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State Corporation Commission
of Kansas

BEFORE THE STATE CORPORATION COMMISSION

OF THE STATE OF KANSAS

IN THE MATTER OF THE APPLICATION	**)**	
OF ATMOS ENERGY CORPORATION FOR	**)**	
ADJUSTMENT OF ITS NATURAL GAS	**)**	**DOCKET NO. 19-ATMG-525-RTS**
RATES IN THE STATE OF KANSAS	**)**	

DIRECT TESTIMONY AND SCHEDULES OF

GLENN A. WATKINS

RE: CLASS COST OF SERVICE
CLASS REVENUE ALLOCATION
AND
RESIDENTIAL RATE DESIGN

ON BEHALF OF

THE CITIZENS' UTILITY RATEPAYER BOARD

OCTOBER 31, 2019

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I. INTRODUCTION

Q. Please state your name and business address.

A. My name is Glenn A. Watkins. My business address is 6377 Mattawan Trail, Mechanicsville, Virginia 23116

Q. What is your professional and educational background?

A. I am President and Senior Economist with Technical Associates, Inc., which is an economics and financial consulting firm with offices in the Richmond, Virginia area. Except for a six month period during 1987 in which I was employed by Old Dominion Electric Cooperative, as its forecasting and rate economist, I have been employed by Technical Associates continuously since 1980.

During my career at Technical Associates, I have conducted marginal and embedded cost of service, rate design, cost of capital, revenue requirement, and load forecasting studies involving numerous electric, gas, water/wastewater, and telephone utilities. I have provided expert testimony on more than 250 occasions in Alabama, Arizona, Delaware, Georgia, Illinois, Indiana, Kansas, Kentucky, Maine, Maryland, Massachusetts, Michigan, Montana, Nevada, New Jersey, North Carolina, Ohio, Pennsylvania, Vermont, Virginia, South Carolina, Washington, and West Virginia.

I hold an M.B.A and B.S in economics from Virginia Commonwealth University and am a Certified Rate of Return Analyst. A more complete description of my education and experience as well as a list of my prior testimonies is provided in my Schedule GAW-1.

Q. Have you previously provided testimony before this Commission?

A. Yes. I have provided testimony on the same issues that I will be addressing in this case in the last two Kansas Gas Services' general rate cases (Docket Nos. 16-KGSG-491-RTS and 18-KGSG-560-RTS) on behalf of the Citizens' Utility Ratepayer Board ("CURB").

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

A. Technical Associates, Inc. ("TAI") has been engaged by CURB to investigate and evaluate Atmos Energy Corporation's ("Company" or "Atmos") class cost of service studies ("CCOSS"), class revenue allocations, and proposed Residential rate design. The purpose of my testimony is to present the findings of my investigation and offer my recommendations to the Commission in these areas.

Q. Please provide a summary of your recommendations.

A. Although Company witness Paul Raab and I have fundamental differences of opinion regarding how costs are incurred and how costs should be reasonably allocated, he and I both agree that CCOSS should serve as a guide in developing class revenue responsibility and that different approaches can produce significantly different results. In these regards, Mr. Raab has considered multiple CCOSS in developing his recommended class revenue distribution. I have also evaluated individual class profitability based on various CCOSS results and have concluded that Mr. Raab's proposed class revenue distribution is fair and reasonable.

With regard to Residential rate design, I recommend that the fixed customer charge be reduced from the current level of $18.04 per month to $15.00 per month.

II. CLASS COST OF SERVICE

Q. Please briefly explain the concept of a CCOSS and its purpose in a rate proceeding.

A. Generally there are two types of Class Cost Of Service Studies (CCOSS) used in public utility ratemaking: marginal cost studies and embedded (or fully-allocated) cost studies. Atmos has utilized a traditional embedded cost of service study for purposes of establishing the overall revenue requirement in this case, as well as for class cost of service purposes.

Because the majority of a public utility's plant investment and expense is incurred to serve all customers in a joint manner, most costs cannot be specifically attributed to a particular customer or group of customers. Therefore, the costs jointly incurred to serve all or most customers must be allocated across specific customers or customer rate classes. To the extent that certain costs can be specifically attributed to a particular customer or group of customers, these costs are directly assigned in the CCOSS.

It is generally accepted that to the extent possible, joint costs should be allocated to customer classes based on the concept of cost causation. That is, costs are allocated to customer classes based on analyses that measure the causes of the incurrence of costs to the utility. Although the cost analyst strives to abide by this concept to the greatest extent practical, some categories of costs, such as corporate overhead costs, cannot be attributed to specific exogenous measures or factors, and must be subjectively assigned or allocated to customer rate classes. With regard to those costs to which causation can be attributed, there is often disagreement among cost of service experts on what is an appropriate cost causation measure or factor; e.g., peak demand, energy or throughput usage, number of customers, etc.

Q. In your opinion, how should the results of a CCOSS be utilized in the ratemaking process?

A. Although certain principles are used by all cost of service analysts, there are often significant disagreements on the specific factors that drive individual costs. These disagreements can and do arise as a result of the quality of data and the level of detail available from financial records. There are also fundamental differences in opinions regarding the cost causation factors that should be considered to properly allocate costs to rate schedules or customer classes. Furthermore, and as mentioned previously, cost causation factors cannot be realistically ascribed to some costs such that subjective decisions are required.

In these regards, two different cost studies conducted for the same utility and time period can, and often do, yield different results. As such, regulators should consider CCOSS only as a guide, with the results being used as one of many tools to assign class revenue responsibility.

Q. Have the higher courts opined on the usefulness of cost allocations for purposes of establishing revenue responsibility and rates?

A. Yes. In an important regulatory case involving Colorado Interstate Gas Company and the Federal Power Commission (predecessor to FERC), the United States Supreme Court stated:

> But where as here several classes of services have a common use of the same property, difficulties of separation are obvious. Allocation of costs is not a matter for the slide-rule. It involves judgment on a myriad of facts. It has no claim to an exact science.[1]

[1]*Colorado Interstate Gas Co. v. Federal Power Commission,* 324 U.S. 581, 590 (1945).

Q. Does your opinion, and the findings of the U.S. Supreme Court, imply that cost allocations should play no role in the ratemaking process?

A. Not at all. It simply means that regulators should consider the fact that cost allocation results are not surgically precise and that alternative, yet equally defensible, approaches may produce significantly different results. In this regard, when all cost allocation approaches consistently show that certain classes are over- or under-contributing to costs and/or profits, there is a strong rationale for assigning smaller or greater percentage rate increases to these classes. On the other hand, if one cost allocation approach shows dramatically different results than another approach, caution should be exercised in assigning disproportionately larger or smaller percentage increases to the classes in question.

Q. With regard to the practice of relying upon class cost of service studies in establishing class revenue responsibility, has this Commission provided guidance relating to the usefulness of individual CCOSS?

A. Yes. As noted in Company witness Paul Raab's direct testimony, the Commission found as follows in a KCPL rate case (Docket No. 12-KCPE-764-RTS):

> 66. Under the principle of cost causation adopted by the Kansas courts, one class of customers should not bear the costs created by another class. Absent a reasonable basis, the Commission may not order a discriminatory rate design. A class cost of service (CCOS) study is designed to allocate the utility's total system cost of service to the various customer classes. There is no single, universally accepted method for allocating costs to customer classes. Footnotes omitted. [Order, p. 23]

Q. Please explain the basic concepts of cost allocation for public utilities, particularly natural gas distribution companies ("NGDCs").

A. As I mentioned earlier, the majority of a NGDC's plant investment serves customers in a joint manner. In this regard, the NGDC's infrastructure is a system benefiting all customers. If all customers were the same size and had identical usage characteristics, cost allocation would be simple (even unnecessary). However, in reality, a utility's customer base is not so simple. There are small usage customers and large usage customers, and these customers (or customer groups) tend to vary greatly in the amount of service required throughout the year. Therefore, differences in usage should be considered. Because different groups of customers also utilize the system at varying degrees during the year, consideration should also be given to the demands placed on the system during peak usage periods.

Q. With regard to NGDCs, is there any aspect of class cost allocations that tends to overshadow other issues or is often controversial?

A. Yes. For virtually every NGDC, the largest single rate base item (account) is distribution mains. Furthermore, several other rate base and operating income accounts are typically allocated to classes based on the previous assignment of distribution mains. Therefore, the methods and approaches used to allocate distribution mains to classes are usually by far the most important (in terms of class rate of return ["ROR"] results) and tend to be the most controversial.

Q. What methods are commonly used to allocate natural gas distribution mains?

A. While a myriad of cost allocation methods and approaches have been developed, three methods predominate in the NGDC industry: "Peak Responsibility," "Peak and Average"

("P&A") (also known as "Demand/Commodity" or "Demand/Energy"), and "Customer/Demand," which I will address shortly in more detail. These methods differ in the criteria used to allocate mains, as cost allocation analysts do not universally agree on the cost causative factors or drivers influencing mains investments. There are three criteria generally considered when selecting a mains cost allocation method: peak demand (whether coincident, non-coincident, or actual or design day); annual (average day) usage; and number of customers. Because a NGDC system must be capable of supplying gas to its firm customers during peak demand periods (i.e., on very cold days), relative class peak day demands are often considered a good proxy for measuring the cost causation of mains investment.[2] Annual (or average day) throughput is also often used to allocate mains as this factor reflects the utilization of a utility's mains investment. Number of customers is also sometimes considered when allocating mains. That is, customer counts by class serve as a basis for allocation of mains. Even though annual levels of usage and peak load requirements vary greatly between customer classes (residential versus large industrial), some analysts are of the opinion that customer counts should be considered because at least some infrastructure investment in mains is required simply to "connect" every customer to the system. With these three criteria identified, various methods weigh and utilize these criteria differently within the cost allocation process. In other words, some methods rely on only one criterion while others consider two or more criteria with varying weights given to each factor utilized.

[2] Embedded cost allocations are directly only concerned with relative, not absolute, criteria. That is, because embedded cost allocations reflect nothing more than dividing total system costs between classes, it is the relative (percentage) contributors to total system amounts that is relevant.

As mentioned previously, the three most common NGDC cost allocation methods are the "Peak Responsibility" method (whether coincident or class non-coincident), in which peak day demands are the only factor utilized to allocate mains; the "P&A" or "Demand/Commodity" approach, in which both peak day and annual (average day) throughput is reflected within the allocation of mains;[3] and the Customer/Demand method, which utilizes a combination of peak day demands and customer counts to assign mains cost responsibility.

Under the Customer/Demand method, the weight given to class customer counts and peak day demands is determined from a separate analysis using one of two approaches: minimum-size and zero-intercept. The "minimum-size" approach prices the entire system footage of mains at the cost per foot of the smallest diameter pipe installed. This "minimum-size" cost is then divided by the actual total investment in mains to determine the weight given to customer counts. One (1) minus the customer percentage is then given to the peak day demand within the allocation process. Under the zero-intercept approach, statistical linear regression techniques are used to estimate the cost of a theoretical "zero size" main. Similar to the minimum-size approach, the cost of this estimated zero size pipe per foot is multiplied by the total system footage and is then divided by total mains investment to arrive at a customer weighting.

Q. Did Company witness Raab conduct multiple CCOSS utilizing various methods to allocate mains-related costs?

[3] Under the P&A or Demand/Commodity approach, peak use and annual throughput are either weighted equally or based on system load factor, where load factor is the ratio of average daily usage to peak day usage. When using a load factor approach to weight P&A usage, the weighting of average day usage is that of the system load factor, while the peak day weight is one minus the system load factor.

A. Yes. Mr. Raab conducted three alternative CCOSS utilizing the methods described earlier; i.e., Customer/Demand; Peak Responsibility (using non-coincident peak demands); and, P&A (Demand/Energy).

Q. Does Mr. Raab have a preferred CCOSS method to allocate mains-related costs?

A. Yes. While Mr. Raab recognizes the Commission's finding that there is no single universally accepted method for allocating costs to customer classes and "trying to 'prove' the superiority of one method over the other is a feckless endeavor,"[4] it is clear that Mr. Raab is of the opinion that the Customer/Demand method is preferred over the Peak Responsibility or P&A methods.[5]

Q. On page 13 of his direct testimony, Company witness Paul Raab claims that there are two very important factors that drive a natural gas utility's cost of service. These include the fact that NGDC's are a capital intensive enterprise and that the system must be sized in order to meet customers' demands during peak periods. Do you agree with this assertion?

A. Not in the context in which Mr. Raab draws his conclusions (that is, Mr. Raab states on page 13, "this combination of capital intensity and sizing to meet peak day demands dictates the prominence of customers served and the 'rate of use' customer demand characteristic when discussing the primary causes of cost incurrence.") In other words, Mr. Raab claims that cost causation is related to number of customers and peak demand. With regard to the customer component, Mr. Raab opines that because NGDCs are capital

[4] Raab direct testimony, page 6.
[5] See for example, Mr. Raab's direct testimony, page 6, lines 20 through 22 and page 13, lines 7 through 14.

intensive and customers must be physically connected to the distribution system, there must be a "customer" component associated with cost incurrence.

In this regard, there is not a single customer that connects to a natural gas system simply to be connected. Rather, natural gas customers connect to a system in order to consume natural gas for their energy needs. While it is obvious that customers must be physically connected to an NGDC's system, natural gas consumption is the very purpose for the existence of Atmos; i.e., an infrastructure system of pipes to distribute natural gas to its consumers to meet their energy needs. NGDCs do not install mains throughout their service territory if there is no anticipated natural gas to be distributed through those mains. Indeed, the Company's current tariff concerning its extension of mains requires that there be enough revenue (natural gas usage) to warrant the economic investment required to extend the Company's distribution system.[6]

Q. What is Mr. Raab's opinion of the Peak & Average method, which he refers to as the Demand/Energy method?

A. Mr. Raab clearly opposes consideration of the P&A method. On page 7 of his direct testimony, Mr. Raab characterizes the P&A method as a "format that is designed to achieve a particular objective (i.e., shift costs away from low load factor residential customers) rather than reflect any measure of cost causation . . . ."

Furthermore, on page 14 of his direct testimony, Mr. Raab states: "This [Peak & Average] methodology gives no weight to the critical point that these facilities were sized and built to meet the highest demand that occurs during the winter period for Atmos

[6] Atmos Energy Corporation Kansas tariff, General Terms and Conditions for Service, Section 8. Distribution Main Extension Policy.

Energy." As I will explain later in my testimony, Mr. Raab's statement is factually incorrect.

Q. Do you agree with Mr. Raab's assertion that the P&A method is designed to meet a particular objective?

A. No. While Mr. Raab and I have philosophical differences of opinion as it relates to cost causation and how costs should be allocated across classes, I do not characterize his preference for the Customer/Demand as a particular allocation approach to meet a particular objective (i.e., shift costs away from high load factor industrial customers) rather than reflect any measure of cost causation.

Q. Does NARUC recognize the P&A approach as an objective method to allocate costs?

A. Yes. The current (1989) NARUC <u>Gas Distribution Rate Design Manual</u> identifies the most commonly used demand allocation methods for NGDCs: Coincident Demand method; Non-Coincident Demand method; and, Average and Peak (P&A) method. With regard to the P&A method, this Manual states as follows:

> d. <u>Average and Peak Demand Method</u>
> **This method reflects a compromise between the coincident and non-coincident demand methods.** Total demand costs are multiplied by the system's load factor to arrive at the capacity costs attributed to average use and are apportioned to the various customer classes on an annual volumetric basis. The remaining costs are considered to have been incurred to meet the individual peak demands of the various classes of service and are allocated on the basis of the coincident peak of each class. **This method allocates cost to all classes of customers and tempers the apportionment of costs between the high and low load factor customers** (pages 27 and 28) [**Emphasis added**].

Q. In your experience, have some commissions relied exclusively upon the P&A method as the preferred cost allocation approach for NGDCs?

A. Yes. While I have not conducted a formal survey, I practice throughout the Country. The Washington Utilities and Transportation Commission has a stated policy that the P&A method is the approved cost allocation approach for all NGDCs (Puget Sound Energy, Avista Corporation, Cascade Natural Gas, and Northwest Natural Gas). Similarly, the Pennsylvania Public Utility Commission has a long-standing practice of considering both peak demands and average usage for allocating distribution mains for all NGDCs in the State (Columbia Gas, Peoples Natural Gas, National Fuel Distribution Company, Valley Energy, UGI Utilities, Philadelphia Gas Works, and PECO Gas). The Maryland Public Service Commission has accepted the P&A method for Washington Gas Light. The Virginia State Corporation Commission has recently found that the P&A method is the most appropriate method to allocate distribution mains cost for Washington Gas Light.[7] The Delaware Public Service Commission has accepted and relied upon the P&A method for its only NGDC (Delmarva Power & Light). The Rhode Island Public Utilities Commission does not endorse the P&A method per se, but rather, utilizes a method of weighted monthly consumption; i.e., considers only usage (National Grid Gas Services).

Q. Has Mr. Raab himself acknowledged that the P&A method is a traditional and accepted method?

A. Yes. In an Atmos Energy Kentucky rate case (Case No. 2013-00148), Mr. Raab stated as follows:

[7] Final Commission Order pending. This reference is to the Hearing Examiner's Report and Recommended Decision.

> While I may not necessarily agree with Mr. Watkins' classifications and allocations, I would admit that there is support for his approach in previously filed cost of service studies in other jurisdictions. Both approaches utilize traditional and accepted classification and allocations methods and yet produce widely divergent results of the "cost of service."[8]

Q. Earlier you indicated that Mr. Raab's statement that the P&A methodology gives no weight to the critical point that these facilities were sized and built to meet the highest demand that occurs during the winter period is factually incorrect. Please explain.

A. The P&A method considers both peak demand and average usage (throughput). In this case, the P&A method gives 53.47% weight to peak usage and 46.53% weight to throughput. As such, the P&A method does indeed give weight to peak demand.

Q. In your opinion, is there a preferred method to allocate natural gas distribution mains costs?

A. Yes. In my opinion, the P&A approach is the fairest and most equitable method to assign natural gas distribution mains costs to the various customer classes. This method recognizes each class's utilization of the Company's facilities throughout the year, and also recognizes that some classes rely upon the Company's facilities (mains) more than others during peak periods.

Q. Earlier you indicated that some analysts prefer to employ the Peak Responsibility method in which mains are allocated solely on the basis of peak loads. In your opinion, why is this method generally inferior to the P&A method to allocate mains?

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[8] Kentucky PSC Case No. 2018-00148, Rebuttal testimony of Paul H. Raab, page 5, lines 15 through 19.

A. While it is appropriate to consider and reflect class peak demands when allocating distribution mains, it should not be the only criteria. A NGDC system is constructed and is in existence in order to serve the natural gas energy needs of its customers throughout the year. If Atmos' (or any NGDC's) customers only demand gas for one day of the year (the so-called peak day), the costs to deliver gas throughout the system would be prohibitively high such that a system would never exist. In other words, Atmos' customers demand and utilize natural gas every day of the year, not just one day out of 365 days. If by chance, a customer did require gas for only one day a year, it would be prohibitively expensive to the Company (and ultimately the customer) to provide service. Atmos would have to recover the investment in mains from a very small amount of natural gas energy (usage), which would be economically infeasible.

The major shortcoming of the Peak Responsibility method (which allocates mains entirely on peak day demand) is that it is premised on the assumption that there is a direct and linear relationship between peak loads, system capacity, and costs. In fact, there is no direct relationship between peak loads (capacity requirements) and the cost incurred to install mains. With regard to system capacity, the amount of gas that can be delivered throughout a NGDC system is not only a function of the size of pipe(s) but also the pressurization of gas within these pipes as well as the presence or absence of looping various segments of the distribution system. For example, if the peak load on one line segment of mains is double that of another line segment, the cost of mains for the larger capacity pipe may be higher, but it is not double that of the lower capacity. In very simple terms, and all else constant, the *capacity* of pipes increase by a factor of exactly 4 to 1 as the *diameter* of pipe increases.[9] Therefore, if the size of a pipe is doubled, the capacity of the pipe increases by a factor of four. At the same time, the cost of this additional capacity is far less than four times as much.[10]

Additionally, and as important as the geometric capacity of pipe at a given pressure, the amount of gas required to be pushed through a distribution system can be met with larger pipes at lower pressures or smaller pipes at higher pressures. With improvements in materials, technology, and pipe coupling, we are seeing that NGDCs are replacing their systems with *smaller* plastic pipes operated at *higher* pressures. Because the allocation of mains only concerns the assignment of the pipes costs, there is not a clear relationship between a main segment's capacity (peak load ability) and the cost of that pipe. The relevance of this is that an allocation method that only considers peak load assumes there is a direct and perfectly linear relationship between load (capacity) and the cost of mains. As demonstrated above, this assumption is clearly not accurate.

Q. Mr. Raab's preferred method allocates distribution mains partially on some measure of peak demand and partially on number of customers. What rationale is used to allocate mains investment, at least partially, based on customer counts?

A. I am aware of two rationales, or arguments, used to advocate the allocation of natural gas distribution mains based partially on number of customers. While the conceptual argument

[9] The volume of a cylinder (pipe) is equal to pi (3.14159) x Radius^2 x length. Therefore, it can be seen that as the diameter doubles, the area (volume) of the pipe increases by four times that of the smaller pipe.

[10] The cost of mains investment reflects the cost of capitalized labor to install the main plus the cost of materials (the piping). Although the labor cost of installing pipe increases somewhat with larger size pipe, these additional labor costs tend to be much smaller than the capacity added. Similarly, although the materials cost of the pipe also increases, it is by a much smaller percentage than the capacity added.

has no economic or practical logic in my opinion, the second rationale may produce reasonable results in some instances, but it is rarely applicable to NGDCs.

The first rationale used by some analysts is that because every customer (regardless of size) must be physically connected to the utility's distribution network, there is some minimum level of investment required to simply connect customers to the distribution system. It is certainly true that, unless natural gas is delivered in a portable tank or cylinder, some form of physical "plumbing" is required to deliver natural gas to each and every end-user.[11] Indeed, this is the very purpose of the distribution system. However, no customer connects to a NGDC system simply to be connected but never utilizes natural gas, nor do NGDCs haphazardly install natural gas mains where no usage is present or anticipated. Because there is no economic utility (benefit) derived from simply being connected to a system, there is no economic (or cost causative) basis for assigning some value of a NGDC's distribution mains required to simply connect customers.

The second rationale used to consider number of customers within the allocation of mains relates to customer densities and differences in the mix of customers (by class) throughout a utility's service area. Possibly the best way to explain why customer densities may be relevant in the assignment of distribution costs to individual classes is by way of example. Consider two different utilities: an electric utility with urban, suburban, and rural service areas and another electric utility with only urban and suburban customers. With respect to the electric utility with a rural service area, many miles of conductors and associated plant must be installed in order to serve the demands of relatively few customers. Conversely, many more customers are served on a per mile basis for the urban/suburban

[11] If natural gas was delivered to end-users in tanks (as is done with propane), there would be no distribution system, or mains, to allocate.

utility. With respect to the utility with a rural service area, an allocation based on usage or demand may be unfair if some classes are located mainly in urban or suburban areas, while other classes of customers are located in rural areas. As a result, some cost studies classify distribution plant as partially demand-related and partially customer-related.

Q. In the above example, you referred to electric utilities instead of natural gas utilities. Is there a reason why you selected the electric utility industry for your example?

A. Yes. Although the concepts are the same between electric and natural gas distribution facilities (e.g., conductors are synonymous with mains), electric utilities are *required* to serve rural (sparsely populated) areas. NGDCs, however, have no such requirement. Moreover, electric utilities are required to connect all consumers regardless of density or usage. That is not the case for NGDCs: their tariffs allow them to connect only those customers in areas with sufficient customer densities and usage.

As a general matter, a Customer/Demand classification of *electric* distribution facilities may be appropriate given the characteristics of a utility's service area, but is rarely appropriate for NGDCs with more densely populated service areas and that are not required to serve all potential residences and businesses.

Q. Please explain the importance of Mr. Raab's classification and allocation of distribution mains based partially on number of customers and based partially on NCP demands under his Customer/Demand study.

A. Under Mr. Raab's Customer/Demand CCOSS, he has allocated distribution mains using a weighting of 58.05% based on number of customers and 41.95% based on NCP demands.

Because of the use of internal (or composite) allocators, many other expense and rate base items are also directly or indirectly allocated based on this mains allocation. By allocating more than half of the Company's mains investment based simply on customer counts, Mr. Raab has assigned the same cost responsibility of this 58% weighting to a small apartment-dwelling customer that uses natural gas only for cooking as he does to a very large industrial customer that uses millions of MCF per year.

Q. Is there a simple way to show the bias and over-assignment of costs to small volume user classes under Mr. Raab's cost allocation approach?

A. Yes. Mr. Raab's classification process results in an ultimate allocation of two-thirds (67.06%) of the Company's total requested non-gas revenue requirement based simply on number of customers.[12]

Q. Have you examined Mr. Raab's CCOSS utilizing the P&A (Demand/Commodity) method?

A. Yes. Mr. Raab allocates the demand portion (58%) of distribution mains based on class non-coincident peak ("NCP") demands while the more traditional P&A approach considers coincident peak, or design day, demands. While I do not normally have a fundamental disagreement with the use of NCPs within the P&A method, Atmos' customer mix and load profiles are somewhat atypical from most other NGDCs in the country. This is because of the significant irrigation load. As is the case with virtually every NGDC in the country, Atmos' system peak demand occurs on a cold Winter day (January for Atmos).

[12] Calculated as $47,161,150 (per Exhibit PHR-2, page 2) divided by $70,327,557 (per Exhibit PHR-2, page 1).

However, Irrigation customers tend to use very little natural gas during system peak periods as shown in the table below:

TABLE 1
Irrigation
Monthly MCF Throughput
3-Year Average
(2016-2018)[13]

Jan.	3,910
Feb.	10,587
Mar.	46,640
Apr.	73,403
May	51,212
June	77,955
July	126,802
Aug.	115,803
Sept.	78,334
Oct.	21,247
Nov.	33,853
Dec.	15,834

As can be seen in the above table, the Irrigation class peaks in the Summer when total system throughput is relatively small. As such, Irrigation customers can be considered off-peak users of natural gas. The spirit and concept of the P&A method is that recognition should be given to both concepts that distribution mains are sized and placed into service to meet peak load requirements as well as the utilization of natural gas throughout the year. For Atmos, the P&A method assigns somewhat less than half (42%) of cost responsibility based on annual throughput such that the Irrigation class is assigned costs based on this class's usage over the entire year. However, in my opinion, it would be unfair to then assign the remaining 58% of costs to the Irrigation class based on this class's NCP which

[13] Calculated per Irrigation_Supplemental_Data_Staff.xls, provided by Commission Staff.

occurs during the off-peak Summer months. As such, I have adjusted Mr. Raab's P&A study to reflect coincident peak demands instead of NCP demands.

Q. Have you made any other adjustments to Mr. Raab's P&A study?

A. Yes. In examining Mr. Raab's P&A Excel spreadsheet (Exhibit PHR-4), I observed that he classified and allocated certain O&M expenses totally on demand while the corresponding plant items were classified and allocated in a different manner. Typically, O&M expenses associated with particular plant items are classified and allocated on the same basis as plant investment. As a result, I have classified and allocated certain O&M expenses somewhat differently than Mr. Raab as shown in the table below:

TABLE 2
Comparison of Raab and CURB
Allocation of O&M Expenses

O&M Expense	Raab Classification/ Allocation	CURB Classification/ Allocation
Oper. Dist. Mains & Services	Demand	Cust., Demand/Throughput
Maint. Dist. Supervision & Eng.	Demand	Cust., Demand/Throughput
Maint. of Dist. Mains	Demand	Demand/Throughput
Maint. of Services	Demand	Customer
Maint. of Meters & House Regulators	Demand	Customer

Q. Please provide a comparison of class rates of return under your P&A study to those obtained by Mr. Raab's P&A study.

A. The following tables provide a comparison of P&A class RORs and relative RORs at current rates under Mr. Raab's and my studies:

TABLE 3
P&A RORs at Current Rates

Class	Raab	CURB
Residential Sales	4.53%	4.21%
Com/PA Sales	7.05%	7.35%
Schools Sales	6.29%	6.90%
Industrial Sales	5.34%	6.59%
SGS	27.49%	26.72%
Irrigation Sales	**0.70%**	**15.12%**
Firm Transport	6.80%	6.52%
Schools Transport	5.38%	5.54%
Irrigation Transport	**0.04%**	**8.29%**
Interruptible Transport	1.10%	0.77%
Total	4.87%	4.87%

TABLE 4
P&A Relative RORs at Current Rates

Class	Raab	CURB
Residential Sales	93%	86%
Com/PA Sales	145%	151%
Schools Sales	129%	142%
Industrial Sales	110%	135%
SGS	564%	549%
Irrigation Sales	**14%**	**310%**
Firm Transport	140%	134%
Schools Transport	111%	114%
Irrigation Transport	**1%**	**170%**
Interruptible Transport	23%	16%
Total	100%	100%

While there are minor differences in absolute and relative RORs for most classes, there are dramatic differences as it relates to the Irrigation Sales and Transport classes. Under Mr. Raab's P&A approach that uses class NCP demands, Irrigation customers' current revenues are significantly deficient while under my approach that uses coincident peak demands, these Irrigation customers' current revenues are significantly higher than their cost of service.

Q. Please provide a summary of class RORs at current rates under Mr. Raab's three CCOSS as well as your P&A study.

A. The following table provides a comparison of Mr. Raab's CCOSS results under the three methods he performed as well as under my P&A study:

TABLE 5
Comparison of Class Relative RORs at Current Rates

	Raab			CURB
Method →	Cust./Demand	Pk. Responsibility	P&A	P&A
Dist. Mains Demand →	NCP	NCP	NCP	CP
Residential Sales	60%	89%	93%	86%
Com/PA Sales	235%	142%	145%	151%
Schools Sales	264%	118%	129%	142%
Industrial Sales	340%	113%	110%	135%
SGS	272%	557%	564%	549%
Irrigation Sales	146%	1%	14%	310%
Firm Transport	539%	190%	140%	134%
Schools Transport	257%	104%	111%	114%
Irrigation Transport	138%	8%	1%	170%
Interruptible Transport	319%	68%	23%	16%
Total	100%	100%	100%	100%

As can be seen above, Mr. Raab's NCP and P&A approaches generally produce similar results. Furthermore, Mr. Raab's Customer/Demand study tends to show much higher RORs for the large volume classes than those obtained under his NCP and P&A approaches. This is largely due to the fact that Mr. Raab's Customer/Demand study results are driven by a large portion of costs allocated simply based on customer counts. When Mr. Raab's P&A study is compared to my P&A study, we see that most classes' RORs are fairly similar with the exception of the Irrigation classes in which Mr. Raab allocates the demand portion of distribution mains on NCPs, resulting in extremely low RORs for the Irrigation classes. Conversely, I allocate the demand portion of distribution mains on CPs, resulting in extremely high RORs for the Irrigation classes. A summary of my P&A

CCOSS is provided in my Schedule GAW-2 while the details are contained in my workpapers.

Q. What are your findings and recommendations concerning class cost allocations in this case?

A. As explained earlier in my testimony, class cost allocation studies cannot be considered surgically precise for a variety of reasons. As a result, it is appropriate to consider the results of multiple CCOSS in evaluating class revenue responsibility. This philosophy is consistent with this Commission's prior opinions concerning CCOSS and also appears to be consistent with Mr. Raab's testimony to some degree. In these regards, while I am of the opinion that the P&A method reasonably reflects cost causation and is fair and equitable to all customers and I strongly disagree with the Customer/Demand approach applied to Atmos, I recognize that the Customer/Demand method is sometimes used in the NGDC industry. Furthermore, I also recognize that Staff has historically preferred the Peak Responsibility method wherein distribution mains are allocated on class NCPs. With this being said, there should not be sole reliance on any single CCOSS, but rather, consideration should be given to all studies in evaluating class revenue responsibility.

III. CLASS REVENUE DISTRIBUTION

Q. How does the Company propose to allocate, or assign, its requested $10.526 million base rate increase before the amortization of EDIT?

A. Company witness Raab also sponsors Atmos' class revenue allocations and rate design. In developing his allocation of the Company's proposed overall increase to individual classes, Mr. Raab first recommends that no class receive a rate decrease in this case. Next, Mr. Raab recommends no change in rates or revenues for Small Generator Sales Service or Special Contract customers. Finally, Mr. Raab recommends equal percentage increases to all other classes based on total non-gas revenues.[14]

Q. Do you agree with Mr. Raab's proposed class revenue distribution?

A. Yes. While class cost of service results should serve as one of the guides in evaluating class revenue responsibility, the various studies conducted for this case produce widely different results for many classes. For example, the relative RORs for the Interruptible Transportation class range from 16% to 319% of the system average ROR. Likewise, the Irrigation Sales relative ROR ranges from 1% to 310%. However, the Small Generator Sales and Firm Transport class's average relative RORs (over the four studies conducted) are significantly higher than the other classes; i.e., 486% and 251%, respectively.

The following table provides each class's relative RORs at current rates under each study conducted by Mr. Raab as well as my P&A study along with his proposed class revenue increases:

[14] Total non-gas revenues include base rate revenues, an allocation of Special Contract revenues, and Miscellaneous Service revenues.

TABLE 6
Comparison of Relative RORs at Current Rates and Company Proposed Revenue Increases
($000)

	Indexed ROR							
	Raab				**Avg.**	Current	Raab	Raab
	Customer/ Demand	Peak Demand	P&A	CURB P&A	**All Studies**	Non-Gas Revenue	Proposed Increase	Percent Increase
Resid. Sales	60%	89%	93%	86%	**82%**	$43,148.4	$8,037.5	18.63%
Com/PA Sales	235%	142%	145%	151%	**168%**	$10,184.5	$1,897.1	18.63%
Schools	264%	118%	129%	142%	**163%**	$74.2	$13.8	18.63%
Ind. Sales	340%	113%	110%	135%	**174%**	$85.6	$15.9	18.63%
SGS	272%	557%	564%	549%	**486%**	$35.9	$0	0.00%
Irrig. Sales	146%	1%	14%	310%	**118%**	$863.8	$160.9	18.63%
Firm Trans.	539%	190%	140%	134%	**251%**	$3,256.6	$0	0.00%
Schools Trans.	257%	104%	111%	114%	**146%**	$753.0	$140.3	18.63%
Irrig. Trans.	138%	8%	1%	170%	**79%**	$44.2	$8.2	18.63%
Interrupt. Trans.	319%	68%	23%	16%	**106%**	$1,355.2	$252.4	18.63%
Total	100%	100%	100%	100%	**100%**	$59,801.3	$10,526.2	17.60%

As a result, I have concluded that no increases to the Small Generator Sales and Firm Transport classes are appropriate and that equal percentage increases to all other classes are also reasonable.

Q. Mr. Raab's proposed class revenue distribution is based on an increase of $10.526 million which is before recognition of the amortization of EDIT. How does Mr. Raab reflect the amortization of EDIT in his proposal?

A. Mr. Raab allocates the total Company amortization of EDIT ($889,580) to classes in proportion to his proposed base rate increases.

Q. Is Mr. Raab's approach reasonable?

A. Yes.

Q. In the event that the Commission authorizes an overall increase less than the amount requested by Atmos, do you recommend an alternative class revenue allocation?

A. Yes. If the Commission authorizes an overall increase in the base rate revenue requirement less than that requested by the Company, I recommend that the authorized overall increase be allocated in proportion to the class increases shown above.

IV. RESIDENTIAL RATE DESIGN

Q. Please explain Atmos' current and proposed Residential rate structure.

A. The Company's Residential base rates are structured with a fixed monthly customer (service) charge plus a flat delivery charge per CCF. Mr. Raab proposes to increase the base rate fixed monthly service charge from $18.04 per month to $22.00 per month which represents a 22.0% increase. In addition, the Company proposes a rate case expense surcharge that would be in effect for one year wherein this surcharge would be collected on a fixed charge per customer basis of $0.51 per month. The current Residential base delivery charge is $0.14439 per CCF and under the Company's proposal, this would be increased by 10.6% to $0.15972 per CCF.

Q. Given the current residential customer charge of $18.04 per month and the current delivery charge of $0.14439 per CCF, what percentage of total Residential base rate revenues are collected from the fixed monthly customer charge?

A. As shown in Section 17 of the Company's Filing, $32.436 million is collected from residential fixed monthly customer charges, while $17.114 million is collected from the volumetric delivery charge. As such, 63.2% of total Residential base rate revenues are collected from the fixed monthly customer charge. Under Mr. Raab's proposed rates, 65.5% of residential base rate revenues would be collected from fixed monthly customer charges (excluding his proposed $0.51 rate case expense surcharge).[15]

Q. Does this high percentage of revenues collected from fixed charges concern you?

A. Yes. When almost two-thirds of the Company's base rate (margin) revenue is collected from unavoidable fixed monthly charges, it inhibits residential customers' ability to control their natural gas bills and is contrary to conservation efforts since a large portion of the customer's bill is fixed in nature and does not vary with consumption. Furthermore, such a high percentage of margin revenue collected from residential fixed charges clearly reduces the Company's risk in that customer charge revenues is guaranteed revenue with virtually no risk.

Q. Is the Company's current or proposed residential fixed monthly charge reasonable or in the public interest?

A. No. Atmos' objective to collect a large percentage of its sunk investment costs (aka fixed costs) through fixed charges, as well as its proposed increases to such charges, violate the regulatory principle of gradualism, violate the economic theory of efficient competitive pricing, and are contrary to effective conservation efforts.

Q. Does the Company's proposal to collect a substantial portion of Residential base rate revenue from fixed monthly charges comport with the economic theory of competitive

[15] $32.436 million in customer charges and $17.114 million in delivery charges.

markets or the actual practices of such competitive markets?

A. No. The most basic tenet of competition is that prices determined through a competitive market ensure the most efficient allocation of society's resources. Because public utilities are generally afforded monopoly status under the belief that resources are better utilized without duplicating the fixed facilities required to serve consumers, a fundamental goal of regulatory policy is that regulation should serve as a surrogate for competition to the greatest extent practical.[16] As such, the pricing policy for a regulated public utility should mirror those of competitive firms to the greatest extent practical.

Q. Please briefly discuss how prices are generally structured in competitive markets.

A. Under economic theory, efficient price signals result when prices are equal to marginal costs.[17] It is well known that costs are variable in the long run. Therefore, efficient pricing results from the incremental variability of costs even though a firm's short-run cost structure may include a high level of sunk or "fixed" costs or be reflective of excess capacity. Indeed, competitive market-based prices are generally structured based on usage; i.e., volume-based pricing. A colleague of mine often uses the following analogy: an oil refinery costs well over a billion dollars to build, such that its cost structure is largely comprised of sunk, or fixed, costs, but these costs are recovered one gallon at a time.

Q. Please briefly explain the economic principles of efficient price theory and how short-run fixed costs are recovered under such efficient pricing.

[16] James C. Bonbright, et al., *Principles of Public Utility Rates*, p. 141 (Second Edition, 1988).
[17] Strictly speaking, efficiency is achieved only when there is no excess capacity such that short-run marginal costs equal long-run marginal costs. In practice, there is usually at least some excess capacity present such that pricing based on long-run marginal costs represents the most efficient utilization of resources.

A. Perhaps the best known micro-economic principle is that in competitive markets (i.e., markets in which no monopoly power or excessive profits exist), prices are equal to marginal cost. Marginal cost is equal to the incremental change in cost resulting from an incremental change in output. A full discussion of the calculus involved in determining marginal costs is not appropriate here. However, it is readily apparent that because marginal costs measure the changes in costs with output, short-run "fixed" costs are irrelevant in efficient pricing. This is not to say that efficient pricing does not allow for the recovery of short-run fixed costs. Rather, they are reflected within a firm's production function such that no excess capacity exists and that an increase in output will require an increase in costs -- including those considered "fixed" from an accounting perspective. As such, under efficient pricing principles, marginal costs capture the variability of costs, and prices are variable because prices equal these costs.

Q. Please explain how efficient pricing principles are applied to the natural gas distribution industry.

A. Universally, utility marginal cost studies include three separate categories of marginal costs: demand, energy, and customer. Consistent with the general concept of marginal costs, each of these costs varies with incremental changes. Marginal demand costs measure the incremental change in costs resulting from an incremental change in peak load (demand). Marginal energy (commodity) costs measure the incremental change in costs resulting from an incremental change in CCF (energy) consumption. Marginal customer costs measure the incremental change in costs resulting from an incremental change in number of customers.

Particularly relevant here is understanding what costs are included within, and the procedures used to determine, marginal customer costs. Since marginal customer costs reflect the measurement of how costs vary with the number of customers, they only include those costs that directly vary as a result of adding a new customer.

Q. Please explain how this theory of competitive pricing should be applied to regulated public utilities such as Atmos.

A. Due to Atmos' investment in system infrastructure, there is no debate that many of its short-run costs are fixed in nature. However, as discussed above, efficient competitive prices are established based on long-run costs, which are entirely variable in nature.

Marginal cost pricing only relates to efficiency. This pricing does not attempt to address fairness or equity. Fair and equitable pricing of a regulated monopoly's products and services should reflect the benefits received for the goods or services. In this regard, those that receive more benefits should pay more in total than those who receive fewer benefits. Regarding natural gas usage, the level of consumption is the best and most direct indicator of benefits received. Thus, volumetric pricing promotes the fairest pricing mechanism to customers and to the utility.

The above philosophy has consistently been the belief of economists, regulators, and policy makers for generations. For example, consider utility industry pricing in the 1800s, when the industry was in its infancy. Customers paid a fixed monthly fee and consumed as much of the utility commodity/service as they desired (usually water). It soon became apparent that this fixed monthly fee rate schedule was inefficient and unfair. Utilities soon began metering their commodity/service and charging only for the amount actually consumed. In this way, consumers receiving more benefits from the utility paid more, in total, for the utility service because they used more of the commodity.

Q. Is the natural gas distribution industry unique in its cost structures, which are comprised largely of fixed costs in the short-run?

A. No. Most manufacturing and transportation industries are comprised of cost structures predominated with "fixed" costs. These fixed costs, also called "sunk" costs, are primarily comprised of investments in plant and equipment. Indeed, virtually every capital-intensive industry is faced with a high percentage of so-called fixed costs in the short run. Prices for competitive products and services in these capital-intensive industries are invariably established on a volumetric basis, including those that were once regulated, e.g., motor transportation, airline travel, and rail service.

Q. How are high fixed customer charge rate structures contrary to effective conservation efforts?

A. High fixed charge rate structures actually promote additional consumption because a consumer's price of incremental consumption is less than what an efficient price structure would otherwise be. A clear example of this principle is exhibited in the natural gas transmission pipeline industry. As discussed in its well-known Order 636, the FERC's adoption of a "Straight Fixed Variable" ("SFV") pricing method[18] was a result of national policy (primarily that of Congress) to encourage increased use of domestic natural gas by promoting additional interruptible (and incremental firm) gas usage. The FERC's SFV

[18] Under SFV pricing, customers pay a fixed charge that is designed to recover all of the utility's fixed costs.

pricing mechanism greatly reduced the price of incremental (additional) natural gas consumption. This resulted in significantly increasing the demand for, and use of, natural gas in the United States after Order 636 was issued in 1992.

FERC Order 636 had two primary goals. The first goal was to enhance gas competition at the wellhead by completely unbundling the merchant and transportation functions of pipelines.[19] The second goal was to encourage the increased consumption of natural gas in the United States. In Order 636's introductory statement, FERC stated:

> The Commission's intent is to further facilitate the unimpeded operation of market forces to stimulate the production of natural gas... [and thereby] contribute to reducing our Nation's dependence upon imported oil… .[20]

With specific regard to the SFV rate design adopted in Order 636, FERC stated: Moreover, the Commission's adoption of SFV should maximize pipeline throughput over time by allowing gas to compete with alternate fuels on a timely basis as the prices of alternate fuels change. The Commission believes it is beyond doubt that it is in the national interest to promote the use of clean and abundant gas over alternate fuels such as foreign oil. SFV is the best method for doing that.[21] Recently, some public utilities have begun to advocate SFV residential pricing, claiming a need for enhanced fixed charge revenues. To support their claim, the companies argue that because retail rates have been historically volumetric-based, there has been a disincentive for utilities to promote conservation or encourage reduced consumption. However, the FERC's objective in adopting SFV pricing suggests the exact opposite. The price signal that results from SFV pricing is meant to

[19] Federal Energy Regulatory Commission, Docket Nos. RM91-11-001 and RM87-34-065, Order No. 636 (Apr. 9, 1992), p. 7.
[20] *Id.* p. 8 (alteration in original).
[21] *Id.* pp. 128-129.

promote additional consumption, not reduce consumption. Thus, a rate structure that is heavily based on a fixed monthly customer charge sends an even stronger price signal to consumers to use more energy.

Q. As a public policy matter, what is the most effective tool that regulators have to promote cost effective conservation and the efficient utilization of resources?

A. Unquestionably, one of the most important and effective tools that this, or any, regulatory Commission has to promote conservation is developing rates that send proper price signals to conserve and utilize resources efficiently. A pricing structure that is largely fixed, such that customers' effective prices do not properly vary with consumption, promotes the inefficient utilization of resources. Pricing structures that are weighted heavily on fixed charges are much more inferior from a conservation and efficiency standpoint than pricing structures that require consumers to incur more cost with additional consumption.

Q. A customer's total natural gas bill is comprised of a base rate component and a purchased gas clause component. The purchased gas clause is volumetrically-priced and represents a significant portion of a customer's total bill. Does the volumetric pricing of these components eliminate the need for a proper pricing signal?

A. No, certainly not. The fact that significant revenue may be collected volumetrically does not lessen the need for a reasonable rate design.

Q. Notwithstanding the efficiency reasons as to why regulation should serve as a surrogate for competition, are there other relevant aspects to the pricing structures

in competitive markets *vis a vis* those of regulated utilities?

A. Yes. In competitive markets, consumers, by definition, have the ability to choose various suppliers of goods and services. Consumers and the market have a clear preference for volumetric pricing. Utility customers are not so fortunate in that the local utility is a monopoly. The only reason utilities are able to seek pricing structures with high fixed monthly charges is due to their monopoly status. In my opinion, this is a critical consideration in establishing utility pricing structures. Competitive markets and consumers in the United States have demanded volumetric-based prices for generations. A regulated utility's pricing structure should not be allowed to counter the collective wisdom of markets and consumers simply because of its market power.

Q. It is sometimes claimed that lower fixed monthly customer charges result in the creation of intra-class subsidies between higher volume users within a particular customer class and lower volume users. Please respond to this assertion.

A. It is well known that residential heating customers have a significantly lower load factor than non-heating customers.[22] This is because non-heating customers tend to not be nearly as weather sensitive as heating customers and so their usage is rather constant throughout the year. On the other hand, residential heating customers demand more and more of the Company's facilities as cold weather and natural gas usage requirements increase. Because high load factor customers evenly spread their demands throughout the year, these customers are cheaper to serve (on a per unit of consumption basis) than low load factor

[22] Load factor is defined as average daily usage divided by peak day usage wherein average daily usage is annual throughput divided by 365 days.

customers. As such, it cannot be said that high usage customers subsidize low usage customers due to a predominant volumetric pricing schedule.

Q. Does Mr. Raab provide any rationale or justification for his proposed $22.00 per month Residential customer charge?

A. No. In reviewing Mr. Raab's direct testimony concerning rate design on pages 23 through 26, Mr. Raab provides no rationale or justification for his proposed customer charge. The only statement Mr. Raab makes can be found on page 23 wherein he states:

> Atmos Energy proposes to keep its current rate designs in place, but modify them to reflect changes and rate levels as appropriate, for those classes where rate increases are indicated based on the guidelines above.

Q. Does Mr. Raab calculate residential customer costs within his various CCOSS?

A. Yes. In performing his various CCOSS, Mr. Raab has placed every rate base and operating income account into three classification buckets: customer; demand; and/or commodity. As a result, Mr. Raab has calculated a monthly residential customer cost based on all of the rate base and expense items included in his customer classification bucket. Mr. Raab's studies produce the following monthly residential customer costs:

TABLE 7
Raab Calculated Residential Customer Costs

Exhibit	Study	Customer Cost Per Month
PHR-2	Customer/Demand	$26.38
PHR-3	Peak Demand	$18.36
PHR-4	Demand/Commodity	$18.52

In evaluating these amounts, it is important to understand that the main reason for the much higher customer cost of $26.38 per month under Mr. Raab's Customer/Demand method is that this amount includes a large portion (67.8%) of distribution mains plant investment and related costs.[23]

Q. Do Mr. Raab's calculated "customer" costs include items that should not be considered in developing residential fixed monthly charges?

A. Yes. Remembering that Mr. Raab places every single cost into one of three buckets, his analysis results in a myriad of general, administrative, and other overhead costs placed into his "customer" bucket that should not be considered in developing fixed residential customer charges. As examples, Mr. Raab's Exhibit PHR-2 includes the following FERC account amounts and percentages as "customer":

TABLE 8
Examples of Residential Cost Classifications in Raab Customer/Demand Study

	Customer	Demand	Commodity	Percent Customer
Gross Plant:				
Distribution Mains	$109,648,924	$52,161,817	$0	67.76%
Industrial. M&R Equip.	$1,685,726	$0	$0	100.00%
General Plant	$6,837,656	$1,707,890	$23,630	79.79%
O&M Expenses:				
Other Distrib. Expenses	$175,524	$43,096	$687	80.04%
Sales Expense	$132,865	$0	$0	100.00%
A&G Exense	$8,298,854	$2,265,978	$7,780	78.49%

As can be seen above, Mr. Raab has included the vast majority of these costs as "customer-related" and are therefore, reflected in his calculated residential monthly customer costs.

Q. How should the level of fixed monthly customer charges be evaluated?

[23] $98.472 million distribution steel and plastic mains are classified as customer-related and $46.859 million is classified as demand-related.

A. Fixed monthly charges should only reflect the direct costs required to connect and maintain a customer's account. As such, customer charges should only reflect the costs of service lines, meters, meter reading, customer records and billing. Customer charges should not include any overhead costs, as these are simply the cost of doing business, nor should they include any costs of mains.

Q. Have you conducted an analysis of the appropriate level of Residential customer charges for Atmos?

A. Yes. I have conducted a direct customer cost analysis for Atmos' Residential customers, which is provided in my Schedule GAW-3. In conducting my direct customer cost analysis, I calculated a residential customer charge revenue requirement based upon CURB's recommended cost of capital as well as under the Company's requested cost of capital. My studies indicate a residential direct customer cost between $8.86 and $9.82 per month as shown in my Schedule GAW-3.

Q. What is your recommendation regarding fixed monthly customer charges for Atmos' residential customers?

A. Considering that the current residential customer charge of $18.04 per month is more than double that of my customer cost analysis at CURB's recommended rate of return,[24] I recommend reducing the residential customer charge to $15.00 per month for this case. This roughly $3.00 reduction per month will comport with gradualism and provide

[24] Fixed customer charges represent guaranteed revenue recovery as these charges are unavoidable and bear no risk. As such, CURB's recommended rate of return of 6.81% reflects the upper-end of the risk and required return associated with fixed monthly customer charges.

residential customers with better natural gas price signals. In addition, my recommended $15.00 per month residential customer charge will continue to recover a significant portion of overhead expenses in the fixed monthly charge. Finally, considering the fact that Atmos has numerous surcharges and riders in place, the Company will have every opportunity to collect its overall residential revenue requirement with my recommended $15.00 per month residential customer charge.

Q. Does this complete your testimony?

A. Yes.

VERIFICATION

COMMONWEALTH OF VIRGINIA)
)
COUNTY OF HENRICO) ss:

Glenn A. Watkins, being duly sworn upon his oath, deposes and states that he is a consultant for the Citizens' Utility Ratepayer Board, that he has read and is familiar with the foregoing *Direct Testimony*, and that the statements made herein are true and correct to the best of his knowledge, information, and belief.

Glenn A. Watkins

SUBSCRIBED AND SWORN to before me this 25th day of October, 2019.

Jennifer R. Dolen
Notary Public

My Commission expires: 10/31/22

JENNIFER R. DOLEN
NOTARY PUBLIC
REG # 7315146
MY COMMISSION EXPIRES 10/31/2022
COMMONWEALTH OF VIRGINIA

BACKGROUND & EXPERIENCE PROFILE

GLENN A. WATKINS

PRESIDENT/SENIOR ECONOMIST
TECHNICAL ASSOCIATES, INC.

EDUCATION

1982 - 1988	M.B.A., Virginia Commonwealth University, Richmond, Virginia
1980 - 1982	B.S., Economics; Virginia Commonwealth University
1976 - 1980	A.A., Economics; Richard Bland College of The College of William and Mary, Petersburg, Virginia

POSITIONS

Jan. 2017-Present	President/Senior Economist, Technical Associates, Inc.
Mar. 1993-Dec. 2016	Vice President/Senior Economist, Technical Associates, Inc. (Mar. 1993-June 1995 Traded as C. W. Amos of Virginia)
Apr. 1990-Mar. 1993	Principal/Senior Economist, Technical Associates, Inc.
Aug. 1987-Apr. 1990	Staff Economist, Technical Associates, Inc., Richmond, Virginia
Feb. 1987-Aug. 1987	Economist, Old Dominion Electric Cooperative, Richmond, Virginia
May 1984-Jan. 1987	Staff Economist, Technical Associates, Inc.
May 1982-May 1984	Economic Analyst, Technical Associates, Inc.
Sep. 1980-May 1982	Research Assistant, Technical Associates, Inc.

EXPERIENCE

I. Public Utility Regulation

A. Costing Studies -- Conducted, and presented as expert testimony, numerous embedded and marginal cost of service studies. Cost studies have been conducted for electric, gas, telecommunications, water, and wastewater utilities. Analyses and issues have included the evaluation and development of alternative cost allocation methods with particular emphasis on ratemaking implications of distribution plant classification and capacity cost allocation methodologies. Distribution plant classifications have been conducted using the minimum system and zero-intercept methods. Capacity cost allocations have been evaluated using virtually every recognized method of allocating demand related costs (e.g., single and multiple coincident peaks, non-coincident peaks, probability of loss of load, average and excess, and peak and average).

Embedded and marginal cost studies have been analyzed with respect to the seasonal and diurnal distribution of system energy and demand costs, as well as cost effective approaches to incorporating energy and demand losses for rate design purposes. Economic dispatch models have been evaluated to determine long range capacity requirements as well as system marginal energy costs for ratemaking purposes.

B. Rate Design Studies -- Analyzed, designed and provided expert testimony relating to rate structures for all retail rate classes, employing embedded and marginal cost studies. These rate structures have included flat rates, declining block rates, inverted block rates, hours use of demand blocking, lighting rates, and interruptible rates. Economic development and special industrial rates have been developed in recognition of the competitive environment for specific customers. Assessed alternative time differentiated rates with diurnal and seasonal pricing structures. Applied Ramsey (Inverse Elasticity) Pricing to marginal costs in order to adjust for embedded revenue requirement constraints.

GLENN A. WATKINS

C. Forecasting and System Profile Studies -- Development of long range energy (Kwh or Mcf) and demand forecasts for rural electric cooperatives and investor owned utilities. Analysis of electric plant operating characteristics for the determination of the most efficient dispatch of generating units on a system-wide basis. Factors analyzed include system load requirements, unit generating capacities, planned and unplanned outages, marginal energy costs, long term purchased capacity and energy costs, and short term power interchange agreements.

D. Cost of Capital Studies -- Analyzed and provided expert testimony on the costs of capital and proper capital structures for ratemaking purposes, for electric, gas, telephone, water, and wastewater utilities. Costs of capital have been applied to both actual and hypothetical capital structures. Cost of equity studies have employed comparable earnings, DCF, and CAPM analyses. Econometric analyses of adjustments required to electric utilities cost of equity due to the reduced risks of completing and placing new nuclear generating units into service.

E. Accounting Studies -- Performed and provided expert testimony for numerous accounting studies relating to revenue requirements and cost of service. Assignments have included original cost studies, cost of reproduction new studies, depreciation studies, lead-lag studies, Weather normalization studies, merger and acquisition issues and other rate base and operating income adjustments.

II. Transportation Regulation

A. Oil and Products Pipelines -- Conducted cost of service studies utilizing embedded costs, I.C.C. Valuation, and trended original cost. Development of computer models for cost of service studies utilizing the "Williams" (FERC 154-B) methodology. Performed alternative tariff designs, and dismantlement and restoration studies.

B. Railroads -- Analyses of costing studies using both embedded and marginal cost methodologies. Analyses of market dominance and cross-subsidization, including the implementation of differential pricing and inverse elasticity for various railroad commodities. Analyses of capital and operation costs required to operate "stand alone" railroads. Conducted cost of capital and revenue adequacy studies of railroads.

III. Insurance Studies

Conducted and presented expert testimony relating to market structure, performance, and profitability by line and sub-line of business within specific geographic areas, e.g. by state. These studies have included the determination of rates of return on Statutory Surplus and GAAP Equity by line - by state using the NAIC methodology, and comparison of individual insurance company performance vis a vis industry Country-Wide performance.

Conducted and presented expert testimony relating to rate regulation of workers' compensation, automobile, and professional malpractice insurance. These studies have included the determination of a proper profit and contingency factor utilizing an internal rate of return methodology, the development of a fair investment income rate, capital structure, cost of capital.

Other insurance studies have included testimony before the Virginia Legislature regarding proper regulatory structure of Credit Life and P&C insurance; the effects on competition and prices resulting from proposed insurance company mergers, maximum and minimum expense multiplier limits, determination of specific class code rate increase limits (swing limits); and investigation of the reasonableness of NCCI's administrative assigned risk plan and pool expenses.

GLENN A. WATKINS

IV. Anti-Trust and Commercial Business Damage Litigation

Analyses of alleged claims of attempts to monopolize, predatory pricing, unfair trade practices and economic losses. Assignments have involved definitions of relevant market areas(geographic and product) and performance of that market, the pricing and cost allocation practices of manufacturers, and the economic performance of manufacturers' distributors.

Performed and provided expert testimony relating to market impacts involving automobile and truck dealerships, incremental profitability, the present value of damages, diminution in value of business, market and dealer performance, future sales potential, optimal inventory levels, fair allocation of products, financial performance; and business valuations.

MEMBERSHIPS AND CERTIFICATIONS

Member, Association of Energy Engineers (1998)
Certified Rate of Return Analyst, Society of Utility and Regulatory Financial Analysts (1992)
Member, American Water Works Association
National Association of Business Economists
Richmond Association of Business Economists
National Economics Honor Society

**EXPERT TESTIMONY
PROVIDED BY
GLENN A. WATKINS**

YEAR	CASE NAME	JURISDICTION	DOCKET NO.	SUBJECT OF TESTIMONY
1985	SAVANNAH ELECT. & PWR CO.	GA. PSC	3523U	SALES FORECAST, RATE DESIGN ISSUES
1990	CENTRAL MAINE PWR CO.	ME. PUC	89-68	MARGINAL COST OF SERVICE
1990	COMMONWEALTH GAS SERVICES (Columbia Gas)	VA. SCC	PUE900034	CLASS COST OF SERVICE
1990	WARNER FRUEHAUF	U.S. BANKRUPTCY CT.	n/a	VALUE OF STOCK, COST OF CAPITAL
1991	W. VA. WATER	WVA PSC	91-140-W-42T	RATE DESIGN
1992	S.C. WORKERS COMPENSATION	SC DEPT OF INSUR	92-034	INTERNAL RATE OF RETURN
1992	GRASS v. ATLAS PLUMBING, et.al.	RICHMOND CIRCUT CT	n/a	DAMAGES, BREACH OF COVENANT NOT TO COMPETE (PROFFERED TEST)
1992	VIRGINIA NATURAL GAS	VA SCC	PUE920031	JURISDICTIONAL & CLASS COST OF SERVICE
1992	ALLSTATE INSURANCE COMPANY (DIRECT)	N.J. DEPT OF INSUR	INS 06174-92	COST ALLOCATIONS, PROFITABILITY
1992	ALLSTATE INSURANCE COMPANY (REBUTTAL)	N.J. DEPT OF INSUR	INS 06174-92	COST ALLOCATIONS, PROFITABILITY
1993	MOUNTAIN FORD v FORD MOTOR COMPANY	FEDERAL DISTRICT CT	n/a	VEHICLE ALLOCATIONS, INVENTORY LEVELS, INCREMENTAL PROFIT, & DAMAGES
1993	SOUTH WEST GAS CO.	AZ. CORP COMM	U-1551-92-253	DIRECT: CLASS COST ALLOCATIONS
1993	SOUTH WEST GAS CO.	AZ. CORP COMM	U-1551-92-253	SURREBUTTAL: CLASS COST ALLOCATIONS
1993	POTOMAC EDISON CO.	VA. SCC	PUE930033	COST ALLOCATIONS,RATE DESIGN
1995	VIRGINIA AMERICAN WATER CO.	VA. SCC	PUE950003	JURISDICTIONAL ALLOCATIONS
1995	NEW JERSEY AMERICAN WATER COMPANY	N.J. B.P.U.	WR95040165	COST ALLOCATIONS,RATE DESIGN
1995	PIEDMONT NATURAL GAS COMPANY	S.C. P.S.C.	95-715-G	COST ALLOCATIONS,RATE DESIGN,WEATHER NORMALIZATION
1995	CYCLE WORLD v. HONDA MOTOR CO.	VA. DMV	None	MARKET PERFORMANCE, FINANCIAL IMPACT OF NEW DEALER
1996	HOUSE BILL # 1513	VA. GEN'L ASSEMBLY	N/A	WATER / WASTEWATER CONNECTION FEES
1996	VIRGINIA AMERICAN WATER CO.	VA. SCC	PUE950003	JURISDICTIONAL ALLOCATIONS
1996	ELIZABETHTOWN WATER CO.	N.J. B.P.U.	WR95110557	COST ALLOCATIONS,RATE DESIGN
1996	ELIZABETHTOWN WATER CO.	N.J. B.P.U.	WR95110557	SURREBUTTAL COST ALLOCATIONS,RATE DESIGN
1996	SOUTH JERSEY GAS CO.	N.J. B.P.U.	GR96010032	CLASS COST OF SERVICE
1996	VIRGINIA LIABILITY INSURANCE COMPETITION	VA. SCC	INS960164	COST ALLOCATIONS, INSURANCE PROFITABILITY
1996	SOUTH JERSEY GAS CO.	N.J. B.P.U.	GR96010032	REBUTTAL - CLASS COST OF SERVICE
1996	HOUSE BILL # 1513	VA. GEN'L ASSEMBLY	N/A	WATER / WASTEWATER CONNECTION FEES
1997	NISSAN v. CRUMPLER NISSAN	VA. DMV	None	MARKET DETERMINATION & PERFORMANCE
1997	PHILADELPHIA SUBURBAN WATER CO. (DIRECT)	PA. PUC	R-00973952	COST ALLOCATIONS,RATE DESIGN,RATE DISCOUNTS
1997	PHILADELPHIA SUBURBAN WATER CO. (REBUTTAL)	PA. PUC	R-00973952	COST ALLOCATIONS,RATE DESIGN,RATE DISCOUNTS
1997	PHILADELPHIA SUBURBAN WATER CO. (SURREBUTTAL)	PA. PUC	R-00973952	COST ALLOCATIONS,RATE DESIGN,RATE DISCOUNTS
1997	VIRGINIA AMERICAN WATER CO.	VA. SCC	PUE970523	JURISDICTIONAL/CLASS ALLOCATIONS
1998	VIRGINIA ELECTRIC POWER COMPANY	VA. SCC	PUE960296	CLASS COST OF SERVICE and TIME DIFFERENTIATED FUEL COSTS
1998	NEW JERSEY AMERICAN WATER COMPANY	N.J. B.P.U.	WR98010015	CLASS COST OF SERVICE,RATE DESIGN, REVENUES
1998	AMERICAN ELECTRIC POWER COMPANY	VA. SCC	PUE960296	CLASS COST OF SERVICE and TIME DIFFERENTIATED FUEL COSTS
1998	FREEMAN WRONGFUL DEATH	FfEDERAL DISTRICT CT.		LOST INCOME, WORK EXPECTANCY
1998	EASTERN MAINE ELECTRIC COOPERATIVE	MAINE PUC	98-596	REVENUE REQUIREMENT
1998	CREDIT LIFE/AH RATE FILING	VA. SCC		PRIMA FACIA RATES, LEVEL OF COMPETITION
1999	CREDIT LIFE & A&H LEGISLATION	VA. GEN'L ASSEMBLY	N/A	COST ALLOCATIONS, INSURANCE PROFITABILITY
1999	MILLER VOLKSWAGEN v. VOLKSWAGEN oF AMERICA	VA. DMV	None	VEHICLE ALLOCATIONS/CSI
1999	COLUMBIA GAS of VIRGINIA	VA. SCC	PUE980287	RATE STRUCTURE
1999	NCCI (WORKERS COMPENSATION INSURANCE)	VA. SCC	INS990165	WORKERS COMPENSATION RATES
1999	ROANOKE GAS	VA. SCC	PUE980626	Rate Design/ Weather Norm
2000	PERSON-SMITH v. DOMINION REALITY	RICHMOND CIRCUIT	n/a	LOST INCOME
2000	CREDIT LIFE/AH RATE FILING	VA. SCC		PRIMA FACIA RATES, LEVEL OF COMPETITION
2000	UNITED CITIES GAS	VA. SCC		Cost Allocations/ Rate Design
2001	VERMONT WORKERS COMPENSATION RATE CASE	VT. INSURANCE COMM.	n/a	WORKERS COMPENSATION RATES
2001	SERRA CHEVROLET v. GENERAL MOTORS CORP.	ALABAMA CIRCUIT CT.	98-2089	ECONOMIC DAMAGES
2001	VIRGINIA POWER ELECTRIC RESTRUCTURING	VA. SCC	PUE000584	RATE Design (UNBUNDLING)
2001	AMERICAN ELECTRIC POWER RESTRUCTURING	VA. SCC	PUE010011	RATE Design (UNBUNDLING)
2001	NCCI (WORKERS COMPENSATION INSURANCE)	VA. SCC	INS010190	WORKERS COMPENSATION RATES
2002	PHILADELPHIA SUBURBAN WATER CO. (DIRECT)	PA. PUC	R00016750	COST ALLOCATIONS AND RATE DESIGN
2002	HAROLD MORRIS PERSONAL INJURY	FED. DIST CT (RICHMOND)	n/a	LOST WAGES
2002	PIEDMONT NATURAL GAS	S.C. PSC	2002-63-G	REVENUE RQMT, COST OF CAPITAL
2002	VIRGINIA AMERICAN WATER COMPANY	VA. SCC	PUE-2002-00375	JURISDICTIONAL/CLASS ALLOCATIONS
2002	ROANOKE GAS COMPANY	VA. SCC	PUE-2002-00373	WEATHER NORMALIZATION RIDER
2002	SOUTH CAROLINA ELECTRIC & GAS (ELECTRIC)	S.C. PSC	2002-223-E	REVENUE RQMT.
2003	NCCI (WORKERS COMPENSATION INSURANCE)	VA. SCC	INS-2003-00157	WORKERS COMPENSATION RATES
2003	CREDIT LIFE/AH RATE FILING	VA. SCC		PRIMA FACIA RATES, LEVEL OF COMPETITION
2003	ROANOKE GAS	VA. SCC	PUE-2003-00425	WEATHER NORMALIZATION ADJUSTMENT RIDER
2003	SOUTHWESTERN VIRGINIA GAS CO.	VA. SCC	PUE-2003-00426	WEATHER NORMALIZATION ADJUSTMENT RIDER

**EXPERT TESTIMONY
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YEAR	CASE NAME	JURISDICTION	DOCKET NO.	SUBJECT OF TESTIMONY
2004	SOUTH CAROLINA PIPELINE COMPANY	S.C. PSC	2004-6-G	COST OF GAS AND INTERUPT. SALES PROGRAM
2004	VIRGINIA AMERICAN WATER COMPANY	VA. SCC	PUE-2003-00539	JURISDICTIONAL/CLASS ALLOCATIONS
2004	SCE&G FUEL CONTRACT	S.C. PSC	2004-126-E	GAS CONTRACT FOR COMBINED CYCLE PLANT
2004	WASHINGTON GAS LIGHT	VA. SCC	PUE-2003-00603	RATE DESIGN/ WNA RIDER
2004	ATMOS ENERGY	VA. SCC	PUE-2003-00507	RATE DESIGN/ WNA RIDER
2004	SCE&G RATE CASE (ELECTRIC)	S.C. PSC	2004-178-E	COST OF CAPITAL/ REV RQMT.
2004	MEDICAL MALPRACTICE LEGISLATION	VA. GENERAL ASSEMBLY	N/A	INDUSTRY RESTRUTURE/ PROFITABILITY
2004	ATLAS HONDA v. HONDA MOTOR CO.	VA. DMV	None	NEW DEALER PROTEST
2004	NCCI (WORKERS COMPENSATION INSURANCE)	VA. SCC	INS-2004-00124	WORKERS COMPENSATION RATES
2004	NATIONAL FUEL GAS DISTRIBUTION	PA. PUC	R00049656	COST ALLOCATIONS/ RATE DESIGN
2005	WASHINGTON GAS LIGHT	VA SCC	PUE-2005-00010	WEATHER NORMALIZATION ADJUSTMENT RIDER
2005	Serra Chevrolet	US Federal Ct.	CV-01-P-2682-S	Dealer incremental profits and costs
2005	NEWTOWN ARTESIAN WATER	PA. PUC		REV. RQMT./ RATE STRUCTURE
2005	CITY OF BETHLEHEM WATER RATE CASE	PA. PUC		REV. RQMT./ RATE STRUCTURE
2005	NCCI (WORKERS COMPENSATION INSURANCE)	VA SCC	INS-2005-00159	WORKERS COMPENSATION RATES
2005	Virginia Natural Gas	VA SCC	PUE-2005-00057	Revenue Requirement/ Alt. Regulation Plan
2006	Olathe Hyundai v. Hyundai Motors of America	KS DMV	None	Dealer impact analysis
2006	Virginia Credit Life & A&H Prima Facia Rates	VA SCC	INS-2006-00013	Market Structure
2006	Columbia Gas of Virginia	VA SCC	PUE-2005-00098	Revenue Requirements/ Alt. Regulation Plan
2006	PPL Gas	PA. PUC	R-00061398	COST ALLOCATIONS/ RATE DESIGN
2006	NCCI (WORKERS COMPENSATION INSURANCE)	VA SCC	INS-2006-00197	WORKERS COMPENSATION RATES
2007	Level of Private Pass. Auto Competition	Ma. Dept of Insur	N/A	Private Pass Auto level of competition
2007	WASHINGTON GAS LIGHT	VA SCC	PUE-2006-00059	Cost Allocations/ Rate Design/ Alt Regulation Plan
2007	Valley Energy	PA. PUC	R-00072349	Cost of Capital/Rate Design
2007	Wellsboro Electric	PA. PUC	R-00072350	Cost of Capital/Rate Design
2007	Citizens' Electric Of Lewisburg, Pa	PA. PUC	R-00072348	Cost of Capital/Rate Design
2007	NCCI (WORKERS COMPENSATION INSURANCE)	VA SCC	INS-2007-00224	WORKERS COMPENSATION RATES
2007	Georgia Power	Ga.PSC	25060-U	Cost Allocations/Rate Design
2008	Columbia Gas of Pennsylvania	PA. PUC	R-2008-2011621	COST ALLOCATIONS/ RATE DESIGN
2008	Greenway Toll Road Investigation	VA. GENERAL ASSEMBLY	N/A	Affiliate Transactions
2008	Puget Sound Energy (Electric)	Wa. UTC	UE-072300	Cost Allocations/Rate Design
2008	Puget Sound Energy (Gas)	Wa. UTC	UE-072301	Cost Allocations/Rate Design
2008	Blue Grass Electric Cooperative	Ky PSC	2008-00011	Cost Allocations/Rate Design
2008	Columbia Gas of Ohio	OH PUC	08-72-GA-AIR, et. al	Cost Allocations/Rate Design
2008	Virginia Natural Gas	Va SCC	PUE-2008-00060	Natl Gas Conservation/ Revenue Decoupling
2008	Equitable Natural Gas	PA. PUC	R-2008-2029325	Cost Allocations/Rate Design/ Discounted Rates
2008	LG&E (Electric)	Ky PSC	2008-000252	Cost Allocations/Rate Design/ Weather Normalization
2008	LG&E (Natural Gas)	Ky PSC	2008-000252	Cost Allocations/Rate Design
2008	Kentucky Utilities	Ky PSC	2008-00251	Cost Allocations/Rate Design/ Weather Normalization
2008	Pike County Natural Gas	PA. PUC	R-2008-2046520	Cost Allocations/Rate Design
2008	Pike County Electric	PA. PUC	R-2008-2046518	Cost Allocations/Rate Design
2008	Newtown Artesian Water	PA. PUC	R-2008-2042293	Revenue Requirement
2009	Leesburg Water & Sewer	Va. Circuit Ct.	Civil Action 42736	Revenue Requirement/ Excess Rates
2009	Central Penn Gas, Inc.	PA. PUC	R-02008-2079675	Cost Allocation/Rate Design
2009	Penn Natural Gas, Inc.	PA. PUC	R-2008-2079660	Cost Allocation/Rate Design
2009	Credit Life/ A&H ratemaking	Va. SCC	n/a	Market Structure and Availability
2009	Fairfax County v. City of Falls Church Virginia	Fairfax Circuit Ct. (Va.)	CL-2008-16114	Water Revenue Requirement
2009	Avista Utilities (Electric)	Wa. UTC	UE-090134	Electric rate Design
2009	Avista Utilities (Gas)	Wa. UTC	UG-090135	Gas Rate design
2009	Columbia Gas of Kentuky	Ky PSC	2009-00141	Cost Allocations/Rate Design
2009	NCCI (Workers Compensation Rates)	VA SCC	INS-2009-00142	Workers Compensation Rates
2009	Duke Energy of Kentucky (Gas)	Ky. PSC	2009-00202	Rate Design
2009	Duke Energy Carolinas (Electric)	NC UC	E-7 Sub 909	Cost Allocations/Rate Design
2009	PacifiCorp	Wa. UTC	UE-090205	Rate Design/Low Income
2009	Puget Sound Energy (Electric)	Wa. UTC	UE-090704	Cost Allocations/Rate Design
2009	Puget Sound Energy (Gas)	Wa. UTC	UG-090705	Cost Allocations/Rate Design
2009	United Water of Pennsylvania	PA PUC	2009-212287	Cost Allocations/Rate Design
2010	Aqua Virginia, Inc.	VA SCC	PUE-2009-00059	Rate Design
2010	Kentucky Utilities	Ky PSC	2009-00548	Cost Allocations/Rate Design/ Weather Normalization
2010	LG&E (Electric)	Ky PSC	2009-00549	Cost Allocations/Rate Design

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YEAR	CASE NAME	JURISDICTION	DOCKET NO.	SUBJECT OF TESTIMONY
2010	LG&E (Natural Gas)	Ky PSC	2009-00549	Cost Allocations/Rate Design/ Weather Normalization
2010	Philadelphia Gas Works	PA PUC	2009-2139884	Cost Allocations/Rate Design
2010	Columbia Gas of Pennsylvania	PA PUC	2009-2149262	Cost Allocations/Rate Design
2010	PPL Electric Company	PA PUC	2010-2161694	Cost Allocations/Rate Design
2010	York Water Company	PA PUC	2010-2157140	Cost Allocations/Rate Design
2010	Valley Energy, Inc.	PA PUC	2010-2174470	Cost of Capital/Revenue Requirement/Rate Design
2010	NCCI (WORKERS COMPENSATION INSURANCE)	VA SCC	INS-2010-00126	WORKERS COMPENSATION RATES
2010	Columbia Gas of Virginia	VA SCC	PUE-2010-00017	Cost of Capital/Revenue Requirement/Rate Design
2010	Georgia Power Company	GA PSC	Docket No. 31958	Cost Allocations/Rate Design
2010	City of Lancaster, Bureau of Water	PA PUC	R-2010-2179103	Cost of Capital
2011	Columbia Gas of Pennsylvania	PA PUC	R-2010-2215623	Cost Allocations/Rate Design
2011	Owen Electric Cooperative	KY PSC	PUE-2011-00037	Rate Design
2011	Virginia Natural Gas	VA SCC	PUE-2010-00142	Pipeline Prudency/Cost Allocations/Rate Design
2011	United Water of Pennsylvania	PA PUC	2011-2232985	Cost Allocations/Rate Design
2011	PPL Electric Company (Remand)	PA PUC	2010-2161694	Negotiated Industrial Rate
2011	NCCI (WORKERS COMPENSATION INSURANCE)	VA SCC	2011-00163	WORKERS COMPENSATION RATES
2011	Artesian Water Company	DE PSC	11-207	Cost Allocations/Rate Design
2011	Arizona-American Water Company	AZ. CORP COMM	W-01303A-10-0448	Excess Capacity/Need For Facilities
2012	Tidewater Utilities, Inc.	DE PSC	11-397	Cost of Capital/Revenue Requirement/Rate Design
2012	PPL Electric	PA PUC	R-2012-2290597	Cost Allocations/Rate Design
2012	NCCI (WORKERS COMPENSATION INSURANCE)	VA SCC	INS-2012-00144	WORKERS COMPENSATION RATES
2012	Credit Life Accident & Health	VA SCC	INS-2012-00014	Market Structure and Performance
2012	Avista Utilities (Electric)	Wa. UTC	UE-120436	Electric rate Design
2012	Avista Utilities (Gas)	Wa. UTC	UG-120437	Gas Rate design
2012	Kentucky Utilities	Ky PSC	2012-00221	Cost Allocations/Rate Design/ Weather Normalization
2012	LG&E (Electric)	Ky PSC	2012-00222	Cost Allocations/Rate Design
2012	LG&E (Natural Gas)	Ky PSC	2012-00222	Cost Allocations/Rate Design/ Weather Normalization
2012	Columbia Gas of Pennsylvania	PA PUC	2012-2321748	Cost Allocations/Rate Design/Revenue Distribution
2013	Virginia Natural Gas - CARE Plan	VA SCC	2012-00118	Energy Conservation and Decoupling
2013	Columbia Gas of Maryland	MD OPC	9316	Cost Allocations/Rate Design
2013	Delmarva Power & Light	DE PSC	12-546	Revenue Requirement/Rate Design
2013	PacifiCorp	Wa. UTC	13-0043	Residential Customer Charges
2013	Gas-On-Gas Competition - Generic Investigation	PA PUC	2012-232-0323	Treatment of Rate Discounts
2013	Northern Virginia Electric Cooperative Pole Attachment Fees	VA SCC	2013-00055	Financial Performance
2013	Georgia Power Company	GA PSC	36989	Cost Allocations/Rate Design
2013	Atmos Energy Kentucky	KY PSC	2013-00148	Cost Allocations/Rate Design
2013	Columbia Gas of Kentuky	KY PSC	2013-00167	Cost Allocations/Rate Design
2013	NCCI (Workers Compensation Insurance)	VA SCC	INS-2013-00158	Workers Compensation Rates
2013	Duquesne Light Company	PA PUC	R-2013-2372129	Cost Allocations/Rate Design
2014	CITY OF BETHLEHEM WATER RATE CASE	PA PUC	R-2013-2390244	Cost of Capital
2014	PEPCO Maryland	MD OPC	9336	Rate Design
2014	Avista Utilities, Inc. (Gas)	Wa. UTC	UG-140189	Cost Allocations/Rate Design
2014	Tidewater Utilities, Inc.	DE PSC	13-466	Cost of Capital/Rate Design
2014	Columbia Gas of Pennsylvania	PA PUC	R-2014-2406274	Cost Allocations/Rate Design
2014	Columbia NAS Pilot	PA PUC	R-2014-2407345	Mains Extension Policy
2014	Emporium Water Company	PA PUC	R-2014-2402324	Cost of Capital
2014	City of Lancaster, Bureau of Water	PA PUC	R-2014-2418872	Cost of Capital
2014	NCCI (Workers Compensation Insurance)	VA SCC	INS-2014-00172	Workers Compensation Rates
2014	Artesian Water Company	DE PSC	14-132	Revenue Requirement/Rate Design
2014	Peoples Service Expansion Tariff	PA PUC	R-2014-2429613	Mains Extension Policy
2014	PacifiCorp	Wa. UTC	UE-140762	Cost Allocations/Rate Design
2015	Exelon/PHI Acquisition	DE PSC	14-193	Merger/Acquisition
2015	Choptank Electric Cooperative	MD OPC	9368	Cost Allocations/Rate Design
2015	PECO Energy Company-Service Expansion Tariff	PA PUC	R-2014-2451772	Mains Extension Policy
2015	Indianapolis Power & Light	Indiana OUCC	44576	Cost Allocations/Rate Design
2015	Columbia Gas of Virginia	VA SCC	PUE-2014-00020	Rate Design-Customer Charges
2015	PPL Electric Corporation	PA PUC	R-2015-2469275	Cost Allocations/Rate Design
2015	PECO Energy Company	PA PUC	R-2015-2468981	Cost Allocations/Rate Design
2015	Credit Life/AH Rate Filing	VA SCC	INS-2015-00022	Market Structure and Performance
2015	NCCI (Workers Compensation Insurance)	VA SCC	INS-2015-00064	Workers Compensation Rates
2016	Northern Indiana Public Service Company	Indiana OUCC	Cause No. 44688	Cost Allocations/Rate Design
2016	Washington Suburban Sanitary Complaint Comission	MD OPC	Case No. 9391	Rate Structure

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YEAR	CASE NAME	JURISDICTION	DOCKET NO.	SUBJECT OF TESTIMONY
2016	UGI Utilities, Inc. - Gas Division	PA PUC	R-2015-2518438	Cost Allocations/Rate Design
2016	Cascade Natural Gas	WA UTC	UG-152286	Revenue Requirements
2016	Chesapeake Utilities, Inc.	DE PSC	15-1734	Revenue Requirements/Cost Allocations/Rate Design
2016	Suez Water Company	DE PSC	16-0163	Revenue Requirements/Cost Allocations/Rate Design
2016	Avista Utilities, Inc. (Gas & Electric)	WA UTC	UE-160228/UG-160229	Attrition
2016	Anthem/Cigna Merger	VA SCC	INS-2015-00154	Market Structure/Level of Competition
2016	Columbia Gas of Maryland	MD OPC	Case No. 9417	Cost Allocations/Rate Design/Main Line Extensions Policy
2016	Peoples Service Expansion Tariff	PA PUC	R-2016-2542918	Mains Extension Policy
2016	NCCI (Workers Compensation Insurance)	Va SCC	INS-2016-00158	Workers Compensation Rates: Cost of Capital, IRR
2016	Kansas Gas Service	KS CURB	16-KGSG-491-RTS	Cost Allocations/Rate Design
2016	Delmarva Power & Light - Electric	DE PSC	16-0649	Revenue Requirements/Cost Allocations/Rate Design
2016	Delmarva Power & Light - Gas	DE PSC	16-0650	Revenue Requirements/Cost Allocations/Rate Design
2016	Washington Gas Light	VA SCC	PUE-2016-00001	Cost Allocations/Rate Design
2016	Kentucky Utilities	Ky PSC	2016-00370	Cost Allocations/Rate Design
2016	Louisville Gas & Electric	Ky PSC	2016-00371	Cost Allocations/Rate Design
2016	Atlantic City Sewerage	NJ Rate Counsel	WR16100957	Cost of Capital
2017	UGI Penn Natural Gas	PA PUC	R-2016-2580030	Cost Allocations/Rate Design
2017	Puget Sound Energy	WA UTC	UE-170033 & UG-170034	Cost Allocations/Rate Design
2017	Pennsylvania-American Water	PA PUC	R-2017-259583	Cost of Capital
2017	Virginia Natural Gas	VA SCC	PUE-2016-00143	Cost Allocations/Rate Design
2017	Aqua-Limerick Valuations	PA PUC	A-2017-2605434	Discounted Cash Flow Valuation
2017	PAWC-McKeesport Valuations	PA PUC	A-2017-2606103	Discounted Cash Flow Valuation
2017	Indiana Michigan Power Company	Indiana OUCC	Cause No. 44967	Cost Allocations/Rate Design
2017	Choptank Electric Cooperative	MD OPC	Case No. 9459	Rate Design
2017	NCCI (Workers Compensation Insurance)	Va SCC	INS-2017-00059	Workers Compensation Rates: Cost of Capital, IRR
2017	Duke Energy Kentucky	Ky PSC	2017-00321	Cost Allocations/Rate Design
2018	Delmarva Power & Light - Electric	DE PSC	17-0977	Revenue Requirements and Rate Design
2018	Delmarva Power & Light - Gas	DE PSC	17-0978	Revenue Requirements and Rate Design
2018	Delmarva Power & Light Plug-In Vehicle Charging	DE PSC	17-1094	Ratepayer subsidies for Electric Vehicles
2018	Chesapeake Utilities, Inc. Natural Gas Expansion	DE PSC	17-1224	Mains Extension Policy
2018	Indianapolis Power & Light	Indiana OUCC	Cause No. 45029	Cost Allocations/Rate Design
2018	Duquesne Light Company	PA PUC	R-2018-3000124	Cost Allocations/Rate Design/EV Subsidy/Microgrid
2018	PAWC-Sadsbury Valuations	PA PUC	A-2018-3002437	Discounted Cash Flow Valuation
2018	SUEZ Water Company-Mahoning Valuations	PA PUC	A-2018-3003519	Discounted Cash Flow Valuation
2018	Baltimore Gas & Electric Company	MD OPC	Case No. 9484	Cost Allocations/Rate Design
2018	Kansas Gas Service	KS CURB	18-KGSG-560-RTS	Cost Allocations/Rate Design
2018	Aqua Pennsylvania, Inc.	PA PUC	R-2018-3003558	Cost of Capital
2019	Washington Gas Light	VA SCC	PUR-2018-00080	Cost Allocations/Rate Design
2019	Kentucky Utilities/Louisville Gas & Electric	Ky PSC	2018-00294	Cost Allocations/Rate Design
2019	Northern Indiana Public Service Company	Indiana OUCC	Cause No. 45159	Cost Allocations/Rate Design
2019	Montana-Dakota Utilities	Montana Consumer Counsel	D2018.9.60	Cost Allocations/Rate Design
2019	Peoples Natural Gas Company	PA PUC	R-2018-3006818	Cost Allocations/Rate Design/Negotiated Rates
2019	Virginia-American Water Company	VA SCC	PUR-2018-00175	Cost Allocations/Rate Design
2019	PAWC-Exeter Valuations	PA PUC	A-2018-3004933	Discounted Cash Flow Valuation
2019	Aqua-Cheltenham Valuations	PA PUC	A-2019-3008491	Discounted Cash Flow Valuation
2019	PAWC-Steelton Valuations	PA PUC	A-2019-3006880	Discounted Cash Flow Valuation
2019	Chesapeake Utilities	DE PSC	19-0054	WNA Rider/Cost of Equity
2019	Indiana Michigan Power Company	Indiana OUCC	Cause No. 45235	Cost Allocations/Rate Design
2019	Avista Remand (Customer Refunds)	WA UTC	UE-150204 & UG-150205	Distribution of Refund to Classes
2019	Avista Utilities, Inc. - Gas	WA UTC	UG-19-00335	Cost Allocations/Rate Design
2019	Sierra Pacific Power Company	NV PUC	19-06002	Cost Allocations/Rate Design

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ATMOS ENERGY CORPORATION - KANSAS
CURB Peak & Average CCOSS
(Distribution Demand Allocated on CP Demand)

	Total Company	Residential Sales	Com/PA Sales	Schools Sales	Industrial Sales	SGS	Irrigation Sales	Firm Transport	Schools Transport	Irrigation Transport	Interruptible Transport
Operating Revenues	$ 59,801,309	$ 43,148,428	$ 10,184,509	$ 74,159	$ 85,576	$ 35,893	$ 863,827	$ 3,256,569	$ 752,991	$ 44,193	$ 1,355,165
Operating Expenses:											
Operating & Maintenance	$ 21,306,678	$ 17,243,115	$ 2,642,153	$ 18,672	$ 20,395	$ 7,663	$ 133,891	$ 653,866	$ 153,903	$ 8,318	$ 424,703
Interest on Customer Deposits	$ 22,919	$ 21,241	$ 1,678	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Depreciation & Amortization	$ 14,558,833	$ 10,383,118	$ 2,321,893	$ 17,569	$ 21,136	$ 3,734	$ 147,983	$ 876,573	$ 218,053	$ 10,649	$ 558,127
Taxes Other Than Income	$ 9,064,021	$ 6,520,270	$ 1,429,970	$ 10,796	$ 12,932	$ 2,379	$ 89,700	$ 525,564	$ 130,707	$ 6,417	$ 335,285
Total Operating Expenses	$ 44,952,451	$ 34,167,743	$ 6,395,693	$ 47,037	$ 54,463	$ 13,776	$ 371,574	$ 2,056,004	$ 502,663	$ 25,384	$ 1,318,114
Income Before Taxes	$ 14,848,858	$ 8,980,684	$ 3,788,816	$ 27,122	$ 31,113	$ 22,117	$ 492,253	$ 1,200,565	$ 250,328	$ 18,810	$ 37,050
Interest Expense	$ 4,532,471	$ 3,243,067	$ 730,923	$ 5,555	$ 6,677	$ 1,170	$ 46,014	$ 262,673	$ 65,615	$ 3,306	$ 167,472
Income Taxes:											
State Income Taxes	$ 722,147	$ 401,633	$ 214,053	$ 1,510	$ 1,711	$ 1,466	$ 31,237	$ 65,652	$ 12,930	$ 1,085	$ (9,129)
Federal Income Taxes	$ 2,014,790	$ 1,120,557	$ 597,207	$ 4,212	$ 4,772	$ 4,091	$ 87,150	$ 183,170	$ 36,075	$ 3,028	$ (25,471)
Total Deferred Income Taxes	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Allowance for Step Rate	$ (1,500)	$ (834)	$ (445)	$ (3)	$ (4)	$ (3)	$ (65)	$ (136)	$ (27)	$ (2)	$ 19
Total Income Taxes	$ 2,735,437	$ 1,521,356	$ 810,814	$ 5,719	$ 6,479	$ 5,554	$ 118,322	$ 248,686	$ 48,978	$ 4,111	$ (34,582)
Net Income	$ 12,113,420	$ 7,459,329	$ 2,978,002	$ 21,403	$ 24,634	$ 16,563	$ 373,931	$ 951,879	$ 201,350	$ 14,699	$ 71,632
Total Rate Base	$ 248,709,963	$ 177,260,691	$ 40,508,167	$ 310,201	$ 373,805	$ 61,989	$ 2,473,156	$ 14,607,259	$ 3,632,389	$ 177,269	$ 9,305,037
Rate of Return	4.87%	4.21%	7.35%	6.90%	6.59%	26.72%	15.12%	6.52%	5.54%	8.29%	0.77%
Relative Rate of Return	100%	86%	151%	142%	135%	549%	310%	134%	114%	170%	16%

ATMOS ENERGY CORPORATION - KANSAS DIVISION
Residential Customer Cost Analysis

	COMPANY COC	CURB COC
Gross Plant		
Services	$77,788,182	$77,788,182
Meters	$24,549,986	$24,549,986
Meter Installations	$22,422,868	$22,422,868
Regulators	$1,853,456	$1,853,456
Regulators Installations	$192,271	$192,271
Total Gross Plant	**$126,806,763**	**$126,806,763**
Accum. Depreciation Reserve		
Services	($24,314,748)	($24,314,748)
Meters	($11,991,653)	($11,991,653)
Meter Installations	($5,339,031)	($5,339,031)
Regulators	$517,716	$517,716
Regulators Installations	($178,821)	($178,821)
Total Depr. Reserve	**($41,306,537)**	**($41,306,537)**
Total Rate Base	**$85,500,226**	**$85,500,226**
Operation & Maintenance Expenses		
Oper Meter & House Reg.	$227,099	$227,099
Oper Customer Install Exp	$116,862	$116,862
Services Maintenance	$1,946	$1,946
Maint Meter & House Reg	$49,776	$49,776
Meter Reading	$858,390	$858,390
Records & Collections	$120,789	$120,789
Total O&M Expenses	**$1,374,862**	**$1,374,862**
Depreciation Expense		
Services	$2,242,290	$2,242,290
Meters	$647,918	$647,918
Meter Installations	$1,142,273	$1,142,273
Regulators	$172,811	$172,811
Regulators Installations	$0	$0
Total Depreciation Expense	**$4,205,292**	**$4,205,292**
Revenue Requirement		
Interest	$1,558,255	$1,632,042
Equity Return	$5,268,780	$4,189,374
Income Tax	$1,902,555	$1,512,782
Total	**$8,729,591**	**$7,334,198**
Revenue For Return	$8,729,591	$7,334,198
O&M Expenses	$1,374,862	$1,374,862
Depreciation Expense	$4,205,292	$4,205,292
Subtotal Customer Revenue Requirement	$14,309,745	$12,914,352
Plus: Uncollectible @ 1.18035% 1/	$168,905	$152,435
Total Customer Revenue Requirement	$14,478,650	$13,066,787
Number of Bills	1,474,356	1,474,356
Monthly Cost	**$9.82**	**$8.86**

1/ Calculated per CCOSS of $496,564 (Residential uncollectible) divided by $42,069,092 (Residential rate revenue).

CERTIFICATE OF SERVICE

19-ATMG-525-RTS

I, the undersigned, hereby certify that a true and correct copy of the above and foregoing document was served by electronic service on this 31st day of October, 2019, to the following:

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