Piedmont's new billing system**.[29]

Q59. HAS THIS PIEDMONT WORKED WITH THE COSUMER ADVOCATE TO ADDRES THE BILLING DETAIL SINCE JULY 25, 2022?

A59. It has not. The bill detail has remained the same since that time.

Q60. WHAT INFORMATION IS NORMALLY PROVIDED ON A RESIDENTIAL CUSTOMER'S UTILTY BILL?

A60. A utility bill usually identifies the individual rates and charges assessed, along with the usage amounts, for the given month such that a customer is able to understand the source of the charges. The U.S. Department of Energy ("DOE") published a guidance document titled "Understanding Your Utility Bills: Natural Gas" that explains the basics of utility bills and how they can be analyzed.[30] This guidance

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[29] *Order Denying Proposed Annual Review of Rates Mechanism*, pp. 36-37, TRA Docket No. 21-00135 (July 25, 2022) (emphasis added.)

[30] Oak Ridge National Laboratory and US Department of Energy, "Understanding Your Utility Bills: Natural Gas", ORNL/SPR-2021/1832 (Spring 2021) (https://betterbuildingssolutioncenter.energy.gov/sites/default/files/attachments/Utility%20Bill%20-%20Natural%20Gas%20PDF_UUBG-NG-V8-5.20.21.pdf).

document provides a sample bill and states:[31]

> Some common things to look out for on your bills are the gas usage volume, measurement units, BTU (energy) factor, usage and transportation charges, penalties, other riders, taxes, and fees (Figure 7). In addition to the usage and cost information, other important components in the bills include account number, meter readings, number of days in the period, historical gas usage, and average temperature during the billing period.

Further, the guidance document explains: [32]

> **Customer Charge**
> A customer charge is a fixed charge **that is seen on every invoice** independent of NG consumption for the billing period. This is the fee that the utility company charges for providing utility and account management services.

The publication includes detailed discussions of the various charges and components.

Q61. ARE THE CHARGES LISTED ABOVE USUALLY FOUND IN A CUSTOMER BILL?

A61. Yes, they are. These individual components are common in customer bills across utility industries and across the country.[33]

Q62. WHY IS IT IMPORTANT THAT A UTILITY BILL CONTAINS THE INDIVIDUAL COMPONENTS THAT MAKE UP A MONTHLY BILL?

A62. In a free market, price information is critical to enable consumers to make informed decisions. For a rate regulated monopoly service that is considered a critical service, price information and structure is even more important. Customers have

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31 *Id.* at p. 9.

32 *Id.* at p. 10.

33 See attached Confidential Exhibit CDK-10(a) for sample bills and a redacted customer electric bill.

limited alternative options, such as adjusting consumption patterns or engaging in public discourse. In these markets, transparent pricing is critical for understanding consumer response and creating trust.

Q63. HOW DO PIEDMONT'S BILLS COMPARE TO THE SAMPLE PROVIDED BY THE DOE?

A63. Piedmont's bills are missing most of the rates listed in DOE's publication. As stated above, Piedmont's bills fail to include even the most basic charge that DOE says, which "is a fixed charge that is seen on every invoice independent of NG consumption."[34]

In addition, Piedmont's bills do not include the commodity charge or taxes. Piedmont's bills do include the Purchase Gas Adjustment ("PGA"). However, it does not explain if the adjustment is in dollars or cents, or the role that the PGA plays in the current charges.

Q64. DOES THE STATE OF TENNESS HAVE RULES REGARDING BILLING INFORMATION?

A64. Yes, it does. Rules of Tennessee Public Utility Commission Chapter 1220-04-05-.15 lists information that must be included in the bills for regulated gas companies. The Rule states, in part, that the bill **shall** show:[35]

> (c) The number of units billed;
>
> (d) The applicable rate schedule, or identification of the applicable rate schedule. If the actual rates are not shown, the bill shall contain a

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[34] Oak Ridge National Laboratory and US Department of Energy, "Understanding Your Utility Bills: Natural Gas", ORNL/SPR-2021/1832, p. 10 (Spring 2021) (https://betterbuildingssolutioncenter.energy.gov/sites/default/files/attachments/Utility%20Bill%20-%20Natural%20Gas%20PDF_UUBG-NG-V8-5.20.21.pdf).

[35] TENN. COMP. R & REGS 1220-04-05-.15(1) (April, 2018).

statement to the effect that the applicable rate schedule will be furnished on request;

(e) The gross and/or net amount of the bill;

(h) Any conversions from meter reading units to billing units, or any calculations to determine billing units from recording or other devices, or any other factors, such as purchased gas or fuel adjustments, used in determining the bill. In lieu of such information on the bill, a statement must be on the bill advising that such information can be obtained by contacting the utility's principal office.

Q65. PIEDMONT'S BILLS IDENTIFY THE RATE SCHEDULE AND WHERE THE INFORMATION CAN BE FOUND. DOES THAT MEET THE RULE REQUIREMENT?

A65. No. The bill does not include:

- A statement to the effect that the applicable rate schedule will be furnished upon request.
- A statement advising that the necessary information can be obtained by contacting the utility's principal office.

The bill contains three different directions to web sites, one to pay the bill[36], one directing customers for the rate schedule and calculation[37], and another for further understanding of the bill.[38]

- The first link is to pay the bill.
- The second link is to the Piedmont home page where the customer must restart the process to understand and navigate through Piedmont's website.
    - "Rates" is one of the options found under the "Billing and

[36] Piedmont Natural Gas home page, Pay Bill (https://www.piedmontng.com/home/billing-and-payment/pay-bill) (last visited August 4, 2025).

[37] Piedmont Natural Gas home page, Billing & Payment, Rates, Tennessee (https://www.duke-energy.com/-/media/pdfs/png/tn-tariffandserviceregulations.pdf?rev=8fd664d880ef4f2b8a58c8715e7849e4) (last visited August 4, 2025).

[38] Piedmont Natural Gas home page, Billing & Payment, Inserts (https://www.duke-energy.com/-/media/pdfs/png/how-to-read-bill.pdf?rev=56f87447e5694cdb9508e4e8865ab886) (last visited August 4, 2025).

Payment"

  - The "Rates" page has a "Tennessee" option under the "Tariff and Service Regulations" tab. This takes the user to the actual tariff. Further down the page there is a statement that says, "Please select from the information below to find natural gas rates for your state." This is an interactive option that does not always appear and may require the user to refresh the page. A customer is given access to a PDF by state, year, and month. The PDF for July 2025 (effective April 2025), Exhibit CDK-11, provides the rates by month, customer charge, and therm.

The page does not explain how the bill is calculated and does not include other possible fees, such as gross receipts taxes, or the fuel clause adjustment, which is located on the actual bill. This rates page is far from user friendly and does not directly provide billing information.

- The third link sends the customer to a general explanation of how to read a bill (Attached as Exhibit CDK-12). The pages do not provide the specific information necessary for the customer to calculate the specific bill, the current rates, or even links to the current rates.

Simply offering a web link to a site that provides some of the information necessary to calculate a bill does not meet the requirement. If the link generated an actual bill and all the supporting calculations, then the use of a web link may meet these requirements. However, even where a clear bill is generated with the attending calculations, the use of a web link assumes that all customers have reasonable access to and are familiar with the internet. Even if providing a web link is sufficient, those provided by Piedmont do not directly enable a customer to understand and calculate their bill. In addition, Piedmont's bill assumes that customers are utility tariff literate, able to gather the necessary information from the various sources and can perform the necessary calculations.

Q66. DOES THE COMPANY CLAIM THAT IT MEETS THE BILL REQUIREMENTS?

A66. Yes. In its Revised Response to Consumer Advocate DR No. 2-42 (Exhibit CDK-13) asking for clarification regarding the customer bill Piedmont:

- Confirmed that the fees and charges are not on the bill and stated that the bill form is in compliance with all applicable Commission requirements.
- Stated that the website provides access to the approved TPUC-approved rates and charges.
- Stated that where taxes are applicable to a customer's bill, the component is separately identified. It added that since taxes are not applicable to service or bills provided by Piedmont for residential service.

Q67. DO YOU AGREE WITH PIEDMONT'S REPONSE?

A67. No. Piedmont's bills and consumer information were assessed for ease of use. The Company's Response to Consumer Advocate DR No. 2-42 did not change the preceding analysis.

Q68. DO YOU AGREE WITH PIEDMONT'S EXPLANATION FOR REPORTING TAXES ON THE BILL?

A68. No. Consumer Advocate DR. No. 2-43(d) asked the Company to confirm that the customer bill does not specifically identify the tax component of the total bill. The Revised Response specifically addressed income tax only. It did not address other taxes or fees.

Q69. WHAT IS YOUR RECOMMENDATION REGARDING PIEDMONT'S CUSTOMER BILLS?

A69. Piedmont's customer bills need to provide more price information including the monthly charge, the volumetric rate, and any other fees or rates that make up the total bill. It is also my recommendation that Piedmont should not limit the "other fees or rates" to ones only applicable in the Tennessee jurisdiction.[39]

Q70. DOES THIS COMPLETE YOUR TESTIMONY?

A70. Yes. However, I reserve the right to incorporate any new information that may subsequently become available.

[39] For example, it would still be helpful to customers to have specific line items for things that may result in a zero charge like the income tax category specifically highlighted by the Company in Response to Consumer Advocate DR No. 2-43(d).

IN THE TENNESSEE PUBLIC UTILITY COMMISSION
AT NASHVILLE, TENNESSEE

IN RE:	)	
	)	
PETITION OF PIEDMONT NATURAL GAS COMPANY, INC. FOR APPROVAL OF ITS 2025 ANNUAL REVIEW OF RATES MECHANISM PURSUANT TO TENN. CODE ANN. § 65-5-103(d)(6)	)	**DOCKET NO. 25-00036**
	)	

AFFIDAVIT

I, Clark Kaml, 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.

CLARK D. KAML

TERRA ALLEN
STATE OF TENNESSEE NOTARY PUBLIC
HICKMAN COUNTY
My Commission Expires JAN. 31, 2027

Sworn to and subscribed before me this 5th day of August, 2025.

NOTARY PUBLIC

My commission expires: 1/31/2027.

CA Attachment 1

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STATE ATTORNEY GENERAL
CONSUMER ADVOCATE DIVISION

BEFORE THE TENNESSEE REGULATORY AUTHORITY

NASHVILLE, TENNESSEE

October 7, 1998

IN RE:	)	
PETITION OF CHATTANOOGA GAS COMPANY TO PLACE INTO EFFECT A REVISED NATURAL GAS TARIFF	)	**DOCKET NO. 97-00982**

ORDER

MELVIN J. MALONE
CHAIRMAN

H. LYNN GREER, JR.
DIRECTOR

SARA KYLE
DIRECTOR

TABLE OF CONTENTS

INDEX OF TABLES

IN RE: PETITION OF CHATTANOOGA GAS COMPANY TO PLACE INTO EFFECT A REVISED NATURAL GAS TARIFF, DOCKET NO. 97-00982

This matter came before the Tennessee Regulatory Authority (hereafter the "Authority") upon the Petition of the Chattanooga Gas Company (hereafter the "Company" or "Chattanooga Gas"), a wholly owned subsidiary of Atlanta Gas Light Company, Inc. (hereafter "AGL") for a general rate increase. This matter was heard by the Authority from February 9 to 13, 1998.

I. PROCEDURAL BACKGROUND

On May 1, 1997, Chattanooga Gas Company, filed a Petition with the Authority pursuant to Tenn. Code Ann. § 65-5-203, to place into effect a revised natural gas Tariff, superseding its existing tariff and rate schedule presently filed with the Authority. On May 23, 1997, the Consumer Advocate Division, Office of the Attorney General (hereafter known as the "Advocate"), filed its Petition to Intervene and Participate as a Party. On June 25, 1997, Associated Valley Industries group (hereafter known as "AVI"), a coalition of certain industrial users of natural gas, filed a Petition to Intervene. The Petitions for leave to intervene from the Advocate and from AVI were granted at the Authority Conference on July 1, 1997, and Director Melvin J. Malone was appointed Hearing Officer in this matter. On July 23, 1997, Chattanooga Manufacturers Association (hereafter known as "CMA") filed its Petition for Leave to Intervene.

On August 6, 1997, a Pre-Hearing Conference was held before Authority Director Melvin J. Malone. At that Pre-Hearing Conference the admission of CMA as a party to the proceeding was approved. On August 13, 1997, a Report and Recommendation from the Hearing Officer was submitted to the Authority providing dates for the submission of any additional data requests and responses, for the filing of additional direct and rebuttal testimony, and for a Hearing. By Order, dated September 3, 1997, the Authority adopted the procedural schedule set forth in the Hearing Officer's Report and Recommendation with amendments. The Authority set this matter for Hearing from October 13 through 17, 1997. On October 2, 1997, the Parties submitted a joint motion to continue the Hearing dates to a date to be determined by the Authority. At the Authority Conference on October 7, 1997, the motion was granted and Chattanooga Gas, through its counsel, waived its right under Tenn. Code Ann. § 65-5-203(b)(1), to place the proposed rate increase into effect within six (6) months of the date of the initial tariff filing.

On October 7, 1997, a Pre-Hearing Conference was held before Director Melvin J. Malone in his capacity as Hearing Officer. On October 29, 1997, a Report and Recommendation was submitted to the Authority from the Hearing Officer providing dates for the Hearing. By Order, dated January 30, 1998, the Authority adopted the Hearing schedule set forth in the Report and Recommendation. This matter was set for Hearing by the Authority from February 9 to 13, 1998.

II. HEARING AND APPEARANCES

On February 9 to 13, 1998, a Hearing was convened before the Directors of the Authority, at which time, the following appearances were entered by counsel:

FOR THE COMPANY:

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Gene Shiles, Esq.
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L. Craig Dowdy, Esq.
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FOR THE ADVOCATE:

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FOR AVI and CMA:

Henry Walker, Esq.
Boult, Cummings, Conners & Berry
414 Union Street, Suite 1600
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Dave Higney
Grant, Konvalinka & Harrison
633 Chestnut Street
Chattanooga, TN 37401

The Company presented testimony from Harrison F. Thompson, Kenneth A. Royse, H. Edwin Overcast, Gerald A. Hinesley, Victor L. Andrews, Donald S. Roff, Fred A. Carillo, Lisa E. Howard Wooten, Gregory E. Aliff, and James E. Kissel. AVI and CMA presented the testimony of Donald E. Johnstone, Michael Gorman, James Selecky, Robert Colby, Harry Faulkner III, Thomas E. Hodge, and Donald E. Huffman. The Advocate presented the testimony of Dr. Stephen N. Brown, Archie R. Hickerson, Daniel W. McCormac, and R. Terry Buckner.

At the Authority Conference on July 7, 1998, the Directors of the Authority, after public deliberation, announced their decision in this matter pursuant to Tenn. Code Ann. § 4-5-314.

III. LEGAL BACKGROUND AND CRITERIA FOR ESTABLISHING JUST AND REASONABLE RATES

The Authority considers petitions seeking adjustments of rates and charges under Tenn. Code Ann. § 65-5-203, which requires:

> 1) That the Authority shall have the power upon written complaint, or upon its own initiative, to hear and determine whether the increase, change or alteration being sought by a public utility is just and reasonable; [1]
>
> 2) That the burden of proof to show that the increase, change or alteration is just and reasonable shall be on the public utility making the same; and
>
> 3) In determining whether such increase, change or alteration is just and reasonable, the Authority shall take into account the safety, adequacy and efficiency or lack thereof of the service or services furnished by the public utility.

The Authority has wide latitude in setting rates for public utilities under its jurisdiction. C.F. Industries v. Tennessee Public Service Commission, 599 S.W.2d 536 (Tenn. 1980). The court in C.F. Industries stated that, "[T]he process of setting rates is not required to follow any particular course, so long as the end result does not violate the just and reasonable standard." Id. at 543 (quoting Allied Chemical Corp. v. Georgia Power Co., 224 S.E.2d 396, at 399 (Ga. 1976)).

[1] The TRA has the power to fix just and reasonable rates "which shall be imposed, observed, and followed thereafter" by any public utility. Tenn. Code Ann. § 65-5-201. Consumer Advocate Division v. Tennessee Regulatory Authority, No. 01-A-01-9708-BC-00931, op. at 6 (Tenn.Ct. App., July 1, 1998) (further citing Consumer Advocate Division V. Bissell, No. 01-A-01-9601-BC-00049 (Tenn. Ct. App., Aug. 26,1996)).

IV. TEST PERIOD

In a rate case the Authority must, as a preliminary determination, decide which test period is appropriate. The purpose in the selection of a test period is to provide an indication of the rate of return that is likely to be produced under the existing rate structure in the reasonably foreseeable future. The test period takes into consideration the estimated effect of reasonably expected revenues, expenses and investments.

The Company proposed a historical test period for the twelve (12) months that ended September 30, 1996, with adjustments for attrition through September 30, 1998. Each of the Parties in this case adopted this same test period for their forecasts. The Authority concludes, therefore, that this is a reasonable and appropriate test period in this case for rate setting purposes.

V. CONTESTED ISSUES

In its original filing, the Company requested a rate increase of $4,422,602. The Advocate asserted that a rate increase was not just and that the Company should be ordered to reduce current rates by $1,393,407.[2] AVI and CMA asserted that the Company could justify only a $6,399 increase.[3] The following sections represent the issues contested by the Parties.

V(a). RATE BASE

Rate Base is the Company's net investment, which is financed through investor supplied funds, in property used and useful in providing utility service. This is the amount of investment on which the Company should be allowed the opportunity to earn a fair and reasonable rate of return. The Company forecasted a Rate Base of $101.4 million, while the Advocate and AVI proposed $94.6 million and $87.7 million, respectively.

V(a)1. PLANT IN SERVICE AND CONSTRUCTION WORK IN PROGRESS

Plant in Service represents the original investment cost to the Company of the assets used in providing utility service. Construction Work in Process ("CWIP") represents the cost of investment that is currently under construction and will be transferred to Plant in Service when completed.

The actual balance in this account at September 30, 1996, was $125,916,379 to which the Company forecasted additions of $14,098,556 through the midpoint of the attrition year. The Company provided a detailed project by project breakdown of the plant additions budgeted for

2 See Advocate Pre-Filed Exhibit, Schedule 1.

3 In Table 1 of AVI witness Michael Gorman's testimony, AVI proposed a zero ($0) rate change. The calculations which result derive a rate increase of $6,399. The difference can be attributed to rounding.

1997 and 1998. The Advocate used a "simple average" of previous plant additions to develop Utility Plant in Service that resulted in its Plant In Service forecast being $0.600 million higher than the Company's budgeted forecast. AVI accepted the Company's forecasted amount for Plant In Service and CWIP. Additionally, no testimony was presented on these issues at the Hearing, either in direct or rebuttal testimony. Since the Company's attrition forecast of $140,014,935 is supported by a detailed budget and workpapers, the Directors unanimously approved the Company's forecast.

V(a)2. ACQUISITION ADJUSTMENT

An Acquisition Adjustment represents the amount of investment by the utility that is over and above the original cost of assets placed in service. On September 30, 1988, Atlanta Gas Light Company purchased the assets of Chattanooga Gas from Jupiter Corporation for $35 million, plus $1,279,456 in legal and accounting fees, for a total of $36,279,456. The purchase price exceeded the Company's September 30, 1988, book value of $22,653,104 by $13,626,352, which represents the total acquisition adjustment. Chattanooga Gas has been amortizing this acquisition adjustment over a 40-year period, and as of May 1, 1997, the unamortized balance was $9,553,422.

Chattanooga Gas requested that the Authority recognize the unamortized balance of the acquisition adjustment, $9,553,422, in Rate Base. Additionally, the Company requested that the annual amortization of $411,024 be included in Cost of Service. This is the first time that the Company has asked for recognition of the acquisition adjustment in the Rate Base and Cost of Service from September 1988 to the present.[4] In support of its request, the Company stated that the facts that existed at the time AGL first purchased the Chattanooga system have drastically changed. For example, the Company argues that extensive improvements and efficiencies were

[4] Chattanooga Gas Company Post-hearing Brief, at page 7.

realized because of the acquisition. The Company provided supporting schedules showing savings to the ratepayers resulting from the acquisition. Finally, the Company portrayed the favorable results of its management audit and customer surveys as proof that the operations of Chattanooga Gas have improved to the ratepayers' benefit.

The Advocate opposed recognizing the Acquisition Adjustment for ratemaking purposes. The Advocate argued that recognizing the Acquisition Adjustment would force Chattanooga Gas' ratepayers to pay twice for assets that had been "over-depreciated" for book purposes. Additionally, the Advocate argued that the Company's exhibits showing savings to the ratepayers from the acquisition were in error. The Advocate highlighted errors in the Company's original exhibit quantifying the savings to ratepayers since the acquisition. The Advocate refined its original schedules to illustrate that customers of Chattanooga Gas were in a less favorable position after the acquisition by AGL. On September 10, 1997, the Company filed a revised exhibit that eliminated several of these errors. The Directors found that this later filing, however, still contained incorrect calculations. The Advocate maintained that correcting these errors revealed that additional payments in excess of benefits would have to be made by the ratepayers.

AVI opposed recognizing the Acquisition Adjustment in the Company's Cost of Service. The arguments advanced by AVI in opposition to the Acquisition Adjustment were structurally identical to those of the Advocate.

The Directors found that while the level of service provided by Chattanooga Gas may have increased from that of the Company's previous owners, such increases in service quality originated from investments in plant made by the current owners. This increase in investment, and therefore the change in service, has been recognized through increases to the Plant in Service component of Rate Base on which a fair rate of return is provided. The Directors also found that the Company's arguments for recognition of an Acquisition Adjustment ten (10) years after the acquisition by AGL, were not dispositive of the issue. Therefore, the Directors of the Authority unanimously denied the Company's request to include an Acquisition Adjustment in the Rate Base.

V(a)3. CASH

Utility companies, including Chattanooga Gas, are required by their financial institutions to maintain certain minimum cash balances in order to avoid service charges. This cash balance represents an asset, supplied by the investors of the Company, and has been traditionally recognized by this agency as an addition to Rate Base. The Company included $2,373,422 as the cash element of their Rate Base. This amount represents the average daily balance of their cash accounts, and correctly ties to the Company's ledger. Although the Advocate accepted the Company's calculation of cash, AVI objected to including cash in the Rate Base calculation. Michael Gorman, AVI's witness, stated in his direct testimony that the Company did not demonstrate that this minimum cash bank balance is necessary to avoid service charges.[5] In his testimony, however, Mr. Gorman used the phrase "this minimum cash bank balance,"[6] suggesting that a cash balance is warranted. Mr. Gorman, on behalf of AVI, only offered zero dollars as an alternative. The Company did not dispute AVI's objection in their rebuttal testimony.

A majority of the Directors found that utility companies are typically required to maintain minimum cash balances in order to avoid service charges, and that this Agency has traditionally recognized and approved cash balances of this type as an addition to Rate Base. A majority of the Directors concluded that it would be a contradiction to accept zero dollars as being reasonable, as

5 Michael Gorman Pre-Filed Direct Testimony, at page 17.
6 Id., at page 6.

suggested by AVI. For these reasons, the majority of Directors adopted the Company's position of $2,373,422 as the appropriate cash element to include in Rate Base.[7]

V(a)4. MATERIALS AND SUPPLIES

Materials and Supplies ("M&S") generally refers to construction inventories. M&S includes items such as pipes, meters, and other equipment that will soon be placed into service. M&S can also include items that are kept on hand for emergency purposes.

The Company included its twelve (12) month historical average balance for M&S during the test period to arrive at its forecast of M&S. This amount was also accepted by AVI. Since the Advocate did not testify concerning their methods used to calculate M&S of $346,273, or oppose the Company's position, the Authority unanimously adopted the Company's forecast of $453,221 as the appropriate amount for M&S to include in Rate Base.

V(a)5. GAS INVENTORIES

Gas inventories represent the average value of gas that the Company stores for withdrawal during the peak winter months. While the actual cost of the gas placed into storage is recovered through the Authority's purchased gas adjustment ("PGA") process, the return on the investment required to store gas in inventory is recovered through a rate case proceeding.

The Company has included the twelve (12) month historical average balance during the test period of $5,419,144 to arrive at its forecast of gas inventories. This amount was also accepted by AVI. Because the Advocate did not present any testimony or offer any evidence regarding its calculation of its $6,659,404 forecast of gas inventory,[8] the Directors unanimously approved the Company's forecast of $5,419,144.

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7 Director Kyle voted no on this issue.

8 Consumer Advocate Pre-Filed Exhibit, Schedule 3.

V(a)6. DEFERRED RATE CASE EXPENSE

Deferred Rate Case Expense represents the unamortized portion of costs the Company has incurred for regulatory proceedings before the Authority. This item also includes Chattanooga Gas' share of its total cost of proceedings before the Federal Energy Regulatory Commission ("FERC"). In addition, costs relating to the Company's Management Audit, which was ordered by the Tennessee Public Service Commission in the Company's last rate case, are included in this item. The Company capitalizes these costs and amortizes them over a previously prescribed period. The amortization of these costs is then treated on the income statement as an expense.

The Company has taken the balance in this account at September 30, 1996, added its estimated outside costs for completing this rate case of $183,500, and continued with its current monthly amortization of $1,288 to arrive at its average Deferred Rate Case Expense of $200,668 in the attrition year for Rate Base. However, in computing Rate Case Expense for the Net Operating Income ("NOI"), the Company chose to increase the test period amount by their growth factor. The Company also excluded the deferred costs of their Management Audit in their forecast.

The Advocate included $47,309 in Rate Base for their forecast of Deferred Rate Case Expense. The Advocate's calculations of $144,500[9] did not recognize the cost of the management audit. AVI accepted the Company's calculation of Deferred Rate Case Expense.

The Directors determined that the balance of the Deferred Rate Case Expense should relate to the amortization included as Rate Case Expense in the computation of Net Operating Income. To compute this item, the Directors concluded that the beginning balance should first be increased

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[9] There is no evidence in the record regarding how or why the Advocate chose to change the Company's original forecast of $183,500.

by the estimated cost of this case and then amortized over a new three (3) year period as illustrated below:

DEFERRED RATE CASE EXPENSE

9/30/96 Deferred Rate Case Expense	$38,420
9/30/96 Deferred Management Audit Expense	135,744
Estimated Costs to Complete 1997 Rate Case	183,500
Total Deferred Balance	**$357,664**
Amortization Period (Years)	3
Annual Rate Case Expense	**$119,221**
Monthly Rate Case Expense	$9,935
Months from 9/30/96 to 3/31/98[10]	18
Total Amortization at 3/31/98	**$178,830**
Total Deferred Balance	$357,664
Amortization through 3/31/98	178,830
Deferred Rate Case Expense at 3/31/98	**$178,834**

The Directors found that they could not accept any one method proposed by the Parties for Deferred Rate Case Expense, and then ignore this calculation in the development of Rate Case Expense for Net Operating Income. The Directors, therefore, determined and adopted $178,834 as the proper forecast for Deferred Rate Case Expense, and $119,221 as the proper forecast for Rate Case Expense.

V(a)7. PREPAYMENTS

Prepayments are an investment in working capital that are made in advance of the period to which they apply and include items such as prepaid rents, insurance, and taxes. The amortization of these costs are then treated on the income statement as an expense.

[10] March 31, 1998, represents the midpoint of the attrition year (October 1, 1997 -- September 30, 1998). Therefore, March 31, is the appropriate point in time to measure the Company's net investment against their earnings.

The Company included $1,189,348 representing the test period average of this account from October 1995 to September 1996 as its forecast of Prepayments during the attrition year. AVI accepted the Company's forecast in their Exhibits. The Advocate included only $769,193 in its Exhibits for Prepayments. Further, the Advocate presented no testimony or rationale on the methodology behind its forecast for Prepayments. The Advocate presented no cross-examination of any witness at the Hearing or made mention of this issue in its post-hearing briefs.

Since the Company's forecast of $1,189,348 represents the test period average of this account for October 1995 to September 1996, the Directors unanimously adopted the Company's forecast as the proper estimate for Prepayments.

V(a)8. OTHER ACCOUNTS RECEIVABLE

The category "Other Accounts Receivable" represents amounts owed to the Company by their customers that are not associated with regular gas service. An example of Other Accounts Receivable would be for amounts due from customers for main extensions that are being paid on an installment basis.

The Company included $92,028 representing the test period average of this account for October 1995 to September 1996 in Rate Base as its forecast of Other Accounts Receivable during the attrition year. AVI accepted the Company's forecast. The Advocate included $138,738 in its case for Other Accounts Receivable. However, the Advocate presented no testimony or rationale regarding the calculation of its forecast. The Directors were not presented with cross-examination of any witness at the Hearing relating to this issue.

Because the Directors found no evidence to support any other forecast, the Directors unanimously adopted the Company's forecast as the proper estimate for Other Accounts Receivable.

V(a)9. LEAD LAG STUDY

The Lead/Lag Study measures the average amount of capital provided by investors, over and above the investment in other Rate Base issues, to finance company activities between the time expenditures are required to provide services and the time collections are received for services. The Lead/Lag Study recognizes that there is an investment required on the part of the stockholders to pay for the day-to-day expenses of the utility before they are recovered through rates charged to the ratepayer.

Each of the Parties adopted the Company's Revenue Lag Day forecast of 41.60 days. However, there arose a dispute over the proper number of expense lag days to include. The Advocate proposed a separate treatment on lag days for uncollectible expense, but offered no testimony regarding the rationale for this change. The Directors, therefore, unanimously accepted the position of the Company and AVI that lag days concerning uncollectible expense should be included with other operating expenses.

A second dispute concerned AVI's elimination of depreciation expense from the calculation of expense lag days. The Company and the Advocate each included Depreciation Expense in the Lead/Lag Study at zero (0) days. AVI contended that Accumulated Depreciation was already included in Rate Base and that the Company was already earning a return on those assets. However, the Directors recognized that including the Depreciation Expense in the Lead/Lag Study at zero (0) Lag Days is necessary to recognize that investor funding has occurred, but was not yet recovered. The Directors approved the positions of the Company and the Advocate on this item.

A third dispute involved the appropriate lag days for interest expense. The Company used zero lag days for this issue while the Advocate and AVI used 85.5 and 82.5 days, respectively. Because the Authority permitted the recognition of Interest Expense in the Lead/Lag Study in prior cases, the Directors determined that the recognition of Interest Expense should be recognized in this case. The Directors unanimously concluded, therefore, that Interest Expense should be included in the Lead/Lag Study at 84 days.

A final area of dispute involved the appropriate lag days for Preferred Dividends and Net Earnings. Including the preferred dividends and net earnings in the Lead/Lag Study recognizes that investor funding has occurred, but that it has not been recovered. AVI excluded these items from the Lead/Lag Study based on its characterization of them as non-cash expenditures.

The Directors found that consideration of each of the prior adjustments produces an Expense Lag of 38.46 days, resulting in a net lag day effect of 3.14 days.[11] In addition, multiplying the net lag days by the daily cost of service of $660,923 and taking incidental collections of $49,828 into consideration gives $266,399 for the results of the Lead/Lag Study.

LEAD/LAG STUDY RESULTS

	Company[12]	Consumer Advocate[13]	AVI[14]	Authority
Revenue Lag Days	41.60	41.60	41.60	41.60
Expense Lag Days	34.80	38.40	42.98	38.46
Net Lag Days	**6.80**	**3.20**	**-1.38**	**3.14**
Daily Cost of Service	$262,727	$248,986	$234,583	$226,399
Operating Funds Advanced	$1,786,544	$805,866	$-322,783	$710,751
Incidental Collections	-49,828	-49,828	-49,828	-49,828
Lead/Lag Study Results	**$1,736,716**	**$756,038**	**$-372,611**	**$660,923**

The Directors, therefore, adopted $660,923 as the appropriate amount to include for the Lead/Lag component of Rate Base.

11 Preferred dividends and net earnings are included in the Lead/Lag Study at 0 days.
12 Chattanooga Gas Exhibit 5, Schedule 8, Page 3 of 4.
13 Advocate Pre-Filed Exhibit, Schedule 5.
14 AVI Exhibit MPG-1, Schedule 8. However, on page 17 of his direct testimony, Mr. Gorman uses $396,530 for his Lead/Lag results. He then carries the $396,530 figure to his Rate Base calculation. This discrepancy remains unexplained.

V(a)10. ACCUMULATED DEPRECIATION

Recovery of the dollars invested in Plant in Service is permitted over the plant's estimated useful life by a systematic depreciation charge. The Accumulated Depreciation account represents the amount of plant that has already been recovered from utility customers through the annual Depreciation Expense charges on the income statement.

The Company applied the results of its Depreciation Study to its forecast of Plant in Service to calculate its Depreciation Expense and Accumulated Depreciation of $46,569,377. AVI accepted this same amount of Accumulated Depreciation. The Advocate included $46,478,394 as their forecast of Accumulated Depreciation. This figure is $90,983 less than the Company's calculation. According to the Advocate, this difference is due to using a "simple average" rather than a thirteen (13) month average to develop Accumulated Depreciation.[15]

In consideration of the Authority's previous acceptance of the Company's forecast of Plant in Service, see section (V(a)1.), of this Order, that was based upon a thirteen (13) month average, the Directors unanimously adopted the Company's companion forecast of $46,569,377 for Accumulated Depreciation.

V(a)11. ACCUMULATED AMORTIZATION OF ACQUISITION ADJUSTMENT

This item represents the Company's total accumulated amortization of their Acquisition Adjustment. Treatment of any Acquisition Adjustment governs the appropriate handling for the related Accumulated Amortization. Because of the action taken on the Acquisition Adjustment in section V(a)2. of this Order, the Directors determined that this issue was moot.

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[15] R. Terry Buckner Pre-Filed Direct Testimony, at page 18.

V(a)12. ACCUMULATED DEFERRED FEDERAL INCOME TAXES

The Directors found no disagreements among the Parties on the $5,131,816 amount of Accumulated Deferred Federal Income Taxes ("ADFIT") forecast by the Company. The Directors, therefore, unanimously adopted the Company forecast in the amount of $5,131,816 for ADFIT.

V(a)13. CUSTOMER ADVANCES FOR CONSTRUCTION

Customer Advances for Construction represent funds that are advanced from ratepayers for various construction projects. The Directors found no disagreement among the Parties over the forecast of Customer Advances, and unanimously adopted the Company's forecast of

$384,855 as the proper amount for this account.

V(a)14. CONTRIBUTIONS IN AID OF CONSTRUCTION

Contributions In Aid of Construction represents funds that are received from ratepayers for certain construction projects. These projects are undertaken when the Company's facilities are either extended or relocated at the customer's request in an area that is not likely to be economically feasible to serve under normal conditions. The Company forecasted an attrition year balance of $1,908,645. AVI also used this amount in their calculation of Rate Base. The Advocate included $1,858,651 in its exhibit for Contributions In Aid of Construction. The Advocate, however, presented no testimony or other rationale regarding the calculation of its forecast. Since the Company's forecast reflects the actual test period average balance, and because the record was absent evidence to support any other calculation, the Directors unanimously adopted the Company's forecast of $1,908,645.

V(a)15. RESERVE FOR UNCOLLECTIBLE ACCOUNTS

The Company included $278,723 in their Reserve for Uncollectible Accounts based on the development of an uncollectible factor that was then applied to estimated revenues for the attrition period. While AVI accepted the Company's forecast for this issue, the Advocate projected an uncollectible reserve balance of $257,864.

Based on the record, a majority of the Directors concluded, that it is reasonable that a Company with net revenues forecasted in excess of $32 million may establish a bad debt reserve of $257,864 or approximately 8/10ths of 1 percent of its projected revenue. Additionally, the majority concluded that, based on the Company's past bad debt experience, its estimate for the attrition period was reasonable. Further, the majority restated that no party challenged the Company's estimate, except the small undocumented adjustment by the Advocate. Therefore, a majority of the Directors adopted Chattanooga Gas' attrition period Reserve for Uncollectible Accounts in the amount of $278,723.[16]

V(a)16. OTHER RESERVES

Other Reserves represents an allowance that the Company has established for maintenance of their liquefied natural gas (LNG) facility. This allowance represents the net accumulation of expenses that were previously recognized in Net Operating Income, and must be deducted from Rate Base. The Company included $549,562 in their forecast for Other Reserves. This amount was also accepted by AVI in their forecast of Rate Base. The Advocate included $409,201 for Other Reserves. The record reflects that the Advocate presented neither testimony nor rationale on the methodology used to calculate their forecast. As the record supported the Company's forecast, the Directors unanimously adopted the forecast by Chattanooga Gas for Other Reserves in the amount of $549,562.

[16] Director Kyle voted no on this issue.

V(a)17. CUSTOMER DEPOSITS

Customer Deposits represents funds received from ratepayers as security against potential losses arising from customer failure to pay for service. These funds represent a liability of the Company for repayment either after a specified period or upon satisfaction of certain credit requirements. These funds also represent a source of non-investor supplied capital, and must therefore be deducted from the Rate Base calculation.

The Company included $3,766,190 in their forecast of Customer Deposits. AVI accepted this amount in its forecast of Rate Base. The Advocate, however, adjusted Chattanooga Gas' forecast to reflect a balance of $1,917,229 based upon the Company's acknowledgment that it overstated its forecast of Customer Deposits. Since there were no disputes entered into the record by any of the Parties regarding the Advocate's forecast, the Directors unanimously adopted the Advocate's forecast in the amount of $1,917,229 as the appropriate amount for Customer Deposits.

V(a)18. ACCRUED INTEREST ON CUSTOMER DEPOSITS

The rules of the Authority require gas utilities to accrue interest on Customer Deposits. This interest is then refunded to the customer along with the security deposit after a specified period when credit worthiness has been demonstrated. The Directors concluded that, because the Interest on Customer Deposits is recognized as an expense in computing Net Operating Income, the accrued interest that has not been paid out should be treated as a deduction to Rate Base.

All of the Parties included $671,344, in Rate Base for their forecast of Accrued Interest on Customer Deposits. However, even though the Company admitted to an error in their forecast of Customer Deposits, none of the Parties made a corresponding adjustment to the Accrued Interest on Customer Deposits.

The Directors, therefore, unanimously approved $686,049 which represents the thirteen (13) month test period average for this account, as the proper forecast for Accrued Interest on Customer Deposits. Therefore, the Directors found after considering the adjustments described previously, that a Rate Base of $92,955,599 is calculated as illustrated in the following table.

COMPARATIVE RATE BASE CALCULATIONS

	Company[17]	Advocate[18]	AVI[19]	Authority
Additions:				
Plant in Service and CWIP	$140,014,935	$140,614,494	$140,014,935	$140,014,935
Acquisition Adjustment	13,355,565	0	0	0
Cash	2,373,422	2,373,422	0	2,373422
Materials and Supplies	453,221	346,273	453,221	453,221
Gas Inventories	5,419,144	6,659,404	5,419,144	5,419,144
Deferred Rate Case Expense	200,668	47,309	200,668	178,834
Prepayments	1,189,348	769,193	1,189,348	1,189,348
Other Accounts Receivable	92,028	138,738	92,028	92,028
Lead/Lag Study	1,736,716	756,038	-396,530	660,923
Total Additions	**$164,835,047**	**151,704,871**	**$146,972,814**	**$150,381,855**
Deductions:				
Accumulated Depreciation	$46,569,377	$46,478,394	$46,569,377	$46,569,377
Accu Amort of Acq Adj.	4,196,041	0	0	0
Accumulated Deferred FIT	5,131,816	5,131,815	5,131,816	5,131,816
Customer Advances	384,855	384,974	384,855	384,855
Contributions in Aid of Const.	1,908,645	1,858,651	1,908,645	1,908,645
Reserve for Uncollectibles	278,723	257,864	278,723	278,723
Other Reserves	549,562	409,201	549,562	549,562
Customer Deposits	3,766,190	1,917,229	3,766,190	1,917,229
Accrued Int on Cust Deposits	671,344	671,344	671,344	686,049
Total Deductions	**$63,456,553**	**$57,109,472**	**$59,260,512**	**$57,426,256**
Rate Base	**$101,378,494**	**$94,595,399**	**$87,712,302**	**$92,955,599**

17 Company Exhibit 5, Schedule 8, Page 1 of 4.
18 Consumer Advocate Pre-Filed Exhibit, Schedule 3.
19 AVI Exhibit MPG-1.

V(b). NET OPERATING INCOME

Net Operating Income ("NOI") represents the earnings of the Company under present rates that are available after all issues of the cost of providing utility service have been considered.

V(b)1. BASE RATE REVENUES

Base Rate Revenues represent the gross margin, gas revenues less gas cost, of the Company at present rates. The Company forecasted their Base Rate Revenues under present rates to be $31,206,762. In their forecast, the Company included the sales volumes for certain Industrial customers at contract rates that were proposed in other dockets, but were subsequently denied. Volumes to these customers should now be priced at the existing Industrial tariff rate. According to the Advocate, making this special contract change will add $606,518 to the Company's base rate forecast, while AVI projects a $635,458 adjustment. The Company did not dispute either of these adjustments in its rebuttal testimony.

As there was no dispute that the adjustments should be made, and because the amounts proposed are close, the Directors unanimously determined that an average of the two adjustments, or $620,988 be adopted. Further, the Directors unanimously approved adding the $620,988 adjustment to the Company's original forecast of $31,206,762 that resulted in a forecast of $31,827,750 for Base Rate Revenues.

V(b)2. OTHER REVENUES

Other Revenues represent revenues that the Company indirectly collects which are not necessarily involved in providing gas service. For example, discounts that are forfeited by the customers who do not promptly pay their bills are included in Other Revenues. The Company included $929,361 in their forecast of Other Revenues. AVI accepted the Company's forecast for this item. The Advocate made two adjustments to the Company's forecast. The Advocate first added $13,862[20] for returned check charges. According to the Advocate, the Company omitted these charges from their forecast. There was no controversy with the Company regarding this issue.

The Advocate's second adjustment to the Company's forecast decreased forfeited discount revenue by $59,657.[21] The Advocate's calculation was based upon a five-year average ratio of forfeited discount revenue to total revenue. Again, there was no dispute on this adjustment with the Company or AVI for this item.

Due to the lack of objections on the record to the adjustments, the Directors unanimously adopted the Advocate's position and included the Advocate's $883,749 amount in Other Revenues. In addition, the Directors also unanimously approved the Advocate's five-year average forfeited discount ratio of 0.006837[22] for the Revenue Conversion Factor.

V(b)3. ALLOWANCE FOR FUNDS USED DURING CONSTRUCTION

Allowance for Funds Used During Construction is not a revenue item, but represents a reduction, or capitalization, of interest expense and equity costs that the Company incurs on projects taking more than thirty (30) days to complete. All of the Parties accepted the Company's forecast of $32,373 for this item. The Directors unanimously concluded, therefore, that the Company's forecast was reasonable and adopted a forecast of $32,373 for this item.

20 Daniel W. McCormac Pre-Filed Direct Testimony, at page 5.
21 Id.
22 Advocate Pre-Filed Exhibit, Schedule 14.

V(b)4. SALARIES AND WAGES

Salaries and Wages represent the direct labor and benefit expenses of the Company's employees in Chattanooga. The Company's calculation was $3,136,136 for Salary and Wage Expense. AVI accepted the Company's forecast for Salary and Wages. The Advocate forecasted $3,084,307 in Salary and Wage Expense, which was $51,829 less than the Company's forecast. There is no mention in the Advocate's testimony of the cause for this difference. Because the record fails to reflect explanations for the difference in the Advocate's calculations, the Directors unanimously accepted the Company's forecast of $3,136,136 for Salary and Wage Expense.

V(b)5. DISTRIBUTION EXPENSE

Distribution Expense relates to costs incurred in operating and maintaining the Company's gas distribution system. Some examples of items that would be classified as Distribution Expense would include expenses relating to dispatching, metering, and maintenance of the Company's mains and service lines. Because these types of expenses cannot be easily priced individually, the Parties agree that they must rely on a growth factor to forecast distribution expenses.

The growth factor contains an inflation component and a customer growth component that produces a measure of the expected annual growth. The annual growth factor is then compounded for the number of months to the end of the attrition period to produce a total growth factor. The test period level of expenses is then multiplied by the total growth factor to give the attrition period forecast expense.

V(b)5a. CUSTOMER GROWTH RATE

The Company computed a compound customer growth rate of 8.95 for twenty-four (24) months that produces a 4.38 percent annual growth. The Company's computation is slightly below the Advocate's proffered annual customer growth rate of 4.65 percent. The record reflects that the

Advocate made no adjustment to the Company's revenue calculation for customer growth. Since the record appeared to reflect that the Advocate accepted the Company's customer growth calculation for revenues, the Directors unanimously found that it was consistent to accept the Company's customer growth calculation for expenses. Therefore, on this sub-item, the Directors unanimously adopted the Company's annual customer growth calculation of 4.38 percent.

V(b)5b. CUSTOMER GROWTH ADJUSTMENT

The Advocate argued that 50 percent of the annual customer rate should be considered based on this Authority's historical practice of adjusting customer growth by 50 percent in natural gas company rate cases. The Company objected to this adjustment in their rebuttal testimony. The Directors determined that, historically, not all expenses increased over time due to customer growth. While some expenses such as vehicle maintenance expenses increase proportionately with customer growth, others such as office maintenance expenses have no correlation with customer growth. Therefore, on this sub-item, the Directors unanimously adopted the 50 percent adjustment proposed by the Advocate.

V(b)5c. COMPOUND INFLATION RATE

The Company computed a compound inflation rate of 6.67 percent for twenty-four (24) months as measured by the Consumer Price Index. This computation produced a 3.15 percent annual inflation rate. The Advocate used 2.19 percent as its annual inflation rate as measured by the gross domestic product ("GDP") deflator. At the Hearing, the Company witness stated that either index could be used as a measure of inflation. This Authority has recognized that the GDP index is a more appropriate measure for use in rate cases. Therefore, the Directors unanimously adopted an annual GDP factor of 2.36 percent based on the blue-chip indicator's publication as stated on page 13 of Mr. Buckner's testimony from the Advocate's Office.[23]

V(b)5d. COMPOUND GROWTH FACTOR

Considering all of the sub-items included in distribution expense, a compound growth factor of 9.31 percent is produced as shown below.

GROWTH FACTOR CALCULATIONS

	Company[24]	Consumer Advocate[25]	Authority[26]
1. Annual Customer Growth Rate	4.38%	4.65%	4.38%
2. Percentage Allowed	100%	50%	50%
3. **Net Annual Customer Growth Rate**	**4.38%**	**2.33%**	**2.19%**
4. Annual Inflation Rate	3.15%	2.19%	2.36%
5. **Total Annual Growth Factor**	**7.53%**	**4.52%**	**4.55%**
6. Months to Compound	24	19	24
7. **Total Compound Growth Factor**	**15.62%**	**7.25%**	**9.31%**

The Directors adopted 9.31 percent as the proper factor to grow expenses in this matter that are not specifically priced out. By applying the 9.31 percent growth factor to the Company's September 30, 1996, adjusted test period distribution expenses of $848,394, the growth factor produces an attrition period balance of $927,379. The Directors found, therefore, that $927,379 was a proper level of distribution expense.

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23 R. Terry Buckner Pre-Filed Direct Testimony at page 13.

24 Gerald A. Hinesley Pre-Filed Direct, at page 4.

25 The Advocate's total compound growth factor is 7.25 percent according to R. Terry Buckner Pre-Filed Direct Testimony, at page 13. His testimony describes this growth factor as compounded for a 19 month period (May 31, 1997 through September 30, 1998), it is, however, a 16 month period.

26 The annual customer growth rate of 4.38 percent is the rate used by the Company.

V(b)6. STORAGE EXPENSE

Storage Expense relates to costs, other than labor and gas, incurred in operating and maintaining the Company's gas storage assets. The Company owns a liquefied natural gas (LNG) facility that is included in the Rate Base calculation under Plant in Service. The LNG facility cools natural gas to a very low temperature until it is converted into a liquid state. The liquefied gas is then stored until needed, at which time it is heated and vaporized back into a gaseous state. This process makes it efficient to store large quantities of natural gas in a relatively small containment area. The cost of operating and maintaining the LNG facility is accounted for as Storage Expense.

Chattanooga Gas and the Advocate forecasted Storage Expenses of $987,610 and $813,689, respectively. AVI accepted the Company's forecast for Storage Expense in their calculation of NOI. The Directors concluded that the difference between the Company and Advocate's calculation of Storage Expense resulted from the use of their different growth factors. After reducing the Company's test year Storage Expense for $34,000[27] in certain non-recurring items, the Directors unanimously concluded that applying the adopted growth factor of 9.31 percent to the September 30, 1996, adjusted test period balance of $820,191, produced an attrition amount of $896,551. The Directors, therefore, approved $896,551 as the proper level of Storage Expense.

V(b)7. CUSTOMER ACCOUNTS EXPENSE

Customer Accounts Expense relates to costs incurred, excluding labor, in billing and collecting amounts owed by Company customers. Some examples of items that would be classified as Customer Accounts Expense would include meter reading, cashiers, and collection expenses.

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[27] See Authority clarification request #78 with response filed by Chattanooga Gas and copies to all Parties filed August 13, 1997. This Adjustment was not taken into account by either the Company or the Advocate.

The Directors unanimously concluded that applying the adopted growth factor of 9.31 percent to the September 30, 1996, adjusted test period balance of $88,951 produced an attrition period balance in this category of $97,232. The Directors, therefore, unanimously approved a balance of $97,232 as the appropriate forecast for Customer Accounts Expense.

V(b)8. UNCOLLECTIBLE EXPENSE

Uncollectible expenses recognize the Company's annual provision for amounts due from customers that will not be collected. On October 1, 1996, the Company changed the methodology by which it recognizes uncollectible expenses to one that estimated the expense based on actual net write-offs in the uncollectible account. The Company's new methodology would not have been recognized in this rate proceeding because the test period ended September 30, 1996. Therefore, the Company chose to update their test period to the twelve (12) months that ended February 28, 1997, for Uncollectible Expense, and use the September 30, 1996, test period for all other items.[28] By updating the test period to February 28, 1997, the Company recognized $385,019 in their forecast for Uncollectible Expense.

Both AVI and the Advocate disagreed with the Company's methodology. The Advocate argued that the Company's calculation was more than double the historical amounts for the previous six (6) fiscal years.[29] The Advocate also argued that the Company did not present any evidence that shows that the expense will continue at this rate. The Advocate chose to include only $165,968 in its forecast as Uncollectible Expense. This amount represents the average of the Company's actual net write-offs for the last seven (7) years and eight (8) months. AVI also opposed the Company's proposed forecast of Uncollectible Expense because it is not based on test

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[28] *In re: Petition of Chattanooga Gas Company to Place Into Effect a Revised Natural Gas Tariff, Hearing on the Merits before the Tennessee Regulatory Authority, Transcript of Proceedings*, February 10, 1998, Volume 2B, at page 177.

[29] R. Terry Buckner Pre-Filed Direct Testimony, at page 12.

year data as previously described.[30] AVI proposed instead to use the 1996 actual Uncollectible Expense of $199,019 in its forecast.

The Directors concluded that it would not be appropriate to recognize an eight (8) month period in the development of any annual average as the Advocate has done. Rather, the Directors unanimously adopted the use of a seven (7) year average of the net write-offs from 1990 to 1996 as the proper forecast of Uncollectible Expense. This produces $138,006 in forecasted Uncollectible Expense. The Directors concluded that this methodology recognizes that the aged delinquent accounts should be properly recognized as a recurring event over a longer period of time. This adoption also changes the Uncollectible Expense component of the Revenue Conversion Factor to 0.005368.[31]

V(b)9. SALES PROMOTION EXPENSE

Sales Promotion Expense relates to costs incurred, excluding labor, to promote or retain the use of utility services by present or prospective customers. Some examples of items that would be classified as Sales Promotion Expense would include demonstrating expenses, selling expenses, and advertising expenses.

The Company forecasted Sales Promotion Expense of $455,531. The Company's forecast was made by taking the test period balance of Sales Promotion Expense in the amount of $367,929[32] and then eliminating labor expenses. The balance was then increased by the Company's compound inflation and customer growth factor. This forecast was adopted by AVI in their calculation of NOI.

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30 Michael Gorman Pre-Filed Direct Testimony, at page 21.

31 Uncollectible Expense of $138,006 / Test Year Residential and Commercial Revenues of $25,707,838 = 0.005368.

32 Company Workpapers O&M-6 and O&M-7.

The Advocate recommended a forecast based on a standard criterion of .5 percent of revenues. Further, the Advocate stated that the Tennessee Public Service Commission found the .5 percent factor to be consistent with the rule on sales promotional expense, and referred to this factor as a policy. The Directors stated emphatically that neither the Authority nor the Tennessee Public Service Commission ever adopted a policy of .5 percent for the expense of promotions. The Directors found that in the 1984 Application of Nashville Gas Company, a Division of Piedmont Natural Gas Company, Inc., for an Adjustment of its Rates and Charges, a .5 percent factor was applied to nonpayroll cost only. The .5 percent factor was unique to that case. The Directors clearly and unequivocally stated that there is no policy for this .5 percent factor as the Advocate asserted. Further, the Court of Appeals dispels the Advocate's argument on this issue.[33] Applying

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[33] The Court of Appeals held:

> This is an issue on which the briefs of the principal parties seem to be speaking different languages. The following explanation is the best we can glean from the record. In 1984 the Public Service Commission adopted a rule that disallowed as a recoverable expense by a utility any "promotional or political advertising." The prohibition covered advertising for the purpose of encouraging any person to select or use gas service or additional gas service. It did not cover (among other things) advertising informing customers how to conserve energy or to reduce peak demand for gas, or advertising promoting the use of energy efficient appliances. See former Rule 1220-4-5-.45, Tenn. Regis.
>
> In a 1985 proceeding involving a rate increase application by NGC, the Commission deviated from the rule and allowed advertising expenses up to .5 percent of revenues. In March of 1996 the Commission repealed 1220A-5-.45 and proposed a new rule that would allow a utility to recover "all prudently incurred expenditures for advertising." Apparently the rule had not made it completely through the adoption procedure when the TRA heard this case below. Nevertheless, based on proof of $1,486,000 in external advertising expenses, $800,000 in marketing personnel payroll and $300,000 in miscellaneous sales expenses, the TRA allowed the recovery of all but approximately half of the external advertising expenses. The CAD urged disallowance of all the related expenses except approximately $647,000 and NGC claims that the TRA erred in reducing the external operating expenses because there was no proof that they were imprudently incurred.
>
> We think the TRA was justified in its conclusion on this issue. Based on the testimony in the record that the advertising expenses were incurred to meet competition, to add new customers on existing mains, and to get existing customers to use more gas, the TRA concluded that the rate payers benefited from at least part of the external advertising.

Consumer Advocate Division v. Tennessee Regulatory Authority, No. 01-A-01-9708-BC-00931, op. at 8, 9 (Tenn. Ct. App., July 1, 1998).

the 9.31 percent growth factor discussed previously to the test period balance produces a forecast of $430,670. The Directors, therefore, unanimously concluded that $430,670 was an appropriate forecast for promotion expense, and adopted the sales promotion expense forecast of the Company.

V(b)10. ADMINISTRATIVE AND GENERAL EXPENSE

Administrative & General Expense ("A&G") relates to costs incurred, excluding payroll, in operating the utility that are not directly chargeable to a particular function. Some examples of items that would be classified as A&G Expense would include audit and pension expense. The Company calculated $2,448,665 for A&G Expense while the Advocate only included $2,115,562 in their forecast. AVI accepted the Company's forecast in their calculation of NOI. The table below highlights the differences between the Parties for A&G Expense.

DETAIL OF A&G EXPENSE

	Company and AVI	Consumer Advocate[34]	Authority
Growth Factor	$1,000,969	$928,506	$787,373
Rate Case Expense	168,144	64,334	119,221
Other Items	1,279,552	1,122,722	1,279,552
Total	**$2,448,665**	**$2,115,562**	**$2,186,146**

Applying the growth factor of 9.31 percent[35] to the September 30, 1996, adjusted test period balance of $720,312 produces an attrition amount of $787,373. The Directors, therefore, unanimously adopted $787,373 as the appropriate level of A&G Expense relating to customer growth and inflation.

[34] The Advocate's A&G Expenses related to growth based on the test period is the amount increased by the Advocate's growth factor. However, the difference in the calculation was not able to be reconciled with the Advocate's case.

[35] See Section V(b)5e.

The Company used their growth factor to determine the attrition year level of Rate Case Expense. The Company took the test period expense of $145,428 and increased it by 15.62 percent[36] to arrive at an attrition-year-rate-case expense of $168,144. The Advocate estimated the cost to complete the current case to be $144,500. [37] The Advocate took this estimated cost and amortized it over three years to give an annual amortization of $48,167. The Advocate then added one year of additional amortization or $16,167 from the Company's 1995 rate case to obtain their total Rate Case Expense of $64,334.

The Directors found that these Rate Case Expense calculations should have been related to the Deferred Rate Case Expense. The Directors concluded that the estimated cost of this case should be added to the test period Deferred Rate Case Expense with the total amortized over a new three year period. This calculation produced Rate Case Expense of $119,221. The Directors, therefore, adopted $119,221 as the proper level of A&G Expense relating to Rate Case Expense.

Finally, the Advocate reduced the Company's forecast of the remaining items of A&G Expense from $1,279,552 to $1,122,722. However, the Directors found that the Advocate failed to document its reasoning for this reduction in its testimony or through cross-examination at the Hearing. Therefore, the Directors unanimously adopted $1,279,552 as the appropriate level of A&G Expense relating to "other items" of A&G Expense.

The total for all three components of A&G Expense equals $2,186,146. Therefore, the Directors unanimously approved this amount as the proper level of A&G Expense.

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36 Gerald A. Hinesley Pre-Filed Direct Testimony, at page 4, and Company Workpaper O&M-1.

37 R. Terry Buckner Pre-Filed Direct Testimony, at page 14.

V(b)11. CORPORATE ALLOCATIONS

During the 1996 fiscal year, corporate shared services were allocated based on a percentage of approximately 3.8 percent[38] of AGL's customers in Tennessee and Georgia. Beginning in October 1996, the Company changed its allocation methodology. The new overhead allocation methodology uses numerous allocation percentages, depending on the type of service rendered. Allocations can be based on the number of full-time employees, number of users, hours used, number of customers or any combination of these drivers. The allocation percentages are updated monthly using a computer allocation model.

James Kissel, a Senior Manager with Deloitte & Touche Consulting Group testifying for Chattanooga Gas, stated that the purpose of his testimony was to "demonstrate that the methodology is rational, fair and equitable."[39] He also stated that his testimony "addresses only the approach to allocating costs and not the actual cost levels of the various business functions."[40] In his Pre-filed testimony, he goes into great detail describing the various services that are allocated and the rationale for selecting the appropriate drivers to allocate these services. Using a "typical year," he stated that Chattanooga Gas would receive a composite allocation of 3.7 percent.[41] This was reiterated where he stated that, ". . . the new methodology allocates 3.7 percent of the central service costs to Chattanooga Gas Company."[42] He detailed, as did Mr. Thompson, President of Chattanooga Gas Company,[43] that there was an increase in cost allocation to Chattanooga Gas due to the inclusion of costs not formerly allocated to Chattanooga Gas.[44] Mr. Kissell's estimate of the

38 James E. Kissel, Pre-Filed Direct Testimony, at page 15.
39 Id., at page 2.
40 James E. Kissell Pre-Filed Direct Testimony, at page 2.
41 Id, at page 11.
42 Id, at page 13.
43 Harrison F. Thompson Pre-Filed Direct Testimony,at page 5
44 James E. Kissell Pre-Filed Direct Testimony, at pages 11-13.

increase to Chattanooga Gas, when costs were fully allocated, was approximately $2.3 million. [45] Mr. Kissell also responded that allocating costs on a single driver, such as customers, does not accurately reflect the amount of resources consumed by the individual business organization. [46]

The Advocate argued that there were several problems with accepting the Company's new methodology for allocating common costs. First, because the methodology is excessively complex, it would be extremely difficult for a regulator to verify that costs are being accurately allocated to Tennessee. Secondly, because there are multifactors involved, the potential exists for AGL to manipulate costs between jurisdictions, thereby recovering over or under 100 percent of its common costs. A company's "external auditors rarely, if ever, certify the accuracy of charges between jurisdictions, but usually examine only the Company's operations in total." [47] Instead, the Advocate recommends that AGL allocate its common costs using a single allocation component based upon the number of customers in Georgia and Tennessee. [48] The Advocate also argued that this methodology would not only leave a cleaner audit trail, but also allow regulators to verify the accuracy of the charges allocated to Tennessee and Georgia customers.

In addition to disagreeing with the Company's allocation methodology, the Advocate also disagreed with the Company's allocated expenses of $5.227 million. The Company annualized their fiscal year-to-date base costs. These annualized costs were then allocated to Chattanooga Gas using the new allocation model.

The Advocate also annualized the base costs to be allocated, and then used a single allocation percentage of 3.73 percent based on the number of Tennessee customers. The Advocate argued that the Company claimed that the new methodology allocates 3.7 percent of the central

45 James E. Kissell Pre-Filed Direct Testimony , at page 11.
46 Id., at page 15.
47 R. Terry Buckner Pre-Filed Direct Testimony, at page 8.
48 Id., at page 5.

service costs, while the actual composite percentage allocated to Chattanooga Gas in the Company's case is 5.13 percent. These different approaches account for $1.249 million of the difference between the Advocate and the Company's case for this item. The Advocate next indicated that the difference in the rate of return on allocated net assets accounts for an additional $0.155 million. Finally, the Advocate argued an additional difference of $0.093 million occurred because the Company did not allocate any of its corporate office costs to non-utility operations. As a result of its analysis, the Advocate recommended an inclusion of $3.730 million in Corporate Allocated Expenses.

AVI stated that the Company did not provide support for the allocation factors used to forecast its estimated shared service allocation to Chattanooga Gas.[49] AVI also argued that this item represents the largest single adjustment to the test year cost of service, and that the Company should be compelled to provide support to show the complete derivation of all elements used to establish this reallocation. Absent a clear demonstration of support for the Company's calculations, AVI asked that the reallocation be rejected.[50]

While Company witness James Kissel testified that the new methodology is the "most fair, equitable and rational approach,"[51] his colleague at Deloitte & Touche, Gregory E. Aliff, co-author of ACCOUNTING FOR PUBLIC UTILITIES, stated that:

> For a utility, the basic goals of intercompany cost allocation methodologies are to:
> (1) prevent or limit, to the extent possible, any cross-subsidization of one activity or entity by another; and
> (2) minimize the time and expense necessary to reflect and audit the transactions.
>
> The second goal of a cost allocation system is to minimize the time and expense necessary to record and audit transactions. This goal is important because the system for

49 Michael Gorman Pre-Filed Direct Testimony, at page 22.
50 Id., at page 22.
51 James E. Kissell Pre-Filed Direct Testimony, at page 15.

> allocating shared costs must be understandable and workable. The personnel responsible for the accounting and reporting of the costs must be able to apply the system properly if it is to produce the desired results. In addition, an overly detailed or complex system could increase business costs and diminish any cost benefits of the shared activities. Thus, it is possible for the system to impact the economics of the business transaction.
>
> The time and expense necessary to audit the transactions is also an important consideration. Similar to accounting and reporting for these transactions, auditing intercompany transactions should not impose an extreme cost burden or be so time consuming as to prevent effective system testing. These requirements would most likely result in resistance to or nonacceptance of the system by regulators and others."[52]

The Directors' review of the record in this matter compelled them to concur with the Advocate in concluding that the complexity of the allocation methodology implemented by Chattanooga Gas makes it difficult to accept. The Directors made no judgments regarding the accuracy of AGL's allocation methodology, but did conclude that regulation requires a more audit-friendly environment. The Directors found further that the burden for determining fairness, equity, and accuracy of costs imposed on Tennessee ratepayers should not shift to the Authority either by design or by chance. While the Directors stated that they fully endorse systems that more accurately ascribe costs to cost causes, they determined that an allocation system must minimize the time and expense necessary to reflect and audit transactions. Therefore, the Directors unanimously concluded that the use of a single allocation formula based on customers in Tennessee and Georgia is the most appropriate method of allocation of common cost at the present time. Additionally, the Directors found that the Advocate correctly asserted that the Company did not allocate any of its corporate office costs to nonutility operations. Therefore, the Directors unanimously adopted the Advocate's forecast of $3.730 million in Corporate Allocated Expenses. Additionally, the Directors unanimously adopted the Advocate's recommendation for a single allocation factor, based on

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52 R.L. HAHNE AND G.E. ALIFF, ACCOUNTING FOR PUBLIC UTILITIES, Matthew Bender, Accounting Series, §19.02, page 19-4, 19-5.

customers for financial reporting purposes, and that this factor shall only be updated within a rate case.

V(b)12. INTEREST ON CUSTOMER DEPOSITS

Authority rules require gas utilities to accrue interest on Customer Deposits. This interest is then refunded to the customer along with the security deposit after a specified period when credit worthiness has been demonstrated.

The Company and AVI forecasted incorrect amounts for this issue. The Advocate had attempted to correct the error but ignored its effect on accrued interest in customer deposits. Therefore, the Directors found that the Advocates' forecast should be discarded. The Directors concluded that the test period balance for this account was representative of the attrition year. The Directors, therefore, unanimously adopted the test period balance of $126,744 for Interest on Customer Deposits.

V(b)13. MISCELLANEOUS EXPENSE RELATING TO CHARITABLE DONATIONS

The Company included $37,540, in their case as Miscellaneous Expense. This item represents donations to the civic, community and charitable organizations of Chattanooga and Cleveland, Tennessee. According to testimony from the Company's witness, Chattanooga Gas feels a responsibility to be a good corporate citizen and therefore makes these donations to various organizations. [53]

The Advocate objects to these types of expenses and has excluded them from their case. According to the Advocate, charitable donations should not be allowed in setting rates. [54] AVI accepted the Company's calculation for charitable donations in their case.

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53 Gerald A. Hinesley Pre-Filed Rebuttal Testimony, at page 4.

54 R. Terry Buckner Pre-Filed Direct Testimony, at page 14.

A majority of the Directors found that accounting principles and standards under which regulated companies operate generally will not support charitable contributions in a rate case. The majority concluded that such a finding is consistent with the Authority's position in the Nashville Gas[55] case although charitable contributions were voluntarily withdrawn. A majority of the Directors concluded that this was an inappropriate recovery, and adopted the Advocate's position in which Miscellaneous Expenses in the determination of Net Operating Income were excluded.[56]

V(b)14. DEPRECIATION AND AMORTIZATION EXPENSE

Depreciation and Amortization Expense represent the systematic recovery of capital invested in assets placed in service by the Company. As Depreciation and Amortization Expenses are recognized, the balance of Accumulated Depreciation is increased in determining the proper level of Rate Base.

In this case, the Company submitted a new depreciation study, which changes their depreciation rates. The greatest reason for the change in depreciation rates is the Company's projected "net salvage value" percentage.

The Company testified that, historically, Account #376 (Mains) has experienced a negative salvage rate of 20 percent, but due to increases in the cost of removal related to cast iron main replacement, a negative 40 percent salvage value has been used in the proposed depreciation rates. For Account #380 (Services) the Company testified that the current rates include a 60 percent negative salvage rate and that they anticipate a "modest adjustment" in the salvage rate of this asset; therefore, the Company used a 55 percent negative salvage rate.[57]

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[55] In Re: Application of Nashville Gas Company, a Division of Piedmont Natural Gas Company, Inc. for an Adjustment of its Rates and Charges, Docket No. 96-00977 (Tenn. Reg. Authority, February 19, 1997).

[56] Director Greer voted no on this Issue, having previously moved to allow this expense to be included on the basis of public expectations that utilities would participate in the community.

[57] Donald Roff Pre-Filed Direct Testimony, at page 11.

Based on a historical analysis of the past fifteen years, AVI contended that a negative 15 percent salvage value more accurately reflects what will occur in the future for Account #376 (Mains). Reducing the net salvage value from 40 percent to 15 percent effectively reduces the annual depreciation percentage for this account from 2.81 percent to 2.31 percent. AVI testified that the net salvage value for Account #380 (Services) has averaged 42 percent over the last five years. Reducing the net salvage value from 55 percent to 40 percent effectively reduces the annual depreciation percentage for this account from 4.43 percent to 4.00 percent.[58] If AVI's salvage rates are used for these two categories, the result is an annual decrease in Depreciation and Amortization Expense of $476,157. The Advocate proposed eliminating depreciation on land rights that would reduce the Company's Depreciation Expense by approximately $10,000.[59]

The Directors concluded that both AVI and the Advocate made solid arguments for the proper calculation of depreciation expense. However, the Directors were hesitant to accept AVI's or the Advocate's proposal without an accumulated depreciation quantification in the record. The Directors determined that absent such quantification in the record, the Company's proposal for purposes of this case must be given greater weight. Accordingly, the Directors approved the Company's forecast of $4,820,597 for Depreciation and Amortization Expense.

V(b)15. TAXES OTHER THAN INCOME

Taxes Other Than Income includes Property Taxes, Franchise Taxes, Gross Receipts Taxes, Authority Fees, Payroll Taxes, and Other General Taxes. The Company included $3,952,807 in their case for Taxes Other Than Income, while the Advocate only forecasted $3,552,189 for a difference between these Parties of $400,618. AVI accepted the Company's forecast of Taxes

58 James T. Selecky Pre-Filed Direct Testimony, at page 2.
59 R. Terry Buckner Pre-Filed Direct Testimony, at page 19.

Other Than Income in its forecast of NOI. The Directors determined that Taxes Other Than Income may be illustrated by each of the specific components shown in the following table.

TAXES OTHER THAN INCOME

	Company and AVI	Consumer Advocate	Authority
Property Taxes	$2,310,714	$2,094,035	$2,094,035
Gross Receipts Tax	692,453	541,741	541,741
Payroll Taxes	242,890	238,749	242,890
TRA Inspection Fee	168,804	166,058	166,058
Franchise Tax	267,321	240,981	240,981
Other General Taxes	270,625	270,625	270,625
Total Taxes Other Than Income	**$3,952,807**	**$3,552,189**	**$3,556,330**

The Advocate stated that the Company calculated their Property Taxes incorrectly by using the unequalized assessment value. In addition, the Advocate argued that the Company incorrectly calculated Gross Receipts Taxes by taking a five year average of the effective rate, which does not reflect the current effective tax rate. The Advocate then argued that the Company used its proposed Acquisition Adjustment in its calculation of the Franchise Tax. Since the Advocate recommended disallowance of the Acquisition Adjustment, they also recommended that it be removed from the Franchise Tax Calculation.[60]

Finally, the Advocate reduced the Company's payroll taxes based on its proposed reduction in Salary and Wage Expense. Parallel to the Advocate's recommended disallowance of a portion of the Salary and Wage Expense, was the Advocate's recommendation that the associated payroll taxes be removed.[61]

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60 R. Terry Buckner Pre-Filed Direct Testimony, at page 16.
61 Id., at page 17.

The Directors determined from the record that of the various adjustments that the Advocate made to Taxes Other Than Income, the only issue to which the Company took exception was the Advocate's adjustment to payroll taxes. The record reflects that the Company's exception resulted from its belief that the Advocate's payroll adjustments were inappropriate. [62] Therefore, because the Directors adopted the Company's calculation of Salary and Wage Expense, they also adopted the Company's calculation of payroll taxes. Further, the Directors found that there was a lack of discussion on the record contrary to the position of the Advocate on the remaining components of Taxes Other Than Income. Therefore, the Directors unanimously adopted the Advocate's forecast of Taxes other than Income. In addition, the Directors concluded that adoption of these adjustments results in a total forecast of $3,556,330 for Taxes Other Than Income. Therefore, the Directors unanimously approved $3,556,330, as the appropriate amount of Taxes Other Than Income.

V(b)16. TENNESSEE EXCISE TAX EXPENSE

Tennessee Excise Tax Expense represents the Company's income tax due to the state based on the tariffs currently in place. The Tennessee Excise Tax is a 6 percent income tax on the earnings of the Company. After considering all of the previous adjustments, a forecast of $545,670 for Tennessee Excise Tax Expense was calculated. The Directors, therefore, unanimously approved $545,670 as the appropriate forecast amount for Tennessee Excise Tax based upon the decisions adopted within this Order. See the chart following Section V(b)17 for calculations.

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62 Gerald A. Hinesley Pre-Filed Rebuttal Testimony, at page 4.

V(b)17. FEDERAL INCOME TAX EXPENSE

Federal Income Tax Expense represents the Company's current income tax due to the federal government based on the tariffs currently in place. The federal income tax is a 35 percent income tax on the earnings of the Company.

Taking all previous adjustments into account, a forecast of $2,992,092 for Federal Income Tax Expense is calculated. The Directors unanimously determined that the Federal Income Tax Expense must be calculated based upon the results of the decisions adopted within this Order. See the following chart.

CHATTANOOGA GAS COMPANY
Excise and Income Taxes
For the 12 Months ending September 30, 1998

Line No.		Authority	Company	Consumer Advocate	AVI
1	Operating Revenues	$ 32,711,499	$ 32,136,117	$ 32,697,029	$ 32,771,581
2	Salaries and Wages	3,136,136	3,136,136	3,084,307	3,136,136
3	Distribution Expense	927,379	980,895	1,368,826	980,895
4	Storage Expense	896,551	987,610	794,418	987,610
5	Customer Relations Expense	97,232	487,858	206,015	487,858
6	Sales Promotion Expense	430,670	455,531	455,531	455,531
7	Administrative and General Expense	6,054,152	7,675,537	5,575,270	7,489,537
8	Interest on Customer Deposits	126,744	225,965	115,034	225,965
9	Miscellaneous Expense	0	37,540	0	37,540
10	Depreciation & Amortization Expense	4,820,597	5,231,621	4,810,722	4,344,440
11	Taxes Other Than Income	3,556,330	3,952,808	3,552,189	3,952,807
12	NOI Before Excise and Income Taxes	$ 12,665,708	$ 8,964,616	$ 12,734,717	$ 10,673,262
13	AFUDC	32,373	32,373	32,373	32,373
14	Interest Expense	3,603,577	3,933,485	3,667,147	3,400,312
15	Pre-tax Book Income	$ 9,094,504	$ 5,063,504	$ 9,099,943	$ 7,305,323
16	Schedule M Adjustments	0	0	0	0
17	Excise Taxable Income	$ 9,094,504	$ 5,063,504	$ 9,099,943	$ 7,305,323
18	Excise Tax Rate	6.00%	6.00%	6.00%	6.00%
19	Excise Tax Payable	$ 545,670	$ 303,810	$ 545,997	$ 438,319
20	Excise Tax - Deferred	0	0	0	0
21	State Income Tax Expense	$ 545,670	$ 303,810	$ 545,997	$ 438,319
22	Pre-tax Book Income	$ 9,094,504	$ 5,063,504	$ 9,099,943	$ 7,305,323
23	Excise Tax	545,670	303,810	545,997	438,319
24	Schedule M Adjustments	0	0	0	0
25	FIT Taxable Income	$ 8,548,834	$ 4,759,694	$ 8,553,946	$ 6,867,004
26	FIT Rate	35.00%	35.00%	35.00%	35.00%
27	Federal Income Tax Payable	$ 2,992,092	$ 1,665,893	$ 2,993,881	$ 2,403,451
28	ITC Amortization	0	0	0	0
29	Amortization of Excess Deferred FIT	0	0	0	0
30	FIT - Deferred	0	0	0	0
31	Federal Income Tax Expense	$ 2,992,092	$ 1,665,893	$ 2,993,881	$ 2,403,451
32	Total Federal and State Income Taxes	$ 3,537,762	$ 1,969,703	$ 3,539,878	$ 2,841,771

V(b)18. CALCULATION OF NET OPERATING INCOME

After each of the previous adjustments is taken into account, a Net Operating Income of $9,160,319 is calculated as follows.

COMPARATIVE NET OPERATING INCOME CALCULATIONS

	Company[63]	Consumer Advocate[64]	AVI[65]	Authority
Base Rate Revenues	$31,206,762	$31,813,280	$31,842,220	$31,827,750
Other Revenues	929,361	883,749	929,361	883,749
AFUDC	32,373	32,373	32,373	32,373
Net Revenues	**$32,168,496**	**$32,729,402**	**$32,803,954**	**$32,743,872**
Salaries & Wages	$3,136,136	$3,084,307	$3,136,136	$3,136,136
Distribution Expense	980,895	1,368,826	980,895	927,379
Storage Expense	987,610	813,689	987,610	896,551
Customer Accounts Expense	102,839	126,867	102,839	97,232
Uncollectible Expense	385,019	165,968	199,019	138,006
Sales Promotion Expense	455,531	79,148	455,531	430,670
Admn & General Expense	2,448,665	2,115,562	2,448,665	2,186,146
Corporate Allocations	5,226,872	3,730,000	5,226,872	3,730,000
Interest on Customer Deposits	225,965	115,034	225,965	126,744
Miscellaneous Expense	37,540	0	37,540	0
Depr & Amort Expense	5,231,621	4,810,722	4,344,440	4,820,597
Taxes Other Than Income	3,952,807	3,552,189	3,952,807	3,556,330
Tennessee Excise Tax Expense	303,810	545,997	438,319	545,670
Federal Income Tax Expense	1,665,893	2,993,881	2,403,451	2,992,092
Total Operating Expenses	**$25,141,203**	**$23,502,190**	**$24,940,089**	**$23,583,553**
Net Operating Income	**$7,027,293**	**$9,227,212**	**$7,863,865**	**$9,160,319**

V(c). CAPITAL STRUCTURE AND FAIR RATE OF RETURN

The Directors found that, although the Advocate and AVI did not endorse Chattanooga Gas' proposed capital structure and cost rates for short- and long-term debt and preferred stock, neither did they suggest any alternatives. Therefore, the Directors adopted the capital structure and cost rates on debt and preferred stock proposed by Chattanooga Gas.

63 Chattanooga Gas Exhibit 5, Schedule 4.
64 Advocate Pre-Filed Exhibit, Schedule 8.
65 AVI Schedule MPG-1.

On cost of equity, none of the witnesses' analyses went completely unrebutted. The Directors rejected the position of Dr. Andrews, the Chattanooga Gas witness, that Chattanooga Gas is an independent firm. The Directors adopted the testimony of Dr. Brown, for the Consumer Advocate, and Mr. Gorman, for AVI, that AGL is the appropriate company to reference for determining the cost of equity. This finding eliminated all of the cost of equity estimates underlying Dr. Andrews' recommended cost of equity of 12.25 percent, since he relied on data for firms "comparable" to Chattanooga Gas and not AGL. Moreover, the Directors concluded that Dr. Andrews' DCF estimate of 11.06 percent is biased and that his Capital Asset Pricing Model is flawed.

Dr. Brown's DCF estimate along with his capital asset pricing model and Mr. Gorman's DCF estimate and risk premium estimate of the cost of equity, taken as a group, provided enough useful information for deciding the cost of equity in this case. These estimates defined a range, from Dr. Brown's DCF estimate at 10.4 percent to his capital asset pricing model at 11.14 percent that includes Dr. Andrews' DCF calculation of 11.06 percent as well as Dr. Brown's recommended 10.55 percent and Mr. Gorman's recommended 10.80 percent.

The Directors rejected Dr. Brown's compounding theory that formed the basis of his recommended 10.55 percent cost of equity. This theory was rebutted by Dr. Andrews and not recommended by any other witnesses. This decision is consistent with the decision of the Authority in the most recent Nashville Gas Company rate case. Further, Dr. Brown testified at the Hearing that he did not know of any other jurisdiction where this approach had been adopted.

The Directors found that the range established between witness Dr. Brown's DCF estimate at 10.4 percent and his capital asset pricing model at 11.14 percent was sufficient to encompass returns on equity proffered by all Parties in this proceeding. Although Chattanooga Gas' witness

Andrews' DCF estimate was found to be biased, the upper range of his model at 11.06 percent is within the range identified by Dr. Brown between his DCF calculation on the low side at 10.4 percent and his capital asset pricing model estimate on the high side at 11.14 percent. Therefore, the Directors unanimously adopted 11.06 percent as the cost of equity in this proceeding. The Directors further noted for the record that this percentage falls within the range supported by all Parties.

The resulting overall cost of capital of 9.08 percent flows from the decisions on capital structure and cost rates as shown in the following table.

CAPITAL STRUCTURE AND COST OF CAPITAL

Component	Percent	Cost Rate	Weighted Cost
Short Term Debt	5.28	5.80 %	0.31 %
Long Term Debt	46.07	7.75 %	3.57 %
Preferred Stock	4.49	7.04 %	0.32 %
Common Equity	44.16	11.06 %	4.88 %
Total	100.00		9.08 %

V(d). REVENUE CONVERSION FACTOR

The Directors unanimously adopted a revenue conversion factor of 1.634321, illustrated below, to reflect the changes to the Company's rate case amounts for other revenues and uncollectible expenses.

REVENUE CONVERSION FACTOR

Line		Rate	Balance
1	Operating Revenues		1.000000
2	Add: Forfeited Discount Ratio	0.006837[66]	0.006837
3	Balance		1.006837
4	Deduct: Uncollectible Ratio	0.005368[67]	0.005405
5	Balance		1.001432
6	Deduct: State Excise Tax Rate	0.060000[68]	0.060086
7	Balance		0.941346
8	Deduct: Federal Income Tax Rate	0.350000[69]	0.329471
9	Balance		0.611875
10	Revenue Conversion Factor (Line 1/Line 9)		1.634321

V(e). REVENUE DEFICIENCY OR SURPLUS

The Directors found, that after placing into effect their decisions with respect to Docket No. 97-00982, Chattanooga Gas Company, Petition to Place Into Effect the Revised Natural Gas Tariff, the calculations from these decisions indicate that there is a revenue surplus in the amount of $1,166,213[70] as illustrated in the following chart.

66 See Section V(b)2.
67 See Section V(b)8.
68 Statutory Rate.
69 Statutory Rate.
70 The revenue design calculation deficiency was announced at the Authority Conference on July 21, 1998.

COMPARATIVE REVENUE DEFICIENCY (SURPLUS) CALCULATIONS

	Company	Consumer Advocate	AVI	Authority
Rate Base	$101,378,494	$94,595,399	$87,712,302	$92,955,599
Operating Income at Current Rates	$7,027,293	$9,227,212	$7,863,865	$9,160,319
Earned Rate of Return[71]	6.93%	9.75%	8.97%	9.35%
Fair Rate of Return	9.61%	8.85%	8.97%	9.09%
Required Operating Income[72]	$9,742,473	$8,371,693	$7,867,793	$8,446,742
Operating Income Deficiency (Surplus)[73]	$2,715,180	$(855,519)	$3,928	$(713,577)
Gross Revenue Conversion Factor	1.628843	1.628727	1.628843	1.634321
Revenue Deficiency (Surplus)[74]	**$4,422,602**	**$(1,393,407)**	**$6,399**	**$(1,166,213)**

V(f). <u>RATE DESIGN</u>

V(f)1. IGCA RIDER, LOST AND UNACCOUNTED FOR PROVISION AND DAILY BALANCING PROVISION

The Directors found that there was mirroring in the Company's proposal to change the industrial tariff by including an interruptible gas cost adjustment ("IGCA") rider, a lost and unaccounted for provision, and a daily balancing provision. The Directors concluded that these changes could better reflect the cost of providing service to the industrial class. However, the Directors unanimously found that these types of tariff changes can best be negotiated between the Parties outside the context of a rate case, and denied the Company's request.

71 Operating Income at Current Rates / Rate Base.
72 Rate Base multiplied by Fair Rate of Return.
73 Required Operating Income - Operating Income at Current Rates.
74 Operating Income Deficiency (Surplus) multiplied by Gross Revenue Conversion Factor.

V(f)2. MISCELLANEOUS CHARGES FOR RECONNECTION AND SERVICE ESTABLISHMENT

The Directors unanimously determined from the record that rates charged by Chattanooga Gas for Reconnection and Service Establishment are higher than those of Nashville Gas and United Cities Gas, and therefore, concluded that these rates shall not be increased at this time.

V(f)3. BILLING VOLUME FOR OUTDOOR LIGHTING

The Directors found that the Company's proposal to change the billing volume for outdoor lighting was appropriate. The Directors further found that the Company's proposal to reduce the minimum daily volumes to qualify for the firm transportation tariff was appropriate. There was no opposition to these issues by the Advocate, AVI or CMA, and therefore, the Directors unanimously approved these two changes.

V(f)4. DETARIFFING

Detariffing is a term used to indicate the Company's proposal to substitute price cap formula regulation for some or all of the industrial segment of the Chatanooga Gas tariff. The Directors found that a formula may satisfy the tariff rate requirements of Rule 1220-4-1-.03. The Directors further found that rates do not have to be the same for all classes of customers to be nondiscriminatory.[75] However, while concluding that creative rate designs under strict rate of return regulations should not be discouraged, the Directors emphasized that there is an effective experimental bypass rule in place which, when properly applied, would effectively assist in keeping industry in the Company's industrial base. Therefore, the Directors unanimously rejected the Company's proposal for industrial rate detariffing.[76]

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75 CF Industries v. Tennessee Public Service Commission, 599 S.W.2d 536 (Tenn. 1980).

76 Chairman Malone did not agree with the rationale expressed by the majority, but joined in the result.

VI. SETTLEMENT OF RATE DESIGN ISSUES

On July 16, 1998, the Parties jointly submitted a Motion to Postpone a Decision on Rate Design to Allow the Parties to Propose a Settlement. This Motion was considered by the Directors at the Authority Conference on July 21, 1998. At that Conference the Directors unanimously approved the Motion to allow the Parties an opportunity to negotiate the Rate Design. The Parties were given until 12:00 Noon on Tuesday, July 28, 1998, to propose their Rate Design. On July 28, 1998, the Parties timely filed their proposed Rate Design. The proposed Rate Design is attached as Exhibit A. The proposed Rate Design settlement was considered by the Directors at the Authority Conference on August 4, 1998. At that Conference, the Directors unanimously approved the proposed Rate Design settlement and ordered that the tariffs, consistent with the provisions of the settlement, shall be filed not later than three (3) business days after the entry of a final Order in this case and shall be effective upon approval of the Authority.

VI(a). WEATHER NORMALIZATION

As a part of the Parties' proposed settlement of Rate Design, they agreed to permit the Company and the Authority Staff to determine the details of the Weather Normalization Adjustment ("WNA") factors. The WNA factors are used on a going forward basis to adjust the residential and commercial rates for weather that is either above or below the normal seasonal range. Accordingly, the Company and the Authority Staff agreed to jointly issue the use of the existing WNA factors from the Company's 1995 rate case, Docket No. 95-02116. The proposed Rate Design settlement, including adoption of the WNA factors, was considered by the Directors at the Authority Conference on August 4, 1998. At that Conference, the Directors unanimously approved the proposed Rate Design, including the provisions of the proposed settlement concerning the WNA factors.

VII. DISPOSITION OF THE MOTION TO STRIKE REQUEST OF FINDINGS FROM CHATTANOOGA GAS BY THE ADVOCATE

On September 29, 1997, the Consumer Advocate Division filed an Objection and Motion to Strike Request of Findings submitted by Chattanooga Gas. The Hearing Officer requested the Parties to submit proposed charges of law, but did not request the Parties to file any proposed findings of fact or the Request of Findings as submitted by Chattanooga Gas. Therefore, the Directors unanimously granted the Objection and Motion to Strike Request of Findings submitted by the Advocate.

IT IS THEREFORE ORDERED THAT:

1. The rates filed by Chattanooga Gas Company on May 1, 1997, are denied;

2. For purposes of the rates herein, the annual test period shall be the historical test period for the twelve (12) months that ended September 30, 1996, with adjustments for attrition through September 30, 1998;

3. For purposes of the rates herein, the cost of equity shall be 11.06 percent and the cost of capital shall be 9.08 percent;

4. The request of the Company for an Acquisition Adjustment to Rate Base is denied;

5. The allocation factor for the financial reporting of corporate expense shall be based on customers and be updated within a rate case;

6. The request of the Company for an industrial tariff interruptible gas cost adjustment rider, a lost and unaccounted for provision and a daily balancing provision is denied;

7. The request of the Company for an increase in Reconnection and Service Establishment is denied;

8. The request of the Company to change the billing volume for outdoor lighting is approved;

9. The request of the Company to reduce the minimum daily volume to qualify for the firm transportation tariff is approved;

10. The proposal of the Company for industrial rate detariffing is denied;

11. The Agreement on a Rate Design negotiated among the Parties and submitted in a filing to the Authority on July 28, 1998, is approved;

12. The Agreement among the Parties to permit the Authority Staff and the Company to determine the details of the Weather Normalization Adjustment factors is approved;

13. The Company is directed to file tariffs with the Authority that are designed to produce a reduction of $1,166,213 in revenue for service rendered;

14. The tariffs shall be filed not later than three (3) business days after the date of entry of this Order and shall be effective upon approval of the Authority;

15. Chattanooga Gas Company shall file any and other tariffs necessary to be consistent with this Order;

16. The Objection and Motion to Strike Request of Findings submitted by the Office of the Attorney General, Consumer Advocate Division is granted;

17. Any party aggrieved with the Authority's decision in this matter may file a Petition for Reconsideration with the Authority within ten (10) days from and after the date of this Order; and

18. Any party aggrieved with the Authority's decision in this matter has the right of judicial review by filing a Petition for Review in the Tennessee Court of Appeals, Middle Division, within sixty (60) days from and after the date of this Order.

CHAIRMAN

DIRECTOR

DIRECTOR

ATTEST:

EXECUTIVE SECRETARY

CA Attachment 1

RECEIVED
JUL 28 1998
TN REGULATORY AUTHORITY
GENERAL COUNSEL'S OFFICE

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REC'D TN REGULATORY AUTH.
'98 JUL 28 PM 12 46
OFFICE OF THE EXECUTIVE SECRETARY

July 28, 1998

Mr. David Waddell, Executive Secretary
Tennessee Regulatory Authority
460 James Robertson Parkway
Nashville, Tennessee 37243

Re: *Petition of Chattanooga Gas Company*
Docket No. 97-00982

Dear David:

Attached is a rate design proposal submitted on behalf of all the parties to this case. The proposal is complete except for calculations relating to weather normalization which, the parties agree, should be worked out between Chattanooga and the TRA's technical staff. The proposed tariff provides rate reductions for all customer classes and addresses the problem of bypass by large industrial users.

The proposed tariff has been reviewed by rate design experts from Chattanooga and AVI/CMA. Chattanooga does not oppose the proposed tariff. AVI/CMA agrees to the proposal. The Consumer Advocate's Office has also reviewed and agreed to the proposal. In order to meet the TRA's noon deadline for filing this proposal, counsel for Chattanooga and the Consumer Advocate, both of whom are out of town, have authorized counsel for AVI/CMA to file this agreement on behalf of all parties. The parties' rate design experts (Dan McCormac, Don Johnstone, and Lisa Howard Wooten) are available to answer any questions the TRA or its staff may have about this proposed rate design.

Respectfully submitted,

BOULT, CUMMINGS, CONNERS & BERRY, PLC

By: Henry

Henry Walker

HW/dc
Enclosure
cc: Parties of Record

0502162.01
003320-012 07/28/98

Exhibit A

Chattanooga Gas Company
Gross Profit From Sales and Transportation of Gas
For the 12 Months Ending September 30, 1998

TRA #97-00982
CMA/AVI/CGC Settlement
7/28/98 11:00 am

	Proforma Dekatherms 1	Proforma Bills 2	Current Gross Profit Margin 3	Current Gross Profit 4	Proposed Increase in Gross Profit Margin 5	Proposed Gross Profit Margin 6	Proposed Gross Profit 7	Percent Increase in Gross Profit 8	Proposed Increase in Gross Profit 9
Residential - Winter		288,478	$ 7.50	$ 2,163,585	$ 0	$ 7.50	$ 2,163,585	0%	
First 2.5 Mcf	705,140		3.0050	2,118,946	(0.1050)	2.9000	2,044,908	-3%	
Next 2.5 Mcf	647,683		2.0050	1,298,624	(0.0050)	2.0000	1,295,366	0%	
Over 5 Mcf	2,303,947		1.8050	4,158,624	(0.0550)	1.7500	4,031,907	-3%	
Res. - Summer		281,512	$ 7.50	$ 2,111,340	$ 0	$ 7.50	$ 2,111,340	0%	
First 2.5 Mcf	440,446		2.7190	1,197,573	(0.6180)	2.1000	924,937	-23%	
Next 2.5 Mcf	126,648		1.5210	192,629	(0.0210)	1.5000	189,968	-1%	
Over 5 Mcf	76,227		0.4710	35,903	(0.0210)	0.4500	34,302	-4%	
R-4 Multi-fam-Winter		2,604	$ 6.00	$ 15,624	$ 0	$ 6.00	$ 15,624	0%	
Flat rate /Mcf	20,193		2.0860	42,123	(0.2860)	1.8000	36,347	-14%	
R-4 Multi-fam-Summer		2,604	$ 6.00	$ 15,624	$ 0	$ 6.00	$ 15,624	0%	
Flat rate /Mcf	6,779		1.7110	11,599	(0.1110)	1.6000	10,846	-6%	
Residential (R-1 & R-4)	4,327,071	286,720		$ 13,362,193			$ 12,874,774	-3.6%	$ (487,419)
C-1 Winter		48,417	$ 20.00	$ 968,340	$ 0	$ 20.00	$ 968,340	0%	
First 300 Mcf	2,213,623		2.8000	6,198,144	(0.0500)	2.7500	6,087,463	-2%	
Next 200 Mcf	295,764		2.5240	746,508	(0.0140)	2.5100	742,368	-1%	
Next 1000 Mcf	513,718		2.4610	1,264,260	(0.0160)	2.4450	1,256,041	-1%	
Over 1,500 Mcf	296,152		1.2820	379,667	(0.0170)	1.2650	374,632.28	-1%	
C-1 Summer		46,253	$ 15.00	$ 693,795	$ 0	$ 15.00	$ 693,795	0%	
First 300 Mcf	703,262		2.2990	1,616,799	(0.1400)	2.1590	1,518,343	-6%	
Next 200 Mcf	92,196		1.9140	176,463	(0.2000)	1.7140	158,024	-10%	
Next 1000 Mcf	196,265		1.7080	335,221	(0.1100)	1.5980	313,631	-6%	
Over 1,500 Mcf	88,554		1.2820	113,528	(0.0170)	1.2650	112,021	-1%	
Commercial (C-1)	4,399,534	94,670		12,492,724			12,224,858	-2.1%	(268,066)
Industrial- Other		883	$ 300.00	$ 264,900	$ 0	$ 300.00	$ 264,900	0%	
Demand Units	130,759		$ 3.06	$ 400,123	$ (0.06)	3.0000	$ 392,277	-2%	
0-1,500 Mcf	1,401,374		0.9088	1,273,569	(0.0200)	0.8888	1,245,541	-2%	
1,501-4,000 Mcf	1,731,019		0.7798	1,349,849	(0.0200)	0.7598	1,315,228	-3%	
4,001-15,000 Mcf	2,804,499		0.4712	1,321,480	(0.0400)	0.4312	1,209,300	-8%	
Over 15,000 Mcf	4,136,077		0.3200	1,323,545	(0.0550)	0.2650	1,096,060	-17%	
Industrial	10,072,969		0.5230	$ 5,933,464		0.4831	$ 5,523,307	-6.5%	$ (410,158)
Miscellaneous Items:									
Connections		1,297	30.00	38,910	0 $	30.00	38,910	0%	
Seasonal Reconnects R-1		475	30.00	14,250	0	30.00	14,250	0%	
Seasonal Reconnects C-1		56	45.00	2,520	0	45.00	2,520	0%	
Service Establishment - Turn ons		7,336	15.00	110,040	0	15.00	110,040	0%	
Service Establishment - Meter Sets		3,070	25.00	76,750	0	25.00	76,750	0%	
Bad check & other fees				13,862			13,862		
Miscellaneous				256,332			256,332	0.0%	0
Gross Profit (before forfeited discounts)				$ 32,044,713			$ 30,879,070	-3.6%	$ (1,165,643)
Forfeited Discounts				627,247			619,277		(7,970)
Total	18,799,674	671,195		$ 32,671,960			$ 31,498,347		$ (1,173,613)

Source: CGC Exh. 11, Sch. 4 & TRA data request item 76, sheet 28

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How Arbitrary Is "Arbitrary"? — or, Toward the Deserved Demise of Full Cost Allocation

By WILLIAM J. BAUMOL, MICHAEL F. KOEHN, and ROBERT D. WILLIG

The authors of this article observe that an effort to deregulate some of the activities of a regulated company while continuing to subject other activities to a rate of return ceiling may lead utility regulators back to a full allocation of cost approach to regulation which has been discredited by marginal and incremental cost analysis. In a series of hypothetical and actual examples they demonstrate the futility of efforts to allocate joint and common costs or investments between various services or products of the same firm. They conclude that if a firm is to be partially regulated and partially unregulated, rate base and rate of return as the basis of regulation must be abandoned.

Recent moves toward deregulation of a number of industries have, paradoxically, brought with them a resurgence in regulatory reliance upon the discredited accounting device referred to as "full allocation" or "full distribution" of the fixed and common costs of the regulated firm. Despite a number of reasoned moves in Congress and the courts in the direction of a marginal and incremental analysis that economics so clearly suggests, regulators seem vulnerable to entrapment into readoption of the full allocation approach by their attempt to deregulate some of the firm's activities while continuing to subject the remaining activities of the enterprise to a rate of return ceiling. Whenever there are costs and investments common to the regulated and the unregulated activities only some sort of arbitrary apportionment (allocation) of these between the two sets of activities can permit the calculation of a number that *pretends* to approximate the "true" rate of return on the regulated outputs.

This article briefly reviews the burdens upon consumers and the public generally that are likely to result. However, its major purpose is to puncture the legend that a fully allocated cost calculation produces numbers approximating any substantive economic magnitudes. We will show that different and equally plausible allocation criteria yield shockingly different numerical results, so that by judicious choice of allocation criterion, the partisan calculator can make the process yield virtually any numbers he chooses (in advance) to obtain.

Full Allocation and Sequential Deregulation

If a rate base and rate of return standard is used to

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Michael F. Koehn is a principal of Analysis Group, Inc., an economics consulting firm. He also teaches economics at the University of California in Irvine. He is the author of several professional articles and a book on finance and regulation. **Dr. Koehn** received a bachelor's degree in economics from the University of California and a PhD degree from the Wharton School at the University of Pennsylvania.

Robert D. Willig is a professor of economics and public affairs at Princeton University. He is a member of the New Jersey Governor's Task Force on Electricity and has written, lectured, testified, and consulted widely on the subjects of industrial organization, government and business, and microeconomic policy. **Dr. Willig** received a PhD degree in economics and an MS degree in operations research from Stanford University, and an AB degree from Harvard University.

govern the regulatory process, there is really no alternative to full allocation of costs and investments, given a decision to divide products of a firm which are closely related in their production into an unregulated portion and a regulated one. Where the activities of a firm benefit from substantial common investments or substantial common outlays (or both), there is no way to calculate a rate of return for any or all of the company's individual activities, one by one. Indeed, the difficulty is not that we cannot determine these numbers, but that such numbers themselves are necessarily figments of the imagination. An example will make this clear.

Imagine two processes, each of which requires its own machine, each costing $1 million, and that both processes require a superclean atmosphere which a $3 million item of equipment can simultaneously provide for the two activities. The bulk of the firm's investment is obviously devoted to the air purifier, and its cost is therefore the key component in a calculation of the company's overall rate of return. But who other than a medieval theologian can pretend really to know what portion of the firm's air purifier investment is truly to be ascribed to each of the firm's products? The truth of the matter is that the $3 million investment is ascribable totally to the two products together, and that no *particular* percentage of the investment may be ascribable more defensibly than some other percentage figure to either of the products by itself. But without knowing what portion of the firm's total investment is properly attributable to either product it is impossible to calculate a rate of return on either product by itself. Indeed, no meaning can really be given to the concept.[1]

If regulatory rules nevertheless require the undefinable to be defined, the only option open to those who must comply with the rules is to adopt some arbitrary device, usually dressed up to give it an appearance of reasonableness — an arbitrary rule that divides up indivisible investments and costs. This, of course, is what full allocation means.

But an arbitrary division criterion produces just the sort of results the term "arbitrary" implies. Depending upon the conventional criterion chosen for the division of investments and costs, one will obtain widely differing results from the calculation. It is generally acknowledged that the result will be affected by this choice. But there seems to be an impression that any such calculation, if carried out with sufficient care, will yield a reasonable approximation to some underlying true figure. That impression is totally unfounded. We have already shown here that where the common component of cost and investment is substantial, there is no such thing as the "true" rate of return on a portion of the firm's activities. But, in addition, although it is not generally realized, changes in the basis of allocation can make an enormous difference to the results that emerge, as will be demonstrated presently. In other words, one can have absolutely no confidence in the results obtained from any such calculation. Moreover, the numbers that emerge readily lend themselves to manipulation by any interested party through selective choice of basis of allocation.

Social Costs of Regulatory Reliance on Full Cost Allocation

As a result of the arbitrariness of full cost allocation, only increased problems for rational regulation, for the regulated firm, and for the public, can follow from any attempt at partial or sequential deregulation while continuing to control what purports to be the rate of return of the portion of the company that remains under regulation. As we have seen, such a course of action makes arbitrary allocation of investments and costs inescapable. Because of the arbitrariness of such a process and the extreme volatility of its results when the basis of allocation is changed, one can be confident that it will lead to a profusion of protracted disputes over the figures and the shares of the joint and common costs that are to be recovered from different groups of ratepaying customers of the firm.

In addition, as deregulation proceeds, increasingly fine definitions of services will undoubtedly have to be employed, and the demands upon the allocation processes will grow correspondingly. Such developments are likely to make the very process of allocation of joint and common outlays all but unmanageable by the firm or by the regulator.

But administrative difficulties are not the central issue. Rather, a number of other consequences of the full allocation process that are clearly detrimental to the public interest should be the main concern here. This is not the place to review the many unfortunate results of use of full allocation to regulate rates and earnings, since these have many times been described at length (and perhaps ad nauseum). We will only note that because the numbers that emerge from the process are indeed arbitrary, any prices determined by the regulator with their aid can only have a random relation to the prices that would emerge in competitive markets; i.e., the prices required if economic efficiency is not to be undermined.

In addition, the full allocation approach to price setting tends to foreclose any opportunity for the regulated firm to obtain adequate earnings. It is true that regulators who set rates on the basis of fully allocated costs (FAC) attempt to select a set of rates which, if realized in practice, will yield a viable return to the enterprise. But no regulator can force consumers to pay more than they are willing to pay, given the alternatives competition offers to them. As a result, in any regulated market (however defined) customers will end up paying the lower of two pertinent prices: that dictated by market forces, and that decreed by the regulator on the basis of a cost allocation.

If in some markets (as is normally the case) the FAC price is below the free market level, while in other markets the relationship is reversed, the regulated firm will be unable to charge the free market price in the former, and will be precluded from charging the FAC price in the latter. The net result tends to be a shortfall in overall revenues from the regulated services that the firm cannot make up for by high prices in the deregulated arenas, which will all presumably have been selected to be sufficiently competitive to prevent such overpricing automatically.

Arbitrariness of the Fully Allocated Cost Figures

As has been said, the obvious (but specious) way to go about the calculation of the profitability of a subset of the products of a firm is the adoption of some allocation procedure for the purpose. It is all too easy to concoct defenses for the approach. It is said to be "practical" and have a long period of usage behind it. But here, to paraphrase Disraeli, practicality consists in practicing the blunders of our predecessors. It is said that by careful and rational choice of an allocation criterion, taking account of the use to which the figures will be put, one can arrive at defensible calculations. Two examples making absolutely no extreme assumptions will demonstrate the error of this conclusion. The first example is hypothetical and is intended to make clear the source of the problem. The second example uses actual data from a very real enterprise.

Railroad regulation has been an arena in which many metaphysical disputes over the proper method of allocation have long been under way. Faced with the industry's heavy investment in track, which is a cost incurred in common on behalf of every type of traffic, a variety of allocation criteria have been advocated over the years, each criterion having been selected carefully to comport with the interests of its advocate. To minimize the appearance of arbitrariness "relative use" has usually been agreed to as the proper allocative criterion. But how should relative use be measured? By volume of shipments (number of cars)? By their relative weight (ton-miles)? By their relative value?

Clearly, when the shippers of lead try to prove they are being overcharged, they will advocate the use of bulk or value rather than weight as the proper standard on which to allocate investment, so that lead shipment will be assigned a small share of the responsibility for the railroad's track investment, and the calculated rate of return on lead shipments will be comparatively high. Similarly, precious metal shippers on a comparable mission can be relied on to find arguments against the use of value of shipment as the proper basis of allocation, while shippers of balsa wood will dependably argue that volume is a defective allocative criterion.

The consequences of the choice among such allocative criteria are not minor. This will first be shown with the aid of the following hypothetical example:

Suppose (i) that a railroad's traffic from origin A to destination B is composed exclusively of shipments of lead, precious metals, and balsa wood; (ii) that its investment in track, signals, tunnels, et cetera along the way is $100 million, with another $10 million of specialized investment on behalf of individual products; (iii) that the railroad derives annual net revenues (revenues minus direct costs) from each product equal to $3.2/3 million. Then its overall rate of return on investment will be 10 per cent; i.e., [3 × 3.2/3]/110.

Table 1 shows the hypothetical bulk (boxcar loads), weight, and values of the three products' annual shipments as well as their direct investments, on the assumption that these investments are proportionate to number of boxcars used.

Next, Table 2 shows the investment assigned to each product if the $100 million of track is allocated proportionately to carloads, weight, or value. The arithmetic is straightforward.

Table 3 shows the investment assigned to each product when the $10 million of specialized investment is included in the allocation.

Finally, Table 4 shows rates of return, calculated by dividing each product's $3-2/3 million revenue contribution by its assigned investment figures in Table 3.

Table 1

Basic Data for Hypothetical Railroad

Commodity	Carloads (000)	Weight (000 Tons)	Value (Millions)	Direct Investment
Lead	10.0	90	5	2.0
Balsa Wood	39.5	1	5	7.9
Precious Metals	0.5	9	90	0.1

Table 2

Allocated Investments
($ Millions)

Commodity	Allocation Basis: Carloads	Weight	Value
Lead	20	90	5
Balsa Wood	79	1	5
Precious Metals	1	9	90
Total	100	100	100

Table 3

Total Assigned Investments
($ Millions)

Commodity	Allocation Basis: Carloads	Weight	Value
Lead	22.0	92.0	7.0
Balsa Wood	86.9	8.9	12.9
Precious Metals	1.1	9.1	90.1
Total	110.0	110.0	110.0

Table 4

Attributed Rates of Return on Investment
(Per Cent)

Commodity	Allocation Basis: Carloads	Weight	Value
Lead	16.7	4.0	52.4
Balsa Wood	4.2	41.2	28.4
Precious Metals	333.6	40.3	4.1

It is clear from Table 4 that the figures for balsa wood span the narrowest of the ranges for the three commodities. Yet, it is seen that by judicious choice of the allocation criterion its rate of return can be changed from a clearly inadequate 4.2 per cent (Column 1) to an excessive 41 per cent (Column 2). The precious metals figure is even more sensitive, being transformable from a low of 4.1 per cent to a high well in excess of 300 per cent. This, surely, is a most curious way to calculate *the* rate of return for a product line.

Such maleability of fully allocated costs and rates of return is not a mere artifact of our hypothetical example. Tables 5 and 6 represent numbers for T. Rowe Price Associates, a large mutual fund manager, and one of its money market mutual funds, with which the authors of this article recently had occasion to work.[2] Table 5 shows for the entire firm and for Prime Reserve Fund four sets of data which were used as the bases for our five allocations of those costs of the firm which were not directly attributable to any one or another of its mutual funds. These costs were, in turn, allocated by us on the basis of (1) relative mutual fund revenues, (2) relative number of labor hours utilized, (3) relative amounts spent on wages, and (4) relative number of customers served. (Because costs increase sharply with number of customers served in the mutual fund industry, in contradistinction to the size of their transactions, number of customers is not an unpersuasive allocation criterion.) Finally, since each of the preceding allocation criteria is to some degree persuasive, we have provided a fifth hybrid criterion (5), the balanced factors allocation, which uses a judiciously selected weighted average of criteria (1) to (4). The method of selection of the weights and its purpose will soon be clear.

Table 6 shows the results. For example, for 1980 the calculations allege that the rate of return on investment earned by Prime Reserve Fund was a horrendously unprofitable −125 per cent if number of customers was used as the allocation criterion, while that same mutual fund was found from an allocation based on wage costs to be earning a shockingly excessive 247 per cent on its capital.

Of course, if Prime Reserve were seeking to justify its rate of return none of the preceding methods would

TABLE 5

Derivation of Alternate Cost Allocations for Prime Reserve Fund

Allocation Method	1978	1979	1980	1981
a) Revenues				
Entire Firm (T. Rowe Price Associates)	$19,975	$23,044	$29,609	$38,731
Division A (Prime Reserve Fund)	270	1,735	4,212	8,145
Division A as a Percentage of Total Firm	1.4%	7.5%	14.2%	21.0%
Allocated Expenses	$242	$1,492	$3,274	$6,725
b) Direct Labor Hours				
Entire Firm	NA	NA	550,290	695,966
Division A	NA	NA	75,922	166,491
Division A as a Percentage of Total Firm	NA	NA	13.8%	23.9%
Expenses Allocated to A	NA	NA	$3,175	$7,650

Table continued on next page.

TABLE 5 (Continued)

Derivation of Alternate Cost Allocations for Prime Reserve Fund

Allocation Method	1978	1979	1980	1981
c) Direct Labor Dollars				
Entire Firm	NA	NA	$11,696	$15,830
Division A	NA	NA	1,146	2,199
Division A as a Percentage of Total Firm	NA	NA	9.8%	13.9%
Expenses Allocated to A	NA	NA	$2,255	$4,442
d) Number of Customers				
Entire Firm	248,490	281,210	350,957	460,993
Division A	8,338	57,343	114,607	217,027
Division A as a Percentage of Total Firm	3.4%	20.4%	32.7%	47.1%
Expenses Allocated to A	$602	$4,041	$7,515	$15,054
e) Balanced Factors Allocation*				
Entire Firm	NA	NA	NA	NA
Division A	NA	NA	NA	NA
Division A as a Percentage of Total Firm	NA	NA	17.7%	25.9%
Expenses Allocated to A	NA	NA	$3,991	$7,916

*This allocation of costs is based on a judicious assessment of the relative roles of number of customers, revenues, direct labor hours, and direct labor dollars, assigning these the respective weights in 1980 of 46.4 per cent, 20.1 per cent, 19.6 per cent, and 13.9 per cent; and in 1981 of 44.5 per cent, 19.8 per cent, 22.6 per cent, and 13.1 per cent. These weights relate to the relative size of each activity — operations, research, sales promotion, and portfolio management — as measured by direct costs and the use of an allocation rule, revenue, number of customers, et cetera, thought "best" to reflect the activity of each department.

SOURCE: "Statement of Product Line Revenues and Expenses," annual company reports and internal company documents.

TABLE 6

Ostensible Profitability of T. Rowe Prime Reserve Fund As Calculated by Various Cost Allocation Methods

	Cost Allocation Criterion				
1979 Pretax Return	**No. of Customers**	**Revenues**	**Direct Labor Hours**	**Direct Labor Dollars**	**Balanced Factors Allocation**
Return on Sales	−132.9%	14.0%	NA	NA	NA
Return on Capital	−191.7%	54.9%	NA	NA	NA
Return on Assets	−113.9%	32.6%	NA	NA	NA
1980 Pretax Return					
Return on Sales	−78.4%	22.3%	24.6%	46.5%	5.2%
Return on Capital	−124.9%	81.7%	93.0%	247.0%	15.4%
Return on Assets	−71.1%	46.5%	52.9%	140.6%	8.8%
1981 Pretax Return					
Return on Sales	−84.8%	17.4%	6.1%	45.5%	2.8%
Return on Capital	−110.7%	51.0%	15.6%	201.1%	6.7%
Return on Assets	−72.9%	33.6%	10.3%	132.3%	4.4%

SOURCE: Table 5 and annual company reports, various years.

CA Attachment 2

really serve the purpose, since some indicate that its earnings were far too low while others seem to imply the opposite. However, any clever advocate defending Prime Reserve position has a better choice — the balanced factors method, whose weights have indeed been selected judiciously — to show that the fund earned a most reasonable return on capital, 15.4 per cent in 1980 and 6.7 per cent in 1981. Such are the wonders of cost allocation.

Concluding Comment

The implications of the preceding data are clear. Fully allocated cost figures and the corresponding rate of return numbers simply have zero economic content. They cannot pretend to constitute approximations to *anything*. The "reasonableness" of the basis of allocation selected makes absolutely no difference except to the success of the advocates of the figures in deluding others (and perhaps themselves) about the defensibility of the numbers. There just can be no excuse for continued use of such an essentially random or, rather, fully manipulable calculation process as a basis for vital economic decisions by regulators.

Endnotes

[1]Of course, it is possible to calculate each product's incremental investment, incremental cost, and incremental return, but there is no rational ground on which to regulate the *earnings* of a particular company activity on the basis of any or all of those figures. There is no reason, for example, to claim that it is desirable for all services to yield equal *incremental* rates of return.

[2]The following analysis was prepared on behalf of T. Rowe Price Associates in Schuyt N. Rowe Price Reserve Fund, Inc., United States District Court, Southern District of New York. The data and analyses are a matter of public record.

Reviewing the Market Value of Assets

The chief financial officers of 200 of this country's largest corporations acknowledged in a recent survey that they are now paying a great deal of attention to the highest-value use of their companies' assets. Nearly three-quarters of the officers polled by Temple, Barker & Sloane, Inc., at the end of last year indicated that their firms have adopted the practice of scrutinizing the market value of assets. Of those firms that perform market value studies, some 57 per cent do them annually, while another 14 per cent review asset value every few years. The remainder (29 per cent) focus attention on the issue "when needed."

"Unfortunately," said Dr. Michael Tennican, a senior vice president of the Lexington, Massachusetts-based general management consulting firm, "for some firms in the latter category, 'when needed' might be better stated as 'too late.' We are aware of a number of situations," he said, "where companies have seriously begun thinking about restructuring only *after* receiving a call from an outsider who has a desire to take over the task from incumbent management — and who has the shares and the financing required to press the point."

According to Dr. Tennican, pressures for improvement from boards of directors and threats of takeover from corporate raiders will continue to motivate large U. S. corporations to look for opportunities to reinvigorate profitability through restructuring. A key first step to improving profitability, he argues, is for the firm to examine expected returns on the market value of assets dedicated to each identifiable line of business.

"Since traditional accounting systems provide data primarily on historic asset costs rather than market values, corporations need to undertake separate periodic market value studies in order to create maximum value for their shareholders," Dr. Tennican explained. The TBS survey found that when asset value studies are performed, they are typically done (in 90 per cent of the cases reported) by line of business. Approximately 40 per cent of the companies that had performed such studies engaged in some form of restructuring following their reviews.

Exhibits filed Confidentially with Testimony:

1. Confidential Exhibit CDK-1 (excel)
2. Confidential Exhibit CDK-2
3. Confidential Exhibit CDK-3
4. Confidential Exhibit CDK-4
5. Confidential Exhibit CDK-10
6. Confidential Exhibit CDK-10(a)

PIEDMONT NATURAL GAS COMPANY, INC.
DOCKET NO. 25-00036
CONSUMER ADVOCATE'S SECOND SET OF DISCOVERY REQUESTS
Date Issued: July 2, 2025
Date Due: July 14, 2025

2-43. Rate Design. Refer to Company Response to Consumer Advocate DR No. 1-35. Piedmont indicated that rates are designed to achieve an overall rate of return of 6.95%. Is this rate dependent on the costs allocated to the class rate? If it is not, explain why this is not the case.

RESPONSE: Piedmont's proposed Base Rates in this proceeding, in aggregate, yield an overall rate of return of 6.95%, consistent with the Fair Rate of Return and Total Revenue Requirement Deficiency for the ABRR shown on Schedule 1 in the Company's 2025 ARM Annual Filing. Piedmont's proposed rate design for the ABRR Revenue Requirement Deficiency in this proceeding is fully in compliance with the requirements of the Company's TPUC-approved ARM Tariff (Service Schedule No. 318). It is also consistent with the rate design used for the ABRR Revenue Requirement Deficiency proposed by the Company, accepted by the CAD in settlement, and adopted by the TPUC in each of Piedmont's two prior Annual ARM proceedings. And it is consistent with the settled and approved rate design established in Piedmont's last general rate case.

Specifically, in this proceeding (and consistent with the TPUC-approved outcomes in Piedmont's prior ARM proceedings and Piedmont's last general rate case), Piedmont equally apportioned the Total Revenue Requirement Deficiency for the ABRR to each Applicable Rate Schedule. This is evident from Schedule 26.0 in the Company's 2025 ARM Filing, which demonstrates the following:

PIEDMONT NATURAL GAS COMPANY, INC.
DOCKET NO. 25-00036
CONSUMER ADVOCATE'S SECOND SET OF DISCOVERY REQUESTS
Date Issued: July 2, 2025
Date Due: July 14, 2025

- that the Total Revenue Requirement Deficiency for the ABRR of $8.679 million comports with a 4.1% increase to the Company's Base Margin Revenues (this is shown on Line 11, Columns [C] and [E]);
- that the Margin Revenue Increase allocated to each Applicable Rate Schedule is 4.1% (this is shown in Column [E] on Lines 1 through 8).

From that equal apportionment of a 4.1% increase in the Base Margin Revenues for each Applicable Rate Schedule, the dollar values on Lines 1 through 8 in Column [D] on Schedule 26.0 show the Annual Margin Revenues from each Applicable Rate Schedule to be achieved by the proposed changes to Base Rates effective October 1, 2025, from this 2025 Annual ARM Filing.

In compliance with Piedmont's TPUC-approved ARM Tariff (Service Schedule No. 318), the Base Margin Rates are defined as the volumetric rates per therm for each Applicable Rate Schedule (not the fixed monthly charges or other rate components for each Applicable Rate Schedule), and sets forth the Base Margin Rates as the appropriate rate components to be amended in accordance with the approved ABRR Revenue Requirement Deficiency (or Sufficiency) in each Annual ARM Filing. For this reason, Piedmont's proposed rate design for recovery of the entirety of the $8.679 million ABRR Revenue Requirement Deficiency is an adjustment to the Base Margin Rates per therm.

Name and title of responsible person: Conitsha Barnes, Director - Gas Rate & Regulatory Strategy

PIEDMONT NATURAL GAS COMPANY, INC.
DOCKET NO. 25-00036
CONSUMER ADVOCATE'S SECOND SET OF DISCOVERY REQUESTS
Date Issued: July 2, 2025
Date Due: July 14, 2025

Name and title of preparer: Keith Goley, Lead Rates & Regulatory Strategy Analyst

Response provided by Piedmont Natural Gas Company, Inc. on July 14, 2025.

PIEDMONT NATURAL GAS COMPANY, INC.
TENNESSEE

Effective: November 1, 2012

301 - Residential

	November-March	April-October
Monthly Charge	17.45	13.45
Rate/Therm	0.71582	0.66582

302 - Small General

Monthly Charge	Rate/Therm November-March	Rate/Therm April-October
44.00	0.74982	0.69582

352 - Medium General

Monthly Charge	Rate/Therm November-March	Rate/Therm April-October
225.00	0.74982	0.69582

342 - Natural Gas Vehicle Fuel

Monthly Charge	Rate/Therm	Rate/GGE
40.00	0.62691	0.78991

303 - Firm General Sales

		Units	Rate/Therm
Monthly Charge	800.00	First 15,000	0.36569
Demand (Therm)	2.20448	Next 25,000	0.35840
		Next 50,000	0.33337
		Over 90,000	0.37420

304 - Interruptible General Sales

Monthly Charge	Units	Rate/Therm
800.00	First 15,000	0.36569
	Next 25,000	0.35840
	Next 50,000	0.33337
	Over 90,000	0.37420

313 - Firm Transportation

		Units	Rate/Therm
Monthly Charge	800.00	First 15,000	0.09682
Demand (Therm)	2.20448	Next 25,000	0.08953
		Next 50,000	0.06450
		Over 90,000	0.02764

PIEDMONT NATURAL GAS COMPANY, INC.
TENNESSEE

Effective: November 1, 2012

314- Interruptible Transportation

Monthly Charge	Units	Rate/Therm
800.00	First 15,000	0.09682
	Next 25,000	0.08953
	Next 50,000	0.06450
	Over 90,000	0.02764

310- Resale Service

		Rate/Therm
Demand (Therm)	2.20448	0.35887

306 - Schedule for Limiting and Curtailing Service

	Rate/Therm November-March	Rate/Therm April-October
Emergency Service	$1.00 + gas cost	$1.00 + gas cost
Unauthorized Over Run Penalty	$1.50 + gas cost	$1.50 + gas cost

309 - Special Availability Service

Actual rates are negotiated. See Rate Code 303 and 304 for maximum rates and monthly charges.

Important Notice

Piedmont Natural Gas Company is required by law to charge the rates on file with and approved by the Tennessee Regulatory Authority. Although the rates herein are believed to be an accurate representation of the approved rates as of the dates indicated on the rate schedules, no representation is made as to the accuracy or completeness of the rates shown above. The official rates can be reviewed at the office of the Tennessee Regulatory Authority.

Franchise Fee Notice

In accordance with the Tennessee Public Service Commission order in Docket U-7074, customers metered inside Davidson County are required to pay an additional 6.62% for collection of the Metro Franchise Fee. Customers served by the Fairview, Greenbrier, Hartsville, Mt. Juliet and White House systems are required to pay 5.0%. Customers served by the Franklin and Nolensville systems are required to pay 3.0%. Commercial customers on the Ashland City systems are required to pay 5.0%.

Natural Gas Vehicle Fuel Notice

The Monthly Charge for Rate Schedule 342 is not applicable to gas service provided at the Company's Premises. The Company may bill in units of Gas Gallon Equivalent ("GGE") for gas service provided at the Company's Premises under Rate Schedule 342. The rates convert 1.26 Therms to 1 GGE.

Reconnect Fees

Residential and Commercial	
February Through August	$55.00
September Through January	$85.00

Returned Check Charge

Returned Check Charge	$20.00

PIEDMONT NATURAL GAS COMPANY, INC.
TENNESSEE

Effective: April 2025

Effective for bills rendered on and after the first billing cycle of April 2025

301 - Residential

	November-March	April-October
Monthly Charge	17.45	13.45
Rate/Therm	1.35498	1.23297

302 - Small General

Monthly Charge	Rate/Therm November-March	Rate/Therm April-October
44.00	1.34224	1.22591

352 - Medium General

Monthly Charge	Rate/Therm November-March	Rate/Therm April-October
225.00	1.23742	1.13836

343 - Experimental Motor Vehicle Fuel

Monthly Charge depends on the customer-specific corresponding Rate Schedule
Rate Per Therm depends on the customer-specific corresponding Rate Schedule
Compression Charge, if applicable, is $0.50 per therm (maximum)

303 - Firm General Sales

		Units	Rate/Therm
Monthly Charge	800.00	First 15,000	0.79683
Demand (Therm)	1.53417	Next 25,000	0.76863
		Next 50,000	0.69422
		Over 90,000	0.65831

304 - Interruptible General Sales

Monthly Charge	Units	Rate/Therm
800.00	First 15,000	0.69555
	Next 25,000	0.66756
	Next 50,000	0.63258
	Over 90,000	0.56688

313 - Firm Transportation

		Units	Rate/Therm
Monthly Charge	800.00	First 15,000	0.28226
Demand (Therm)	1.53417	Next 25,000	0.25406
		Next 50,000	0.17965
		Over 90,000	0.14374

PIEDMONT NATURAL GAS COMPANY, INC.
TENNESSEE

Effective: April 2025

Effective for bills rendered on and after the first billing cycle of April 2025

314- Interruptible Transportation

Monthly Charge	Units	Rate/Therm
800.00	First 15,000	0.18098
	Next 25,000	0.15299
	Next 50,000	0.11801
	Over 90,000	0.05231

310- Resale Service

		Rate/Therm
Demand (Therm)	1.53417	1.03094

306 - Schedule for Limiting and Curtailing Service

	Rate/Therm November-March	Rate/Therm April-October
Emergency Service	$1.00 + gas cost	$1.00 + gas cost
Unauthorized Over Run Penalty	$1.50 + gas cost	$1.50 + gas cost

309 - Special Availability Service

Actual rates under this rate schedule are negotiated. Refer to the Tennessee Tariff and Service Regulations for details and availability.

Important Notice

Piedmont Natural Gas Company is required by law to charge the rates on file with and approved by the Tennessee Public Utility Commission. Although the rates herein are believed to be an accurate representation of the approved rates as of the dates indicated on the rate schedules, no representation is made as to the accuracy or completeness of the rates shown above. The official rates can be reviewed at the office of the Tennessee Public Utility Commission.

Franchise Fee Notice

In accordance with the Tennessee Public Service Commission order in Docket U-7074, customers metered inside Davidson County are required to pay an additional 6.59% for collection of the Metro Franchise Fee. Customers served by the Ashland City, Fairview, Franklin, Greenbrier, Hartsville, Mt. Juliet and White House systems are required to pay 5.0%. Customers served by the Nolensville system are required to pay 3.0%.

Reconnect Fees

Residential and Commercial	
February Through August	$55.00
September Through January	$85.00

Returned Check Charge

Returned Check Charge	$20.00

PUBLIC VERSION

PIEDMONT NATURAL GAS COMPANY, INC.
DOCKET NO. 25-00036
CONSUMER ADVOCATE'S FIRST SET OF DISCOVERY REQUESTS
DATE ISSUED: JUNE 5, 2025
DATE DUE: JUNE 20, 2025

1-40. Rate Design. Has Piedmont conducted a stand alone cost study for the individual customer classes?

RESPONSE: Piedmont did not conduct a stand-alone cost study for this proceeding. The cost of service study conducted by Piedmont in this proceeding is attached to the Company's May 20, 2025, TN ARM Filing as Schedule 26A.

Name and title of responsible person: Keith Goley, Lead Rates & Regulatory Strategy Analyst

Name and title of preparer: Keith Goley, Lead Rates & Regulatory Strategy Analyst

Response provided by Piedmont Natural Gas Company, Inc. on June 20, 2025.

PUBLIC VERSION

PIEDMONT NATURAL GAS COMPANY, INC.
DOCKET NO. 25-00036
CONSUMER ADVOCATE'S FIRST SET OF DISCOVERY REQUESTS
DATE ISSUED: JUNE 5, 2025
DATE DUE: JUNE 20, 2025

1-41. Rate Design. Has Piedmont conducted a marginal (or incremental) cost study to identify the cost to connect each new customer in each class? If so, was this done for areas where the infrastructure already exists, where new infrastructure is required, or some combination?

RESPONSE: Piedmont did not conduct a marginal cost study in this proceeding. The cost of service study conducted by Piedmont in this proceeding is attached to the Company's May 20, 2025, TN ARM Filing as Schedule 26A.

Name and title of responsible person: Keith Goley, Lead Rates & Regulatory Strategy Analyst

Name and title of preparer: Keith Goley, Lead Rates & Regulatory Strategy Analyst

Response provided by Piedmont Natural Gas Company, Inc. on June 20, 2025.

PIEDMONT NATURAL GAS COMPANY, INC.
TENNESSEE

Effective: April 2025

Effective for bills rendered on and after the first billing cycle of April 2025

301 - Residential

	November-March	April-October
Monthly Charge	17.45	13.45
Rate/Therm	1.35498	1.23297

302 - Small General

Monthly Charge	Rate/Therm November-March	Rate/Therm April-October
44.00	1.34224	1.22591

352 - Medium General

Monthly Charge	Rate/Therm November-March	Rate/Therm April-October
225.00	1.23742	1.13836

343 - Experimental Motor Vehicle Fuel

Monthly Charge depends on the customer-specific corresponding Rate Schedule

Rate Per Therm depends on the customer-specific corresponding Rate Schedule

Compression Charge, if applicable, is $0.50 per therm (maximum)

303 - Firm General Sales

		Units	Rate/Therm
Monthly Charge	800.00	First 15,000	0.79683
Demand (Therm)	1.53417	Next 25,000	0.76863
		Next 50,000	0.69422
		Over 90,000	0.65831

304 - Interruptible General Sales

Monthly Charge	Units	Rate/Therm
800.00	First 15,000	0.69555
	Next 25,000	0.66756
	Next 50,000	0.63258
	Over 90,000	0.56688

313 - Firm Transportation

		Units	Rate/Therm
Monthly Charge	800.00	First 15,000	0.28226
Demand (Therm)	1.53417	Next 25,000	0.25406
		Next 50,000	0.17965
		Over 90,000	0.14374

PIEDMONT NATURAL GAS COMPANY, INC.
TENNESSEE

Effective: April 2025

Effective for bills rendered on and after the first billing cycle of April 2025

314- Interruptible Transportation

Monthly Charge	Units	Rate/Therm
800.00	First 15,000	0.18098
	Next 25,000	0.15299
	Next 50,000	0.11801
	Over 90,000	0.05231

310- Resale Service

		Rate/Therm
Demand (Therm)	1.53417	1.03094

306 - Schedule for Limiting and Curtailing Service

	Rate/Therm November-March	Rate/Therm April-October
Emergency Service	$1.00 + gas cost	$1.00 + gas cost
Unauthorized Over Run Penalty	$1.50 + gas cost	$1.50 + gas cost

309 - Special Availability Service

Actual rates under this rate schedule are negotiated. Refer to the Tennessee Tariff and Service Regulations for details and availability.

Important Notice

Piedmont Natural Gas Company is required by law to charge the rates on file with and approved by the Tennessee Public Utility Commission. Although the rates herein are believed to be an accurate representation of the approved rates as of the dates indicated on the rate schedules, no representation is made as to the accuracy or completeness of the rates shown above. The official rates can be reviewed at the office of the Tennessee Public Utility Commission.

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In accordance with the Tennessee Public Service Commission order in Docket U-7074, customers metered inside Davidson County are required to pay an additional 6.59% for collection of the Metro Franchise Fee. Customers served by the Ashland City, Fairview, Franklin, Greenbrier, Hartsville, Mt. Juliet and White House systems are required to pay 5.0%. Customers served by the Nolensville system are required to pay 3.0%.

Reconnect Fees

Residential and Commercial	
February Through August	$55.00
September Through January	$85.00

Returned Check Charge

Returned Check Charge	$20.00

Exhibit CDK-12

Understanding your bill.

Account Summary

Includes current billing information, such as your previous bill amount and balance, total current charges, adjustments, applicable fees and taxes. Together, these create your total amount due.

Natural Gas Usage History

The bar graph displays your average monthly energy usage for the past year, including average temps for cooler months. The one-year comparison chart compares your monthly usage to the previous year. Use this information to monitor your energy usage and view energy trends. Save Energy & Money

Current Reading

Your meter reading for the current billing period. Therms Calculation shows how your reading is then used to calculate the total number of billed therms.

An explanation of the terms used in the Therms Calculation can be found on the back of the bill.

Payment Slip

If you'd like to pay by mail, this removable payment slip should be returned with a check or money order in the included envelope.

A variety of other convenient payment methods are available. Learn more

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Piedmont Natural Gas. piedmontng.com 800.752.7504

Your Natural Gas Bill

page 1 of 3

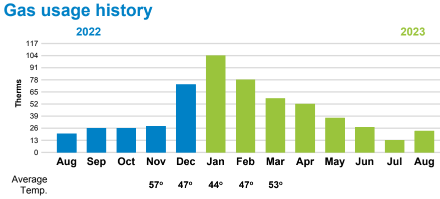
Service address Bill date Sep 2, 2023
SALLY EXAMPLE For service Jul 21 - Aug 21
123 MAINE RD 32 days
ANYTOWN, SC 23456
Account number **9999 9999 9999**

Account summary

Previous bill amount	**$36.18**
Payment(s) received as of Sep 02 - thank you	-36.18
Previous balance	0.00
Current billing and other basic charges	
Gas - Current month charges	41.35
Tax	2.89
Total current charges	44.24
Total account balance	**44.24**
Total amount due Sep 29	**$44.24**
Late fees will be assessed after due date	

Always call 811 before you dig. Making this one free, easy call at least 3 business days before you dig anywhere gets your utility lines marked and helps protect you from injury and expense. For more info about calling 811, visit www.piedmontng.com or call 1.800.752.7504.

Gas usage history



One-year comparison

	Days in Service Period	Total Therms Used	Average Therms Used Per Day
Current	32	23	0.7188
Aug 2022	27	20	0.7407

Your current rate is 101 Residential Service.
Rate schedule and calculation information are available at piedmontng.com.

Current reading — based on actual read on Aug. 21

Meter	Service Period	Meter Reading			Therms Calculation				
		Previous	Current	Difference	Billed Units	X Meter Multiplier	= Gas Used (CCF)	X Heat Factor	= **Total Therms Used**
9999999	Jul 21 to Aug 21 32 days	1791	1813	22	22	1.000	22.000	1.03196	**23**

See back of bill for explanation of terms and late fee calculation.
To further understand your bill, visit ***piedmontng.com/UnderstandMyBill.***

Make check payable to Piedmont Natural Gas or pay instantly at *piedmontng.com/payment.* Be sure to write your account number on your check.

Please return this portion with your payment. Thank you for your business.

Piedmont Natural Gas.
PO Box 1090
Charlotte, NC 28201-1090

Account number **9999 9999 9999**

Amount due

$44.24
by Sep 29

After Sep 29, the amount due will increase to $44.68.

☐ *Please check here and fill out reverse to enroll in Share the Warmth Round Up*

$________________ **Amount enclosed**

SALLY EXAMPLE
123 MAINE RD
ANYTOWN, SC 23456

Piedmont Natural Gas
PO Box 1246
Charlotte, NC 28201-1246

99999999999999900099000000000000000000099990000000099999

FRONT

Customer Information

This section displays where natural gas service is provided, as well as the date your bill is mailed, billing period and number of days included in this billing period. Your account number also appears in bold print for easy reference.

Messages for You

Check the right side of your bill each month, along with included bill inserts, for important messages. If required, additional bill messages may be found on subsequent pages.

Current Rate

This section will display your current rate schedule.

Find your current amount due, due date and related payment messages, including contribution options for Share the Warmth Round Up.

For more information on billing and payments

RESIDENTIAL BUSINESS

Piedmont Natural Gas.

This sample shows a standard bill for a residential customer. All dates and charges are illustrative only and do not represent all possible billing configurations. Additional information can be found on the back of your bill, including definitions of key terms and important phone numbers.

Exhibit CDK-12

Understanding your bill.

Explanation of Terms

A helpful explanation of terms found on your bill.

Customer Service Options

Outlines the various ways our customer service representatives can help you manage your account. Scan the QR code with your smartphone for access to additional resources and information.

Important Phone Numbers

Find important contact information to connect with customer service, make payments and request to have underground lines marked prior to digging.

Checks & Late Payment Information

Learn more about how we process checks and apply late payment charges.

Share the Warmth

Share the Warmth helps families in need pay their energy bills. Discover more about the program.

Piedmont Natural Gas® piedmontng.com 800.752.7504

page 2 of 2

Account number **9999 9999 9999**

Explanation Of Terms

CCF - 100 cubic feet, a measurement of the volume of natural gas used.

METER MULTIPLIER - some meters require that the registration be multiplied by a factor to arrive at the actual usage.

HEAT FACTOR - a factor that measures the energy content of natural gas.

THERM - a unit of heating value equal to 100,000 British thermal units (BTU's).

Explicación de Términos

CCF - 100 pies cúbicos, medida del volumen de gas natural utilizado.

MULTIPLICADOR DEL MEDIDOR - Algunos medidores requieren que se multiplique el registro por un factor para llegar al verdadero uso.

FACTOR CALORÍFICO - factor que mide el contenido energético del gas natural.

TERMIA - unidad de valor térmico equivalente a 100,000 unidades térmicas británicas (BTU).

Customer Service Options

At your convenience, visit our website at www.piedmontng.com 24 hours a day, 7 days a week for all of your customer service needs:

- Answer questions about your bill
- Start or stop Service
- Bank draft enrollment
- Pay by credit card
- Payment options and locations
- Equal Payment Plan (EPP) enrollment
- Natural gas rate schedules
- Money and energy saving tips
- Search for natural gas contractors and dealers near you
- Contact us via email

Opciones del Servicio de Atención al Cliente

Visite nuestro sitio web: www.piedmontng.com las veinticuatro horas del día, los siete días de la semana pa ra todas sus necesidades de servicio al cliente:

- Responder preguntas sobre su factura
- Iniciar o suspender el servicio
- Inscripción de giro bancario
- Pagar con tarjeta de crédito
- Opciones y lugares de pago
- Inscripción en el Plan de pagos iguales (EPP)
- Tarifarios de gas natural
- Consejos para ahorrar dinero y energía
- Buscar contratistas y concesionarios de gas natural cerca de usted
- Comunicarse con nosotros mediante correo electrónico

Important Phone Numbers

Automated Account Information Or Customer Service.................. 800.752.7504

International.. 1.704.382.7644

Digging in your yard or elsewhere?
Locate underground lines before digging.. **811**

Números Teléfonicos Importantes

Información automatizada de cuenta o Servicio a Clientes............. 800.752.7504

Internacional.. 1.704.382.7644

¿Necesita excavar en su terreno o en otro lugar?
Ubicar líneas subterráneas de servicios públicos antes de excavar.................. **811**

When you provide a check as payment, you authorize us either to use information from your check to make a one-time electronic fund transfer from your account or to process the payment as a check transaction. When we use information from your check to make an electronic fund transfer, funds may be withdrawn from your account as soon as the same day we receive your payment, and you will not receive your check back from your financial institution. You may opt out of this process by calling Customer Service.

Late Payment: All bills are payable by the due date. A late payment charge of 1.0% will be added to natural gas balances if not paid by the due date. A late charge of 1.5% ($0.50 minimum) will be added to appropriate non-utility balances not paid by the due date. Late fees will not be applied to "Share the Warmth" donations.

Share the Warmth Round up - Enrollment Form

Piedmont Natural Gas introduces *Share the Warmth* Round Up, a simple way for Piedmont customers to help local families and individuals in need pay their home energy bills.

Enroll today and we'll round up your monthly bill to the nearest dollar and contribute the difference to an approved Share the Warmth agency in your area.

Piedmont Natural Gas®
piedmontng.com

Join Us!
To enroll in *Share the Warmth* Round Up, please complete and return this enrollment form.

☐ I would like to enroll in Piedmont's *Share the Warmth* Round Up Program.

Customer name: ______________________

City, State, Zip: ______________________

Mailing address: ______________________

____

Signature (must match name on account)

BACK

Piedmont Natural Gas®

2-42. Consumer Bill. Refer to Company Response to Consumer Advocate DR No. 1-34, and the residential customer's natural gas bill that was provided. Respond to the following:

a. Confirm that the monthly service fee, customer charge, or current rate is not independently identified on the bill;

b. Conform the website cited on the bill does not include the current monthly service fee, customer charge, or current rate;

c. Confirm that the rate per unit of commodity (therm) is not specifically posted on the customer bill or on the website cited on the bill; and

d. Confirm the customer bill does not specifically identify the tax component of the total bill.

REVISED RESPONSE:

a. Confirmed. Piedmont's customer bill form is in compliance with all applicable Commission requirements.

b. Denied. Piedmont's website provides access to the TPUC-approved rates and charges applicable for billing Piedmont's customers under each and every Rate Schedule. Such information is shown on the website for the current billing month in effect, as well as for several prior months/years. Therein, the monthly charge for each Rate Schedule (a fixed charge) is separately identified from the applicable volumetric charges (rates per therm), including the volumetric rates by step where applicable.

c. Confirmed for customer bill. Denied for Piedmont website; see the Company's response to subparts (a) and (b) of this data request.

d. Denied. Where taxes are applicable to a customer's bill, the tax component of the billed amount is separately identified as a billing line item. Taxes are not applicable to the service or bills provided by Piedmont under Rate Schedule 301 Residential Service; sales of natural gas to residential customers in Tennessee are exempt from sales tax under TN Code Sec. 67-6-334(a).

Name and title of responsible person: Conitsha B. Barnes, Director – Rates & Regulatory Strategy

Name and title of preparer: Conitsha B. Barnes, Director – Rates & Regulatory Strategy

Revised Response provided by Piedmont Natural Gas Company, Inc. on July 16, 2025.