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In accordance with NRS Chapter 719,
this filing has been electronically signed and filed
by: /s Beverly Joiner

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July 5, 2024

Trisha Osborne
Assistant Commission Secretary
Public Utilities Commission of Nevada
1150 East William Street
Carson City, NV 89701

Re: Docket Nos. 24-02026 and 24-02027

Dear Ms. Osborne:

Please accept for filing the Testimony of Glenn A. Watkins filed on behalf of the Bureau of Consumer Protection in the above-referenced dockets.

Should you have any questions regarding this filing, please contact me at (775) 684-1295.

Sincerely,

ERNEST FIGUEROA
Consumer Advocate

<u>/s/ Raquel Fulghum</u>
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RF/bj

cc: Parties of Record

BEFORE THE

PUBLIC UTILITIES COMMISSION OF NEVADA

In the Matter of the Application by SIERRA PACIFIC POWER COMPANY D/B/A NV ENERGY, filed pursuant to NRS 704.110(3) and NRS 704.110(4), addressing its annual revenue requirement for general rates charged to all classes of electric and gas customers	)	**Docket Nos. 24-02026 and 24-02027**

PREPARED DIRECT TESTIMONY

OF

GLENN A. WATKINS

ON BEHALF OF THE

NEVADA BUREAU OF CONSUMER PROTECTION

JULY 5, 2024

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BEFORE THE PUBLIC UTILITIES COMMISSION OF NEVADA

Sierra Pacific Power Company D/B/A NV Energy
Docket Nos. 24-02026 & 24-02027

PREPARED DIRECT TESTIMONY OF

Glenn A. Watkins

I. INTRODUCTION AND SUMMARY

Q.1 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.2 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 an office 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 43-year career at Technical Associates, I have conducted hundreds of marginal and embedded cost of service, rate design, cost of capital, revenue requirement, and load forecasting studies involving electric, gas, water/wastewater, and telephone utilities throughout the United States and Canada and have provided expert testimony in Alabama, Alaska, 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. In addition, I have provided expert testimony before State and Federal courts as well as before State legislatures. A more complete description of my education, experience, and expert witness appearances are provided in Exhibit-Watkins-Direct-1.

Q.3 HAVE YOU PREVIOUSLY PROVIDED EXPERT TESTIMONY BEFORE THIS COMMISSION?

A. Yes. I provided testimony on cost of service and rate design issues in the two most recent Southwest Gas Corporation general rate cases (Docket Nos. 23-09012 and 21-09001), Great Basin Water Company's last general rate case (Docket No. 21-12025), and Sierra Pacific Power Company's 2019 general rate case (Docket No. 19-06002).[1]

Q.4 WHAT IS THE PURPOSE OF YOUR TESTIMONY IN THIS PROCEEDING?

A. Technical Associates, Inc. ("TAI") has been engaged by the Bureau of Consumer Protection ("BCP") to evaluate Sierra Pacific Power Company's ("SPPC" or "Company") proposed Residential fixed monthly basic service charges for its electric and natural gas operations. The purpose of my testimony is to present the findings of my investigation and offer my recommendations to the Commission as it relates to fixed monthly charges.

Q.5 PLEASE BRIEFLY SUMMARIZE YOUR FINDINGS AND RECOMMENDATIONS.

[1] My testimony was ultimately adopted by BCP witness David Chairez due to a scheduling conflict.

A. With regard to the Company's electric operations, I have determined that the Company's proposed Residential fixed monthly charges for single-family dwellings of $45.30 and multi-family dwellings of $18.80 are unreasonable. Indeed, I have conducted an analysis of the appropriate costs that should be considered in evaluating electric fixed monthly charges and have determined that a reduction to the current fixed charges of $16.50 (single-family) and $8.00 (multi-family) should be reduced to $12.50 and $6.00, respectively.

With regard to the Company's natural gas operations, I have determined that the Company's proposed Residential fixed monthly charge of $18.00 is unreasonable. I have also conducted an analysis of the appropriate costs that should be considered in evaluating natural gas fixed monthly charges and have determined that a reduction to the current fixed charge of $14.00 should be reduced to no more than $12.00 per month.

II. <u>ELECTRIC OPERATIONS</u>

Q.6 PLEASE IDENTIFY SPPC'S VARIOUS RESIDENTIAL ELECTRIC RATES.

A. Currently, the Company offers several rate schedules to Residential customers including:

- Single-Family Domestic Service ("D-1");
- Multi-Family Domestic Service ("DM-1");
- Optional Time-of-Use [separately for Single-Family ("OD-1 TOU") and Multi-Family ("ODM-1 TOU")];
- Optional Critical Peak Pricing [separately for Single-Family ("OD-1-CPP") and Multi-Family ("ODM-1-CPP)];
- Optional Domestic Critical Peak and Demand Pricing ("OD-1-CPP-DDP"); and,

- Optional Domestic Electric Vehicle Recharge Time-of-Use ("OD-REVRR-TOU").

These rate schedules generally apply to both net energy metered ("NEM") with rooftop solar as well as traditional Residential customers without distributed generation. The D-1 and D-1 NEM rates comprise 99% of the Company's single-family Residential customers (239,761 D-1 and D-1 NEM customers compared to 242,184 total single-family customers). Similarly, the DM-1 and DM-1 NEM rates comprise more than 99% of multi-family Residential customers (84,984 versus 85,071 total multi-family customers).

Q.7 PLEASE PROVIDE A COMPARISON OF THE CURRENT AND COMPANY PROPOSED SINGLE-FAMILY (D-1) AND MULTI-FAMILY (DM-1) RATES.

A. Although the Company's rate schedules comprise base rates ("BTGR") and various riders (including fuel) that are established in separate proceedings, the following provides a comparison of the Company's current and proposed D-1 and DM-1 BTGR rates:[2]

TABLE 1
SPPC Current & Proposed Single-Family (D-1) BTGR Rates

	Current	SPPC Proposed	Change	Percent Change
Basic Service Charge ("BSC")	$16.50	$45.30	$28.80	174.5%
Energy Charge	$0.05745	$0.03292	-$0.02453	-42.7%

TABLE 2
SPPC Current & Proposed Multi-Family (DM-1) BTGR Rates

	Current	SPPC Proposed	Change	Percent Change
Basic Service Charge	$8.00	$18.80	$10.80	135.0%
Energy Charge	$0.05566	$0.04457	-$0.01109	-19.9%

[2] BTGR rates are the same for D-1 and D-1 NEM.

Q.8 HAVE YOU CALCULATED THE PERCENTAGE OF RESIDENTIAL ELECTRIC BTGR REVENUES THAT ARE COLLECTED FROM FIXED MONTHLY CHARGES UNDER CURRENT AND COMPANY PROPOSED RATES?

A. Yes. The following tables show the percentage of Residential (D-1 and DM-1) BTGR revenue collected from fixed monthly charges under current and Company proposed rates:

TABLE 3
Residential BTGR Revenues

	Billing Determinants	Current Rates: Rate	Revenue	Percent of Total
Rate D-1				
Bills	2,877,132	$16.50	$47,472,678	27.8%
kWh	2,143,338,879	$0.05745	$123,134,819	72.2%
Total			$170,607,497	100.0%
Rate DM-1				
Bills	1,019,808	$8.00	$8,158,464	24.5%
kWh	452,283,040	$0.05566	$25,174,074	75.5%
Total			$33,332,538	100.0%

Source: Certification Statement O Workpapers.

TABLE 4
Residential BTGR Revenues

	Billing Determinants	SPPC Proposed Rates: Rate	Revenue	Percent of Total
Rate D-1				
Bills	2,877,132	$45.30	$130,334,080	64.9%
kWh	2,143,338,879	$0.03292	$70,558,716	35.1%
Total			$200,892,795	100.0%
Rate DM-1				
Bills	1,019,808	$18.80	$19,172,390	48.7%
kWh	452,283,040	$0.04457	$20,158,255	51.3%
Total			$39,330,645	100.0%

Source: Certification Statement O Workpapers.

As can be seen above, about 28% (27.8%) of the current Residential D-1 BTGR revenue is collected from fixed monthly charges. Under the Company's proposal, this will increase to almost 65% (64.9%). What this means is that under the Company's proposal, almost two-thirds of the Company's margin (BTGR) revenues would be collected from fixed monthly charges wherein customers have no ability to control their electric rates. While it is true that a customer's total electric bill also includes the recovery of fuel and energy costs through the BTER rate, this high percentage of fixed charge revenue is certainly not consistent with cost causation, does not provide a proper price signal to customers, and is inequitable to low volume Residential customers.

Similarly, with regard to the multi-family Residential (DM-1) rate, the BTGR fixed charge revenue would increase from almost 25% (24.5%) to almost 50% (48.7%).

Q.9 WHAT IS THE COMPANY'S RATIONALE FOR PROPOSING SUCH MASSIVE INCREASES TO THE RESIDENTIAL MONTHLY FIXED CHARGES (BSC), AND AT THE SAME TIME, PROPOSING LARGE REDUCTIONS TO THE VARIABLE ENERGY CHARGES?

A. Company witness Janet Wells claims there are three reasons for proposing such significant changes to the Residential rate structure. First, she claims that her proposed rate restructuring will stabilize customer bills over the course of the entire year. Second, she claims that the higher fixed charge will result in more predictability in customer's bills and mitigate changes in customer bills between the summer and winter seasons. Third, Witness Wells claims that the Company's proposed fixed monthly charges will send appropriate price signals of the costs that are fixed in nature and do not vary with customers' usage such that this will reduce intraclass customer subsidies. With regard to her alleged intraclass customer subsidies, Ms. Wells acknowledges that this particularly relates to traditional versus NEM Residential customers.[3]

Q.10 IS WITNESS WELLS' FIRST AND SECOND REASONING ACCURATE?

A. By mathematical definition, yes. That is, if a rate schedule is restructured such that significantly more revenue is collected from non-by passable fixed charges rather than volumetric charges, by definition, customers' bills will vary less on a season-by-season and month-by-month basis. However, this should not be construed as an appropriate or accepted ratemaking practice. This will be discussed in more detail later in my testimony.

Q.11 BEFORE YOU ADDRESS THE SO-CALLED INTRACLASS SUBSIDY RECEIVED BY NEM CUSTOMERS, PLEASE PROVIDE A SUMMARY OF THE RELATIVE SIZE OF SPPC'S NEM CUSTOMERS AS WELL AS A COMPARISON OF THE USAGE AND LOAD CHARACTERISTICS OF NEM VS. TRADITIONAL RESIDENTIAL CUSTOMERS.

A. Currently, Residential NEM customers comprise about 3.5% of the total number of SPPC'S Residential customers (11,419 compared to 327,131 total number of Residential customers).[4] As such, non-NEM customers constitute about 96.5% of all Residential customers.

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[3] Direct Testimony of Janet Wells, page 22.

[4] Calculated per Certification Filing Statements J and O.

With regard to the usage and load characteristics of traditional versus NEM Residential customers, the total SPPC system peak occurs in the summer between about 4:00 p.m. and 6:00 p.m. With regard to the total Residential class, these customers tend to peak about an hour later than the system between about 5:00 p.m. and 7:00 p.m. However, Residential NEM customers tend to peak much later than other Residential customers between about 8:00 p.m. and 10:00 p.m.[5] These differences in the timing of peak loads are particularly relevant in evaluating cost causation as well as any assertions of intraclass subsidies between traditional and NEM Residential customers.

As indicated above, the SPPC's system peak generally occurs between about 4:00 p.m. and 6:00 p.m. on hot summer days. During this time period, NEM customers' solar panels are contributing a significant amount of energy and load thereby helping reduce the overall system load. In this regard, NEM customers' loads are not anywhere near their peak at the time of the system peak. This is particularly relevant in evaluating production and transmission system costs.

As we move down to the distribution system, we see that the Residential NEM customers' peak load occurs much later than the total Residential class load. This is also particularly relevant in evaluating cost causation as well any alleged cross-subsidization between traditional and NEM customers. The Company's distribution system is comprised of various circuits serving fairly small geographic areas such that Residential NEM customers are interspersed within the same circuits as traditional Residential customers. As such, the

[5] SPPC provided hourly system and class loads in its workpaper entitled: "3A-Current North Class Loads.xlsx."

fact that NEM customers' loads are lower than their fellow traditional Residential customers at the time of the Residential peaks, the NEM customers help reduce the cost of the distribution system utilized to serve all Residential customers. Put somewhat differently, if no Residential customers had solar distributed generation, the Residential peaks would all occur at about the same time and the Residential peak load would be that much higher. However, the presence of Residential NEM customers tends to disperse (diversify) the Residential load on the distribution system, thereby reducing the Company's overall distribution costs.

Q.12 IT IS SOMETIMES SAID THAT NEM CUSTOMERS ARE BEING SUBSIDIZED BY TRADITIONAL CUSTOMERS BECAUSE NEM CUSTOMERS DO NOT CONTRIBUTE THEIR FAIR SHARE OF REVENUES RELATIVE TO THE COSTS THEY IMPOSE ON THE DISTRIBUTION SYSTEM. PLEASE COMMENT ON THESE CLAIMS.

A. These claims arise because NEM customers still rely on the Company's distribution system to meet their individual peak load requirements albeit during a later point in time in the day than traditional customers' peak load requirements. Without getting into the manner and rate at which NEM customers are credited for excess energy supplied to the grid, it is important to recognize that NEM customers tend to peak much later than traditional Residential NEM customers. This diversity in load requirements tends to reduce the overall cost of the distribution system to all Residential customers. In this regard, the costs of individual distribution substations, primary and secondary poles, conductors, and conduit are lower than if there was no distributed generation. While it may true that the costs of an NEM customer's service line and transformer are likely the same with or without solar distributed generation, it should be remembered that SPPC will install a service line and transformer based on the largest potential load of an individual customer regardless of whether that customer later installed distributed generation.

As an analogy, suppose a Residential customer changes their air conditioning equipment from a less efficient unit to a very efficient evaporated cooler system, the Company will not reinstall a smaller service line and transformer for that customer. The same is true for customers that elect to install solar panels on their home.

Q.13 WHAT ARE YOUR CONCLUSIONS REGARDING THE COMPANY'S OBJECTIVE TO INCREASE THE NON-BY PASSABLE FIXED MONTHLY CHARGE BY ALMOST THREE TIMES THAT OF THE CURRENT RATE?

A. While the Company's first two objectives to smooth out Residential customers' total electric bills throughout the year are contrary to proper ratemaking principles (which will be discussed in more detail later in my testimony), it is apparent to me that the Company's overarching motivation is to increase revenue contributions from Residential NEM customers. In this regard, it should be remembered that utility regulation and rate design is a process of averaging. To illustrate, it may be more expensive to serve a very rural Residential customer than customers in more densely populated areas (due to the number of poles and miles of conductors required to serve that customer), however, all customers whether they be urban, suburban, or rural, all pay the same rate as a result of the rate design calculus. Similarly, an individual Residential customer that elects to replace their inefficient appliances with very efficient devices (and thereby reduces its total electric bill) does not pay higher rates than customers with less efficient appliances.

In short, SPPC's Residential NEM customers comprise only about 3.5% of the total Residential class such that the Company's proposed rate restructuring with a massive increase to the fixed monthly customer charge that would apply to <u>all</u> Residential customers, is tantamount to throwing the baby out with the bath water.

Q.14 HOW DID SPPC DEVELOP ITS PROPOSED RATE D-1 BSC OF $45.30 PER MONTH AND RATE DM-1 BSC OF $18.80 PER MONTH?

A. In developing its proposed Residential D-1 fixed monthly charge of $45.30 and DM-1 charge of $18.80, the Company included 100% of the costs associated with providing distribution service. This includes all costs associated with distribution substations, primary voltage distribution costs (primarily poles, OH and UG lines), secondary voltage distribution costs (poles, lines, and transformers), service lines, metering costs, customer accounting, and any other costs considered distribution related. In other words, the Company proposes to collect all unbundled costs associated with the distribution function through the non-by passable fixed BSC.

Q.15 DO THE COMPANY'S PROPOSED RESIDENTIAL D-1 AND DM-1 FIXED MONTHLY CHARGES COMPORT WITH ACCEPTED RATEMAKING PRINCIPLES AND PRACTICES?

A. No. Not only does the Company propose to include those costs that are considered "customer related," it also includes all costs that are clearly demand related and do not vary with number of customers. Indeed, even under the Company's own marginal cost calculations, the vast majority of distribution costs are considered "demand related" or "Rule 9/Facilities related."[6] Therefore, the Company's proposed D-1 and DM-1 fixed monthly charges are nothing more than a straight-fixed variable rate design since no distribution costs are considered "variable" in nature.

Q.16 HOW DOES COMPANY WITNESS WELLS JUSTIFY HER PROPOSAL TO COLLECT ALL DISTRIBUTION RELATED COSTS THROUGH A FIXED MONTHLY CHARGE?

A. Throughout her testimony, Ms. Wells attempts to justify her proposal to collect all distribution related costs through a fixed monthly customer charge by referring to accounting related costs that are separated between "fixed" costs and "variable" costs. To illustrate, Ms. Wells makes the following statements:

> . . . the movement to cost-based levels send appropriate price signals of the **costs that are fixed in nature** and do not vary with a customer's usage. [emphasis added][7]
>
> . . . the cost-based BSC also stabilizes bills for NEM customers. Under the current BSC rate, NEM customers can end up **avoiding fixed costs because these fixed costs** are collected through the usage rate. [emphasis added][8]
>
> Annually, the total bill for a typical D-1 NEM customer is approximately $178 more using the proposed BSC and resulting usage rate as opposed to maintaining the current BSC. This difference reflects the appropriate

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[6] Rule 9 relates to the allowable cost for line extensions. The Company's calculated Rate D-1 marginal distribution costs are $44.58 per month (before reconciliation to embedded costs) of which $20.56 is considered demand related and $19.88 are related to Rule 9.
[7] Direct Testimony of Janet Wells, page 22, lines 22-23.
[8] *Id.*, page 25, lines 1-2.

> compensation of **fixed charges that are avoided when those costs are included in the usage rate rather than the fixed BSC**. [emphasis added][9]
>
> Sierra is proposing the increase to its GSC as the first step to mitigating the shortfall that results from NEM customers paying less than the appropriate share of **fixed costs**. NEM customers, who can and do avoid paying usage-based charges, inherently and disproportionally benefit when **fixed costs** are recovered in the usage-based charge when the BSC is set lower than the proposed cost-based levels. [emphasis added][10]

Q.17 DOES THE COMPANY'S PROPOSED RESIDENTIAL D-1 AND DM-1 FIXED MONTHLY CHARGES VIOLATE THE ECONOMIC THEORY OF COMPETITIVE MARKETS?

A. Yes. 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.[11] As such, the pricing policy for a regulated public utility should mirror those of competitive firms to the greatest extent practical.

Q.18 PLEASE BRIEFLY DISCUSS HOW PRICES ARE GENERALLY STRUCTURED IN COMPETITIVE MARKETS.

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[9] *Id.*, page 25, lines 9-13.
[10] *Id.*, page 27, lines 8-12.
[11] James C. Bonbright, et al., Principles of Public Utility Rates, p. 141 (Second Edition, 1988).

A. Under economic theory, efficient price signals result when prices are equal to marginal costs.[12] It is well known that all 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. Thus, in competitive markets, sunk or "fixed" costs are fairly recovered through the sale of goods and services. SPPC has not offered any compelling reason to ignore this competitive practice. To the contrary, the high fixed monthly charges proposed by SPPC would penalize customers who attempt to conserve energy. Indeed, and as shown in my Table 1, the Company's proposed massive increase to the fixed monthly BSC results in their proposal to actually reduce the variable energy charge. This then sends a price signal for Residential customers to utilize more energy not only during peak periods but also throughout the year which thereby increases the need for additional generation and transmission facilities which then increases the overall cost to serve all customers. In other words, the Company's proposal is entirely contrary to efficient pricing and is at odds with conservation efforts.

Q.19 PLEASE BRIEFLY EXPLAIN THE ECONOMIC PRINCIPLES OF EFFICIENT PRICE THEORY AND HOW SHORT-RUN FIXED COSTS ARE RECOVERED UNDER SUCH EFFICIENT PRICING.

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[12] 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 all costs, and prices are variable because prices equal these variable incremental (marginal) costs.

Q.20 PLEASE EXPLAIN HOW THE THEORY OF COMPETITIVE PRICING SHOULD BE APPLIED TO REGULATED PUBLIC UTILITIES SUCH AS SPPC.

A. Due to SPPC's 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 electricity 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.21 IS THE ELECTRIC UTILITY 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.22 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[13] 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 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.[14] 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… .[15]

[13] Under SFV pricing, customers pay a fixed charge that is designed to recover all of the utility's fixed costs.
[14] Federal Energy Regulatory Commission, Docket Nos. RM91-11-001 and RM87-34-065, Order No. 636 (Apr. 9, 1992), p. 7.
[15] *Id.* p. 8 (alteration in original).

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.[16]

Since FERC Order 636 was issued, some public utilities have advocated for SFV Residential pricing (particularly for distribution service), claiming a need for enhanced fixed charge revenues. To support their claim, these companies have argued that because retail rates have been historically volumetrically 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 promote additional consumption, not reduce consumption. Thus, a rate structure that has a high level of fixed monthly customer charges sends an even stronger price signal to consumers to use more energy.

Q.23 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

[16] *Id.* pp. 128-129.

inefficient utilization of resources. Pricing structures with high fixed charges are much more inferior from a conservation and efficiency standpoint than pricing structures that require consumers to incur more costs with additional consumption.

Q.24 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 competitive 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.25 WHAT COSTS SHOULD BE CONSIDERED IN EVALUATING THE LEVEL AND REASONABLENESS OF FIXED MONTHLY CHARGES?

A. Non-by passable fixed monthly charges should only include those direct costs required to connect and maintain a customer's account. These direct costs include the capital costs (including a fair rate of return) associated with services and meters, O&M costs relating to meters, meter reading, customer billing, customer records, as well as variable revenue related taxes. They should not include any overhead costs such as allocations of administrative and general plant and expenses.

Q.26 HAVE YOU CONDUCTED A DIRECT CUSTOMER COST ANALYSIS FOR RESIDENTIAL D-1 AND DM-1 RATES THAT ONLY INCLUDE THOSE COSTS REQUIRED TO CONNECT AND MAINTAIN A CUSTOMER'S ACCOUNT?

A. Yes. My Exhibit-Watkins-Direct-2 provides my analysis of the Residential D-1 and DM-1 "customer costs" that should be considered in developing customer charges. As indicated, I have determined that the Residential D-1 customer cost is in the range of $6.25 to $6.47 per month and the Residential DM-1 customer cost is in the range of $4.21 to $4.32 per month. The lower end of these ranges reflect BCP's recommended cost of capital while the upper ranges reflect the Company's proposed cost of capital.

Q.27 IS THERE ACADEMIC SUPPORT FOR YOUR OPINION THAT CERTAIN DISTRIBUTION COSTS CLASSIFIED AS "CUSTOMER-RELATED," AS WELL AS A SIGNIFICANT PORTION OF THE COMPANY'S OVERHEAD EXPENSES, ARE NOT PROPERLY CONSIDERED AS TRUE CUSTOMER COSTS?

A. In his well-known treatise <u>Principles of Public Utility Rates</u>, Professor James C. Bonbright states:

> . . . if the hypothetical cost of a minimum-sized distribution system is properly excluded from the demand-related costs for the reason just given, while it is also denied a place among the customer costs for the reason stated previously, to which cost function does it then belong? The only defensible answer, in our opinion, is that it belongs to none of them. Instead, it should be recognized as a strictly unallocable portion of total costs. And this is the

> disposition that it would probably receive in an estimate of long-run marginal costs. But fully-distributed cost analysts dare not avail themselves of this solution, since they are the prisoners of their own assumption that "the sum of the parts equals the whole." **They are therefore under impelling pressure to fudge their cost apportionments by using the category of customer costs as a dumping ground for costs that they cannot plausibly impute to any of their other cost categories.** [emphasis added] (Second Edition, page 492)

Q.28 IS THERE AN AUTHORITATIVE PUBLICATION THAT DISCUSSES THE DETERMINATION OF RESIDENTIAL CUSTOMER CHARGES FOR RATE DESIGN PURPOSES?

A. Yes. A NARUC Publication entitled <u>Charging for Distribution Utility Services: Issues in Rate Design</u> states the following as it relates to the determination of fixed monthly customer charges:

> In evaluating proposals for redesign of distribution rates, commissions may be asked to consider structures that call for some blend of customer and usage charges, weighted so as to increase the revenue share of the fixed rate elements (in relation to historical allocations). Although much of the discussion in this paper has been cast in either-or terms (usage-based vs. fixed rates), its general prescriptions apply no less to any intermediate proposal: the magnitude of a shift from usage-based to fixed rate elements will have predictable effects on consumer demand, utility revenues, and long-term dynamic efficiency. As one moves along the continuum of rate designs from usage-based to fixed, the benefits of the former give way more and more to the difficulties of the latter. This is the kind of trade-off that commissions are often faced with balancing: **our analysis concludes that the balance strongly favors a rate structure that allows consumers to avoid charges, when there [are] cost-effective alternatives that they value more highly. Usage-based rates fit this bill; so do hook-up fees** [emphasis added] (page 46).

Q.29 WHAT IS YOUR RECOMMENDATION REGARDING RESIDENTIAL D-1 AND DM-1 FIXED MONTHLY CHARGES?

A. With regard to single-family Rate D-1, I have determined that on a cost basis, fixed charges are only supported with a rate up to slightly less than $6.50 per month. This is significantly below the current D-1 basic service charge of $16.50 per month. In accordance with reasonable cost causation as well as the promotion of conservation, I recommend that the D-1 fixed monthly charge be reduced to $12.50 per month.

Similarly, with regard to multi-family Rate DM-1, I have determined that on a cost basis, the fixed charge is only supported with a rate of about $4.30 per month. As such, I recommended that the current DM-1 fixed monthly charge be reduced to $6.00 per month.

In these regards, it should be understood that my recommended reductions to the current fixed monthly charges will not only recover those direct costs required to connect and maintain a customer's account but also include a provision for various administrative, general, and other overhead expenses.

Finally, as explained above, the Company's proposal that would collect all distribution related costs in a fixed monthly charge (BSC) is contrary to accepted industry practices and conflicts with the economic and policy goals of promoting energy conservation.

III. NATURAL GAS OPERATIONS

Q.30 PLEASE PROVIDE A COMPARISON OF THE CURRENT AND COMPANY PROPOSED RESIDENTIAL NATURAL GAS RATES.

A. Although the Company's rate schedules comprise BTGR and various riders (including gas cost recovery) that are established in separate proceedings, the following provides a comparison of the Company's current and proposed Residential BTGR rates:[17]

TABLE 5
SPPC Current & Proposed Residential Natural Gas BTGR Rates

	Current	SPPC Proposed	Change	Percent Change
Basic Service Charge ("BSC")	$14.00	$18.00	$4.00	28.6%
Consumption Charge (per therm)	$0.11727	$0.13849	$0.02122	18.1%

Q.31 DOES THE COMPANY USE THE SAME OBJECTIVES AND REASONS FOR INCREASING THE FIXED MONTHLY BSC FOR NATURAL GAS AS IT DID FOR ELECTRIC OPERATIONS?

A. Yes. Company witness Wells also supports SPPC's gas rate design wherein she utilized the same objectives as for the Company's electric operations including the stabilization of bills throughout the year and recovery of fixed costs through fixed charges.[18]

Q.32 ON PAGE 15 OF HER DIRECT TESTIMONY, COMPANY WITNESS WELLS CLAIMS THAT HER PROPOSED INCREASE IN THE BASIC SERVICE CHARGE WILL LIMIT (REDUCE) INTRACLASS CUSTOMER SUBSIDIES. DO YOU AGREE FOR THIS ASSERTION?

A. No. Ms. Wells' assertion is based simply on the fact that large volume Residential customers contribute more revenue than small volume customers. She then surmises that these large volume customers are contributing more than their fair share towards the recovery of the Company's revenue requirement than small volume customers. However,

[17] BTGR rates are the same for D-1 and D-1 NEM.
[18] Direct Testimony of Janet Wells, pages 14-15.

this does not equate in any way as to the costs incurred to serve large volume versus small volume Residential customers.

Because virtually all larger volume Residential customers use the preponderance of their natural gas during the winter months to heat their homes, it is well known that Residential heating customers have a significantly lower load factor than non-heating customers.[19] 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 customers. The reality of larger usage Residential customers having a lower load factor than low usage Residential customers have cost implications not only on SPPC's distribution costs but also as it relates to the Company's procurement of gas supplies. That is, larger volume Residential customers (with lower load factors) invariably impose much greater costs on the gas supply function since SPPC must not only purchase more gas volumes in the wintertime but also must reserve more upstream pipeline capacity from interstate pipelines. As such, it cannot be said that high usage customers subsidize low usage customers due to a predominant volumetric pricing schedule.

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

Q.33 HAVE YOU CALCULATED THE PERCENTAGE OF RESIDENTIAL NATURAL GAS MARGIN (BTGR) REVENUES THAT ARE COLLECTED FROM FIXED MONTHLY CHARGES UNDER CURRENT AND COMPANY PROPOSED RATES?

A. Yes. The following tables show the percentage of BTGR revenue collected from fixed monthly charges under current and Company proposed rates:

TABLE 6
Residential Natural Gas BTGR Revenues

		Current Rates		
	Billing Determinants	Rate	Revenue	Percent of Total
Bills	2,042,460	$14.00	$28,594,440	68.7%
Therms	111,184,359	$0.11727	$13,038,590	31.3%
Total			$41,633,030	100.0%

Source: Certification Statement O Workpapers.

TABLE 7
Residential Natural Gas BTGR Revenues

		SPPC Proposed Rates		
	Billing Determinants	Rate	Revenue	Percent of Total
Bills	2,042,460	$18.00	$36,764,280	70.5%
Therms	111,184,359	$0.13849	$15,397,922	29.5%
Total			$52,162,202	100.0%

Source: Certification Statement O Workpapers.

As can be seen above, more than two-thirds (68.7%) of the current Residential margin (BTGR) revenue is collected from fixed monthly charges. Under the Company's proposal, this will increase to more than 70% (70.5%). What this means is that more than two-thirds of the Company's margin revenues are collected from fixed monthly charges wherein customers have no ability to control their natural gas rates. While it is true that a customer's total natural gas bill also includes the recovery of the cost of gas through the BTER rate, this high percentage of fixed charge revenue is certainly not consistent with cost causation, does not provide a proper price signal to customers, and is inequitable to low volume Residential customers.

Q.34 IS THERE A SOMEWHAT CONFUSING REPRESENTATION OF THE CURRENT AND PROPOSED RESIDENTIAL BTGR USAGE RATE IN MS. WELLS CERTIFICATION TESTIMONY?

A. Yes. On page 4, lines 10 through 12 of her Certification Testimony, Ms. Wells states:

> The proposed BSC of $18 decreases the usage-based rate from $0.21197 to $0.13849 as compared to maintaining the current $14 BSC.

So that Ms. Wells' representation of a usage rate of $0.21197 is understood, this would be the calculated BTGR usage rate if the current fixed BSC was maintained at $14.00 per month (and accepting the Company's requested overall BTGR increase to the Residential class). While Ms. Wells' calculation of $0.21197 is correct, it should be understood that the Company actually proposes an increase in the BTGR usage rate from $0.11727 to $0.13849.

Q.35 DOES THE COMPANY PROVIDE ANY SUPPORT FOR ITS PROPOSED INCREASE TO ITS MONTHLY FIXED CHARGE FROM $14.00 TO $18.00?

A. Yes. In the Company's Statement O Workpaper sponsored by Hank Will, he calculated a monthly Residential "customer" cost of $18.31.[20]

[20] Workpaper entitled: "2024 Sierra Gas GRC Certification Will Workpapers 1.xlsx, Tab: BSC Calc.

Q.36 DO YOU AGREE WITH MR. WILL'S CALCULATION OF A RESIDENTIAL CUSTOMER COST OF $18.31?

A. No. A careful examination of Mr. Will's "customer" costs reveals that his calculation of $18.31 includes a multitude of inappropriate costs (rate base and expenses) including numerous administrative and general overhead costs as shown below:

TABLE 8
SPPC Inappropriate Costs Included in "Customer" Costs

		Total Customer
Gross Plant		
301.2-303	Intangible Plant	$8,353,892
376	Distribution Mains	$49,939,587
General Plant		$5,116,044
Common Plant		$48,069,426
Total Gross Plant		$111,478,949
Other Additions to Rate Base		
	Cash Working Capital Requirement	$26,121
165	Prepayments - Gas	$642,369
182.3	2016 Gas GRC Incremental Costs	$64,957
182.3	Net Operating Loss Carryforward	($3,966)
182.3	Depreciation Study Costs	$35,729
154	Materials & Supplies - Other	$3,545,036
154	Materials & Supplies - Other	$3,545,036
Total Other Additions to Rate Base		$4,310,246
O&M		
870	Oper. Super., & Engineering	$582,619
874	Mains & Services Ops	$707,058
880	Other Distribution Expenses	$4,189,861
904	Uncollectibles	$379,300
908	Customer Assistance – Other	$54,205
Total A&G		$7,988,357

Q.37 SIMILAR TO THE COMPANY'S ELECTRIC OPERATIONS, HAVE YOU ALSO CONDUCTED A DIRECT CUSTOMER COST ANALYSIS FOR SPPC'S NATURAL GAS OPERATIONS AS IT RELATES TO RESIDENTIAL CUSTOMERS?

A. Yes. My Exhibit-Watkins-Direct-3 presents the results of my natural gas Residential customer cost analysis. As indicated, I have determined that the natural gas Residential customer cost is in the range of \$8.05 to \$8.29 per month. The lower end of this range reflects BCP's recommended cost of capital while the upper range reflects the Company's requested cost of capital.

Q.38 WHAT IS YOUR RECOMMENDATION CONCERNING SPPC'S NATURAL GAS RESIDENTIAL CUSTOMER CHARGES?

A. With regard to natural gas Residential rates, I have determined that on a cost basis, fixed charges are only supported with a rate up to about \$8.30 per month. This is significantly below the current Residential basic service charge of \$14.00 per month. In accordance with reasonable cost causation as well as the promotion of conservation, I recommend that the Residential fixed monthly charge be reduced to \$12.00 per month.

In these regards, it should be understood that my recommended reduction to the current fixed monthly charge will not only recover those direct costs required to connect and maintain a customer's account but also include a provision for various administrative, general, and other overhead expenses.

Q.39 DOES THIS COMPLETE YOUR TESTIMONY?

A. Yes.

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.

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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.

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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
2024	Sierra Pacific Power Company	NV PUC	24-02026 & 24-02027	Residential Customer Charges
2024	Kansas Gas Service	KS CC	24-KGSG-610-RTS	Cost of Service/Revenue Allocations/Rate Design
2024	Duquesne Light Company	PA PUC	R-2024-3046523	Cost of Service/Revenue Allocations/Rate Design/EV TOU
2024	Dominion Energy South Carolina	SC PSC	2024-34-E	Cost of Service/Revenue Allocations/Rate Design
2024	Alaska Power Company	AK RCA	U-23-054	Cost of Service/Revenue Allocations/Rate Design
2024	Duke Energy Carolinas	SC PSC	2023-388-E	Cost of Service/Revenue Allocations/Rate Design
2024	Southern Pioneer Electric Company	KS CC	24-SPEE-415-TAR	Cost of Service/Revenue Allocations/Rate Design
2024	Chugach Electric Association	AK PSC	U-23-047 & U-23-048	Cost of Service/Revenue Allocations/Rate Design
2024	Artesian Water Company	DE PSC	23-0601	Revenue Requirements/Cost of Service/Rate Design
2024	Southwest Gas Corporation	NV PUC	23-09012	Cost of Service/Revenue Allocations/Rate Design
2023	Veolia Water Company	DE PSC	23-0598	Revenue Requirements/Cost of Service/Rate Design
2023	Dominion Biennial Review	VA SCC	PUR-2023-00101	Cost of Service/Revenue Allocations/Rate Design
2023	Mountaineer Gas Company	WV PSC	23-0280-G-42T	Cost of Service/Revenue Allocations/Rate Design
2023	Evergy KS Central & Evergy KS Metro	KS CC	23-EKCE-775-RTS	Cost of Service/Revenue Allocations/Rate Design
2023	Delmarva Power & Light	DE PSC	22-0897	Revenue Requirements & Rate Design
2023	Appalachian Power Company	VA SCC	PUR-2023-00002	Cost Allocations/Rate Design
2023	Dominion Energy South Carolina	SC PSC	2023-70-G	Cost of Service/Revenue Allocations/Rate Design
2023	Philadelphia Gas Works, Inc.	PA PUC	R-2023-3037933	Cost of Service/Revenue Allocations/Rate Design
2023	Virginia Natural Gas, Inc.	VA SCC	PUR-2022-00052	Juris. & Class Cost Allocations/Rate Design
2023	Washington Gas Light Company	VA SCC	PUR-2022-00054	Cost of Service/Revenue Allocations/Rate Design
2023	Northern Indiana Public Service Company	IN IURC	Cause No. 45772	Revenue Allocations/Rate Design
2023	Atmos Energy Corporation	KS CC	23-ATMG-359-RTS	Cost of Service/Revenue Allocations/Rate Design
2022	Duke Energy Progress	SC PSC	2022-254-E	Cost of Service/Revenue Allocations/Rate Design
2022	Georgia Power Company	GA PSC	44280	Cost of Service/Revenue Allocations/Rate Design
2022	Piedmont Natural Gas	SC PSC	2022-89-G	Cost of Service/Revenue Allocations/Rate Design
2022	Puget Sound Energy - Gas	WA UTC	UG-220067	Cost Allocations/Rate Design
2022	Puget Sound Energy - Electric	WA UTC	UE-220066	Cost Allocations/Rate Design
2022	Delmarva Power & Light - Gas	DE PSC	22-0002	Revenue Requirements & Rate Design
2022	Great Basin Water Company	NV PUC	21-12025	Water & Sewer Cost of Service/Rate Design/Revenue Distribution
2022	Kiawah Island Utility	SC PSC	2021-324-WS	Water & Sewer Cost of Service/Rate Design/Revenue Distribution
2022	Southwest Gas Company	NV PUC	21-09001	Cost of Service/Revenue Allocations/Rate Design
2022	Kentucky Utilities d/b/a Old Dominion Power	VA SCC	PUR-2021-00171	Rate Design
2021	Delmarva Power & Light	MD PSC	9670	Cost Allocations/Rate Design
2021	Aqua Pennsylvania Wastewater, Inc.	PA PUC	R-2021-3027386	Cost of Service/Revenue Allocations/Rate Design
2021	Aqua Pennsylvania, Inc.	PA PUC	R-2021-3027385	Cost of Service/Revenue Allocations/Rate Design
2021	Indiana Michigan Power Company	Indiana IURC	Cause No. 45576	Cost Allocations/Rate Design
2021	Dominion Energy	VA SCC	PUR-2021-00058	Cost Allocations/Rate Design/Revenue Distribution
2021	Black Hills Energy	KS CC	21-BHCG-418-RTS	Cost Allocations/Rate Design/Revenue Distribution
2021	Duquesne Light	PA PUC	R-2021-3024750	Cost Allocations/Rate Design/Revenue Distribution
2021	Avista Utilities	WA UTC	UE-200900 & UG-200900	Cost Allocations and Rate Design
2021	Louisville Gas & Electric	KY PSC	Case No. 2020-00350	Cost Allocations/Rate Design/Revenue Distribution
2021	Kentucky Utilities Company	KY PSC	Case No. 2020-00349	Cost Allocations/Rate Design/Revenue Distribution
2021	Virginia Natural Gas	VA SCC	PUR-2020-00095	Juris. & Class Cost Allocations/Rate Design
2021	PECO Energy Company - Gas	PA PUC	2020-3018929	Cost Allocations/Rate Design/Special Contracts

EXPERT TESTIMONY
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YEAR	CASE NAME	JURISDICTION	DOCKET NO.	SUBJECT OF TESTIMONY
2020	Washington Gas Light MD	MD PSC	9651	Cost Allocations/Rate Design
2020	Delmarva Power & Light - Gas	DE PSC	20-0150	Revenue Requirements & Rate Design
2020	Delmarva Power & Light - Electric	DE PSC	20-0149	Revenue Requirements & Rate Design
2020	Appalachian Power Company	VA SCC	2020-00015	Cost Allocations/Rate Design
2020	SUEZ Water	DE PSC	19-0615	Cost Allocations/Rate Design/Revenue Requirement
2020	Cost Allocation Generic Rulemaking	WA UTC	UE-170002 & UG-170003	Cost Allocation Methods
2020	Southern Pioneer Electric Company	KS CC	20-SPEE-169-RTS	Rate Design/Grid Access Charges
2020	Delmarva Power & Light Maryland	MD PSC	9630	Cost Allocations/Rate Design
2020	Aqua - East Norriton Valuation	PA PUC	2019-3009052	Discounted Cash Flow Valuation
2019	Duke Energy Kentucky	KY PSC	2019-00271	Rate Design
2019	Puget Sound Energy-Gas	WA UTC	UG-19-00530	Cost Allocations/Rate Design
2019	Puget Sound Energy-Electric	WA UTC	UE-19-00529	Cost Allocations/Rate Design
2019	Avista Utilities, Inc. - Gas	WA UTC	UG-19-00335	Cost Allocations/Rate Design
2019	Avista Remand (Customer Refunds)	WA UTC	UE-150204 & UG-150205	Distribution of Refund to Classes
2019	Virginia-American Water Company	VA SCC	PUR-2018-00175	Cost Allocations/Rate Design
2019	Washington Gas Light	VA SCC	PUR-2018-00080	Cost Allocations/Rate Design
2019	PAWC-Steelton Valuations	PA PUC	A-2019-3006880	Discounted Cash Flow Valuation
2019	Aqua-Cheltenham Valuations	PA PUC	A-2019-3008491	Discounted Cash Flow Valuation
2019	PAWC-Exeter Valuations	PA PUC	A-2018-3004933	Discounted Cash Flow Valuation
2019	Peoples Natural Gas Company	PA PUC	R-2018-3006818	Cost Allocations/Rate Design/Negotiated Rates
2019	Sierra Pacific Power Company	NV PUC	19-06002	Cost Allocations/Rate Design
2019	Montana-Dakota Utilities	Montana PSC	D2018.9.60	Cost Allocations/Rate Design
2019	Kentucky Utilities/Louisville Gas & Electric	KY PSC	2018-00294	Cost Allocations/Rate Design
2019	Atmos Energy Kansas	KS CC	19-ATMG-525-RTS	Cost Allocations/Rate Design
2019	Duke Energy Indiana	Indiana IURC	Cause No. 45253	Cost Allocations/Rate Design
2019	Indiana Michigan Power Company	Indiana IURC	Cause No. 45235	Cost Allocations/Rate Design
2019	Northern Indiana Public Service Company	Indiana IURC	Cause No. 45159	Cost Allocations/Rate Design
2019	Chesapeake Utilities	DE PSC	19-0054	WNA Rider/Cost of Equity
2018	Aqua Pennsylvania, Inc.	PA PUC	R-2018-3003558	Cost of Capital
2018	SUEZ Water Company-Mahoning Valuations	PA PUC	A-2018-3003519	Discounted Cash Flow Valuation
2018	PAWC-Sadsbury Valuations	PA PUC	A-2018-3002437	Discounted Cash Flow Valuation
2018	Duquesne Light Company	PA PUC	R-2018-3000124	Cost Allocations/Rate Design/EV Subsidy/Microgrid
2018	Baltimore Gas & Electric Company	MD PSC	Case No. 9484	Cost Allocations/Rate Design
2018	Kansas Gas Service	KS CC	18-KGSG-560-RTS	Cost Allocations/Rate Design
2018	Indianapolis Power & Light	Indiana IURC	Cause No. 45029	Cost Allocations/Rate Design
2018	Chesapeake Utilities, Inc. Natural Gas Expansion	DE PSC	17-1224	Mains Extension Policy
2018	Delmarva Power & Light Plug-In Vehicle Charging	DE PSC	17-1094	Ratepayer subsidies for Electric Vehicles
2018	Delmarva Power & Light - Gas	DE PSC	17-0978	Revenue Requirements and Rate Design
2018	Delmarva Power & Light - Electric	DE PSC	17-0977	Revenue Requirements and Rate Design
2017	Puget Sound Energy- Gas	WA UTC	UG-170034	Cost Allocations/Rate Design
2017	Puget Sound Energy- Electric	WA UTC	UG-170034	Cost Allocations/Rate Design
2017	NCCI (Workers Compensation Insurance)	VA SCC	INS-2017-00059	Workers Compensation Rates: Cost of Capital, IRR
2017	Virginia Natural Gas	VA SCC	PUE-2016-00143	Cost Allocations/Rate Design
2017	PAWC-McKeesport Valuations	PA PUC	A-2017-2606103	Discounted Cash Flow Valuation

**EXPERT TESTIMONY
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YEAR	CASE NAME	JURISDICTION	DOCKET NO.	SUBJECT OF TESTIMONY
2017	Aqua-Limerick Valuations	PA PUC	A-2017-2605434	Discounted Cash Flow Valuation
2017	Pennsylvania-American Water	PA PUC	R-2017-259583	Cost of Capital
2017	UGI Penn Natural Gas	PA PUC	R-2016-2580030	Cost Allocations/Rate Design
2017	Choptank Electric Cooperative	MD PSC	Case No. 9459	Rate Design
2017	Duke Energy Kentucky	KY PSC	2017-00321	Cost Allocations/Rate Design
2017	Indiana Michigan Power Company	Indiana IURC	Cause No. 44967	Cost Allocations/Rate Design
2016	Avista Utilities, Inc. (Gas & Electric)	WA UTC	UE-160228/UG-160229	Attrition
2016	Cascade Natural Gas	WA UTC	UG-152286	Revenue Requirements
2016	Washington Gas Light	VA SCC	PUE-2016-00001	Cost Allocations/Rate Design
2016	NCCI (Workers Compensation Insurance)	Va SCC	INS-2016-00158	Workers Compensation Rates: Cost of Capital, IRR
2016	Anthem/Cigna Merger	VA SCC	INS-2015-00154	Market Structure/Level of Competition
2016	Peoples Service Expansion Tariff	PA PUC	R-2016-2542918	Mains Extension Policy
2016	UGI Utilities, Inc. - Gas Division	PA PUC	R-2015-2518438	Cost Allocations/Rate Design
2016	Atlantic City Sewerage	NJ BPU	WR16100957	Cost of Capital
2016	Columbia Gas of Maryland	MD PSC	Case No. 9417	Cost Allocations/Rate Design/Main Line Extensions Policy
2016	Washington Suburban Sanitary Complaint Comission	MD PSC	Case No. 9391	Rate Structure
2016	Louisville Gas & Electric	KY PSC	2016-00371	Cost Allocations/Rate Design
2016	Kentucky Utilities	KY PSC	2016-00370	Cost Allocations/Rate Design
2016	Kansas Gas Service	KS CC	16-KGSG-491-RTS	Cost Allocations/Rate Design
2016	Northern Indiana Public Service Company	Indiana IURC	Cause No. 44688	Cost Allocations/Rate Design
2016	Delmarva Power & Light - Gas	DE PSC	16-0650	Revenue Requirements/Cost Allocations/Rate Design
2016	Delmarva Power & Light - Electric	DE PSC	16-0649	Revenue Requirements/Cost Allocations/Rate Design
2016	Suez Water Company	DE PSC	16-0163	Revenue Requirements/Cost Allocations/Rate Design
2016	Chesapeake Utilities, Inc.	DE PSC	15-1734	Revenue Requirements/Cost Allocations/Rate Design
2015	NCCI (Workers Compensation Insurance)	VA SCC	INS-2015-00064	Workers Compensation Rates
2015	Credit Life/AH Rate Filing	VA SCC	INS-2015-00022	Market Structure and Performance
2015	Columbia Gas of Virginia	VA SCC	PUE-2014-00020	Rate Design-Customer Charges
2015	PECO Energy Company	PA PUC	R-2015-2468981	Cost Allocations/Rate Design
2015	PPL Electric Corporation	PA PUC	R-2015-2469275	Cost Allocations/Rate Design
2015	PECO Energy Company-Service Expansion Tariff	PA PUC	R-2014-2451772	Mains Extension Policy
2015	Choptank Electric Cooperative	MD OPC	9368	Cost Allocations/Rate Design
2015	Indianapolis Power & Light	Indiana IURC	44576	Cost Allocations/Rate Design
2015	Exelon/PHI Acquisition	DE PSC	14-193	Merger/Acquisition
2014	PacifiCorp	WA UTC	UE-140762	Cost Allocations/Rate Design
2014	Avista Utilities, Inc. (Gas)	WA UTC	UG-140189	Cost Allocations/Rate Design
2014	NCCI (Workers Compensation Insurance)	VA SCC	INS-2014-00172	Workers Compensation Rates
2014	Peoples Service Expansion Tariff	PA PUC	R-2014-2429613	Mains Extension Policy
2014	City of Lancaster, Bureau of Water	PA PUC	R-2014-2418872	Cost of Capital
2014	Emporium Water Company	PA PUC	R-2014-2402324	Cost of Capital
2014	Columbia NAS Pilot	PA PUC	R-2014-2407345	Mains Extension Policy
2014	Columbia Gas of Pennsylvania	PA PUC	R-2014-2406274	Cost Allocations/Rate Design
2014	City of Bethlehem	PA PUC	R-2013-2390244	Cost of Capital
2014	PEPCO Maryland	MD OPC	9336	Rate Design
2014	Artesian Water Company	DE PSC	14-132	Revenue Requirement/Rate Design

**EXPERT TESTIMONY
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YEAR	CASE NAME	JURISDICTION	DOCKET NO.	SUBJECT OF TESTIMONY
2014	Tidewater Utilities, Inc.	DE PSC	13-466	Cost of Capital/Rate Design
2013	PacifiCorp	WA UTC	13-0043	Residential Customer Charges
2013	NCCI (Workers Compensation Insurance)	VA SCC	INS-2013-00158	Workers Compensation Rates
2013	Northern Virginia Electric Cooperative Pole Attachment Fees	VA SCC	2013-00055	Financial Performance
2013	Virginia Natural Gas - CARE Plan	VA SCC	2012-00118	Energy Conservation and Decoupling
2013	Duquesne Light Company	PA PUC	R-2013-2372129	Cost Allocations/Rate Design
2013	Gas-On-Gas Competition - Generic Investigation	PA PUC	2012-232-0323	Treatment of Rate Discounts
2013	Columbia Gas of Maryland	MD PSC	9316	Cost Allocations/Rate Design
2013	Columbia Gas of Kentuky	KY PSC	2013-00167	Cost Allocations/Rate Design
2013	Atmos Energy Kentucky	KY PSC	2013-00148	Cost Allocations/Rate Design
2013	Georgia Power Company	GA PSC	36989	Cost Allocations/Rate Design
2013	Delmarva Power & Light	DE PSC	12-546	Revenue Requirement/Rate Design
2012	Avista Utilities (Gas)	WA UTC	UG-120437	Gas Rate design
2012	Avista Utilities (Electric)	WA UTC	UE-120436	Electric rate Design
2012	Credit Life Accident & Health	VA SCC	INS-2012-00014	Market Structure and Performance
2012	NCCI (WORKERS COMPENSATION INSURANCE)	VA SCC	INS-2012-00144	Workers Compensation Rates
2012	Columbia Gas of Pennsylvania	PA PUC	2012-2321748	Cost Allocations/Rate Design/Revenue Distribution
2012	PPL Electric	PA PUC	R-2012-2290597	Cost Allocations/Rate Design
2012	LG&E (Natural Gas)	Ky PSC	2012-00222	Cost Allocations/Rate Design/ Weather Normalization
2012	LG&E (Electric)	Ky PSC	2012-00222	Cost Allocations/Rate Design
2012	Kentucky Utilities	Ky PSC	2012-00221	Cost Allocations/Rate Design/ Weather Normalization
2012	Tidewater Utilities, Inc.	DE PSC	11-397	Cost of Capital/Revenue Requirement/Rate Design
2011	NCCI (WORKERS COMPENSATION INSURANCE)	VA SCC	2011-00163	Workers Compensation Rates
2011	Virginia Natural Gas	VA SCC	PUE-2010-00142	Pipeline Prudency/Cost Allocations/Rate Design
2011	PPL Electric Company (Remand)	PA PUC	2010-2161694	Negotiated Industrial Rate
2011	United Water of Pennsylvania	PA PUC	2011-2232985	Cost Allocations/Rate Design
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	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
2010	Columbia Gas of Virginia	VA SCC	PUE-2010-00017	Cost of Capital/Revenue Requirement/Rate Design
2010	NCCI (WORKERS COMPENSATION INSURANCE)	VA SCC	INS-2010-00126	Workers Compensation Rates
2010	Aqua Virginia, Inc.	VA SCC	PUE-2009-00059	Rate Design
2010	City of Lancaster, Bureau of Water	PA PUC	R-2010-2179103	Cost of Capital
2010	Valley Energy, Inc.	PA PUC	2010-2174470	Cost of Capital/Revenue Requirement/Rate Design
2010	York Water Company	PA PUC	2010-2157140	Cost Allocations/Rate Design
2010	PPL Electric Company	PA PUC	2010-2161694	Cost Allocations/Rate Design
2010	Columbia Gas of Pennsylvania	PA PUC	2009-2149262	Cost Allocations/Rate Design
2010	Philadelphia Gas Works	PA PUC	2009-2139884	Cost Allocations/Rate Design
2010	LG&E (Natural Gas)	Ky PSC	2009-00549	Cost Allocations/Rate Design/ Weather Normalization
2010	LG&E (Electric)	Ky PSC	2009-00549	Cost Allocations/Rate Design
2010	Kentucky Utilities	Ky PSC	2009-00548	Cost Allocations/Rate Design/ Weather Normalization
2010	Georgia Power Company	GA PSC	Docket No. 31958	Cost Allocations/Rate Design
2009	Puget Sound Energy (Gas)	WA UTC	UG-090705	Cost Allocations/Rate Design

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YEAR	CASE NAME	JURISDICTION	DOCKET NO.	SUBJECT OF TESTIMONY
2009	Puget Sound Energy (Electric)	WA UTC	UE-090704	Cost Allocations/Rate Design
2009	PacifiCorp	WA UTC	UE-090205	Rate Design/Low Income
2009	Avista Utilities (Gas)	WA UTC	UG-090135	Gas Rate design
2009	Avista Utilities (Electric)	WA UTC	UE-090134	Electric rate Design
2009	Credit Life/ A&H ratemaking	Va. SCC	n/a	Market Structure and Availability
2009	Leesburg Water & Sewer	Va. Circuit Ct.	Civil Action 42736	Revenue Requirement/ Excess Rates
2009	NCCI (Workers Compensation Rates)	VA SCC	INS-2009-00142	Workers Compensation Rates
2009	Penn Natural Gas, Inc.	PA. PUC	R-2008-2079660	Cost Allocation/Rate Design
2009	Central Penn Gas, Inc.	PA. PUC	R-02008-2079675	Cost Allocation/Rate Design
2009	United Water of Pennsylvania	PA PUC	2009-212287	Cost Allocations/Rate Design
2009	Duke Energy Carolinas (Electric)	NC UC	E-7 Sub 909	Cost Allocations/Rate Design
2009	Duke Energy of Kentucky (Gas)	Ky. PSC	2009-00202	Rate Design
2009	Columbia Gas of Kentuky	Ky PSC	2009-00141	Cost Allocations/Rate Design
2009	Fairfax County v. City of Falls Church Virginia	Fairfax Circuit Ct. (Va.)	CL-2008-16114	Water Revenue Requirement
2008	Puget Sound Energy (Gas)	WA UTC	UE-072301	Cost Allocations/Rate Design
2008	Puget Sound Energy (Electric)	WA UTC	UE-072300	Cost Allocations/Rate Design
2008	Greenway Toll Road Investigation	VA. GENERAL ASSEMBLY	N/A	Affiliate Transactions
2008	Virginia Natural Gas	Va SCC	PUE-2008-00060	Natl Gas Conservation/ Revenue Decoupling
2008	Newtown Artesian Water	PA. PUC	R-2008-2042293	Revenue Requirement
2008	Pike County Electric	PA. PUC	R-2008-2046518	Cost Allocations/Rate Design
2008	Pike County Natural Gas	PA. PUC	R-2008-2046520	Cost Allocations/Rate Design
2008	Equitable Natural Gas	PA. PUC	R-2008-2029325	Cost Allocations/Rate Design/ Discounted Rates
2008	Columbia Gas of Pennsylvania	PA. PUC	R-2008-2011621	Cost Allocations/Rate Design
2008	Columbia Gas of Ohio	OH PUC	08-72-GA-AIR, et. al	Cost Allocations/Rate Design
2008	Kentucky Utilities	Ky PSC	2008-00251	Cost Allocations/Rate Design/ Weather Normalization
2008	LG&E (Natural Gas)	Ky PSC	2008-000252	Cost Allocations/Rate Design
2008	LG&E (Electric)	Ky PSC	2008-000252	Cost Allocations/Rate Design/ Weather Normalization
2008	Blue Grass Electric Cooperative	Ky PSC	2008-00011	Cost Allocations/Rate Design
2007	NCCI (Workers Compensation Insurance)	VA SCC	INS-2007-00224	Workers Compensation Rates
2007	WASHINGTON GAS LIGHT	VA SCC	PUE-2006-00059	Cost Allocations/ Rate Design/ Alt Regulation Plan
2007	Citizens' Electric Of Lewisburg, Pa	PA. PUC	R-00072348	Cost of Capital/Rate Design
2007	Wellsboro Electric	PA. PUC	R-00072350	Cost of Capital/Rate Design
2007	Valley Energy	PA. PUC	R-00072349	Cost of Capital/Rate Design
2007	Level of Private Pass. Auto Competition	Ma. Dept of Insur	N/A	Private Pass Auto level of competition
2007	Georgia Power	Ga.PSC	25060-U	Cost Allocations/Rate Design
2006	NCCI (Workers Compensation Insurance)	VA SCC	INS-2006-00197	Workers Compensation Rates
2006	Columbia Gas of Virginia	VA SCC	PUE-2005-00098	Revenue Requirements/ Alt. Regulation Plan
2006	Virginia Credit Life & A&H Prima Facia Rates	VA SCC	INS-2006-00013	Market Structure
2006	PPL Gas	PA. PUC	R-00061398	Cost Allocations/Rate Design
2006	Olathe Hyundai v. Hyundai Motors of America	KS DMV	None	Dealer impact analysis
2005	Virginia Natural Gas	VA SCC	PUE-2005-00057	Revenue Requirement/ Alt. Regulation Plan
2005	NCCI (Workers Compensation Insurance)	VA SCC	INS-2005-00159	Workers Compensation Rates
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	City of Bethlehem Water Rate Case	PA. PUC		Revenue Requirement/Rate Structure
2005	Newtown Artesian Water	PA. PUC		Revenue Requirement/Rate Structure

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YEAR	CASE NAME	JURISDICTION	DOCKET NO.	SUBJECT OF TESTIMONY
2004	NCCI (Workers Compensation Insurance)	VA. SCC	INS-2004-00124	Workers Compensation Rates
2004	Atmos Energy	VA. SCC	PUE-2003-00507	Rate Design/WNA Rider
2004	Washington Gas Light	VA. SCC	PUE-2003-00603	Rate Design/WNA Rider
2004	Virginia American Water Company	VA. SCC	PUE-2003-00539	Jurisdictional Class Allocations
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	SCE&G Rate Case (Electric)	S.C. PSC	2004-178-E	Cost of Capital/Revenue Requirement
2004	SCE&G Fuel Contract	S.C. PSC	2004-126-E	Gas Contract For Combined Cycle Plant
2004	South Carolina Pipeline Company	S.C. PSC	2004-6-G	Cost of Gas and Interupt. Sales Program
2004	National Fuel Gas Distribution	PA. PUC	R00049656	Cost Allocations/Rate Design
2003	Southwestern Virginia Gas Co.	VA. SCC	PUE-2003-00426	Weather Normalization Adjustment Rider
2003	Roanoke Gas	VA. SCC	PUE-2003-00425	Weather Normalization Adjustment Rider
2003	Credit Life/AH Rate Filing	VA. SCC		Prima Facia Rates, Level of Competition
2003	NCCI (Workers Compensation Insurance)	VA. SCC	INS-2003-00157	Workers Compensation Rates
2002	Roanoke Gas Company	VA. SCC	PUE-2002-00373	Weather Normalization Rider
2002	Virginia American Water Company	VA. SCC	PUE-2002-00375	Jurisdictional/Class Allocations
2002	South Carolina Electric & Gas (Electric)	S.C. PSC	2002-223-E	Revenue Requirement
2002	Piedmont Natural Gas	S.C. PSC	2002-63-G	Revenue Requirement and Cost Of Capital
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
2001	Vermont Workers Compensation Rate Case	VT. INSURANCE COMM.	n/a	Workers Compensation Rates
2001	NCCI (Workers Compensation Insurance)	VA. SCC	INS010190	Workers Compensation Rates
2001	American Electric Power Restructuring	VA. SCC	PUE010011	Rate Design (Unbundling)
2001	Virginia Power Electric Restructuring	VA. SCC	PUE000584	Rate Design (Unbundling)
2001	SERRA CHEVROLET V. GENERAL MOTORS CORP.	ALABAMA CIRCUIT CT.	98-2089	Economic Damages
2000	United Cities Gas	VA. SCC		Cost Allocations/Rate Design
2000	Credit Life/AH Rate Filing	VA. SCC		Prima Facia Rates, Level of Competition
2000	PERSON-SMITH V. DOMINION REALITY	RICHMOND CIRCUIT	n/a	Lost Income
1999	Roanoke Gas	VA. SCC	PUE980626	Rate Design/Weather Norm
1999	NCCI (Workers Compensation Insurance)	VA. SCC	INS990165	Workers Compensation Rates
1999	Columbia Gas of Virginia	VA. SCC	PUE980287	Rate Structure
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
1998	Credit Life/AH Rate Filing	VA. SCC		Prima Facia Rates, Level of Competition
1998	American Electric Power Company	VA. SCC	PUE960296	Class Cost of Service and Time Differentiated Fuel Costs
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	Eastern Maine Electric Cooperative	MAINE PUC	98-596	Revenue Requirement
1998	Freeman Wrongful Death	FfEDERAL DISTRICT CT.		Lost Income, Work Expectancy
1997	Virginia American Water Co.	VA. SCC	PUE970523	Jurisdictional/Class Allocations
1997	NISSAN V. CRUMPLER NISSAN	VA. DMV	None	Market Determination & Performance
1997	Philadelphia Suburban Water Co. (Surrebuttal)	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. (Direct)	PA. PUC	R-00973952	Cost Allocations, Rate Design, Rate Discounts
1996	Virginia Liability Insurance Competition	VA. SCC	INS960164	Cost Allocations, Insurance Profitability
1996	Virginia American Water Co.	VA. SCC	PUE950003	Jurisdictional Allocations

**EXPERT TESTIMONY
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YEAR	CASE NAME	JURISDICTION	DOCKET NO.	SUBJECT OF TESTIMONY
1996	House Bill # 1513	VA. GEN'L ASSEMBLY	N/A	Water/Wastewater Connection Fees
1996	House Bill # 1513	VA. GEN'L ASSEMBLY	N/A	Water/Wastewater Connection Fees
1996	South Jersey Gas Co.	N.J. B.P.U.	GR96010032	Rebuttal - Class Cost of Service
1996	South Jersey Gas Co.	N.J. B.P.U.	GR96010032	Class Cost of Service
1996	Elizabethtown Water Co.	N.J. B.P.U.	WR95110557	Surrebuttal Cost Allocations, Rate Design
1996	Elizabethtown Water Co.	N.J. B.P.U.	WR95110557	Cost Allocations, Rate Design
1995	Virginia American Water Co.	VA. SCC	PUE950003	Jurisdictional Allocations
1995	CYCLE WORLD V. HONDA MOTOR CO.	VA. DMV	None	Market Performance, Financial Impact of New Dealer
1995	Piedmont Natural Gas Company	S.C. P.S.C.	95-715-G	Cost Allocations, Rate Design, Weather Normalization
1995	New Jersey American Water Company	N.J. B.P.U.	WR95040165	Cost Allocations, Rate Design
1993	Potomac Edison Co.	VA. SCC	PUE930033	Cost Allocations, Rate Design
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	Surrebuttal: Class Cost Allocations
1993	South West Gas Co.	AZ. CORP COMM	U-1551-92-253	Direct: Class Cost Allocations
1992	Virginia Natural Gas	VA SCC	PUE920031	Jurisdictional & Class Cost of Service
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	Allstate Insurance Company (Rebuttal)	N.J. DEPT OF INSUR	INS 06174-92	Cost Allocations, Profitability
1992	Allstate Insurance Company (Direct)	N.J. DEPT OF INSUR	INS 06174-92	Cost Allocations, Profitability
1991	W. Va. Water	WVA PSC	91-140-W-42T	Rate Design
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
1990	Central Maine Pwr Co.	ME. PUC	89-68	Marginal Cost of Service
1985	Savannah Elect. & Pwr Co.	GA. PSC	3523U	Sales Forecast, Rate Design Issues

**Note: Does not include Expert Reports submitted to Courts or Regulatory agencies in which cases that settled prior to testimony.
Testimony prior to 2003 may be incomplete.**

Sierra Pacific Power Company
Residential (D-1 and DM-1) Electric Customer Cost Analysis

			D-1 Customer Cost		DM-1 Customer Cost	
			SPPC COC	BCP COC	SPPC COC	BCP COC
Gross Plant						
369	Services		$105,568	$105,568	$13,704	$13,704
370	Meter		$4,270	$4,270	$1,573	$1,573
370.1	AMI Meters		$24,681	$24,681	$9,091	$9,091
	Total Gross Plant		**$134,519**	**$134,519**	**$24,368**	**$24,368**
Accum Depr						
	Services		($27,714)	($27,714)	($3,598)	($3,598)
	Meter		($1,221)	($1,221)	($450)	($450)
	AMI Meters		($8,768)	($8,768)	($3,230)	($3,230)
	Total Accum. Depreciation		**($37,703)**	**($37,703)**	**($7,277)**	**($7,277)**
	Net Plant		**$96,816**	**$96,816**	**$17,091**	**$17,091**
Operation & Maintenance						
586	Op. Meter Expenses		$631	$631	$232	$232
587	Customer Installations		$4	$4	$0.33	$0
597	Maint. Meter Expense		$163	$163	$60	$60
902	Meter Reading Expense		$632	$632	$233	$233
903	Cust Records & Collection Exp		$3,875	$3,875	$1,427	$1,427
	Total O&M Expenses		**$5,306**	**$5,306**	**$1,953**	**$1,953**
Depreciation Expense						
369	Services		$1,769	$1,769	$230	$230
370	Meter		$295	$295	$109	$109
370.1	AMI Meters		$1,257	$1,257	$463	$463
	Total Deprecation Expense		**$3,321**	**$3,321**	**$801**	**$801**
Revenue Requirement						
	Interest		$2,120	$2,128	$374	$376
	Equity return		$5,557	$5,076	$981	$896
	Federal Income Tax		$1,477	$1,349	$261	$238
	Revenue For Return		$9,154	$8,553	$1,616	$1,510
	O & M Expenses		$5,306	$5,306	$1,953	$1,953
	Depreciation Expense		$3,321	$3,321	$801	$801
	Subtotal Customer Revenue Requirement		$17,781	$17,180	$4,371	$4,265
	Franchise, Business, & Commerce Tax 1/	0.2384%	$42	$41	$10	$10
	Mill Tax	0.3030%	$54	$52	$13	$13
	Uncollectible 2/	0.2089%	$37	$36	$9	$9
	Total Revenue Requirement		$17,915	$17,309	$4,404	$4,297
	Number of Bills		2,769,360	2,769,360	1,020,072	1,020,072
	TOTAL CUSTOMER COST		$6.47	$6.25	$4.32	$4.21

1/ Per Statement N.
2/ Total Uncollectible Expense of $2,112,710 ÷ Total Sales Revenue of $1,011,575,028.

Sierra Pacific Power Company
Residential D-1 Customer Cost Allocations Detail

		Total Company																
		Recorded and Allocated Statement N	Factor Facilities	Factor Dist Demand	Factor Meters	Factor Customer Acct.	Amount Facilities	Amount Dist Demand	Amount Meters	Amount Customer Acct.	D-1 Allocator Facilities	D-1 Allocator Dist Demand	D-1 Allocator Meters	D-1 Allocator Customer Acct.	D-1 Allocated Amount Facilities	D-1 Allocated Amount Dist Demand	D-1 Allocated Amount Meters	D-1 Allocated Amount Customer Acct.	Total
Gross Plant																			
369	Services	$211,436 1/	44.74%	55.26%			$94,590	$116,846	$0	$0	62.19%	40.00%	0.00%	0.00%	$58,827	$46,741	$0	$0	$105,568
370	Meter	$8,738 1/			100.00%		$0	$0	$8,738	$0	0.00%	0.00%	48.87%	0.00%	$0	$0	$4,270	$0	$4,270
370.1	AMI Meters	$50,503 1/			100.00%		$0	$0	$50,503	$0	0.00%	0.00%	48.87%	0.00%	$0	$0	$24,681	$0	$24,681
	Total Gross Plant	**$270,677**					**$94,590**	**$116,846**	**$59,241**	**$0**					**$58,827**	**$46,741**	**$28,951**	**$0**	**$134,519**
Accum Depr																			
	Services	($55,507) 2/	44.74%	55.26%			($24,832)	($30,675)	$0	$0	62.19%	40.00%	0.00%	0.00%	($15,444)	($12,271)	$0	$0	($27,714)
	Meter	($2,498) 2/			100.00%		$0	$0	($2,498)	$0	0.00%	0.00%	48.87%	0.00%	$0	$0	($1,221)	$0	($1,221)
	AMI Meters	($17,941) 2/			100.00%		$0	$0	($17,941)	$0	0.00%	0.00%	48.87%	0.00%	$0	$0	($8,768)	$0	($8,768)
	Total Accum. Depreciation	**($75,946)**					**($24,832)**	**($30,675)**	**($20,439)**	**$0**					**($15,444)**	**($12,271)**	**($9,988)**	**$0**	($37,703)
	Net Plant	**$194,731**					**$69,758**	**$86,171**	**$38,802**	**$0**					**$43,384**	**$34,470**	**$18,963**	**$0**	**$96,816**
Operation & Maintenance																			
586	Op. Meter Expenses	$1,291 3/			100%		$0	$0	$1,291	$0	0.00%	0.00%	48.87%		$0	$0	$631	$0	$631
587	Customer Installations	$6 3/	100%				$6	$0	$0	$0	62.19%	0.00%	0.00%		$4	$0	$0	$0	$4
597	Maint. Meter Expense	$334 3/			100%		$0	$0	$334	$0	0.00%	0.00%	48.87%		$0	$0	$163	$0	$163
902	Meter Reading Expense	$1,172 3/				100%	$0	$0	$0	$1,172				53.94%	$0	$0	$0	$632	$632
903	Cust Records & Collection Exp	$7,185 3/				100%	$0	$0	$0	$7,185				53.94%	$0	$0	$0	$3,875	$3,875
	Total O&M Expenses	**$9,988**					**$6**	**$0**	**$1,626**	**$8,357**					**$4**	**$0**	**$794**	**$4,508**	**$5,302**
Depreciation Expense																			
369	Services	$3,543 4/	44.7%	55.3%			$1,585	$1,958	$0	$0	62.19%	40.00%	0.00%	0.00%	$986	$783	$0	$0	$1,769
370	Meter	$604 4/			100.0%		$0	$0	$604	$0	0.00%	0.00%	48.87%	0.00%	$0	$0	$295	$0	$295
370.1	AMI Meters	$2,573 4/			100.0%		$0	$0	$2,573	$0	0.00%	0.00%	48.87%	0.00%	$0	$0	$1,257	$0	$1,257
	Total Deprecation Expense	**$6,720**					**$1,585**	**$1,958**	**$3,176**	**$0**					**$986**	**$783**	**$1,552**	**$0**	**$3,321**

1/ Per Statement G-1 pg. 3
2/ Per Statement G-2 pg. 3
3/ Per Statement K pg. 7
4/ Per Statement L pg. 1

Sierra Pacific Power Company
Residential DM-1 Customer Cost Allocations Detail

		Total Company																	
		Recorded and	Factor				Amount				DM-1 Allocator				DM-1 Allocated Amount				
		Allocated		Dist		Customer		Dist		Customer				Customer				Customer	
		Statement N	Facilities	Demand	Meters	Acct.	Facilities	Demand	Meters	Acct.	Facilities	Demand	Meters	Acct.	Facilities	Demand	Meters	Acct.	Total
Gross Plant																			
369	Services	$211,436 1/	44.74%	55.26%			$94,590	$116,846	$0	$0	5.19%	7.53%	0.00%	0.00%	$4,911	$8,793	$0	$0	$13,704
370	Meter	$8,738 1/			100.00%		$0	$0	$8,738	$0	0.00%	0.00%	18.00%	0.00%	$0	$0	$1,573	$0	$1,573
370.1	AMI Meters	$50,503 1/			100.00%		$0	$0	$50,503	$0	0.00%	0.00%	18.00%	0.00%	$0	$0	$9,091	$0	$9,091
	Total Gross Plant	**$270,677**					**$94,590**	**$116,846**	**$59,241**	**$0**					**$4,911**	**$8,793**	**$10,664**	**$0**	**$24,368**
Accum Depr																			
	Services	($55,507) 2/	44.74%	55.26%			($24,832)	($30,675)	$0	$0	5.19%	7.53%	0.00%	0.00%	($1,289)	($2,308)	$0	$0	($3,598)
	Meter	($2,498) 2/			100.00%		$0	$0	($2,498)	$0	0.00%	0.00%	18.00%	0.00%	$0	$0	($450)	$0	($450)
	AMI Meters	($17,941) 2/			100.00%		$0	$0	($17,941)	$0	0.00%	0.00%	18.00%	0.00%	$0	$0	($3,230)	$0	($3,230)
	Total Accum. Depreciation	**($75,946)**					**($24,832)**	**($30,675)**	**($20,439)**	**$0**					**($1,289)**	**($2,308)**	**($3,679)**	**$0**	($7,277)
	Net Plant	**$194,731**					**$69,758**	**$86,171**	**$38,802**	**$0**					**$3,622**	**$6,485**	**$6,985**	**$0**	**$17,091**
Operation & Maintenance																			
586	Op. Meter Expenses	$1,291 3/			100%		$0	$0	$1,291	$0	0.00%	0.00%	18.00%		$0	$0	$232	$0	$232
587	Customer Installations	$6 3/	100%				$6	$0	$0	$0	5.19%	0.00%	0.00%		$0	$0	$0	$0	$0
597	Maint. Meter Expense	$334 3/			100%		$0	$0	$334	$0	0.00%	0.00%	18.00%		$0	$0	$60	$0	$60
902	Meter Reading Expense	$1,172 3/				100%	$0	$0	$0	$1,172				19.87%	$0	$0	$0	$233	$233
903	Cust Records & Collection Exp	$7,185 3/				100%	$0	$0	$0	$7,185				19.87%	$0	$0	$0	$1,427	$1,427
	Total O&M Expenses	**$9,988**					**$6**	**$0**	**$1,626**	**$8,357**					**$0**	**$0**	**$293**	**$1,660**	**$1,953**
Depreciation Expense																			
369	Services	$3,543 4/	44.7%	55.3%			$1,585	$1,958	$0	$0	5.19%	7.53%	0.00%	0.00%	$82	$147	$0	$0	$230
370	Meter	$604 4/			100.0%		$0	$0	$604	$0	0.00%	0.00%	18.00%	0.00%	$0	$0	$109	$0	$109
370.1	AMI Meters	$2,573 4/			100.0%		$0	$0	$2,573	$0	0.00%	0.00%	18.00%	0.00%	$0	$0	$463	$0	$463
	Total Deprecation Expense	**$6,720**					**$1,585**	**$1,958**	**$3,176**	**$0**					**$82**	**$147**	**$572**	**$0**	**$801**

1/ Per Statement G-1 pg. 3
2/ Per Statement G-2 pg. 3
3/ Per Statement K pg. 7
4/ Per Statement L pg. 1

Sierra Pacific Power Company
Residential Natural Gas Customer Cost Analysis

Acct. No.	Description		Residential SPPC COC	Residential BCP COC
Gross Plant				
380	Services		$112,321	$112,321
381	Meters		$63,490	$63,490
382	Meter Installations		$1,826	$1,826
383	House Regulators		$5,819	$5,819
	Total Gross Plant		**$183,456**	**$183,456**
Accum. Depreciation Reserve				
380	Services		($81,424)	($81,424)
381	Meters		($34,078)	($34,078)
382	Meter Installations		($1,740)	($1,740)
383	House Regulators		($2,901)	($2,901)
	Total Accum. Depr.		**($120,143)**	**($120,143)**
	Total Net Plant		**$63,313**	**$63,313**
Operation & Maintenance Expenses				
878	Meter & House Reg		$495	$495
879	Customer Installation		$1	$1
892	Mtce. Of Services		$1,310	$1,310
893	Mtce. Of Meter & House Reg		$157	$157
902	Meter Reading		$221	$221
903	Cust. Records & Collection		$3,009	$3,009
	Total O&M Expenses		**$5,192**	**$5,192**
Depreciation Expense				
380	Services		$2,404	$2,404
381	Meters		$3,070	$3,070
382	Meter Installations		$14	$14
383	House Regulators		$148	$148
	Total Depr. Expenses		$5,636	$5,636
Revenue Requirement				
	Interest		$1,387	$1,364
	Equity Return		$3,634	$3,267
	Federal Income Tax		$966	$868
	Revenue for Return		$5,986	$5,499
	O & M Expenses		$5,192	$5,192
	Depreciation Expense		$5,636	$5,636
	Subtotal Customer Rev. Req.		$16,815	$16,327
	Franchise, Business, & Commerce Tax 1/	0.1805%	$30	$29
	Mill Tax	0.3030%	$51	$49
	Uncollectible 2/	0.002071	$35	$34
	Total Revenue Requirement		$16,931	$16,440
	Number of Customers		170,205	170,205
	Number of Bills		2,042,460	2,042,460
	TOTAL CUSTOMER COST		$8.29	$8.05

1/ Per Statement I.
2/ Total Uncollectible Expense of $379,300 ÷ Total Sales Revenue of $183,186,000.

Sierra Pacific Power Company
Residential Natural Gas Customer Cost Allocations Detail

Acct. No.	Description	Total Company	Alloc. Name	Alloc. Pct.	Residential Natural Gas
Gross Plant 1/					
380	Services	$122,837	_A09	91.44%	$112,321
381	Meters	$80,555	_A10	78.82%	$63,490
382	Meter Installations	$2,317	_A10	78.82%	$1,826
383	House Regulators	$7,382	_A10	78.82%	$5,819
	Total Gross Plant	**$213,090**			**$183,456**
Accum. Depreciation Reserve 1/					
380	Services	($89,047)	_A09	91.44%	($81,424)
381	Meters	($43,237)	_A10	78.82%	($34,078)
382	Meter Installations	($2,208)	_A10	78.82%	($1,740)
383	House Regulators	($3,681)	_A10	78.82%	($2,901)
	Total Accum. Depr.	**($138,173)**			**($120,143)**
	Total Net Plant	**$74,918**			**$63,313**
Operation & Maintenance Expenses 1/					
878	Meter & House Reg	$628	_A10	78.82%	$495
879	Customer Installation	$1	_A10	78.82%	$1
892	Mtce. Of Services	$1,432	_A09	91.44%	$1,310
893	Mtce. Of Meter & House Reg	$199	_A10	78.82%	$157
901	Customer Accounts - Supervision	$237	_A02	89.75%	$213
902	Meter Reading	$246	_A02	89.75%	$221
903	Cust. Records & Collection	$3,353	_A02	89.75%	$3,009
	Total O&M Expenses	$6,096			$5,405
Depreciation Expense 1/					
380	Services	$2,629	_A09	91.44%	$2,404
381	Meters	$3,896	_A10	78.82%	$3,070
382	Meter Installations	$18	_A10	78.82%	$14
383	House Regulators	$188	_A10	78.82%	$148
	Total Depr. Expenses	$6,730			$5,636

1/ Per Exhibit Will Certification -3

AFFIRMATION

STATE OF NEVADA)
) ss
CLARK COUNTY)

Pursuant to the requirements of NRS 53.045(1) and NAC 703.710, Glenn A. Watkins, being first duly sworn under penalty of perjury, says that he is the person identified in the foregoing prepared direct testimony and/or exhibits; that such direct testimony and/or exhibits were prepared by or under the direction of said person; that the answers and/or information appearing therein are true to the best of his knowledge and belief; and that if asked the questions appearing therein, his answer thereto would, under oath, be the same.

I declare under penalty of perjury that the foregoing is true and correct.

Further affiant sayeth naught.

Dated: July 5, 2024

Glenn A. Watkins

CERTIFICATE OF SERVICE

Docket Nos. 24-02026 and 24-02027

I certify that I am an employee of the Bureau of Consumer Protection and that on this day I have served the foregoing document upon all parties of record in this proceeding by emailing or mailing a true copy thereof, properly addressed with postage prepaid or forwarded as indicated below to:

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Dated: July 5, 2024.

/s/ Beverly Joiner
An Employee of the
Bureau of Consumer Protection

Bureau of Consumer Protection
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