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BEFORE THE ARKANSAS PUBLIC SERVICE COMMISSION

In the Matter of the Application of Summit Utilities Arkansas, Inc., for a General Change or Modification in Its Rates, Charges and Tariffs	)))))	**Docket No. 23-079-U**

Direct Testimony and Exhibits

of

Jonathan Ly

On Behalf of

ARKANSAS GAS CONSUMERS, INC.

July 10, 2024

J. POLLOCK
INCORPORATED

BEFORE THE ARKANSAS PUBLIC SERVICE COMMISSION

In the Matter of the Application of Summit Utilities Arkansas, Inc., for a General Change or Modification in Its Rates, Charges and Tariffs	)))))	**Docket No. 23-079-U**

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LIST OF EXHIBITS

Exhibit	Description
JL-1	Summary of AGC's Revised Class Cost-of-Service Study
JL-2	AGC's Recommended Class Revenue Allocation

GLOSSARY OF ACRONYMS

Term	Definition
Act 725	Arkansas Act 725 of 2015
AGC	Arkansas Gas Consumers, Inc.
CCOSS	Class Cost-of-Service Study
LCS-1	Large Commercial Firm Service
NARUC	National Association of Regulatory Utility Commissioners
SUA	Summit Utilities Arkansas, Inc.

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Direct Testimony of Jonathan Ly

1. INTRODUCTION, QUALIFICATIONS AND SUMMARY

Q PLEASE STATE YOUR NAME AND BUSINESS ADDRESS.

A Jonathan Ly, 1314 Welch Street, Unit A, Houston, TX 77006.

Q WHAT IS YOUR OCCUPATION AND BY WHOM ARE YOU EMPLOYED?

A I am a regulatory consultant affiliated with J. Pollock, Incorporated.

Q PLEASE STATE YOUR EDUCATIONAL BACKGROUND AND EXPERIENCE.

A I have a Bachelor of Arts degree in Integrative Biology from the University of California, Berkeley and a Master's degree in Energy and Earth Resources from the University of Texas at Austin. Since joining J. Pollock, Incorporated in 2018, I have participated in numerous regulatory proceedings regarding the ratemaking process, resource planning, certificates of convenience and necessity, and assessments of planned new resources in Arkansas, Florida, Georgia, Michigan, Minnesota, New Mexico, New York, North Carolina, Texas, and Wyoming. My qualifications are documented in **Appendix A**. A list of my appearances is provided in **Appendix B**.

Q ON WHOSE BEHALF ARE YOU TESTIFYING IN THIS PROCEEDING?

A I am testifying on behalf of the Arkansas Gas Consumers, Inc. (AGC). AGC's members are customers of Summit Utilities Arkansas, Inc. (SUA) that primarily purchase gas delivery service on the Large Commercial Firm Service (LCS-1) tariff.

Q WHAT IS THE PURPOSE OF YOUR TESTIMONY?

A I address SUA's proposed class cost-of-service study (CCOSS) and provide the Commission with a revised CCOSS for consideration which corrects SUA's classification of its distribution mains, as well as other adjustments discussed more fully herein. In addition, I provide a class revenue allocation based on the results of AGC's revised CCOSS as set forth herein, including adjustments to SUA's revenue requirement as recommended by AGC's other witness, Ms. Billie LaConte.

Q PLEASE BRIEFLY SUMMARIZE THE PURPOSE OF THE TESTIMONY FILED BY AGC'S OTHER WITNESS, MS. LACONTE.

A My colleague, Ms. Billie LaConte, will address SUA's requested return on equity, capital structure, operation and maintenance expense, incentive compensation, and Volunteer Time Off. As noted above, I incorporate her recommendations into AGC's revised CCOSS.

Q ARE YOU SPONSORING ANY EXHIBITS WITH YOUR TESTIMONY?

A Yes. I am sponsoring **Exhibits JL-1** and **JL-2**. These exhibits were prepared by me or under my supervision and direction. In addition, I have prepared **Appendix C**, which discusses the procedures typically used in a gas CCOSS.

Q ARE YOU ACCEPTING SUA'S POSITIONS ON THE ISSUES NOT ADDRESSED IN YOUR DIRECT TESTIMONY?

A No. One should not interpret the fact that I do not address every issue raised by SUA as an endorsement of its proposals.

Summary

Q PLEASE SUMMARIZE YOUR FINDINGS AND RECOMMENDATIONS.

A My findings and recommendations are as follows:

Class Cost-of-Service Study

- SUA inappropriately uses the average of the results of its studies using the minimum size main and zero-intercept methodologies to classify the costs of its distribution mains between customer- and demand-related portions.
- However, Arkansas Act 725 of 2015 (Act 725) explicitly states that the customer-related portion of distribution mains should be determined solely using the minimum size main methodology.
- Furthermore, as discussed in the testimony of my colleague, Ms. LaConte, there are a number of adjustments that should be made to SUA's revenue requirement and reflected in the CCOSS.[1]
- The Commission should reject SUA's proposed CCOSS and approve AGC's revised CCOSS which incorporates these changes.

Class Revenue Allocation

- SUA's proposed class revenue allocation is based upon the results of its CCOSS, but includes rate smoothing adjustments to recognize the principle of gradualism.
- However, because SUA's CCOSS is flawed as previously described, the results of its class revenue allocation are incorrect and should not be used to set rates in this proceeding.
- Instead, the Commission should approve AGC's recommended class revenue allocation based upon the revised CCOSS, subject to further modification based on reasonable recommendations made by other parties in testimony filed this same date.

[1] See Testimony of Ms. Billie LaConte, filed this same day.

2. CLASS COST-OF-SERVICE STUDY

Q WHAT IS A CLASS COST-OF-SERVICE STUDY?

A A CCOSS is an analysis used to determine each customer classes' responsibilities for a utility's costs and whether the revenues generated by each class are sufficient to cover the costs to serve those customers. In the context of a CCOSS, a class represents a group of customers with similar usage patterns and service characteristics. The procedures typically used in a CCOSS are described in more detail in **Appendix C**.

Q HOW IS A CLASS COST-OF-SERVICE STUDY TYPICALLY CONDUCTED?

A As explained in more detail in **Appendix C**, a CCOSS is generally conducted in three phases. First, costs are distinguished by type in a process called *functionalization*. The causes of these costs are then identified in a second process called *classification*. Lastly, these costs are then assigned to each of the customer classes based upon each class's responsibility for incurring each type of cost in a process known as *allocation.*

Q HAVE YOU REVIEWED THE CLASS COST-OF-SERVICE STUDY FILED BY SUA IN THIS PROCEEDING?

A Yes. I have reviewed the CCOSS conducted by SUA and found that, with a few exceptions, it generally comports with accepted practice. Specifically, SUA improperly classifies the customer cost component of its distribution mains, as I discuss in further detail below. Furthermore, as discussed by my colleague, Ms. LaConte, SUA has requested an inappropriate return on rate base and overstated its test-year expenses for maintenance associated with is distribution mains, incentive compensation, and Volunteer Time Off.

Q HOW ARE DISTRIBUTION MAINS TYPICALLY CLASSIFIED IN A GAS CLASS COST-OF-SERVICE STUDY ?

A As described in the National Association of Regulatory Utility Commissioners (NARUC) Gas Rate Design manual, distribution main costs are typically functionalized into two portions: customer-related and demand-related.[2] Specifically, the NARUC Gas Distribution Rate Design Manual identifies the minimum size main theory as a methodology to identify the customer-related portion of the distribution system that is necessary to connect a customer to the system to receive service:

> Under the minimum size main theory, all distribution mains are priced out at the historic unit cost of the smallest main installed in the system, and assigned as customer costs. The remaining book cost of distribution mains is assigned to demand.[3]

Q DOES SUA USE THE MINIMUM SIZE MAIN METHODOLOGY TO CLASSIFY THE CUSTOMER PORTION OF DISTRIBUTION MAINS IN ITS CLASS COST-OF-SERVICE STUDY ?

A No. Instead of utilizing the minimum size main methodology, SUA employs a hybrid methodology that averages the results of the minimum size main study with another methodology known as the zero-intercept or zero-inch method.[4]

Q WHAT IS THE ZERO-INTERCEPT METHOD?

A The zero-intercept method is an alternative method used to identify the customer-related portion of distribution mains. Whereas the minimum size main method uses the historical cost of the smallest mains that have a significant presence on a utility's

[2] NARUC, *Gas Rate Design* at 28 (Aug. 6 1981).

[3] NARUC, *Gas Distribution Rate Design Manual* at 22 (Jun. 1989).

[4] Direct Testimony of Timothy S. Lyons at 19.

system, the zero-intercept method is based upon a regression analysis of the relationship between differently sized distribution mains and their average costs to identify the costs of a theoretical zero-inch distribution main. Under the zero-intercept method, the costs for a system using this theoretical zero-inch distribution main are classified as customer-related, and all costs for distribution mains in excess of this amount are classified as demand-related.

Q WHAT ARE THE RESULTS OF SUA'S DISTRIBUTION MAIN CLASSIFICATION STUDIES AND WHAT CLASSIFICATION PROPORTIONS DOES IT PROPOSE TO USE IN ITS CLASS COST-OF-SERVICE STUDY ?

A The results of SUA's minimum size and zero-intercept studies, as well as the average of these methodologies which SUA proposes to use in its CCOSS, are summarized in **Table 1**.

Table 1
Summary of SUA's Distribution Main Classification

Description	Minimum Size	Zero-Intercept	SUA Proposed
Customer-Related	66.17%	41.91%	54.04%
Demand-Related	33.83%	58.09%	45.96%
Total	100.00%	100.00%	100.00%

Source: Direct Testimony of Timothy S. Lyons at 21-22.

Q IS IT REASONABLE FOR SUA TO USE THE AVERAGE OF THE MINIMUM SIZE AND ZERO-INTERCEPT STUDIES TO CLASSIFY DISTRIBUTION MAINS?

A No. The proposal to use the average results of these two methodologies is not supported by Act 725, which explicitly states:

> The customer-related portion of natural gas distribution plant costs related to account numbers 374 through 376…shall be the percentage of the average cost of all mains that is represented by the average cost of the

> minimum size main and computed using a cost allocation method based upon the predominant size main that is installed by the natural gas public utility that is at least two inches (2") in diameter, with the investment costs of the predominant size mains set as the minimum size.[5]

The methodology described in this passage is identical to the minimum size method. Act 725 does not contemplate either a zero-intercept method or a hybrid approach — the Act makes no mention of the zero-intercept or any other alternative methodology for classifying customer-related distribution main costs.

Q MR. LYONS STATES THAT BOTH THE MINIMUM SIZE AND ZERO-INTERCEPT METHODS ARE RECOGNIZED BY THE NARUC GAS DISTRIBUTION RATE DESIGN MANUAL, WHICH IS RECOGNIZED IN ACT 725, AND THEREFORE, A HYBRID APPROACH AVERAGING THESE TWO METHODS IS A REASONABLE METHODOLOGY. IS HIS STATEMENT ACCURATE?

A No. The NARUC Gas Distribution Rate Design Manual referenced in Act 725 does not include a description of the zero-intercept study. Rather than discussing two separate methodologies, the Manual describes a single "zero or minimum size main theory." It uses these two terms to refer to a single methodology based upon "the historic unit cost of the smallest main installed in the system…"[6] The Manual does not make any reference to the use of a regression analysis to identify the costs of a theoretical zero-inch main. Therefore, the costs for distribution mains in SUA's CCOSS should not be classified on a hybrid basis as proposed by SUA. Instead, these costs should be classified based solely on the results of the minimum size study.

[5] Act 725 of 2015, codified at Ark. Code Ann. § 23-4-422(b)(3)(B)(ii).

[6] NARUC, *Gas Distribution Rate Design Manual* at 22 (Jun. 1989).

Q ARE THERE FURTHER ADJUSTMENTS THAT SHOULD BE MADE TO SUA'S CLASS COST-OF-SERVICE STUDY?

A Yes. As discussed by my colleague, Ms. LaConte, there are four further adjustments that should be made to SUA's CCOSS:

1. SUA's proposed rate of return is excessive as a result of SUA's inflated equity ratio and return on equity request. Therefore, the proposed return on rate base should be decreased to no higher than 5.8392% based upon Ms. LaConte's analysis;
2. The amount of incentive compensation for which SUA is seeking cost recovery from customers includes amounts related to SUA's financial targets. These amounts should not be recoverable from customers, and therefore the amount of incentive compensation expense should be reduced by at least $1.4 million. In addition, SUA capitalizes $0.5 million in incentive compensation, which should also be removed from the cost of service;
3. Given that SUA has invested a significant amount of capital in its distribution mains, the costs for maintenance of its distribution mains should not increase as SUA projects. Maintaining the average cost of maintenance per mile of installed mains would reduce expenses for the maintenance of mains included in by $1.4 million; and
4. SUA provides its employees with paid Volunteer Time Off. However, this employee benefit is unrelated to providing SUA's customers with gas service and should not be included in SUA's cost of service. Consequently, approximately $167,000 should be removed from among various FERC Accounts.

Q HAVE YOU PREPARED A CORRECTED CLASS COST-OF-SERVICE STUDY WHICH UTILIZES THE MINIMUM SIZE METHOD TO CLASSIFY DISTRIBUTION MAIN COSTS AND REDUCES SUA'S PROJECTED REVENUE REQUIREMENT AS RECOMMENDED BY MS. LACONTE?

A Yes. The results of my revised CCOSS are provided in **Exhibit JL-1. Table 2** summarizes the results to show the resulting rates of return, relative rates of return and cost-based increases based on my revised CCOSS.

Table 2
Summary of AGC's Recommended
Class Cost-of-Service Study Results
At Present Rates

Rate Class	Rate of Return	Relative Rate of Return	Cost-Based Increase
Residential	-0.18%	-0.30	58.0%
SCS-1	3.38%	5.80	20.2%
SCS-2	9.58%	16.45	-20.8%
SCS-3	31.59%	54.26	-59.7%
LCS-1	1.39%	2.38	46.4%
System Average	0.58%	1.00	49.4%

The rate of return for each class is the ratio of the operating income from each class to its allocated rate base. A rate of return equal to or greater than the system average rate of return indicates that a class is producing sufficient revenues to meet its cost of service. The relative rate of return for each class is the ratio of that class's rate of return to the system average. A relative rate of return of 1.00 indicates that the rate of return from a customer class is equal to the system average, while a relative rate of return above or below 1.00 indicates that a class is subsidizing (above) or being subsidized (below) by other classes. Lastly, the cost-based increase represents the increase in revenues needed to move each rate class to cost based upon the results of AGC's revised CCOSS.

As Table 2 demonstrates, the majority of SUA's customer classes have rates of return in excess of the system average. Only the Residential class is producing returns below system average.

Q WHAT DO YOU RECOMMEND?

A I recommend the Commission reject the results of SUA's proposed CCOSS based upon the average of the minimum size and zero-intercept studies to classify distribution main costs. Instead, the Commission should approve the results of AGC's revised CCOSS which appropriately utilizes the results of SUA's minimum size main study to classify these costs consistent with Act 725 and also reflects the recommendations made by Ms. LaConte.

Q CAN AGC'S CLASS COST-OF-SERVICE STUDY BE FURTHER ADJUSTED?

A Yes. It is likely that the General Staff, Attorney General's Office, and other parties may recommend adjustments in addition to the recommendations discussed herein. I reserve the right to incorporate these additional adjustments to AGC's revised COSS, to the extent they are appropriate, in my rebuttal testimony.

Q HAVE YOU IDENTIFIED ANOTHER POTENTIAL ISSUE IN SUA'S CLASS COST-OF-SERVICE STUDY?

A Yes. SUA states that it provides assistance to customers in need through its Heating Assistance Fund.[7] However, it is unclear whether these costs are included in SUA's CCOSS, and if so, how they are allocated. Although I have issued discovery requests on these issues, I have not received a response as of the time of this filing; therefore, I reserve the right to address the allocation of these costs in rebuttal.

[7] Direct Testimony of Kurt W. Adams at 12-13.

3. CLASS REVENUE ALLOCATION

Q WHAT IS CLASS REVENUE ALLOCATION?

A Class revenue allocation refers to the assignment of a revenue change among a utility's customer classes. The process is ideally and typically informed by the results of a CCOSS, but utilities often use some degree of judgment in assigning the base revenue increase to various customer classes to alleviate harsh rate impacts, and therefore, deviate from cost-based rates. In this proceeding, SUA's CCOSS is based upon a projected revenue requirement of $281.3 million, which represents a revenue deficiency of $106.1 million.[8] However, SUA's proposed class revenue allocation and rate design are based upon a requested increase of $104.7 million.[9]

Q HOW IS SUA PROPOSING TO ALLOCATE THE REQUESTED REVENUE INCREASE AMONG THE RATE CLASSES?

A SUA's proposed class revenue allocation is based upon the results of its CCOSS, but modified to account for three rate smoothing adjustments to recognize the principle of gradualism. First, because the SCS-2 and SCS-3 rate classes were shown to produce revenues in excess of their cost of service, the proposed revenue for these rate classes was set to equal their present revenues such that no rate classes experienced a rate decrease given that SUA is requesting an overall revenue increase. Second, under a cost-based revenue allocation, the LCS-1 rate class would have experienced a 94.3% percent increase.[10] Because SUA is requesting a total revenue increase of

[8] Errata to the Direct Testimony of Phillip B. Gillam at 39.

[9] *Id*., at 5.

[10] Direct Testimony of Timothy S. Lyons at 28-29.

59.7%, such an increase would have been excessive.[11] Therefore, SUA limited the increase allocated to LCS-1 by 65.3%.[12] Lastly, SUA increased the revenues allocated to SCS-1 to offset the decrease in revenues allocated to LCS-1.[13] SUA's proposed class revenue allocation is summarized in **Table 3** below.

Table 3
SUA's Proposed
Delivery Revenue Increase

Rate Class	Proposed
Residential	61.9%
SCS-1	51.1%
SCS-2	0.0%
SCS-3	0.0%
LCS-1	65.3%
Total	59.7%

Source: Schedule H-2-B.

Q DO YOU AGREE WITH THE RESULTS OF SUA'S RECOMMENDED CLASS REVENUE ALLOCATION?

A No. As previously discussed, SUA's improper classification of distribution mains misstates the relative rates of return for each rate class. Further, my colleague, Ms. LaConte, has identified a number of modifications that should be made to SUA's CCOSS. Collectively, correcting these errors in SUA's CCOSS results in a drastically different cost-based revenue allocation.

[11] Summit AR G-H Schedules, at tab Schedule H-2-B.

[12] Direct Testimony of Timothy S. Lyons at 28-29.

[13] *Id*.

Q HAVE YOU PREPARED A RECOMMENDED CLASS REVENUE ALLOCATION THAT PROPERLY REFLECTS THE CLASSIFICATION OF DISTRIBUTION MAINS, AS WELL AS MS. LACONTE'S REVENUE REQUIREMENT ADJUSTMENTS?

A Yes. The results of my recommended class revenue allocation are shown in **Exhibit JL-2** and summarized in **Table 4**. Also shown are the cost-based increases based upon AGC's revised CCOSS for comparison.

Table 4
AGC's Cost-Based and Proposed Delivery Revenue Increase

Rate Class	Cost-Based	Proposed	Proposed Relative Increase
Residential	58.0%	57.9%	1.17
SCS-1	20.2%	20.2%	0.41
SCS-2	-20.8%	0.0%	0.00
SCS-3	-59.7%	0.0%	0.00
LCS-1	46.4%	46.4%	0.94
Total	49.4%	49.4%	1.00

Q PLEASE DESCRIBE YOUR RECOMMENDED CLASS REVENUE ALLOCATION.

A Similar to SUA's approach to establishing a class revenue allocation, I began with the results of AGC's revised CCOSS and applied a series of rate smoothing adjustments. Under AGC's revised CCOSS, the SCS-2 and SCS-3 rate classes were also shown to produce revenues in excess of their cost of service. I, therefore, set the proposed revenues for these rate classes to equal their present revenues in a manner identical to SUA's smoothing adjustment. The most notable distinction in my recommended class revenue allocation, however, is that under AGC's revised CCOSS, no class required an increase significantly above the system average to be moved to cost. Consequently, the SCS-1 and LCS-1 rate classes revenues are set to cost based on

the results of AGC's CCOSS, as each of these classes would have received a below system average increase. Lastly, the revenue adjustments necessary to set the proposed revenues for SCS-2 and SCS-3 at their present revenues are used to offset the Residential rate class revenue increase, as it would be the only rate class to experience an above average increase.

As a result of AGC's recommended class revenue allocation, no rate class will experience an increase or decrease that is significantly above or below the system average. Further, rate classes experience a rate increase will effectively be moved to cost.

Q WHAT IS THE SIGNIFICANCE OF ALIGNING THE REVENUES TO BE COLLECTED FROM EACH RATE CLASS WITH THE COST OF SERVICE FOR EACH RESPECTIVE CLASS?

A Recognizing the cost to serve different rate classes is critical because it provides a basis for cost-based rates, which are necessary to send appropriate price signals to customers. These price signals are important because they can inform customers on how their usage of the gas system causes a utility to incur the costs necessary to serve them. This results in treating all classes equitably, while also promoting engineering efficiency, and stability.

Q HOW DO COST-BASED RATES PROMOTE EQUITY, ENGINEERING EFFICIENCY, AND STABILITY?

A Cost-based rates are equitable because, under such design, the revenues received from each customer class are no greater than what it costs the utility to provide service to that class, plus a reasonable rate of return. In addition to promoting equity, the price signals provided by cost-based rates provide customers with the information

necessary to make efficient use of the gas distribution system to avoid incurring additional costs, which can enable a utility to avoid overbuilding infrastructure to serve its customers. Lastly, cost-based rates provide stability in a utility's earnings because the revenues received from customers and the expenses incurred to serve them both vary in alignment with customer usage.

Q WHAT DO YOU RECOMMEND?

A I recommend that the Commission reject SUA's class revenue allocation, as it is based upon a CCOSS which improperly classifies the customer- and demand-related portions of SUA's distribution mains and lacks the necessary adjustments discussed herein. Instead, I recommend the Commission approve AGC's recommended class revenue allocation shown in **Exhibit JL-2** (subject to further modification based on reasonable recommendations made by other parties in testimony filed this same date), which is based upon a revised CCOSS consistent with Act 725 and will effectively move a majority of SUA's rate classes to cost.

4. CONCLUSION

Q WHAT FINDINGS SHOULD THE COMMISSION MAKE BASED ON YOUR DIRECT TESTIMONY?

A I recommend the Commission:

- Reject the results of SUA's CCOSS, as it improperly classifies distribution main costs using a hybrid of the minimum size main and zero-intercept methodologies, contrary to the requirements of Act 725 and, furthermore, is based on an inflated return on rate base and overstates its test-year expenses for maintenance associated with distribution mains, incentive compensation, and Volunteer Time Off.

- Approve AGC's revised CCOSS (subject to further modification based on reasonable recommendations made by other parties in testimony filed this same date) which appropriately classifies distribution mains using the minimum size main methodology and adjusts SUA's return on rate base as well as expenses for incentive compensation, distribution main maintenance, and Volunteer Time Off.

- Reject SUA's proposed class revenue allocation based upon its flawed CCOSS.

- Approve AGC's recommended class revenue allocation based upon its revised CCOSS (also subject to further modification based on reasonable recommendations made by other parties in testimony filed this same date).

Q DOES THIS CONCLUDE YOUR DIRECT TESTIMONY?

A Yes.

APPENDIX A

Qualifications of Jonathan Ly

Q PLEASE STATE YOUR NAME AND BUSINESS ADDRESS.

A Jonathan Ly. My business mailing address is 1314 Welch Street, Unit A, Houston, TX 77006.

Q WHAT IS YOUR OCCUPATION AND BY WHOM ARE YOU EMPLOYED?

A I am a regulatory consultant affiliated with J. Pollock, Incorporated.

Q PLEASE STATE YOUR EDUCATIONAL BACKGROUND AND EXPERIENCE.

A I received a Bachelor of Arts degree in Integrative Biology from the University of California, Berkeley in 2013 and a Master's degree in Energy and Earth Resources from the University of Texas at Austin in 2017. In addition, I have completed a course in utility accounting and finance.

I joined J. Pollock, Incorporated in 2018 as an energy analyst assisting consultants in the preparation of financial and economic studies of investor-owned, cooperative, and municipal utilities on revenue requirements, cost of service and rate design, tariff review and analysis, integrated resource planning, and certificates of convenience and necessity. I began working as a regulatory consultant affiliated with J. Pollock, Incorporated in 2021 expanding upon my responsibilities and assignments in matters I had previously worked on as an energy analyst. I have been involved in various projects in multiple states including Arkansas, Florida, Georgia, Michigan, Minnesota, New Mexico, New York, North Carolina, Texas, and Wyoming.

Q PLEASE DESCRIBE J. POLLOCK, INCORPORATED.

A J. Pollock assists clients to procure and manage energy in both regulated and competitive markets. The J. Pollock team also advises clients on energy and regulatory issues. Our clients include commercial, industrial and institutional energy consumers. J. Pollock is a registered broker and Class I aggregator in the State of Texas.

APPENDIX B
Testimony Filed in Regulatory Proceedings
by Jonathan Ly

PROJECT	UTILITY	ON BEHALF OF	DOCKET	TYPE	STATE / PROVINCE	SUBJECT	DATE
240201	DUKE ENERGY FLORIDA, LLC	Florida Industrial Power Users Group	20240025-EI	Direct	FL	Solar Projects; Cost-Effectiveness Analysis; Consumer Protections	6/11/2024
240202	TAMPA ELECTRIC COMPANY	Florida Industrial Power Users Group	20240026-EI	Direct	FL	Solar Projects; Cost-Effectiveness Analysis; Consumer Protections	6/6/2024
240101	DUKE ENERGY CAROLINAS, LLC	Carolina Utility Customers Association, Inc.	E-7. SUB 1304	Direct	NC	Fuel and Fuel-Related Cost Factors	5/23/2024
221201	CONSUMERS ENERGY COMPANY	Association of Businesses Advocating Tariff Equity	U-21490	Rebuttal	MI	Uncollectible Expense Allocation; Economic Breakeven Points	5/17/2024
220604	SOUTHWESTERN PUBLIC SERVICE COMPANY	Occidental Permian Ltd.	23-00384-UT	Stipulation Support	NM	Stipulation Support regarding Long-Term Purchased Power Agreement and Ratemaking Treatment	5/10/2024
221201	CONSUMERS ENERGY COMPANY	Association of Businesses Advocating Tariff Equity	U-21490	Direct	MI	Class Cost-of-Service Study; Revenue Allocation; Rate Design	4/22/2024
220604	SOUTHWESTERN PUBLIC SERVICE COMPANY	Occidental Permian Ltd.	23-00384-UT	Direct	NM	Long-Term Purchased Power Agreement; Ratemaking Requests	4/1/2024
210301	LCRA TRANSMISSION SERVICES CORPORATION	Texas Industrial Energy Consumers	55867	Direct	TX	Wholesale Transmsision Rate	3/18/2024
231203	MINNESOTA POWER	Large Power Intervenors	E-015/GR-23-155	Direct	MN	Advanced Metering Infrastructure; Class Revenue Allocation; Rider for Voluntary Renewable Energy	3/18/2024
240102	NATIONAL FUEL GAS DISTRIBUTION CORPORATION	Multiple Intervenors	23-G-0627	Direct	NY	Class Revenue Allocation; Rate Design	3/1/2024
220604	SOUTHWESTERN PUBLIC SERVICE COMPANY	Occidental Permian Ltd.	23-00252-UT	Direct	NM	Certificate of Convenience and Necessity	12/1/2023
230301	EL PASO ELECTRIC COMPANY	Texas Industrial Energy Consumers	54929	Direct	TX	Certificate of Convenience and Necessity	10/24/2023
220504	SOUTHWESTERN PUBLIC SERVICE COMPANY	Texas Industrial Energy Consumers	54634	Direct	TX	Revised Class Cost-of-Service Study; Class Revenue Allocation; Energy Assistance Program	8/4/2023
230502	ENTERGY ARKANSAS, LLC	Arkansas Electric Energy Consumers, Inc.	22-082-U	Surrebuttal	AR	Additional Sum associated with Power Purchase Agreements	7/20/2023
230502	ENTERGY ARKANSAS, LLC	Arkansas Electric Energy Consumers, Inc.	22-082-U	Direct	AR	Additional Sum associated with Power Purchase Agreements	6/8/2023
221201	CONSUMERS ENERGY COMPANY	Association of Businesses Advocating Tariff Equity	U-21308	Rebuttal	MI	Uncollectible Expense Allocator	5/8/2023
221201	CONSUMERS ENERGY COMPANY	Association of Businesses Advocating Tariff Equity	U-21308	Direct	MI	Class Cost-of-Service Study, Allocation of Other Distribution Plant; Average & Peak Versus Average & Excess Methods	4/17/2023
220503	ENTERGY ARKANSAS, LLC	Arkansas Electric Energy Consumers, Inc.	20-049-U	Surrebuttal	AR	Capacity Need and Capacity Value; Risk to Non-Participants; Negative Impacts on Competition; Best Practices	8/1/2022
220503	ENTERGY ARKANSAS, LLC	Arkansas Electric Energy Consumers, Inc.	20-049-U	Direct	AR	Capacity Need and Capacity Value; Risk to Non-Participants; Negative Impacts on Competition; Best Practices	6/22/2022

APPENDIX C

Procedure for Conducting a Class Cost-of-Service Study

Q WHAT PROCEDURES ARE USED IN A CLASS COST-OF-SERVICE STUDY?

A The basic procedure for conducting a class cost-of-service study (CCOSS) is fairly simple. First, one identifies the different types of costs (functionalization), determines their primary causative factors (classification), and then apportions each item of cost among the various service classes (allocation). Adding up the individual pieces gives the total cost for each class.

Identifying the utility's different levels of operation is a process referred to as functionalization. The utility's investments and expenses are separated into production, storage, transmission, distribution, and other functions. To a large extent, this is done in accordance with the Uniform System of Accounts developed by the Federal Energy Regulatory Commission (FERC).

Once costs have been functionalized, the next step is to identify the primary causative factor (or factors). This step is referred to as classification. Costs are classified as demand-related, energy- (or commodity-) related or customer-related. Demand (or capacity) related costs vary with peak demand, which is measured in kilowatts or peak day send out. This includes production, transmission, and some distribution investment and related fixed operation and maintenance (O&M) expenses. As explained later, peak demand determines the amount of capacity needed for reliable service. Energy-related costs vary with natural gas throughput, which is measured in dekatherms. Energy-related costs include purchased gas and variable O&M expense. Customer-related costs vary directly with the number of customers such as meters, service laterals, billing, and customer service, and they may also include a portion of distribution mains.

Each functionalized and classified cost must then be allocated to the various customer classes. This is accomplished by developing allocation factors that reflect the percentage of the total cost that should be paid by each class. The allocation factors should reflect cost-causation; that is, the degree to which each class caused the utility to incur the cost.

Further, each customer class should be comprised of customers having similar characteristics. The relevant characteristics include the type of end-use customer (*e.g.,* residential, general service sales, transportation), average size and how delivery service is provided. Allocating costs to homogeneous customer classes will ensure that the rates derived from a class cost-of-service study are just and reasonable and reflect the actual cost to serve.

Q WHAT KEY PRINCIPLES ARE RECOGNIZED IN A CLASS COST-OF-SERVICE STUDY FOR NATURAL GAS DELIVERY SERVICE?

A A properly conducted CCOSS recognizes two key cost-causation principles. First, not all gas customers purchase gas supplied by a local distribution company (LDC). Some customers purchase and transport their own gas to the city gate. Thus, the LDC does not incur purchased gas and other related costs to serve a transportation customer. Second, not all customers take the same delivery service. Larger transportation customers may take delivery service directly from either the transmission system or high-pressure distribution mains. Third, the use of storage services will depend on the tolerances between actual and nominated gas deliveries. The smaller the tolerances, the lower the amount of storage services. Fourth, since cost causation is also related to how natural gas is used, both the timing and rate of gas consumption (*i.e.*, demand) are critical. Consistent with the obligation to serve and to ensure reliability, the LDC

must purchase sufficient gas supply to meet the maximum needs of its sales customers. The LDC must also construct the required distribution mains and other facilities to attach customers to the system, and these facilities must be sized to meet the expected contribution to the peak day design, which is the maximum expected demand on the delivery system.

SUMMIT UTILITIES ARKANSAS
Summary of AGC's Revised Class Cost-of-Service Study
For The Test Year Ending December 31, 2024

Line No.	Description	Arkansas Jurisdiction	Residential	SCS-1	SCS-2	SCS-3	LCS-1
		(1)	(2)	(3)	(4)	(5)	(6)
1	**RATE BASE**						
2	Gross Plant in Service	$ 1,792,805,012	$ 1,380,621,938	$ 300,364,817	$ 3,679,091	$ 100,480	$ 108,038,687
3	Accumulated Depreciation	688,798,742	540,961,498	111,304,394	1,534,671	43,994	34,954,184
4	Total Net Plant	$ 1,104,006,269	$ 839,660,440	$ 189,060,422	$ 2,144,419	$ 56,486	$ 73,084,503
5	Working Capital Assets	118,781,180	81,138,410	27,363,408	483,030	11,485	9,784,848
6	Other Rate Base Items	-	-	-	-	-	-
7	**TOTAL RATE BASE**	**$ 1,222,787,450**	**$ 920,798,849**	**$ 216,423,830**	**$ 2,627,449**	**$ 67,971**	**$ 82,869,351**
8	**NON-FUEL OPERATING REVENUES**						
9	Present Rate Schedules/Class	$ 175,269,971	$ 128,811,695	$ 35,208,901	$ 631,064	$ 39,112	$ 10,579,199
10	Other Operating Revenues	6,711,338	6,182,964	517,992	6,504	1,502	2,376
11	**TOTAL OPERATING REVENUES**	**$ 181,981,309**	**$ 134,994,659**	**$ 35,726,893**	**$ 637,567**	**$ 40,614**	**$ 10,581,575**
12	**EXPENSES**						
13	Operations and Maintenance Expense						
14	Distribution	41,133,004	31,060,559	6,922,953	81,423	1,935	3,066,134
15	Customer Accounts	11,509,822	10,497,961	997,416	8,523	3,478	2,444
16	Customer Services and Informational	571,688	507,660	62,834	912	10	272
17	Sales	363,981	323,216	40,005	581	6	173
18	Administrative and General	36,188,200	28,569,651	5,498,646	65,235	3,822	2,050,845
19	ETC						
20	TOTAL OPERATION & MAINTENANCE EXPENSE	$ 89,766,695	$ 70,959,047	$ 13,521,855	$ 156,674	$ 9,251	$ 5,119,868
21	Depreciation and Amortization Expense	68,778,540	54,843,998	10,710,120	143,109	4,232	3,077,082
22	Taxes Other Than Income Taxes	14,689,084	11,171,895	2,515,497	28,532	752	972,408
23	Income Taxes	1,626,461	(368,224)	1,669,680	57,504	4,905	262,595
24	**TOTAL EXPENSES**	**$ 174,860,780**	**$ 136,606,717**	**$ 28,417,152**	**$ 385,819**	**$ 19,139**	**$ 9,431,953**
25	OPERATING INCOME	$ 7,120,529	$ (1,612,058)	$ 7,309,741	$ 251,749	$ 21,475	$ 1,149,622
26	EARNED RETURN ON RATE BASE	0.58%	-0.18%	3.38%	9.58%	31.59%	1.39%

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SUMMIT UTILITIES ARKANSAS
AGC's Recommended Class Revenue Allocation
Test Year Ending December 31, 2024
(Amounts in $000)

Line	Class	Present Rate Schedule Revenues	Cost-Based Increase	Smoothing Adjustment	Recommended Increase Amount	Recommended Increase Percent
		(1)	(2)	(3)	(4)	(5)
1	Residential	$128,812	$74,706	($154)	$74,552	57.9%
2	SCS-1	35,209	$7,101	$0	$7,101	20.2%
3	SCS-2	631	($131)	$131	$0	0.0%
4	SCS-3	39	($23)	$23	$0	0.0%
5	LCS-1	10,579	$4,911	$0	$4,911	46.4%
6	Total	$175,270	$86,564	$0	$86,564	49.4%

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CERTIFICATE OF SERVICE

I hereby certify that a copy of the foregoing has been delivered on all parties of record by electronic mail via the APSC's Electronic Filing System this 10th day of July 2024.

/s/ *M. Shawn McMurray*
M. Shawn McMurray ABN 92250

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BEFORE THE ARKANSAS PUBLIC SERVICE COMMISSION

In the Matter of the Application of Summit Utilities Arkansas, Inc., for a General Change or Modification in Its Rates, Charges and Tariffs	)))))	**Docket No. 23-079-U**

PUBLIC VERSION – CONFIDENTIAL INFORMATION REDACTED

Direct Testimony and Exhibits

of

Billie S. LaConte

On Behalf of

ARKANSAS GAS CONSUMERS, INC.

July 10, 2024

J. POLLOCK
INCORPORATED

BEFORE THE ARKANSAS PUBLIC SERVICE COMMISSION

In the Matter of the Application of Summit Utilities Arkansas, Inc., for a General Change or Modification in Its Rates, Charges and Tariffs	)))))	**Docket No. 23-079-U**

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LIST OF SCHEDULES

Exhibit	Description
BSL-1	Excerpt from RRA Regulatory Focus, Major Energy Rate Case Decisions in the US January – December 2023
BSL-2	Impact of Reducing ROE to National Average Authorized ROE
BSL-3	Discounted Cash Flow Analysis
BSL-4	Two-Stage Discounted Cash Flow Analysis
BSL-5	Capital Asset Pricing Model
BSL-6	Risk Premium Analysis
BSL-7	Impact of Reducing ROE to 9.7%
BSL-8	Impact of Reducing Equity Ratio to 50%

GLOSSARY OF ACRONYMS

Term	Definition
ADIT	Accumulated Deferred Income Taxes
AGC	Arkansas Gas Consumers, Inc.
BDA	Billing Determinant Adjustment
CAPM	Capital Asset Pricing Model
CenterPoint	CenterPoint Energy Resources Gas
DCF	Discounted Cash Flow
DIMP	Distribution Integrity Management Plan
ECAPM	Empirical Capital Asset Pricing Model
EDIT	Excess Deferred Income Taxes
MRP	Market Risk Premium
Moody's	Moody's Investor Service
O&M	Operation and Maintenance
ROE	Return on Equity
RRA	Regulatory Research Associates
S&P	Standard & Poor's
SCHC	Southern Col Holdco LLC
SSER	System Safety Enhancement Rider
SUA	Summit Utilities Arkansas
TIMP	Transmission Integrity Management Plan
Value Line	Value Line Investment Survey
VTO	Volunteer Time Off
Zacks	Zacks Investment Research

Direct Testimony of Billie S. LaConte

1. INTRODUCTION, QUALIFICATIONS AND SUMMARY

Q PLEASE STATE YOUR NAME AND BUSINESS ADDRESS.

A Billie S. LaConte, 14323 South Outer 40 Rd., Suite 206N, St. Louis, MO 63017.

Q WHAT IS YOUR OCCUPATION AND BY WHOM ARE YOU EMPLOYED?

A I am an energy advisor and Associate at J. Pollock, Incorporated.

Q PLEASE STATE YOUR EDUCATIONAL BACKGROUND AND EXPERIENCE.

A I have a Bachelor of Arts degree in Mathematics from Boston University and a Master's degree in Business Administration from Washington University. Since graduating in 1995, I have been engaged in a variety of consulting assignments, including energy procurement and regulatory matters in both the United States and several Canadian provinces. More details are provided in **Appendix A**. A list of my appearances is provided in **Appendix B**.

Q ON WHOSE BEHALF ARE YOU TESTIFYING IN THIS PROCEEDING?

A I am testifying on behalf of the Arkansas Gas Consumers, Inc. (AGC). AGC's members are customers of Summit Utilities Arkansas, Inc. (SUA) that primarily purchase gas delivery service on the Large Commercial Firm Service tariff.

Q WHAT IS THE PURPOSE OF YOUR TESTIMONY?

A I address SUA's requested return on equity (ROE), capital structure, expenses, incentive compensation and excess deferred income taxes (EDIT).

Q ARE YOU SPONSORING ANY EXHIBITS WITH YOUR TESTIMONY?

A Yes. I am sponsoring Exhibits **BSL-1** through **BSL-8**. These exhibits were prepared by me or under my supervision and direction. In addition, I have prepared **Appendix C**, which consists of the Discovery Responses referenced in my testimony and **Appendix D,** which provides more detailed information on the various ROE methodologies utilized by analysts to estimate ROE.

Q ARE YOU ACCEPTING SUA'S POSITIONS ON THE ISSUES NOT ADDRESSED IN YOUR DIRECT TESTIMONY?

A No. One should not interpret the fact that I do not address every issue raised by SUA as an endorsement of its proposals. I specifically reserve the right to accept or support additional adjustments to SUA's revenue requirement recommended by other parties in testimony filed on this date.

Summary

Q PLEASE SUMMARIZE YOUR FINDINGS AND RECOMMENDATIONS.

A My findings and recommendations are as follows:

Return on Equity

- Determining a fair and reasonable ROE for SUA requires applying widely used and accepted analytical methodologies — Discounted Cash Flow (DCF), Capital Asset Pricing Model (CAPM), and the Risk Premium methods. Other considerations include SUA's low regulatory risk, and the national average of authorized ROEs for natural gas distribution utilities.
- The 11.00% ROE recommended by SUA's ROE witness, Mr. Dylan D'Ascendis, is based on improper application of widely used and accepted methods, as well as other methods that are either not widely used or accepted by regulatory commissions in other jurisdictions, such as a non-price regulated ROE approach and the Empirical Capital Asset Pricing Model (ECAPM), in addition to a size risk adjustment.

- Applying widely used and accepted methodologies, my recommended ROE for SUA is 9.7%, which is based on the results of my ROE analyses. A 9.7% ROE is a fair and reasonable ROE for SUA and recognizes its very low regulatory risks. In addition, if the proposed Billing Determinant Adjustment Rider and requested expansion of its System Safety Enhancement Rider are approved, SUA's financial risk will be lowered significantly, thus further supporting a 9.7% ROE at the most — arguably it could reasonably be lower.

Capital Structure

- SUA is seeking a 55.59% equity ratio, based on the actual capital structure of its parent company, Southern Col Holdco LLC's. This is significantly higher than SUA's currently authorized capital structure that was maintained by its predecessor, CenterPoint Energy Resources Gas (CenterPoint), which had a 48.5% common equity ratio. A 55.59% equity ratio is an excessive and significant shift which should be rejected.
- SUA's capital structure should not comprise more than 50% equity. This is sufficient to maintain SUA's parent company's "target" credit rating and is similar to SUA's currently authorized capital structure (48.5%).

Expenses

- SUA is requesting $92.7 million in O&M expense. Of this amount, approximately $10.4 million relates to maintenance of mains.
- SUA is investing significantly in its distribution mains system. However, the average cost of maintenance per mile of distribution main is increasing by almost 16%. This is counterintuitive — newer mains require less maintenance. Thus, SUA's average cost per mile of main should not be increasing.
- SUA's maintenance of mains cost should be reduced by $1.4 million to recognize the lower cost of maintenance for newer mains.
- SUA is seeking to recover approximately $167,000 related to Volunteer Time Off, whereupon SUA compensates its employees for volunteering their time during company office hours. While SUA may pay its employees for volunteer work, the expense related to paying employees for volunteer work should not be borne by SUA's ratepayers, as they do not receive any benefit from the volunteer hours and it is not a requirement to provide cost effective, reliable service.

Incentive Compensation

- SUA is seeking $4.7 million in incentive compensation. Of this amount, approximately 40% is based on the company meeting financial targets.
- Financial targets benefit SUA and its shareholders, not ratepayers. Therefore, at least $1.9 million of incentive compensation should be rejected (40% of $4.7 million).

Excess Deferred Income Taxes

- SUA is seeking to pre-emptively modify its EDIT based on an IRS ruling for another unrelated utility, which would effectively modify the amount of EDIT that SUA must refund to customers based on the Commission's Order in Docket No. 18-050-TF directing SUA to refund its EDIT liability to customers.
- The IRS ruling does not apply to SUA and, specifically, does not set a precedent. Therefore, SUA's proposed adjustment to its EDIT should be rejected.

Q HOW IS YOUR TESTIMONY ORGANIZED?

A My testimony is organized as follows:

- A discussion of the factors that affect a utility's ROE;
- ROE analyses;
- An evaluation of Mr. D'Ascendis' ROE analyses;
- An evaluation of SUA's proposed capital structure;
- Expenses;
- Incentive Compensation; and
- Excess Deferred Income Taxes.

2. FACTORS IMPACTING THE RETURN ON EQUITY

Q WHAT FACTORS SHOULD THE COMMISSION CONSIDER WHEN DETERMINING AN APPROPRIATE RETURN ON EQUITY FOR SUA?

A First and foremost, a fair and reasonable ROE should be based on the results derived from accepted methodologies, such as DCF, CAPM, and the Risk Premium methods. Further, the inputs and assumptions used in applying the accepted methodologies should consider current financial and economic realities, such as:

- The principles for setting the authorized ROE;
- SUA's financial risk; and
- The ROEs authorized by state regulatory commissions.

I discuss each of these considerations in detail below.

Principles for Determining a Fair Rate of Return

Q HAS THE UNITED STATES SUPREME COURT ESTABLISHED PRINCIPLES TO DETERMINE A FAIR RETURN ON EQUITY FOR A REGULATED MONOPOLY?

A Yes. The U.S. Supreme Court established the principles that should be used to determine a fair return on capital for regulated monopolies. Specifically, in the case of *Federal Power Comm v Hope Natural Gas Co* the Supreme Court explained:

> The rate-making process under the [Natural Gas] Act, i.e., the fixing of 'just and reasonable' rates, involves a balancing of the investor and the consumer interests….From the investor or company point of view it is important that there be enough revenue not only for operating expenses but also for the capital costs of the business. These include service on the debt and dividends on the stock. [citation omitted] By that standard the return to the equity owner should be commensurate with returns on investments in other enterprises having corresponding risks. That return, moreover, should be sufficient to assure confidence in the financial integrity of the enterprise, so as to maintain its credit and to attract capital.[1]

[1] *Federal Power Comm et al v. Hope Natural Gas Co City of Cleveland*, 320 US 591, 603 (1944).

Also, in *Bluefield Water Works & Improvement Co v. the Pub Serv Comm of West Virginia* the Supreme Court recognized that utilities compete with other firms in the market for investor capital and should have the opportunity to earn a fair return on capital. The Court stated:

> A public utility is entitled to such rates as will permit it to earn a return on the value of the property which it employs for the convenience of the public equal to that generally being made at the same time and in the same general part of the country on investments in other business undertakings which are attended by corresponding risks and uncertainties; but it has no constitutional right to profits such as are realized or anticipated in highly profitable enterprises or speculative ventures. The return should be reasonably sufficient to assure confidence in the financial soundness of the utility and should be adequate, under efficient and economical management, to maintain and support its credit and enable it to raise the money necessary for the proper discharge of its public duties.[2]

As such, my ROE analyses are premised on these guiding principles.

Risk-Free Cost of Capital

Q HOW HAS THE RISK-FREE COST OF CAPITAL CHANGED IN THE PAST TWENTY YEARS?

A The risk-free cost of capital is represented by the yield on 30-year U.S. Treasury bonds. The 30-year U.S. Treasury bond interest rate is used because the term of the security should closely match the lifetime of the underlying assets. The risk-free cost of capital has steadily declined over the last 20 years, although it has very recently increased due to Federal monetary policy.[3]

[2] *Bluefield Waterworks & Improvement Co v. Pub Serv Comm of West Virginia et al*, 262 US 679, 692-93 (1923).

[3] Calculated using data from U.S. Department of the Treasury, Resource center: https://www.treasury.gov/resource-center/data-chart-center/interest-rates/Pages/TextView.aspx?data=yield

Q WHAT ARE THE IMPLICATIONS OF THE OVERALL DECLINE IN THE RISK-FREE COST OF CAPITAL IN DETERMINING A FAIR AND REASONABLE RETURN ON EQUITY?

A All other things being equal, a declining risk-free cost of capital should translate into a correspondingly lower authorized ROE.

Q WILL A HIGHER RISK-FREE COST OF CAPITAL INCREASE SUA'S REQUIRED COST OF CAPITAL?

A All else being equal, the impact of any potential increase would be minimal. As discussed in my testimony, the CAPM and Risk Premium methodologies incorporate the forecast risk-free cost of capital and demonstrate that a lower ROE is warranted compared to SUA's current 9.5% ROE.[4]

Financial Risk

Q WHAT IS FINANCIAL RISK?

A Financial risk represents variability in income. Quantifying financial risk includes an analysis of a utility's financial statements and cash flow/leverage analyses. To the extent such variability is small, or has been reduced by other means, the risk to SUA's shareholders is lowered.

Q WHAT FACTORS CAN INFLUENCE THE LEVEL OF FINANCIAL RISK FOR A PARTICULAR UTILITY?

A Financial risk is highly influenced by the regulatory climate. All other things being equal, a utility is less risky if it is regulated by a Commission that:

[4] *In the Matter of the Application of CenterPoint Energy Resources Corp., D/B/A CenterPoint Energy Arkansas Gas, for a General Change or Modification in Its Rates, Charges and Tariffs,* Docket No. 15-098-U, Order No. 8 at 13 (Sept. 2, 2016).

- authorizes rates for a multi-year period;
- authorizes separate piecemeal cost recovery clauses and revenue decoupling that adjust rates automatically outside of base rate cases; and
- employs other constructive ratemaking practices.

Q WHAT DO YOU MEAN BY PIECEMEAL COST RECOVERY CLAUSES?

A Piecemeal (or single-issue) ratemaking refers to a utility being allowed to implement adjustment clauses that permit it to change rates outside of a base rate case, while ignoring the utility's earnings. Utilities are able to mitigate risk by implementing an adjustment clause that allows rates to change on an expedited basis outside the context of a traditional rate case in which all costs and revenues would be considered.

Q DOES SUA CURRENTLY HAVE ANY ADJUSTMENT CLAUSES IN PLACE THAT REDUCE ITS VARIABILITY IN INCOME AND LOWER ITS FINANCIAL RISK?

A Yes. SUA has the System Safety Enhancement Rider (SSER), which was implemented as part of the Settlement Agreement in Docket No. 21-060-U. The SSER allows SUA to recover approximately 29% of its capital expenditures through the rider, which reduces regulatory lag.[5] SUA is seeking to expand the SSER to include additional capital investments associated with its Distribution Integrity Management Plan (DIMP) and Transmission Integrity Management Plan (TIMP), among other things.[6] Furthermore, SUA is seeking approval of a new Billing Determinant Adjustment (BDA) rider, which is a partial decoupling mechanism.[7] The open-ended expansion of the SSER and approval of Rider BDA would significantly reduce SUA's

[5] Direct Testimony of Vernon McNully at 29.

[6] *Id*. at 30.

[7] AGC is not taking a position at this time on whether the Commission should approve SUA's request for an expanded SSER and the new Rider BDA.

financial risk by removing regulatory lag and reducing financial volatility, and could justify an even lower ROE than I recommend today.

Q HOW MUCH OF SUA'S CAPITAL EXPENDITURES WOULD BE RECOVERED THROUGH THE SYSTEM SAFETY ENHANCEMENT RIDER IF IT IS EXPANDED?

A SUA would recover approximately 69% of its total capital expenditures through the Rider if it is expanded, with no limit.[8]

Q HOW DOES LOWER RISK IMPACT SUA'S EXPECTED COST OF CAPITAL?

A Lower risk leads to lower financial volatility. SUA has several tools available to reduce its regulatory lag, including the aforementioned adjustment clauses. Therefore, investors' required return for SUA will be lower. Hence, these risk-reducing measures support an ROE that is lower not only than SUA's requested ROE of 11%, but also than its current ROE of 9.5%.

ROEs Authorized By State Regulatory Commissions

Q WHAT RETURNS ON EQUITY HAVE STATE REGULATORY COMMISSIONS RECENTLY AUTHORIZED FOR REGULATED NATURAL GAS INVESTOR-OWNED UTILITIES?

A The national average authorized ROE for natural gas utilities was 9.53% in 2022 and 9.60% in 2023 as reported by Regulatory Research Associates (RRA). An excerpt of the RRA Report is provided in **Exhibit BSL-1**. These averages reflect the actual decisions from rate cases in Arkansas, as well as decisions by other state regulatory commissions in general rate cases. As discussed later, this is a reasonable basis for assessing the trend in authorized ROEs.

[8] SUA Response to AGC-004-001.

Q HOW DOES SUA'S REQUESTED RETURN ON EQUITY COMPARE TO THE NATIONAL AVERAGE FOR NATURAL GAS UTILITIES?

A SUA's requested 11% ROE is 140 basis points higher than the 9.60% national average authorized ROE for other natural gas utilities in 2023.

Q HOW WOULD SUA'S PROJECTED REVENUE DEFICIENCY BE AFFECTED IF THE COMMISSION SET SUA'S RETURN ON EQUITY AT THE RRA NATIONAL AVERAGE FOR 2023?

A SUA's projected revenue deficiency would decrease by $12.8 million. The details of this calculation are shown in **Exhibit BSL-2**.

Q SHOULD THE COMMISSION CONSIDER DETERMINATIONS MADE IN OTHER REGULATORY JURISDICTIONS?

A Yes. A Commission should be informed by the determinations made by other state regulatory commissions. This is because the trend in authorized ROEs indicates that, in general, utilities' financial and credit risks are lower than in the past due, in part, to the implementation of a plethora of cost recovery mechanisms and other enhancements that have reduced regulatory lag. The national authorized average ROE is an important consideration when determining the ROE for SUA.

3. RETURN ON EQUITY

Q WHAT IS A FAIR RETURN ON EQUITY FOR SUA?

A Based on my analyses, I have calculated an ROE range of 8.43% - 11.07%. The components of this are shown in Table 2 below.

BSL Direct Table 2
Estimated ROE

Component	Low	Mean	High
Constant Growth DCF	8.43%	9.71%	11.07%
Two-Stage DCF		9.56%	
CAPM Historical MRP		10.57%	
CAPM Projected MRP		9.73%	
Risk Premium		8.79%	

Q HOW DID YOU DETERMINE THE FAIR RETURN ON EQUITY FOR SUA?

A I used two DCF analyses (a Constant Growth and Two-Stage Model), two CAPM analyses, and the Risk Premium method. **Appendix D** provides a description of these ROE methodologies. These are standard methods that have been used for years to determine the appropriate ROE for utilities and are also methods employed by Mr. D'Ascendis. Where analysts generally differ is their choice of inputs: the group of comparable companies; the time period for calculating the stock price; the estimated growth rate; the risk associated with various stocks, and so on. Those choices affect the numerical results. In this case, I differ from SUA regarding the values of some inputs, its risk profile, the composition of the proxy group and, therefore, the results.

Q IS YOUR RECOMMENDED RETURN ON EQUITY OVERLY-RELIANT ON QUANTITATIVE ANALYSES?

A No. My methodology relies on a combination of quantitative models and an assessment of SUA's risk profile to determine the appropriate ROE.

Q HOW DID YOU DETERMINE YOUR RECOMMENDED RETURN ON EQUITY RANGE FOR SUA?

A The recommended range is based on my quantitative and qualitative analysis. My recommended range is 8.43% - 11.07%. The midpoint is 9.75% and the average is 9.69%. Based on my analyses, I recommend a 9.70% ROE.

Q WHY IS IT IMPORTANT TO STRIKE THE RIGHT BALANCE BETWEEN QUANTITATIVE MODELS AND QUALITATIVE CONSIDERATIONS WHEN DETERMINING THE APPROPRIATE RETURN ON EQUITY?

A Quantitative results provide a reasonable estimate of an appropriate ROE, but one should also consider other qualitative factors, such as relative risk to a proxy group, when determining the ROE.

Proxy Group

Q WHAT DO YOU MEAN BY A PROXY GROUP?

A A proxy group is a group of companies involved in similar operations as SUA.

Q WHY IS A PROXY GROUP RELEVANT IN DETERMINING AN APPROPRIATE ROE?

A A proxy group is relevant because it provides a group of companies that are comparable in risk to SUA, hence estimating the cost of equity for the proxy group represents the economic opportunity costs that have an impact on the ROE for SUA.

Q WHAT CHARACTERISTICS SHOULD A PROXY GROUP OF UTILITIES HAVE IN COMMON?

A An appropriate proxy group should consist of utilities with the following common characteristics:

- Consistently pays positive, quarterly cash dividends;
- Covered by more than one equity analyst;
- Regulated natural gas operating revenues greater than 50% of total operating revenues;
- Moody's Investor Service (Moody's) credit rating of Baa3 or higher;
- Has positive earnings growth by at least two of the following analysts: Value Line, Yahoo! Finance, or Zacks Investment Research (Zacks); and
- Not involved in any merger or acquisition related activities within the past six months.

Q WHY ARE THESE CHARACTERISTICS RELEVANT WHEN CONSTRUCTING A REPRESENTATIVE GROUP OF COMPANIES SIMILAR TO SUA?

A It is important to construct a proxy group that is fundamentally comparable to SUA. This will allow SUA to earn an ROE that is commensurate with returns on investments in other enterprises having corresponding risks as required by *Hope*. I chose these characteristics because:

- Paying positive, quarterly cash dividends indicates that a company is growing;
- The company is engaged in similar operations as SUA;
- Coverage by more than one equity analyst provides a robust estimate of its earnings growth;
- Natural gas revenues greater than 50% indicate the company is primarily an natural gas utility, with operating characteristics similar to SUA;
- A Moody's credit rating of Baa3 or higher indicates the company is investment grade, similar to SUA;

- SUA has positive growth forecasts and therefore, the comparable companies should also have similar growth prospects; and
- Utilities involved in mergers or acquisitions exhibit distorted stock prices that are not representative of "normal" operating conditions.

Q WHAT UTILITIES DO YOU INCLUDE IN YOUR PROXY GROUP?

A My proxy group includes the following nine comparable utilities:

- Atmos Energy Corporation
- Black Hills Corporation
- New Jersey Resources Corporation
- Nisource, Incorporated
- Northwest Natural Holding Company
- ONE Gas, Incorporated
- Spire, Incorporated
- Southwest Gas Holdings, Incorporated
- WEC Energy Group, Incorporated

Q HOW DOES YOUR PROXY GROUP COMPARE TO MR. D'ASCENDIS' PROXY GROUP?

A Mr. D'Ascendis' proxy group includes six companies, all of which are also in my proxy group. My expanded proxy group improves my estimated ROE because the results are enhanced by the additional data.

Q IN TERMS OF DETERMINING AN APPROPRIATE RETURN ON EQUITY FOR SUA, HOW IMPORTANT IS IT TO ESTABLISH A REASONABLE AND PRUDENT PROXY GROUP?

A A reasonable proxy group must be established to meet the requirement of *Hope* that the return to the equity owner should be commensurate with returns on investments in other enterprises having corresponding risks. Establishing an appropriate proxy

group is an important first step when determining the ROE for SUA. Proxy groups should include companies that are similar in nature to SUA's operations, otherwise the application of the ROE methodologies will produce distorted results that are not representative of an appropriate ROE.

Q DOES MR. D'ASCENDIS HAVE A SEPARATE PROXY GROUP THAT HE USED IN HIS RETURN ON EQUITY ANALYSES?

A Yes. Mr. D'Ascendis also uses a proxy group of 50 domestic, non-price regulated companies to estimate SUA's ROE. As discussed in more detail later, non-price regulated companies are not comparable to regulated natural gas utilities and should not be used to estimate SUA's ROE.

Discounted Cash Flow Method

Q WHAT ARE THE RESULTS OF YOUR SINGLE-STAGE DCF METHOD?

A My single-stage DCF results in an estimated ROE range for SUA of 8.43% (low estimate), 9.71% (mean estimate) and 11.07% (high estimate). The low estimate is based on the lowest forecast growth rate for each utility. The mean estimate is based on the average forecast growth rate for each utility and the high estimate is based on the highest growth estimate for each utility. The results are shown in more detail in **Exhibit BSL-3**. The exhibit includes the constant growth DCF calculations for each company in my proxy group using forecast growth rates from Value Line, Yahoo! Finance, and Zacks.

Q WHAT IS YOUR ESTIMATED RETURN ON EQUITY USING THE TWO-STAGE MODEL?

A The estimated ROE using the two-stage DCF method is 9.56%. The detailed calculations are provided in **Exhibit BSL-4**.

Compared to the single stage DCF method, the two-stage DCF method provides a more realistic expectation of growth in the short-term and in the long term. A regulated utility's ROE that is based solely on analysts' short-term forecasts may overstate (or understate) the expected ROE. In the two-stage DCF method, the short-term growth rate is recognized, but it does not dictate the estimated ROE for the long-term.

Q PLEASE SUMMARIZE THE RESULTS OF YOUR DCF ANALYSES.

A The results of my DCF analyses are summarized in Table 3.

Table 3
Estimated ROE Using DCF Method

Model	Value
Constant Growth Low	8.43%
Constant Growth Mean	9.71%
Constant Growth High	11.07%
Two-Stage	9.56%

Source: Exhibits BSL-3 and BSL-4.

Based on the results of my DCF analyses, a reasonable ROE for SUA is 9.69%, which is the average of my DCF results; however, my recommendation is for 9.7%.

Capital Asset Pricing Model

Q PLEASE DESCRIBE YOUR CAPITAL ASSET PRICING MODEL ANALYSIS.

A My CAPM analyses uses the average of the betas for each company in my proxy group and two estimates of the market risk premium (MRP). The CAPM analyses were performed as a check against the reasonableness of my DCF analyses.

Q WHAT MARKET RISK PREMIUM DID YOU USE IN YOUR ANALYSES?

A I used two MRP estimates, the historical MRP estimate (7.03%) and the projected MRP (6.11%). The historical MRP (1926-2022) was provided by Mr. D'Ascendis using data from Kroll's *2023 SBBI Yearbook*.[9]

Q HOW DID YOU CALCULATE THE PROJECTED MARKET RISK PREMIUM?

A The projected MRP is based on the projected return for stocks in the Standard and Poor's (S&P) 500 using Value Line Data and Bloomberg data, as provided by Mr. D'Ascendis. The forecast annual return is calculated by applying the DCF methodology to each stock in the S&P 500, using both the Value Line data and the Bloomberg data separately. I excluded any company that had a negative growth rate or a growth rate greater than 20%. The forecast return for each stock was then weighted by its market capitalization. The sum of the weighted returns produces the expected market return, which is 10.96% using the Value Line data and 9.66% using the Bloomberg data. Next, I subtracted the projected risk-free rate (4.2%), which results in a projected MRP of 6.76% using the Value Line data and 5.46% using the

[9] Direct Testimony and Schedules of Dylan W. D'Ascendis, Schedule DWD-5 at 2.

Bloomberg. I used the average of the two MRPs, or 6.11%, for my projected market risk premium.

Q DOES THE HISTORICAL MARKET RISK PREMIUM PROVIDE A GOOD APPROXIMATION OF FUTURE MARKET RISK PREMIUMS?

A Yes. Long-term data provides the MRP throughout many economic cycles, providing a reasonable expectation of future performance.

Q WHY DID YOU ALSO USE TWO PROJECTED MARKET RISK PREMIUMS?

A While long-term historical data provides a reasonable expectation of future performance, ROE estimates are forward looking and may include projected data to estimate the ROE. Therefore, I incorporated two projected MRPs to provide an additional CAPM ROE estimate.

Q HOW DID YOU DETERMINE BETA?

A To determine the beta, I reviewed the betas from Value Line for each utility in my proxy group. Based on the betas for the proxy group, the average beta is 0.91, as compared to Mr. D'Ascendis' 0.79 average beta.[10]

Q HOW DID MR. D'ASCENDIS ESTIMATE BETA?

A Mr. D'Ascendis' estimated the beta using data from Bloomberg and Value Line.

[10] Direct Testimony of Dylan W. D'Ascendis, Schedule DWD-5 at 1.

Q WHAT RISK-FREE RATE DID YOU USE IN YOUR CAPITAL ASSET PRICING MODEL ANALYSES?

A I used the average of the forecast yield on 30-year treasury bonds for the first three quarters of 2025, or 4.2%, from Blue Chip Financial Forecast.[11]

Q WHAT ARE YOUR ESTIMATED RETURNS ON EQUITY USING YOUR CAPITAL ASSET PRICING MODEL ANALYSES?

A My estimated ROE using the historical MRP is 10.57%. Using the projected MRP, the estimated ROE is 9.73%. The detailed calculations are provided in **Exhibit BSL-5.**

Risk Premium Method

Q PLEASE DESCRIBE YOUR RISK PREMIUM ANALYSIS.

A Similar to Mr. D'Ascendis' analysis, I compared the authorized ROEs for natural gas utilities since 1980 to the risk-free rate at the time the ROE was authorized. Based on this data, I used the average historical ROE and long-term risk-free rate to determine SUA's ROE.

I would note that authorized ROEs are typically based on estimates of the required return at the time of the proceeding. My application of the Risk Premium method recognizes the average, expected historical risk premium for natural gas utilities over the long term. This provides a realistic long-term estimate of the risk premium for natural gas utilities. The results are shown in Table 4 on the following page.

[11] Vol. 43, No. 5, Blue Chip Financial Forecasts at 2 (May 1, 2024).

Table 4 Risk Premium Method	
Description	**Amount**
Historical Average Authorized ROE	12.52%
Historical 30-Year Treasury Yield	9.67%
Historical Risk Premium	2.85%
Projected A2 Utility Bond Yield	5.94%
Return on Equity	8.79%
Source: Exhibit BSL-6.	

The long-term nature of my risk premium estimate recognizes that the risk premium can fluctuate depending on market conditions and investor expectations. Therefore, using the average risk premium over this time-period is a reasonable method to estimate the current risk premium. The 8.79% ROE is similar to my 8.43% ROE using the low DCF methodology. The detailed Risk Premium calculations are provided in **Exhibit BSL-6.**

Summary

Q WHAT DO YOU RECOMMEND?

A As previously explained, the estimated ROE based on my analysis ranges from 8.43% to 11.07%, with an average of 9.69% and a 9.75% midpoint. Based on my analysis, I recommend a 9.7% ROE for SUA. This will lower SUA's requested revenue increase by $11.9 million as can be seen on **Exhibit BSL-7** (based on SUA's proposed 55.59% equity ratio). Determining the appropriate ROE for a utility is not an exact science; one must take into consideration several factors when doing so. My quantitative analysis and review of SUA's financial risk as it relates to the expansion of Rider SSER and implementation of Rider BDA, support my recommended ROE of 9.7%, which is a fair

and reasonable ROE for the utility. My proxy group is comparable to SUA based on appropriate criteria and I use standard, accepted methods to estimate SUA's ROE.

Q WILL YOUR RECOMMENDED RETURN ON EQUITY PROVIDE APPROPRIATE COMPENSATION FOR RISK?

A Yes. My recommended ROE recognizes SUA's risk profile, including its adjustment clauses and reduced regulatory lag, and how those factors contribute to an appropriate ROE.

Q DOES YOUR RECOMMENDED RETURN ON EQUITY APPROPRIATELY BALANCE THE INTERESTS OF SUA WITH THE INTERESTS OF ITS RATEPAYERS?

A Yes. It balances the interests of investors by providing a return that is equivalent to the cost of capital for a comparable utility while providing fair and reasonable rates to its ratepayers.

4. EVALUATION OF MR. D'ASCENDIS' RETURN ON EQUITY ANALYSIS

Q HAVE YOU REVIEWED THE BASIS FOR SUA'S PROPOSED 11% RETURN ON EQUITY?

A Yes. Mr. D'Ascendis' proposed ROE of 11% is excessive because it is based on erroneous assumptions, which I discuss in-depth later. Further, he improperly uses financial risk adjustments to increase his requested ROE.

Q WHAT METHODS DOES MR. D'ASCENDIS USE TO SUPPORT HIS RECOMMENDED 11% RETURN ON EQUITY?

A Mr. D'Ascendis based his recommendation on four methods to determine his recommended ROE of 11%. He used the DCF CAPM, ECAPM, and Risk Premium methods. For each method, he estimates the ROE using his regulated natural gas proxy group sample and a non-price regulated proxy group sample.

Q DID MR. D'ASCENDIS MAKE ANY ADJUSTMENTS TO HIS RETURN ON EQUITY ANALYSIS?

A Yes. He adjusted the results derived under the various methods to include a size risk adjustment, which is discussed more fully below.

Q WHAT IS YOUR ASSESSMENT OF MR. D'ASCENDIS' RETURN ON EQUITY ANALYSIS?

A Mr. D'Ascendis' ROE estimates are too high for numerous reasons. First, the inclusion of the non-price regulated proxy group is not comparable to SUA and overstates the ROE. Second, his CAPM, ECAPM, and Risk Premium analyses use unrealistic assumptions. Third, his business risk adjustment is unnecessary because it compares

the size of SUA to the proxy group holding companies, which is not an apples-to-apples comparison.

Q HOW IS MR. D'ASCENDIS' PROXY GROUP NOT COMPARABLE?

A Mr. D'Ascendis used two separate proxy groups. The first comprises regulated natural gas utilities, as discussed above.

The second proxy group comprises non-price regulated entities that are "similar in total risk" as measured by their betas and the results of a Value Line regression analysis to the regulated utilities in his first proxy group.[12] The non-price regulated entities group includes such companies as Texas Instruments, Inc., Microsoft, and Bristol-Meyers Squib, which are not comparable to a regulated natural gas utility. Furthermore, using a non-price regulated proxy group is not well accepted and produces ROEs that are well above those that were estimated using his regulated natural gas proxy group.

Mr. D'Ascendis' DCF Analysis

Q DO YOU HAVE ANY CONCERNS WITH MR D'ASCENDIS' DISCOUNTED CASH FLOW ANALYSIS?

A No. I found no flaws with Mr. D'Ascendis' application of the DCF analysis.

Flaws With Mr. D'Ascendis' CAPM Analyses

Q WHAT CAPM METHODS DID MR. D'ASCENDIS USE?

A Mr. D'Ascendis' CAPM analysis uses various estimates of the MRP, based on historical and projected data.

[12] Direct Testimony of Dylan W. D'Ascendis at 39.

Mr. D'Ascendis' historical CAPM method uses a risk-free rate of 4.44%, and the average of his historical long-term market risk premiums of (7.03%, 7.96% and 9.38%).[13] His projected CAPM method uses the same risk-free rate and projected long-term market risk premiums of 11.07%, 9.77% and 13.77%.[14] The average beta used in his CAPM analyses (0.79) is from Bloomberg and Value Line.[15] Using this data, he estimates the return on equity for each company in his proxy group.

Q WHAT IS THE ESTIMATED RETURN ON EQUITY USING MR. D'ASCENDIS' CAPM METHODOLOGY?

A Mr. D'Ascendis' estimated ROE is 12.24%.[16]

Q DO YOU HAVE CONCERNS WITH MR. D'ASCENDIS' CAPM ROE ESTIMATE?

A Yes. Two of his projected MRPs are based on the projected growth of stocks in the S&P 500 and one is based on the projected growth of over 2,000 stocks in Value Line. However, his projected MRPs include companies with negative growth and growth above 20%. This results in a distorted MRP. Both of these growth estimates are unsustainable and should be removed. I removed the Value Line MRP, as it is not possible to remove stocks with growth above 20% or with negative growth rates. I corrected the projected MRP based on projected returns for the S&P 500, which reduces the average projected MRP to 5.75% (from 9.83%) and lowers the estimated ROE to 8.98%.

[13] *Id*., Schedule DWD-5 at 2.

[14] *Id.*

[15] *Id*. at 1

[16] *Id*.

Q DO YOU HAVE ANY CONCERNS WITH MR. D'ASCENDIS CAPM ANALYSES USING HISTORICAL MARKET RISK PREMIUMS?

A Yes. Mr. D'Ascendis relied on the actual, historical MRP, as well as the results of a regression analysis of the historical market data and the application of the Predictive Risk Premium Model to the historical data, which is not widely used. Neither of these adjustments to the historical MRP are necessary, and serve to inflate the actual, historical MRP. Therefore, two of Mr. D'Ascendis' historical MRPs should be rejected and only the actual historical MRP should be used. Removing these MRPs reduces the estimated ROE to 9.99% (4.44% + .79 * 7.03%).

Flaws With Mr. D'Ascendis' ECAPM Analyses

Q PLEASE DESCRIBE MR. D'ASCENDIS' ECAPM ANALYSES.

A Mr. D'Ascendis' ECAPM analyses are similar to his CAPM analyses except that he adjusts the formula using a component called alpha (α). The formula for his ECAPM analyses is:

$$K_e = R_f + x*(R_p) + (1-x) * \beta * (R_p)$$

Where:

K_e = the estimated cost of equity

R_f = the risk-free rate

x = adjustment factor

β = beta

R_p = the market risk premium

The value he used for x is 0.25.[17] The ECAPM analyses used the same parameters that were used in his CAPM analyses. His ECAPM analysis produces a 12.75%.[18]

Q WHY DOES THE ECAPM INCLUDE AN ADJUSTMENT FACTOR?

A The adjustment factor is included because over the long term it has been shown that companies with betas lower than one are underestimated; that is, their risk is actually higher than the risk defined by the beta. Companies with betas greater than one are overestimated; that is, their risk is actually lower than the risk shown by beta.

Q WHAT IMPACT DOES THE ADJUSTMENT FACTOR HAVE ON THE ECAPM ANALYSES?

A The adjustment produces an overstated ROE because it readjusts the beta. This readjustment results in higher betas for low-risk securities and lower betas for high-risk securities.

Q IS IT NECESSARY TO READJUST THE BETAS IN AN ECAPM ANALYSIS?

A No. The betas were already adjusted by Value Line to account for the under-estimation (or over-estimation) of the ROE.[19] There is no need to perform an ECAPM analysis as it results in readjusting the formula to capture a phenomenon that the adjusted beta has already corrected.

[17] *Id*. at 34-35.

[18] *Id*., Schedule DWD-5 at 1.

[19] Value Line Investment Services.

Flaws With Mr. D'Ascendis' Risk Premium Analyses

Q HOW ARE MR. D'ASCENDIS' RISK PREMIUM ANALYSES FLAWED?

A Mr. D'Ascendis' Risk Premium analyses estimate the ROE using three estimates of the equity risk premium and a prospective bond yield for A2 rated public utility bonds. The first equity risk premium uses the market-based risk premium used in Mr. D'Ascendis' CAPM analysis, adjusted by beta. The second equity risk premium analysis is based on an implied equity risk premium using historical data. The third equity risk premium is based on the historical relationship between allowed ROEs in natural gas utility rate cases and the yield on Moody's A-rated public utility bonds at the time the ROEs were authorized. Using this data, Mr. D'Ascendis created a regression analysis to estimate the risk premium. Mr. D'Ascendis' regression analysis purports to demonstrate that there is an inverse relationship between equity risk premium and interest rates.

However, his regression analysis does not take into account other factors that could affect the equity risk premium. Other factors could include different Federal monetary and fiscal policies.

Q ARE THE SAME FLAWS EVIDENT IN YOUR APPLICATION OF THE RISK PREMIUM METHOD?

A No. As explained above, I recognize the average historical spread of authorized ROEs over long-term, risk-free rates. The actual risk premium reflects all information that may affect the spread, not just interest rates. Therefore, a historical risk premium based on actual data provides a more accurate estimate and the proper risk premium derived ROE is 8.79%. As demonstrated above, my revised risk premium analysis compares the actual historical risk premium and the projected risk-free rate.

Non-Price Regulated ROE Analyses

Q PLEASE DESCRIBE MR. D'ASCENDIS' NON-PRICE REGULATED RETURN ON EQUITY ANALYSES.

A Mr. D'Ascendis performed the same DCF, CAPM, ECAPM and Risk Premium analyses using a proxy group comprised of non-price regulated companies he deemed to have comparable financial risk to the proxy group of regulated natural gas utilities. His estimated ROE based on these analyses is 12.82%.[20]

Q DO YOU AGREE WITH HIS NON-PRICE REGULATED RETURN ON EQUITY ESTIMATE?

A No. As stated earlier, these companies are not comparable to regulated natural gas utilities. It is not appropriate to compare regulated companies with those that face market-based competition with respect to allowed returns. Furthermore, the methods Mr. D'Ascendis used to estimate the non-price regulated ROE have the same errors as stated previously. Therefore, I recommend that Mr. D'Ascendis' 12.82% ROE be rejected.

Other Flaws With Mr. D'Ascendis' ROE Analysis

Q HOW ELSE IS MR. D'ASCENDIS' RETURN ON EQUITY ANALYSIS FLAWED?

A Mr. D'Ascendis included an additional 10-basis point size adjustment to his estimated ROE to determine his final ROE estimate.[21]

[20] *Id*., Schedule DWD-1 at 2.

[21] *Id*. at 46-47.

Q WHY DOES MR. D'ASCENDIS ASSERT THAT A SIZE ADJUSTMENT IS NEEDED?

A Mr. D'Ascendis asserts that SUA faces additional business risk as compared to the proxy group due to its relative size. Mr. D'Ascendis compared the market capitalization for each company in his proxy group to an estimated market capitalization for SUA. The average market capitalization for the proxy group is $3.6 billion and his estimated market capitalization for SUA is $998 million.[22] Based on the estimated size difference, he determined that a business risk adjustment should be made.

Q IS A SIZE ADJUSTMENT APPROPRIATE AND NECESSARY?

A No. SUA is a subsidiary of Summit Utilities, Inc., which has natural gas and transmission subsidiaries in six states. Mr. D'Ascendis is comparing his estimated market capitalization of SUA to the market capitalization of the companies in his proxy group, most of which are holding companies, similar to the structure of Summit Utilities, Inc. (*i.e*, they also have natural gas distribution operations). This is not an apples-to-apples comparison. For example, the market capitalization of Atmos Energy Corporation is $16 billion. However, Atmos has ten natural gas distribution utilities (among other non-regulated subsidiaries). Mr. D'Ascendis is comparing the solely estimated market capitalization for SUA to the market capitalization of ten natural gas utilities combined.[23] The size adjustment is incorrect and should be rejected.

[22] *Id*.

[23] https://www.atmosenergy.com/utility-operationsrates/utility-operations/

Impact of Correcting SUA's ROE Analysis

Q IF THE VARIOUS FLAWS IN MR. D'ASCENDIS' RETURN ON EQUITY ANALYSES ARE CORRECTED, HOW WOULD THIS AFFECT SUA'S ESTIMATED ROE?

A SUA's ROE is significantly lower after correcting the errors in Mr. D'Ascendis' analyses and removing his business risk adjustment. Based on the results of my corrections to his ROE analysis, and properly weighting his DCF results, it is clear that SUA's cost of equity should be lower. Table 5 provides the results of my revisions to Mr. D'Ascendis' ROE analyses.

BSL Direct Table 5
Revised ROE

Methodology	ROE
DCF Constant Growth	10.61%
CAPM Historical MRP	9.99%
CAPM Projected MRP	8.98%
Risk Premium	8.79%
Average	9.59%

Summary of the Flaws With Mr. D'Ascendis' ROE Analysis

Q PLEASE SUMMARIZE YOUR CRITIQUE OF MR. D'ASCENDIS' ROE ANALYSES.

A Mr. D'Ascendis' recommended ROE of 11% is overstated. His reasoning for adjusting SUA's ROE due to its size is unfounded and should be rejected.

Mr. D'Ascendis' proxy group includes companies that are not comparable in risk to SUA. It is not appropriate to compare regulated companies with those that face market-based competition with respect to allowed return.

Mr. D'Ascendis relies on four methods to estimate an ROE for SUA, three of which have flaws:

1. His CAPM analysis includes incorrect estimates of the MRP, which results in overstating the ROE;
2. ECAPM is not a common method and produces overstated ROEs by adjusting betas that have already been adjusted; and
3. The Risk Premium analysis uses incorrect equity risk premiums, and it also relies on the relationship between interest rates and the risk premium. It does not include other factors that could impact the risk premium, such as Federal monetary and fiscal policies.

For the reasons discussed herein, Mr. D'Ascendis' ROE analyses produce an excessive ROE and should not be relied upon.

5. CAPITAL STRUCTURE

Q WHAT IS SUA'S PROPOSED CAPITAL STRUCTURE?

A SUA is seeking a capital structure composed of 44.41% debt and 55.59% equity.[24]

Q IS SUA'S PROPOSED CAPITAL STRUCTURE REASONABLE?

A No. Its proposed capital structure features a much higher equity component than that which was authorized for its predecessor, CenterPoint, and its claimed bases for so dramatically increasing the equity percentage are unfounded.

Q WHY DOES SUA CLAIM ITS CAPITAL STRUCTURE SHOULD INCLUDE A 55.59% COMMON EQUITY?

A SUA's capital structure witness, Mr. Root, states that SUA is seeking a capital structure similar to Southern Col Holdco LLC's (SCHC) target capital structure, which is SUA's indirect parent company. SCHC's target capital structure is set to maintain an implied credit rating of A3/A- (Moody's/S&P), maintain "appropriate credit metrics to ensure that debt covenants are met" and to "ensure that there is adequate cash generated from the business to service debt and fund ongoing operations."[25]

Q DO YOU ACCEPT THIS CLAIM?

A No. First, neither SUA nor SCHC have a credit rating. Even if SUA or SCHC had a credit rating, a lower credit rating due to a lower common equity ratio would be less costly for ratepayers because debt is cheaper than equity. Furthermore, SUA's predecessor, CenterPoint had a Baa1 rating from Moody's and an A- rating from S&P,

[24] Direct Testimony of Dylan W. D'Ascendis, Exhibit DWD-1 at 1.

[25] Direct Testimony of Craig Root at 7.

yet its common equity ratio approved by the Commission for SUA's Formula Rate Plan case was 48.5%.[26]

Q HOW ELSE IS SUA'S PROPOSED CAPITAL STRUCTURE UNREASONABLE?

A When SUA acquired CenterPoint it decided to remove accumulated deferred income taxes (ADIT) from its capital structure. Because ADIT is a zero-cost capital component, removing it from the capital structure effectively increases SUA's rate of return. In fact, to hold customers harmless from the impact of the elimination of ADIT on the cost of capital, SUA agreed to provide a $29.9 million ratepayer credit.[27]

Q WHY SHOULD THE COMMISSION REJECT SUA'S PROPOSED COMMON EQUITY RATIO?

A SUA's proposed common equity ratio results in higher costs to ratepayers because equity is more expensive than debt. A higher equity ratio, coupled with the elimination of ADIT, significantly increases SUA's rate of return.

Q DO YOU HAVE ANY OTHER REASON WHY THE COMMISSION SHOULD REJECT SUA'S PROPOSED CAPITAL STRUCTURE?

A Yes. SUA provided SCHC's actual capital structure as of December 31, 2023. The capital structure is:

[26] Docket No. 15-098-U, *Order* No. 8 at 12-13 (Sep. 2, 2016).

[27] *In the Matter of the Joint Application of CenterPoint Energy Resources Crop. And Summit Utilities Arkansas, Inc. for All Necessary Authorizations and Approvals for Summit Utilities Arkansas, Inc. to Acquire the Arkansas Assets of CenterPoint Energy Resources Corp. and for Approval of a Certificate of Public Convenience and Necessity for Summit Utilities Arkansas, Inc.*, Docket No. 21-060-U, Joint Motion to Approve Settlement Agreement and to Waive Hearing at 6-7 (Oct. 14, 2021), as approved by *Order* at 21-22 (Dec. 6, 2021).

Table 6 SCHC Capital Structure As of Dec. 31, 2024		
Description	**$**	**%**
Debt	[redacted]	
Equity		
Total		
Source: SUA Confidential Response to AG-01-26U, Consolidated Balance Sheet.		

As shown in Table 6, SCHC's actual capital structure as of December 31, 2024 is only [redacted]% equity, yet SUA is requesting a 55.59% equity ratio, almost 1,300 basis points higher than the actual equity ratio, which SUA claims is its target capital structure. This excessive amount of equity is not only more costly to ratepayers, it is a significant departure from SCHC's actual capital structure.

Q WHAT DO YOU RECOMMEND?

A I recommend the Commission lower SUA's proposed common equity ratio to no higher than 50%. This is above SUA's currently authorized common equity ratio of 48.5% and provides a more balanced capital structure, which would protect customers from excessive rates while allowing SCHC to maintain its "target" credit rating. The effect of the adjustment to the common equity ratio is a decrease in the revenue requirement of $6.8 million (assuming the proposed 11% ROE). The derivation of the $6.8 million is shown in **Exhibit BSL-8**.

6. EXPENSES

Q WHAT IS SUA'S PROPOSED OPERATING AND MAINTENANCE EXPENSE?

A SUA's proposed O&M expense is $92.7 million.[28] It is also seeking recovery of $167,000 for Volunteer Time Off, which I will discuss later.[29]

Q HAS SUA'S OPERATING AND MAINTENANCE EXPENSE INCREASED COMPARED TO CENTERPOINT'S OPERATIONS AND MAINTENANCE EXPENSE?

A Yes. The amount of O&M, as compared to CenterPoint's O&M expense as of September 30, 2021 was $89.5 million, or a $3.2 million increase.[30] However, certain expenses have increased significantly, such as FERC Account 887, Maintenance of Mains, which increased by 15.7%, from $9 million to $10.4 million.[31]

Q IS THE PROPOSED MAINTENANCE OF MAINS COST APPROPRIATE?

A No. SUA has invested significant amounts in rehabilitation, system maintenance, and system improvements (approximately $96 million), which include the TIMP and DIMP programs.[32] Therefore, the maintenance of mains cost should not be increasing, as the mains it has installed require less maintenance than the older mains.

[28] Direct Testimony of Phillip B. am at 11.

[29] SUA Response to APSC-090-1, Attachment APSC-90-1 2023 VTO FERC.

[30] Direct Testimony of Phillip B. Gillam at 11.

[31] SUA Response to AGC-002-002.

[32] Direct Testimony of Vernon McNully at 5.

Q WHAT IS THE HISTORICAL MAINTENANCE OF MAINS EXPENSE AMOUNT?

A As previously stated, in 2022 the Maintenance of Mains expense was $9 million and the proposed amount is $10.4 million — an increase of 15.7%.[33]

Q WHAT IS THE AVERAGE COST PER MILE OF DISTRIBUTION MAIN FOR THE MAINTENANCE OF MAINS COST?

A In 2022, SUA had 13,895 miles of distribution main and $9 million of expense, for an average cost of $645.60 per mile.[34] In the test year, SUA projects 13,909 miles of main and $10.4 million of expense, for an average cost of $745.99 per mile.[35] The average cost per main should not be increasing — newer main is being installed, which requires less maintenance. Therefore, although the mileage of mains is increasing, the maintenance of mains cost should not be increasing, as the mains SUA has installed require less maintenance than the older mains.

Q WHAT DO YOU RECOMMEND?

A I recommend that SUA maintain the average cost of maintenance per mile of installed mains, which is $645.60 per mile. Multiplying the average cost times the projected amount of mains, 13,909 miles, results in approximately $9 million in mains costs ($645.60 * 13,909). Therefore, I recommend that SUA reduce its requested $10.4 million maintenance of mains expense by $1.4 million to $9 million.

[33] SUA Response to AGC-002-002.

[34] *Id.*

[35] *Id.*

Q WHAT IS THE VOLUNTEER TIME OFF EXPENSE?

A As previously noted, SUA is seeking to recover $167,000 related to its Volunteer Time Off (VTO) hours, whereupon SUA compensates employees for volunteering their service to a non-profit organization of their own choosing. The parent company's goal was to achieve 5,500 hours across all operating companies (including SUA), which was exceeded by 3,375 VTO hours, for a total of 8,875 VTO hours. Of this amount SUA employees accounted for 4,366.25 VTO hours.[36]

Q SHOULD SUA COMPENSATE EMPLOYEES FOR THEIR VOLUNTARY HOURS OF SERVICE?

A SUA may compensate its employees for participating in charitable work during company working hours. To be clear, I am not opining on SUA's decision to compensate employees for VTO hours, which are matters within SUA's managerial discretion — I am only testifying that these expenses should be borne by shareholders rather than recovered through base rates. However, this expense should not be borne by ratepayers. The VTO hours are not benefiting customers and are not required for SUA to provide reliable and cost-effective service to ratepayers.

Q WHAT DO YOU RECOMMEND?

A I recommend that SUA may continue to compensate its employees for VTO hours, but should not include that expense in its revenue requirement. Therefore, SUA's revenue requirement should be reduced by $167,000.

[36] SUA Response to APSC-090-1.

7. INCENTIVE COMPENSATION

Q WHAT IS INCENTIVE COMPENSATION?

A. Incentive compensation is the additional payment to employees to reward certain behavior and/or results. The reward is contingent upon achieving pre-established goals and objectives. SUA is seeking $4.7 million in incentive compensation costs.[37] Of this amount, approximately $1.2 million would be capitalized and $3.5 million expensed.

Q WHY IS INCENTIVE COMPENSATION AN ISSUE IN SETTING RATES?

A Not all incentive compensation benefits customers. Incentive compensation based on achieving certain operational goals may be a reasonable expense that may benefit customers. However, incentive compensation targeted to achieve certain financial goals is for the benefit of shareholders and provides little, if any, benefit to customers. Thus, this type of incentive compensation should not be charged to customers. Recovering some incentive compensation from ratepayers may be reasonable; however, the amount SUA is requesting is too high due to inclusion of inappropriate portions of the expense as discussed below.

Q WHY IS THE AMOUNT OF INCENTIVE COMPENSATION PROPOSED FOR RECOVERY THROUGH BASE RATES TOO HIGH?

A The amount is too high because SUA seeks to recover a portion of short-term incentive compensation that is based on meeting financial targets, as well as operational targets.

[37] SUA Response to AG-002-005U.

Q WHAT IS THE STRUCTURE OF SUA'S SHORT-TERM INCENTIVE COMPENSATION PLAN?

A The incentive compensation plan's structure for 2023 is shown in Table 7.

Table 7
Short-Term Incentive Compensation Structure

Description	%
Safety	15%
Corporate Excellence	35%
Peaks Renewables	10%
Financial	40%
Total	100%

As shown above, 40% of SUA's incentive compensation is tied to achieving financial goals, including targeted Earnings Before Income Taxes, Depreciation and Amortization (EBITDA), as well as the dividend yield.[38] The target for EBITDA in 2024 is $152.5 million and the dividend yield target is 2.9%.[39]

Q SHOULD SUA RECOVER INCENTIVE COMPENSATION COSTS THAT ARE BASED ON MEETING FINANCIAL TARGETS?

A No. It is reasonable to allow recovery of expenses associated with the *operational* goals of customer satisfaction, safety, and other operational metrics since cost containment provides a customer benefit and is properly recovered through rates. However, the portion of annual incentive payouts associated with meeting *financial* goals in the test year should be disallowed. Disallowing the financial portion of these

[38] SUA Response to APSC-009U.

[39] *Id*.

expenses properly places the costs of these incentives with the beneficiaries of these programs, namely the shareholders. To be clear, I am not opining on SUA's decision to award incentive compensation based on financial targets or the merit of the applicable employees, which are matters within SUA's managerial discretion — I am only testifying that these expenses should be borne by shareholders rather than recovered through base rates.

Q WHAT DO YOU RECOMMEND REGARDING RECOVERY OF INCENTIVE COMPENSATION EXPENSES?

A I recommend the Commission disallow 100% of the proposed incentive compensation costs tied to meeting financial targets. These costs account for $0.5 million that are capitalized and $1.4 million that are expensed in the proposed test year. Disallowing these expenses properly places the cost of these incentives with the beneficiaries of these programs, namely the shareholders.

8. EXCESS DEFERRED INCOME TAX ASSET

Q PLEASE DESCRIBE SUA'S PROPOSED ADJUSTMENT TO ITS EXCESS DEFERRED INCOME TAX LIABILITY.

A SUA witness, Paul Schulte, describes a Private Letter Ruling (PLR) issued by the IRS to another utility which addresses the cost of removal portion of depreciation expense. In the PLR, the IRS states that the cost of removal portion of depreciation expense creates a deferred tax asset, which is not protected under IRS normalization rules. SUA's previous owner, CenterPoint, included the removal portion of depreciation expense in the calculation of the protected EDIT liabilities, which are currently being amortized and returned to customers. SUA preemptively claims that to avoid normalization violations it will separate the cost of removal portion of book versus tax depreciation from the original EDIT liability and also from the depreciation expense used in the average rate assumption method calculation and include it as part of the unprotected EDIT asset.

Q DO YOU AGREE WITH SUA'S PROPOSED ADJUSTMENT?

A No. First, SUA is proposing this change which does not align with the Commission's Order directing the utility to refund its excess ADIT liability to ratepayers.[40] Second, the PLR cited by SUA pertains to another (unidentified) utility, yet SUA assumes that the PLR is also directed to SUA. Furthermore, the PLR specifically states:

[40] *In the Matter of a Tariff Filing of CenterPoint Energy Arkansas Gas for a Tax Adjustment Rider in Compliance with Order No. 6 in Docket No. 18-006-U*, Docket No. 18-050-TF, Order No. 1 at 1 (Sept. 21, 2018).

> This ruling is directed only to the taxpayer requesting it. Section 6110(k)(3) of the Code provides that it may not be used or cited as precedent.[41]

Q WHAT DO YOU RECOMMEND?

A I recommend that the Commission reject SUA's proposal to modify its EDIT liability, as it does not comply with the Commission's Order regarding the refund (or recovery) of SUA's EDIT liability (or asset), and because the PLR does not apply to SUA.

[41] Direct Testimony of Paul Schulte, Exhibit PS-3 at 10.

9. CONCLUSION

Q WHAT FINDINGS SHOULD THE COMMISSION MAKE BASED ON YOUR DIRECT TESTIMONY?

A Based on the analysis presented in my direct testimony, I recommend the Commission make the following findings:

- SUA's authorized ROE should be no higher than 9.7%.
- SUA's common equity ratio should be no higher than 50%.
- SUA's expenses should be reduced by $1.6 million, to recognize the lower maintenance of mains cost and to remove VTO hours compensation. (add something about the $167K for the Volunteer thing?)
- SUA's incentive compensation should be reduced by $1.9 million.
- Reject SUA's proposed modification to its EDIT liability.

The total value of my proposed adjustments is a reduction of at least $21 million from SUA's claimed revenue requirement.

Q DOES THIS CONCLUDE YOUR DIRECT TESTIMONY?

A Yes.

APPENDIX A
Qualifications of Billie S. LaConte

Q PLEASE STATE YOUR NAME AND BUSINESS ADDRESS.

A Billie S. LaConte. My business mailing address is 14323 S. Outer 40 Rd., Town and Country, Missouri 63017.

Q WHAT IS YOUR OCCUPATION AND BY WHOM ARE YOU EMPLOYED?

A I am an energy advisor and am currently employed by J. Pollock, Incorporated as Associate Consultant.

Q PLEASE STATE YOUR EDUCATIONAL BACKGROUND AND EXPERIENCE.

A I have a Bachelor of Arts Degree in Mathematics from Boston University and a Master's degree in Business Administration from Washington University.

Upon graduation in May 1995, I joined Drazen Consulting Group, Inc. (DCGI). DCGI was incorporated in 1995 assuming the utility rate and economic consulting activities of Drazen Associates, Inc., active since 1937. I joined J.Pollock in May 2015.

During my tenure at DCGI and J.Pollock my work has focused on revenue requirement issues, cost of capital (return on equity and capital structure), cost allocation, rate design, sales and price forecasts, power cost forecasting, electric restructuring issues, integrated resource plans, formula rate plans, asset management agreements and contract interpretation.

I have been engaged in a wide range of consulting assignments including energy and regulatory matters in both the United States and several Canadian provinces. This has included advising clients on economic and strategic issues concerning the natural gas pipeline, oil pipeline, electric, wastewater and water utilities. I have testified on cost of capital issues, including return on equity, cost of

debt, and capital structure, as well as revenue requirement issues. I have prepared cost allocation and rate design studies to provide timely support to clients engaged in settlement negotiations in electric and gas utilities, provided power cost forecasting studies to assist clients in project planning and negotiated contracts with electric utilities for standby services and interruptible rates. I have also prepared studies on electric and gas utilities' performance-based rates (PBR) and benchmarking programs to evaluate their success and to provide recommendations on methods to be used. I worked on contract interpretation to resolve contract disputes for several clients. I have provided financial and cost of service analysis for natural gas pipelines certificate approval from the Federal Energy and Regulatory Commission (FERC) and the Canadian National Energy Board (NEB). Additionally, I completed the Corporate Credit Rating Analysis course presented by Moody's Analytics.

I have worked on various projects located in many states and several Canadian provinces including Alberta, British Columbia, Saskatchewan, Nova Scotia and Quebec. I have testified before the state regulatory commissions of Arkansas, Florida, Georgia, Iowa, Louisiana, Michigan, Minnesota, Missouri, New Mexico, North Carolina, Pennsylvania, Texas and South Carolina, and the provincial regulatory boards of Alberta and Nova Scotia. I similarly have appeared before the St. Louis Metropolitan Sewer District Commission and the City of Philadelphia Water, Sewer and Storm Water Rate Board.

Q PLEASE DESCRIBE J. POLLOCK, INCORPORATED.

A J. Pollock assists clients to procure and manage energy in both regulated and competitive markets. The J. Pollock team also advises clients on energy and regulatory issues. Our clients include commercial, industrial and institutional energy consumers. J. Pollock is a registered Class I aggregator in the State of Texas.

APPENDIX B
Testimony Filed in Regulatory Proceedings
by Billie S. LaConte

UTILITY	ON BEHALF OF	DOCKET	TYPE	REGULATORY JURISDICTION	SUBJECT	DATE
DOMINION ENERGY SOUTH CAROLINA, INC.	South Carolina Utility Energy Users Committee	2024-34-E	Surrebuttal	SC	Return on Equity; Capital Structure	7/3/2024
MICHIGAN GAS UTILITIES CORPORATION	Association of Businesses Advocating Tariff Equity	U-21540	Direct	MI	Operation and Maintenance Expense	7/1/2024
PECO ENERGY COMPANY - ELECTRIC DIVISION	Philadelphia Area Industrial Energy Users Group	R-2024-3046931	Direct	PA	Class Cost-of-Service Study; Class Revenue Allocation	6/17/2024
PECO ENERGY COMPANY - GAS DIVISION	Philadelphia Area Industrial Energy Users Group	R-2024-3046932	Direct	PA	Class Cost-of-Service Study; Class Revenue Allocation; Volumetric Rate Differential	6/17/2024
DOMINION ENERGY SOUTH CAROLINA, INC.	South Carolina Utility Energy Users Committee	2024-34-E	Direct	SC	Return on Equity; Capital Structure	6/5/2024
CONSUMERS ENERGY COMPANY	Association of Businesses Advocating Tariff Equity	U-21490	Direct	MI	Proposed Trackers; Return on Equity; Capital Structure; Home Products Program Sale	4/22/2024
MINNESOTA POWER	Large Power Intervenors	E-015/GR-23-155	Direct	MN	Return on Equity; Capital Structure; Adjustment Clauses; Incentive Compensation; Prepaid Pension Asset	3/18/2024
PENNSYLVANIA-AMERICAN WATER COMPANY	Pennsylvania-American Large Water Users Group	R-2023-3043189 R-2023-3043190	Surrebuttal	PA	Class Cost-of-Service Study; Allocation of Subsidy; Environmental Compliance Investment Charge; Revenue Decoupling and Return on Equity; Industrial Rate Design; Deferral Mechanism; Arrearage Management Plan Cost Allocation	3/4/2024
PENNSYLVANIA-AMERICAN WATER COMPANY	Pennsylvania-American Large Water Users Group	R-2023-3043189 R-2023-3043190	Rebuttal	PA	Cost-of-Service Study; Revenue Allocation; Rate Design; Riders DIS and DRS; Revenue Decoupling Mechanism	2/21/2024
PENNSYLVANIA-AMERICAN WATER COMPANY	Pennsylvania-American Large Water Users Group	R-2023-3043189 R-2023-3043190	Direct	PA	Return on Equity; Incentive Compensation; Alternative Ratemaking Mechanisms; Class Cost-of-Service Study; Wastewater Subsidy and Allocation; Rate Design; Reveue Requirement Scale-Back	2/1/2024
ENTERGY ARKANSAS, LLC	Arkansas Electric Energy Consumers, Inc.	16-036-FR	Settlement Support	AR	Support of Settlement	10/31/2023
ENTERGY ARKANSAS, LLC	Arkansas Electric Energy Consumers, Inc.	16-036-FR	Direct	AR	Projected Year FLIP Investment; Solar Plant Capital Additions; Power Through Program; Legal Fees	10/4/2023
DUKE ENERGY CAROLINAS, LLC	Carolina Utility Customers Assocation, Inc.	E-7, Sub 1276	Direct	NC	Return on Equity; Capital Structure; Performance Incentive Mechanisms	7/19/2023
PHILADELPHIA GAS WORKS	Philadelphia Industrial and Commercial Gas Users Group PICGUG	2023-3037933	Surrebuttal	PA	Class Cost-of-Service Study; Class Revenue Allocation; Universal Service Plan Costs	7/7/2023
PHILADELPHIA GAS WORKS	Philadelphia Industrial and Commercial Gas Users Group PICGUG	2023-3037933	Rebuttal	PA	Class Cost-of-Service Study; Class Revenue Allocation; Universal Service Plan Costs	6/26/2023
PHILADELPHIA GAS WORKS	Philadelphia Industrial and Commercial Gas Users Group PICGUG	2023-3037933	Direct	PA	Class Cost-of-Service Study; Class Revenue Allocation	6/2/2023
SOUTHWESTERN PUBLIC SERVICE COMPANY	Texas Industrial Energy Consumers	22-00286-UT	Settlement Support	NM	Support of Settlement	5/26/2023
PHILADELPHIA WATER DEPARTMENT	Philadelphia Large Users Group	2023 General Rate Proceeding	Rebuttal	Philadelphia Rate Board	Class Cost-of-Service Study; Stormwater Incentive Program; Late Payment Fee Allocation; TAP Enrollment; Retroactive Arrearage Forgiveness	4/27/2023

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UTILITY	ON BEHALF OF	DOCKET	TYPE	REGULATORY JURISDICTION	SUBJECT	DATE
SOUTHWESTERN PUBLIC SERVICE COMPANY	Texas Industrial Energy Consumers	22-00286-UT	Direct	NM	Future Test Year; Revenue Requirement Issues	4/21/2023
CONSUMERS ENERGY COMPANY	Association of Businesses Advocating Tariff Equity	U-21308	Direct	MI	Projected Test-Year Adjustments; Proposed Trackers; Return on Equity; Capital Structure	4/17/2023
PHILADELPHIA WATER DEPARTMENT	Philadelphia Large Users Group	2023 General Rate Proceeding	Direct	Philadelphia Rate Board	Class Cost-of-Service Study	4/12/2023
DUKE ENERGY PROGRESS, LLC	Nucor Steel - South Carolina	2022-254-E	Surrebuttal	SC	Regulatory Asset Amortization Periods	12/22/2022
NORTHERN STATES POWER	Xcel Large Industrials	E002/GR-21-630	Surrebuttal	MN	Return on Equity; Prepaid Pension Asset; Incentive Compensation; Coal Plant Amortization	12/6/2022
DUKE ENERGY PROGRESS, LLC	Nucor Steel - South Carolina	2022-254-E	Direct	SC	Coal Combustion Residual Amortization; Other Regulatory Asset Amortization	12/1/2022
NORTHERN STATES POWER	Xcel Large Industrials	E002/GR-21-630	Rebuttal	MN	Incentive Compensation; Prepaid Pension Asset	11/8/2022
ENTERGY ARKANSAS, LLC	Arkansas Electric Energy Consumers, Inc.	16-036-FR	Settlement Support	AR	Support of Settlement	11/2/2022
GEORGIA POWER COMPANY	Georgia Association of Manufacturers	44280	Direct	GA	Return on Equity; Capital Structure	10/20/2022
ENTERGY ARKANSAS, LLC	Arkansas Electric Energy Consumers, Inc.	16-036-FR	Direct	AR	Projected Year Feeder Level Investment Plan; Power Through Program	10/5/2022
NORTHERN STATES POWER	Xcel Large Industrials	E002/GR-21-630	Direct	MN	Return on Equity; Incentive Compensation; Pre-Paid Pension Asset	10/3/2022
PENNSYLVANIA-AMERICAN WATER COMPANY	Pennsylvania-American Large Water Users Group	R-2022-3031672/73	Rejoinder	PA	Class Cost-of-Service Study	9/6/2022
PENNSYLVANIA-AMERICAN WATER COMPANY	Pennsylvania-American Large Water Users Group	R-2022-3031672/73	Surrebuttal	PA	Wastewater Subsidy Allocation; Revenue Stabilization Mechanism; Customer Reclassification	9/1/2022
ONCOR ELECTRIC DELIVERY COMPANY LLC	Texas Industrial Energy Consumers	53601	Direct	TX	Self-Insurance Reserve; Annual Storm Expense; Regulatory Asset Amortization	8/26/2022
PENNSYLVANIA-AMERICAN WATER COMPANY	Pennsylvania-American Large Water Users Group	R-2022-3031672/73	Rebuttal	PA	Revenue Requirement Allocation; Class Cost-of-Service Study	8/19/2022
PECO ENERGY COMPANY	Philadelphia Area Industrial Energy Users Group	R-2022-3031113	Surrebuttal	PA	Design Day Demand; Rate Differentials	8/4/2022
PENNSYLVANIA-AMERICAN WATER COMPANY	Pennsylvania-American Large Water Users Group	R-2022-3031672/73	Direct	PA	Wasterwater Subsidy and Allocation; Revenue Stabilization Mechanism; Customer Classification; Revenue Requirement Scale Back	7/29/2022
PECO ENERGY COMPANY	Philadelphia Area Industrial Energy Users Group	R-2022-3031113	Rebuttal	PA	Class Cost-of-Service Study; Scale Back of Rates; Design Day Demand; Rate Differentials; Universal Service Programs	7/21/2022
PECO ENERGY COMPANY	Philadelphia Area Industrial Energy Users Group	R-2022-3031113	Direct	PA	Class Cost-of-Service Study; Class Revenue Allocation	6/22/2022
AUSTIN ENERGY	Texas Industrial Energy Consumers	None	Direct	TX	Cash Flow Method; Financial Metrics; General Fund Transfer; Internally Generated Funds	6/22/2022
CONSUMERS ENERGY COMPANY	Association of Businesses Advocating Tariff Equity	U-21148	Rebuttal	MI	Uncollectible Expense; Rate Stability Target	4/29/2022

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UTILITY	ON BEHALF OF	DOCKET	TYPE	REGULATORY JURISDICTION	SUBJECT	DATE
CONSUMERS ENERGY COMPANY	Association of Businesses Advocating Tariff Equity	U-21148	Direct	MI	Return on Equity, Capital Structure; Renewable Natural Gas Plant; Incentive Compensation; Transportation Demand Charge; Gas Curtailment and Requirements for Plant Protection; Unauthorized Gas Usage Charge	4/8/2022
SEMCO ENERGY GAS COMPANY	Association of Businesses Advocating Tariff Equity	U-21169	Direct	MI	Facilities Improvement Demand Surcharge	3/18/2022
ENTERGY ARKANSAS, LLC	Arkansas Electric Energy Consumers, Inc.	16-036-FR	Settlement Support	AR	Support of Settlement	10/27/2021
EL PASO ELECTRIC COMPANY	Freeport-McMoRan Copper & Gold, Inc.	52195	Direct	TX	Return on Equity; Nuclear Non-Fuel Operation and Maintenance; Rate Case Expense; Retiring Generating Units	10/22/2021
ENTERGY ARKANSAS, LLC	Arkansas Electric Energy Consumers, Inc.	16-036-FR	Direct	AR	Projected Year Capital Additions; Projected Year O&M expense	10/5/2021
PECO ENERGY COMPANY	Philadelphia Area Industrial Energy Users Group	R-2021-3024601	Surrebuttal	PA	Return on Equity; Post-Test Year Adjustment	8/5/2021
CENTERPOINT ENERGY ARKANSAS GAS	Arkansas Gas Consumers, Inc.	21-044-U	Direct	AR	Formula Rate Plan Extension; Return on Equity; Class Cost-of-Service Study	7/19/2021
PECO ENERGY COMPANY	Philadelphia Area Industrial Energy Users Group	R-2021-3024601	Direct	PA	Return on Equity; Post-Test Year Adjustment	6/28/2021
FLORIDA LIGHT & POWER COMPANY	Florida Inudstrial Power Users Group	20210015-EI	Direct	FL	Cost of Capital; Early Plant Retirement; Rate Case Expense Amortization; Income Tax Change Mechanism	6/21/2021
DTE GAS COMPANY	Association of Businesses Advocating Tariff Equity	U-20940	Direct	MI	Return on Equity; Operation and Maintenance Expenses; Incentive Compensation	6/3/2021
SOUTHWESTERN PUBLIC SERVICE COMPANY	Occidental Permian Ltd.	20-00238-UT	Direct	NM	Rate Design, Retired Plant, Expense Amortization	5/17/2021
PHILADELPHIA WATER DEPARTMENT	Philadelphia Large Users Group	Fiscal Years 2022-2023	Rebuttal	Philadelphia Rate Board	Class Cost-of-Service Study; Stormwater Incentive Program	4/7/2021
SOUTHWESTERN ELECTRIC POWER COMPANY	Texas Industrial Energy Consumers	51415	Direct	TX	Early Plant Retirement; Excess Accumulated Deferred Federal Income Taxes; Self-Insurance Reserve; Imputed Capacity	3/31/2021
SHARYLAND UTILITIES, L.L.C.	Texas Industrial Energy Consumers	51611	Direct	TX	Rate-Case Expenses; Operation and Maintenance Expense; Transmission Cost of Service Refund Rider	3/8/2021
PECO ENERGY COMPANY	Philadelphia Area Industrial Energy Users Group	2020-3018929	Surrebuttal	PA	Revenue Allocation; Rate Design	2/9/2021
PECO ENERGY COMPANY	Philadelphia Area Industrial Energy Users Group	2020-3018929	Rebuttal	PA	Allocation of Distribution Mains; Revenue Allocation; Rate Design; Universal Service Fund Charge	1/19/2021
PECO ENERGY COMPANY	Philadelphia Area Industrial Energy Users Group	2020-3018929	Direct	PA	Class Cost-of-Service Study; Class Revenue Allocation	12/22/2020
ENTERGY ARKANSAS, LLC	Arkansas Electric Energy Consumers, Inc.	16-036-FR	Surrebuttal (FRP Extension)	AR	FRP Extension; Return on Equity; Capital Structure; Class Cost-of-Service Study; Industrial Rate Design	11/17/2020
PENNSYLVANIA-AMERICAN WATER COMPANY	Pennsylvania-American Large Water Users Group	2020-3019369 2020-3019371	Surrebuttal	PA	Rate Design; Regionalization and Consolidation Surcharge; Return on Equity	10/20/2020
ENTERGY ARKANSAS, LLC	Arkansas Electric Energy Consumers, Inc.	16-036-FR	Direct (FRP Extension)	AR	FRP Extension; Return on Equity; Capital Structure; Class Cost-of-Service Study; Industrial Rate Design	10/19/2020

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UTILITY	ON BEHALF OF	DOCKET	TYPE	REGULATORY JURISDICTION	SUBJECT	DATE
ENTERGY ARKANSAS, LLC	Arkansas Electric Energy Consumers, Inc.	16-036-FR	Direct (2020 Eval. Report)	AR	Historical Year Netting Adjustment; :Long-Term Debt Costs	10/5/2020
PENNSYLVANIA-AMERICAN WATER COMPANY	Pennsylvania-American Large Water Users Group	2020-3019369 2020-3019371	Rebuttal	PA	Rate Design	9/29/2020
PENNSYLVANIA-AMERICAN WATER COMPANY	Pennsylvania-American Large Water Users Group	2020-3019369 2020-3019371	Direct	PA	Regionalization and Consolidation Surcharges; Commercial Rate Design	9/8/2020
CONSUMERS ENERGY COMPANY	Association of Businesses Advocating Tariff Equity	U-20697	Rebuttal	MI	Financial Compensation Mechanism; Deferred Capital Spending Recovery Mechanism; Karn 1 & 2 Retention and Separation costs, return on equity, storm restoration deferral; PowerMIFleet Pilot Foundational Infrastructure Program; Conservation Voltage Reduction	7/14/2020
CENTERPOINT ENERGY RESOURCES CORP	Arkansas Gas Consumers, Inc.	17-010-FR	Direct	AR	Projected Year Capital Expenditures; Capitalization Policy; Projected Year Adjustments	7/2/2020
CONSUMERS ENERGY COMPANY	Association of Businesses Advocating Tariff Equity	U-20697	Direct	MI	Return on Equity; Capital Structure; Debt Cost; Additional Surcharges and Deferred Regulatory Accounts	6/24/2020
CONSUMERS ENERGY COMPANY	Association of Businesses Advocating Tariff Equity	U-20650	Rebuttal	MI	Return on Equity; Statistical Analysis of Distribution Mains Allocation	5/5/2020
CONSUMERS ENERGY COMPANY	Association of Businesses Advocating Tariff Equity	U-20650	Direct	MI	Return on Equity; Capital Structure; Long-Term Debt Cost	4/14/2020
DTE GAS COMPANY	Association of Businesses Advocating Tariff Equity	U-20642	Rebuttal	MI	Return on Equity	4/14/2020
DTE GAS COMPANY	Association of Businesses Advocating Tariff Equity	U-20642	Direct	MI	Return on Equity; Operation and Maintenance Expenses	3/24/2020
CONSUMERS ENERGY COMPANY	Association of Businesses Advocating Tariff Equity	U-20618	Direct	MI	Certificate of Convenience and Necessity	1/17/2020
ENTERGY ARKANSAS, LLC	Arkansas Electric Energy Consumers, Inc.	16-036-FR	Settlement Support	AR	Support of Settlement	10/30/2019
GEORGIA POWER COMPANY	Georgia Association of Manufacturers and Georgia Industrial Group	42516	Direct	GA	Alternate Rate Plan; Coal Combustion Residual Cost Recovery; Amortization of Retired Plant	10/17/2019
ENTERGY ARKANSAS, LLC	Arkansas Electric Energy Consumers, Inc.	16-036-FR	Direct	AR	Tax Cuts and Jobs Act Impact; Projected Year Revenues; Projected Year BRORB; Grid Modernization; Advanced Metering Infrastructure Expense	10/4/2019
SOUTHWESTERN ELECTRIC POWER COMPANY	Western Arkansas Large Energy Consumers	19-008-U	Surrebuttal	AR	SWEPCO's Formula Rate Review; Energy Cost Recovery Rider; Distribution Reliability Rider	9/24/2019
CENTERPOINT ENERGY RESOURCES CORP	Arkansas Gas Consumers, Inc.	17-010-FR	Settlement Support	AR	Support of Settlement	7/31/2019
SOUTHWESTERN ELECTRIC POWER COMPANY	Western Arkansas Large Energy Consumers	19-008-U	Direct	AR	SWEPCO's Formula Rate Review; Capital Structure; Distribution Reliability Rider; Arkansas Formula Rate Plans	7/16/2019
CENTERPOINT ENERGY RESOURCES CORP	Arkansas Gas Consumers, Inc.	17-010-FR	Direct	AR	Formula Rate Plan, Capital Additions, Operation and Maintenance Expenses	7/2/2019
ENTERGY LOUISIANA, LLC	Occidential Chemical Corporation	U-35130	Cross-Answering	LA	Fuel Tracking Mechanism	7/1/2019
CENTERPOINT ENERGY HOUSTON ELECTRIC, LLC	Texas Industrial Energy Consumers	49421	Direct	TX	Unprotected Excess Deferred Income Tax Rider; Incentive Compensation	6/6/2019

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UTILITY	ON BEHALF OF	DOCKET	TYPE	REGULATORY JURISDICTION	SUBJECT	DATE
ENTERGY LOUISIANA, LLC	Occidential Chemical Corporation	U-35130	Direct	LA	Fuel Tracking Mechanism	5/10/2019
CONSUMERS ENERGY COMPANY	Association of Businesses Advocating Tariff Equity	U-20322	Rebuttal	MI	Return on Equity	4/29/2019
CENTERPOINT ENERGY RESOURCES CORP	Arkansas Gas Consumers, Inc.	18-057	Supplemental Surrebuttal	AR	Gas Distribution Uprstream Services Contracting Process	4/23/2019
CENTERPOINT ENERGY RESOURCES CORP	Arkansas Gas Consumers, Inc.	18-057	Surrebuttal	AR	Gas Distribution Uprstream Services Contracting Process	4/12/2019
CONSUMERS ENERGY COMPANY	Association of Businesses Advocating Tariff Equity	U-20322	Direct	MI	Return on Equity; Capital Structure; Project vs. Historical Test Year; Earnings Sharing Mechanism	4/5/2019
DUKE ENERGY PROGRESS, LLC	Nucor Steel - South Carolina	2018-318-E	Direct	SC	Excess Deferred Income Tax Rider; Post-Test Year Adjustments; Coal Ash Pond Closure Expense; End-of-Life Nuclear Costs; Regulatory Assets; Return on Equity and Equity Ratio	3/4/2019
CENTERPOINT ENERGY RESOURCES CORP	Arkansas Gas Consumers, Inc.	18-057	Direct	AR	Gas Distribution Uprstream Services Contracting Process	2/12/2019
ENTERGY ARKANSAS, INC.	Arkansas Electric Energy Consumers, Inc.	16-036-FR	Settlement Support	AR	Support of Settlement	10/30/2018
ENTERGY ARKANSAS, INC.	Arkansas Electric Energy Consumers, Inc.	16-036-FR	Direct	AR	Formula Rate Plan Tariff; Long-Term Debt Cost and Preferred Equity; Projeced Year Capital Additions; Historical Year Capital Additions	10/4/2018
CONSUMERS ENERGY COMPANY	Association of Businesses Advocating Tariff Equity	U-20134	Rebuttal	MI	Return on Equity	10/1/2018
CONSUMERS ENERGY COMPANY	Association of Businesses Advocating Tariff Equity	U-20134	Direct	MI	Return on Equity, Capital Structure and Long-Term Debt Cost, Investment Recovery Mechanism Excess Sharing Mechanism	9/10/2018
CENTERPOINT ENERGY RESOURCES CORP	Arkansas Gas Consumers, Inc.	17-010-FR	Opposition	AR	Opposition to Settlement Agreement	8/3/2018
CENTERPOINT ENERGY RESOURCES CORP	Arkansas Gas Consumers, Inc.	17-010-FR	Direct	AR	Impact of Tax Cuts and Jobs Act of 2017; Forecast Revenues; Uncollectible Expense; Pipeline Integrity Assessment and Remediation Expense	7/2/2018
ENTERGY ARKANSAS, INC.	Arkansas Electric Energy Consumers, Inc.	17-052	Surrebuttal	AR	Utility Restructuring Costs and Tax Effects	5/31/2018
PUBLIC SERVICE COMPANY OF NEW MEXICO	City of Farmington, New Mexico; Board of County Commissioners for San Juan County	17-00174	Direct	NM	Integrated Resource Plan; Future of San Juan Generation Station	5/4/2018
ENTERGY ARKANSAS, INC. and CENTERPOINT ENERGY ARKANSAS GAS	Arkansas Electric Energy Consumers, Inc. and Arkansas Gas Consumers, Inc.	18-006	Direct	AR	Effect on Revenue Requirement due to 2017 Tax Cuts and Jobs Act	3/29/2018
CONSUMERS ENERGY COMPANY	Association of Businesses Advocating Tariff Equity	U18424	Rebuttal	MI	Rate of Return	3/21/2018
ENTERGY ARKANSAS, INC.	Arkansas Electric Energy Consumers, Inc.	18-014-TF	Direct	AR	Impact of Tax Cuts and Jobs Act of 2017 and Tax Adjustment Rider	3/19/2018
CONSUMERS ENERGY COMPANY	Association of Businesses Advocating Tariff Equity	U-18424	Direct	MI	Rate of Return, Capital Structure	2/28/2018
CENTERPOINT ENERGY ARKANSAS GAS	Arkansas Gas Consumers, Inc.	17-050-U	Surrebuttal	AR	Asset Management Agreement Proposal	1/12/2018

APPENDIX B
Testimony Filed in Regulatory Proceedings
by Billie S. LaConte

UTILITY	ON BEHALF OF	DOCKET	TYPE	REGULATORY JURISDICTION	SUBJECT	DATE
CENTERPOINT ENERGY ARKANSAS GAS	Arkansas Gas Consumers, Inc.	17-050-U	Direct	AR	Asset Management Agreement Proposal	12/8/2017
ENTERGY ARKANSAS, INC.	Arkansas Electric Energy Consumers, Inc.	16-036-FR	Settlement Support	AR	Support of Settlement	10/31/2017
ENTERGY ARKANSAS, INC.	Arkansas Electric Energy Consumers, Inc.	16-036-FR	Direct	AR	Forecast Revenues, Cost of Debt, Revenue Requirement and Capital Additions	10/4/2017
CONSUMERS ENERGY COMPANY	Association of Businesses Advocating Tariff Equity	U-18322	Rebuttal	MI	Return on Equity	9/7/2017
CONSUMERS ENERGY COMPANY	Association of Businesses Advocating Tariff Equity	U-18322	Direct	MI	Return on Equity, Capital Structure	8/10/2017
CENTERPOINT ENERGY RESOURCES CORP	Arkansas Gas Consumers, Inc.	17-010-FR	Settlement Support	AR	Support of Settlement	7/31/2017
CENTERPOINT ENERGY RESOURCES CORP	Arkansas Gas Consumers, Inc.	17-010-FR	Direct	AR	Rate of Return, Capital Structure, Labor Expense	7/3/2017
ENTERGY ARKANSAS, INC.	Arkansas Electric Energy Consumers, Inc.	16-036-FR	Settlement Support	AR	Support of Settlement	10/24/2016
ENTERGY ARKANSAS, INC.	Arkansas Electric Energy Consumers, Inc.	16-036-FR	Direct	AR	Rate of Return, Forecast Revenue, Capitalization	9/30/2016
METROPOLITAN EDISON COMPANY; PENNSYLVANIA ELECTRIC COMPANY AND WEST PENN POWER	MEIUG, PICA and WPPII	2016-2537349, 2016-2537352, 2016-2537359	Surrebuttal	PA	Return on Equity	8/31/2016
METROPOLITAN EDISON COMPANY; PENNSYLVANIA ELECTRIC COMPANY AND WEST PENN POWER	MEIUG, PICA and WPPII	2016-2537349, 2016-2537352, 2016-2537359	Direct	PA	Return on Equity	7/22/2016
NORTHERN STATES POWER	Xcel Large Industrials	15-826	Direct	MN	Return on Equity, Multi-Year Rate Plan	6/14/2016
CENTERPOINT ENERGY RESOURCES CORP	Arkansas Electric Energy Consumers, Inc.	15-098-U	Surrebuttal	AR	Return on Equity, Formula Rate Plan, Capital Structure	6/7/2016
CENTERPOINT ENERGY RESOURCES CORP	Arkansas Electric Energy Consumers, Inc.	15-098-U	Direct	AR	Return on Equity, Captial Structure	4/14/2016
MISSOURI-AMERICAN WATER COMPANY	BJC Healthcare	WR-2011-0337	Rebuttal	MO	Return on Equity	1/19/2012
MISSOURI-AMERICAN WATER COMPANY	BJC Healthcare	WR-2011-0337	Direct	MO	Return on Equity	11/17/2011
METROPOLITAN ST. LOUIS SEWER DISTRICT	Barnes-Jewish Hospital	N/A	Supplemental	MO	Rate Model	9/16/2011
METROPOLITAN ST. LOUIS SEWER DISTRICT	Barnes-Jewish Hospital	N/A	Surrebuttal	MO	Rate Increase, CIRP, Consent Decree	8/19/2011
METROPOLITAN ST. LOUIS SEWER DISTRICT	Barnes-Jewish Hospital	N/A	Rebuttal	MO	Rate Increase, CIRP, Consent Decree	7/18/2011
AMEREN UE	Missouri Energy Group	ER-2011-0028	Surrebuttal	MO	Return on Equity, Energy Efficiency Cost Recovery	4/15/2011
AMEREN UE	Missouri Energy Group	ER-2011-0028	Rebuttal	MO	Return on Equity, Energy Efficiency Cost Recovery	3/25/2011
AMEREN UE	Missouri Energy Group	ER-2011-0028	Direct	MO	Return on Equity	2/8/2011
AMEREN UE	Missouri Energy Group	EO-2010-0255	Direct	MO	Prudence Audit of FAC Periods 1 and 2	11/22/2010

APPENDIX B
Testimony Filed in Regulatory Proceedings
by Billie S. LaConte

UTILITY	ON BEHALF OF	DOCKET	TYPE	REGULATORY JURISDICTION	SUBJECT	DATE
ENTERGY ARKANSAS, INC.	Arkansas Electric Energy Consumers, Inc.	09-084-U	Direct - In Support	AR	Supporting the Proposed Settlement Agreement	5/11/2010
ENTERGY ARKANSAS, INC.	Arkansas Electric Energy Consumers, Inc.	09-084-U	Surrebuttal	AR	Return on Equity	4/14/2010
ENTERGY ARKANSAS, INC.	Arkansas Electric Energy Consumers, Inc.	09-084-U	Direct	AR	Return on Equity	2/26/2010
AMEREN UE	Missouri Energy Group	ER-2010-0036	Direct	MO	Energy Efficiency Costs	12/18/2009
AMEREN UE	Missouri Energy Group	ER-2008-0318	Surrebuttal	MO	Return on Equity	11/5/2008
AMEREN UE	Missouri Energy Group	ER-2008-0318	Direct	MO	Return on Equity, Off-System Sales	8/28/2008
METROPOLITAN ST. LOUIS SEWER DISTRICT	Missouri Energy Group	N/A	Rebuttal	MO	Long-Term Financial Plan, Capital Financing	5/2/2007
AMEREN UE	Missouri Energy Group	ER-2007-0002	Surrebuttal	MO	Return on Equity, Interruptible Demand, Response Pilot	2/27/2007
AMEREN UE	Missouri Energy Group	ER-2007-0002	Direct	MO	Interruptible Rate	12/29/2006
AMEREN UE	Missouri Energy Group	ER-2007-0002	Direct	MO	Return on Equity, Off-System Sales, Sharing Mechanism, 10% Cap on Residentials	12/15/2006
AMEREN UE	Missouri Energy Group	EA-2005-0180	Rebuttal	MO	Economic Analysis	1/31/2005
NOVA SCOTIA POWER INC.	Avon Valley Greenhouses	NSUARB-P-881	Direct	NS	Cost of Capital	10/12/2004
MISSOURI-AMERICAN WATER COMPANY	Missouri Energy Group	WR-2003-0500	Surrebuttal	MO	Working Capital, Return on Equity, Cost Allocation	12/5/2003
MISSOURI-AMERICAN WATER COMPANY	Missouri Energy Group	WR-2003-0500	Rebuttal	MO	Rate Design	11/10/2003
MISSOURI-AMERICAN WATER COMPANY	Missouri Energy Group	WR-2003-0500	Direct	MO	Return on Equity, Acquisition Adjustment, Cash Working Capital	10/3/2003
METROPOLITAN ST. LOUIS SEWER DISTRICT	Missouri Energy Group	N/A	Direct	MO	Revenue Requirement, Financial Planning	4/22/2003
INTERSTATE POWER AND LIGHT COMPANY	Lee County Energy Users Group- Direct	RPU-02-3	Surrebuttal	IA	Revenue Requirement, Return on Equity	9/19/2002
METROPOLITAN ST. LOUIS SEWER DISTRICT	Missouri Energy Group	N/A	Surrebuttal	MO	Revenue Requirement, Capital Financing	8/13/2002
METROPOLITAN ST. LOUIS SEWER DISTRICT	Missouri Energy Group	N/A	Surrebuttal	MO	Revenue Requirement, Captial Financiaing, Cost Allocation	7/28/2002
INTERSTATE POWER AND LIGHT COMPANY	Lee County Energy Users Group- Direct	RPU-02-3	Direct	IA	Revenue Requirement, Return on Equity	7/26/2002
METROPOLITAN ST. LOUIS SEWER DISTRICT	Missouri Energy Group	N/A	Rebuttal	MO	Revenue Requirement, Capital Financing	7/10/2002

APPENDIX C

Discovery Responses Relied Upon in Direct Testimony

Excerpt From Discovery Response	Footnote/Table	Testimony Pg. No.
SUA Response to AGC-004-001	Footnote 8	9
SUA Response to AG-01-26U (Confidential)	Table 6	35
SUA Response to APSC-090-1	Footnote 29 Footnote 36	35 37
SUA Response to AGC-002-002	Footnote 31 Footnotes 33, 34, 35	35 36
SUA Response to AG-002-005U	Footnote 37	38
SUA Response to APSC-009U	Footnotes 38, 39	39

APSC FILED Time: 7/10/2024 9:56:01 AM: Recvd 7/10/2024 9:55:35 AM: Docket 23-079-U-Doc. 88

ARKANSAS PUBLIC SERVICE COMMISSION
APSC 23-079-U
2023 SUA RATE CASE

REQUEST NO.: AGC-004-001

COMPANY NAME: SUMMIT UTILITIES ARKANSAS

DATE RECEIVED: 6/19/2024

DATE DUE: 7/3/2024

EXTENSION DATE:

INFORMATION REQUESTED:
Regarding SUA's request to expand the SSER, Mr. McNully states on page 29 of his direct testimony that SUA currently recovers 29% of its capital expenditures through the SSER. If SUA receives approval to expand the SSER, identify the total amount of capital expenditures (as a percentage of SUA's total capital expenditures during the test year) that would be recovered through the rider.

REQUESTED BY: ARKANSAS GAS CONSUMERS

RESPONSE:
Roughly 69% of SUA's total capital expenditures for 2023 could have potentially been eligible for inclusion in the SSER recovery mechanism under the proposed SSER expansion.

SPONSOR:
Phillip Gillam, Jennifer Lilly, Tommy Williams

RESPONSIVE DOCUMENTS:
None

The foregoing response to the above information request is accurate and complete, and contains no material misrepresentations or omissions based upon present facts known to the undersigned. The undersigned agrees to immediately inform the Requestor if any matters are discovered which would materially affect the accuracy or completeness of the information provided in response to the above information request.

/s/ Brooke South Parsons
Signature of Company Representative

DATE PROVIDED: JULY 03, 2024

CONFIDENTIAL, SUBJECT TO PROTECTIVE ORDER NO. 1 ISSUED IN APSC DOCKET NO. 23-079-U

APSC FILED Time: 7/10/2024 9:56:01 AM: Recvd 7/10/2024 9:55:35 AM: Docket 23-079-U-Doc. 96

ARKANSAS PUBLIC SERVICE COMMISSION
APSC 23-079-U
2023 SUA RATE CASE

REQUEST NO.: AG-001-026U

COMPANY NAME: SUMMIT UTILITIES ARKANSAS

DATE RECEIVED: 3/4/2024

DATE DUE: 6/11/2024

EXTENSION DATE:

INFORMATION REQUESTED:
Identify all sources of annual internally generated cash flow to the Company's Parent Company.

REQUESTED BY: ARKANSAS ATTORNEY GENERAL

RESPONSE:
Please see the attached confidential 2023 audited consolidated and unaudited consolidating financial statements for the Company's parent company, Southern Col Holdco, LLC.

SPONSOR:
Craig Root

RESPONSIVE DOCUMENTS:
Confidential AG-001-026U Financial Statements Southern Col Holdco LLC 2023-12-31.pdf

The foregoing response to the above information request is accurate and complete, and contains no material misrepresentations or omissions based upon present facts known to the undersigned. The undersigned agrees to immediately inform the Requestor if any matters are discovered which would materially affect the accuracy or completeness of the information provided in response to the above information request.

/s/ Brooke South Parsons
Signature of Company Representative

DATE PROVIDED: JUNE 11, 2024

CONFIDENTIAL, SUBJECT TO PROTECTIVE ORDER NO. 1 ISSUED IN APSC DOCKET NO. 23-079-U
APSC FILED Time: 7/10/2024 9:56:01 AM: Recvd 7/10/2024 9:55:35 AM: Docket 23-079-U-Doc. 96

Southern Col Holdco, LLC and Subsidiaries

Consolidated Financial Statements
December 31, 2023 and 2022

CONFIDENTIAL, SUBJECT TO PROTECTIVE ORDER NO. 1 ISSUED IN APSC DOCKET NO. 23-079-U
APSC FILED Time: 7/10/2024 9:56:01 AM: Recvd 7/10/2024 9:55:35 AM: Docket 23-079-U-Doc. 96

Southern Col Holdco, LLC and Subsidiaries
Consolidated Balance Sheets
December 31, 2023 and 2022

[redacted]

The accompanying notes are an integral part of these consolidated financial statements.

CONFIDENTIAL, SUBJECT TO PROTECTIVE ORDER NO. 1 ISSUED IN APSC DOCKET NO. 23-079-U
APSC FILED Time: 7/10/2024 9:56:01 AM: Recvd 7/10/2024 9:55:35 AM: Docket 23-079-U-Doc. 99

Southern Col Holdco, LLC and Subsidiaries
Consolidated Balance Sheets
December 31, 2023 and 2022

[redacted]

The accompanying notes are an integral part of these consolidated financial statements.

ARKANSAS PUBLIC SERVICE COMMISSION
APSC 23-079-U
APSC FILED Time: 7/10/2024 9:56:01 AM: Recvd 7/10/2024 9:55:35 AM: Docket 23-079-U-Doc. 96
2023 SUA RATE CASE

REQUEST NO.: APSC-090-1

COMPANY NAME: SUMMIT UTILITIES ARKANSAS

DATE RECEIVED: 4/22/2024

DATE DUE: 5/7/2024

EXTENSION DATE:

INFORMATION REQUESTED:

1. Please provide the total number of Volunteer Time Off (VTO) hours by month for the 12 months ended December 31, 2023.
2. Please provided the total compensation paid, by month, by FERC account (both capital and expense) , for VTO for the 12 months ended December 31, 2023.

REQUESTED BY: ARKANSAS PUBLIC SERVICE COMMISSION - DON MALONE

RESPONSE:

1. The total Volunteer Time Off for SUA is 4,366.25 hours for the year 2023. The attached file has the breakout by month.

2. See attached for the dollar amounts posted by FERC for 2023.

SPONSOR:
Teresita Trevino, Ladonna Marsh

RESPONSIVE DOCUMENTS:
APSC-090-1 2023 VTO FERC.xlsx
APSC-090-1 VTO Hours 2023.xlsx

The foregoing response to the above information request is accurate and complete, and contains no material misrepresentations or omissions based upon present facts known to the undersigned. The undersigned agrees to immediately inform the Requestor if any matters are discovered which would materially affect the accuracy or completeness of the information provided in response to the above information request.

/s/ Brooke South Parsons
Signature of Company Representative

DATE PROVIDED: MAY 07, 2024

Month	VTO Hours
Jan-23	79.50
Feb-23	70.25
Mar-23	253.75
Apr-23	213.25
May-23	331.50
Jun-23	532.75
Jul-23	513.75
Aug-23	305.50
Sep-23	260.00
Oct-23	246.50
Nov-23	464.00
Dec-23	1,065.50
Total	4,336.25

ARKANSAS PUBLIC SERVICE COMMISSION
APSC 23-079-U
APSC FILED Time: 7/10/2024 9:56:01 AM: Recvd 7/10/2024 9:55:35 AM: Docket 23-079-U-Doc. 96
2023 SUA RATE CASE

REQUEST NO.: APSC-090-1

COMPANY NAME: SUMMIT UTILITIES ARKANSAS

DATE RECEIVED: 4/22/2024

DATE DUE: 5/7/2024

EXTENSION DATE:

INFORMATION REQUESTED:

1. Please provide the total number of Volunteer Time Off (VTO) hours by month for the 12 months ended December 31, 2023.
2. Please provided the total compensation paid, by month, by FERC account (both capital and expense) , for VTO for the 12 months ended December 31, 2023.

REQUESTED BY: ARKANSAS PUBLIC SERVICE COMMISSION - DON MALONE

RESPONSE:

1. The total Volunteer Time Off for SUA is 4,366.25 hours for the year 2023. The attached file has the breakout by month.

2. See attached for the dollar amounts posted by FERC for 2023.

SPONSOR:
Teresita Trevino, Ladonna Marsh

RESPONSIVE DOCUMENTS:
APSC-090-1 2023 VTO FERC.xlsx
APSC-090-1 VTO Hours 2023.xlsx

The foregoing response to the above information request is accurate and complete, and contains no material misrepresentations or omissions based upon present facts known to the undersigned. The undersigned agrees to immediately inform the Requestor if any matters are discovered which would materially affect the accuracy or completeness of the information provided in response to the above information request.

/s/ Brooke South Parsons
Signature of Company Representative

DATE PROVIDED: MAY 07, 2024

SUA Employees - VTO

FERC	Jan-23	Feb-23	Mar-23	Apr-23	May-23	Jun-23	Jul-23	Aug-23	Sep-23	Oct-23	Nov-23	Dec-23	Total
1070	597.57	277.41	2,220.08	2,543.81	4,586.21	3,030.87	5,563.41	3,865.85	1,828.27	6,065.85	2,578.98	12,545.86	45,704.15
1840	-	-	66.90	-	-	222.12	129.41	-	-	-	-	-	
8740	709.15	581.70	1,545.60	2,195.80	5,273.00	3,553.15	4,007.70	1,700.09	4,554.42	1,110.78	2,720.09	9,057.22	37,008.69
8760	-	-	-	203.50	-	314.98	479.39	619.35	195.31	-	116.61	138.05	2,067.18
8780	291.00	333.82	901.58	726.93	1,875.00	2,154.80	1,041.44	559.82	1,075.35	547.20	627.19	2,095.88	12,230.00
8790	241.32	272.56	845.98	705.81	1,784.64	1,608.37	1,022.51	586.74	1,197.69	368.31	760.70	2,364.79	11,759.42
8870	261.43	280.69	1,252.45	1,454.23	2,983.31	1,148.68	1,876.93	1,346.64	2,434.99	450.57	1,513.79	5,974.92	20,978.63
8890	-	-	-	271.33	-	419.98	639.18	825.80	260.41	-	155.47	184.07	2,756.24
8900	-	-	-	135.67	-	209.99	319.59	412.90	130.20	-	77.74	92.03	1,378.12
8920	70.98	75.02	367.40	702.14	801.96	310.25	773.64	624.93	753.73	446.84	292.44	1,691.82	6,911.15
8930	72.16	80.64	272.73	237.40	579.82	453.80	351.00	217.27	425.04	92.95	279.06	836.92	3,898.80
8940	72.16	80.64	272.73	237.40	579.82	453.80	351.00	217.27	425.04	92.95	279.06	836.92	3,898.80
9020	48.50	55.64	150.26	115.50	312.50	350.38	160.26	76.10	173.80	91.20	101.29	345.48	1,980.91
9030	194.00	222.54	601.05	462.01	1,250.00	1,467.58	641.03	304.39	1,293.65	65.58	405.17	1,381.91	8,288.91
9200	64.02	301.35	1,267.55	520.23	254.34	93.90	188.26	520.31	1,074.52	182.54	1,781.73	2,053.05	8,301.79
	2,622.29	2,562.00	9,764.30	10,511.76	20,280.59	15,792.65	17,544.76	11,877.46	15,822.41	9,514.77	11,689.31	39,598.91	167,162.80

ARKANSAS PUBLIC SERVICE COMMISSION
APSC 23-079-U
APSC FILED Time: 7/10/2024 9:56:01 AM: Recvd 7/10/2024 9:55:35 AM: Docket 23-079-U-Doc. 96
2023 SUA RATE CASE

REQUEST NO.: AGC-002-002

COMPANY NAME: SUMMIT UTILITIES ARKANSAS

DATE RECEIVED: 5/13/2024

DATE DUE: 5/28/2024

EXTENSION DATE:

INFORMATION REQUESTED:
Referring to Schedule C-3:

a. Explain in detail why Account No. 920 was zero in the historical portion of the test year and why it is increasing by $12.4 million in the projected portion of the test year.
b. Explain why Account No. 923 was zero in the historical portion of the test year and is increasing by $6.2 million in the projected portion of the test year.
c. Explain why Account No. 925 was zero in the historical portion of the test year and is increasing by $3.3 million in the projected portion of the test year.
d. Provide SUA's average cost of maintenance per mile of distribution main for 2022, 2023 and the test year.

REQUESTED BY: ARKANSAS GAS CONSUMERS

RESPONSE:
Please see Phillip Gillam's Direct Testimony pgs. 37-38. As noted in Mr. Gillam's testimony, the Company converted to SAP near the end of 2022. In 2023, after the 2022 Yearend audited financials were initially completed, a review was done of the FERC accounting system within SAP. As a result of that review, the Company prepared numerous journal entries, resulting in 1) the reclassification of significant dollars, mostly among the administrative and general accounts, 2) the correction of account mapping, and 4) the addition or deletion of FERC accounts among other things. The correcting entries were largely made in August of 2023 with a few entries occurring in later months. FERC accounts 920, 923 and 925 did not have costs booked during the historic portion of the test year due to errors in mapping of accounts within SAP, and/or incorrect FERC assignment through journal entries, cost centers or orders.

a. FERC 920 costs were largely booked to FERC 921 in error during the historic portion of the test year. The projected portion of the test is not increasing by $12.4 million, as that amount represent the full test year.

b. FERC 923 costs were largely booked to FERC 903 and FERC 921 in error during the historic portion of the test year. The projected portion of the test year is not increasing by $6.2 million, as that amount represents the full test year.

c. FERC 925 costs were largely booked to FERC 921 in error during the historic portion of the test year. The projected portion of the test year is not increasing by $3.3 million, as that

amount represents the full test year.

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d. See attached file DR AGC-002-002 for 2022 and 2023/TY cost per mile for mains.

SPONSOR:
Christopher Gray, Phillip Gillam, Sheri Richard

RESPONSIVE DOCUMENTS:
AGC-002-002 DR AGC-002-002.xlsx

The foregoing response to the above information request is accurate and complete, and contains no material misrepresentations or omissions based upon present facts known to the undersigned. The undersigned agrees to immediately inform the Requestor if any matters are discovered which would materially affect the accuracy or completeness of the information provided in response to the above information request.

/s/ Brooke South Parsons
Signature of Company Representative

DATE PROVIDED: MAY 28, 2024

Year	Miles of Main	FERC 887	Cost per mile
2023 & TY	13,909.08	10,376,070.09	$ 745.99
2022	13,894.53	8,970,287.32	$ 645.60

Note: Excludes any cost allocation for FERC 885 Supervision and Engineering

ARKANSAS PUBLIC SERVICE COMMISSION
APSC 23-079-U
APSC FILED Time: 7/10/2024 9:56:01 AM: Recvd 7/10/2024 9:55:35 AM: Docket 23-079-U-Doc. 96
2023 SUA RATE CASE

REQUEST NO.: AG-002-005U

COMPANY NAME: SUMMIT UTILITIES ARKANSAS

DATE RECEIVED: 3/4/2024

DATE DUE: 6/28/2024

EXTENSION DATE:

INFORMATION REQUESTED:
Please provide a schedule breaking down the costs for each of the Company's Incentive Compensation the Company has included in this instant filing, both before capitalization and after capitalization (expensed). Please provide the associated metric or performance goal resulting in the balance. Please also provide the number of employees eligible under each plan. Please also include the benefits to ratepayers in implementing these payments and recovering these payments from ratepayers:

a. STI-Union and Non-Union / Officer and Non-Officer
b. LTI- Union and Non-Union / Officer and Non-Officer
c. Restricted Stock Awards – Union and Non-Union / Officer and Non-Officer
d. Bonuses – Union and Non-Union / Officer and Non-Officer
e. Other Incentive Type Pay
f. Allocated from Corporate (Summit Utilities, Inc.)

REQUESTED BY: ARKANSAS ATTORNEY GENERAL

RESPONSE:
a. Please see the attachment, "Updated Incentive Capitalization" for all STI Non-Union/Non-Officer costs booked to capital and expense through December 2023. Summit Utilities Arkansas does not have any STI-Union or STI-Officer costs. 475 SUA and 390 SUI employees were eligible for STI in 2023.

b.-e. No updates to previous DR AG-002-005.

f. Summit Utilities, Inc. allocates a portion of STI, sign on bonuses and retention bonuses to its subsidiaries. Please see attachment, "Updated Incentive Capitalization" for total Corporate Allocated incentives through December 2023 test year.

SPONSOR:
Jen Fallon, Sam Springer, Andy Hagler

RESPONSIVE DOCUMENTS:

AG-002-005U Updated Incentive Capitalization.xlsx

APSC FILED Time: 7/10/2024 9:56:01 AM: Recvd 7/10/2024 9:55:35 AM: Docket 23-079-U-Doc. 96

The foregoing response to the above information request is accurate and complete, and contains no material misrepresentations or omissions based upon present facts known to the undersigned. The undersigned agrees to immediately inform the Requestor if any matters are discovered which would materially affect the accuracy or completeness of the information provided in response to the above information request.

/s/ Brooke South Parsons
Signature of Company Representative

DATE PROVIDED: JUNE 28, 2024

Summit Utilities Arkansas, Inc
AG-002-005U
Direct & Indirect Incentive Compensation Capitalization

2023 SUA STI Capitalization as of 12/31/2023

	SUA-Direct	
	STI	
Capital	362,204.91	
Expense	1,933,801.15	
Other Deferred	83,860.71	
	2,379,866.77	*

2023 Incentives Allocated from Corporate as of 12/31/23

	Corp-Alloc			
	STI	Sign-On Bonus	Retention Bonus	Total
Capital	660,012.56	51,962.18	84,901.84	796,876.58
Expense	1,380,060.57	53,089.46	86,743.73	1,519,893.76
	2,040,073.13	105,051.64	171,645.57	2,316,770.34

* SUA-Direct incentives decreased in December due to a year-end true-up.

ARKANSAS PUBLIC SERVICE COMMISSION
APSC 23-079-U
APSC FILED Time: 7/10/2024 9:56:01 AM: Recvd 7/10/2024 9:55:35 AM: Docket 23-079-U-Doc. 96
2023 SUA RATE CASE

REQUEST NO.: APSC-009U

COMPANY NAME: SUMMIT UTILITIES ARKANSAS

DATE RECEIVED: 1/25/2024

DATE DUE: 6/28/2024

EXTENSION DATE:

INFORMATION REQUESTED:
Incentive Compensation:

1. Please provide a copy of each written incentive compensation plan that includes a detailed description of the criteria used in determining an award and which employees are eligible to receive an award under each specific plan in effect for calendar years 2022, 2023 and 2024 that has an amount charged on SUA's general ledger.

2. For each incentive compensation (IC) plan provided in response to Q.1 above, please provide the date costs began being allocated or direct charged to SUA and provide a brief narrative to describe the IC plan, participants, and goals to achieve a payout from the plan.

Plan(s) Metrics:

3.For each IC plan provided in response to Q.1 above, please provide the criteria or objectives(s) that must first be achieved (such as EPS goal, dividends paid, etc.) for the Company to fund each IC plan for the years ended December 31, 2022, 2023, and 2024.

4. For each incentive compensation plan provided in response to Q.1 above, please provide the annual metrics for each plan broken down into the various components or targets/goals, the weighting of the targets/goals, the driver of each set of targets/goals (such as financial goals such as a level of maintenance expense or gross margin; customer service goals such as number of complaints or CSR call time; safety goals such as number of lost time accidents or auto accidents; etc.) for each employee or officer of the company to earn an incentive compensation plan award per each IC plan.

SUA General Ledger Amounts:

5. For each IC plan provided in response to Q.1 above, please provide the total amount recorded on SUA's general ledger, by IC plan, by FERC account (both expense and capital accounts), by allocated and direct charged, for the twelve months ending December 31, 2020, 2021, 2022, and 2023.

6. For each IC Plan amount provided in response to Q.5, please provide each IC plan total amount broken out by each target/goal such as financial, customer service, and/or safety related goals that were achieved for the total payout recorded on SUA's general ledger by IC plan for the twelve months ended 12/31/2020, 12/31/2021, 12/31/2022, and 12/31/2023.

Example: Short Term IC Plan 2023 payout recorded $100,000 comprised of

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Safety Targets Achieved LT Accidents 40% - $40,000 & Safety Meeting Attendance 20% - $20,000; Financial Targets Achieved EPS 10% $10,000 & GM 5% $5,000 payouts; and

Customer Service Targets Achieved No. of Complaints 25% $25,000 payouts

7. Please provide the name, telephone number, and email address of the person to discuss employee incentive compensation plans and executive incentive compensation plans.

REQUESTED BY: ARKANSAS PUBLIC SERVICE COMMISSION - DON MALONE

RESPONSE:
1. SUI's 2024 STIP Plan Document will be submitted under separate email using a secure file share link.

2.-4. See attached 2024 Corporate Scorecard. No additional updates to prior response in APSC-009.

5. For updated 2023 amounts see attached "Updated 2023 SUA Incentives by FERC." For Q1 2024 amounts see "Q1 2024 SUA Incentives by FERC." No updates to 2022 amounts provided in previous DR APSC-009.

6. For updated 2023 amounts see attached "Updated 2023 Incentives by Targets." For Q1 2024 amounts see "Q1 2024 SUA Incentives by Targets." No updates to 2022 amounts provided in previous DR APSC-009.

7. No updates to previous DR APSC-009.

SPONSOR:
Jen Fallon, Sam Springer

RESPONSIVE DOCUMENTS:
APSC-009U 2024 Corporate Scorecard.pdf
APSC-009U Q1 2024 SUA Incentives by FERC.xlsx
APSC-009U Q1 2024 SUA Incentives by Targets.xlsx
APSC-009U Updated 2023 Incentives by Targets.xlsx
APSC-009U Updated 2023 SUA Incentives by FERC.xlsx

The foregoing response to the above information request is accurate and complete, and contains no material misrepresentations or omissions based upon present facts known to the undersigned. The undersigned agrees to immediately inform the Requestor if any matters are discovered which would materially affect the accuracy or completeness of the information provided in response to the above information request.

/s/ Brooke South Parsons
Signature of Company Representative

DATE PROVIDED: JUNE 28, 2024

2024 Corporate Scorecard

WEIGHT	CORPORATE GOALS	MEASUREMENT		
		THRESHOLD	TARGET	STRETCH
15%	**SAFETY** • Personal Injuries • Vehicle Accidents • Pipeline Replacement – AR/OK • Pipeline Damages	 1.94 2.47 107 miles 6.48	 TRIR = 1.57 VIR = 1.97 122 miles 5.4/1,000 locates	 0.81 1.53 137 miles 4.32
35%	**CORPORATE EXCELLENCE** • Environmental, Social, Governance • Customer Facing Order Completion • Emergency Response Time • Audited Financial Statements Issued • Monthly Financial Reports Issued (Days)	 95% 45 mins April 30 16	 ESG Scorecard 97.5% 30 mins April 30 14	 100% 22.5 mins April 30 12
10%	**PEAKS RENEWABLES** • Peaks Development Pipeline (Stages 1/2/3/4/Const)	8 / 3/ 2 / 2 / 0	10 / 5 / 2 / 1 / 1	12 / 6 / 3 / 2 /2
40%	**FINANCIAL** • Adjusted EBITDA • Dividend Yield	$138M $78 M (2.7%)	$152.5M $84 M (2.9%)	$160.0M $90 M (3.1%)

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APPENDIX D

Return on Equity Methodologies

Single Stage Discounted Cash Flow

The discounted cash flow model is used by investors to determine the present value of a stock, based on future cash flows (dividends), which are discounted by the stock's known return and its forecast growth.

The formula is:

$$P = \frac{D}{r-g}$$

Where:

P = current stock price

D = dividend yield

r = rate of return

g = growth rate

We can rearrange the formula thus:

$$r = \frac{D}{P} + g$$

In other words, the expected return equals (1) the current dividend rate, plus (2) the expected growth in dividends. The expected growth in dividends is also measured by the expected growth in earnings.

The stock prices are based on the average closing prices for the past 30 days. The 30-day average is used to ensure that the results reflect stock prices over a period of time that is not overly reliant on any particular events affecting stock prices on a given day and that represent capital market conditions over the past month.

The growth rates are the forecast earnings per share growth rates for the next five years from Value Line, Yahoo! Finance, and Zacks. The dividends are forecast

figures, also from Value Line. These have been adjusted to reflect any quarterly adjustments during the year.

Two-Stage Discounted Cash Flow Methodology

A two-stage DCF analysis uses two separate growth estimates. The first stage measures the near-term growth rate based on the analysts' forecast earnings growth used in my constant growth DCF analysis. The second stage is the forecast of the long-term growth rate of gross domestic product (GDP). Using these inputs, the model re-calculates the growth rate, using the same dividend yield as in the single stage DCF methodology.

The two-stage method is used because analysts' growth rates for the first stage may not be sustainable over the long term. The two-stage model recognizes short-term growth (whether it be higher or lower than the long term), but also accounts for a more realistic, long-term growth rate. Analysts' growth rates should be viewed in conjunction with other growth estimates to achieve a reasonable forecast of expected earnings.

The long-term growth in GDP is used because the underlying assumption is that mature, established companies can grow at a rate that is similar to, or lower than, the GDP growth rate. While some companies in the economy will grow faster than GDP for a while, this cannot happen consistently over a long period.

Capital Asset Pricing Model

The CAPM is a Risk Premium method that is used to estimate the ROE. It states that the expected return of a security equals the risk-free rate plus a risk premium. Simply put, investors require a premium over the risk-free rate if they are going to invest in a riskier security. The formula for the CAPM is:

*Expected ROE = Risk-Free Rate + β*Market Risk Premium*

The equity risk premium for a particular stock is the MRP times the stock's beta (β). The MRP is the difference between the return on the market on average (*i.e.*, the S&P 500) and the risk-free rate. Thus, it is the premium that reflects the risk on an average stock. Beta is the price volatility of that stock relative to the market as a whole. Thus, the risk premium for a *specific* stock equals the *average MRP* times the beta. Since utility stocks are lower risk than the average stock, the risk premium for a utility stock is lower than the average MRP. Multiplying the beta times the MRP gives the appropriate risk premium for the company (or group of comparable companies) being studied.

The risk-free rate is the projected yield on 30-year U.S. Treasury bonds. This rate is considered to be risk-free because the return is guaranteed by the U.S. government.

Two MRP estimates may be used, including the historical MRP estimate and a projected MRP. The historical MRP is based on historical data dating back to 1996. The projected MRP is based on the projected median three-to-five year price appreciation of the 1,700 stocks from Value Line and the projected median dividend yield over the next 12 months for all dividend paying stocks. The forecast annual return is based on the forecast annual growth rate of the stocks plus the forecast

median dividend produces a projected annual return. The projected risk-free rate is deducted from the projected annual return to determine the projected MRP.

Beta measures the volatility of a security in comparison to the market as a whole. A beta equal to 1.00 means that a stock's price fluctuates exactly as the market as a whole. A beta higher than 1.00 implies that the stock's price is more volatile than the market; a beta less than 1.00 implies the stock's price is less volatile than the market. The standard formula for estimating beta is the covariance between a security's return and the return of the market divided by the variance of the market returns over a specified period. Beta is based on the betas provided in Value Line.

Beta measures the amount of compensation an investor needs to take on additional risk, as compared to the risk-free rate. Value Line's method to estimate beta is based on "a regression analysis of the relationship between weekly percentage changes in the price of a stock and weekly percentage changes in the NYSE Composite Index over a period of five years. Value Line then adjusts these Betas to account for their long-term tendency to converge toward 1.00."[42]

The risk-free rate is based on the projected return on long-term treasuries. This rate is considered risk-free because the security is backed by the U.S. government.

Risk Premium Method

The Risk Premium method estimates the ROE for a utility as the sum of a bond yield plus a risk premium yield. The bond yield is the projected return on the long-term government bond plus the historical risk premium. The risk premium is a measure of the additional return an investor requires due to the additional risk of the security. The

[42] Value Line Publishing, Using Beta, Andrew J. Cueter, (Oct. 2, 2012).

risk premium is the measure of the difference between the historical authorized return on equity for regulated electric, natural gas or water utilities and the historical yield on 30-year Treasury bonds.

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S&P Global

RRA Regulatory Focus

Major Energy Rate Case Decisions

February 6, 2024

Major energy rate case decisions in the US

January-December 2023

Quarterly update on decided rate cases

Lisa Fontanella, Research Director

Contributors: Brian Collins, Jim Davis, Russell Ernst, Lillian Federico, Monica Hlinka, Jason Lehmann, Dan Lowrey

Editor: Wyatt Scott

For detailed data

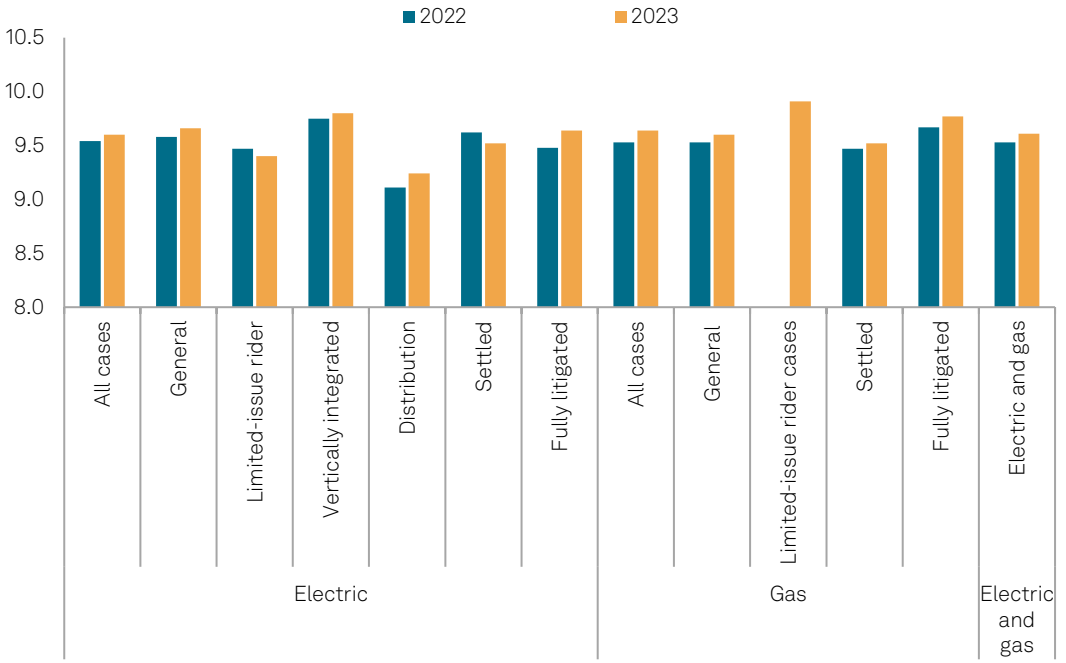
Access the RRA's electric and gas rate case decisions as of Dec. 31, 2023, data tables.

Energy authorized returns on equity rose in 2023 as the pace of rate case activity reached record-high levels, with nearly 165 decisions issued by state public utility commissions, including 106 electric or gas equity return determinations.

To learn more or to request a demo, visit spglobal.com/marketintelligence.

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Average authorized ROE (%)



	2022	2023
Electric averages		
All cases	9.54	9.60
General rate cases	9.58	9.66
Limited-issue rider cases	9.47	9.40
Vertically integrated cases	9.75	9.80
Distribution cases	9.11	9.24
Settled cases	9.62	9.52
Fully litigated cases	9.48	9.64
Gas averages		
All cases	9.53	9.64
General rate cases	9.53	9.60
Limited-issue rider cases		9.91
Settled cases	9.47	9.52
Fully litigated cases	9.67	9.77
Composite electric and gas averages		
Electric and gas	9.53	9.61
US Treasury		
30-year bond yield	3.11	4.09

Data compiled Jan. 26, 2024.
ROE = return on equity.
Sources: Regulatory Research Associates, a group within S&P Global Commodity Insights; US Treasury Department.
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SUMMIT UTILITIES

Exhibit BSL-2

Impact of Reducing ROE to National Average Authorized ROE

	Proposed ROE for the Test Year Ending December 31, 2024						National Average ROE for 2023					
Line	Description	% Amount of Total Capital	Cost Rate %	Wtd. Cost of Total Capital (%)	Pre-tax Multiplier	Pre-tax Cost of Capital	Description	% Amount of Total Capital	Cost Rate %	Wtd. Cost of Total Capital (%)	Pre-tax Multiplier	Pre-tax Cost of Capital
1	Long-Term Debt	44.41%	4.81%	2.14%	1.0000	2.14%	Long-Term Debt	44.41%	4.81%	2.14%	1.000	2.14%
2	Common Equity	55.59%	11.00%	6.11%	1.3450	8.22%	Common Equity	55.59%	9.60%	5.34%	1.345	7.18%
3	Total	100.00%		8.25%		10.36%	Total	100.00%		7.47%		9.31%
4	Test Year Rate Base			$1,223,251,086			Impact of Change in ROE					($12,804,023)

SOURCES:
Exhibit DWD-1
Schedule A-1

SUMMIT UTILITIES

Discounted Cash Flow Analysis

Exhibit BSL-3

Line	Company	Ticker	Avg of 30-day Closing $	Last Qtrly Dividend Payment	Current Annual Div (D0)	Current Dividend Yield	Value Line	Yahoo Finance	Zack's	Expected Average Growth Rate	Expected Dividend Yield	Low Analyst ROE	Mean Analyst ROE	High Analyst ROE
		(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)
1	Atmos Energy Corporation	ATO	115.38	0.805	3.22	2.79%	7.00%	7.40%	7.00%	7.13%	2.89%	9.89%	10.02%	10.29%
2	Black Hills Corporation	BKH	55.14	0.650	2.60	4.72%	3.50%	0.70%	n/a	2.10%	4.76%	5.46%	6.86%	8.26%
3	New Jersey Resources*	NJR	43.05	0.420	1.68	3.90%	5.00%	6.00%	6.00%	5.67%	4.01%	9.01%	9.68%	10.01%
4	NiSource Inc.	NI	28.60	0.265	1.06	3.71%	9.50%	7.40%	6.00%	7.63%	3.85%	9.85%	11.48%	13.35%
5	Northwest Natural Holding Company*	NWN	37.08	0.488	1.95	5.26%	6.50%	2.80%	3.70%	4.33%	5.38%	8.18%	9.71%	11.88%
6	ONE Gas, Inc.	OGS	61.74	0.660	2.64	4.28%	3.50%	5.00%	5.00%	4.50%	4.37%	7.87%	8.87%	9.37%
7	Spire Inc.	SR	60.11	0.660	2.64	4.39%	3.50%	6.36%	5.00%	4.95%	4.50%	8.00%	9.45%	10.86%
8	Southwest Gas	SWX	75.72	0.620	2.48	3.28%	10.00%	4.00%	6.00%	6.67%	3.38%	7.38%	10.05%	13.38%
9	WEC Energy	WEC	81.83	0.835	3.34	4.08%	6.00%	7.21%	7.95%	7.05%	4.23%	10.23%	11.28%	12.18%
10	Average											8.43%	9.71%	11.07%
11	Minimum											5.46%	6.86%	8.26%
12	Maximum											10.23%	11.48%	13.38%

SOURCES:
Column 2: Yahoo! Finance
Column 3: Value Line Investment Survey
* Zack's growth rates from DWD-3 at 1.

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SUMMIT UTILTIES

Exhibit BSL-4

Two-Stage Discounted Cash Flow Analysis

Line	Company	Stock Symbol	Stock Price Price	Expected Annualized Dividend	First Stage Growth Rate	Second Stage Growth Rate	ROE
		(1)	(2)	(3)	(4)	(5)	(6)
1	Atmos Energy Corporation	ATO	115.38	2.89%	4.76%	1.70%	9.35%
2	Black Hills Corporation	BKH	55.14	4.76%	1.40%	1.70%	7.86%
3	New Jersey Resources	NJR	43.05	4.01%	3.78%	1.70%	9.49%
4	NiSource Inc.	NI	28.60	3.85%	5.09%	1.70%	10.64%
5	Northwest Natural Holding Company	NWN	37.08	5.38%	2.89%	1.70%	9.97%
6	ONE Gas, Inc.	OGS	61.74	4.37%	3.00%	1.70%	9.07%
7	Spire Inc.	SR	60.11	4.50%	3.30%	1.70%	9.50%
8	Southwest Gas	SWX	75.72	3.38%	4.44%	1.70%	9.53%
9	WEC Energy	WEC	81.83	4.23%	4.70%	1.70%	10.63%
10	Average						9.56%
11	Minimum						7.86%
12	Maximum						10.64%

SUMMIT UTILITIES **Exhibit BSL-5**

Capital Asset Pricing Model

Line	Company	Ticker	Current Beta (B)	Projected Risk-Free Rate (R_f)	Historical Risk Premium (R_p)	Historical CAPM ROE	Projected Risk Premium (R_p)	Projected Risk Premium CAPM ROE
		(1)	(2)	(3)	(4)	(5)	(6)	(7)
1	Atmos Energy Corporation	ATO	0.85	4.20%	7.03%	10.18%	6.11%	9.39%
2	Black Hills Corporation	BKH	1.05	4.20%	7.03%	11.58%	6.11%	10.61%
3	New Jersey Resources	NJR	1.00	4.20%	7.03%	11.23%	6.11%	10.31%
4	NiSource Inc.	NI	0.95	4.20%	7.03%	10.88%	6.11%	10.00%
5	Northwest Natural Holding Company	NWN	0.85	4.20%	7.03%	10.18%	6.11%	9.39%
6	ONE Gas, Inc.	OGS	0.85	4.20%	7.03%	10.18%	6.11%	9.39%
7	Spire Inc.	SR	0.85	4.20%	7.03%	10.18%	6.11%	9.39%
8	Southwest Gas	SWX	0.90	4.20%	7.03%	10.53%	6.11%	9.70%
9	WEC Energy	WEC	0.85	4.20%	7.03%	10.18%	6.11%	9.39%
10	Average		0.91			10.57%		9.73%
11	Minimum		0.85			10.18%		9.39%
12	Maximum		1.05			11.58%		10.61%

SOURCES:
Column 2: Value Line Investment Survey
Column 3: Blue Chip Financial Forecast
Column 4: Exhibit No. TAW-1 (A-14), Schedule D-5 at 7.
Column 6: Projected S&P return less risk-free rate.

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SUMMIT UTILITIES **Exhibit BSL-6**

Risk Premium Analysis

	Average ROE 1980 - 2023	Average Yield on Utility Bond	Risk Premium
	12.52%	9.67%	2.85%
Projected Return on A2 Utility Bond			5.94%
Return on Equity			8.79%

SUMMIT UTILITIES

Impact of Reducing ROE to 9.7%

Exhibit BSL-7

	Proposed ROE for the Test Year Ending December 31, 2024						AGC Recommended ROE					
Line	**Description**	**% Amount of Total Capital**	**Cost Rate %**	**Wtd. Cost of Total Capital (%)**	**Pre-tax Multiplier**	**Pre-tax Cost of Capital**	**Description**	**% Amount of Total Capital**	**Cost Rate %**	**Wtd. Cost of Total Capital (%)**	**Pre-tax Multiplier**	**Pre-tax Cost of Capital**
1	Long-Term Debt	44.41%	4.81%	2.14%	1.000	2.14%	Long-Term Debt	44.41%	4.81%	2.14%	1.000	2.14%
2	Common Equity	55.59%	11.00%	6.11%	1.345	8.22%	Common Equity	55.59%	9.70%	5.39%	1.345	7.25%
3	Total	100.00%		8.25%		10.36%	Total	100.00%		7.53%		9.39%
4	Test Year Rate Base			$1,223,251,086			Impact of Change in ROE					($11,889,450)

SOURCES:
Exhibit DWD-1 at 1.
Schedule A-1.

SUMMIT UTILITIES

Exhibit BSL-8

Impact of Reducing Equity Ratio to 50%

	Proposed Capital Structure for the Test Year Ending December 31, 2024						AGC Recommended Capital Structure					
Line	Description	% Amount of Total Capital	Cost Rate %	Wtd. Cost of Total Capital (%)	Pre-tax Multiplier	Pre-tax Cost of Capital	Description	% Amount of Total Capital	Cost Rate %	Wtd. Cost of Total Capital (%)	Pre-tax Multiplier	Pre-tax Cost of Capital
1	Long-Term Debt	44.41%	4.81%	2.14%	1.000	2.14%	Long-Term Debt	50.00%	4.81%	2.41%	1.000	2.41%
2	Common Equity	55.59%	11.00%	6.11%	1.345	8.22%	Common Equity	50.00%	11.00%	5.50%	1.345	7.40%
3	Total	100.00%		8.25%		10.36%	Total	100.00%		7.91%		9.80%
4	Test Year Rate Base			$1,223,251,086			Impact of Change in Common Equity Ratio					($6,827,341)

SOURCES:
Exhibit DWD-1 at 2.
Schedule A.

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CERTIFICATE OF SERVICE

I hereby certify that a copy of the foregoing has been delivered on all parties of record by electronic mail via the APSC's Electronic Filing System this 10th day of July 2024.

/s/ *M. Shawn McMurray*
M. Shawn McMurray ABN 92250

APSC FILED Time: 7/10/2024 10:49:08 AM: Recvd 7/10/2024 10:48:15 AM: Docket 23-079-U-Doc. 97

BEFORE THE
ARKANSAS PUBLIC SERVICE COMMISSION

IN THE MATTER OF THE APPLICATION OF SUMMIT UTILITIES ARKANSAS, INC., FOR A GENERAL CHANGE OR MODIFICATION IN ITS RATES, CHARGES AND TARIFFS	))))	DOCKET NO. 23-079-U

DIRECT TESTIMONY

OF

JEFF HILTON
DIRECTOR
GAS AND WATER UTILITIES SECTION

ON BEHALF OF THE GENERAL STAFF OF THE
ARKANSAS PUBLIC SERVICE COMMISSION

JULY 10, 2024

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INTRODUCTION

Q. Please state your name and business address?

A. My name is Jeff Hilton. My business address is Arkansas Public Service Commission ("Commission"), 1000 Center Street, Little Rock, Arkansas 72201.

Q. Would you please describe your qualifications and background?

A. I joined the General Staff ("Staff") in October 1998, as a Public Utility Auditor. In December 2000, I was promoted to the Manager of the Audits section and to the Director of Revenue Requirements in July 2009. In September 2020, I was promoted to the Director of Gas and Water utility section. Prior to joining Staff, I held progressively more responsible accounting, management, and faculty positions in public accounting and higher education.

My educational qualifications include a Bachelor of Science degree in Accounting from Henderson State University. I am a Certified Public Accountant licensed to practice in the State of Arkansas. In the maintenance of this certification, I have completed numerous additional academic or continuing professional education hours and seminars. Since joining Staff, I have attended conferences and seminars pertaining to utility-related issues, including the Annual Regulatory Studies Program sponsored by the National Association of Regulatory Utility Commissioners ("NARUC"). I have previously presented testimony and exhibits as an expert witness before this Commission in several proceedings addressing electric, gas, and water utility rate issues; have assisted in the development of Staff's positions in many more cases; and

have served as project manager for Staff in a number of rate applications, accounting, and other dockets filed with the Commission, including this Docket.

PURPOSE OF TESTIMONY

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

A. The purpose of my Direct Testimony is to address the Application for Approval of a General Change or Modification in its Rates, Charges and Tariffs ("Application") of Summit Utilities, Arkansas, Inc. ("SUA" or "Company") filed on January 25, 2024, and revised on February 20, 2024.[1] I will discuss Staff's recommended Revenue Requirement and provide a list of Staff's witnesses. I will also address certain Operating Expenses, Other Revenues, the Revenue Conversion Factor ("RCF") and the Company's requested modification to its System Safety Enhancement Rider ("SSER"), its Tariffs, and the Payment Center Report. In my discussion, I will address the Direct Testimonies of Company witnesses identified in my testimony below.

STAFF WITNESS LIST

Q. Please identify Staff's witnesses presenting Direct Testimony and the respective issues addressed by each witness.

A. A list of Staff's witnesses who are filing Direct Testimony in this Docket and the respective issues addressed by each are as follows:

[1] The footnote to Doc. No. 60, Revised Schedule A-1, PDF p. 8 states: "Revenue Requirement increased. The Company is limited to the originally filed Total Non-Fuel Revenue Requirement of $286,660,736 and the originally filed Revenue Deficiency of $104,679,427 in Docket No. 23-079-U-Doc. 18 (Schedule A-1)."

Witness	Issue(s) Addressed
Jeff Hilton	Witness List
	Revenue Requirement
	Operating Expenses
	Other Revenues
	Revenue Conversion Factor
	SSER
	Tariff Changes
	Payment Center Reporting
Middleton Ray	Payroll and related benefits
	Incentive Compensation
Michael Pitts	Gross Plant-in-Service
	Accumulated Depreciation
	Property Taxes
	Depreciation Expense
Claude Robertson	Depreciation Rates and Parameters
	Vintage Accounting
Don Malone	Working Capital Assets
	Current, Accrued, and Other Liabilities
	Accumulated Deferred Income Taxes
	Excess Accumulated Deferred Income Taxes
	Income Tax Expense
Dan Daves	Capital Structure
	Cost of Capital (Rate of Return)
Robert H. Swaim	Billing Determinants
	Base Rate Revenues at Current Rates
	Rate Design
	Billing Determinants Adjustment Rider
	Weather Normalization Adjustment Rider
Mark Burdette	Cost of Service Study

TEST YEAR AND *PRO FORMA* YEAR

Q. What test year and *pro forma* year did SUA utilize in its Application?

A. SUA's Application used a test year ending December 31, 2023, comprised of six months of actual data and six months of projected data and a *pro forma* year ending December 31, 2024.[2]

Q. What test year and *pro forma* year did Staff use in its review and adjustments?

A. Staff's test year reflects twelve months of actual data for the year ending December 31, 2023, with adjustments to the *pro forma* year for known and measurable changes through December 31, 2024. The updated Minimum Filing Requirements ("MFRs") were provided in response to Staff data request APSC-001.

NON-GAS REVENUE REQUIREMENT

Q. What is the Revenue Requirement determined by Staff?

A. Staff's determination of SUA's non-gas Revenue Requirement is shown on Direct Exhibit JH-1, Summary of Operations. As shown on Direct Exhibit JH-1, Staff's recommendations result in a Revenue Deficiency of $74,571,448 and a non-gas Revenue Requirement of $254,457,895. In contrast, SUA's proposed Revenue Deficiency is $104,679,427 with a non-gas Revenue Requirement of $286,660,736,[3] for a difference of $30,107,979 and -$32,202,841 from Staff's determination, respectively. As discussed below, my

[3] Application, Schedule A-1, Doc. 18, Part 1, p. 12.

Exhibit JH-7 summarizes and reconciles the differences between Staff's and the Company's non-gas Revenue Requirements.

Q. What other exhibits are you sponsoring?

A. In addition to Direct Exhibit JH-1, I am sponsoring Direct Exhibits JH-2 through JH-6, which summarizes the development of Staff's recommended non-gas Revenue Requirement.

Staff's adjustments to both the Company's historical test year and all of the principal components in the determination of SUA's Rate Base are shown in my Direct Exhibits JH-2 and JH-3. Staff's proposed Rate Base reflects Net Plant-in-Service of $1,129,492,716 and Working Capital Assets ("WCA") of $95,745,409 for a Total Rate Base of $1,225,238,125. In contrast, the Company's proposed Net Plant-In-Service is $1,104,469,905 with WCA of $118,781,180 for a total Rate Base of $1,223,251,086.[4]

Staff's adjustments to the Company's historical test year and the determination of the *pro forma* year Operating Revenues and Expenses are shown on my Direct Exhibits JH-4 and JH-5, respectively. Staff's computations reflect Operating Revenues of $179,886,447 reduced by Total Expenses of $167,787,191 to derive Net Utility Operating Income of $12,099,256. SUA's proposed Operating Revenues are $181,981,309 and its proposed Operating

[4] Application, Schedule B-1, Doc. No. 18, Part 2, p. 2.

Expenses are $177,797,261, yielding a Net Utility Operating Income of $4,184,048.[5]

Staff's income tax calculation is shown on my Direct Exhibit JH-6 and is based on the operating revenues and expenses reflected on my Direct Exhibit JH-4. Staff's weighted cost of debt of 1.82%, as provided by Staff witness Dan Daves, was applied to Staff's Rate Base to determine the amount of fixed charges to include in the income tax calculation.

The Revenue Requirement Reconciliation, shown on my Direct Exhibit JH-7, reconciles the differences between the non-gas Revenue Requirement of Staff and the Company and summarizes the differences in five areas: Rate Base, Rate of Return, Income Taxes, the Revenue Conversion Factor, and Operating Expenses. The reconciliation begins with the Company's requested non-gas Revenue Requirement of $286,660,736 and makes adjustments to arrive at Staff's recommended non-gas Revenue Requirement of $254,457,895, for a total difference of $32,202,841.

OPERATING EXPENSES

Table 1
Non-Contested Expense Adjustments

Adj. No.	Description	Staff Amount	Company Amount*	Difference
IS-1	Cost of Gas Adjustment	(268,978,147)	(168,616,064)	(100,362,083)
IS-2	Miscellaneous Taxes (Other Than Income)	(8,033)	(8,039)	6
IS-9	Advertising & Marketing	(922,529)	(479,477)	(443,052)
IS-10	Other Expenses Adjustment	(418,450)	(121,077)	(297,373)

[5] Application, Schedule C-1, Doc. No. 18, Part 3, pp. 2-3.

Adj. No.	Description	Staff Amount	Company Amount*	Difference
IS-11	Interest on Customer Deposits	89,460	94,808	(5,348)
IS-14	Meals & Travel Adjustment	(375,037)	(366,982)	(8,055)
IS-15	Postage Expense Adjustment	168,749	533,348	(364,599)
IS-17	Pipeline Locator Fees	1,166,079	1,365,001	(198,922)

*Difference only due to Staff's use of an updated test year

Table 2
Contested Revenue and Expense Adjustments

Adj. No.	Description	Staff Amount	Company Amount	Difference
IS-3	Revenue Adjustment	(273,642,924)	(152,770,979)	(120,871,945)
IS-4	Forfeited Discounts Revenue Normalization	1,537,787	2,476,629	(938,842)
IS-6	Bad Debt	(7,295,558)	(5,777,601)	(1,517,957)
IS-7	Rate Case Amortization	182,976	707,440	(524,464)
IS-20	Deferred COVID Expense Recovery	1,267,826	2,113,044	(845,218)

REVENUE

Sales Revenue

Q. Did Staff include an adjustment to Rate Schedule Revenue?

A. Yes. I included an adjustment for Rate Schedule Revenue as discussed in Staff witness Robert H. Swaim's Direct Testimony. Staff's Adjustment IS-3 reduces SUA's actual test year revenue of $447,021,397 by $273,642,924 to *pro forma* Rate Schedule Revenue of $173,378,473. SUA's adjustment of ($152,770,979), reduced its partially projected test year revenue of $328,040,950 to *pro forma* Rate Schedule Revenue of $175,269,971, which

also includes SSER Revenue of $3,773,524.[6] Staff's total revenue adjustment is ($120,871,945) less than SUA's revenue adjustment based on a partially-projected test year. Staff's *pro forma* Rate Schedule Revenue is less than SUA's by $1,891,498; however, excluding SSER Revenue from SUA's total *pro forma* Revenue, it is more than the Company's revenue by $1,882,026.

Forfeited Discounts

Q. How does your Adjustment IS-4 to forfeited discounts revenue compare to SUA's?

A. The Company normalized the test year forfeited discounts revenue by taking a five-year average. I based my calculation on the Company's updated Minimum Filing Requirement ("MFR") Schedule C-4, which contains the ratio of forfeited discounts revenue to total revenues for five years. However, I excluded the anomalous years of 2020 and 2021, using a three-year ratio, and applied it to Staff's *pro forma* Total Revenue excluding the revenue associated with the SSER and the Winter Storm Uri gas costs, both of which already include a level of Forfeited Discounts Revenue due to the inclusion of the pre-tax rate of return in determining the amounts recovered. My *pro forma* level of $3,014,410 differs from the Company's Application *pro forma* amount of $3,484,639, by $470,229.

EXPENSES

Uncollectible Accounts Expense

Q. How did SUA determine its Uncollectible Accounts Expense?

[6] Application, Schedule C2-IS3, Doc. No. 18, Part 3, p. 11.

A. SUA determined its Uncollectible Accounts ratio based on its Schedule C-4, which reflects a five-year average for each rate class ending in 2022. SUA then applied the ratio to each rate class's *pro forma* revenue including fuel cost to determine its *pro forma* level of $4,281,820.

Q. Please describe the differences in your calculation of Uncollectible Accounts Expense.

A. I used the Company's updated Schedule C-4 but excluded the anomalous years of 2020 and 2021, using a three-year ratio. I then applied the ratio for each rate class to Staff's *pro forma* revenues, excluding the revenue associated with the SSER and the Winter Storm Uri gas costs, both of which already include a level of Uncollectible Accounts Expense due to the inclusion of the pre-tax rate of return in determining the amounts recovered. As a result, my *pro forma* Uncollectible Accounts Expense is $3,493,450, which is $788,370 less than the Company's Application.

Rate Case Expense

Q. How did SUA determine its rate case expense?

A. The Company based its rate case expense on its estimate of $1,414,881, amortized over two years, for a *pro forma* level of expense of $707,440, as shown on its IS-7 Rate Case Expense Workpaper.[7]

Q. Please describe your determination of rate case expense.

[7] Application, Doc. 18, Part 3, Schedule C2-IS7, p. 14.

A. I determined a recommended level based on the Company's estimate but reduced the legal fees by $500,000 to reflect the lower end of the proposed range. I then normalized the amount over five years, which is the interval reflected in the last rate case. My Adjustment IS-7 of $182,976 increases actual test year expense to my recommended *pro forma* amount of rate case expense, a difference from the Company's Application of $524,464.

Deferred COVID-19 Expense Recovery

Q. What amount of deferred COVID-19 expense did SUA request in its Application?

A. Company witness Gillam discussed its Adjustment IS-20, referencing the regulatory asset that was allowed in Docket No. 20-012-A due to the moratorium on customer disconnections.[8] Because this is SUA's first opportunity to collect the net expense of $6,339,131, the Company has proposed to collect the amount over three years, including an additional $2,113,044 in *pro forma* expense.

Q. Do you agree with SUA's adjustment?

A. No. I agree with the total amount of expense, net of savings as proposed, but I disagree with the amortization period of three years, recommending five years instead. This period is consistent with my recommended rate case normalization period. This results in a *pro forma* expense amount of $1,267,826, which differs from SUA's request by $845,218.

[8] Direct Testimony of Phillip B. Gillam, Doc. 21, p. 31.

REVENUE CONVERSION FACTOR

Q. What is the purpose of the RCF?

A. The RCF increases the income deficiency by the additional amount of income taxes, uncollectible accounts expense and forfeited discounts revenue associated with the base rate increase in revenue.

Q. What RCF did SUA propose?

A. SUA's RCF for each rate class is shown on its Application Schedule C-5,[9] respectively, and was calculated using the Composite Tax Rate which incorporates both the Arkansas and Federal income tax rates (4.8% and 21.0%, respectively) in a five-year average ending 2022 of the Uncollectible Accounts Ratio from MFR Schedule C-4. The Forfeited Discounts ratio was not included in SUA's calculation, nor was the reduced State Income Tax Rate of 4.3% used. The rate classes' RCFs were then included in SUA's Schedule G-1 for the determination of a composite RCF of 1.34495.

Q. What is Staff's RCF?

A. I determined the RCF for each rate class in the same manner as SUA, however, I used the three-year averages ending in 2022, excluding 2020 and 2021. In addition, I included the lower Arkansas Income Tax Rate recently approved for 2024 and included the Forfeited Discounts Ratio. Staff's composite RCF of 1.3253 was determined in the Cost-of-Service Study as shown in Staff witness

[9] Application, Doc. No. 18, Part 3, Schedules C-4 and C-5, pp. 34-37; *see also* Doc. 13, Part 1, Schedule A-1, p. 12.

Burdette's Direct Exhibit MB-1. The impact of Staff's RCF as compared to the Company's is shown in my Direct Exhibit JH-7.

RATE SCHEDULES, EXEMPTION SCHEDULES, RIDERS AND REPORTS

System Safety Enhancement Rider

Q. Please describe SUA's SSER.

A. As approved in the Company's Acquisition Docket,[10] the SSER, Rider Schedule No. 2, supports the expedited replacement of mains and services projects in compliance with SUA's Distribution Integrity Management Program ("DIMP") and Transmission Integrity Management Program ("TIMP"). The SSER was accepted with certain limitations, such as being filed monthly to recover only historical capital investments, net of retirements once they are closed to plant and in service along with related depreciation expense. In addition, the total incremental revenue requirement is limited to 5% of $169.5 million each year, which were SUA's initial base rates, and which require a leak reduction savings of $106,314 per year.

The approval of the SSER was in the context of a Settlement, which also included a Customer Credit Rider ("CCR") that included the CERC credit of $22 million, SUA's ratepayer credit of $4 million, and SUA's estimated net present value of the impact of the elimination of ADIT on the cost of capital of $29.9 million to be refunded over three years. Also, Section 2.4.2 of the SSER indicated that it will only remain in effect until the effective date of new rates

[10] *See* Order Nos. 11 and 12, Docket No. 21-060-U, Doc. Nos. 142 and 145.

following the Company's filing a general rate case application. Therefore, as envisioned in the Settlement, unless authorized otherwise, the SSER will expire at the conclusion of this rate case, at approximately the same time as the expiration of the CCR.

Q. Did SUA request Commission approval of the SSER?

A. Not exactly. SUA only requested expansion of the interim SSER previously approved in Docket No 21-060-U.[11] SUA assumes that going forward it already has approval of the SSER and only seeks to expand it in this docket. As a result, the Company did not provide testimony typically required to support the approval of a rider, such as demonstration of meeting the traditional test that the costs are significant, volatile, and out of the utility's control.[12] Nor was testimony provided on the additional criteria considered by the Commission in Docket No. 19-035-U, of whether the rider shifts risks of costs from the utility onto customers; what other states have done with respect to recovery of this type of cost; and whether changes in the industry or unique circumstances warrant the rider.[13]

Q. Do you recommend approval of SUA's request regarding Commission approval of the SSER?

A. Yes; however, not as amended. The Company should continue to prioritize safety-related investments, which is the basis for my recommendation in lieu of

[11] Direct Testimony of Kurt W. Adams, Doc. 19, p. 24.
[12] Order No. 11, Docket No. 17-038-U, Doc. 147, p. 86, Footnote 10.
[13] Order No. 7, Docket No. 19-035-U, Doc. 97, p. 50.

the Company meeting the Commission's traditional criteria for approval of a rider. I disagree with including reliability expenditures in the SSER and only recommend expenditures consistent with those directly related to safety. Further, adding reliability projects to the SSER allows the Company to prioritize reliability projects consistent with the replacement of mains and services and other such goals, which lessens the need for the rider. SUA will be provided the opportunity to recover prudently incurred reliability projects in its next rate case, but in the context of full consideration of all the components in the Company's cost of service, not in disregard of any cost reductions or additional revenue that may offset the cost of these projects. Finally, SUA has not offered anything to ratepayers to balance the more timely cost recovery the SSER affords; in fact, the Company proposes to eliminate both the savings due to reduced leak repairs and the cap on its allowed revenue requirement.

Q. What modifications to the SSER request do you recommend to help balance the interests of all parties?

A. First, I suggest that the Company continue to include in the rider a cumulative level of savings due to the reduction in O&M expenses as a result of the capital investments.

Second, I recommend continuation of a cap determined on an annual basis on recovery through the rider using a percentage of SUA's base rate revenue requirement of no more than 4% as determined in this rate case.

Third, as noted above, the SSER should exclude reliability improvement projects.

Fourth, I recommend recognition of the additional accelerated depreciation-related Accumulated Deferred Income Tax ("ADIT") associated with the capital investments being included for recovery by reducing gross plant. Note, that this treatment is for purposes of this rider only and will not be included in future rate cases.

Fifth, I recommend exclusion from plant, both in the SSER and upon inclusion in future rate cases, Long-Term and Short-Term Incentive Compensation consistent with this rate case.

Lastly, I recommend modification of the proposed tariff language (1) to exclude any future requirements of the U.S. Department of Transportation's Pipeline and Hazardous Materials Safety Administration ("PHMSA") or the Arkansas Gas Pipeline Code; (2) to allow only projects eligible for recovery under Act 310 of 1981, as amended and defined at Ark. Code Ann. § 23-4-501(a)(1), if SUA or its predecessor has been previously approved by the Commission for its recovery; and (3) that language be added to the tariff that no additional monthly filings in the SSER be made once the Company has filed its Application for a general change in rates in future rate cases, allowing for an orderly cut-off of plant additions and their inclusion in base rates in future pending rate cases.

Please note, that any specific modification to SSER requested by SUA that I did not specifically address should not be deemed to be accepted.

Municipal Tax Adjustment Clause

Q. What did SUA request in regard to its Municipal Tax Adjustment Clause?

A. The Company is requesting to update Attachment A of Rider Schedule No. 3, Municipal Tax Adjustment. This update reflects changes to municipal franchise tax rates.[14]

Q. Do you agree with the requested change?

A. Yes. I recommend Commission approval of this update to Attachment A of Rider Schedule No. 3.

General Service Rule 5.08

Q. Did SUA request a waiver of the Commission's General Service Rules ("GSR")?

A. Yes. As discussed by SUA witness Fred Kirkwood, the Company requests a waiver of General Service Rule 5.08, "Estimated Usage for Billing," as applicable to Residential and Small Business Sales customers.[15] The excerpt of GSR 5.08 which SUA seeks to waive reads as follows:

> If a utility estimates usage, it shall use the customer's consumption for the same time at that location the year before. A utility may apply a weather-sensitive factor to the consumption in arriving at the current month's estimated usage. If no figures are available for the current customer at that location for the previous

[14] Direct Testimony of Phillip B. Gillam, Doc. 21, p. 46.
[15] Direct Testimony of Fred Kirkwood, Doc. 23, pp. 20-21.

> year, a utility shall use the class average to estimate consumption.

SUA's request is to modify the last sentence. The requested revised language is to insert, "SUA may use the customer's prior month's usage at that location, if available. If neither the customer's usage from the previous year or the previous month at that location is available," before the last clause of the last sentence. The revised language would read:

> If no figures are available for the current customer at that location for the previous year, SUA may use the customer's prior month's usage at that location, if available. If neither the customer's usage from the previous year or the previous month at that location is available, a utility shall use the class average to estimate consumption.

Q. Do you agree with the Company's request for a waiver of GSR Rule 5.08?

A. I agree that SUA's request is reasonable. I also agree with Company witness Kirkwood's assertion that this language is generally consistent with the approach used by Arkansas Oklahoma Gas Corporation ("AOG") and Black Hills Energy Arkansas, Inc. ("BHEA") and that this revised language allows for greater precision than a class average of all customers in that class. AOG and BHEA both use algorithms based on the prior month's usage, and this is the primary way to estimate a bill. SUA's recommendation of the prior month's usage is an <u>alternate</u> method to be used only if the previous year's usage is unavailable, but prior to using the class average. Therefore, SUA should consider the two alternatives of prior year's weather-adjusted usage and the

prior month's usage and use the more conservative of the two methods if reasonable.

Rate Schedule No. 3, Large Commercial Firm Service pooling and agency agreement notice requirements

Q. Please discuss the Pooling Service Agreements and Agency Agreements included in Rate Schedule No. 3, Large Commercial Firm Service ("LCS-1"), and summarize SUA's request in regard to the notice requirements.

A. As described in SUA's LCS-1 tariff Section 3.23.2, Pooling is the aggregation of the Receipt Point(s) available to customers subject to the Pooling Service Agreement and deliveries made at Delivery Point(s) delivered subject to the Pooling Service Agreement. The Pool Manager, having documented agency authority, shall submit nominations and allocation information for all customers subject to the Pooling Service Agreement. The Pooling Service Agreement allows for and controls the terms of the aggregation of Receipt Point(s) and Delivery Point(s) available to transport customers, as shown in the Appendix to the tariff. An Agency Agreement authorizes the customer's gas supplier or energy consultant to act as his agent for services provided by the Company.

SUA enters into pooling agreements with suppliers or agents who represent SUA's transportation service customers that are eligible for the transportation supply option under the Company's SCS-1 or LCS-1 tariff rate schedules or with a customer wanting to aggregate their multiple transportation accounts that are eligible for the transportation supply option under the

Company's SCS-1 or LCS-1 tariff rate schedules. SUA enters into agency agreements with a supplier or agent and the qualifying transportation customer who is eligible for the transportation supply option.

SUA requests that the language in the tariff at Section 3.23.6 and the related Appendix, including the Pooling Service Agreement and Agency Agreement, be updated to reflect a thirty-day notice prior to the termination or alteration of a Pooling Service Agreement or Agency Agreement rather than the current five-day notice. Mr. Kirkwood explains that a thirty-day notice would allow SUA customers sufficient time to secure an alternative gas supplier should a Pooling Service Agreement or Agency Agreement be terminated. For SUA, this additional time would prevent unnecessary interruptions in gas supply to SUA's customers, which is especially critical during adverse weather conditions, when securing additional gas supply can be challenging.

Q. Do you agree with the Company's proposed notice requirement changes?

A. Yes. I agree with the Company's request as reasonable.

Telemetry language for large commercial and small commercial transportation customers

Q. What did SUA propose in regard to Telemetry for large and small transportation customers?

A. SUA is proposing to modify the existing tariff language to require new large volume commercial customers, transportation or sales, or small commercial transportation customers to have wireless telemetry equipment and service.

Telemetry equipment is used to determine hourly and daily flow of gas at a customer's point of delivery. Telemetering, or remote metering, is achieved by installing a device on or near the gas meter to be remotely monitored via analog phone line or wireless service.

Any existing customers that currently use analog service will be allowed to continue to use such service; however, if any existing analog equipment must be replaced due to equipment failure, it must be replaced with wireless telemetry equipment.

There are currently two options for analog telemetry and two options for wireless telemetry. The current analog customers will not be affected unless the customers phone line is not working, but as noted above, the analog options are not available for new customers. For wireless, SUA provides the wireless service for $10 per month or wireless service and telemetry equipment for $40 or $94 per month, depending on whether pressure instrumentation is required or not.

SUA's basis for this change is the evolution of telecommunications from analog to digital communications, along with telecommunication manufacturers' phasing out of analog telemetry units in favor of digital units, and the failure of some current customers that are required to have telemetry service to repair their analog telecommunication lines in a timely manner, which can drive up cost of service and affect operational efficiency.

Q. Do you agree with SUA's proposed tariff changes to Rate Schedule No. 2 Small Commercial Firm Sales Service, Section 2.4; Rate Schedule No 3, Large Commercial Firm Service, Section 3.6, and the Large Volume Commercial Customer Agreement (System Supply Option and Transportation Supply Option) contained in the Appendix; Rate Schedule No. 4, Small Commercial Firm Sales Service – Off-Peak, Section 4.3; and Rate Schedule No. 8 Small Commercial Firm Sales Service – NGV, Section 8.4?

A. Yes. I agree with the Company's request as reasonable.[16]

Payment Center Report

Q. Please discuss the Payment Center Report required of SUA.

A. The Payment Center Report was required as a result of Docket No. 08-128-TF, wherein SUA's predecessor, CenterPoint Energy Resources Corp d/b/a CenterPoint Energy Arkansas Gas ("CEA") filed its request to begin charging customers a $1.00 fee and to revise Policy Schedule No. 11 reflecting the fee to be charged customers. The Commission was concerned about providing a free pay agent in close proximity to customers and also the costs associated with the program. The policy schedule was approved, first as a pilot, then permanently in 2012. Order No. 9 closed the docket. However, the discontinuation of the reporting was never addressed and has continued since

[16] Application, Doc. No. 18, part 8, Schedule H-10, pp. 40-42, 53-55, 88-90, 99-101, 116-118, and 123-125.

that time. SUA's website does point customers to the fee free locations, which are paid by SUA at $1.25, but does not show the locations charging the $1.00 fee. The Company is not proposing to change the Policy Schedule.

SUA is requesting to forego its quarterly reporting of fee and no-fee authorized payment centers and the volume and charges to both the Company and to its customers.

Q. What is your recommendation regarding the Payment Center Report?

A. SUA maintains a list of payment centers on its website, but I recommend that the website is clear as to whether the payment center is free or not and that all payment centers are included. SUA should also continue to maintain the supporting data required in the report, for any future requests. With those recommendations, I support SUA's request to forego any further filed Payment Center Reports.

SUMMARY OF RECOMMENDATIONS

Q. What are your recommendations?

A. I recommend that the Commission:

- Reject SUA's revenue requirement request and accept Staff's;
- Reject SUA's proposed SSER Rider and accept Staff's recommended modifications;
- Accept SUA's update to its Municipal Tax Adjustment Clause;
- Waive General Service Rule 5.08 for SUA;

- Accept SUA's revised Rate Schedule No. 3, Large Commercial Firm Service pooling and agency agreement notice requirements;
- Accept SUA's telemetry language for large commercial and small commercial transportation customers; and
- Accept SUA's proposal to discontinue filing Payment Center Reports upon meeting the conditions of maintaining the data and including all payment centers on its website, specifying whether they require a fee or not.

Q. Does this conclude your testimony?

A. Yes.

CERTIFICATE OF SERVICE

I, Joshua A. Baxter, hereby certify that a copy of the foregoing has been served on all parties of record on July 10, 2024, via the Arkansas Public Service Commission's Electronic Filing System.

/s/ JOSHUA A. BAXTER
Joshua A. Baxter

APSC FILED Time: 7/10/2024 10:50:34 AM: Recvd 7/10/2024 10:48:53 AM: Docket 23-079-U-Doc. 98

BEFORE THE
ARKANSAS PUBLIC SERVICE COMMISSION

IN THE MATTER OF THE APPLICATION OF SUMMIT UTILITIES ARKANSAS, INC., FOR A GENERAL CHANGE OR MODIFICATION IN ITS RATES, CHARGES AND TARIFFS	))))	DOCKET NO. 23-079-U

DIRECT EXHIBITS

OF

JEFF HILTON
DIRECTOR
GAS AND WATER UTILITIES SECTION

ON BEHALF OF THE GENERAL STAFF OF THE
ARKANSAS PUBLIC SERVICE COMMISSION

JULY 10, 2024

 APSC FILED Time: 7/10/2024 10:50:34 AM: Recvd 7/10/2024 10:48:53 AM: Docket 23-079-U-Doc. 98
TEST YEAR ENDED DECEMBER 31, 2023
SUMMARY OF OPERATIONS

(1)	(2)	(3)
Line No.	Description	Arkansas
1	Adjusted Rate Base	$ 1,225,238,125
2	Adjusted Operating Revenue	$ 179,886,447
3	Adjusted Operating Expense	$ 167,787,191
4	Adjusted Operating Income	$ 12,099,256
5	Current Rate of Return	0.99%
6	Required Rate of Return	5.58%
7	Required Operating Income	$ 68,368,287
8	Operating Income Deficiency/(Excess)	$ 56,269,031
9	Revenue Conversion Factor	1.3253
10	Revenue Deficiency/(Excess)	$ 74,571,448
11	Total Non-Gas Revenue Requirement	$ 254,457,895
12	Less: Other Revenues	6,507,974
13	Total Rate Schedule Revenue Requirement	247,949,921

SUMMIT UTILITIES ARKANSAS, INC. **DIRECT EXHIBIT JH-2**
DOCKET NO. 23-079-U
TEST YEAR ENDED DECEMBER 31, 2023
SUMMARY OF RATE BASE

(1)	(2)	(3)	(4)	(5)
Line No.	Description	Total Company December 31, 2023	Staff Adjustments	As Adjusted By Staff
1	Gross Utility Plant-In-Service	$ 1,680,547,407	$ 134,394,026	$ 1,814,941,433
2	Less: Accumulated Depreciation	$ (634,743,126)	$ (50,705,590)	$ (685,448,717)
3	Net Utility Plant-In-Service	$ 1,045,804,280	$ 83,688,436	$ 1,129,492,716
4	Construction Work-In-Progress	$ 20,410,287	$ (20,410,287)	$ -
5	Working Capital Assets	$ 343,860,155	$ (248,114,746)	$ 95,745,409
6	Non-Utility Property			$ -
7	Gas Plant Acquisition Adjustment	$ 690,091,096	$ (690,091,096)	$ -
8	Total Rate Base	$ 2,100,165,818	$ (874,927,693)	$ 1,225,238,125

SUMMIT UTILITIES ARKANSAS, INC. **DIRECT EXHIBIT JH-3**
DOCKET NO. 23-079-U
ARSC FILED Time: 7/10/2024 10:50:34 AM: Recvd 7/10/2024 10:48:53 AM: Docket 23-079-U-Doc. 98
TEST YEAR ENDED DECEMBER 31, 2023
ADJUSTMENTS TO RATE BASE

(1)	(2)	(3)	(4)	(5)	
Line No.	Staff Adj. No.	Description	Staff Witness	Staff Adjustments	
1		Adjustments to Utility Gross Plant-In-Service			
2	RB-2	CWIP Placed in Service Pro Forma Year	Pitts	$ 162,461,129	
3	RB-3	Pro Forma Retirements	Pitts	$ (15,826,521)	
4	RB-4	Pro Forma Reclassifications	Pitts	$ (7,773,000)	
5	RB-12	ARO - Adjustment	Pitts	$ (2,280,944)	
6	RB-13	STIC	Pitts	$ (1,749,525)	
7	RB-14	Volunteer Time Off	Pitts	$ (57,145)	
8	RB-15	Rebranding Capital Expenditures	Pitts	$ (379,968)	
9		Total Adjustments to Utility Gross Plant-In-Service			$ 134,394,026
10		Adjustments to Accumulated Depreciation			
11	RB-1	Pro Forma Capital Expenditures	Pitts	$ 8,550,586	
12	RB-3	Pro Forma Retirements	Pitts	$ 15,826,521	
12	RB-5	Pro Forma RWIP /Retirements	Pitts	$ (54,319)	
14	RB-6	Pro Forma Depreciation	Pitts	$ (66,357,897)	
14	RB-7	Remove CWIP/ RWIP	Pitts	$ (8,982,020)	
16	RB-12	ARO - Adjustment	Pitts	$ 228,094	
17	RB-13	STIC	Pitts	$ 66,767	
18	RB-14	Volunteer Time Off	Pitts	$ 2,179	
17	RB-15	Rebranding Capital Expenditures	Pitts	$ 14,500	
20		Total Adjustments to Accumulated Depreciation			$ (50,705,590)
21		Adjustments to Construction Work-In-Progress			
22	RB-7	Remove CWIP/ RWIP	Pitts		$ (20,410,287)
23		Adjustments to Working Capital Assets			
24	RB-10	Adjust 13-Month Average Balance	Malone	$ (294,973,142)	
25	RB-11	Adjust Working Capital Assets to 13 month Averge Balance	Malone	$ 46,858,397	
26		Total Adjustments to Working Capital Assets			$ (248,114,746)
27		Other Adjustments			
28	RB-9	Remove Acquisition Adjustment	Pitts	$ (690,091,096)	
29	RB-12	ARO - Adjustment	Pitts	$ -	
30		Total Other Adjustments			$ (690,091,096)
31		Total Rate Base Adjustments			$ (874,927,693)

SUMMIT UTILITIES ARKANSAS, INC. **DIRECT EXHIBIT JH-4**
DOCKET NO. 23-079-U
TEST YEAR ENDED DECEMBER 31, 2023
STATEMENT OF INCOME AND EXPENSE

(1)	(2)	(3)	(4)	(5)
Line No.	Description	Total Company December 31, 2023	Staff Adjustments	As Adjusted By Staff
1	Operating Revenue:			
2	Sales Revenues	$ 447,021,397	$ (273,642,924)	$ 173,378,473
3	Other Operating Revenues	$ 4,970,187	$ 1,537,787	$ 6,507,974
4	Total Operating Revenue	$ 451,991,584	$ (272,105,137)	$ 179,886,447
5	Operating Expenses:			
6	Cost of Gas Purchased	$ 264,280,513	$ (264,280,513)	$ -
7	Transmission Expense	$ 4,697,634	$ (4,697,634)	$ (0)
8	Distribution Expense	$ 44,174,516	$ (553,306)	$ 43,621,210
9	Customer Accounts Expense	$ 19,112,626	$ (6,630,385)	$ 12,482,241
10	Customer Service & Information Expense	$ 574,465	$ (88,262)	$ 486,204
11	Sales Expense	$ 403,143	$ (220,595)	$ 182,549
12	General & Administrative Expense	$ 36,486,045	$ (2,213,396)	$ 34,272,649
13	Depreciation & Amortization Expense	$ 60,675,448	$ 7,176,444	$ 67,851,892
14	Taxes Other Than Income	$ 14,288,810	$ (167,129)	$ 14,121,681
15	Total Operating Expense	$ 444,693,201	$ (271,674,775)	$ 173,018,426
16	Federal & State Income Tax	$ (250,511)	$ (4,980,724)	$ (5,231,235)
17	Total Expenses	$ 444,442,690	$ (276,655,499)	$ 167,787,191
18	Net Utility Operating Income (Loss)	$ 7,548,894	$ 4,550,362	$ 12,099,256

(1)	(2)	(3)	(4)	$ (5)	$ (6)	$ (7)	(8)	(9)	(10)	(11)
								Customer	Customer	
	Staff's			Operating	Cost	Transmission	Distribution	Accounts	Information	Sales
Line	Adj.		Staff	Revenue	of Gas	Expense	Expense	Expense	Expense	Expense
No.	No.	Description	Witness	(480-495)	(800-813)	(850-867)	(870-894)	(901-905)	(907-910)	(911-916)
1	IS-1	Cost of Gas Adjustment	Hilton	$0	($264,280,513)	($4,697,634)	-	-	-	-
2	IS-2	Miscellaneous Taxes (Other Than Income)	Hilton	$0	$0	$0	-	-	-	-
3	IS-3	Revenue Adjustment	Hilton	($273,642,924)	$0	$0	-	-	-	-
4	IS-4	Forfeited Discount Normalization	Hilton	$1,537,787	$0	$0	-	-	-	-
6	IS-6	Bad Debt Adjustment	Hilton	$0	$0	$0	-	(7,295,558)	-	-
7	IS-7	Rate Case Amortization Adjustment	Hilton	$0	$0	$0	-	-	-	-
9	IS-9	Advertising & Marketing Adjustment	Hilton	$0	$0	$0	-	-	(88,262)	(220,595)
10	IS-10	Other Expenses Adjustment	Hilton	$0	$0	$0	(13,745)	(918)	-	-
11	IS-11	Interest on Customer Deposits	Hilton	$0	$0	$0	-	89,460	-	-
12	IS-12	Payroll Adjustment	Ray	$0	$0	$0	(1,179,171)	(135,129)	-	-
13	IS-13	Benefits Adjustment	Ray	$0	$0	$0	-	-	-	-
14	IS-14	Meals & Travel Adjustment	Hilton	$0	$0	$0	(190,671)	(55,807)	-	-
15	IS-15	Postage Expense Adjustment	Hilton	$0	$0	$0	-	-	-	-
16	IS-16	Property Tax Adjustment	Pitts	$0	$0	$0	-	-	-	-
17	IS-17	Pipeline Locator Fees	Hilton	$0	$0	$0	1,166,079	-	-	-
18	IS-18	Corporate Pro Forma Adjustments	Ray	$0	$0	$0	-	-	-	-
19	IS-19	Depreciation Expense Adjustment	Pitts	$0	$0	$0	-	-	-	-
20	IS-20	Deferred COVID Expense Recovery	Hilton	$0	$0	$0	-	1,267,826	-	-
21	IS-21	Deferred Income Tax Expense - ARO	Malone	$0	$0	$0	-	-	-	-
22	IS-22	Income Tax	Malone	$0	$0	$0	-	-	-	-
23	IS-23	Non-Utility Expenditures	Malone	$0	$0	$0	(13,162)	-	-	-
24	IS-24	Vegetation Control	Malone	$0	$0	$0	(212,357)	-	-	-
25	IS-25	Non-Recurring Transactions	Malone	$0	$0	$0	-	-	-	-
26	IS-26	Volunteer Time Off	Ray	$0	$0	$0	(110,280)	(11,007)	-	-
27	IS-27	Transportation Depreciation Allocation	Pitts	$0	$0	$0	-	-	-	-
28	IS-28	Call Center	Malone	$0	$0	$0	-	(489,252)	-	-
46		TOTAL ADJUSTMENTS		($272,105,137)	($264,280,513)	($4,697,634)	($553,306)	($6,630,385)	($88,262)	($220,595)

(1)	(2)	(3)	(4)	(12)	(13)	(14)	(15)	(16)
				Admin &		Taxes	Income	
	Staff's				Depreciation	Other Than	Tax	Impact on
Line	Adj.		Staff		Expense	Income	Expense	Net Operating
No.	No.	Description	Witness		(403-407)	(408.1)	(409-411)	Income
1	IS-1	Cost of Gas Adjustment	Hilton	-	-	-	-	268,978,147
2	IS-2	Miscellaneous Taxes (Other Than Income)	Hilton	-	-	(8,033)	-	8,033
3	IS-3	Revenue Adjustment	Hilton	-	-	-	-	(273,642,924)
4	IS-4	Forfeited Discount Normalization	Hilton	-	-	-	-	1,537,787
6	IS-6	Bad Debt Adjustment	Hilton	-	-	-	-	7,295,558
7	IS-7	Rate Case Amortization Adjustment	Hilton	182,976	-	-	-	(182,976)
9	IS-9	Advertising & Marketing Adjustment	Hilton	(613,673)	-	-	-	922,529
10	IS-10	Other Expenses Adjustment	Hilton	(403,787)	-	-	-	418,450
11	IS-11	Interest on Customer Deposits	Hilton	-	-	-	-	(89,460)
12	IS-12	Payroll Adjustment	Ray	(182,598)	-	(110,542)	-	1,607,440
13	IS-13	Benefits Adjustment	Ray	(229,104)	-	-	-	229,104
14	IS-14	Meals & Travel Adjustment	Hilton	(128,559)	-	-	-	375,037
15	IS-15	Postage Expense Adjustment	Hilton	168,749	-	-	-	(168,749)
16	IS-16	Property Tax Adjustment	Pitts	-	-	(24,501)	-	24,501
17	IS-17	Pipeline Locator Fees	Hilton	-	-	-	-	(1,166,079)
18	IS-18	Corporate Pro Forma Adjustments	Ray	(190,852)	-	(14,094)	-	204,946
19	IS-19	Depreciation Expense Adjustment	Pitts	-	8,312,597	(248,139)	-	(8,064,458)
20	IS-20	Deferred COVID Expense Recovery	Hilton	-	-	-	-	(1,267,826)
21	IS-21	Deferred Income Tax Expense - ARO	Malone	-	-	-	-	0
22	IS-22	Income Tax	Malone	-	-	-	(4,980,724)	4,980,724
23	IS-23	Non-Utility Expenditures	Malone	(69,943)	-	-	-	83,105
24	IS-24	Vegetation Control	Malone	-	-	-	-	212,357
25	IS-25	Non-Recurring Transactions	Malone	(725,985)	-	-	-	725,985
26	IS-26	Volunteer Time Off	Ray	(20,619)	-	(9,959)	-	151,865
27	IS-27	Transportation Depreciation Allocation	Pitts	-	(888,014)	-	-	888,014
28	IS-28	Call Center	Malone	-	-	-	-	489,252
46		TOTAL ADJUSTMENTS		($2,213,396)	$7,424,583	($415,268)	($4,980,724)	$4,550,362

 APSC FILED Time: 7/10/2024 10:50:34 AM: Recvd 7/10/2024 10:48:53 AM: Docket 23-079-U-Doc. 98
TEST YEAR ENDED DECEMBER 31, 2023
INCOME TAX CALCULATION

(1) Line No.	(2) Description	(3) State Income Taxes	(4) Federal Income Taxes
1	Operating Revenues	$ 179,886,447	$ 179,886,447
2	Less:		
3	Operating Expenses	$ 173,018,426	$ 173,018,426
4	Fixed Charges	$ 22,350,794	$ 22,350,794
5	Operating Income Before Taxes	$ (15,482,772)	$ (15,482,772)
6	State Income Tax @ 4.3%	$ (665,759)	$ (665,759)
7	Federal Taxable Income		$ (14,817,013)
8	Federal Income Tax @ 21%		$ (3,111,573)
9	Less ITC Amortization		$ -
10	Total Federal Income Tax		$ (3,111,573)
11	Total State & Federal Income Tax before EDIT (Refund)/Collection		$ (3,777,332)
12	State EDIT Collection PF Year @ 4.3% corporate		
13	rate amortized 5 years		$ 28,067
14	ARAM Federal EDIT Refund		$ (2,037,800)
15	COR DTA of $25,568,161 amort for 46 years		$ 555,830
16	Net Federal Protected EDIT Customer Refund		$ (1,481,970)
17	Total State & Federal Income Tax		$ (5,231,235)
18	Less: Test Year State & Federal Income Tax		$ -
19	Adjustment		$ (5,231,235)

20	Calculation of Fixed Charges	Amount
21	Total Arkansas Rate Base	$ 1,225,238,125
22	Weighted Cost of Debt	1.82%
23	Fixed Charges	$ 22,350,794

 APSC FILED Time: 7/10/2024 10:50:34 AM: Recvd 7/10/2024 10:48:53 AM: Docket 23-079-U-Doc. 98
TEST YEAR ENDED DECEMBER 31, 2023
REVENUE REQUIREMENT RECONCILIATION

	Expense Adjustment No.	Revenue Requirement Impact	Company to Staff Revenue Requirement
SUA Non-Gas Revenue Requirement			$ 286,660,736
Rate Base Impact:			
Plant-In-Service		$ 1,677,704	
Working Capital Assets		$ (1,544,479)	
Total Rate Base Impact			$ 133,225
Rate of Return Impact:			
Return on Equity		$ 5,787,755	
Current, Accrued, and Other Liabilities		$ 1,779,984	
Capital Structure		$ 5,283,156	
Accumulated Deferred Income Taxes		$ -	
Other		$ 1,837,260	
Total Rate of Return Impact			$ (14,688,155)
Taxes & Revenue Conversion Factor Impact:			
State & Federal Income Tax Expense		$ (6,857,696)	
Revenue Conversion Factor Impact		$ (8,545,742)	
Total Tax & Revenue Conversion Factor Impact			$ (15,403,438)
Operating Expense Adjustments Impact:			
Test Year Projected vs. Actual		$ 108,289,704	
Cost of Gas Adjustment	IS-1	$ (100,362,083)	
Miscellaneous Taxes (Other Than Income)	IS-2	$ 6	
Bad Debt Adjustment	IS-6	$ (1,517,957)	
Rate Case Amortization Adjustment	IS-7	$ (524,464)	
Advertising & Marketing Adjustment	IS-9	$ (443,052)	
Other Expenses Adjustment	IS-10	$ (297,373)	
Interest on Customer Deposits	IS-11	$ (5,349)	
Payroll Adjustment	IS-12	$ (2,312,531)	
Benefits Adjustment	IS-13	$ (374,024)	
Meals & Travel Adjustment	IS-14	$ (8,054)	
Postage Expense Adjustment	IS-15	$ (364,600)	
Property Tax Adjustment	IS-16	$ (256,826)	
Pipeline Locator Fees	IS-17	$ (198,922)	
Corporate Pro Forma Adjustments	IS-18	$ (731,090)	
Depreciation Expense Adjustment	IS-19	$ (649,964)	
Deferred COVID Expense Recovery	IS-20	$ (845,217)	
Non-Utility Expenditures	IS-23	$ (83,105)	
Vegetation Control	IS-24	$ (212,357)	
Non-Recurring Transactions	IS-25	$ (725,985)	
Volunteer Time Off	IS-26	$ (151,865)	
Transportation Depreciation Allocation	IS-27	$ (888,014)	
Call Center	IS-28	$ (489,252)	
Total Operating Expense Adjustments Impact		$ (3,152,373)	$ (3,152,373)
Staff Non-Gas Revenue Requirement			$ 254,457,895
Total Revenue Requirement Difference			$ 32,202,841

CERTIFICATE OF SERVICE

I, Joshua A. Baxter, hereby certify that a copy of the foregoing has been served on all parties of record on July 10, 2024, via the Arkansas Public Service Commission's Electronic Filing System.

/s/ JOSHUA A. BAXTER
Joshua A. Baxter

APSC FILED Time: 7/10/2024 10:54:09 AM: Recvd 7/10/2024 10:50:13 AM: Docket 23-079-U-Doc. 99

BEFORE THE
ARKANSAS PUBLIC SERVICE COMMISSION

IN THE MATTER OF THE APPLICATION OF SUMMIT UTILITIES ARKANSAS, INC. FOR APPROVAL OF A GENERAL CHANGE OR MODIFICATION IN RATES, CHARGES, AND TARIFFS	)))))	DOCKET NO. 23-079-U

REDACTED DIRECT TESTIMONY

OF

MIDDLETON RAY
MANAGER OF AUDITS

ON BEHALF OF THE GENERAL STAFF OF THE
ARKANSAS PUBLIC SERVICE COMMISSION

JULY 10, 2024

INTRODUCTION

Q. Please state your name and business address?

A. My name is Middleton Ray. My business address is Arkansas Public Service Commission ("Commission" or "APSC"), 1000 Center Street, Little Rock, Arkansas 72201.

Q. Would you please describe your qualifications and background?

A. I joined the General Staff of the Commission ("Staff") in 2018, as a Public Utility Auditor and was promoted to Senior Public Utility Auditor in 2019. I was promoted to my current position in 2022. Before joining Staff, I was a tax manager employed by Fortune 500 companies for 30 years.

My educational qualifications include a Bachelor of Science in Accounting from the University of Arkansas Little Rock. I am a Certified Public Accountant licensed to practice in the State of Arkansas and have been licensed to practice in Texas and Arkansas for more than 39 years. In maintenance of this certification, I have completed numerous additional academic and continuing professional education hours and seminars. Since joining Staff, I have completed *The Basics – Practical Regulatory Training for the Electric Industry* sponsored by the New Mexico State Center for Public Utilities and the National Association of Regulatory Utility Commissioners.

I have previously filed testimony before the Commission on matters concerning utility company ratemaking and revenue requirement issues.

PURPOSE OF TESTIMONY

Q. What is the purpose of your Direct Testimony in this Docket?

A. The purpose of my Direct Testimony is to address the Application for Approval of a General Change or Modification in Rates, Charges, and Tariffs ("Application") of Summit Utilities Arkansas, Inc. ("SUA" or "Company") filed on January 25, 2024. In doing so, I address certain expense and rate base adjustments.

Specifically, I discuss Staff's adjustments to Payroll Expense and related taxes, benefits, and Short-Term Incentive Compensation ("STI"). In doing so, I address the respective portions of the Direct Testimonies of SUA witnesses Kurt W. Adams,[1] Phillip B. Gillam,[2] and Sam Springer.[3] I have summarized the contested adjustments in Table 1 below:

Table 1
Contested Adjustments

Adj. No.	Description	Staff Amount	Company Amount	Difference
IS-12[4]	Payroll and Payroll Tax			
	Payroll	$2,420,136	$656,306	
	STI[5]	[redacted]	N/A	
	Overtime	($1,619,052)	N/A	
	Payroll Tax	($9,201)	$48,785	
	Total	($133,788)	$705,091	($838,879)
IS-13[6]	Benefits	($229,104)	$144,920	($374,024)
IS-18[7]	Corporate Pro Forma	[redacted]	$526,144	($923,278)

[1] Doc. 19.
[2] Doc. 21.
[3] Doc. 32.
[4] Doc. 18, Part 3, C2-IS-12.
[5] Direct Exhibits of Middleton Ray, Confidential Direct Exhibit MR-1.
[6] Doc. 18, Part 3, C2-IS-13.
[7] Doc. 18, Part 3, C2-IS-18.

Adj. No.	Description	Staff Amount	Company Amount	Difference
IS-26[8]	Volunteer Time-Off	($151,865)	N/A	($151,865)
RB-13[9]	STI Capitalized			
	SUA	[redacted]	N/A	[redacted]
	SUI	[redacted]	N/A	[redacted]
	Total	[redacted]	N/A	[redacted]

TEST YEAR AND *PRO FORMA* YEAR

Q. What test year and *pro forma* year did SUA utilize in its Application?

A. SUA's Application used a test year ending December 31, 2023, comprised of six months of actual data and six months of projected data, with *pro forma* year adjustments ending December 31, 2024.[10]

Q. What test year and *pro forma* year did Staff use in its review and adjustments?

A. Staff's test year reflects twelve months of actual data for the year ending December 31, 2023, with adjustments to the *pro forma* year for known and measurable changes through December 31, 2024, the same as the Company. Because SUA's test year ended on December 31, 2023, Staff requested updated Minimum Filing Requirements, which were provided on April 11, 2024.

EMPLOYEE-RELATED EXPENSES

Q. Please discuss the Company's payroll and payroll tax adjustment for SUA employees.

[8] Direct Exhibit MR-1.
[9] Direct Exhibits of Middleton Ray, Confidential Direct Exhibit MR-1.
[10] Application, Doc. 18, Part 1, p. 3.

A. As described by Company witness Gillam in his Direct Testimony, SUA's payroll Adjustment IS-12 included base pay as of December 31, 2023.[11] In addition, SUA included a 4% increase for 2024 merit raises. SUA's Adjustment IS-12 of $705,091 resulted in its *pro forma* regular payroll level, including payroll taxes, of $27,431,438 in its Application.[12]

Q. Did the Company make adjustments for incentive compensation in its Application?

A. No. The Company did not adjust expense for STI. However, the Company did not include long-term incentive compensation in its Application.[13] Nor did SUA make an adjustment to remove STI from its rate base.

The Company's STI plan is funded based on the overall performance of Summit Utilities, Inc. ("SUI").[14] My adjustment removes 50 percent of *pro forma* STI as financially based compensation, due to providing a shared benefit to both shareholders and ratepayers consistent with the Commission's recognition of the shared benefit of financial incentives by both shareholders and ratepayers and the lack of ratepayer benefits associated with earnings-based incentives. Staff has recommended and the Commission has accepted similar adjustments to disallow 50% of STI based on the funding mechanism since it was ordered in Docket No.

[11] Doc. 21, p. 26, lines 15-22.
[12] Doc. 18, Part 3, C2-IS-12.
[13] Doc. 32, p. 9, line 9.
[14] *Id*. at p. 5, line 5.

13-028-U.[15] My adjustment removes STI of [redacted] from *pro forma* payroll and related tax expense.

Q. Do you agree with the level of overtime SUA included in its Application?

A. No. I made an adjustment of $1,619,052 to reduce payroll by including a normalized level of overtime based on a five-year average.

Q. Do you agree with the level of payroll taxes SUA included in its Application?

A. No. I made an adjustment of $229,201 to reduce payroll tax expense based on my adjustments to STI and overtime.

Q. Do you agree with the Company's Adjustment IS-13 for Benefits?

A. No. I made an adjustment of $229,104 to increase benefits using the Company's burden rate based on my adjustments to STI and overtime.

Q. Do you agree with the Company's Adjustment IS-18 for Corporate *Pro Forma* Expenses?

A. No. I made an adjustment of $397,134 to reduce payroll and payroll tax expense allocated from SUI to remove STI consistent with my Adjustment IS-12.

Q. Did you propose Adjustment IS-26 for Volunteer Time-Off?

A. Yes. I made an adjustment of $151,865 to reduce payroll, payroll tax, and benefits expense to remove volunteer time that does not provide a benefit to Arkansas ratepayers.

RATE BASE ADJUSTMENTS

Q. Do you recommend a reduction to plant and related expenses for STI?

[15] *See* Order No. 21, Docket No. 13-028-U, Doc. 431, p. 54.

A. Yes. In addition to the expense reductions I recommended in my Adjustments IS-12 and IS-18, I recommend a reduction in Rate Base by [redacted] for financially based incentive compensation for a total of [redacted] included since the beginning of 2022. Similar to my expense adjustments, this adjustment is also based on the Commission's recognition of the shared benefit of financial incentives by both shareholders and ratepayers and the lack of ratepayer benefits associated with earnings-based incentives and removes the capitalized portion of disallowed incentives. This adjustment is consistent with the Settlement Agreement as modified in Order No. 12 of Docket No. 19-008-U.[16] Staff witness Michael L. Pitts included the reduction to plant and related depreciation, as discussed in his Direct Testimony.

SUMMARY OF RECOMMENDATIONS

Q. What are your recommendations?

A. I recommend the Commission accept Staff's adjustments to Payroll Expense and related taxes, STI, overtime, volunteer time, and Rate Base Adjustments, as described previously and demonstrated on Table 1, and reject the corresponding amounts proposed by SUA.

Q. Does this conclude your testimony?

A. Yes.

[16] Order No. 12, Docket No. 19-008-U, Doc. 294, pp. 93-96.

CERTIFICATE OF SERVICE

I, Joshua A. Baxter, hereby certify that a copy of the foregoing has been served on all parties of record on July 10, 2024, via the Arkansas Public Service Commission's Electronic Filing System.

/s/ JOSHUA A. BAXTER
Joshua A. Baxter

APSC FILED Time: 7/10/2024 10:54:14 AM: Recvd 7/10/2024 10:50:50 AM: Docket 23-079-U-Doc. 100

BEFORE THE
ARKANSAS PUBLIC SERVICE COMMISSION

IN THE MATTER OF THE APPLICATION OF SUMMIT UTILITIES ARKANSAS, INC. FOR APPROVAL OF A GENERAL CHANGE OR MODIFICATION IN RATES, CHARGES, AND TARIFFS	)))))	DOCKET NO. 23-079-U

REDACTED DIRECT EXHIBITS

OF

MIDDLETON RAY
MANAGER OF AUDITS

ON BEHALF OF THE GENERAL STAFF OF THE
ARKANSAS PUBLIC SERVICE COMMISSION

JULY 10, 2024

REDACTED DIRECT EXHIBIT MR-1

STAFF DR-9

APSC FILED Time: 7/10/2024 10:54:14 AM: Recvd 7/10/2024 10:50:50 AM: Docket 23-079-U-Doc. 100

ENTIRE CONFIDENTIAL EXHIBIT MR-1 REDACTED

PURSUANT TO

COMMISSION PROTECTIVE ORDER NO. 1

IN DOCKET NO. 23-079-U

APSC FILED Time: 7/10/2024 10:54:14 AM: Recvd 7/10/2024 10:50:50 AM: Docket 23-079-U-Doc. 100

ENTIRE CONFIDENTIAL EXHIBIT MR-1 REDACTED

PURSUANT TO

COMMISSION PROTECTIVE ORDER NO. 1

IN DOCKET NO. 23-079-U

DIRECT EXHIBIT MR-2

STAFF DR-90

ARKANSAS PUBLIC SERVICE COMMISSION
APSC 23-079-U
APSC FILED Time: 7/10/2024 10:54:14 AM: Recvd 7/10/2024 10:50:50 AM: Docket 23-079-U-Doc. 100
2023 SUA RATE CASE

REQUEST NO.: APSC-090-1

COMPANY NAME: SUMMIT UTILITIES ARKANSAS

DATE RECEIVED: 4/22/2024

DATE DUE: 5/7/2024

EXTENSION DATE:

INFORMATION REQUESTED:

1. Please provide the total number of Volunteer Time Off (VTO) hours by month for the 12 months ended December 31, 2023.
2. Please provided the total compensation paid, by month, by FERC account (both capital and expense) , for VTO for the 12 months ended December 31, 2023.

REQUESTED BY: ARKANSAS PUBLIC SERVICE COMMISSION - DON MALONE

RESPONSE:

1. The total Volunteer Time Off for SUA is 4,366.25 hours for the year 2023. The attached file has the breakout by month.

2. See attached for the dollar amounts posted by FERC for 2023.

SPONSOR:
Teresita Trevino, Ladonna Marsh

RESPONSIVE DOCUMENTS:
APSC-090-1 2023 VTO FERC.xlsx
APSC-090-1 VTO Hours 2023.xlsx

The foregoing response to the above information request is accurate and complete, and contains no material misrepresentations or omissions based upon present facts known to the undersigned. The undersigned agrees to immediately inform the Requestor if any matters are discovered which would materially affect the accuracy or completeness of the information provided in response to the above information request.

/s/ Brooke South Parsons
Signature of Company Representative

DATE PROVIDED: MAY 07, 2024

CERTIFICATE OF SERVICE

I, Joshua A. Baxter, hereby certify that a copy of the foregoing has been served on all parties of record on July 10, 2024, via the Arkansas Public Service Commission's Electronic Filing System.

/s/ JOSHUA A. BAXTER
Joshua A. Baxter

APSC FILED Time: 7/10/2024 10:54:22 AM: Recvd 7/10/2024 10:52:10 AM: Docket 23-079-U-Doc. 101

BEFORE THE
ARKANSAS PUBLIC SERVICE COMMISSION

IN THE MATTER OF THE APPLICATION OF SUMMIT UTILITIES ARKANSAS, INC. FOR A GENERAL CHANGE OR MODIFICATION IN ITS RATES, CHANGES AND TARIFFS	))))	DOCKET NO. 23-079-U

DIRECT TESTIMONY

OF

MICHAEL L. PITTS
SENIOR PUBLIC UTILITY AUDITOR
AUDITS SECTION

ON BEHALF OF THE GENERAL STAFF OF THE
ARKANSAS PUBLIC SERVICE COMMISSION

JULY 10, 2024

INTRODUCTION

Q. Please state your name and business address.

A. My name is Michael L. Pitts. My business address is Arkansas Public Service Commission ("APSC" or "Commission"), 1000 Center Street, Little Rock, Arkansas 72201.

Q. By whom are you employed and in what capacity?

A. I am employed by the General Staff ("Staff") of the APSC as a Senior Public Utility Auditor in the Audits Section. In that capacity, I provide support to the Manager of Audits, analyze utility company filings, conduct field audits, identify and evaluate accounting issues, develop positions on those issues and present those positions in written and oral testimony before the APSC, and perform other duties as assigned.

Q. Please state your qualifications and background.

A. I joined the Staff in January 2018 as a Public Utility Auditor. I was promoted to my current position in February 2021. Before joining Staff, I was employed as a Senior Revenue Agent with the Internal Revenue Service for more than 42 years. My educational qualifications include a Bachelor of Science in Accounting from the University of Arkansas Little Rock.

I am a Certified Public Accountant and have been licensed to practice in the State of Arkansas for more than 40 years. In maintenance of this certification, I have completed numerous additional academic and continuing professional education hours and seminars. Since joining Staff, I have completed The Basics

– Practical Regulatory Training for the Electric Industry sponsored by the New Mexico State University Center for Public Utilities and the National Association of Regulatory Utility Commissioners. I have previously filed testimony before the Commission on aspects of public utility revenue requirements such as rate base; working capital assets; current, accrued, and other liabilities; revenues; and operating expenses, including depreciation and income taxes. In my current position, my responsibilities include the overall development of Staff's case in providing a recommended total revenue requirement.

PURPOSE OF TESTIMONY

Q. What is the purpose of your Direct Testimony?

A. The purpose of my Direct Testimony is to make recommendations regarding the proposed level of Gross Plant-in-Service ("GPIS"), Accumulated Depreciation ("AD"), and depreciation expense to be included in rates. In doing so, I will address the Direct Testimony and Exhibits of Phillip B. Gillam, filed on behalf of Summit Utilities Arkansas, Inc. ("SUA" or "Company").[1] I am sponsoring the adjustments in Table 1 and 2, below, that correspond to Company adjustments as reflected in its Application.[2] I agree with Company's adjustments which I have listed below in Table 1, "Summary of Company Adjustments – Non-Contested." My testimony will discuss those issues found in Table 2, "Summary of Company Adjustments – Contested," in which I have listed adjustments where I differ from the Company.

[1] Direct Testimony and Exhibits of Phillip B. Gilliam 23-079-U, Docs. 21 and 22.
[2] Application for Approval of a General Change in Rates and Tariffs, Doc. 18, Part 1.

Table 1

"Summary of Company Adjustments Non-Contested"

Line No.	Adj. No.	Description	Staff Adjustment Amount	Company Adjustment Amount		Difference *
1		Plant				
2	RB-2	CWIP Placed in Service	162,461,129	162,461,129	a	-
3	RB-3	Retirements	(15,826,521)	(15,351,728)	a	(474,793)
4	RB-4	Reclassifications	(7,773,000)	(7,773,000)	a	-
5		Accumulated Depreciation				
6	RB-1	Capital Expenditures	8,550,586	8,550,586	b	-
7	RB-3	Retirements	15,826,521	15,351,728	b	474,793
8	RB-5	RWIP/Retirements	(54,319)	-	b	(54,319)
9	RB-6	Depreciation Expense	(66,357,897)	(65,348,174)	b	(1,009,723)
10	RB-7	Remove CWIP/RWIP	(8,982,020)	(5,305,395)	c	(3,676,625)
11		CONSTRUCTION WORK IN PROCESS				
12	RB-1	Capital Expenditures	162,461,129	162,461,129	d	-
13	RB-2	CWIP Placed in Service	(162,461,129)	(162,461,129)	d	-
14	RB-7	Remove CWIP/RWIP	(20,410,287)	(45,112,024)	e	24,701,737
15		ACQUISITION ADJUSTMENT				
16	RB-9	Remove Acquisition Adjustment	(690,091,096)	(690,091,096)	f	-
17		Expense Adjustment				
18	IS-16	Property Tax Adjustment				
19		Test Year	10,781,927	10,525,101	g	256,826
20		Proforma Year	10,757,426	10,757,426	g	-
21		Adjustment	(24,501)	232,325		(256,826)

*** Any differences are due to the Company using a partially-projected test year and Staff's use of an actual test year.**

Source of Company Adjustments

a Doc 23-079-UDoc.18 Item II Page 3 -4 of 40
b Doc 23-079-UDoc.18 Item II Page 5 of 40
c Doc 23-079-UDoc.18 Item II Page 10 of 40
d Doc 23-079-UDoc.18 Item II Page 6 of 40
e Doc 23-079-UDoc.18 Item II Page 11 of 40
f Doc 23-079-UDoc.18 Item II Page 12 of 40
g Doc 23-079-UDoc.18 Item III Page 25 of 51

Table 2

"Summary of Company Adjustments Contested"

Line No.	Adj. No.	Description	Staff Adjustment Amount	Company Adjustment Amount		Difference
1		Plant				
2	RB-12	Asset Retirement Obligation (ARO)	(2,280,944)	-		(2,280,944)
3	RB-13**	Short Term Incentive Compensation (STIC)	(1,749,525)	-		(1,749,525)
4	RB-14**	Volunteer Time Off	(59,943)			(59,943)
5	RB-15***	Rebranding Capital Expenditures	(379,968)			(379,968)
6		Accumulated Depreciation				
7	RB-12	Asset Retirement Obligation (ARO)	228,094			228,094
8	RB-13**	Short Term Incentive Compensation (STIC)	66,767		h	66,767
9	RB-14**	Volunteer Time Off	2,179		i	2,179
13	RB-15***	Rebranding Capital Expenditures	14,500		j	14,500
11		Expense Adjustment				
12	IS-19	Depreciation Expense Adjustment				
13		Test Year	59,994,684	59,994,684	k	-
14		Proforma Year	68,739,906	68,778,540	k	(38,634)
15		Adjustment	8,745,222	8,783,856		(38,634)
16		Transportation Equipment Depreciation Expense Allocation				
17	IS-27	Depreciation Expense Adjustment				
18		Test Year	-	-		-
19		Proforma Year	(888,014)	-		(888,014)
20		Adjustment	(888,014)	-		(888,014)

**** These adjustments are addressed in the Direct Testimony of Middleton Ray**

h Direct Testimony Middleton Ray page 5 lines 3-16

i Direct Testimony Middleton Ray page 6 &7 lines 15 -22 &1-4

***** This adjustment is addressed in the Direct Testimony of Don Malone page 23 lines 6-17**

k. Direct Testimony Don Malone page 23 Lines 6-17

Source of Company Adjustments

k Doc 23-079-U Doc. 18 Item III Page 28 of 51

GPIS AND AD

Q. Briefly summarize your recommended *Pro Forma* Year GPIS and AD and compare Staff's amounts to those requested by the Company in its Application.

A. In the Company's Application, it requested *Pro Forma* Year ("PY") GPIS of $1,793,268,648 and PY AD of $688,798,742, which is based upon six-months actual amounts and six-months projected amounts in the test year and twelve-

months projected amounts in the PY.[3] I am recommending PY GPIS of $1,814,938,635 and PY AD of $685,448,610, which is based upon twelve-months actual amounts in the test year and twelve-months projected amounts in the PY. My adjustments are more accurate than Company's because I used twelve-months actual additions in the test period compared to Company's use of six-months actuals.

Q. Please explain your Adjustment RB-12 Asset Retirement Obligation ("ARO") of $2,280,944.

A. The Company's Application provided no adjustment to remove the ARO from the Plant Balance.[4] In Staff's discussion with Company personnel, it was agreed that the ARO balance should be removed from SUA's Plant balance.[5] My adjustment removes ARO costs and is more appropriate than the Company's Plant Balance. In addition, my adjustment results in a reduction to AD of $228,094.

Q. Please discuss your Adjustment RB-13 Short-Term Incentive Compensation ("STIC").

A. The Company's Application provided no adjustment to remove any STIC from GPIS or from AD.[6] My Adjustment RB-13 removes $1,749,525 from GPIS and $66,767 from AD at the currently-approved depreciation rates attributable to Plant. Adjustment RB-13 is addressed in Staff witness Middleton Ray's Direct

[3] Application, Part 7, PDF p. 2, MFR Schedule G-1.
[4] Direct Exhibit MP – 1, Correspondence with Company.
[5] Direct Exhibit MP – 1, Correspondence with Company.
[6] Direct Testimony of Ray Middleton, p5 l3-16

Testimony.[7] There is also a corresponding depreciation expense adjustment, IS-19, as discussed below.

Q. Please discuss your Adjustment RB-14 Volunteer Time Off.

A. The Company's Application provided no adjustment to remove any capitalized Volunteer Time Off from either GPIS or from AD.[8] My adjustment removes $59,943 from GPIS and $2,286 from AD at the currently approved depreciation rates attributable to Plant. Adjustment RB-14 is also addressed in the Direct Testimony of Staff witness Middleton Ray.[9] There is also a corresponding depreciation expense adjustment, IS-19, discussed below.

Q. Please discuss your Adjustment RB-15 Rebranding Capital Expenditures.

A. The Company's Application provided no adjustment to remove any Rebranding Capital Expenditures from GPIS or from AD.[10] My adjustment removes $379,968 from GPIS and $14,500 from AD at the currently approved depreciation rates attributable to Plant. Adjustment RB-15 is addressed in the Direct Testimony of Staff witness Don Malone.[11] There is also a corresponding depreciation expense adjustment, IS-19, discussed below.

Q. What is SUA's requested Depreciation and Amortization Expense?

A. The Company's adjustment was calculated by applying its requested depreciation rates to its projected GPIS amounts.[12] This resulted in a *pro forma*

[7] Direct Testimony of Ray Middleton, p5 l3-16.
[8] Direct Testimony of Ray Middleton, p6 & 7, l15-22 & 1-4
[9] Direct Testimony of Ray Middleton, p6 & 7, l15-22 & 1-4
[10] Direct Testimony of Don Malone, p 23 l 6-17
[11] Direct Testimony of Don Malone, p 23 l 6-17.
[12] Docket 23-079-U Doc. 18_6 page 7

level of depreciation and amortization expense of $68,778,540, which is an increase of $8,714,423 to its test-year depreciation and amortization expense of $60,064,117. SUA's test-year expense also included an ARO of $69,433,[13] which the Company removed, resulting in a net increase of $8,783,856 in expense.

Q. Would you please discuss your Adjustment IS-19 Depreciation and Amortization Expense?

A. My Adjustment IS-19 reduces the Company's *pro forma* depreciation expense by $38,634[14] to $8,745,222. My depreciation expense was calculated by applying the depreciation rates provided by Staff witness Claude Robertson to my *pro forma* GPIS, as adjusted.[15] In addition, my depreciation expense adjustment includes a reclassification of ($248,139) from FERC account 406.0 Amortization – Intangibles to FERC account 404.3 Amortization of Other Limited-Term Gas Plant of $248,139.[16] As the reclassification was a transfer from one account to another, the net adjustment to my depreciation adjustment was $0. Therefore, my depreciation expense adjustment comprehends all adjustments to GPIS, including the reductions discussed above which the Company did not make.

[13] Docket 23-079-U Doc. 18_3 Page 3 of 51
[14] Direct Exhibit MP-2 Depreciation Expense
[15] Direct Testimony of Claude Robertson, p8 l1-3
[16] Direct Exhibit MP – 3 and APSC-109.

Q. Please explain your Adjustment IS-27 Transportation Equipment Depreciation Expense Allocation.

A. In its most recent rate case (APSC Docket No. 15-098-U) SUA's predecessor company, CenterPoint Energy Resources Corp. d/b/a CenterPoint Energy Arkansas ("CEA") made an adjustment to *pro forma* transportation depreciation expense to remove the portion that was capitalized. CEA's adjustment was necessary because transportation depreciation expense is reclassified as a part of transportation overhead and applied to both O&M and capital expenditures. Therefore, a capitalization ratio was applied to the transportation depreciation expense *pro forma* amount. SUA did not make a similar adjustment in its Application in this docket. However, because SUA does allocate fleet costs per its clearing account 184230,[17] I have made a similar adjustment to that made in Docket No. 15-098-U. Since transportation depreciation becomes part of transportation overhead, a capitalization ratio was applied to the pro forma amount of $3,014,305, resulting in a *pro forma* transportation depreciation expense reduction of $888,014[18] ($3,014,305 X cap rate of 29.46%).

Q. What are your recommendations?

A. I recommend the Commission approve my use of updated *pro forma* amounts based on the actual test year and my *pro forma* adjustments supported by my testimony as follows:

[17] Docket 23-079-U Doc. 18_5 page 80 of 253
[18] Direct Exhibit MP-4 Transportation Expense

1. Reduce GPIS by $2,280,944 for the removal of ARO, as shown in RB-12;

2. Remove STIC from GPIS of $1,749,525, as shown in RB-13;

3. Remove Volunteer Time Off from GPIS of $59,943, as shown in RB-14;

4. Remove Rebranding Capital Expenditures from GPIS of $379,968, as shown in RB-15;

5. Reduce AD by $228,094 for the removal of ARO, as shown in RB-12;

6. Remove STIC from AD of $66,767, as shown in RB-13;

7. Remove Volunteer Time Off from AD of $2,286, as shown in RB-14;

8. Remove Rebranding Capital Expenditures from AD of $14,500, as shown in RB-15;

9. Reduce Depreciation Expense by $38,740, as shown in IS-19; and

10. Reduce Transportation Depreciation Expense by $888,014, as shown in IS-27.

Q. Does this conclude your testimony?

A. Yes.

CERTIFICATE OF SERVICE

I, Joshua A. Baxter, hereby certify that a copy of the foregoing has been served on all parties of record on July 10, 2024, via the Arkansas Public Service Commission's Electronic Filing System.

/s/ JOSHUA A. BAXTER
Joshua A. Baxter

APSC FILED Time: 7/10/2024 10:56:14 AM: Recvd 7/10/2024 10:52:50 AM: Docket 23-079-U-Doc. 102

BEFORE THE
ARKANSAS PUBLIC SERVICE COMMISSION

IN THE MATTER OF THE APPLICATION OF SUMMIT UTILITIES ARKANSAS, INC. FOR A GENERAL CHANGE OR MODIFICATION IN ITS RATES, CHANGES AND TARIFFS	))))	DOCKET NO. 23-079-U

DIRECT EXHIBITS

OF

MICHAEL L. PITTS
SENIOR PUBLIC UTILITY AUDITOR
AUDITS SECTION

ON BEHALF OF THE GENERAL STAFF OF THE
ARKANSAS PUBLIC SERVICE COMMISSION

JULY 10, 2024

APSC FILED Time: 7/10/2024 10:56:14 AM: Recvd 7/10/2024 10:52:50 AM: Docket 23-079-U-Doc. 102

From: Phillip Gillam
To: Michael Pitts
Cc: Don Malone
Subject: RE: [EXTERNAL EMAIL] Plant Balance at 12/31/2023
Date: Tuesday, May 28, 2024 3:41:47 PM

Michael: The difference is the ARO balance ($2,280,941) and the Leases. The 12/31/23 balance should be the $1,678,266,466 mentioned below. We'll update the B-1 and F-1.3 to remove the ARO balance. The Capital Leases were not included in the rate case schedules and gets you to the $1,693,549,740 mentioned below. I'll let you know how quickly we can revise the schedules affected after I discuss with my analysts. It shouldn't take more than a day or two at the most.

Thanks……Phillip

From: Michael Pitts <Michael.Pitts@arkansas.gov>
Sent: Tuesday, May 28, 2024 7:12 AM
To: Phillip Gillam <pgillam@summitutilities.com>
Cc: Don.Malone <Don.Malone@arkansas.gov>
Subject: [EXTERNAL EMAIL] Plant Balance at 12/31/2023

Good Morning,

I have a reconciliation question for you. On 4/11/2024, SUA filed updated schedules B-1 Updated and F-1.3 Updated, each reporting Plant Balances at 12/31/2023 of $1,680,547,407. However, in response to APSC-087 dated 4/18/2024, SUA reported Plant Balance at 12/31/2023 of $1,678,266,466 and in the attached SUA reported Plant balance at 12/31/2023 of $1,693,549,740. Please explain the differences between these workpapers. Please provide a revised F-1.3 schedule to correspond to the correct 12/31/2023 Plant and Accumulated Depreciation balance.

Thanks

Michael L. Pitts
Arkansas Public Service Commission
Senior Public Utility Auditor
501.682.5985

Michael.Pitts@arkansas.gov

If you received this message in error, please do not read, copy, or share it. Instead, please notify the sender immediately and permanently delete all copies in your possession.

DIRECT EXHIBIT MP-2 DEPRECIATION EXPENSE

SUA 23-079-U

PRO FORMA

DEPRECIATION EXPENSE

		AS FILED	STAFF	ADJUSTMENT
	Intangible Plant			
3021	FRANCHISES	$ -	-	
3030	INTANGIBLES - INTERCONNECT	74,705	74,705	(0)
3031	INTANGIBLES MISCELLANEOUS - PICARRO	1,543,766	1,543,766	-
3032	INTANGIBLES MISCELLANEOUS	1,604,168	1,585,036	(19,132)
3902	STRUCTURES AND IMPROVEMENTS (GENERAL)	248,139		(248,139)
	Sub-Total Intangible Plant	$3,470,778	3,203,506	(267,272)
	Distribution Plant			
3740	LAND AND LAND RIGHTS (DISTRIBUTION)	$ -	-	
3742	LAND AND LAND RIGHTS (DISTRIBUTION)	78,602	81,843	3,241
3751	STRUCTURES AND IMPROVEMENTS (DISTRIBUTION)	11,004	1,041	(9,963)
3753	STRUCTURES AND IMPROVEMENTS (DISTRIBUTION)	9,367	9,367	(0)
3754	STRUCTURES AND IMPROVEMENTS (DISTRIBUTION)	149,704	149,704	0
3755	STRUCTURES AND IMPROVEMENTS (DISTRIBUTION)	116,716	126,509	9,793
3760	MAIN (DISTRIBUTION)	21,303,336	21,494,441	191,105
3780	M/R STATION EQUIP (DIST GENERAL)	735,353	766,649	31,296
3783	M/R STATION EQUIP (DIST GENERAL)	38,036	38,349	313
3790	M/R STATION EQUIP (DIST CITY GATE)	39,016	38,972	(44)
3800	SERVICES	30,925,222	31,550,470	625,248
3811	METERS	725,773	796,339	70,566
3812	METERS	1,242,776	1,247,449	4,673
3813	METERS	365,461	365,461	(0)
3820	METER INSTALLATIONS	840,278	836,453	(3,825)
3831	HOUSE REGULATORS	568,465	550,354	(18,111)
3832	HOUSE REGULATORS	357,534	372,692	15,158
3850	INDUSTRIAL M/R STATION EQUIP	268,544	298,957	30,413
3851	INDUSTRIAL M/R STATION EQUIP	309,843	309,843	0
	Sub-Total Distribution Plant	$58,085,030	59,034,895	949,865
	General Plant			
3900	STRUCTURES AND IMPROVEMENTS (GENERAL)	$ -	-	
3901	STRUCTURES AND IMPROVEMENTS (GENERAL)	267,734	260,529	(7,205)
3910	OFFICE FURNTURE AND EQUIPMENT	170,225	165,909	(4,316)
3912	OFFICE FURNTURE AND EQUIPMENT	1,502,492	1,243,833	(258,659)
3920	TRANSPORTATION EQUIPMENT	2,911,053	3,014,320	103,267
3940	TOOLS, SHOP, GARAGE EQUIPMENT	1,455,691	1,053,367	(402,324)
3960	POWER OPERATED EQUIPMENT	183,978	190,049	6,071
3970	COMMUNICATION EQUIPMENT	64,725	54,670	(10,055)
3971	COMMUNICATION EQUIPMENT	364,587	182,380	(182,207)
3980	MISC EQUIPMENT	302,247	336,447	34,200
	Sub-Total General Plant	$7,222,732	6,501,505	(721,227)
	Total	$68,778,540	68,739,906	(38,634)

C-1 ORIGINAL

C-3

DESCRIPTION	FERC ACCT	TEST YEAR	PRO FORMA YEAR	ADJUSTMENT
DEPRECIATION EXPENSE	4030	55,703,605	65,536,399	9,832,794
ARO DEPRECIATION EXPENSE	4031	69,433		(69,433)
AMORTIZATION OF OTHER LIMITED TERM GAS	404.3			
AMORTIZATION EXPENSE	4050	4,042,939	3,203,506	(839,433)
AMORTIZE INTANGIBLES	4060	248,139	-	(248,139)
		60,064,117	68,739,906	8,675,789

SAU C-2 IS19

DESCRIPTION	FERC ACCT	TEST YEAR	PRO FORMA YEAR	ADJUSTMENT
DEPRECIATION EXPENSE	4030	55,703,605	65,307,762	9,604,157
ARO DEPRECIATION EXPENSE	4031	69,433		(69,433)
AMORTIZATION OF OTHER LIMITED TERM GAS	404.3			
AMORTIZATION EXPENSE	4050	4,042,939	3,470,778	(572,161)
AMORTIZE INTANGIBLES	4060	248,139	-	(248,139)
		60,064,117	68,778,541	8,714,424
		-	(38,635)	(38,634)

ARKANSAS PUBLIC SERVICE COMMISSION
APSC 23-079-U
APSC FILED Time: 7/10/2024 10:56:14 AM: Recvd 7/10/2024 10:52:50 AM: Docket 23-079-U-Doc. 102
2023 SUA RATE CASE

REQUEST NO.: APSC-109

COMPANY NAME: SUMMIT UTILITIES ARKANSAS

DATE RECEIVED: 6/11/2024

DATE DUE: 6/26/2024

EXTENSION DATE:

INFORMATION REQUESTED:

1. Please provide the composition of FERC account 406 – Amortization of Intangibles in the amount $248,139, at the beginning of the test year and end of the test year December 31, 2023.

2. Please provide a listing of the intangible assets and their balances at the beginning of the test year January 1, 2023, and end of test year December 31, 2023, that has been or is being amortized to FERC account 406. In addition, please include the annual rate of amortization for each asset listed.

REQUESTED BY: ARKANSAS PUBLIC SERVICE COMMISSION - DON MALONE

RESPONSE:
1. Please refer to the attached file APSC-109 AR 23-079-U (Intangibles related to 406000 balance).xlsx.

2. See response to item 1. After further review, the Company believes that these leasehold improvements should be amortizing to FERC 404.3, Amortization of Other Limited-Tem Gas Plant.

SPONSOR:
Ann Byrd, Peter Hobbs

RESPONSIVE DOCUMENTS:
APSC-109 AR 23-079-U (Intangibles related to 406000 balance).xlsx

The foregoing response to the above information request is accurate and complete, and contains no material misrepresentations or omissions based upon present facts known to the undersigned. The undersigned agrees to immediately inform the Requestor if any matters are discovered which would materially affect the accuracy or completeness of the information provided in response to the above information request.

/s/ Brooke South Parsons
Signature of Company Representative

APSC FILED Time: 7/10/2024 10:56:14 AM: Recvd 7/10/2024 10:52:50 AM: Docket 23-079-U-Doc. 102

DATE PROVIDED: JUNE 25, 2024

Summit Utilities Arkansas, Inc.
Docket No: AR 23-079-U
Data Request: APSC-059-Q8

Per F-1.3 in Docket No. 23-079-U

Line No.	Acct. Number (1)	Sub FCA (2)	Acct. Description (3)	STAFF DEPRECIATION EXPENSE
39	10100, 10600	3900	STRUCTURES AND IMPROVEMENTS (GENERAL)	-
40	10100, 10600	3901	GEN STRUCTURES - IMPROVEMENTS	260,529
41	10100, 10600	3910	OFFICE FURNTURE AND EQUIPMENT	165,909
42	10100, 10600	3912	COMPUTER EQUIPMENT	1,243,833
43	**10100, 10600**	**3920**	**TRANSPORTATION EQUIPMENT**	**3,014,320**
46	10100, 10600	3940	TOOLS, SHOP, GARAGE EQUIPMENT	1,053,367
47	10100, 10600	3960	POWER OPERATED EQUIPMENT	190,049
48	10100, 10600	3970	COMMUNICATION EQUIPMENT	54,670
49	10100, 10600	3971	DATA COLLECTION EQUIP	182,380
50	10100, 10600	3980	MISC EQUIPMENT	336,447
51			TOTAL GENERAL	6,501,505

CAP RATE	IS-27 TRANSPORTATION DEPRECIATION EXPENSE ADJUSTMENT
0.2946	**888,014**

PAGE 5

1

CERTIFICATE OF SERVICE

I, Joshua A. Baxter, hereby certify that a copy of the foregoing has been served on all parties of record on July 10, 2024, via the Arkansas Public Service Commission's Electronic Filing System.

/s/ JOSHUA A. BAXTER
Joshua A. Baxter

APSC FILED Time: 7/10/2024 11:03:39 AM: Recvd 7/10/2024 11:01:38 AM: Docket 23-079-U-Doc. 106

BEFORE THE
ARKANSAS PUBLIC SERVICE COMMISSION

IN THE MATTER OF THE APPLICATION OF SUMMIT UTILITIES ARKANSAS, INC. FOR A GENERAL CHANGE OR MODIFICATION IN ITS RATES, CHARGES, AND TARIFFS	))))	DOCKET NO. 23-079-U

DIRECT TESTIMONY

OF

CLAUDE ROBERTSON, CDP
SENIOR CAPITAL RECOVERY ANALYST
FINANCIAL ANALYSIS SECTION

ON BEHALF OF THE GENERAL STAFF
OF THE ARKANSAS PUBLIC SERVICE COMMISSION

JULY 10, 2024

SUMMIT UTILITIES ARKANSAS, INC.
DOCKET NO. 23-079-U
DIRECT TESTIMONY OF CLAUDE ROBERTSON, CDP

INTRODUCTION

Q. Please state your name and business address.

A. My name is Claude Robertson. My business address is the Arkansas Public Service Commission ("Commission" or "APSC"), 1000 Center Street, Little Rock, Arkansas 72203-0400.

Q. In what capacity are you employed at the Commission?

A. I am employed by the General Staff ("Staff") of the Arkansas Public Service Commission ("Commission" or "APSC") as a Senior Capital Recovery Analyst in the Financial Analysis Section. In that capacity, I perform analyses of utility company information and utility company filings, develop Staff's positions as they relate to the utility filings, present those positions, when necessary, in written and oral testimony before the Commission, and perform other duties as assigned. My primary area of responsibility involves capital recovery issues including reviewing and developing depreciation rates for the regulated utilities in Arkansas.

Q. Briefly describe your education and experience.

A. I graduated from Northwestern State University in Louisiana with bachelor degree's in business administration and accounting. I held accounting positions in corporate settings as an Accountant, Analyst, and more recently before joining the Commission, as a Finance Manager for a non-profit corporation in the medical industry in charge of supervising the accounting department. I have twenty-five years of experience in the accounting and depreciation environment which

includes corporate and regulatory accounting. I joined Staff in 2012 as an Auditor in the Audits Section. In 2018, I was promoted to the position of Senior Auditor – Capital Recovery in the Financial Analysis Section and am now a Senior Capital Recovery Analyst. In my current position, I am responsible for reviewing and conducting comprehensive depreciation studies for utility companies subject to the Commission's jurisdiction. I also review utility requests to maintain or change depreciation rates, evaluate the basis for such requests, and develop Staff's position in response.

I have regularly participated in utility regulatory training opportunities including "The Basics, Practical Regulatory Training" course sponsored by the Center for Public Utilities, a branch of the College of Business Administration and Economics at New Mexico State University, in conjunction with the National Association of Regulatory Utility Commissioners. My training also includes the "Depreciation Fundamentals," "Life Analysis Methods and Applications," "Analyzing Salvage in the Real World," and "Preparing and Supporting a Depreciation Study" courses sponsored by the Society of Depreciation Professionals ("SDP") in conjunction with SDP's Annual Meetings. I am currently a member of SDP.

Q. Do you hold certification as a depreciation expert?

A. Yes. I have successfully passed the examination to become a Certified Depreciation Professional ("CDP"). The examination is administered by SDP and

is based on its established national standards for depreciation professionals. Further, I regularly pursue professional development and education in the field of depreciation to maintain the CDP certification.

Q. Have you previously filed testimony before the Commission?

A. Yes. I have previously testified before the Commission in numerous dockets, including Dockets Nos. 87-166-TF, 19-019-U, 19-014-U, 17-010-FR, 16-052-U, 16-036-FR, 15-021-U, 15-015-U, 14-020-U, 13-111-U, 13-028-U, 22-064-U, 22-085-U, and 23-074-U.

PURPOSE OF TESTIMONY

Q. What is the purpose of your testimony?

A. My testimony addresses the proposal by Summit Utilities Arkansas ("SUA" or "Company") to change depreciation rates as set forth in Schedule F-1.3 Summit Arkansas of its Application for Approval of a General Change in Rates and Tariffs ("Application") filed on January 24, 2024, as revised on February 20, 2024. Specifically, I will address the Direct Testimonies and Exhibits of Company witnesses Dane A. Watson filed in support of SUA's requested depreciation rates and Phillip B. Gillam, who describes the purpose of F-1.3 and states that the Company is requesting a change in depreciation rates.[1] The effect of the proposed

[1] Direct Testimony and Direct Exhibits of Dane A. Watson, Docket No. 23-079-U. Docs 38 and 39.

depreciation rates is included in the depreciation expense Adjustment IS-19 as described in the Direct Testimony of Company witness Gillam.[2]

SUMMARY OF THE COMPANY'S REQUEST

Q. What test year and *pro forma* year did SUA use in its application?

A. SUA's Application is based on its partially-projected test year ending December 31, 2023 and includes additional projections through it *pro forma* year December 31, 2024.

Q. What test year and *pro forma* year did Staff use in its Direct Testimony?

A. Staff based its case on the updated test year ending December 31, 2023, which reflects twelve months of historical data provided in response to APSC-001 and includes *pro forma* projections through December 31, 2024.

Q. Please provide a summary of SUA's request pertaining to depreciation rates in this case.

A. The depreciation rates proposed by SUA in this docket, when applied to the Company's *pro forma* year end plant balances as stated in Schedule F-1.3, resulted in depreciation expense of $68,778,540, compared to a depreciation expense of $67,178,561 resulting from the currently approved rates, for an increase of $1,599,979.[3] Table 1 below shows the functional impact of the proposed rates along with the resulting increase in total depreciation expense.

[2] Direct Testimony and Exhibits of Phillip B. Gillam, Docket No. 23-079-U, Docs. No. 21, p. 29, line, 14 - p. 30, line 3.
[3] SUA Revised Application, Doc. No. 60, Schedule F-1.3.

Table 1
Depreciation Expense Comparison*

	Using Current Rates		Using Company Proposed Rates		Change	
Function	**Annual Expense**	**Composite Rate**	**Annual Expense**	**Composite Rate**	**$**	**%**
Intangibles	3,718,222,	12.35%	3,470,778	11.53%	-247,444	-.82%
Distribution	58,155,132	3.46%	58,085,030	3.45%	-70,102	-.01%
General	5,305,207	6.60%	7,222,732	8.98%	1,917,525	2.38%
Total Plant	**67,178,561**	**3.75%**	**68,778,540**	**3.84%**	**1,599,979**	**.09%**

**Annual expense amounts reflected are from the revised Application Schedule F-1.3 filed by SUA on February 20, 2024*

The depreciation rates for which SUA requests approval are the result of a depreciation study conducted by Alliance Consulting Group ("Alliance") as of December 31, 2022. The study is presented by Company witness Watson, a partner at Alliance, in his Direct Exhibit DAW-1.[4]

OVERVIEW OF STAFF'S RECOMMENDATION

Q. What are your recommendations in this Docket.

A. I recommend the Commission:

- Approve the depreciation and amortization rates proposed by Mr. Watson and the parameters upon which they are based, with the exception of the amortization rates for Accounts 3912 Furniture and Equipment (Computers) and 3940 Tools, Shop, Garage Equipment for which I am recommending that the Commission retain the current amortization rates for these two accounts. Although, I do not necessarily endorse each of the specifics

[4] Direct Exhibits of Dane A. Watson, Docket No. 23-079-ZU, Doc 39.

presented in the study, in this particular case, the overall results of the Company's depreciation study are reasonable with the exception that I noted above;

- Move the Theoretical Reserve under accrued amortization amount to a Regulatory Account and amortize over 10-years and allow a return of the assets, but not a return on the assets;
- Approve the continued use of Vintage Accounting for accounts 3910, 3912, 3940, 3970, 3971, and 3980; and
- Require the Company to request approval of an interim depreciation rate if the Company establishes a new account that is not merely a sub-account of an existing account or adds assets to an account that had a zero balance as of the depreciation study date for which no rate was approved in this docket.

Q. When were the currently approved depreciation rates established?

A. The current depreciation rates were approved September 2, 2016, by Order No. 8 in Docket No. 15-098-U.[5]

Q. Where do your recommended depreciation and amortization rates appear as an adjustment in the determination of Staff's revenue requirement?

[5] Docket No. 15-098-U, Doc 249, Order No. 8, Page 45.

A. Using my recommended depreciation and amortization rates, and Staff witness Michael Pitts adjusted plant balances, the proposed depreciation expense is included as a component of Adjustment IS-19.

STAFF'S REVIEW

Analysis of Proposed Depreciation Rates

Q. Did you review the depreciation study filed in support of the requested depreciation rates?

A. Yes. I reviewed the direct testimony and exhibits filed by Company witness Watson in support of the recommended depreciation rates.[6] I also reviewed the workpapers prepared by Mr. Watson that were provided at that time. As an additional part of my review, I performed my own depreciation study using Company data updated through December 31, 2022. The results, while not identical to Mr. Watson's, confirmed the overall reasonableness of the Company's requested depreciation and amortization rates with the exceptions as listed above.

The requested depreciation rates are based on the straight-line method, average life group procedure, and remaining life technique, which are typically used by Staff and have been previously approved by this Commission.

Q. Did you conduct a site visit in concurrence with your depreciation study?

A. Yes. I participated in a site visit of the Little Rock facilities where I observed various assets and discussed these assets with field personnel. This site visit allowed me

[6] Direct Testimony and Exhibits of Dane A. Watson, Docket No. 23-079-U. Docs 38 and 39.

to observe representative portions of SUA's plant and gain valuable insight into the operations of these assets.

Q. Did you analyze the Net Salvage recommendation by Mr. Watson?

A. Yes, I analyzed the Net Salvage recommendations which consist of Gross Salvage, Retirements, and Cost of Removal through December 31, 2022, and found the Net Salvage recommendations to be reasonable.

Q. What was Mr. Watson's reasoning for reducing the amortization life of General Accounts 3912 Computers and 3940 Tools, Shop, Garage Equipment from what is currently approved in rates?

A. Mr. Watson requested a change in Account 3912 Computers from 5-years to 4-years[7] and 15-years to 10-years for 3940 Tools, Shop, Garage Equipment as a result of an interview with the Company.[8]

Q. Did you do an analysis of Mr. Watson's requested change in amortization life of these same accounts 3912 Computers and 3940 Tools, Shop, Garage Equipment?

A. Yes, I interviewed Company personnel, sent data requests, and analyzed the accounts in question.

Q. What were the results of your analysis?

[7] Direct Exhibits of Dane A. Watson, Docket No. 23-079-U, Doc 39, p. 38.
[8] Direct Exhibits of Dane A. Watson, Docket No. 23-079-U, Doc 39, p. 40.

A. The Company responded to Data Request APSC-080, stating that there are no existing policies on asset retirement for General Plant Accounts and the assets are retired as needed.

Q, Please explain Staff's recommendation to retain the current 5-year amortization period for Account 3912 Furniture and Equipment (Computers)?

A. As Table 2 below shows, the balances by year for Account 3912 Computers has assets that are still in service and used and useful beyond the 4-year amortized life that is requested by the Company. In total, the Company has 72.7% (65.9% + 6.8%) of assets that have exceeded the 4-years amortization life recommended by Mr. Watson and are still in service, and used and useful. Based on my analysis I recommend retaining the current 5-year amortization period for Account 3912 Furniture and Equipment (Computers).

Table 2
Account 3912 Computers

Vintage Year	Years in Service	Costs	% of Cost	Assets in Service > 4 Years
2022	0.5	130,704.61	4.4%	N/A
2021	1.5	165,778.83	5.6%	N/A
2020	2.5	433,445.86	14.5%	N/A
2019	3.5	82,932.31	2.8%	N/A
2018	4.5	1,967,921.61	65.9%	65.9%
2017	5.5	203,906.90	6.8%	6.8%
	Total Costs	**2,984,690.12**	**100.0%**	72.7%

Per Direct Exhibit CR-3

Q. Please explain Staff's recommendation to retain the current 15-year amortization period for Account 3940 Tools, Shop, Garage Equipment?

A. The Company has requested a change in the amortization life of Account 3940 Tools, Shop, Garage Equipment from 15-years to 10-years.[9] As Table 3 below shows, the Company has 30.93% of assets that are still in service that are in excess of the 10-years amortization life the Company has recommended for this account. These assets are in-service and are being used by the Company for its operations. Based on this analysis, I recommend retaining the current 15-year amortization period for Account 3940 Tools, Shop, Garage Equipment.

Table 3
Account 3940 Tools, Shop, Garage Equipment

Vintage Year	Years in Service	Costs	% of Cost	Assets in Service > 10 Years
2022	0.5	1,206,415.89	10.65%	N/A
2021	1.5	1,731,088.25	15.28%	N/A
2020	2.5	513,341.90	4.53%	N/A
2019	3.5	1,410,454.85	12.45%	N/A
2018	4.5	621,408.33	5.49%	N/A
2017	5.5	426,335.44	3.76%	N/A
2016	6.5	293,764.07	2.59%	N/A
2015	7.5	608,087.76	5.37%	N/A

[9] Watson Direct Exhibit DAW-1 Page 40.

Vintage Year	Years in Service	Costs	% of Cost	Assets in Service > 10 Years
2014	8.5	827,198.91	7.30%	N/A
2013	9.5	186,869.78	1.65%	N/A
2012	10.5	382,181.08	3.37%	3.37%
2011	11.5	341,951.43	3.02%	3.02%
2010	12.5	197,350.33	1.74%	1.74%
2009	13.5	702,884.57	6.20%	6.20%
2008	14.5	302,063.59	2.67%	2.67%
2000-2007	15.5 to 22.5	1,576,826.73	13.92%	13.92%
	Total Costs	**11,328,222.91**		**30.93%**

Per Direct Exhibit CR-3

Q. How do Staff's proposed rates compare to the Company's proposed rates by function based upon plant as of the *pro forma* year, December 31, 2024?

A. Yes. Table 4 shown below compares the depreciation and amortization composite expense percentages by function, based on Staff's *pro forma* plant.[10]

Table 4
Depreciation Rate Comparison Based on Staff's *Pro Forma* Plant
Per Direct Exhibit CR-4

Function	SUA Current Rates	SUA Proposed Rates	Staff Proposed Rates	Staff Over/(Under) Current Rates	Staff Over/(Under) Proposed Rates
Intangible Plant	12.55%	11.67%	11.67%	-.88%	0%

[10] Direct Exhibit CR-4

Distribution Plant	3.46%	3.45%	3.45%	-.01%	0%
General Plant	6.58%	9.04%	7.52%	.94%	-1.52%
Total Plant	3.74%	3.83%	3.79%	.05%	-.04%

In terms of total dollar differences in depreciation and amortization expense, per my Direct Exhibit CR-4 and solely due to amortization rate differences; my depreciation and amortization expense is $68,739,906 as compared to the Company's depreciation and amortization expense of $69,576,758; a reduction of $836,852. The differences in Staff's recommended depreciation and amortization expense and the Company's are explained in the Direct Testimony of Staff witness Michael Pitts.[11]

Theoretical Reserve

Q. What is a Theoretical Reserve analysis?

A. A theoretical reserve is calculated by estimating the remaining life of a group of assets and calculating what the reserve for the group would have been if that remaining life had been used throughout the life of the assets up to the current point in time. This calculation is then compared to the actual reserve to determine if the assets are over/under accrued. Any over/under accrual is then amortized to adjust for the difference between the book reserve and theoretical reserve.

Q. Do you agree with the Company's proposed Theoretical Reserve calculations?

[11] Direct Testimony of Michael Pitts, page 7, lines 18 to Page 8, Lines 1-17.

A. No. However, the difference between Staff's Theoretical Reserve and Mr. Watson's is entirely the result of amortization of Accounts 3912 Computers and 3940 Tools, Shop, Garage Equipment. Due to the differences in the amortization period for these accounts, my Theoretical Reserve over/under accrual is calculated at $584,698 compared to Mr. Watson's $1,693,565. This represents a difference of ($1,108,866).[12] I am in agreement with Mr. Watson on using a 10-year amortization period for the Theoretical Reserve under accrued difference. This will create an annual amortization of $58,470 ($584,698 / 10).[13] I recommend the stranded costs be moved to a Regulatory Asset and the Company receive a return of the costs, but not a return on the costs.

Q. Has Staff recommended moving stranded costs to a Regulatory Asset, and only receive a return of the cost and not a return on the costs in past dockets?

A. Yes. In Docket Nos. 22-085-U[14] and 21-097-U[15], Staff recommended costs be moved to a Regulatory Asset and the companies be allowed a return of, but not on the costs. Both these dockets were settled, and the Commission approved Staff's recommendations for stranded costs.

SUMMARY OF STAFF'S RECOMMENDATIONS

Q. Please summarize your recommendations in this docket?

[12] Robertson Direct Exhibit CR-5
[13] Robertson Direct Exhibit CR-5.
[14] Docket No. 22-085-U, Doc No. 155, Charlotte T. Emery Settlement Testimony, Page 5, Lines No. 12-15.
[15] Docket No. 21-097-U, Doc No. 161, Jeff Hilton Settlement Testimony, Page 7, Lines 4-11.

A. I recommend the Commission:

- Accept the Company's proposed depreciation and amortization rates as submitted on Schedule F-1.3 of the Application and the parameters which support them, except for Accounts 3912 Computer Equipment and 3940 Tools, Shop, Garage Equipment. In an effort to keep the record clear and for the ease of the Commission, I have prepared Direct Exhibit CR-1[16] and Direct Exhibit CR-2[17] containing the recommended rates and parameters put forth in Company witness Watson's testimony, as modified for the exceptions as noted above:
- Require the Company to request approval of an interim depreciation rate if the Company establishes a new account that is not merely a sub-account of an existing account or adds assets to an account that had a zero balance as of the depreciation study date for which no rate was approved in this Docket; and
- Accept my recommendations for the under accrued Theoretical Reserve and move the under accrued balance to a Regulatory Asset and allow a return of the cost, but not a return on the cost of the assets;
- Approve the continued use of Vintage Accounting for accounts 3910, 3912, 3940, 3970, 3971, and 3980.

Q. Does this conclude your Direct Testimony?

[16] Robertson Direct Exhibit CR-1.
[17] Robertson Direct Exhibit CR-2.

A. Yes.

CERTIFICATE OF SERVICE

I hereby certify that a copy of the foregoing has been served on all parties of record in accordance with the Commission's Rules of Practice and Procedure Rule 3.07(b) this 10th day of July, 2024.

/s/ Joshua Baxter
Joshua Baxter

APSC FILED Time: 7/10/2024 11:03:53 AM: Recvd 7/10/2024 11:02:51 AM: Docket 23-079-U-Doc. 107

BEFORE THE
ARKANSAS PUBLIC SERVICE COMMISSION

IN THE MATTER OF THE APPLICATION OF SUMMIT UTILITIES ARKANSAS, INC. FOR A GENERAL CHANGE OR MODIFICATION IN ITS RATES, CHARGES, AND TARIFFS	))))	DOCKET NO. 23-079-U

DIRECT EXHIBITS

OF

CLAUDE ROBERTSON, CDP
SENIOR CAPITAL RECOVERY ANALYST
FINANCIAL ANALYSIS SECTION

ON BEHALF OF THE GENERAL STAFF
OF THE ARKANSAS PUBLIC SERVICE COMMISSION

JULY 10, 2024

STAFF RECOMMENDED DEPRECIATION RATES
SUMMIT UTILITIES ARKANSAS, INC.

DOCKET NO. 23-079-U

Distribution		Staff Rate - Summit Direct
	Intangible Plant	
302.10	PERPETUAL FRANCHISE & CONSENT	0.00%
303.00	INTANGIBLES INTERCONNECT	2.00%
303.10	INTANGIBLES MISCELLANEOUS - PICARRO	20.00%
303.20	INTANGIBLES MISCELLANEOUS	10.00%
390.20	SOFTWARE EA	10.00%
	Distribution Plant	
374.0	DISTRIBUTION LAND	0.00%
374.2	DISTRIBUTION LAND RIGHTS	1.51%
375.1	DIST STRUCTURES - CG ML INDUST M/R	1.20%
375.3	DIST STRUCTURES - M/R AND DIST STATION	1.83%
375.4	DIST STRUCTURES - OTHER	1.48%
375.5	DIST STRUCTURES - IMPROVEMENTS	2.24%
376.0	MAIN (DISTRIBUTION)	2.11%
378.00	M/R STATION EQUIP (DIST GENERAL)	4.71%
378.30	M/R STATION EQUIP (DIST ODORIZER)	3.34%
379.00	M/R STATION EQUIP (DIST CITY GATE)	1.69%
380.00	SERVICES	6.74%
381.10	METERS - DOMESTIC	1.94%
381.20	METERS - ERTS	4.25%
381.30	METERS - INDUS / LARGE	2.49%
382.00	METER INSTALLATIONS	2.68%
383.10	DIST REGULATORS	2.89%
383.20	DIST REGULATORS IND	2.76%
385.01	INDUSTRIAL M/R STATION EQUIP	2.55%
385.1	INDUSTRIAL M/R STATION EQUIP OTHER	2.39%
	General Plant - Depreciated	
390.10	GEN STRUCTURES - IMPROVEMENTS	2.35%
392.00	TRANSPORTATION EQUIPMENT	9.08%
396.00	POWER OPERATED EQUIPMENT	3.24%
	General Plant - Amortized	
391.00	OFFICE FURNTURE AND EQUIPMENT	5.00%
391.20	COMPUTER EQUIPMENT	20.00%
394.00	TOOLS, SHOP, GARAGE EQUIPMENT	6.67%
397.00	COMMUNICATION EQUIPMENT	10.00%
397.10	DATA COLLECTION EQUIP	10.00%
398.00	MISC EQUIPMENT	10.00%

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STAFF RECOMMENDED DEPRECIATION PARAMETERS
SUMMIT UTILITIES ARKANSAS, INC.
DOCKET NO. 23-079-U

	Intangible Plant	Curve Shape	Average Service Life	Remaining Life	Net Salvage Percent	Reserve Ratio at 12/31/2021
3021	PERPETUAL FRANCHISE & CONSENT	N/A	N/A	N/A	0%	0%
3030	INTANGIBLES INTERCONNECT	Amort	50	0.00	0%	25%
3031	INTANGIBLES MISCELLANEOUS - PICARRO	Amort	5	5.00	0%	0%
3032	INTANGIBLES MISCELLANEOUS	Amort	10	10.00	0%	24%
3902	SOFTWARE EA	Amort	10	10.00	0%	26%
	Sub-Total Intangible Plant					
	Distribution Plant					
3740	DISTRIBUTION LAND	N/A	N/A	N/A	0%	4%
3742	DISTRIBUTION LAND RIGHTS	SQ	75	49.69	0%	25%
3751	DIST STRUCTURES - CG ML INDUST M/R	S6	65	30.04	0%	64%
3753	DIST STRUCTURES - M/R AND DIST STATION	R5	62	30.17	0%	45%
3754	DIST STRUCTURES - OTHER	R4	48	35.38	0%	48%
3755	DIST STRUCTURES - IMPROVEMENTS	L0	38	31.13	-5%	35%
3760	MAIN (DISTRIBUTION)	R2.5	65	51.94	-40%	30%
3780	M/R STATION EQUIP (DIST GENERAL)	R1.5	40	31.24	-65%	18%
3783	M/R STATION EQUIP (DIST ODORIZER)	L0	13	8.02	0%	73%
3790	M/R STATION EQUIP (DIST CITY GATE)	R5	57	26.74	-5%	60%
3800	SERVICES	R4	38	25.29	-130%	59%
3811	METERS - DOMESTIC	R3	36	18.49	0%	64%
3812	METERS - ERTS	R3	14	7.37	0%	69%
3813	METERS - INDUS / LARGE	R4	30	14.98	0%	63%
3820	METER INSTALLATIONS	R2.5	41	28.62	-10%	33%
3831	DIST REGULATORS	S4	27	19.35	0%	44%
3832	DIST REGULATORS IND	S6	31	18.27	0%	50%
3850	INDUSTRIAL M/R STATION EQUIP	L1.5	40	35.83	-2%	10%
3851	INDUSTRIAL M/R STATION EQUIP OTHER	R2.5	48	24.57	-25%	66%
3901	GEN STRUCTURES - IMPROVEMENTS	R1.5	43	41.71	0%	2%
3910	OFFICE FURNTURE AND EQUIPMENT	Amort	20	20.00	0%	21%
3912	COMPUTER EQUIPMENT	Amort	4	4.00	0%	72%
3920	TRANSPORTATION EQUIPMENT	L3	9	5.47	18%	32%
3940	TOOLS, SHOP, GARAGE EQUIPMENT	Amort	10	10.00	0%	44%
3960	POWER OPERATED EQUIPMENT	L2.5	15	9.46	20%	49%
3970	COMMUNICATION EQUIPMENT	Amort	10	10.00	0%	65%
3971	DATA COLLECTION EQUIP	Amort	10	10.00	0%	2%
3980	MISC EQUIPMENT	Amort	10	10.00	0%	63%

SUMMIT UTILITIES ARKANSAS, INC.
THEORETICAL RESERVE
AS OF DECEMBER 31, 2022

Account	Description	Vintage Year	Age	Plant Balance	Average Service Life		% of Assets in excess of 4 and 10 years	Assets Costs in Service > 4 Years	Assets Costs in Service > 10 Years
3912 Computer Equipment									
3912	Computer Equipment	2022	0.5	130,704.61	5	4.38%			
3912	Computer Equipment	2021	1.5	165,778.83	5	5.55%			
3912	Computer Equipment	2020	2.5	433,445.86	5	14.52%			
3912	Computer Equipment	2019	3.5	82,932.31	5	2.78%			
3912	Computer Equipment	2018	4.5	1,967,921.61	5	65.93%	65.93%	1,967,921.61	
3912	Computer Equipment	2017	5.5	203,906.90	5	6.83%	6.83%	203,906.90	
3912	**Totals**			**2,984,690.12**		**100.00%**	**72.77%**	**2,171,828.51**	
3940 Tools, Shop, Garage Equip.									
3940	Tools, Shop, Garage Equip.	2022	0.5	1,206,415.89	15	10.65%			
3940	Tools, Shop, Garage Equip.	2021	1.5	1,731,088.25	15	15.28%			
3940	Tools, Shop, Garage Equip.	2020	2.5	513,341.90	15	4.53%			
3940	Tools, Shop, Garage Equip.	2019	3.5	1,410,454.85	15	12.45%			
3940	Tools, Shop, Garage Equip.	2018	4.5	621,408.33	15	5.49%			
3940	Tools, Shop, Garage Equip.	2017	5.5	426,335.44	15	3.76%			
3940	Tools, Shop, Garage Equip.	2016	6.5	293,764.07	15	2.59%			
3940	Tools, Shop, Garage Equip.	2015	7.5	608,087.76	15	5.37%			
3940	Tools, Shop, Garage Equip.	2014	8.5	827,198.91	15	7.30%			
3940	Tools, Shop, Garage Equip.	2013	9.5	186,869.78	15	1.65%			
3940	Tools, Shop, Garage Equip.	2012	10.5	382,181.08	15	3.37%	3.37%		382,181.08
3940	Tools, Shop, Garage Equip.	2011	11.5	341,951.43	15	3.02%	3.02%		341,951.43
3940	Tools, Shop, Garage Equip.	2010	12.5	197,350.33	15	1.74%	1.74%		197,350.33
3940	Tools, Shop, Garage Equip.	2009	13.5	702,884.57	15	6.20%	6.20%		702,884.57
3940	Tools, Shop, Garage Equip.	2008	14.5	302,063.59	15	2.67%	2.67%		302,063.59
3940	Tools, Shop, Garage Equip.	2007	15.5	23,255.16	15	0.21%	0.21%		23,255.16
3940	Tools, Shop, Garage Equip.	2006	16.5	327,325.41	15	2.89%	2.89%		327,325.41
3940	Tools, Shop, Garage Equip.	2005	17.5	222,963.91	15	1.97%	1.97%		222,963.91
3940	Tools, Shop, Garage Equip.	2004	18.5	248,186.77	15	2.19%	2.19%		248,186.77
3940	Tools, Shop, Garage Equip.	2003	19.5	357,315.01	15	3.15%	3.15%		357,315.01
3940	Tools, Shop, Garage Equip.	2002	20.5	187,241.00	15	1.65%	1.65%		187,241.00
3940	Tools, Shop, Garage Equip.	2001	21.5	71,674.71	15	0.63%	0.63%		71,674.71
3940	Tools, Shop, Garage Equip.	2000	22.5	138,864.76	15	1.23%	1.23%		138,864.76
3940	**Totals**			**11,328,222.91**		**100.00%**	**30.93%**		**3,503,257.73**

23-079-U Sub FCA	Description	PIS 12/31/2024	Accum Depreciation 12/31/2024	Staff Proposed Rate	Staff Proposed Dep Expense	SUA Proposed Rate	SUA Proposed Dep Expense	Currently Approved Dep Rates	Currently Approved Dep Expense	Staff vs Company Dep Expense Inc/(Dec)	Staff vs Current Dep Expense In/(Dec)
	Intangible Plant										
3021	PERPETUAL FRANCHISE & CONSENT	137,343	-	0.00%							
3030	INTANGIBLES INTERCONNECT	3,735,243	944,472	2.00%	74,705	2.00%	74,705	2.00%	74,705	0	0
3031	INTANGIBLES MISCELLANEOUS - PICARRO	7,718,830	-	20.00%	1,543,766	20.00%	1,543,766	14.29%	1,103,021	0	440,745
3032	INTANGIBLES MISCELLANEOUS	15,850,355	13,495,482	10.00%	1,585,036	10.00%	1,585,036	14.29%	2,265,016	0	(679,980)
	Sub-Total Intangible Plant	27,441,770	14,439,954	11.67%	3,203,506	11.67%	3,203,506	12.55%	3,442,741	**0**	(239,235)
				Composite							
	Distribution Plant										
3740	DISTRIBUTION LAND	4,447,798	115,376	0.00%	-	0.00%	-	0.00%	-	0	0
3742	DISTRIBUTION LAND RIGHTS	5,420,085	1,125,206	1.51%	81,843	1.51%	81,843	1.33%	72,087	0	9,756
3751	DIST STRUCTURES - CG ML INDUST M/R	86,779	157,004	1.20%	1,041	1.20%	1,041	1.10%	955	0	87
3753	DIST STRUCTURES - M/R AND DIST STATION	511,856	208,471	1.83%	9,367	1.83%	9,367	2.91%	14,895	0	(5,528)
3754	DIST STRUCTURES - OTHER	10,115,149	4,835,654	1.48%	149,704	1.48%	149,704	0.86%	86,990	0	62,714
3755	DIST STRUCTURES - IMPROVEMENTS	5,647,727	1,601,300	2.24%	126,509	2.24%	126,509	2.55%	144,017	0	(17,508)
3760	MAIN (DISTRIBUTION)	1,018,693,879	275,732,532	2.11%	21,494,441	2.11%	21,494,441	1.94%	19,762,661	0	1,731,780
3780	M/R STATION EQUIP (DIST GENERAL)	16,277,048	3,692,377	4.71%	766,649	4.71%	766,649	4.82%	784,554	0	(17,905)
3783	M/R STATION EQUIP (DIST ODORIZER)	1,148,187	896,243	3.34%	38,349	3.34%	38,349	4.15%	47,650	0	(9,300)
3790	M/R STATION EQUIP (DIST CITY GATE)	2,306,049	1,358,424	1.69%	38,972	1.69%	38,972	1.42%	32,746	0	6,226
3800	SERVICES	468,107,867	271,804,353	6.74%	31,550,470	6.74%	31,550,470	6.89%	32,252,632	0	(702,162)
3811	METERS - DOMESTIC	41,048,390	20,370,247	1.94%	796,339	1.94%	796,339	1.45%	595,202	0	201,137
3812	METERS - ERTS	29,351,745	25,941,359	4.25%	1,247,449	4.25%	1,247,449	10.00%	2,935,175	0	(1,687,725)
3813	METERS - INDUS / LARGE	14,677,129	9,700,285	2.49%	365,461	2.49%	365,461	1.93%	283,269	0	82,192
3820	METER INSTALLATIONS	31,210,939	6,107,412	2.68%	836,453	2.68%	836,453	1.34%	418,227	0	418,227
3831	DIST REGULATORS	19,043,375	9,454,882	2.89%	550,354	2.89%	550,354	3.46%	658,901	0	(108,547)
3832	DIST REGULATORS IND	13,503,349	6,934,296	2.76%	372,692	2.76%	372,692	2.31%	311,927	0	60,765
3850	INDUSTRIAL M/R STATION EQUIP	11,723,809	377,431	2.55%	298,957	2.55%	298,957	2.52%	295,440	0	3,517
3851	INDUSTRIAL M/R STATION EQUIP OTHER	12,964,151	9,391,015	2.39%	309,843	2.39%	309,843	3.03%	392,814	0	(82,971)
		1,706,285,313	649,803,869	3.4598%	59,034,895	3.4598%	59,034,895	3.4631%	59,090,140	**0**	(55,245)
				Composite							
3901	GEN STRUCTURES - IMPROVEMENTS	11,086,361	168,707	2.35%	260,529	2.35%	260,529	0.47%	52,106	0	208,424
3910	OFFICE FURNTURE AND EQUIPMENT	3,318,174	566,692	5.00%	165,909	5.00%	165,909	5.00%	165,909	0	0
3912	COMPUTER EQUIPMENT	6,219,165	4,195,804	20.00%	1,243,833	25.00%	1,554,791	20.00%	1,243,833	(310,958)	0
3920	TRANSPORTATION EQUIPMENT	33,197,356	5,270,969	9.08%	3,014,320	9.08%	3,014,320	5.77%	1,915,487	0	1,098,832
3940	TOOLS, SHOP, GARAGE EQUIPMENT	15,792,608	6,933,617	6.67%	1,053,367	10.00%	1,579,261	6.67%	1,053,367	(525,894)	0
3960	POWER OPERATED EQUIPMENT	5,865,705	3,032,710	3.24%	190,049	3.24%	190,049	5.76%	337,865	0	(147,816)
3970	COMMUNICATION EQUIPMENT	546,700	380,517	10.00%	54,670	10.00%	54,670	10.00%	54,670	0	0
3971	DATA COLLECTION EQUIP	1,823,803	302,154	10.00%	182,380	10.00%	182,380	10.00%	182,380	0	0
3980	MISC EQUIPMENT	3,364,474	353,720	10.00%	336,447	10.00%	336,447	10.00%	336,447	0	0
		81,214,347	21,204,890	7.52%	6,501,505	9.04%	7,338,357	6.58%	5,342,064	**(836,852)**	**1,159,440**
				Composite							
		1,814,941,431	**685,448,713**	3.79%	**68,739,906**	3.83%	**69,576,758**	3.74%	**67,874,946**	**(836,852)**	**864,960**

Summit Utilities Arkansas, Inc.
Docket No. 23-079-U
Theoretical Reserve
As of December 31, 2022

Staff Recommended Theoretical Reserve

		Plant	Accum Depreciation	Theoretical Reserve A/D	Difference (Deficit)/Surplus	Reserve Amortization Period	Annual Reserve Amortization Amount
3910	OFFICE FURNTURE AND EQUIPMENT	2,431,158	518,339	653,256	(134,917)	10	(13,492)
3912	COMPUTER EQUIPMENT	2,984,690	2,142,109	2,312,616	(170,507)	10	(17,051)
3940	TOOLS, SHOP, GARAGE EQUIPMENT	11,328,223	4,976,499	5,184,736	(208,237)	10	(20,824)
3970	COMMUNICATION EQUIPMENT	513,603	332,436	417,632	(85,196)	10	(8,520)
3971	DATA COLLECTION EQUIP	742,282	12,371	37,114	(24,743)	10	(2,474)
3980	MISC EQUIPMENT	463,220	292,942	254,041	38,901	10	3,890
		18,463,176	**8,274,696**	**8,859,394**	**(584,698)**	10	**(58,470)**

Summit Utilities Recommended Theoretical Reserve

New Asset Group	Description	Plant Balance 12/31/2022	Book Reserve 12/31/2022	Theoretical Reserve 12/31/2022	Reserve Difference (Deficit)/Surplus	Reserve Amortization Period	Annual Reserve Amortization Amount
3910	Office Furniture and Equipment	2,431,158	518,339	653,256	(134,917)	10	(13,492)
3912	Computer Equipment	2,984,690	2,142,109	2,593,803	(451,694)	10	(45,169)
3940	Tools, Shop, and Garage Equipment	11,328,223	4,976,499	6,012,415	(1,035,916)	10	(103,592)
3970	Communication Equipment	513,603	332,436	417,632	(85,196)	10	(8,520)
3971	Data Collection Equipment	742,282	12,371	37,114	(24,743)	10	(2,474)
3980	Miscellaneous Equipment	463,220	292,942	254,041	38,901	10	3,890
		18,463,176	**8,274,696**	**9,968,261**	**(1,693,565)**	10	**(169,356)**

Watson Direct Exhibit DAW-1, Appendix A2, Page 1.

Staff vs Company Theoretical Reserve Difference	**(1,108,866)**	**(110,887)**

APSC FILED Time: 7/10/2024 11:03:53 AM: Recvd 7/10/2024 11:02:51 AM: Docket 23-079-U-Doc. 107

CERTIFICATE OF SERVICE

I hereby certify that a copy of the foregoing has been served on all parties of record in accordance with the Commission's Rules of Practice and Procedure Rule 3.07(b) this 10th day of July, 2024.

/s/ Joshua Baxter

Joshua Baxter

APSC FILED Time: 7/10/2024 11:18:44 AM: Recvd 7/10/2024 11:16:53 AM: Docket 23-079-U-Doc. 110

BEFORE THE
ARKANSAS PUBLIC SERVICE COMMISSION

IN THE MATTER OF THE APPLICATION OF SUMMIT UTILITIES ARKANSAS, INC. FOR A GENERAL CHANGE OR MODIFICATION IN ITS RATES, CHARGES AND TARIFFS	))))	DOCKET NO. 23-079-U

DIRECT TESTIMONY

OF

ROBERT H. SWAIM, CEM
SENIOR RATE ANALYST
COST ALLOCATION AND RATE DESIGN

ON BEHALF OF THE GENERAL STAFF OF THE
ARKANSAS PUBLIC SERVICE COMMISSION

JULY 10, 2024

ARSC-FILED Time: 7/10/2024 11:18:44 AM: Recvd 7/10/2024 11:16:53 AM: Docket 23-079-U-Doc. 110

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INTRODUCTION

Q. Please state your name and business address.

A. My name is Robert H. Swaim, and my business address is Arkansas Public Service Commission ("Commission"), 1000 Center Street, Little Rock, Arkansas, 72201.

Q. By whom are you employed and in what capacity?

A. I am employed by the Commission's General Staff ("Staff") as a Senior Rate Analyst. In that capacity, I analyze utility company filings; identify and evaluate issues; develop positions on those issues; and present those positions, when necessary, in written and oral testimony before the Commission.

Q. Please state your qualifications and background.

A. I have over twenty years of experience with Staff, having filed testimony in several cases before the Commission addressing electric, gas, and water utility related matters.

Before joining Staff, I was employed by Entergy Services, Inc. for more than twenty years in various capacities, including Manager of Forecasting. In that position, I was responsible for the Load, Energy, and Revenue Forecasts for each of the Entergy System's regulated electric, natural gas, and steam utility operations. Those functions included the estimation of econometric models, weather adjustment, marketing program impact analysis, and detailed modeling to depict the rates and revenue

recovery mechanisms in the retail jurisdictions of Arkansas, Louisiana, Mississippi, New Orleans, and Texas.

My educational qualifications include a Bachelor of Science in General Studies and a Master of Science in Economics, and I have completed all the requirements for a Doctor of Philosophy in Economics, except the dissertation, all from Louisiana State University in Baton Rouge, Louisiana. My areas of study in the Ph.D. program included Microeconomic Theory, The Regulation of Public Utilities, and Econometrics. I taught Principles of Economics at Louisiana State University, the University of New Orleans, the University of Arkansas at Little Rock ("UALR"), and Webster University. I have also taught Statistics at UALR. Since joining Staff, I have received specialized training, including Utility Regulatory Training sponsored by the Center for Public Utilities, a branch of the College of Business Administration and Economics at New Mexico State University, and Electric Utility Systems training sponsored by Electric Utility Consultants, Inc. I have received training from the Association of Energy Engineers and have qualified as a Certified Energy Manager ("CEM"), License No. 19172.

PURPOSE OF TESTIMONY

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

A. The purpose of my testimony is to address several issues related to the Application for Approval of a General Change in Rates and Tariffs

("Application") filed by Summit Utilities Arkansas, Inc. ("SUA" or "Company") on January 25, 2024. More specifically, I will address SUA's proposed:

- Weather normalized billing determinants (customer counts, Ccf volumes, and Ccf demands);
- Weather Normalization Adjustment Rider ("WNA") Tariff and its associated Degree Day Factors ("DDF");
- Billing Determinant Adjustment ("BDA") Tariff;
- Rate Schedule Revenue Requirement; and
- Rate design.

I will also address the Company's design day (i.e., peak load) forecast and its Mains allocator that are utilized in Staff's Cost of Service Study ("COSS") and which are discussed in the Direct Testimony of Staff witness Mark Burdette.

In so doing, I will address the Direct Testimony of SUA witnesses Phillip Gillam and Timothy Lyons.

SUMMARY OF RECOMMENDATIONS

Q. Briefly summarize your recommendations.

A. I recommend that the Commission:

- Reject SUA's *pro forma* billing determinants and accept those I recommend;
- Reject SUA's proposed Rate Schedule Revenues at present rates and accept Staff's proposed Rate Schedule Revenues at present rates;

- Reject SUA's WNA Bases and DDFs and accept those I recommend;
- Reject SUA's BDA and order SUA to delete the provisions for true-up adjustments for the System Safety Enhancement Rider ("SSER") and Government Mandated Expenditure Surcharge ("GMES") rider from the BDA;
- Reject SUA's design day (i.e., peak load) forecast and accept Staff's peak load forecast;
- Reject SUA's Rate Schedule Revenue Requirement used for designing rates; and
- Accept Staff's mitigated Rate Schedule Revenue Requirement.

BILLING DETERMINANTS AND BASE RATE REVENUES

Q. What is the difference between SUA's proposed *pro forma* billing determinants and your *pro forma* billing determinants?

A. A comparison of my recommended billing determinants and resulting base rate revenues to those filed by SUA is shown in Table 1, below. My recommended *pro forma* year customer count is 199 customers higher than SUA's recommended customer count. My recommended *pro forma* weather normalized Ccf volumes are higher than those proposed by SUA by approximately 9.4 million Ccf, an increase of 1.57%. In total, my recommended billing determinants, excluding rider revenues, produce $1,882,026 (1.10%) more in base rate revenues at SUA's current rates than the Company's recommended billing determinants.

1

Table 1

BILLING DETERMINANTS COMPARISON DETAIL @ CURRENT RATES	SUA	Staff	Diff	% Diff
Residential				
Customers (Average Annual)	366,114	366,351	237	0.06%
Volume (Ccf)	195,664,213	198,160,504	2,496,291	1.28%
Use Per Customer	534.44	540.90	6.47	1.21%
Revenue	$126,005,528	$127,027,804	$1,022,276	0.81%
SCS 1 SSO				
Customers (Average Annual)	44,920	44,896	(24)	(0.05%)
Volume (Ccf)	118,350,179	125,690,799	7,340,620	6.20%
Use Per Customer	2,634.69	2,799.58	165	6.26%
Revenue	$27,341,617	$28,532,347	$1,190,730	4.36%
SCS 1 TSO				
Customers (Average Annual)	395	395	0	0.00%
Volume (MMBtu)	4,177,890	4,031,213	(146,677)	(3.51%)
Use Per Customer	10,581.40	10,209.91	(371)	(3.51%)
Revenue	$7,065,421	$6,883,392	($182,028)	(2.58%)
SCS 2 SSO				
Customers (Average Annual)	658	645	(12)	(1.87%)
Volume (Ccf)	3,728,172	3,418,253	(309,920)	(8.31%)
Use Per Customer	5,668.92	5,296.88	(372)	(6.56%)
Revenue	$624,807	$572,868	($51,940)	(8.31%)
SCS 2 TSO				
Customers (Average Annual)	0	0	0	0.00%
Volume (Ccf)	0	0	0	0.00%
Use Per Customer	0.00	0.00	0	0.00%
Revenue	$0	$0	$0	0.00%
SCS 3 SSO				
Customers (Average Annual)	4	4	0	0.00%
Volume (Ccf)	45,255	42,482	(2,773)	(6.13%)
Use Per Customer	11,313.80	10,620.60	(693)	(6.13%)
Revenue	$8,400	$7,936	($464)	(5.53%)
SCS 3 TSO				
Customers (Average Annual)	3	3	0	0.00%
Volume (Ccf)	10,096	10,098	2	0.02%
Use Per Customer	3,365.33	3,366.14	1	0.02%
Revenue	$30,595	$30,599	$4	0.01%
LCS 1 SSO				
Customers (Average Annual)	2	2	0	0.00%
Demand (MMBtu)	9,036	9,036	0	0.00%
Volume (Ccf)	1,079,310	1,079,310	0	0.00%
Use Per Customer	539,655	539,655.00	0	0.00%
Revenue	$82,722	$82,722	$0	0.00%
LCS 1 TSO				
Customers (Average Annual)	194	192	(2)	(0.95%)
Demand (MMBtu)	2,128,027	2,107,884	(20,143)	(0.95%)
Volume (Ccf)	273,878,629	271,286,160	(2,592,469)	(0.95%)
Use Per Customer	1,411,746	1,411,723	(22)	(0.00%)
Revenue	$10,337,358	$10,240,806	($96,552)	(0.93%)
TOTAL				
Customers (Average Annual)	**412,289**	**412,488**	**199**	**0.05%**
Volume (Ccf)	**596,933,745**	**603,718,820**	**9,357,401**	**1.57%**
Use Per Customer	**1,447.85**	**1,463.60**	**16**	**1.09%**
Revenue	**$171,496,447**	**$173,378,473**	**$1,882,026**	**1.10%**

Q. What did your review of SUA's proposed *pro forma* billing determinants include?

A. I reviewed and analyzed the test year data, the adjustments to the test year data, and the resulting *pro forma* year billing determinants.

Q. How did the Company develop its test year billing determinant data?

A. SUA used a test year ending December 31, 2023. The test year consisted of actual observations of bill counts and volumes for the first six months, January 2023 through June 2023, and projected bill counts and volumes for the last six months, July 2023 through December 2023. The historical weather data consisted of daily high and low temperatures for the ten years ending June 2023. This data was used to develop weather-normalized billing determinants for the *pro forma* year.

Q. What was the scope of your review of the accuracy of the test year billing determinants?

A. I compared the calendar year 2022 bill counts and volumes to the 2022 Annual Report filed by SUA with this Commission and with the Federal Energy Regulatory Commission. In every instance, the data was reported consistently. Therefore, I concluded that the billing determinants derived from SUA's accounting system and included in SUA's filing are materially accurate.

Q. Did you review the methods used by SUA to develop *pro forma* billing determinants?

A. Yes. SUA used a multi-year regression analysis to estimate the base use and DDFs to be employed to weather adjust actual temperatures. This is a departure from its prior practice of using Staff's methodology, as in its predecessor's last general rate case, Docket No. 15-098-U.[1]

Q. What adjustments did SUA make to the test year billing determinants in developing its recommended *pro forma* billing determinants?

A. In general, SUA made two major adjustments: (1) adjustments of customer counts for growth or decline and (2) adjustments of volume for any known effects, principally weather.

Q. How were SUA's adjustments calculated?

A. In general, for customer classes that are weather sensitive, including Residential ("RS-1") and Small Commercial Service 1 ("SCS-1") customers, the regressions were run on six years of actual data to estimate a base load usage[2] ("Base") for the current month and monthly use per customer per heating degree day ("HDD") for the current month and prior month. This analysis resulted in three estimated coefficients which the Company then

[1] In Docket No. 21-060-U, the Commission issued Order No. 11, Doc. 142, approving SUA's acquisition of certain of Centerpoint Energy Resources Corp.'s public utility natural gas assets, comprised of an operating unit or system which provides service to customers in Arkansas. The operating unit so acquired formerly operated under the name "Centerpoint Energy Arkansas Gas ("CEA").

[2] Base load usage is the non-temperature sensitive use per customer which is normally reflected in the non-heating months of July, August, and September.

used to explain the actual monthly weather sensitivity in the Test Year. Substituting thirty-year normal weather for the three weather variables into the test year resulted in an estimate of the use per customer that could be expected in the *pro forma* year.

The Test Year customer counts were modified by growth estimates and the results multiplied by the *pro forma* use per customer to forecast the volumetric usage that could be expected for the *pro forma* year. The RS-1 and SCS-1 use per customer was then projected using a multi-year regression analysis to project the current and prior month Base and weather sensitive usage (i.e., the DDF[3]).

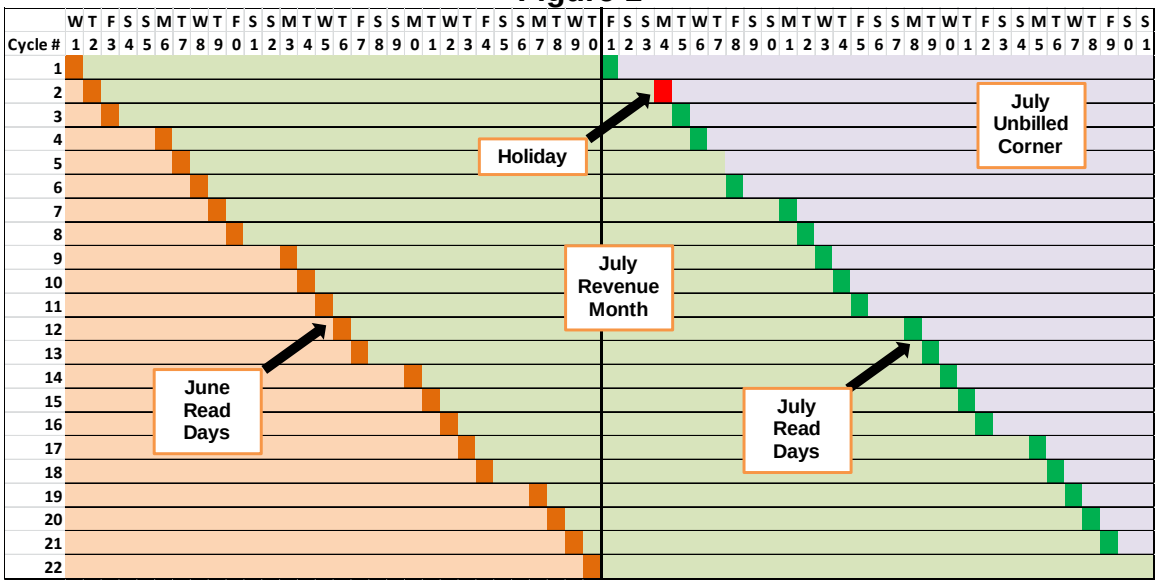
Q. Why are the prior month's HDDs considered in the estimating model?

A. SUA, like many utilities, bills its customers over a roughly 20-cycle billing period, so approximately 1/20 of the customers' meters are read on each read date in a billing-month. Typically, the first cycle is read on or near the first working day of the month. Most of the first cycle's usage occurs in the prior month and is associated with prior month weather conditions. The last cycle is read at the end of the month; most of cycle 20 usage occurs in the current month and is associated with current month weather conditions. Billing cycles 2 through 19 will have some usage from both the prior and current calendar months. The early billing cycles will have more of their

[3] The DDF is the temperature sensitive use per customer per HDD. HDDs are defined as the positive difference between the average daily temperature and sixty-five degrees Fahrenheit.

usage in the prior month; the later cycles will have more of their usage in the current month. For example, July's billing-month sales include customer usage in June as well as July. As a result, both the current month and prior month must be considered in estimating the DDF. Figure 1, below, is a generalized representation of a billing month with 21 cycles – although the number of billing cycles does not correspond to SUA's actual billing cycles, the principles are consistent. In SUA's econometric model, separate DDF adjustments are estimated for the current and prior months. In Staff's algebraic model, the weather from the current and prior months are averaged to estimate a single DDF.

Figure 1



Q. Do you have any concerns regarding SUA's methodology for developing its recommended adjustments?

A. Yes. SUA's weather adjustment methodology employs econometric techniques which are not readily understood by people without years of specialized training. Econometric models are also subject to unseen modifications that may alter their results.

Q. What is your recommendation regarding SUA's billing determinants and the regression model that produced them?

A. I recommend the Commission reject the *pro forma* year billing determinants and present rate schedule revenues proposed by SUA and accept Staff's recommended billing determinants and rate schedule revenues as presented in Table 1, above. I also recommend that the Commission reject both SUA's regression-based model and its simplified WNA models and associated results.

Q. What methodology did Staff utilize to develop its *pro forma* billing determinants?

A. Staff utilized a methodology consistent with that which Staff has used in all the rate cases (both electric and gas) for the last twenty years. Those methods were accepted by the Commission in many past cases, including Docket No. 06-124-U, Order No. 6; Docket No. 12-003-U, Order No. 7; Docket No. 13-079-U, Order No. 12; Docket No. 15-011-U, Order No. 10;

Docket No 15-098-U, Order No. 8; Docket No. 17-071-U, Order No. 6; and Docket No. 21-097-U, Order No. 8.

Q. How did you develop your recommended *pro forma* usages?

A. As mentioned above, Staff's methodology uses the most recent five years of usage data ending with the test year to algebraically derive the Base and DDF for each weather sensitive class. The class Base and DDF are then applied to normal weather to estimate the volumes that would be expected in a hypothetical normal year. The non-weather sensitive classes' usages for the Test Year were used for the *pro forma* year Usages.

Q. How did you estimate peak loads for SUA's customers?

A. Using Staff's Base Use and DDF for a winter design day with 55 HDD, I calculated the peak day daily use for each rate class. These peak loads were provided to Staff witness Burdette, for inclusion in Staff's COSS.

Q. Do your proposed changes in billing determinants impact the allocation factors used in Staff's COSS?

A. Yes. The allocation factors used in Staff's COSS are based on the customer counts and volumes that I propose and will be different from the Company's. These billing determinants were provided to Staff witness Burdette, for inclusion in Staff's COSS.

RIDER REVENUE TARIFFS

Q. What are Rider Revenue Tariffs?

A. Riders are tariffs designed to compensate the utility for expenditures incurred between rate cases. They are generally applied to costs that are material and volatile or are ordered by the Commission. Examples include the Gas Supply Rate ("GSR") Rider, the Energy Efficiency Cost Recovery Rider ("EECR"), and the SSER. Riders and their associated revenues do not impact the Base Rate Revenue Requirement at issue in a rate case such as this one.

Q. Has SUA requested any cost recovery Riders in this docket?

A. Yes, SUA has filed updates to its SSER and is requesting reinstatement of its WNA and its BDA.[4] I will address the WNA and BDA and Staff witness Jeff Hilton will address the SSER.

WNA RIDER TARIFF

Q. What is the purpose of the WNA?

A. The WNA compensates the Company for impacts to its sales volumes due to deviations from normal weather and mitigates the effect of weather on both individual customer bills and Company revenues.

[4] These Riders are supported in the Direct Testimony of Phillip B. Gillam, Doc No. 21, pp. 41-43.

Q. Does SUA have a Commission approved WNA it utilizes to adjust its billing determinants

A. Yes. The rider is Rider Schedule No. 4, Weather Normalization Adjustment (WNA) approved by Commission Order No. 12 in Docket No. 21-060-U issued on January 3, 2022.

Q. Has SUA proposed any changes to its WNA?

A. Yes. SUA has changed the Base and DDFs of each rate class and updated the average HDDs to those for the 30-year period ending October 2023. These changes are consistent with SUA's proposed *pro forma* year billing determinants which were estimated using econometric techniques.

Q. After reviewing the current WNA tariff, do you recommend any changes?

A. Yes. I recommend that SUA's filed WNA be updated to reflect the Bases and DDFs shown in Table 2, below, resulting from the development of my recommended *pro forma* year billing determinants in Table 1, above. The normal HDDs in SUA's Attachment No. 1 to the WNA tariff are based on the same 30-year normal HDDs that I used and should be accepted.

Q. Do SUA's DDF estimates impact its WNA?

A. Yes. SUA's WNA is calculated daily for the actual consumption recorded for each customer modified by the normal HDDs that occurred in that billing cycle. Because of the complexity of using two coefficients derived from its six-year regression to estimate the impact of the actual weather on each

customer's bill, the coefficients from SUA's regression model were added together to produce a single DDF as required by its filed WNA. Adding together two coefficients is a violation of basic regression principles and results in an inconsistency in the modeling of use per customer. That inconsistency undermines the reasonableness of the Company's approach.

Q. Do your proposed changes in billing determinants impact SUA's proposed WNA?

A. Yes. The Base and DDF for each weather sensitive class is consistent with those used to estimate *pro forma* usage and so are different in Staff's case than they are in SUA's case. I recommend the Bases and DDFs shown in Table 2, below, be used in the WNA tariff.

Table 2

STAFF WNA PARAMETERS		
DDF	**Residential**	**SCS-1 (SSO)**
STAFF PROPOSED BASE USAGE	9.92	79.95
STAFF PROPOSED DEGREE DAY FACTOR (DDF)	0.14901	0.64803

BDA RIDER TARIFF

Q. What is the purpose of a BDA?

A. A BDA is intended to compensate a Company for deviations from the *pro forma* billing determinants (i.e., customer counts and volumes), excluding those caused due to weather deviations from normal.[5]

Q. Does SUA currently have a Commission approved BDA Rider allowing it to adjust its billing determinants?

A. No, SUA's predecessor, CEA, terminated its BDA when it elected to be regulated under the Formula Rate Plan tariff after its last rate case, Docket No. 15-098-U.

Q. Has SUA proposed a new BDA Rider in this case?

A. Yes. SUA is requesting reinstatement of the BDA Rider tariff that differs from the prior approved BDA tariff[6] in that it has added two true-up

[5] "The primary purpose of the BDA is to account for a decline in CEA's billing determinants subsequent to the implementation of new rates authorized by this Order. As such the BDA should reduce the frequency of rate increase applications by CEA. Additionally, the BDA should further the Commission's conservation and energy efficiency policy objectives as set out in Commission Docket No. 06-004-R. Accordingly, the Commission believes that the BDA tariff should benefit both CEA and its customers." *See* Order No. 6, Docket No. 06-161-U, Doc. 196, p. 14.

[6] The Trial BDA was approved in Order No. 5 of Docket No. 09-092-U. *See* Order No. 5, Docket No. 09-092-U, Doc. 38, pp. 9-10.

adjustments to compensate for the difference between the intended and actual revenue recoveries of the SSER and GMES riders.[7]

Q. Did SUA support reinstatement of a BDA Rider?

A. Yes. SUA witness Fred Kirkwood discusses the continued decline in billing determinants.

Q. Did SUA's previously approved SSER have a "true-up" mechanism?

A. No. The SSER filed in Exhibit 2 of Mr. Gillam's testimony, states, in Section 2.2, "The SSER is not an exact recovery rider, and therefore, no 'true-up' mechanism is required."[8]

Q. Did SUA's previously approved GMES have a "true-up"?

A. No. SUA's previously approved GMES made no mention of a true-up adjustment mechanism.

Q. After reviewing SUA's filed BDA, do you recommend any changes?

A. Yes. I recommend that the true-up adjustments related to the SSER and GMES be rejected as unnecessary and unsupported. I also recommend that SUA's filed BDA be updated to reflect the Bases and DDFs shown in Table 2, above, resulting from the development of my recommended *pro forma* year billing determinants.

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[7] The BDA also calculates the normal weather adjusted gas volumes for use in the determination of its adjustment and should be congruent with the WNA I recommended.
[8] Direct Exhibit PBG-1 to the Direct Testimony of Phillip B. Gillam, Docket No. 23-079-U, Doc No. 22, PDF p. 4.

EXPIRING RIDER REVENUES

Q. What are Expiring Rider Revenues?

A. Expiring Rider Revenues are revenues that are currently being recovered in an exact recovery rider but will be reset to zero when the costs supporting the rider are rolled into or included in the Rate Schedule Revenue Requirement and the Expiring Rider resets to reflect a zero balance.

Q. What are the Expiring Rider Revenues that are currently being recovered in this case?

A. The only Expiring Riders currently being recovered by SUA are the SSER and the Lost Contribution to Fixed Costs ("LCFC") element of the EECR Rider.

Q. Please describe the SSER and its estimation.

A. The SSER seeks to recover expenditures incurred to improve the distribution system's safety and integrity. In this case, I used the rates established in the June 1, 2024, filing in Docket No. 21-060-U to calculate $9,815,646 using Staff's billing determinants.[9] The SSER will reset to zero when the costs supporting the rider are rolled into Base Rate Revenues.

Q. Please describe the LCFC and its estimation.

A. The LCFC is one of the three elements of the EECR Rider. The purpose of the LCFC is to compensate the utility for the portion of base rates

[9] *See* Monthly System Enhancement Rider Filing, Docket No. 21-060-U, Doc. 183.

attributable to fixed costs that were forgone by the reduction in billing determinants due to energy efficiency improvements caused by the utility's energy efficiency programs. In this case, I used the rates established in the May 1, 2023, filing in Docket No. 07-081-TF to calculate $1,421,709 using Staff's billing determinants.[10] The LCFC element of the EECR Rider will reset to zero when the costs supporting the rider are rolled into Base Rate Revenue.

RATE DESIGN

Rate Schedule Revenue Requirement Used in Designing Rates

Q. What are rate schedule revenues?

A. Rate schedule revenues or base rate revenues are revenues which the Company receives from general rate schedules, excluding revenues from riders designed to collect specific costs such as fuel and energy efficiency costs. Base rate revenues are important because *pro forma* year base rate revenues are compared to the revenue requirement from the COSS to determine the revenue deficiency or excess for the various rate classes. Existing base rates for each rate class must be revised to account for the deficiency or excess in that rate class while no adjustment is necessary if revenues match the COSS.

[10] *See* Energy Efficiency Cost Recovery Reporting Workpapers, Docket No. 07-081-TF, Doc. 583, p. 2.

Q. Do your proposed changes in billing determinants impact Staff's determination of the Rate Schedule Revenue Requirement?

A. Yes. The present rate schedule revenues were developed using my *pro forma* billing determinants and were provided to Staff witness Hilton to be included in Staff's Adjustment IS-3.[11] These present rate schedule revenues were also provided to Staff witness Burdette for inclusion in Staff's COSS.

Q. What are the results of Staff's COSS?

A. Staff witness Burdette presents the results of Staff's COSS. Staff's resulting revenue requirement by rate class forms the basis for my rate design recommendations. The result of Staff's COSS, supported by Staff witness Burdette, is reflected on Line 2 of Table 3.

[11] Direct Exhibit JH-5 to the Direct Testimony of Staff witness Jeff Hilton.

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Table 3
Staff's Direct COSS Summary

Line No.	Description (1)	Total Arkansas Retail (2)	Residential (3)	SCS-1 (4)	SCS-2 (5)	SCS-3 (6)	LCS-1 (7
	Staff's Proposed Revenue Requirement before Mitigation						
1	Rate Schedule Revenue @ Present Rates	$ 173,378,473	$ 127,027,804	$ 35,415,739	$ 572,868	$ 38,535	$ 10,323,528
2	Rate Schedule Revenue Requirement	$ 247,949,922	$ 189,287,900	$ 42,824,858	$ 488,346	$ 13,224	$ 15,335,593
3	Revenue Deficiency/(Surplus) (L2-L1)	$ 74,571,449	$ 62,260,096	$ 7,409,119	$ (84,522)	$ (25,310)	$ 5,012,066
4	**% Increase on Base Revenue (L3 / L1)**	**43.01%**	**49.01%**	**20.92%**	**-14.75%**	**-65.68%**	**48.55%**
	Staff's Proposed Revenue Requirement after Mitigation						
5	Rate Sch. Rev. Req. before Mitigation (L2)	$ 247,949,922	$ 189,287,900	$ 42,824,858	$ 488,346	$ 13,224	$ 15,335,593
6	Mitigation Adjustment	$ -	$ (109,833)		$ 84,522	$ 25,310	
7	Rate Sch. Rev. Req. after Mitigation (L5+L6)	$ 247,949,922	$ 189,178,067	$ 42,824,858	$ 572,868	$ 38,535	$ 15,335,593
8	Revenue Deficiency/(Surplus) (L7-L1)	$ 74,571,449	$ 62,150,264	$ 7,409,119	$ -	$ -	$ 5,012,066
9	**% Increase on Base Revenue (L8 / L1)**	**43.01%**	**48.93%**	**20.92%**	**0.00%**	**0.00%**	**48.55%**
10	**% of System Average Increase**	**100.00%**	**113.75%**	**48.64%**	**0.00%**	**0.00%**	**112.88%**

Q. Are the results of Staff's COSS used as the basis to determine rates for each of the customer classes?

A. Yes. The base rate revenue requirement determined in Staff's COSS (on Line 2 of Table 3, above) should be used as the basis for designing rates. The overall increase in base rate revenue requirements, 43.01%, is shown on Line 3 of Table 3. However, Staff's position is that mitigation of the COSS results is warranted given that a reduction in rates is indicated for two of the classes (for SCS-2, a 14.75% reduction, and for SCS-3, a 65.68% reduction) whereas the remaining classes are due a rate increase.

Q. What has been the Commission's policy concerning cost-based rates?

A. As stated on page 17 of Order No. 20 in Docket No. 02-024-U, "[i]t has been the longstanding policy of this Commission that each rate class pay their cost of service."[12] Indeed, "[t]he Commission's policy concerning cost-

[12] Order No. 20, Docket No. 02-024-U, Doc. 173, p.17.

based rates has been tempered with the desire to avoid unnecessary significant adverse customer impacts."[13] Also, when designing rates, changes in rate design should be made gradually to minimize adverse rate impacts. The rate design should attempt to balance SUA's desire for revenue stability and the customer's desire for rate stability. In general, the rate design should provide SUA with a reasonable opportunity to recover its approved revenue requirement, while minimizing the adverse impact on ratepayers.

Q. Based on Staff's COSS, what is your recommendation regarding the revenue requirement used in designing rates?

A. Because of the reduction to the SCS-2 and SCS-3 classes indicated by Staff's COSS, I recommend mitigating the results so that no individual customer class would receive a rate decrease in the context of an overall system increase. This is consistent with Staff's position in prior rate cases.[14] As summarized in Table 3, Staff's COSS results in an overall system increase of 43.01% in base rate revenues.

An inspection of the five rate classes in Table 3 (and in Schedule G-1 of Staff's COSS) shows that SCS-2 and SCS-3 have decreases in the

[13] Order No. 8, Docket No. 15-098-U, Doc. 249, p. 45.
[14] *See*, *for example*, Order No. 20, Docket No. 02-024-U, Doc. 172, pp. 16-17; Order No. 8, Docket No. 15-098-U, Doc. 249, pp. 45-46; Direct Testimony of Matthew S. Klucher, Docket No. 13-028-U, Doc. 205, p. 9, lines 2-10; Direct Testimony of Matthew S. Klucher, Docket No. 16-052-U, Doc. 119, p. 19, lines 9-12; Direct Testimony of Tom D. Stevens, Docket No. 09-084-U, Doc. 178, p. 22, lines 7-13.

context of an overall rate increase. Therefore, I recommend that in this proceeding, the Commission accept the mitigation of Staff's COSS results that I developed by applying the following guidelines:

1. No customer class should receive a rate decrease from current rate revenues; and,
2. Any revenue surplus attributable to the classes that are limited to having no decrease in current revenues should be assigned to the rate class with the highest indicated increase (i.e., Residential).

The results of my recommendation are shown on Line 7 in Table 3, above.

Customer, Volumetric, and Demand Charge Increases

Q. What rate designs does SUA propose?

A. SUA's proposed rate designs increase the customer and volumetric rates of each class by the individual class rate increase. As a consequence, all customers in that class would receive the same percentage increase regardless of consumption levels.

Q. What is your recommendation concerning the design of the customer, volumetric, and demand charges for each rate class?

A. I recommend that SUA be ordered to design compliance rates with increases in the customer and volumetric charges for each rate class that are similar in magnitude to the percentage increases I recommend (shown on Line 7 in Table 3, above) for the respective class. However, I may offer more specific rate design recommendations in my surrebuttal testimony.

RECOMMENDATIONS

Q. Please summarize your recommendations.

A. Based on my analysis and conclusions, I recommend that the Commission:

- Reject SUA's *pro forma* billing determinants and rate schedule revenues and accept those I recommend as presented in Table 1;
- Reject the Bases and DDFs in SUA's WNA and accept those I recommend as presented in Table 2;
- Reject the true-up adjustments for SSER and GMES imbedded in SUA's BDA rider rate design;
- Reject SUA's design day (i.e., peak load) forecast and accept Staff's peak load forecast;
- Reject SUA's rate design and accept that which I recommend; and
- Reject SUA's proposed Rate Schedule Revenue Requirement and accept Staff's mitigated Proposed Rate Schedule Revenue Requirement shown on Line 7 of Table 3 for designing Compliance Rates in this case.

Q. Does this conclude your testimony?

A. Yes, it does.

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CERTIFICATE OF SERVICE

I certify that a copy of the foregoing has been served on all parties of record via the Arkansas Public Service Commission's Electronic Filing System in accordance with the Commission's *Rules of Practice and Procedure* on July 10, 2024.

/s/ JOSHUA A. BAXTER
Joshua A. Baxter

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BEFORE THE
ARKANSAS PUBLIC SERVICE COMMISSION

IN THE MATTER OF THE APPLICATION OF SUMMIT UTILITIES ARKANSAS, INC. FOR A GENERAL CHANGE OR MODIFICATION IN ITS RATES, CHARGES AND TARIFFS	))))	DOCKET NO. 23-079-U

DIRECT TESTIMONY

OF

MARK BURDETTE
SENIOR RATE CASE AUDITOR

ON BEHALF OF THE GENERAL STAFF
OF THE ARKANSAS PUBLIC SERVICE COMMISSION

JULY 10, 2024

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INTRODUCTION

Q. Please state your name and business address.

A. My name is Mark Burdette. My business address is 1000 Center Street, Little Rock, Arkansas 72201.

Q. By whom are you employed and in what capacity?

A. I am employed by the General Staff ("Staff") of the Arkansas Public Service Commission ("Commission" or "APSC") as a Senior Rate Case Auditor in the Cost Allocation and Rate Design section. In that capacity, I analyze utility company filings, identify and evaluate issues, develop positions on those issues, and present those positions, when necessary, in written and oral testimony before the Commission.

Q. Please state your education, qualifications, and background.

A. I have a Bachelor of Science in Electrical Engineering from the University of Iowa and a Master of Business Administration with dual concentrations in Finance and Investments from the Tippie School of Business at the University of Iowa. I worked for almost nine years for the Missouri Office of the Public Counsel as a Regulatory Financial Analyst, where I was a Certified Rate of Return Analyst, writing testimony and testifying in electric, gas, water, and telecommunications cases before the Missouri Public Service Commission. I have also worked in aerospace defense, in plasma wave space physics, and for fourteen years in the wireless telecommunications industry doing switch engineering, capacity planning, financial analysis, and network project implementation.

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PURPOSE OF TESTIMONY

Q. What is the purpose of your testimony?

A. My testimony addresses cost classification and allocation issues related to the Application for Approval of a General Change in Rates and Tariffs ("Application") of Summit Utilities of Arkansas, Inc. ("SUA" or "Company") filed January 25, 2024. I also sponsor Direct Exhibit MB-1, which presents the result of Staff's Cost of Service ("COS") Study ("COSS"). In doing so, I will address the testimony of SUA witness Timothy S. Lyons. Staff witness Robert H. Swaim will discuss the revenue requirement and rate design that is based on Staff's COSS. In addition, Staff witness Swaim will discuss the development of Staff's weather-normalized *pro forma* year billing determinants and the resulting present rate revenues and peak-day volumes which are key inputs into Staff's COSS.

SUMMARY OF RECOMMENDATIONS

Q. What are your recommendations regarding SUA's Cost of Service Study?

A. I recommend the Commission reject the Company's COSS and accept as reasonable the cost classification and allocation methodologies embedded in Staff's COSS. Furthermore, I recommend new rates be designed such that each customer class pays its revenue requirement as determined by Staff's COSS results incorporating Staff's recommended mitigated distribution of the revenue requirement as discussed in the Direct Testimony of Staff witness Robert H. Swaim.

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COST OF SERVICE STUDY OVERVIEW

Q. What is the role of the COSS in establishing rates?

A. The COSS is an important guide used to assist the Commission in determining the just and reasonable COS and rates applicable to each customer class. A COSS allocates a portion of the utility's total base rate revenue requirement to each of the individual customer classes. This is accomplished through the process of allocating the total COS to functional cost components that are then assigned to specific customer classes based on cost-causation principles. In addition, the COSS results provide information regarding the level of classified component costs (e.g., demand, commodity, and customer) by customer class that may be useful in designing rates. Specifically, the COSS is used to assist the Commission in determining both a utility's Arkansas jurisdictional retail base rate revenue requirement and the base rate revenue requirement for each individual retail customer class.

Q. How is a COSS developed?

A. The COSS allocates the utility's total COS to the various customer classes. The COSS is a three-step process: (1) functionalization, (2) classification, and (3) allocation.[1]

The first step is to functionalize total costs into the primary operating functions of the utility, such as production, storage, transmission, distribution, and customer services. Costs are also functionalized to administrative and general, which includes costs that cannot be directly assigned to the primary operating

[1] NARUC Gas Distribution Rate Design Manual, pgs. 20-26.

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functions of production, storage, transmission, distribution, and customer services. Costs are typically functionalized in accordance with the Federal Energy Regulatory Commission ("FERC") Uniform System of Accounts ("USOA").[2] Operation and Maintenance Expenses and Other Expenses are functionalized in a comparable manner.

In the second step, functionalized costs are then classified as: demand, which represents costs that vary with the maximum or "peak" level of throughput or volume imposed on the utility's system; commodity, which represents costs related to the throughput or volume during a time interval without regard to the maximum volume; customer, which represents costs that directly relate to the number and type of customers served by the utility; and revenues, which are directly related to the amount of utility revenue collected from each of the customer classes.

In the third and final step, functionally assigned and classified costs are then allocated to customer classes. Customer classes represent a grouping of customers based on the type of service provided and load characteristics. The three principal customer classes are residential, commercial, and industrial. Costs are directly assigned or allocated to the customer classes based on the allocation factor that is representative of the service characteristic that drives the utility's cost. Demand-related costs are allocated according to some measure of each class's maximum or peak day demand (Ccf), commodity-related costs are allocated according to each class's annual throughput or volume usage (Ccf), and customer-

[2] *Uniform System of Accounts Prescribed for Natural Gas Companies Subject to the Provisions of the Natural Gas Act*, C.F.R. § T. 18, Ch. I, Subch. F, Pt. 201.

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related costs are allocated according to the number of customers in each class, weighted or un-weighted, depending on the nature of the specific cost.

Q. How are allocation factors developed for a COSS?

A. There are generally two types of allocators used to allocate cost to classes, external allocators and internal allocators. External allocators are based on billing determinants, load data, and special studies derived from data collected from the utility's system. Examples of external allocators would be coincident peak day demand or capacity, usage or commodity, and weighted or unweighted number of customers by class. Internal allocators are computed within the COSS by combining more than one cost element previously allocated in the COSS. An example of an internal allocator would be an allocator derived from the ratio of all distribution plant costs to the customer classes. Distribution plant is composed of several individual FERC accounts. Each FERC distribution account has a balance which has been allocated to the classes using various allocators. The sum of all FERC distribution accounts (with their various allocation factors) develops the new internal allocator. This new internal allocator can be used to assign certain remaining costs to customer classes that are related to distribution plant. Internal allocation factors can also become a compound allocation factor when the compound allocation factor is derived by taking a weighted distribution of two or more internal allocators and using them to develop a new, hybrid allocator.

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SUA's COSS

Q. How did the Company develop its COSS?

A. SUA witness Lyons describes his three-step approach to develop SUA's total retail and customer class Non-Gas Revenue Requirement which at first blush, appears consistent with the traditional COSS approach I described above.[3] However upon closer examination, I determined that Company witness Lyons reversed the order of Classification and Allocation in a non-traditional approach in preparing his COSS. I will discuss this in more detail later in my testimony. SUA witness Lyons also states that his approach to preparing the Company's COSS "was generally consistent with the approach utilized in the Company's predecessor, CenterPoint Energy Resources Corp., settlement COSS in its prior base rate proceeding in Docket No. 15-098-U."[4]

The result of the Company's COSS is shown on SUA's Application Schedule G-1. SUA's recommended total COS is based on a test year ending December 31, 2023, including six months of historical data ending on June 30, 2024, and six months of projected data from July 1 through December 31, 2024, adjusted for known and measurable changes during the *pro forma* year as measured by the Company.[5] The result of SUA's COSS is summarized in Table 1 – *SUA's COSS Summary*, below.[6]

[3] Direct Testimony of Timothy S. Lyons, Docket No. 23-079-U, Doc. 36, p. 14, line 9 – p. 16, line 9.
[4] Direct Testimony of Timothy S. Lyons, Docket No. 23-079-U, Doc. 36, p. 3, lines 9 – 11.
[5] Application, Docket No. 23-079-U, Doc. 18, Part 1, p. 3.
[6] Application, Minimum Filing Requirement ("MFR") Schedule G-1, Docket No. 23-079-U, Doc. 18, Part 7, pp. 1-3.

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Table 1
SUA's COSS Summary

Line No.	Description (1)	Total Arkansas Retail (2)	Residential (3)	SCS-1 (4)	SCS-2 (5)	SCS-3 (6)	LCS-1 (7)
1	Rate Schedule Revenue Requirement**	$ 279,949,398	$ 208,599,178	$ 50,192,999	$ 576,302	$ 21,151	$ 20,559,768
2	Other Operating Revenues	$ 6,711,338	$ 6,182,964	$ 517,992	$ 6,504	$ 1,502	$ 2,376
3	Fuel Rider Revenues@Present Rates	$ 235,986,729	$ 143,706,385	$ 88,323,339	$ 3,190,020	$ 39,225	$ 727,760
4	Other Rider Revenues@Present Rates*	$ -	$ -	$ -	$ -	$ -	$ -
5	Total Revenue Requirement (L1+L2+L3+L4)	$ 522,647,465	$ 358,488,527	$ 139,034,330	$ 3,772,826	$ 61,878	$ 21,289,904
	Base Rates Excluding Rolled-In Riders						
6	Present Rate Schedule Revenues*	$ 171,496,447	$ 126,005,528	$ 34,407,037	$ 624,807	$ 38,995	$ 10,420,079
7	Revenue Deficiency/(Surplus) (L1-L6)	$ 108,452,951	$ 82,593,650	$ 15,785,962	$ (48,505)	$ (17,844)	$ 10,139,689
8	**% Increase on Rate Sch. Rev.** (L7/L6)	**63.24%**	**65.55%**	**45.88%**	**-7.76%**	**-45.76%**	**97.31%**
	Base Rates Including Rolled-In Riders						
9	Rolled-In Rider Revenues	$ 3,773,524	$ 2,806,168	$ 801,864	$ 6,256	$ 117	$ 159,119
10	Present Rate Schedule Revenues*	$ 171,496,447	$ 126,005,528	$ 34,407,037	$ 624,807	$ 38,995	$ 10,420,079
11	Revenue Deficiency/(Surplus) (L1-L9-L10)	$ 104,679,427	$ 79,787,483	$ 14,984,098	$ (54,762)	$ (17,961)	$ 9,980,569
12	Total Rate Sch. Rev. Requirement (L9+L10+L11)	$ 279,949,398	$ 208,599,178	$ 50,192,999	$ 576,302	$ 21,151	$ 20,559,768
13	**% Increase on Rate Sch. Rev.** (L11/L10)	**61.04%**	**63.32%**	**43.55%**	**-8.76%**	**-46.06%**	**95.78%**
	Increase in Total Revenues						
14	Total Current Revenues**	$ 417,968,038	$ 278,701,044	$ 124,050,232	$ 3,827,588	$ 79,839	$ 11,309,335
15	Change in Total Rev. Requirement (L5-L14)	$ 104,679,427	$ 79,787,483	$ 14,984,098	$ (54,762)	$ (17,961)	$ 9,980,569
16	**% Increase in Total Rev. Req.** (L15/L14)	**25.04%**	**28.63%**	**12.08%**	**-1.43%**	**-22.50%**	**88.25%**

*Excludes the Rolled-In Riders
**Includes the Rolled-In Riders

Q. What are rate schedule revenues?

A. Rate schedule revenues, commonly referred to as base rate revenues, are revenues the Company receives from its general rate schedules, excluding revenues from riders designed to collect specific costs such as fuel and energy efficiency costs and other operating revenues.[7] I will use the terms "rate schedule revenues" and "base rate revenues" interchangeably in my testimony.

Q. Why are base rate revenues important?

A. Base rate revenues are important because *pro forma* year base rate revenues are compared to the revenue requirement from the COSS to determine the revenue deficiency or excess for the various rate classes. Existing base rates for each rate class must be revised to account for the deficiency or excess in the rate class.

[7] Other operating revenues are fees generated by customer activity charges such as shut-offs, insufficient funds charges, meter testing, etc.

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Q. Did SUA include revenues collected through its current riders as part of its current base rate revenue?

A. Yes. On its MFR Schedule H-2-C, SUA shows the revenue from its System Safety Enhancement Rider ("SSER") included as an element of the revenue requirement.[8]

Q. Do you agree with including the Rolled-In Rider Revenues as part of the current base rate revenues in the COSS?

A. No. The Rolled-In Rider Revenues are not currently recovered in base rates and therefore should not be included as base rate revenues in the COSS in the present rate case. Staff supports a more straightforward approach that excludes the Rolled-In Rider Revenues from the COSS, resulting in a rate schedule revenue deficiency that reflects the entirety of the recommended increase to the Company's current base rates. The results of SUA's COSS are summarized, above, in Table 1 – SUA's COSS Summary. The percentage increase to base rates excluding the Rolled-In Rider Revenues, which more accurately reflects the overall increase in base rates, is summarized in Table 1 – SUA's COSS Summary, line 8. I have also included the percentage increase in base rates, if the Rolled-In Rider Revenues are included, on lines 9-13, which is consistent with how the Company presented its case. The percentage increase to total revenues, which includes all riders, is shown on line 16. Staff witness Swaim will discuss how the inclusion of Rolled-In Rider Revenues into base rates impacts rate design.

[8] Application, MFR Schedule H-2, Docket No. 23-079-U, Doc. 18, Part 8, PDF p. 5, lines 41-42.

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Q. What approach did you use to review the COSS developed by the Company?

A. First, I replicated the Company's COSS model using Staff's model. I accomplished this by entering the Company's data, including its proposed allocation methodologies, into a model developed by Staff. I adjusted Staff's model to reproduce the Company's COSS model in detail. Next, I reviewed the reasonableness of the classification and allocation methodologies used in the Company's COSS.

Q. What were the results of your review of the reasonableness of the classification and allocation methodologies used in the Company's COSS?

A. Based on my review, in addition to its non-traditional approach to classifying and then allocating costs, I identified several specific accounts for which I disagree with the intended classification and allocation methodologies utilized by the Company in its COSS. In several instances, the Company departed from the methodology previously recommended by Staff in Docket No. 15-098-U[9] and adopted as part of the Settlement COSS ultimately approved by the Commission.[10]

Q. Please explain the non-traditional methodology used by SUA.

A. SUA witness Lyons reversed the order of operations for Classification and Allocation of costs. SUA first allocated costs to the rate classes and then classified those costs into demand, commodity, customer or revenue related cost types. The Company's alternative, non-traditional approach, yielded results that were

[9] SUA received approval from the Commission to acquire its jurisdictional utility distribution system from CenterPoint Energy Resources Corp. in Docket No. 21-060-U. The sale closed on Jan. 10, 2022. The most recent prior general rate case proceeding in which current rates for SUA were approved was in Docket No. 15-098-U.

[10] Docket No. 15-098-U, Order No. 8, Doc. 249.

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considerably different from Staff's COSS results that were developed using the traditional approach in which costs are first classified then allocated as described above and as used in prior proceedings before the APSC.

Q. Does this change in methodology alter the results of the COSS?

A. Yes. See Exhibit MB-1 which shows examples of how the two different methods produce different results for particular Rate Classes. In the examples reflected in the exhibit, I have presented a plant account and an expense account for which Staff and the Company used similar cost classifications and allocation factors but differed only in the order in which the steps were applied. The example shows that the methodology used by SUA shifts costs from the Residential Rate Class onto other rate classes. In this example, SUA's methodology shifted:

- $48.8M for Plant account 376.00 Mains away from Residential and primarily onto classes SCS-1 ($24.54M) and LCS-1 ($25.4M); and
- $0.48M for O&M Expense account 887.00 Mains away from Residential and primarily onto classes SCS-1 ($0.24M) and LCS-1 ($0.24M).

Q. Did Company witness Lyons support his decision to alter the order of operations in his COSS?

A. No. There was no support provided in his Direct Testimony.

Q. In addition to the reversal of the cost classification / allocation steps, what were the results of your review of the reasonableness of the classification and allocation methodologies used in the Company's COSS?

A. Based on my review, I disagree with the classification and allocation methodologies utilized by the Company in its COSS for the following:

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- Allocation of Other Working Capital Assets on Schedule G-2.
- Allocation of Certain other Distribution Operation and Maintenance (O&M) Expense Accounts:
  - Distribution Operation Expenses
    - 874 Mains and Services
    - 880 Other Expenses
    - 881 Rents
  - Distribution Maintenance Expenses
    - 885 Supervision & Engineering
    - 894 Other Equipment
- Taxes Other Than Income Tax

My recommended alternative classification and allocation methodologies for these specific rate base and expense items are discussed below in the context of the results of Staff's COSS. In general, my recommended classification and allocation methodologies are consistent with the Agreement approved by the Commission in Order No. 8 in Docket No. 15-098-U, the Company's predecessor's last rate case.

CLASSIFICATION AND ALLOCATION METHODOLOGY

Q. Will you be addressing specific cost allocation issues in your testimony?

A. Yes. I will primarily address cost allocation issues in which Staff's approach differs from that utilized by the Company. A summary of these differences is provided in Table 2, below:

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Table 2
Summary of Differences
Cost Classification and Allocation Methodologies

Account	Description	Company	Staff
Working Capital			
	Other Working Capital Assets	Classified as O&M related; Allocated using OMEXP, its O&M Expenses allocator.	Classified as Plant; allocated using NetPLT allocator (Internal allocator based on Net Plant balances).
Distribution Expenses - Operations			
874	Mains and Services Expense	Classified on Distribution Plant Accounts 376 - Mains & 380 - Services; Allocated using Internal allocator MAINSSERV (weighted by Customer and Demand percentages applied to accounts 376 - Mains and 380 - Services.	Classified as Plant; Allocated using Mains/Services (Internal allocator derived from the balances of plant accounts 376 - Mains and 380 - Services).
880 and 881	Other Expenses and Rents	Classified as Mains; Allocated using MAINS Allocator.	Classified as O&M Expense; Allocated using DEXP_Oper (Internal allocator derived from Operation Expense Accounts 871-879).
Distribution Expenses - Maintenance			
885	Supervision & Engineering Expense	Classified and allocated using an Internal allocation factor OMEXP887-893 (based on allocated costs of Distribution Maintenance Expense Accounts 887 through 893, excludes account 886).	Classified as O&M; Allocated using DEXP_Maint (Internal allocator derived from Distribution Maintenance Expense Accounts 886 through 893 balances - includes 886).
894	Other Equipment	Classified as Mains; Allocated using MAINS allocator.	Classified as O&M; Allocated using DEXP_Maint (Internal allocator derived from Distribution Maintenance Expense Accounts 886 through 893 balances - includes 886).
Taxes Other than Income Tax			
	Taxes Other than Income Tax	SUA aggregates several accounts into a single account called Taxes other than Income Tax. Classified as Net Plant; Allocated using NETPLT (Internal Allocator derived from Net Plant balances).	Staff has separate line items for several accounts that make up Taxes Other than Income Tax. Each line item is appropriately classified and allocated.

Q. What methodology did the Company use to allocate Other Working Capital Assets?

A. The Company classified Other Working Capital Assets as O&M related and allocated it using its allocation factor “O&M Expenses” (OMEXP).

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Q. Do you agree with the Company's use of its O&M Expenses allocation factor for Other Working Capital Assets?

A. No. The Company's current allocation method uses an expense allocation factor rather than a plant allocation factor. A more reasonable allocation method would be to use a plant allocation factor "Net Plant" (NetPLT) as did Staff for Other Working Capital Assets.

Q. What methodology did the Company use to allocate Distribution Operations Expense account 874 Mains and Services?

A. The Company allocated Distribution Operation Expense Account 874.00 Mains and Services using an internal allocation factor "Mains & Services" (MAINSSERV). To derive the Customer-related costs of the Mains/Services allocation factor, SUA weights pro forma customer counts by the overall Customer-related costs of plant accounts 376.00 Mains and 380.00 Services and for the Demand-related costs of the Mains/Services allocator, SUA weights the design day allocator by the overall Demand-related costs of plant accounts 376.00 and 380.00.

Q. What is your recommendation regarding the allocation methodology for account 874 Mains and Services?

A. Staff used an internal allocation factor (Mains/Services) derived from the allocated costs of plant accounts 376 Mains and 380 Services.

Q. What methodology did the Company use to allocate Distribution Operations Expense accounts 880 Other Expenses and 881 Rents?

A. The Company allocated Distribution Operation Expense account 880 Other Expenses and account 881 Rents using its Mains allocator (MAINS) .

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Q. What is your recommendation regarding the allocation methodology for accounts 880 and 881?

A. Staff recommends accounts 880 and 881 be allocated using an internal allocator derived from the allocated costs of Distribution Operation Expense Accounts 871-879 (DEXP_Maint). My recommendation follows the cost-causation principles to allocate costs on the related Distribution Operation Expense Accounts. This is the same recommendation made by Staff witness Karen Wheatley in her direct testimony in 15-098-U for these accounts.[11]

Q. What methodology did the Company use to allocate Distribution Maintenance Expense account 885 Supervision & Engineering?

A. The Company used the internal allocation factor (OMEXP887-893) which is based on the allocated costs of Distribution Maintenance Expense accounts 887 through 893, excluding account 886.

Q. What is your recommendation regarding the allocation methodology for account 885?

A. I recommend Account 885 be allocated based on Distribution Maintenance Expense accounts 886 (inclusive) through 893 (DEXP_Maint). This is the same recommendation made by Staff witness Karen Wheatley in her direct testimony in 15-098-U for these accounts.[12]

[11] Direct Testimony of Karen Wheatley, Docket No. 15-098-U, Doc. 135, p. 17, line 20 through p. 18, line 4.
[12] Direct Testimony of Karen Wheatley, Docket No. 15-098-U, Doc. 135, p. 19, lines 10-11.

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Q. What methodology did the Company use to allocate Distribution Maintenance account 894 Other Equipment?

A. The Company allocated Distribution Maintenance Expense account 894, Other Equipment using its Mains allocator (MAINS) based on the results of its Mains Study.

Q. What is your recommendation regarding the allocation methodology for account 894?

A. I recommend account 894 be allocated based on the allocated costs of Distribution Maintenance Expense Accounts 886 through 893 (DEXP_Maint). This is the same recommendation made by Staff witness Karen Wheatley in her direct testimony in 15-098-U for these accounts.[13]

Q. What methodology did the Company use to allocate Taxes Other than Income Tax?

A. SUA rolls together several tax accounts into Taxes Other Than Income Tax, classifies it all as Net Plant, and allocates the total using the "Net Plant" allocation factor (NETPLT), which is an internal allocator derived from Net Plant balances.

Q. What is your recommendation regarding the methodology for Sales & Use Tax?

A. Staff retains separate line items for the various taxes that comprise Taxes Other Than Income Tax and allocated each item appropriately. I recommend the costs associated with the accounts which comprise Taxes Other Than Income Tax be classified

[13] Direct Testimony of Karen Wheatley, Docket No. 15-098-U, Doc. 135, p. 19, lines 12-15.

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and allocated using Staff's methodology as it more appropriately reflects cost causation principles.

Q. Do you take issue with the derivation of the Mains allocation utilized by SUA's witness Lyons in his COSS?

A. Yes. Company witness Lyons used a simple average of the output from his Minimum Size Study and his Zero Intercept Study when calculating the customer portion of the cost of the distribution mains. This averaging of the two approaches is not the method used by Staff to formulate a COSS and was not the method used by the Company in 15-098-U. In fact, Mr. Lyons provided no support for the validity of the result of averaging the outputs of these two methodologies. Staff has traditionally relied upon the minimum size main study when allocating distribution mains to the customer classes in its COSS. The Commission has generally accepted Staff's COSS as the basis for rate design. Staff witness Swaim also addresses Staff's traditional reliance on the minimum-size main study for use in developing its distribution mains allocator.

Q. What are the results of averaging the two methods?

A. The result of the averaging of these two model outputs is to lower the portion of the distribution mains that are classified as customer. The figure below taken from witness Lyons Direct testimony[14] shows the result of averaging the two methods:

[14] Direct Testimony of Timothy S. Lyons, Docket No. 23-079-U, Doc. 36, p. 23, line 1.

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Figure 11: Proposed Classification of Distribution Main

Mains Classification Study	Customer -Related Portion of Distribution Mains
Average	54.04%
Current Minimum System Study	66.17%
Current Zero-Intercept Study	41.91%

Q. Does Company witness Lyons recognize that the methodology for calculating the customer portion of the cost is different than has been utilized in prior proceedings?

A. Yes.

> **The proposed approach represents a refinement to the settlement COSS in the prior base rate proceeding in Docket No. 15-098-U.** The settlement COSS utilized only the minimum size main method to classify distribution main. The proposed approach utilizes the minimum size and zero-inch mains methods to classify distribution mains – both of which are recognized by the NARUC Gas Distribution Rate Design Manual, which is referenced in Act 725.[15]

While it is accurate that Act 725 recognizes both methods, it does not recommend using an average of the two for classification of distribution mains.

Q. What is the result of averaging the Minimum Size Study and Zero Intercept approaches in determining the customer portion of the demand charge?

A. The result is that the customer portion of distribution mains is reduced and some of the Residential Rate Class COS is shifted to other rate classes. The averaging of the Minimum Size and Zero Intercept results should be rejected by the Commission and Staff's COSS should be accepted in this proceeding. As explained in my testimony, it is not the methodology traditionally accepted by the

[15] Direct Testimony of Timothy S. Lyons, Docket No. 23-079-U, Doc. 36, p. 23, lines 3-8 (emphasis added).

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Commission and Company witness Lyons has provided no foundation for making this change other than both are mentioned in Act 725 and the NARUC Gas Distribution Rate Design Manual.

STAFF'S COSS

Q. Did Staff develop its own COSS?

A. Yes. Traditionally, as described above and as used in prior proceedings before the APSC, costs are first classified then allocated, as Staff did in this proceeding when preparing Staff's COSS. The details of Staff's COSS results are presented in my Direct Exhibit MB-1. Table 3 – *Staff's COSS Summary* presents Staff's COSS.

Table 3
Staff's COSS Summary

Line No.	Description (1)	Total Arkansas Retail (2)	Residential (3)	SCS-1 (4)	SCS-2 (5)	SCS-3 (6)	LCS-1 (7)
1	Rate Schedule Revenue Requirement**	$ 247,949,922	$ 189,287,900	$ 42,824,858	$ 488,346	$ 13,224	$ 15,335,593
2	Other Operating Revenues	$ 6,507,974	$ 5,866,777	$ 617,581	$ 8,755	$ 1,308	$ 13,553
3	Fuel Rider Revenues@Present Rates	$ 238,301,086	$ 153,655,093	$ 82,410,837	$ 1,664,715	$ 20,415	$ 550,027
4	Other Rider Revenues@Present Rates*	$ 10,204,180	$ 5,716,633	$ 1,814,867	$ 49,357	$ 613	$ 2,622,710
5	Total Revenue Requirement (L1+L2+L3+L4)	$ 502,963,162	$ 354,526,403	$ 127,668,143	$ 2,211,172	$ 35,561	$ 18,521,883
	Base Rates Excluding Rolled-In Riders						
6	Present Rate Schedule Revenues*	$ 173,378,473	$ 127,027,804	$ 35,415,739	$ 572,868	$ 38,535	$ 10,323,528
7	Revenue Deficiency/(Surplus) (L1-L6)	$ 74,571,449	$ 62,260,096	$ 7,409,119	$ (84,522)	$ (25,310)	$ 5,012,066
8	**% Increase on Rate Sch. Rev.** (L7/L6)	**43.01%**	**49.01%**	**20.92%**	**-14.75%**	**-65.68%**	**48.55%**
	Base Rates Including Rolled-In Riders						
9	Rolled-In Rider Revenues	$ 9,059,990	$ 7,152,606	$ 1,499,468	$ 18,570	$ 60	$ 389,286
10	Present Rate Schedule Revenues*	$ 173,378,473	$ 127,027,804	$ 35,415,739	$ 572,868	$ 38,535	$ 10,323,528
11	Revenue Deficiency/(Surplus) (L1-L10-L11)	$ 65,511,459	$ 55,107,491	$ 5,909,652	$ (103,092)	$ (25,371)	$ 4,622,779
12	Total Rate Sch. Rev. Requirement (L9+L10+L11)	$ 247,949,922	$ 189,287,900	$ 42,824,858	$ 488,346	$ 13,224	$ 15,335,593
13	**% Increase on Rate Sch. Rev.** (L11/L10)	**37.79%**	**43.38%**	**16.69%**	**-18.00%**	**-65.84%**	**44.78%**
	Increase in Total Revenues						
14	Total Current Revenues**	$ 437,451,703	$ 299,418,912	$ 121,758,492	$ 2,314,264	$ 60,932	$ 13,899,104
15	Change in Total Rev. Requirement (L5-L14)	$ 65,511,459	$ 55,107,491	$ 5,909,652	$ (103,092)	$ (25,371)	$ 4,622,779
16	Total Revenue Requirement (L14 + L15)	$ 502,963,162	$ 354,526,403	$ 127,668,143	$ 2,211,172	$ 35,561	$ 18,521,883
17	**% Increase in Total Rev. Req.** (L15/L14)	**14.98%**	**18.40%**	**4.85%**	**-4.45%**	**-41.64%**	**33.26%**

*Excludes the Rolled-In Riders
**Includes the Rolled-In Riders

Q. Please summarize the difference between Staff's and the Company's COSS results.

A. Significant differences exist between the total recommended revenue requirement for each customer class, when comparing the output from Staff's COSS to that of

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the Company. These differences are due to the ordering of the classification and allocation steps, the use of different allocation methods for certain accounts and differences in the construction of certain allocation factors such as the mains allocator and the design day peak allocator. These differences are reflected on line 14 in Table 4, below:

Table 4
SUA's COSS Results vs. Staff's COSS Results

Line No.	Description (1)	Total Arkansas Retail (2)	Residential (3)	SCS-1 (4)	SCS-2 (5)	SCS-3 (6)	LCS-1 (7)
	SUA's COSS Results - Direct - Excluding Rolled-In Riders						
1	Current Base Rate Revenues	$ 171,496,447	$ 126,005,528	$ 34,407,037	$ 624,807	$ 38,995	$ 10,420,079
2	Base Rate Revenue Requirement	$ 276,175,874	$ 205,793,010	$ 49,391,135	$ 570,046	$ 21,034	$ 20,400,649
3	Revenue Deficiency / (Surplus) (L2 - L1)	$ 104,679,427	$ 79,787,483	$ 14,984,098	$ (54,762)	$ (17,961)	$ 9,980,569
4	**% Increase on Base Revenue (L3 / L1)**	**61.04%**	**63.32%**	**43.55%**	**-8.76%**	**-46.06%**	**95.78%**
5	**% of System Average Increase (L4' / L4 Total)**	**100.00%**	**103.74%**	**71.35%**	**-14.36%**	**-75.46%**	**156.92%**
	Staff's COSS Results - Direct - Excluding Rolled-In Riders						
6	Current Base Rate Revenues	$ 173,378,473	$ 127,027,804	$ 35,415,739	$ 572,868	$ 38,535	$ 10,323,528
7	Base Rate Revenue Requirement	$ 247,949,922	$ 189,287,900	$ 42,824,858	$ 488,346	$ 13,224	$ 15,335,593
8	Revenue Deficiency / (Surplus) (L7 - L6)	$ 74,571,449	$ 62,260,096	$ 7,409,119	$ (84,522)	$ (25,310)	$ 5,012,066
9	**% Increase on Base Revenue (L8 / L6)**	**43.01%**	**49.01%**	**20.92%**	**-14.75%**	**-65.68%**	**48.55%**
10	**% of System Average Increase (L9' / L9 Total)**	**100.00%**	**83.49%**	**9.94%**	**-0.11%**	**-0.03%**	**6.72%**
	Change - COSS Results - Direct - Excluding Rolled-In Riders						
11	Current Base Rate Revenues	$ 1,882,026	$ 1,022,276	$ 1,008,702	$ (51,940)	$ (460)	$ (96,552)
12	Base Rate Revenue Requirement	$ (28,225,952)	$ (16,505,110)	$ (6,566,277)	$ (81,700)	$ (7,810)	$ (5,065,055)
13	Revenue Deficiency / (Surplus) (L12 - L11)	$ (30,107,978)	$ (17,527,386)	$ (7,574,978)	$ (29,760)	$ (7,350)	$ (4,968,504)
14	**% Increase / (Decrease) (L13 / L3)**	**-28.76%**	**-21.97%**	**-50.55%**	**54.34%**	**40.92%**	**-49.78%**

Q. What are the results of Staff's COSS inclusive of rider revenues?

A. Table 5 – *Staff's COSS Results Inclusive of Riders* summarizes Staff's COSS impact on total revenues. The methods and procedures applied in Staff's COSS are generally consistent with traditional ratemaking principles and the methodology approved in 15-098-U, SUA's most recent rate case (as CenterPoint Energy Resources Corp.) The results of Staff's COSS fairly and reasonably reflect the cost to serve the various customer classes and provide a sound basis for designing just and reasonable rates for each of SUA's customer classes.

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Table 5
Staff's COSS Results Inclusive of Riders

Line No.	Description (1)	Total Arkansas Retail (2)	Residential (3)	SCS-1 (4)	SCS-2 (5)	SCS-3 (6)	LCS-1 (7)
1	Rate Schedule Revenue @ Present Rates*	$ 173,378,473	$ 127,027,804	$ 35,415,739	$ 572,868	$ 38,535	$ 10,323,528
2	Rate Schedule Revenue Requirement	$ 247,949,922	$ 189,287,900	$ 42,824,858	$ 488,346	$ 13,224	$ 15,335,593
3	Revenue Deficiency/(Surplus) (L2-L1)	$ 74,571,449	$ 62,260,096	$ 7,409,119	$ (84,522)	$ (25,310)	$ 5,012,066
4	**% Increase on Base Revenue (L3 / L1)***	**43.01%**	**49.01%**	**20.92%**	**-14.75%**	**-65.68%**	**48.55%**
5	**% of System Average Increase**	**100.00%**	**113.96%**	**48.64%**	**-34.30%**	**-152.71%**	**112.88%**
6	Other Revenues	$ 6,507,974	$ 5,866,777	$ 617,581	$ 8,755	$ 1,308	$ 13,553
7	Fuel Revenues	$ 238,301,086	$ 153,655,093	$ 82,410,837	$ 1,664,715	$ 20,415	$ 550,027
8	Other Rider Revenues	$ 10,204,180	$ 5,716,633	$ 1,814,867	$ 49,357	$ 613	$ 2,622,710
9	Total Retail Rev. Req. (L2+L6+L7+L8)	$ 502,963,162	$ 354,526,403	$ 127,668,143	$ 2,211,172	$ 35,561	$ 18,521,883
10	All Present Rate Revenues**	$ 437,451,703	$ 299,418,912	$ 121,758,492	$ 2,314,264	$ 60,932	$ 13,899,104
11	Total Retail Revenue Requirement (L9)	$ 502,963,162	$ 354,526,403	$ 127,668,143	$ 2,211,172	$ 35,561	$ 18,521,883
12	Change in Total Rev. Req. (L11-L10)	$ 65,511,459	$ 55,107,491	$ 5,909,652	$ (103,092)	$ (25,371)	$ 4,622,779
13	**% Increase on Total Rev. Req. (L12 / L10)**	**14.98%**	**18.40%**	**4.85%**	**-4.45%**	**-41.64%**	**33.26%**

*Excludes the Rolled-In Riders
**Includes the Rolled-In Riders

REVENUE REQUIREMENT USED IN DESIGNING RATES

Q. Are the results of the COSS used to determine rates for each of the customer classes?

A. Yes. The base rate revenue requirement determined in the COSS is used as the basis for designing rates. As a result, the percentage increases may be different for each customer class.

Q. Based on Staff's Direct COSS, what is your recommendation regarding the revenue requirement distribution used in designing rates?

A. I recommend rates be designed based on the results of Staff's COSS incorporating Staff's recommended mitigated distribution of the base rate revenue requirement as addressed in the Direct Testimony of Staff witness Swaim.

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RECOMMENDATIONS

Q. What are your recommendations regarding SUA's cost of service in this proceeding?

A. For the reasons outlined above in this testimony, I recommend the Commission reject the Company's COSS and accept as reasonable the cost classification and allocation methodologies embedded in Staff's COSS.

Q. Does this conclude your testimony?

A. Yes.

CERTIFICATE OF SERVICE

I certify that a copy of the foregoing has been served on all parties of record via the Arkansas Public Service Commission's Electronic Filing System on July 10, 2024.

/s/ JOSHUA A. BAXTER
Joshua A. Baxter

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BEFORE THE ARKANSAS PUBLIC SERVICE COMMISSION

IN THE MATTER OF THE APPLICATION OF SUMMIT UTILITIES ARKANSAS, INC., FOR A GENERAL CHANGE OR MODIFICATION IN ITS RATES, CHARGES AND TARIFFS	))))))	**Docket No. 23-079-U**

DIRECT TESTIMONY

OF

LARRY BLANK

ON BEHALF OF

HOSPITALS AND HIGHER EDUCATION GROUP

July 10, 2024

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I. INTRODUCTION

Q. PLEASE STATE YOUR NAME AND BUSINESS ADDRESS FOR THE RECORD.

A. My name is Larry Blank. My business address is TAHOEconomics, LLC, 6061 Montgomery Road, Midlothian, TX 76065. My email address is LB@tahoeconomics.com.

Q. WHERE ARE YOU EMPLOYED?

A. I am the principal of TAHOEconomics, LLC ("Tahoe"), a Texas-registered consulting firm I founded in August 1999 (originally in Nevada), specializing in most policy and ratemaking facets of regulated utility industries. I am also a Professor of Economics at New Mexico State University ("NMSU"). For the purposes of this proceeding, I have been engaged through Tahoe; the expert opinions expressed herein are my own, and nothing in this testimony necessarily reflects the opinions of NMSU.

Q. PLEASE PROVIDE A BRIEF SUMMARY OF YOUR BACKGROUND.

A. I have served the public in various capacities for 40 years. I received a Ph.D. in Economics from The University of Tennessee in 1994, specializing in Industrial Organization & Public Policy (including regulatory policy), Econometrics, and Finance. I previously served as an Economist with the National Regulatory Research Institute ("NRRI") at the Ohio State University and later as the Manager of Regulatory Policy & Market Analysis with the Regulatory Operations Staff of the Nevada Public Utilities Commission. As a consultant, I have served a variety of clients including government agencies, utility customers, and utility companies. I previously filed written testimony in the following utility regulatory commission jurisdictions: Alaska, Arizona, Arkansas, Colorado, Delaware, Georgia, Kansas, Kentucky, Montana, Nevada, New Hampshire, New Mexico, North Carolina,

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Oklahoma, South Carolina Texas, and the Federal Energy Regulatory Commission. At NMSU, I direct the Masters of Economics program and a professional Graduate Certificate Program in Public Utility Regulation & Economics. I also help deliver nationally-recognized rate case training programs through the Center for Public Utilities. These professional training programs are attended by hundreds of regulatory professionals from across the United States and are endorsed by the National Association of Regulatory Utility Commissioners ("NARUC"). My resume is attached as Direct Exhibit LB-1.

Q. ON WHOSE BEHALF ARE YOU TESTIFYING?

A. I am testifying on behalf of the Hospitals and Higher Education Group ("HHEG").

Q. WHO ARE THE MEMBERS OF HHEG?

A. The membership of HHEG receiving retail natural gas service from Summit Utilities Arkansas, Inc. ("SUA" or "Company") consists of the University of Arkansas System, Baptist Health ("Baptist"), and Arkansas Children's Hospital ("ACH").

Q. PLEASE DESCRIBE THE REASON FOR HHEG'S INTERVENTION IN SUA'S GENERAL RATE CASE.

A. HHEG facilities utilizing natural gas include both the small commercial class and the large commercial class as either sales or transportation customers. Many of their patients, students, faculty, and staff are also SUA ratepayers.

II. PURPOSE AND SUMMARY

Q. WHAT IS THE PURPOSE OF YOUR TESTIMONY?

A. I am providing analysis and recommendations on key issues within the SUA general rate case, Docket No. 23-079-U, before the Arkansas Public Service Commission ("APSC" or

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"Commission"). Specifically, I analyze and offer recommendations on capital structure, the System cost of service study design, revenue allocation mitigation, and rate design.

Q. PLEASE SUMMARIZE YOUR RECOMMENDATIONS.

A. 1) The capital structure for external sources should be set at the indirect holding company level as projected by SUA at 51.41% Debt and 48.59% Equity.

2) The Commission should give more weight to the lower range of return on equity estimates due to recent SUA performance concerns.

3) The classification of distribution mains should be based on the minimum system method rather than the mixed method average proposed by SUA.

4) The design day demand proposed by SUA is flawed and should be modified.

5) I recommend my revised cost of service results, which include the use of the minimum system method and revised design day demand, should be used to guide revenue allocation and rate design.

6) The transportation customers and sales customers billing determinants should be combined when calculating the rates for the SCS-1 and LCS-1 rate classes.

III. COST OF CAPITAL

Q. HAVE YOU REVIEWED THE TESTIMONIES OF CRAIG ROOT AND DYLAN D'ASCENDIS ON BEHALF OF THE COMPANY?

A. Yes.

Q. PLEASE SUMMARIZE THE PROPOSALS ON COST OF CAPITAL PROVIDED BY THESE TWO WITNESSES.

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A. Mr. Root proposes a capital structure of 44.41% debt and 55.59% equity[1], based on a projected, pro-forma adjusted capital structure for SUA's indirect parent company, Southern Col Holdco, LLC ("SCHC"). For cost of debt, Mr. Root proposes SCHC's estimated cost of debt at 4.1798%.[2] Mr. D'Ascendis proposes a return on equity of 11.00%.[3]

Q. DO YOU AGREE WITH MR. ROOT'S PROPOSED ADJUSTED CAPITAL STRUCTURE?

A. No. First, the Company has proposed to use the actual capital structure of SCHC as the starting point for developing the entire capital structure for SUA. I agree that SCHC is useful as a proxy for determining the percentages of external capital (debt and equity); however, the internal sources of capital should be determined within SUA. In other words, the only component of the SUA capital structure in need of hypothetical treatment is the external sources of capital (debt and equity) because SUA is currently 100% equity financed by its parent companies. The internal components of the capital structure for SUA should be known and can be incorporated into the financing of the pro forma rate base of SUA rather than relying on the internal components at the holding company level. Relying on the internal sources of capital at the holding company level will tend to distort or dilute the relative weights on each capital component within the structure. Further, the proposed special pro forma adjustments for SUA Winter Storm Uri costs and the acquisition

[1] Root Direct at 10:14 (Doc. 31).

[2] *Id.* at 10:17.

[3] *Id.*

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premium ignores other similar adjustments that may be needed from other jurisdictions such as Oklahoma.

Second, Mr. Root has included an adjustment for debt associated with the Winter Storm Uri Regulatory Asset, which is being recovered outside the rate base through the Gas Supply Rate ("GSR") rider. The Commission's decision regarding appropriate costs and cost recovery associated with Winter Storm Uri should not have an impact on the rate base capital structure. This adjustment increases the equity portion in the rate base capital structure and thereby increases the cost of capital beyond what the Commission has approved for Winter Storm Uri. The Company should not be allowed to increase the cost of capital associated with the rate base as a way of undermining the Commission's decision on appropriate cost recovery for the regulatory asset outside of the rate base.

Third, Mr. Root includes an adjustment to debt and equity related to the recent acquisition premium (goodwill). This adjustment is based on an assumption that the acquisition was financed with 37.5% debt and 62.5% equity. The only reason this adjustment is being proposed is because the Company's starting point for developing the capital structure is the actual capital structure of SCHC. As I indicated above, the only component of the SUA capital structure that requires a proxy or hypothetical determination is the long-term debt, the equity, and possibly the short-term debt. Removal of the acquisition premium from the rate base, as has been done by SUA in this case, effectively eliminates the inclusion of goodwill in the capital structure.

Q. HOW WOULD YOU COMPUTE THE CAPITAL STRUCTURE FOR EXTERNAL SOURCES OF CAPITAL?

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A. I recommend utilizing the long-term debt and common equity of SCHC without the special pro forma adjustments to debt and equity proposed by Mr. Root. If we accept the projected pro forma adjustments of the Company, this results in 51.41% debt and 48.59% equity.

Q. HOW SHOULD THIS BE INCORPORATED INTO THE FULL CAPITAL STRUCTURE OF SUA?

A. All other sources of internal capital of SUA should be accounted for in the financing of the SUA pro forma rate base. The remaining portion of the SUA pro forma rate base would be covered by 51.41% long-term debt and 48.59% common equity. This would be a more appropriate way to determine the weighted average cost of capital rather than attempting to use the internal sources of capital at the total holding company level.

Q. DO YOU HAVE A RECOMMENDATION FOR THE INCLUSION OF SHORT-TERM DEBT?

A. Traditionally, one would expect there to be some amount of short-term debt, but at this time I do not have a recommendation for a hypothetical amount to include. I reserve the right to make or adopt a recommendation on the inclusion of short term debt after reviewing the testimony filed by other parties.

Q. WHAT IS YOUR RECOMMENDED CAPITAL STRUCTURE FOR EXTERNAL SOURCES OF CAPITAL?

A. Table 1, below, provides the summary calculations based on SCHC.

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Table 1. HHEG Recommended External Capital Structure

		SCHC Pro Forma Year as of 12/31/2024					
(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)
Line No.	Description	Amount Beginning of Pro Forma Year (a)	Pro Forma Adjustments (a)	Subtotal Amount End of Pro Forma Year	Special Pro Forma Adjustments	Amount End of Pro Forma Year	External Capital Structure
1	Long-Term Debt	$ 1,163,088,203	$ 100,992,122	$ 1,264,080,325	$ -	$ 1,264,080,325	51.41%
2	Preferred Stock	-	-	-	-	-	0.00%
3	Common Equity	1,084,753,299	109,981,190	1,194,734,489	-	1,194,734,489	48.59%
4	Totals	$ 2,247,841,502	$ 210,973,312	$ 2,458,814,813	$ -	$ 2,458,814,813	100.00%
5	(a) SUA Schedule D-1.3 Holdco						

Q. DO YOU HAVE A RECOMMENDATION REGARDING MR. D'ASCENDIS' PROPOSED RETURN ON EQUITY OF 11.00%?

A. I am not providing an alternative recommendation on ROE. However, I would suggest as the Commission considers weight to the range of cost of equity estimates and recommendations that will eventually fill the record, including those provided by Mr. D'Ascendis, the Commission should give greater weight to the lower end of this range. I recommend giving greater weight to the lower end of the ROE range based on SUA's recent performance.

Q. WHAT EVIDENCE SUGGESTS POOR SERVICE PERFORMANCE BY SUA?

A. See, for example, APSC Docket No. 23-015-U, in which the APSC investigated systemic billing errors by SUA. Although SUA ultimately corrected the many billing errors and credited ratepayers for over-payments, the scale of the billing issues and the ensuing volumes of customer complaints (see Order No. 1: https://apps.apsc.arkansas.gov/pdf/23/23-015-U_2_1.pdf) reflects poor management and widespread customer dissatisfaction.

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See also, Order No. 20, Docket No. 07-044-U, October 12, 2023. In response to SUA's preparedness and performance during the Winter Storm Uri event, the Commission ordered the following:

> *SUA is directed to:*
>
> *1. Continue to review its Design Peak Day and Design Peak Hour planning criteria before issuing the next procurement plan for winter 2024-2025.*
>
> *2. Continue to investigate obtaining more upstream gas supply diversity to minimize the impact of another event with a similar region wide impact.*
>
> *3. Continue to investigate increasing the maximum daily quantity that can be nominated under its pre-existing call options so that it is not forced to find daily spot supply and pay the highest daily prices.*
>
> *4. Participate in collaborative efforts with other Arkansas utilities to implement best practices, consistent with Docket No. 21-036-U; and*
>
> *5. File in Docket No. 21-036-U yearly attestations from senior management regarding the review and implementation of preparedness plans and procedures.*[4]

Q. SHOULD UTILITIES WITH PERFORMANCE ISSUES BE REWARDED WITH HIGHER THAN NECESSARY RETURNS?

A. No. The rate of return should be commensurate with the inherent risk of the Company relative to similarly situated companies, but when that risk is caused by questionable internal management, the shareholders should control such risk through the Company's board of directors.

[4] Order No. 20, Docket No. 07-044-U at 9 (Doc. 217).

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IV. SYSTEM SAFETY ENHANCEMENT RIDER

Q. HAVE YOU REVIEWED THE TESTIMONY OF VERNON MCNULLY ON BEHALF OF SUA?

A. Yes. In Mr. McNully's testimony, he explains the proposed revisions to the company's current System Safety Enhancement Rider ("SSER") and the rationale for the requested expansion of the rider. Mr. McNully identifies inflation, customer additions, public improvement relocations, and reliability improvements along with the discontinuation of CERC's FRP when SUA purchased CERC's Arkansas assets.

Q. DOES MR. MCNULLY RECOGNIZE THAT THE FRP OPTION IS A SUBSTITUTE FOR THE SSER?

A. I believe he does. As he states:

> Prior to implementing its formula rate plan ("FRP") in 2017, the program, which came to be called the "Main Replacement Program" ("MRP"), had expanded to also include steel mains without a cathodic protection system, pre-1984 plastic mains, and associated services. When CERC implemented the FRP, there was no longer a need for the MRP, because the FRP more broadly recovered the costs associated with CERC's substantial investment in pipeline replacement programs. When SUI purchased CERC's Arkansas assets, the SSER was implemented to cover, at least in part, the gap left by the FRP and former MRP. However, the SSER currently only recovers investment in mains and services associated with the Company's DIMP and TIMP programs.[5]

Q. DO YOU HAVE CONCERNS ABOUT THE PROPOSED REVISIONS?

A. The primary concern is the proposed expansion of the SSER to be more inclusive of a broader group of capital expenditures begins to look like an FRP without the process and customer protections provided by an FRP. A general rate case is the proper way to

[5] McNully Direct at. 30:17-31:4 (Doc. 25).

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incorporate capital expenditures into rates, or in the alternative, an FRP as allowed by Arkansas law. The reason general rate cases or an FRP are more appropriate for inclusion of capital costs into rates is because certain capital expenditures and system improvements should bring cost savings such as reduced operation and maintenance costs. Those cost savings are not captured within capital expenditure recovery riders such as the SSER.

Q. WHAT IS YOUR RECOMMENDATION FOR THE PROPOSED EXPANSION OF THE SSER?

A. I recommend the Commission deny the requested expansion and reference the FRP option available to SUA.

V. COST ALLOCATION

Q. HAVE YOU REVIEWED THE COMPANY'S APPROACH TO CLASSIFY DISTRIBUTION MAINS AS DESCRIBED IN TIMOTHY LYONS' TESTIMONY?

A. Yes. The company used the average of the minimum system and zero-inch methods for the classification of distribution mains. Both of these are recognized as alternative methods by the National Association of Regulatory Utility Commissioners' ("NARUC") *Gas Distribution Rate Design Manual*, 1989. SUA's decision to use the average is a departure from the rate case filing in Docket No. 15-098-U in which the minimum system method was used. A settlement was reached in that case in which the parties agreed to some mitigation of the cost of service results.

Q. DO YOU AGREE WITH THE COMPANY'S DECISION TO USE AN AVERAGE OF THE TWO ALTERNATIVE METHODS?

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A. No. SUA should have been consistent with the prior use of the minimum system method for the classification of distribution mains. Although the Company references two recognized methods for cost allocation, averaging the two methods is not a recognized approach and amounts to outcome-driven rate making. In other words, SUA's choice of averaging classification methods is an attempt to create mitigated results relative to the precedent model design. The company goes on to further mitigate the results of this approach by "rate smoothing" adjustments between the SCS-1, SCS-2, SCS-3 and LCS-1 classes. The final result seems to have no reference to any approach based on cost causation or policy.

Q. HOW DO THE COST OF SERVICE RESULTS CHANGE WITH YOUR RECOMMENDED USE OF THE MINIMUM SYSTEM METHOD?

A. In Table 2 below, I provide a comparison of the cost of service percent change from the present rate schedule filed by SUA and the cost of service percent change when the minimum system method is utilized.

Table 2. SUA COSS with Minimum Main Method Compared to SUA Filed*

Cost of Service % Increase on Present Rate Schedule Revenue at SUA proposed Revenue Requirement

Line No.		Arkansas Juris.	Res	SCS-1	SCS-2	SCS-3	LCS-1
1	SUA Filed Cost of Service Study (COSS)	59.7%	61.9%	42.6%	-8.7%	-45.9%	94.3%
2	SUA COSS with Minimum Main Method	59.7%	67.9%	31.8%	-9.3%	-49.2%	58.0%

*SUA Schedule G-1, Line No. 49.

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VI. DESIGN DAY DEMAND CALCULATIONS

Q. HAVE YOU REVIEWED THE METHODOLOGY SUA USED TO CALCULATE DESIGN DAY DEMANDS FOR EACH CUSTOMER CLASS?

A. Yes. The company used regression analysis for each customer class of heat use per degree day per customer as a function of billing heating degree days. The derivation of the demand allocator was included in the company's MFR Schedule WP G-4-1 and described in Timothy Lyons' direct testimony on behalf of the company.

Q. WAS MFP SCHEDULE WP G-4-1 CONSISTENT WITH THE DESCRIPTION IN MR. LYONS'S DIRECT TESTIMONY.

A. Yes, except for the rate classes SCS-2, SCS-3, and SCS-3 TSO's design day demand was calculated by taking the average daily consumption in February 2023. Those rate classes were found to not be weather sensitive, so the company used the average daily consumption for the month with the highest monthly consumption. LCS-1 and LCS-1 TSO's design day demand was calculated using the regression analysis as described in Mr. Lyons' direct testimony because it was found to be weather sensitive based on the regression analysis.

Q. DO YOU AGREE WITH THE METHODOLOGY USED FOR SCS-2, SCS-3, SCS-3 TSO, LCS-1, AND LCS-1 TSO?

A. No. There are flaws in this methodology.

Q. WHY IS THE METHODOLOGY FOR CALCULATING LCS-1 AND LCS-TSO FLAWED?

A. First, while the data set used for the design day demand calculation was found to be weather sensitive for LCS-1 and LCS-1 TSO, the same customer classes were found not to be weather sensitive when the company weather normalized the revenues for each customer

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class. It is nonsensical to identify the same set of customers as weather sensitive for the calculation of allocating cost and not weather sensitive in the revenue calculation. Second, LCS-TSO is the first to be curtailed during extreme conditions. The referenced design day was February 16th, 2021 and the system was under curtailment. LCS-TSO's consumption for the whole month of February 2021, which had 802 heating degree days, was 86% of their January 2021 consumption which had 678 heating degree days and 89% of their March 2021 consumption which had 277 heating degrees days. The next closest max day for heating degree days was December 23, 2022, and the pipeline was under an operation flow order. LCS-TSO's consumption for the entire month of December 2022 which had 611 Heating degrees days was only 81% of the February 2023 consumption which had 367 heating degree days.

Q. WHY IS THE CALCULATION FOR SCS-2, SCS-3, AND SCS-3 TSO FLAWED?

A. The company used February 2023's average daily consumption to calculate SCS-2, SCS-3, and SCS-3 TSO contribution to the system's design day demand. The purpose of calculating a design day demand is to estimate the total system peak day which was determined to be a day with the maximum heating degree days. Arbitrarily choosing the month with the total maximum volume to calculate non-weather sensitive customers' contribution to the design day demand makes no sense. The design day demand is representative of the system's coincident peak not each rate class's non-coincident peak. If the company assumes the system coincident peak is driven by heating degree days, then choosing the month with lower heating degree days than December 2022 and January 2023 is contradictory from the purpose of the exercise.

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Q. WHAT IS YOUR RECOMMENDATION FOR CALCULATING DESIGN DAY DEMANDS FOR SCS-2, SCS-3, SCS-3 TOS, LCS-1, AND LCS-1 TSO?

A. I recommend the company follow the conclusion it made when calculating revenues and based on the factors described in this testimony. The company should not use heating degree days to calculate the design day demand of LCS-1 and LCS-1 TSO. Further, February 2023's average daily consumption should not be used to calculate the non-weather sensitive customer's contribution to the system's peak demand day. I recommend using the annual daily average consumption for SCS-2, SCS-3, SCS-3 TSO, LCS-1 and LCS-1 TSO.

Q. WHAT ARE THE RESULTS OF YOUR RECOMMENDATIONS?

A. The comparison of the Design Day Use % for each customer class are shown below.

Design Day Use (%)

	Total	Residential	SCS-1	SCS-2	SCS-3	LCS-1	SCS-1 TSO	SCS-3 TSO	LCS-1 TSO
Company WP G-4-1	100.00%	48.92%	25.45%	0.17%	0.00%	0.17%	5.50%	0.00%	19.77%
Recommended	100.00%	53.58%	27.88%	0.17%	0.00%	0.05%	6.03%	0.00%	12.30%

Q. WHAT IS THE IMPACT ON THE COST OF SERVICE RESULTS WHEN YOU USE YOUR RECOMMENDED DESIGN DAY RESULTS?

A. In Table 3 below, I provide a comparison of the cost of service percent change from the present rate schedule filed by SUA and the cost of service percent change when my design day recommendation is utilized. Table 3 also provides the COSS results when my design

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day recommendation is combined with my recommendation to use the minimum system method for classification of distribution mains.

Table 3. HHEG COSS Scenarios Compared to SUA Filed*

Cost of Service % Increase on Present Rate Schedule Revenue at SUA proposed Revenue Requirement

Line No.		Arkansas Juris.	Res	SCS-1	SCS-2	SCS-3	LCS-1
1	SUA Filed Cost of Service Study (COSS)	59.7%	61.9%	42.6%	-8.7%	-45.9%	94.3%
2	SUA COSS with Minimum Main Method	59.7%	67.9%	31.8%	-9.3%	-49.2%	58.0%
3	SUA COSS with HHEG Design Day	59.7%	64.7%	48.8%	-9.5%	-49.9%	39.1%
4	With Combined HHEG Recommendations	59.7%	70.0%	36.5%	-9.8%	-52.0%	17.3%
5	Factor Relative to System Average Incr.	1.0	1.2	0.6	-0.2	-0.9	0.3

* Schedule G-1, Line No. 49.

Q. IF YOU INCLUDE BOTH YOUR DESIGN DAY RECOMMENDATIONS AND MINIMUM DISTRIBUTION MAIN METHOD, WHAT ARE THE COST OF SERVICE RESULTS?

Table 3, above, also provides an itemized look at all my recommendations for SUA's cost of service. Line No. 4 provides my combined recommendations.

Q. ARE YOU RECOMMENDING THE RATE CHANGES BASED ON YOUR RESULTS SUMMARIZED IN TABLE 4?

A. Line No. 4 in my Table 3 represents my preferred revenue allocation. The factor provided on Line No. 5 provides the degree to which the cost based increase deviates from the system average increase. A factor greater than 1.0 indicates an above-average increase. Residential customers are a factor of 1.2 relative to the system average increase and are the

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only class that would receive an increase that is above system average. Although the cost-based increase for residential customers is only a factor of 1.2 above the system average, the overall magnitude of SUA's proposed increase probably calls for some mitigation. However, mitigation for the residential class may not be necessary if the Commission approves a significantly lower revenue requirement.

Q. HOW WOULD YOU MITIGATE THE INCREASE TO RESIDENTIAL CUSTOMERS AT THE COMPANY'S PROPOSED REVENUE REQUIREMENT?

A. First, the cost of service results suggest rate decreases for SCS-2 and SCS-3. I would hold SCS-2 and SCS-3 at present rate levels and use the revenue above cost of service to offset the revenue increase for residential customers. Second, I would increase the LCS-1 from 17.3% to 36.1%, which will provide an additional $2,000,000 in revenue that can be used to offset the residential increase. The combined effect for residential customers would be to reduce the increase by 1.6 percentage points from 70.0% to 68.4%. This reduces the residential factor from 1.2 to 1.15.

VII. RATE DESIGN

Q. HAVE YOU REVIEWED THE RATE DESIGN TESTIMONY OF MR. LYONS?

A. Yes, but while it is not discussed in Mr. Lyon's testimony, the company has separated transportation customers from sales customers when calculating the rates for the SCS-1 and LCS-1.

Q. DOES THE COMPANY GIVE A REASON FOR THE HIGHER BASE RATES FOR TRANSPORTATION CUSTOMERS?

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A. No. They have split the revenue requirements between the sales and transportation customers based on their percent of historical revenues and then the base rates are calculated separately. Due to the additional administrative charge and telemetry charges not being increased, the demand and usage rates for SCS-1 TSO and LCS-1 TSO are higher than the demand and usage rates for SCS-1 Sales and LCS-Sales rates. It does not stand to reason that a customer should pay higher demand or usage charges solely due to the change of supplier. The additional cost associated with administering service for a transportation customer is already passed on through the administration charge and any additional telemetry is charged in the telemetry charge.

Q. WHAT IS YOUR RECOMMENDATION?

A. The transportation customers and sales customers billing determinants should be combined when calculating the rates for the SCS-1 and LCS-1 rate classes. The customer demand and/or usage rates for SCS-1 and LCS-1 should be calculated as one SCS-1 and LCS-1 rate class with additional fees for telemetry and administrative cost for transportation customers.

Q. DOES THIS CONCLUDE YOUR TESTIMONY?

A. Yes.

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Exhibit LB-1
APSC Docket No. 23-079-U
Resume of Larry Blank

Larry Blank

Education

Ph.D. in Economics, The University of Tennessee, Knoxville, August 1994.

B.S. in Economics (major), Mathematics (minor), Bemidji State University, Minnesota, May 1989.

Ph.D. Fields of Concentration

Industrial Organization & Public Policy (including utility rates and regulation)
Econometrics
Finance

Professional Experience

Principal Consultant, TAHOEconomics, LLC, August 1999 - Present. Clients have included Government Agencies, Utility Customers, and Utility Companies focusing on most aspects of regulatory policy development and rate regulation for public utilities.

Professor of Economics, Department of Economics, Applied Statistics, & International Business, New Mexico State University (NMSU), August 2021 – Present. Currently teaching graduate-level public utility regulation, business and government, antitrust policy/economics, and applied microeconomics.

Associate Professor of Economics, Department of Economics, Applied Statistics, & International Business, New Mexico State University (NMSU), August 2009 – July 2021.

Associate Director, Center for Public Utilities, NMSU, January 2011 – Present. Electric Utility and Natural Gas Distribution ratemaking training. The Center's training is endorsed by the National Association of Regulatory Utility Commissioners (NARUC).

Senior Associate, Center for Public Utilities, NMSU, August 2003 – December 2010.

Assistant Professor of Economics, Department of Economics & International Business, New Mexico State University (NMSU), August 2003 – July 2009.

Manager of Regulatory Policy and Market Analysis, Regulatory Operations Staff, Public Utilities Commission of Nevada, October 1997 - August 1999.

Responsibilities: Directed a ten-person division with duties covering most aspects of utility regulation and competitive restructuring across all industries (primarily telecommunications, electric, and natural gas); implementation of the Telecommunications Act of 1996; division management of all rates and tariffs; lead management of staff's electric and natural gas restructuring activities. Close coordination with legal division in litigated case preparation

including lead negotiation experience.

Supervising Economist, Regulatory Operations Staff, Public Service Commission of Nevada, March 1996 - October 1997. Duties similar to those above.

Research Economist, National Regulatory Research Institute, The Ohio State University and the National Association of Regulatory Utility Commissioners (NARUC), September 1994 - March 1996.

Lecturer, School of Public Policy and Management, The Ohio State University (taught Graduate Public Finance).

Published Papers and Reports

"Assessing the Impact of Selected Determinants on Renewable Energy Sources in the Electricity Mix," (with Khezri, Karimi, Mamkhezri, and Ghazal). *Energies,* 15 (2022).

"Do Residential Net Metering Customers Pay Their Fair Share of Electricity Costs? Evidence from New Mexico Utilities," *Utilities Policy Journal,* Volume 61, (December 2019).

"An Enhanced Two-Part Tariff Methodology When Demand Charges Are Not Used," (with Doug Gegax). *The Electricity Journal*, Volume 29, No. 3 (2016).

"Residential Winners and Losers behind the Energy versus Customer Charge Debate," (with Doug Gegax). *The Electricity Journal,* Vol. 27, No. 4 (2014).

"Benchmarking Electric Distribution Utilities in the Philippines," (with Doug Gegax and Ben Widner). *Asian Social Science,* Vol. 8, No. 3 (2012).

"Objectively Designing Shared Savings Incentive Mechanisms: An Opportunity Cost Model for Electric Utility Efficiency Programs," (with Doug Gegax). *The Electricity Journal,* Vol. 24, No. 9 (2011), pp. 31-40.

"Endogenous Regulatory Constraints and The Emergence of Hybrid Regulation," (with John Mayo). *Review of Industrial Organization,* Vol. 35 (2009), pp. 233-255.

"Promotions as Coopetition in the Soft Drink Industry," (with Mike Hyman and Michael Meade). *Academy of Marketing Studies Journal*, September, 2009.

"A Dynamic Model of Insurgency: The Case of the War in Iraq," (with C.E. Enomoto, D. Gegax, T. McGuckin, and C. Simmons), *Peace Economics, Peace Science and Public Policy*, Vol. 14, No. 2, 2008.

"The Role of Regulation in Expanding Access to Electricity: Reform in the Philippines," (with Mk Shean), *Energy Update,* Issue No. 4, 2005.

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"Open Entry and Local Telephone Rates: The Economics of IntraLATA Toll Competition," (with David Kaserman, John Mayo, and Simran Kahai), *Review of Industrial Organization*, Vol. 14, No. 4, June 2000, pp. 303-319.

"Dominant Firm Pricing with Competitive Entry and Regulation: The Case of IntraLATA Toll," (with David Kaserman and John Mayo), *Journal of Regulatory Economics*, Vol. 14, 1998, pp. 35-53.

"Concavity Assumptions in Regulatory Models and the Capital Waste Controversy," *Journal of Regulatory Economics*, Vol. 9, 1996, pp. 95-100.

"Key Antitrust Pricing Issues for Regulated Industries with Emerging Competition," *NRRI Quarterly Bulletin*, Vol. 17, No. 2, 1996, pp. 279-298.

"Telephone Vouchers: Experiences in Other Markets," *NRRI Quarterly Bulletin*, Vol. 16, No. 4, 1995, pp. 537-547.

Selected Reports:

Telecommunications Service Quality (with V.W. Davis, D. Landsbergen, R.W. Lawton, N. Zearfoss, and J. Hoag), National Regulatory Research Institute, The Ohio State University, Columbus, March 1996.

Telecommunication Infrastructure Investments and State Regulatory Reform: A Preliminary Look at the Data (with Vivian Davis and Catherine Reed), The National Regulatory Research Institute, The Ohio State University, Columbus, December 1994.

Considerations in Preparing and Reviewing Socioeconomic Impact Assessments for Low-Level Waste Disposal Facilities (with Mary English, Matthew Murray, and Zoe Hoyle), for the U.S. Department of Energy. National Low-Level Waste Management Program, EG&G Idaho, Inc., Idaho Falls, Idaho: August 1992.

Economic Impact of Chem-Nuclear Systems, Inc. on Barnwell County, South Carolina (with Matthew Murray), for the U.S. Department of Energy. Energy, Environment and Resources Center, The University of Tennessee, Knoxville, November 1990.

Grants

U.S. Department of Energy, Technical Assistance to the Energy Regulatory Commission of the

Philippines, January 2002 – January 2005.

U.S. Department of Energy, Sustainable Energy Development Program (Philippines), January 2005 – August 2005. Completed the Open Access Distribution Service Rules governing 140 electric distribution utilities.

Presentations and Conference Participation

"Utility Finance 101: A Discussion of Basics for Commissioners," *Utility Commissioners Wall Street Dialogue,* organized by Gee Strategies Group and Edison Electric Institute, May 2022.

"ERCOT and the week of February 14, 2021," technical presentation to the Lubbock Economics Council, March 4, 2021.

Lead speaker at the Edison Electric Institute's Advanced Ratemaking Course, University of Wisconsin, **every July since 2011.**

"Statistically Determining Proper Recovery of Demand-Related Costs through the Energy Charge," and Discussant: *CRRI University Advanced Workshop in Regulation and Competition,* Monterey, CA, June 2013.

"The FERC's Vintage and Original Purpose Doctrine for Transmission Pricing: Distorted Economics and Economic Distortions," and Discussant: *CRRI University Advanced Workshop in Regulation and Competition,* Monterey, CA, June 2012.

"Objectively Designing Shared Savings Incentive Mechanisms: An Opportunity Cost Model for Electric Utility Efficiency Programs," and Discussant: *CRRI Rutgers University Advanced Workshop in Regulation and Competition,* Sky Top, PA, May 2011.

Presentation: **"Can Regulators Stop the Tax Bleeding of the Universal Service Fund?"** and Discussant: *CRRI Rutgers University Advanced Workshop in Regulation and Competition,* Sky Top, PA, May 2008.

Presentation: **"Endogenous Regulatory Constraints and the Emergence of Hybrid Regulation,"** *Western Economic Association Meetings,* Seattle, WA, July 2007.

Presentation: "PUHCA Uncertainty…States," ***Western Governors' Association Energy Summit,*** Albuquerque, NM, April 15, 2004.

Discussant, *Advanced Workshop in Regulation and Competition,* Monterey, CA, July 6, 2000.

Exhibit LB-1
APSC Docket No. 23-079-U
Resume of Larry Blank

Presentation: **"Nevada Electric Restructuring,"** *Western Risk Management & Claims Workshop*, Western Electric Power Institute, San Diego, CA, July 8, 1999.

Discussant, *Advanced Workshop in Regulation and Competition*, San Diego, CA, July 7-9, 1999.

Participant, *Danish Ministry Workshop on Telecommunications Interconnection*, Special invitation by the Danish Ministry of Research and Information Technology, London, UK, December 14-15, 1998.

Presentation: **"Regulatory Choice: Constraints and Inefficiency,"** *Advanced Workshop in Regulation and Competition*, Monterey, CA, July 10, 1998.

Presentation: **"Regulatory Choice: Constraints and Inefficiency,"** *The 73rd Annual Western Economic Association Conference*, June 29, 1998.

Discussant, *The 25th Annual Telecommunications Policy Research Conference (TPRC)*, Alexandria, VA, September 27-29, 1997.

Presentation: **"Electricity Restructuring Issues,"** two presentations before the *Nevada State Senate Committee on Commerce and Labor*, February 1997.

Presentation: **"Regulating Market Penetration: A Higher-Powered Incentive Scheme for Local Exchange Companies,"** *The Tenth NARUC Biennial Regulatory Information Conference*, Hosted by the National Regulatory Research Institute at The Ohio State University, Columbus, September 11, 1996.

Presentation: **"Regulating Market Penetration: A Higher-Powered Incentive Scheme for Local Telephone Companies,"** *The Advanced Workshop in Regulation and Public Utility Economics*, Hosted by the Center for Research in Regulated Industries at Rutgers University, Lake George, NY, May 30, 1996.

Presentation: **"Balancing Seemingly Conflicting Goals through a Minimum Subscribership Plan: Economic Efficiency and the Risks Borne by Regulators,"** *The 27th Annual Conference of the Institute of Public Utilities*, Williamsburg, VA, December 12, 1995.

Presentation: **"The Minimum Subscribership Plan (MSP): Quality, Prices, and Current Policy,"** *The 23rd Annual Telecommunications Policy Research Conference (TPRC)*, Solomons, MD, October 2, 1995.

Presentation: "**A Positive Theory of Price-Cap and Rate-of-Return Regulation: Substitutes or Complements?"** *Southern Economic Association Meetings*, Orlando, FL, November 22, 1994.

Journal Referee

Peace Economics, Peace Science and Public Policy, July 2011.

The American Economic Review, April 1995.

Case Participation

Electricity:

Regulatory Commission of Alaska, Docket No. U-23-047, "In the Matter of Tariff Revision Designated as TA544-8 Filed by CHUGACH ELECTRIC ASSOCIATION, INC." Expert witness testimony filed on behalf of the City of Seward, March 14, 2024.

KY PSC Case No. 2023-00312, "In the Matter of Electronic Tariff Filing of Big Rivers Electric Corporation and Kenergy Corp. to Revise the Large Industrial Customer Standby Service Tariff." Expert witness testimony filed on behalf of Kimberly-Clark Corporation, December 4, 2023.

KS State Corporation Commission Docket No. 23-EKCE-775-RTS, "In the Matter of the Application of Evergy Kansas Metro, Inc., Evergy Kansas South, Inc. and Evergy Kansas Central, Inc. to make Certain Changes in their Charges for Electric Service Pursuant to K.S.A 66-117." Expert witness testimony filed on behalf of U.S. Department of Defense and all other Federal Executive Agencies. August 29, 2023 (Direct), September 5, 2023 (Cross-Answer).

DE PSC Docket No. 23-0601, "In the Matter of the Application OF ARTESIAN WATER COMPANY, INC. FOR A REVISION OF RATES." Expert witness testimony filed on behalf of Delaware Public Service Commission Staff, March 1, 2024.

DE PSC Docket No. 22-0897, "In the MATTER OF THE APPLICATION OF DELMARVA POWER & LIGHT COMPANY FOR AN INCREASE IN ELECTRIC BASE RATES AND OTHER MISCELLANEOUS TARIFF CHANGES." Expert witness testimony filed on behalf of Delaware Public Service Commission Staff, August 18, 2023.

NC Utilities Commission Docket No. E-2, SUB 1300, "In the Matter of Application of Duke Energy Progress, LLC For Adjustment of Rates and Charges Applicable to Electric Service in North Carolina and Performance-Based Regulation." Expert witness testimony filed on

behalf of U.S. Department of Defense and all other Federal Executive Agencies, March 27, 2023.

NV PUC Docket No. 23-06007, "Application of Nevada Power Company d/b/a NV Energy for authority to adjust its annual revenue requirement for general rates charged to all classes of electric customers and for relief properly related thereto." Expert witness testimony filed on behalf of the Southern Nevada Gaming Group, September 25, 2023.

NV PUC Docket No. 23-02010, "Application of Nevada Power Company d/b/a NV Energy under Advice Letter No. 535 to revise Tariff No. 1-B to revise the Large Customer Market Price Entergy Schedule No. LCMPE to set forth when an Energy Supply Agreement must be filed with an Integrated Resource Plan or Integrated Resource Plan amendment, a requirement for a true-up or adjustment and a requirement for a short form statement O, pursuant to the Order issued in Docket No. 22-03025." Expert witness testimony filed on behalf of the Southern Nevada Gaming Group, July 14, 2023.

NV PUC Docket No. 23-09012, "Application of Southwest Gas Corporation for authority to increase its retail natural gas utility service rates for Southern and Northern Nevada." Expert witness testimony filed on behalf of the Southern Nevada Gaming Group, February 2, 2024.

NM PRC Case No. 22-00058-UT, "In the matter of Public Service Company of New Mexico's Application for Authorization to implement Grid Modernization Components including Advanced Metering Infrastructure." Expert witness testimony on behalf of the City of Albuquerque, 2023.

GA PSC Docket No. 44280, "Georgia Power Company's 2022 Rate Case." Expert witness testimony on behalf of the United States Department of Defense, 2022.

NV PUC Docket No. 22-06014, "Application of Sierra Pacific Power Company for Authority to Adjust is annual Revenue Requirement." Expert witness testimony on behalf of Peppermill Casinos Inc., 2022.

NV PUC Docket No. 22-03028, "Joint Application of Nevada Power Company and Sierra Pacific Power Company for Approval to Merge." Expert witness testimony on behalf of the Southern Nevada Gaming Group, 2022.

WY PSC Docket No. 2003-214-ER-22, "In the matter of the Application of Cheyenne Light, Fuel and Power Company d/b/a Black Hills Energy for a General Rate Increase." Expert witness testimony on behalf of Microsoft Corporation, 2022.

AR PSC Docket No. 22-001-TF, "In the matter of Entergy Arkansas, LLC's Request for Tariff Changes to Rate Schedule No. 41." Expert witness testimony on behalf of Arkansas Electric Energy Consumers, Inc. and the Hospitals and Higher Education Group, 2022.

NM PRC Case No. 19-00018-UT, "In the matter of Public Service Company of New Mexico's Abandonment of San Juan Generating Station Units 1 and 4." Expert witness testimony on behalf of Western Resource Advocates, 2022.

NH PUC Docket No. DE-21-030, "Unitil Energy Systems, Inc. Request for Change in Rates." Expert witness testimony on behalf of the New Hampshire Department of Energy (Staff), 2021.

TX PUC Docket No. 52195, "Application of El Paso Electric Company to Change Rates." Expert witness testimony on behalf of the U.S. Department of Defense, 2021.

TX PUC, Docket No. 51802, "Application of Southwestern Public Service Company for Authority to Change Rates." Expert witness testimony on behalf of the Federal Executive Agencies and Orion Engineered Carbons, 2021.

CO PUC, Proceeding No. 20-AL-0432E, "In the matter of Advice Letter…by Public Service Company of Colorado to revise its Colorado Electric Tariff," Phase II cost allocation and rate design expert witness testimony on behalf of the Federal Executive Agencies (DOE), 2021.

DE PSC, Docket No. 20-0149, "In the matter of the Application of Delmarva Power & Light Company for an Increase in Electric Base Rates." Expert witness testimony on behalf of the Public Service Commission Staff, 2020-21.

NM PRC Case No. 20-00222-UT, "In the matter of the Joint Application of Avangrid, Inc, Avangrid Networks, Inc, NM Green Holdings, Inc, Public Service Company of New Mexico and PNM Resources, Inc. for approval of the Merger…" Expert Witness testimony on behalf of the City of Albuquerque, 2021.

NM PRC Case No. 20-00237-UT, "In the matter of Public Service Company of New Mexico's Application for Approval of its 2022-2023 Transportation Electrification Program." Expert witness testimony on behalf of the City of Albuquerque, 2021.

NM PRC, Docket No. 20-00121-UT, "In the matter of the Petition of Public Service Company of New Mexico, Pursuant to the Efficient Use of Energy Act and the Public Utility Act, for Approval of a Rate Adjustment Mechanism to Remove Regulatory Disincentives

and Original Rider No. 5." Expert witness testimony on behalf of the City of Albuquerque, 2020.

AR PSC, Docket No. 16-036-FR, "In the matter of the Formula Rate Plan filings of Entergy Arkansas, Inc. pursuant to APSC Docket No. 15-015-U." Expert witness testimony on behalf of the Hospitals and Higher Education Group, 2020.

NV PUC, Docket No. 20-06003, "Nevada Power Application to adjust revenue requirement." Expert witness testimony on behalf of the Southern Nevada Gaming Group, 2020.

TX PUC, Docket No. 49831, "Application of Southwestern Public Service Company for Authority to Change Rates." Expert witness testimony on behalf of the United States Department of Energy, 2020.

AZ CC, Docket No. E-01933A-19-0028, "In the matter of the Application of Tucson Electric Power Company for the Establishment of Just and Reasonable Rates…" Expert witness testimony on behalf of the United States Department of Defense and all other Federal Executive Agencies, 2020.

GA PSC, Docket No. 42516, "In RE: Georgia Power Company's 2019 Rate Case." Expert witness testimony on behalf of the United States Department of Defense and all other Federal Executive Agencies, 2019.

DE PSC, Docket 17-0977, "In the matter of the Application of Delmarva Power & Light Company for an Increase in Electric Base Rates." Expert witness testimony on behalf of the Public Service Commission Staff, 2019 (Phase II- State Jurisdictional Allocation).

NM PRC, Case No. 19-00158-UT, "In the matter of the Application of Public Service Company of New Mexico for Approval of PNM Solar Direct Voluntary Renewable Energy Program, Power Purchase Agreement, and Advice Notice Nos. 560 and 561." Expert witness testimony on behalf of the City of Albuquerque, 2019.

AR PSC, Docket No. 19-008-U, "In the matter of the Application of Southwestern Electric Power Company for Approval of a General Change in Rates and Tariff." Expert witness testimony on behalf of the Board of Trustees of the University of Arkansas, 2019.

NM PRC, Case No. 18-00383-UT, "In the matter of the filing of Advice Notice No. 69 by Socorro Electric Cooperative, Inc.." Expert witness testimony on behalf of the City of Socorro and New Mexico Institute of Mining and Technology, 2019.

AR PSC, Docket No. 16-036-FR, "In the matter of the Formula Rate Plan filings of Entergy Arkansas, Inc. pursuant to APSC Docket No. 15-015-U." Expert witness testimony on behalf of the Hospitals and Higher Education Group, 2018.

NM PRC, Case No. 17-00255-UT, "In the matter of Southwestern Public Service Company's Application for revision of its Retail Electric Rates under Advice Notice No. 272." Expert witness testimony on behalf of the City of Albuquerque, 2018.

KS CC, Docket No. 18-WSEE-328-RTS, "In the matter of the Joint Application of Westar Energy, Inc. and Kansas Gas and Electric Company for Approval to make certain changes to their Charges for Electric Service." Expert witness testimony on behalf of the United States Department of Defense and all other Federal Executive Agencies, 2018.

DE PSC, Docket 17-0977, "In the matter of the Application of Delmarva Power & Light Company for an Increase in Electric Base Rates." Expert witness testimony on behalf of the Public Service Commission Staff, 2018.

AK RCA, Docket No. U-17-008, "In the Matter of the Tariff Revision Designated as TA326-121 Filed by the Municipality of Anchorage D/B/A Municipal Light and Power Department." Expert witness testimony on behalf of the Federal Executive Agencies, Dec. 2017.

NM PRC, Case No. 16-00276-UT, "In the matter of the Application of Public Service Company of NM for revision of its Retail Electric Rates." Expert witness testimony on behalf of the City of Albuquerque, 2017.

OK Corporation Commission, Cause No. PUD 201700151, "In the matter of Public Service Company of OK Application for Adjustment in Rates." Expert witness testimony on behalf of the Department of Defense, 2017.

AR PSC, Docket 16-052-U, "In the matter of the Application of Oklahoma Gas and Electric Company for a General Change in Rates, Charges and Tariffs." Expert witness testimony on behalf of the Arkansas River Valley Energy Consumers, 2017.

DE PSC, Docket 16-0649, "In the matter of the Application of Delmarva Power & Light Company for an Increase in Electric Base Rates." Expert witness testimony on behalf of the Public Service Commission Staff, 2016.

OK Corporation Commission, Cause No. PUD 201500208, "In the matter of Public Service Company of OK Application for Adjustment in Rates." Expert witness testimony on behalf of the Department of Defense, 2015.

AR PSC, Docket 15-015-U, "In the Matter of the Application of Entergy Arkansas, Inc. for Approval of Changes in Rates for Retail Electric Service." Expert witness testimony on behalf of the Hospitals and Higher Education Group, 2015.

CO PUC, Docket 14AL-0660E, "In the Matter of Advice Letter NO 1672-Electric Filed by Public Service Company of Colorado PUC No. 7-Electric Tariff to Implement a General Rate Schedule Adjustment and Other Rate Changes Effective July 18, 2014." Expert witness testimony on behalf of the Federal Executive Agencies, November 2014.

AK RCA, Docket No. U-13-184, "In the Matter of the Tariff Revision Designated as TA332-121 Filed by the Municipality of Anchorage D/B/A Municipal Light and Power Department." Expert witness testimony on behalf of the Federal Executive Agencies, May 2014.

AK RCA, Docket No. U-13-006, "In the Matter of the Tariff Revision Designated as TA326-121 Filed by the Municipality of Anchorage D/B/A Municipal Light and Power Department." Expert witness testimony on behalf of the Federal Executive Agencies, October 2013.

AR PSC, Docket No. 13-028-U, "In the matter of the application of Entergy Arkansas, Inc. for approval of changes in rates for retail electric service," expert witness testimony on behalf of Hospitals and Higher Education Group, August 2013.

AZ ACC, Docket No. E-01345A-11-0224, "In the matter of the application of Arizona Public Service Company for a hearing to determine the fair value of the utility property of the company for ratemaking purposes, to fix a just and reasonable rate of return thereon, to approve rate schedules designed to develop such return," expert witness testimony on behalf of the Federal Executive Agencies, January 2012.

NM PRC, Case No. 11-00265-UT, "In the matter of Public Service Company of NM's Renewable Energy Portfolio Procurement Plan for 2012," direct and rebuttal testimony on renewable cost threshold and related matters, on behalf of Public Service Company of New Mexico, October 2011.

AK RCA, Docket No. U-10-31, "In the Matter of the Revenue Requirement and Cost-of-Service Studies Designated as TA304-121 and the Tariff Filing Designated as TA306-121 and TA309-121 Filed by the MUNICIPALITY OF ANCHORAGE D/B/A MUNICIPAL LIGHTAND POWER," expert witness testimony on behalf of the Federal Executive Agencies, prepared December 2010.

AR PSC, Docket No. 08-137-U, "In the Matter of the Consideration of Innovative Approaches to Ratebase Rate of Return Ratemaking Including, but not Limited to, Annual Earnings Reviews,

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Formula Rates, and Incentive Rates for Jurisdictional Electric and Natural Gas Utilities," expert witness testimony responding to the mechanisms related to this docket, 2010.

CO PSC, Docket No. 10M-245E, "In the Matter of Commission Consideration of Public Service Company of Colorado Plan in Compliance with House Bill 10-1365, 'Clean Air-Clean Jobs Act'," expert witness testimony responding to the fundamental ratemaking issues regarding compliance with the Clean Air-Clean Jobs Act, September 2010.

AR PSC, Docket No. 09-084-U, "In the Matter of the Application of Entergy Arkansas, Inc. for Approval of Changes in Rates for Retail Electric Service," expert witness testimony responding to certain aspects of revenue requirement, cost-of-service, and rate design. Also, responding to the proposed Formula Rate Plan, Lost Contributions to Fixed Costs, and the Shared Savings mechanism, 2010.

CO PSC, Docket No. 09AL-299E, "In the Matter of Advice Letter No. 1535 by Public Service Company of Colorado to Revise Its Colorado PUC No. 7 Electric Tariff to Reflect Revised Rates and Rate Schedules to be Effective on June 5, 2009," expert witness testimony responding to the Phase II issues contained in the revised rate design on behalf of the Federal Executive Agencies, December 2009.

CO PSC, Docket No. 09AL-299E, "In the Matter of Advice Letter No. 1535 by Public Service Company of Colorado to Revise Its Colorado PUC No. 7 Electric Tariff to Reflect Revised Rates and Rate Schedules to be Effective on June 5, 2009," expert witness testimony responding to the Phase I issues contained in the proposed revenue requirements on behalf of the Federal Executive Agencies, September 2009.

NV PUC, Docket No. 08-12002, "Application of Nevada Power Company for authority to increase its annual revenue requirement for general rates charged to all classes of customers to recover costs of acquiring the Bighorn Power Plant, constructing the Clark Peakers, environmental retrofits, and other generating, transmission, and distribution plant additions; to reflect changes in cost of service; and for relief properly related thereto," expert witness testimony responding to certain aspects of the cost of service and rate design on behalf of The Board of Regents of the Nevada System of Higher Education, April 2009.

AZ ACC, Docket No. E-01345A-08-0172, "In the Matter of the Application of Arizona Public Service Company for a Hearing to Determine the Fair Value of the Utility Property of the Company for Ratemaking Purposes, to Fix a Just and Reasonable Rate of Return Thereon, to Approve Rate Schedules Designed to Develop Such Return," expert witness testimony responding to certain aspects of the cost of service and rate design on behalf of the Federal Executive Agencies, January 2009.

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FERC, Docket No. EL07-101-000, expert witness testimony assessing transmission rate design on behalf of American Electric Power Service Corporation, August 2007.

MD PSC, Case No. 9092, "In the Matter of the Application of PEPCO for Authority to Revise Rates," conducted training and provided advisory services to the Maryland Commissioners and advisory staff (2007).

AR PSC, Docket No. 06-101-U, "In the Matter of the Application of Entergy Arkansas, Inc. for Approval of Changes in Rates for Retail Electric Service," expert witness surrebuttal testimony responding to the cost of service study used by EAI, Staff, and interveners on behalf of the Federal Executive Agencies, March 2007.

Vermont Department of Public Service, Cost of Service analysis related to Green Mountain Power Corp.

Philippines ERC, design of Open Access Distribution Services Rules, 2005.

Philippines Energy Regulatory Commission, Project Director and key advisor for over three years on policy development related to industry restructuring and over 140 rate unbundling cases, 2001-2005.

Philippines Department of Energy and Energy Regulatory Board, Electricity Ratemaking Training and Rulemaking for Restructured Wholesale and Retail Electricity Industry (July 2000 – February 2001).

TX PUC, Docket No. 22349, Application of TX-NM Power Company for approval of unbundled cost of service rates (testimony filed). 1999-2000.

NV PUC, Docket No. 99-10049, Petition for Advisory Opinion, Rules that may or may not apply to master-metered mobile home parks after restructuring of electric and natural gas markets, (testimony), 1999.

NV PUC, Docket No. 99-4019, Utility.com, Inc., Application for Licensing as an Alternative Seller (testimony), 1999.

NV PUC, Docket No.s 98-12007 and 12009, Sierra Pacific Power Co. And Nevada Power Co. Applications for authorization to provide potentially competitive services through affiliates (testimony), 1998.

NV PUC, Docket No. 98-7023, Sierra Pacific Power Company and Nevada Power Company, Joint

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Application for Approval of Merger (testimony), 1998.

NV PUC, Docket No. 98-9038, Regulatory Operations Staff, Application to Designate Unbundled Services as Potentially Competitive (testimony), 1998.

NV PUC, Docket No. 98-8034, Nevada Power Company, Application to Designate Unbundled Services as Potentially Competitive (testimony), 1998.

NV PUC, Docket No. 97-10004, Nevada Power Company's Green Power Tariff (testimony), 1997.

NV PUC, Docket Nos. 97-11018 and 97-11028, Proposed Unbundling Methodologies of Sierra Pacific Power Co. and Nevada Power Co. (testimonies), 1997.

NV PUC, Docket No. 97-8001, Investigation of issues to be considered as a result of restructuring of electric industry (extensive comments and testimony on all restructuring issues including the development of new regulations), 1997 - 1999.

NV PUC, Docket No. 97-6008, Nevada Power Company's Resource Plan (evaluation of load forecasting), 1997.

NV PUC, Docket No. 97-5034, Rulemaking to establish standards of conduct and related requirements for distribution companies and affiliates, 1997.

NV PUC, Docket No. 96-7020, Nevada Power Company Deferred Energy Case (testimony), 1996.

NV PUC, Docket No. 96-6013 and 96-6014, Sierra Pacific Power Company tariff filing to allow negotiated contracts (testimony), 1996.

NV PUC, Docket No. 95-9022, Nevada Electric Restructuring Investigation (several extensive comments), 1996.

Natural Gas and Water Distribution:

CT PURA, Docket No. 23-11-02, "Application of Connecticut Natural Gas Corporation to Amend its Rate Schedules." Staff consultant advisor including delivery of discovery, cross examination, and review of the record for decision making.

CT PURA, Docket No. 23-08-32, "Application of Connecticut Water Company to Amend its Rate

Schedules." Staff consultant advisor including delivery of discovery, cross examination, and review of the record for decision making.

DE PSC Docket No. 23-0601, "IN THE MATTER OF THE APPLICATION OF ARTESIAN WATER COMPANY, INC. FOR A REVISION OF RATES." Testimony on behalf of PSC Staff. 2024.

CT PURA, Docket No. 22-07-01, "Application of Aquarion Water Company of Connecticut to Amend its Rate Schedules." Staff consultant advisor including discovery, delivery of cross examination and review of the record for decision making.

Dvorak v. City of St. Paul, State of MN District Court, 2nd Judicial District, Court File No. 62-CV-18-2356. Affidavits and Declarations on behalf of the plaintiff on matters pertaining to water utility rate design and undue price discrimination, 2018-2019.

NM PRC, Case No. 18-00124-UT, "In the Matter of the Petition by EPCOR Water New Mexico Inc. for Adjustment of Water Rates for its Clovis District." Expert witness work on behalf of the City of Clovis, 2019.

AR PSC, Docket No. 15-098-U, "In the Matter of the Application of Centerpoint Energy Resources Corp., d/b/a Centerpoint Energy Arkansas Gas, for a General Change or Modification in its Rates, Charges and Tariffs." Expert witness testimony on behalf of the University of Arkansas, 2015-16.

AR PSC, Docket No. 15-011-U, "In the Matter of the Application of SourceGas Arkansas, Inc. for Approval of a General Change in Rates and Tariffs." Expert witness testimony on behalf of the University of Arkansas, 2015.

AR PSC, Docket No. 13-079-U, "In the Matter of the Application of SourceGas Arkansas Inc. for Approval of a General Change in Rates." Expert witness testimony on behalf of the University of Arkansas, May 2014.

NV PUC, Docket No. 12-11010, "Investigation and rulemaking to address a recovery mechanism for the accelerated replacement of gas infrastructure." Expert witness testimony on behalf of the Federal Executive Agencies, December 2012.

NM PRC, Case No. 11-00196-UT, "In the matter of the petition by New Mexico-American Water Co. for adjustment of water rates for its Clovis District." Expert witness testimony on behalf of the City of Clovis, November 2011.

NM PRC, Case Nos. 11-00085-UT and 11-00293-UT, Acquisition and financing of NM American

Water Co. by EPCOR, Inc. Expert witness testimony on financing and customer hold-harmless on behalf of the City of Clovis, July-August 2011.

NM PRC, Case No. 08-00134-UT, "In the Matter of the Petition by New Mexico-American Water Company, Inc. for Adjustment of Water Rates for Its Clovis District," expert witness testimony responding to revenue requirements and rate design in the petition to adjust water rates on behalf of the City of Clovis, December 2008.

NM PRC, Case No. 08-00321-UT, "In the Matter of the Petition by New Mexico-American Water Company, Inc. for a Certificate of Convenience and Necessity and Other Authorizations Related to an Exploratory Test Well into the Lower Dockum Formation to Serve the Clovis District," expert witness testimony assessing accounting and regulatory treatment of the project costs associated with the proposed exploratory test well into the lower Dockum Formation to serve the Clovis district of New Mexico-American Water Company, Inc. ("NMAW" or "Company") on behalf of the City of Clovis, March 2009.

NV PUC, Docket No. 97-8002, Investigation into alternative forms of regulation for natural gas local distribution companies and alternative sellers of natural gas, and related matters (extensive comments and testimony on all restructuring issues including the development of new regulations), 1997.

NV PUC, Docket No. 97-5034, Rulemaking to establish standards of conduct and related requirements for distribution companies and affiliates, 1997.

***Telecommunications*:**

NM PRC, Case No. 18-00295-UT, "In the Matter of the Petition of CenturyLink QC Regarding Effective Competition for Retail Residential Services." Expert witness testimony on behalf of the City of Albuquerque, 2019.

MT PSC, Docket No. D2005.6.105, Investigation on Use of Federal Universal Service Funds (testimony filed on behalf of PSC advocacy staff), 2005.

NM PRC, Case No. 05-00094-UT, Qwest Corporation's Amended Alternative Form of Regulation Plan, (testimony filed on behalf of Qwest regarding computation and appropriateness of refund), 2005.

Line Extension Policy and Contribution in Aid of Construction, expert witness work on behalf of 3 Rivers Telephone Cooperative, before the Montana Eighteenth Judicial District Court, Cause No. DV-04-731, March 2006.

NV PUC, Docket No. 00-7012, Nevada Bell Petition for order commencing a proceeding to determine new costs and rates for unbundled network elements (testimony filed on behalf of wholesale customers), 2000.

FCC CC Docket No. 00-247, Petition for Arbitration, Developed Unbundled Costs and Interconnection Agreement on behalf of Virtual Hipster Corp., December 2000.

Case No. CV771923, Superior Court of the State of California (Santa Clara), Worldcom v. Co-net Communications, Oral Expert Witness Testimony on potential service development including cost and revenue estimates, damage estimate, standard of care in circuit disconnect, and other circuit contractual issues (deposition and oral testimony), April 2000.

NV PUC, Docket Nos. 98-10015 and 99-11007, Nevada Bell Arbitrations on the issue of reciprocal compensation and Internet service provider traffic, 1998.

NV PUC, Review of Interconnection and Resale Agreements between Incumbent Local Exchange Carriers and Competitors for approval in Nevada.

NV PUC, Docket No. 98-6005, Sprint of Nevada, Unbundled Network Element Costs (testimony), 1998.

NV PUC, Docket No. 98-6004, Nevada Bell, Unbundled Network Element Costs (testimony), 1998.

NV PUC, Docket No. 97-11017, Virtual Hipster Corp., Petition to terminate rural exemption of Churchill County Telephone Company (testimony), 1997.

NV PUC, Docket No. 96-8035, GTE, Depreciation Filing (testimony), 1997.

NV PUC, Docket No. 97-5027, Central Telephone Company-Nevada, tariff filing requesting an increase in directory assistance rates (testimony and cost analysis), 1997.

NV PUC, Docket No. 97-5018, Investigation into the impact of the Telecommunications Act of 1996 on Universal Service in Nevada (comments), 1997.

NV PUC, Docket No. 96-4041, Nevada Bell Petition on Confidential Nature of Telecommunications Cost Studies (testimony filed), 1996.

NV PUC, Docket No. 96-9035, Investigation into Procedures and Methodologies to Develop Costs for Bundled or Unbundled Telephone Services (comments, testimony and cost analysis), 1996.

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NV PUC, Docket Nos. 96-3002 and 96-3003, Nevada Bell's Entry into a Plan of Alternative Regulation (testimony), 1996.

CERTIFICATE OF SERVICE

I hereby certify that a copy of the foregoing has been delivered on all parties of record by electronic mail via the APSC's Electronic Filing System this 10th day of July, 2024.

/s/ Randall Bynum
Randall Bynum, Bar No. 89194

Counsel for HHEG

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BEFORE THE
ARKANSAS PUBLIC SERVICE COMMISSION

IN THE MATTER OF THE APPLICATION OF SUMMIT UTILITIES ARKANSAS, INC., FOR A GENERAL CHANGE OR MODIFICATION IN ITS RATES, CHARGES AND TARIFFS	))))	**DOCKET NO. 23-079-U**

DIRECT TESTIMONY

OF

DANTE MUGRACE

ON BEHALF OF

THE OFFICE OF ARKANSAS ATTORNEY GENERAL

TIM GRIFFIN

July 10, 2024

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I. STATEMENT OF QUALIFICATIONS

Q. WHAT IS YOUR NAME AND BUSINESS ADDRESS?

A. My name is Dante Mugrace. My business address is 22 Brooks Avenue, Gaithersburg, MD 20877.

Q. WHAT IS YOUR PRESENT OCCUPATION?

A. I am a Senior Consultant with the Economic and Management Consulting Firm of PCMG and Associates, LLC ("PCMG"). In my capacity as a Senior Consultant, I am responsible for evaluating and examining rate and rate-related requests in proceedings before public utility commissions and various other governmental entities. I prepare expert testimony addressing revenue requirement, economic policy and other policy issues, and methodologies used to set a value on a utility's rate base and cost of service components of revenue requirement.

Q. PLEASE SUMMARIZE YOUR PROFESSIONAL EXPERIENCE.

A. PCMG is an association of experts in utility regulation and policy, economics, accounting, and finance. PCMG's members collectively have over 75 years of experience assisting clients with expert testimony regarding the regulation of electric, gas, water, and wastewater utilities. Prior to my association with PCMG, I was employed as a Senior Consultant with the consulting firm of Snavely King Majoros and Associates ("SKM") from 2013 to 2015. Prior to SKM, I was employed by the New Jersey Board of Public Utilities ("NJBPU") from 1983 to my retirement in 2011. During my tenure at the NJBPU,

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I held various accounting, rate analyst, supervisory, and management positions. My last position was Bureau Chief of Rates in the agency's Water Division ("Bureau Chief of Rates"). I held that position for nearly 10 years. My resume is attached as Exhibit DM-1.

Q. WHAT EXPERIENCE DO YOU HAVE IN THE AREA OF UTILITY RATEMAKING PROCEEDINGS AND OTHER UTILITY MATTERS?

A. In my capacity as Bureau Chief of Rates at NJBPU, I was responsible for overseeing the rate process regarding administrative, financial, and managerial functions of the Rates Bureau, with respect to investor-owned public utility operations and the setting of rates for utility service. I was also responsible for making recommendations to the NJBPU with respect to just and reasonable rates for utility service. My primary duties were to ensure that the jurisdictional utilities had sufficient revenues to cover their operating expenses, the ability to earn a reasonable rate of return on plant investments, and to ensure the provision of safe, adequate, and proper service at reasonable rates. During my time at the NJBPU, I was involved in hundreds of rate and rate-related proceedings. In my capacity as a Senior Consultant previously with SKM and now with PCMG, I have been and am currently involved in rate and rate-related proceedings before the commissions in Massachusetts, Pennsylvania, Maine, Maryland, New Jersey, New York, North Dakota, and Ohio. I was involved in proceedings before the Alberta Utilities Commission establishing parameters for next generation performance-based rate plans. I was also involved in transmission formula rate plans before the Federal Energy Regulatory Commission regarding the PECO Energy Company on behalf of the Pennsylvania Office of Consumer Advocate and the Rockland Electric Company on behalf of the New Jersey Division of Rate Counsel.

Q. WHAT IS YOUR EDUCATIONAL BACKGROUND?

A. I hold a Master of Business Administration with a concentration in Strategic Management from Pace University-Lubin School of Business in New York, New York, a Master of Public Administration from Kean University in Union, New Jersey, and a Bachelor of Science in Accounting from Saint Peter's University in Jersey City, New Jersey.

Q. ON WHOSE BEHALF ARE YOU TESTIFYING?

A. I am testifying on behalf of the Office of Arkansas Attorney General Tim Griffin ("AG").

II. PURPOSE OF TESTIMONY

Q. WHAT IS THE PURPOSE OF YOUR TESTIMONY?

A. The purpose of my testimony is to review and make recommendations to the Arkansas Public Service Commission ("APSC" or "Commission") with respect to Summit Utilities Arkansas, Inc.'s ("SUA" or "Company") Application for Approval of a General Change in Rates and Tariffs ("Application") filed on January 25, 2024.[1] My focus is on the Company's incentive compensation plans which are part of the Company's employee compensation and benefits package. My testimony evaluates the Company's compensation philosophy, particularly with respect to its Short-Term Incentive ("STI") plan. The Company is not seeking recovery of its Long-Term Incentive ("LTI") plan. The Company is also seeking to recover retention bonuses and sign-on bonuses.[2]

[1] SUA's Application for Approval of a General Change in Rates and Tariffs and the direct testimony and exhibits of various witnesses (Doc. Nos. 18-41) and SUA's revised Application and errata testimony (Doc. Nos. 60-63).
[2] *See* Exhibit DM-2, SUA Response to AG-002-015.

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My testimony addresses the Company's proposed incentive compensation as described in the direct testimony of Company witness Sam Springer. I address the Company's proposed level of STI of $2,467,783 and allocated STI of $1,900,300 totaling $4,368,083 for the test year period. The Company has requested recovery of $4,542,807 in STI which includes the Company's $174,724 pro forma adjustment over test year period costs.

III. OVERVIEW AND SUMMARY OF RECOMMENDATIONS

Q. PLEASE PROVIDE A BRIEF OVERVIEW OF SUA'S RATE CASE FILING.

A. On January 25, 2024, SUA filed its Application with the Commission, requesting an overall base rate increase of $104.7 million based on a twelve-month test period ending December 31, 2023, with pro forma adjustments through December 31, 2024.[3] SUA expects this rate increase, if granted, will have the effect of increasing an average residential customer's bill by $18.48 per month or 29.4% on a total bill basis.[4]

SUA provides natural gas utility service to about 410,000 customers in the state of Arkansas. SUA is a wholly owned subsidiary of Summit Utilities, Inc. ("SUI"), a privately held holding company incorporated in Colorado. Through its regulated subsidiaries, SUI provides natural gas service to customers in Arkansas, Oklahoma, Texas, Colorado, Missouri, and Maine.

[3] *See* ERRATA to Direct Testimony of Kurt W. Adams, pp. 17-18 (Doc. No. 61). The Company continues to request $104.7 million despite its errata filing which states that it supports a $106.1 million rate increase.
[4] SUA's Application, p. 3 (Doc. No. 18).

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IV. CASE RECOMMENDATIONS

Q. WHAT DO YOU RECOMMEND REGARDING SUA'S INCENTIVE COMPENSATION AND BONUS EXPENSES?

A. Based upon the use of the Company's test year ending December 31, 2023, with pro forma adjustments through December 31, 2024, I have the following recommendations:

- I recommend a decrease of $2,498,543 from the Company's proposed recovery of $4,542,807 in STI expenses for an allowed STI amount of $2,044,264.[5]
- I recommend disallowance of the $171,646 in retention bonus costs and disallowance of the $105,052 sign-on bonus costs for a total disallowance of $276,697 related to bonuses. These amounts are based upon allocations from SUI as of December 31, 2023.[6]

Q. WHAT DID COMPANY WITNESS MR. SPRINGER STATE REGARDING SUA'S COMPENSATION PHILOSOPHY?

A. Mr. Springer stated that the Company's compensation philosophy is focused on maintaining the competitiveness of its compensation plans as measured from a total compensation perspective.[7] Mr. Springer stated that the value of all components that make up an employee's total compensation is compared against competitor companies to ensure that SUA's compensation plans and levels are sufficient to recruit, retain, and motivate a

[5] Exhibit DM-3.
[6] Exhibit DM-4.
[7] Direct Testimony of Sam Springer, p. 2, lines 7-8 (Doc. No. 32).

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quality workforce.[8] He asserts that this philosophy positively impacts the safety and reliability of the Company's system and the quality of its service to customers through high-performing experienced employees.[9]

Q. WHAT DID THE COMPANY PROPOSE WITH RESPECT TO ITS OVERALL INCENTIVE COMPENSATION COSTS TO BE INCLUDED IN RATES?

A. The Company is proposing to include $4,542,807 in STI costs in rates.[10] The Company's test year incentive compensation costs include $2,467,783 of STI for SUA employees and $1,900,301 of STI allocated from SUI[11] for a total of $4,368,084. Adding the Company's pro forma STI cost adjustment of $174,724 results in the $4,542,807 total request. The Company is not seeking recovery related to its LTI costs.[12]

Q. WHAT IS YOUR GENERAL OPINION WITH RESPECT TO FULL RECOVERY OF INCENTIVE COMPENSATION IN RATES?

A. Basic ratemaking concepts do not provide for 100% recovery of all known and measurable expenses of all types from ratepayers, including recovery of incentive compensation costs. In fact, utilities have the opportunity and the ability to recover their known and measurable expenses using good management techniques and proper operational approaches to provide natural gas service to their customers.

In my opinion, incentive compensation related to financial goals or performance, business decisions and risks, and other related financial decisions should be disallowed

[8] *Id*. at lines 8-12.
[9] *Id*. at lines 12-14.
[10] *See* Exhibit DM-5, SUA Response to AG-002-020.
[11] *See* Exhibit DM-6, SUA Response to AG-002-002.
[12] *Id.*

because these types of costs accrue to the benefit of SUA and do not benefit ratepayers in the provision of safe and reliable natural gas service. I do not believe that incentive compensation costs that relate to increasing the Company's revenue streams and enhancing the Company's business image should be included in the revenue requirement and recovered from ratepayers.

Q. WHAT TYPES OF INCENTIVE COMPENSATION SHOULD THE COMPANY BE ALLOWED TO RECOVER IN RATES?

A. I recommend recovery through rates for only those types of incentives that benefit ratepayers in the form of customer service, safety, reliability, satisfaction, etc. I recommend disallowance of incentives that are related to financial goals, earnings per share, shareholder benefits, or equity increases, including those costs geared toward increasing operating income. A company should not be allowed to foist its incentive pay costs upon ratepayers if ratepayers do not receive a clear benefit from such costs. Pay rewards or incentives often provide a benefit to the employee that does not transfer to ratepayers through the utility's provision of safe and reliable utility service. I do not believe that incentive compensation related to increasing net income and financial performance goals that affect the Company's earnings per share should be paid for by ratepayers. These types of incentive costs benefit the shareholders of the Company and do not directly benefit ratepayers.

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V. STI

Q. HOW DOES THE COMPANY'S STI PLAN WORK?

A. According to Mr. Springer, SUI's STI plan is funded based upon SUI's overall performance and is available to all employees who are not covered by a collective bargaining agreement or temporary employees.[13] Eligible employees participating in the plan have established goals for the performance period which is the calendar year.[14] Employees have a target incentive that is a percentage of their base salary and receive a performance rating based upon their individual achievements as compared to their goals.[15] SUI's annual scorecard is used by SUI's Board of Directors to give a numeric performance score to SUI as an entity. The numeric scorecard is used to determine the incentive pool that will be distributed to employees.[16]

Q. HOW WERE THE BALANCES DEVELOPED TO CALCULATE THE COMPANY'S 2023 STI SCORECARD?

A. The Company calculated its STI test year (2023) balance of $4,367,418.30 using the following scorecard metrics:

[13] Springer Direct, p. 5, lines 5-6.
[14] *Id.* at lines 7-8.
[15] *Id*. at lines 8-10.
[16] *Id*. at lines 16-18.

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Goal	Goal %	Amount (2023)[17]	Amount (2024)
SUI Safety	15%	$655,113	$681,421
Corporate Excellence	50%	$2,183,709	$2,271,140
Peaks Renewables	10%	$436,742	$454,281
SUI Financial	25%	$1,091,855	$1,135,702
Total	**100%**	**$4,367,418**	**$4,542,807**

Q. HAS THE COMPANY'S INCENTIVE COMPENSATION PHILOSOPHY RESULTED IN RETAINING, ATTRACTING, AND ENCOURAGING PERSONNEL AND PROFESSIONAL DEVELOPMENT?

A. The Company stated that its total employment package, inclusive of the incentive compensation programs, contributes to its ability to attract talent that advances the interests of customers, the Company, and other stakeholders in a competitive employment market.[18] SUI's attrition rate has remained below the industry and broader market at 10%.[19] The Company has encouraged personal and professional development at all levels and commits resources to these efforts, including through courses offered within the Company's learning management system which contributes to learning and development to the benefit of customers, the Company and stakeholders.[20] Since beginning operations in January 2022, the Company has not experienced any voluntary turnover at the executive officer level.

[17] *See* Exhibit DM-7, SUA Response to AG-002-006.
[18] *See* Exhibit DM-8, SUA Response to AG-002-014.
[19] *Id*.
[20] *Id*.

The company attributes this to the STI program and a number of other factors which were not expanded on.[21]

Q. ARE THESE ANNUAL INCENTIVE PLANS GUARANTEED TO EMPLOYEES?

A. No. According to Mr. Springer, employees have a target incentive that is a percentage of their salary. Based upon individual achievements as compared to goals, each employee receives a performance rating. The employee's incentive payment is determined by a combination of the achievement of the personal goals along with the achievement of company goals.[22]

Q. WHAT CORPORATE GOALS DOES SUI USE IN DETERMINING STI AND HOW ARE THEY WEIGHTED?

A: According to the 2023 Corporate Scorecard provided in Response to AG-002-006,[23] four Corporate Goals are relevant to STI: Safety, Corporate Excellence, Peaks Renewables, and Financial. They are weighted at 15%, 50%, 10%, and 25%, respectively.

Q. WHAT IS YOUR RECOMMENDATION RELATED TO THE COMPANY'S STI?

A. I am recommending allowance of incentive compensation that is related to the SUI goals titled "Safety" and "Peaks Renewables." I am recommending allowance of a portion of the Company's "Corporate Excellence" category of goals (specifically the "Customer Facing Order Completion" and "Emergency Response Times" subcategories). I am recommending disallowance of incentive compensation that is related to "Environmental,

[21] *See* Exhibit DM-9, SUA Response to AG-002-017.
[22] Springer Direct p. 5, lines 8-12.
[23] *See* Exhibit DM-7, Response to AG-02-006.

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Social and Governance" ("ESG"), "Audited Financial Statements Issued," and "Monthly Financial Reports Issued."

Q. WHAT ARE PEAKS RENEWABLES AND WHY SHOULD RATEPAYERS BEAR THE BURDEN FOR THIS GOAL?

A: Peaks Renewables stands for Pioneering, Excellence, Agility, Kindness and Safety.[24] Pioneering refers to the dedication to development and continuous improvement with a focus on the future. These goals seek and embrace innovative ideas. Excellence refers to reliably delivering results through teamwork, integrity, accountability and taking ownership of individual actions, and keeping a customer-centric focus. Agility refers to embracing a culture of change, pursuing continual growth through collaboration and adaptation. Kindness refers to honoring customers, the communities served, and each other by making respect, safety, excellence, and satisfaction a priority. Safety refers to making colleagues, customers and communities a priority, demonstrating a commitment to prevention and taking responsibility for one another. I believe these types of incentive costs benefit ratepayers because they are related to safety, reliability and service performance. These types of incentive costs are related to ensuring that the ratepayer is provided customer-oriented benefits through accountability and responsibility. I believe that these incentive costs help to ensure that the ratepayer is the focus of company operations and provides commitment to address ratepayer needs.

[24] *See* Exhibit DM-10, Response to AG-002-013.

Q. WHY ARE YOU RECOMMENDING DISALLOWANCE OF CERTAIN OF THE CORPORATE EXCELLENCE GOALS?

A. With respect to the Company's Corporate Excellence goals, the Company proposed a total Incentive of $2,271,404, with five components as follows:

- Environmental, Social and Governance - $454,281
- Customer Facing Order Completion - $454,281
- Emergency Response Time - $454,281
- Audited Financial Statements Issued - $454,281
- Monthly Financial Reports Issued - $454,281

Given that the Company did not provide a breakdown for each of the goals stated above, I allocated these costs evenly across the scorecard to arrive at an individual goal balance of $454,281 ($2,271,404/5).

I believe that costs related to ESG, Audited Financial Statements Issued, and Monthly Financial Reports Issued should be disallowed for recovery from ratepayers. Regarding ESG costs, these are related to a focus on perceived corporate social responsibilities. I believe these types of incentive goals are the responsibility of the Company and should not be recovered from ratepayers. With respect to Audited Financial Statements Issued and Monthly Financial Reports Issued, I believe these costs are the responsibility of the Company in that they are related to financial performance and objectives. These types of goals clearly benefit the Company and its shareholders. My total disallowance related to the Company's Corporate Excellence goals is $1,362,842 related to ESG, Audited Financial Statements Issues and Monthly Financial Reports Issues

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goals. My recommended allowance is $980,562 for the Customer Facing Order Completion and Emergency Response Time goals.

Q. WHY ARE YOU RECOMMENDING DISALLOWANCE OF THE COMPANY'S FINANCIAL GOALS OF THE 2023 CORPORATE SCORECARD?

A. I am recommending disallowance of these types of incentive goals because I believe they do not benefit ratepayers in the area of safe and reliable utility service. I believe these types of incentive goals are focused on Company financial performance, increasing dividend payout and earnings per share, and enhancing net income. These are not the sort of incentive compensation costs that ratepayers should be required to pay. I believe these are not customer-oriented goals but rather Company-oriented goals.

Q. HOW MUCH OF THE COMPANY'S STI COMPENSATION IS GEARED TOWARD FINANCIAL PERFORMANCE?

A. The Company's STI is heavily weighted toward financial performance goals. In fact, financial performance goals make up 55% of total STI costs. Three out of the five subcategories of Corporate Excellence (three-fifths of the 50% for the category equals 30%) and SUI Financial (25%) are all financial performance goals benefitting shareholders. The remaining 45% which appears to benefit ratepayers consists of Safety (15%) and Peaks Renewables (10%), in addition to the remaining two subcategories of Corporate Excellence related to Customer Facing Order Completion (10%) and Emergency Response Time (10%). The 55% described above does not benefit customers in providing safe and reliable utility service. The primary purpose of these goals and costs appears to be financial performance and achievement for the benefit of shareholders.

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The Company states the STI program goes beyond simply being an attraction and retention tool, benefiting ratepayers by improving the areas of safety and efficiency, keeping costs and expenses reasonable, investing in the right strategies to deliver positive outcomes for customers, focusing on customer needs, and ensuring that customers continue to have service in their homes and businesses.[25] However, in my view, 55% or $3,407,105 of the STI cost is allocable to shareholder benefits, shareholder measures, and financial performance (earnings per share). These types of incentives and goals fall outside the realm of customer service and satisfaction and the provision of safe and reliable service, which are at the core of utility regulation.

Q. WHAT ADJUSTMENTS DO YOU PROPOSE WITH RESPECT TO THE COMPANY'S STI?

A. I recommend the following:

Disallowance of Corporate Excellence (ESG costs, Audited Financial Statements Issued and Monthly Financial Reports Issued.	$1,362,842
Disallowance of SUI Financial	$1,135,702
Total	**$2,498,543**

[25] Springer Direct, p. 6, line 19 through p. 7, line 11.

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VI. RETENTION BONUSES AND SIGN-ON BONUSES

Q. HAS THE COMPANY PROPOSED INCLUSION OF RETENTION BONUS AND SIGN-ON BONUS COSTS IN RATES?

A. Yes. The Company stated that the 2023 Incentive Allocation from Corporate as of December 31, 2023, for retention bonuses was $171,646 ($84,884 related to Capitalized costs and $86,762 related to O&M expenses).[26] For sign-on bonuses, the Company is proposing $105,052. ($51,951 related to Capitalized costs and $53,100 related to O&M expenses). The Company stated that the projected 2024 Retention Bonuses and Sign-On Bonuses will be the same or similar to the 2023 actual amounts.[27]

Q. WHY WERE RENTENTION BONUSES INCLUDED FOR RECOVERY?

A. The Company stated that the retention bonus is a sum of money paid to an existing employee as an incentive to remain with the Company. This form of bonus is utilized when an organization is going through a disruptive period of organization change, or when a key employee with specialized skills is at risk of being lured away by other employees. In the event the employee quits or is terminated for cause prior to completing the required retention period, the Company utilizes repayment agreements for this bonus.[28]

[26] *See* Exhibit DM-11, SUA Response to AG-002-005, "Incentive Capitalization" spreadsheet attachment.
[27] *See* Exhibit DM-12, SUA Response to AG-003-005.
[28] *Id.*

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Q. WHAT IS YOUR RECOMMENDATION REGARDING RETENTION BONUS COSTS?

A. I am recommending disallowance of these retention bonus costs. The Company has not provided any evidence of the necessity of these costs. The Company has not shown that employees quit or were lured away by other employers supporting the Company's need to institute the use of such bonuses. No evidence has been provided that demonstrates retention bonuses benefit ratepayers in a way that supports requiring ratepayers to absorb these costs.

Q. WHY DID THE COMPANY INCLUDE SIGN-ON BONUSES FOR RECOVERY?

A. The Company stated that a sign-on bonus is a sum of money paid to a new employee as an incentive to join the Company. The Company utilizes these sign-on bonuses as a way of making the Company's compensation package more attractive to employees. It lowers the risk to the Company as it is a one-time payment and does not commit the Company to paying a higher salary. To encourage employees to stay and perform after receiving the bonus, the Company utilizes repayment agreements in the event the employee quits or is terminated for cause prior to completing a specific period.[29]

Q. WHAT IS YOUR RECOMMENDATION REGARDING THE SIGN-ON BONUSES?

A. I recommend disallowance of these sign-on bonuses. The Company has not provided any evidence of the necessity of these costs. In addition, there is no evidence presented

[29] *Id.*

regarding rate treatment in the event that an employee quits or is terminated prior to the specified period. If the Company cannot recover the cost of the bonus through a repayment agreement, ratepayers should not be expected to absorb the cost. While it may be reasonable to provide this type of incentive to employees, in this instance the Company should be required to pay for these costs.

Q. DOES THIS CONCLUDE YOUR DIRECT TESTIMONY?

A. Yes, it does. I reserve the right to update my testimony in the event subsequent information becomes available that may affect my recommended adjustments in this proceeding.

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CERTIFICATE OF SERVICE

I, Clay Layson, hereby certify that on July 10, 2024, I filed a copy of the foregoing utilizing the Commission's Electronic Filing System, which caused a copy to be served upon all parties of record via electronic mail.

/s/ Clay Layson
Clay Layson

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BEFORE THE
ARKANSAS PUBLIC SERVICE COMMISSION

IN THE MATTER OF THE APPLICATION OF SUMMIT UTILITIES ARKANSAS, INC., FOR A GENERAL CHANGE OR MODIFICATION IN ITS RATES, CHARGES AND TARIFFS	**)** **)** **)** **)**	**DOCKET NO. 23-079-U**

DIRECT EXHIBITS

OF

DANTE MUGRACE

ON BEHALF OF

THE OFFICE OF ARKANSAS ATTORNEY GENERAL
TIM GRIFFIN

July 10, 2024

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DANTE MUGRACE

Education

Master Business Administration, MBA Strategic Management, Pace University, Lubin School of Business, New York, NY, 2010

Master Public Administration, MPA, Kean University, Union, NJ, 2001

Bachelor of Science, BS. Accounting, St. Peter's University, Jersey City, NJ, 1983

Position

Senior Consultant – PCMG and Associates	2014 – present
Senior Consultant – Snavely King Majoros and Associates	2013 – 2014
Independent Consultant	2012 – 2013
Bureau Chief/Administrative Analyst/Accountant – New Jersey Board of Public Utilities	1983 – 2011

Professional Experience

Mr. Mugrace has 35 years' experience in all aspects of regulatory accounting and policy including processing, analyzing and evaluating utility rate case petitions before Public Service Commissions. Mr. Mugrace examines and evaluates rate filings, contracts, agreements and rate matters regarding utility operations and provides recommendations as to best course of action. Additionally, Mr. Mugrace analyzes and reviews utility regulatory matters and sets forth recommendations for resolution of issues, calculates total revenue requirement needed to cover operating expenses and rate of return; researches and evaluates regulatory utility matters to assess impact on various classes of customers, regarding rates, service, compliance and cost of service provisions, as well as annual true-up and tracking mechanisms.

Prior to undertaking consulting assignments, Mr. Mugrace was the Bureau Chief Utility Rate Manager for the New Jersey Board of Public Utilities, in which role he managed and assigned tasks to a staff of 12 professionals and supervisory personal in the daily administrative, financial and managerial functions of the Division. Mr. Mugrace's primary duties were to determine whether the utility had sufficient revenues to cover its operating expenses and earn a return on its plant investment and to ensure that the utility provided safe, reliable and continuing utility service to its customers. Mr. Mugrace set rates and charges for utility companies, which had revenues of up to $500 million, and ensured that the revenue requirement provided for recovery of all operating expenses, return on investment and depreciation. Mr. Mugrace was also responsible for reviewing and verifying that the companies' property, plant and equipment (up to $2.5 billion) were used and useful in providing service to its customers. Mr. Mugrace coordinated and met with the New Jersey State Department of Environmental Protection to

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determine whether water and wastewater utilities were complying with state regulations and were adhering to any regulatory agency directives or orders. Mr. Mugrace developed ways to minimize the rising costs of water utility services by investigating alternative rate structures, analyzing engineering mechanisms and techniques, looking into the feasibility of mergers and acquisitions within the water industry and reviewing financing, and rate alternatives to minimize the impact on ratepayers. Mr. Mugrace was responsible for ensuring that the rate-case process adhered the statutory timeframe for preparing, reviewing and recommending findings to the Board Commissioners on financial operations, costs, revenues and operating expenses, prior to the litigation proceedings. Mr. Mugrace also examined alternative rate recovery mechanisms and clauses, phase-ins of revenue requirements, deferral mechanisms and pass-through of rate charges. Mr. Mugrace assumed the role of Director during transition periods and Administrative changes. Finally, Mr. Mugrace conducted the recruitment and hiring of employees for placement within the Division and the Board.

Professional and Business Affiliations

- Institute of Public Utilities (IPU) Michigan State University (MSU), National Association of Regulatory Utility Commissioners (NARUC), National Association of State Utility Consumer Advocates (NASUCA)

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Regulatory Projects and Appearances

1. In Re: Northern States Power Company for Approval of a 2024 Natural Gas Rate Increase.
   (Appearance: Revenue Requirement on behalf of the North Dakota Public Service Commission Advocacy Staff).
   North Dakota Public Service Commission – Docket No. PU-23-367.

2. In Re: FirstEnergy Pennsylvania Electric Company for Approval of a General Base Rate Case increase for Electric Distribution rates for service.
   (Appearance: Revenue Requirement on behalf of the Pennsylvania Office of Consumer Advocate)
   Pennsylvania Public Utility Commission – Docket No. R-2024-3047068

3. In Re: Duquesne Light Company for Approval of a General Base Rate Case to increase Electric Distribution rates for service.
   (Appearance: Revenue Requirement on behalf of the Pennsylvania Office of Consumer Advocate)
   Pennsylvania Public Utility Commission – Docket No.- R-2024-3046523

4. In Re: Peoples Natural Gas Company, LLC for Approval of a General Base Rate Case increases in Natural Gas Service.
   (Appearance: Revenue Requirement on behalf of the Pennsylvania Office of Consumer Advocate)
   Pennsylvania Public Utility Commission – Docket No. R-2023-3044549

5. In Re: Black Hills Energy Arkansas, Inc. (BHEA) and Summit Utilities Arkansas, Inc. (SUA) for a General Change, or Modification in its Rates, Charges and Tariffs
   (Appearance: Incentive Compensation Proposals on behalf of the Attorney General Office)
   Arkansas Public Service Commission – Docket No. (BHEA) - 23-074-U and Docket No. (SUA) - 23-079-U.

6. In Re: Montana Dakota Utilities Co. for Approval to increase Gas Rates for Natural Gas Service in North Dakota
   (Appearance- Revenue Requirement on behalf of the North Dakota Public Service Commission Advocacy Staff)
   North Dakota Public Service Commission – Docket No. PU-23-341

7. In Re: Otter Tail Power Company for Approval to increase Electric Rates in North Dakota.
   (Appearance: Revenue Requirement on behalf of the North Dakota Public Service Commission Advocacy Staff)
   North Dakota Public Service Commission – Docket No. PU-23-342

8. In Re: New Jersey-American Water Company for Approval to change the level of its Purchased Water and Purchased Wastewater Treatment Adjustment Clause for 2023.
   (Appearance: Accounting Issues on behalf of the New Jersey Division of Rate Counsel)

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New Jersey Board of Public Utilities – Docket No. WR23110791

9. In Re: Verified Petition of Jersey Central Power & Light Company to establish a Rate for Rider Lost Revenue Adjustment Mechanism for Sales Losses incurred during Program Year 2 Pursuant to the Energy Efficiency and Peak Demand Reductions Programs (PY Rider LRAM Filing).
(Appearance: Accounting Issues on behalf of the New Jersey Division of Rate Counsel)
New Jersey Board of Public Utilities – Docket No. ER23110865

10. In Re: Fitchburg Gas & Electric Company; The Berkshire Gas Company; Boston Gas Company d/b/a National Grid; Liberty Utilities; Eversource Gas of Massachusetts d/b/a Eversource Energy and; NSTAR Gas Company d/b/a Eversource Energy – 2023 Gas System Enhancement Program Plan Filings. (DPU GSEP-01; DPU GSEP-02; DPU GSEP-03; DPU GSEP-04; DPU GSEP-05; and DPU GSEP-06, respectively)
(Appearance: Accounting Issues on behalf of the Commonwealth of Massachusetts Office of the Attorney General)
Department of Public Utilities

11. In Re: Northern States Power Company – Advance Determination of Prudence – 345 kV Transmission Line – MN.
(Appearance: Accounting Issues and Revenue Requirement on behalf of the North Dakota Public Service Commission Advocacy Staff.
North Dakota Public Service Commission – Docket No. PU-23-142.

12. In Re: Northern States Power Company – Advance Determination of Prudence- Brookings Second Circuit Project.
(Appearance: Accounting Issues and Revenue Requirement on behalf of the North Dakota Public Service Commission Advocacy Staff.
North Dakota Public Service Commission – Docket No. PU-23-295.

13. In Re: Northern States Power Company – Advance Determination of Prudence – 345 kV Big Stone to Sherburne.
(Appearance: Accounting Issues and Revenue Requirements on behalf of the North Dakota Public Service Commission Advocacy Staff.
North Dakota Public Service Commission – Docket No. PU-23-329.

14. In Re: Rockland Electric Company – Annual Conservation Incentive Program Filing – Reconciliation for the period July 1, 2022 – June 30, 2023.
(Appearance: Accounting Issues on behalf the New Jersey Division of Rate Counsel)
New Jersey Board of Public Utilities – Docket No. ER23070471

15. In Re: Public Service Electric & Gas Company for Approval of Incremental COVID-19 Costs for Recovery through a New Special Purpose Clause and for Authorization to Recovery Uncollectible Costs for Gas Through the Societal Benefits Charge
16. (Appearance: Accounting Issues on behalf of the New Jersey Division of Rate Counsel)
New Jersey Board of Public Utilities – Docket No. ER23070448

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17. In Re: Jersey Central Power & Light Company's Verified Petition Seeking Review and Approval of the Net Deferred Costs Included in its COVID-19 Regulatory Asset and Establishment of a COVID-19 Recovery Charge (JCP&L CRC-Filing)
(Appearance: Accounting Issues on behalf of the New Jersey Division of Rate Counsel)
New Jersey Board of Public Utilities – Docket No. ER23070453.

18. In Re: Aqua New Jersey, Inc. Petition for 2024 PSTAC Rate and True-up for 2021 and 2022 PSTAC.
(Appearance: Accounting Issues on behalf of the New Jersey Division of Rate Counsel)
New Jersey Board of Public Utilities – Docket No. WR23080576

19. In Re: Public Service Electric & Gas Company for Approval of Changes in its Electric Tax Adjustment Credit and Gas Tax Adjustment Credit 2023 (2023 TAC Filing)
(Appearance: Accounting Issues on behalf of the New Jersey Division of Rate Counsel)
New Jersey Board of Public Utilities – Docket No. ER23090634 and GR23090635

20. In Re: New Jersey – American Water Company for Deferral Accounting Authority for the Costs of Implementing the Clean Energy Act of 2018 Benchmarking Requirements.
(Appearance: Accounting Issues on behalf of the New Jersey Division of Rate Counsel)
New Jersey Board of Public Utilities – Docket No. WF23060346

21. In Re: Public Service Electric & Gas Company – Annual BGSS (2023-2024) Commodity Charge Filing for its Residential Gas Customers under its Periodic Pricing Mechanism and for Changes in its Balancing Charge Rate.
(Appearance: Accounting Issues on behalf of the New Jersey Division of Rate Counsel)
New Jersey Board of Public Utilities – Docket No. GR23060331

22. In Re: Public Service Electric & Gas Company – Electric and Gas Green Programs Recovery Charges 2023. (GPRC).
(Appearance: Accounting Issues on behalf of the New Jersey Division of Rate Counsel)
New Jersey Board of Public Utilities – Docket No. ER23070423 and GR23070424

23. In Re: Public Service Electric & Gas Company – Electric Solar Pilot Recovery Charge (SPRC) for its Solar Loan I Program (2023).
(Appearance: Accounting Issues on behalf of the New Jersey Division of Rate Counsel)
New Jersey Board of Public Utilities – Docket No. ER23060412

24. In Re: Middlesex Water Company for approval of Proposed Cost Recovery of Lead Service Line Replacement Program
(Appearance: Accounting Issues on behalf of the New Jersey Division of Rate Counsel)
New Jersey Board of Public Utilities – Docket No. WR23050291

25. In Re: Black Hills Wyoming Gas, LLC d/b/a Black Hills Energy for Approval of a General Rate Increase of $19,262,412 to the Retail Gas Rates.

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(Appearance: Revenue Requirement on behalf of the Wyoming Office of Consumer Advocate)
Wyoming Public Service Commission – Docket No. 30026-78-GR-23

26. In Re: Pittsburgh Water and Sewer Authority for an Increase in Rates for Water Service, Wastewater Service and Stormwater Service
(Appearance: Revenue Requirement on behalf of the Pennsylvania Office of Consumer Advocate)
Pennsylvania Public Utility Commission – Docket Nos. R-2023-3039920 (water), R-2023-3039921 (wastewater), and R-2023-3039919 (stormwater)

27. In Re: Massachusetts Electric and Nantucket Electric Companies d/b/a National Grid – Request for recovery of Incremental Storm related expenses associated with fourteen weather events between February 2020 and December 2020.
(Appearance: Storm Cost recovery (Operating and Maintenance Expenses) on behalf of the Massachusetts Office of Attorney General.
Massachusetts Department of Public Utilities – DPU No. 22-43.

28. In Re: Philadelphia Gas Works – for approval of an Increase in rates for Distribution Gas Service for 2023
(Appearance: Revenue Requirement on behalf of the Pennsylvania Office of Consumer Advocate)
Pennsylvania Public Utility Commission – Docket No. R-2023-3037933

29. In Re: Lanai Water Company, Inc. for Review and Approval of Rate Increases, Revised Rate Schedules and Charges to its Tariff.
(Appearance: Revenue Requirement on behalf of the Hawaii Division of Consumer Advocacy)
Hawaii Public Utilities Commission – Docket No. 2022-0233

30. In Re: Hawaii Water Service Company, Inc., For Approval of a General Rate Increase for Its Pukalani Wastewater Division and Certain Tariff Changes
(Appearance: Revenue Requirement on behalf of the Hawaii Division of Consumer Advocacy)
Hawaii Public Utilities Commission – Docket No. 2022-0186

31. In Re: UGI Utilities – Electric Division for Review of an Electric Base Rate Case proceeding for 2023.
(Appearance: Revenue Requirement on behalf of the Pennsylvania Office of Consumer Advocate)
Pennsylvania Public Utility Commission – Docket No. R-2022-3037368

32. In Re: Southern Maryland Electric Cooperative, Inc. (SMECO) for Authority to Revise its Rates and Charges for Electric Service and Certain Rate Design Changes.
(Appearance: Revenue Requirement on behalf of the Maryland Office of People's Counsel)

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Maryland Public Service Commission – Case No. 9688

33. In Re: Public Service Electric and Gas Company – 2022 Electric and Gas Tax Adjustment Credit (TAC)
(Appearance: Revenue Requirement on behalf of the NJ Division of Rate Counsel)
NJ Board of Public Utilities – BPU Docket Nos. ER22100667 and GR22100668

34. In Re: Public Service Electric and Gas Company – 2022 Green Program Recovery Charge.
(Appearance: Revenue Requirement on behalf of the NJ Division of Rate Counsel)
NJ Board of Public Utilities – BPU Docket Nos. ER22070413 and GR22070414

35. In Re: Rockland Electric Company – Annual Conservation Incentive Program Filing – Reconciliation for the Period July 1, 2021 – June 30, 2022.
(Appearance: Revenue Requirement on behalf of the NJ Division of Rate Counsel)
NJ Board of Public Utilities – BPU Docket No. ER22070469.

36. In Re: Atlantic City Electric Company for Implementation to its Conservation Incentive Program Rate Mechanism and Associated Customer Class Rate (2022)
(Appearance: Revenue Requirement on behalf of the NJ Division of Rate Counsel)
NJ Board of Public Utilities – BPU Docket No. ER22070463

37. In Re: Public Service Electric and Gas Company – 2022/2023 Annual BGSS Commodity Charge filing for its Residential Gas Customers under its Periodic Pricing Mechanism and for changes to its Balancing Charge.
(Appearance: Revenue Requirement on behalf of the NJ Division of Rate Counsel)
NJ Board of Public Utilities – BPU Docket No. GR22060363

38. In Re: Citizens' Electric Company of Lewisburg, PA – 2022 Base Rate Case Proceeding for an Increase in Electric Distribution Rates.
(Appearance: Revenue Requirement on behalf of the Pennsylvania Office of Consumer Advocate)
Pennsylvania Public Utility Commission – Docket No. R-2022-3032369

39. In Re: Valley Energy, Inc. – 2022 Base Rate Case for an Increase in Gas Distribution Rates.
(Appearance: Revenue Requirement on behalf of the Pennsylvania Office of Consumer Advocate)
Pennsylvania Public Utility Commission – Docket No. R-2022-3032300

40. In Re: Berkshire Gas Company – 2021 Gas System Enhancement Program Reconciliation Filing.
(Appearance: Revenue Requirement on behalf of the Massachusetts Attorney General's Office)
Massachusetts Department of Public Utilities – D.P.U. 22-GREC-02

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41. In Re: Liberty Utilities (New England Natural Gas Company) 2021 Gas System Enhancement Program Reconciliation Filing.
(Appearance: Revenue Requirement on behalf of the Massachusetts Attorney General's Office)
Massachusetts Department of Public Utilities – D.P.U. 22-GREC-04

42. In Re: Eversource Gas Company (Eversource Energy) 2021 Gas System Enhancement Program Reconciliation Filing.
(Appearance: Revenue Requirement on behalf of the Massachusetts Attorney General's Office)
Massachusetts Department of Public Utilities – D.P.U. 22-GREC-05

43. In Re: South Jersey Gas Company – 2022 Base Rate Case Proceeding for an Increase in rates for Distribution Gas Service.
(Appearance: Revenue Requirement, CWC and Consolidated Income Taxes on behalf of the New Jersey Division of Rate Counsel)
New Jersey Board of Public Utilities – BPU Docket No. GR22040253

44. In Re: Public Service Electric and Gas Company – 2022 Electric Conservation Incentive Program (CIP) for changes in its Electric CIP rate for 2022.
(Appearance: Revenue Requirement on behalf of the New Jersey Division of Rate Counsel)
New Jersey Board of Public Utilities – Docket No. ER22020035

45. In Re: PECO Energy Company-Gas Division – 2022 Base Rate Case Proceeding for an Increase in rates for Distribution Gas Service.
(Appearance: Revenue Requirement on behalf of the Pennsylvania Office of Consumer Advocate)
Pennsylvania Public Utility Commission – Docket No. R-2022-3031113.

46. In Re: Nova Scotia Power Company- 2022-2024 General Rate Application for an Increase in Rates for Electric Service
(Appearance- Review of COSS – Subcontract with Synapse Energy Economics, Inc. on behalf of the Nova Scotia Utility Review Board)
Nova Scotia Utility and Review Board – Docket No. M10431

47. In Re: Georgia Power Company – 2022 Base Rate Case petition for an Increase in rates for Electric Distribution Service
(Appearance: Review of O&M Expenses for calendar years 2023-2025 on behalf of the Georgia Public Service Commission – Docket No. TBD

48. In Re: UGI Utilities Inc, Gas Division – 2022 Base Rate Case petition for an Increase in Distribution Gas Service Rates
(Appearance: Revenue Requirement on behalf of the Pennsylvania Office of Consumer Advocate)
Pennsylvania Public Utility Commission – Docket No. R-2022-3030218

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49. In Re: Hawaii-American Water Company – Approval of Rate Increases and Revised Rate Schedules for Wastewater Services – 2021
(Appearances: Revenue Requirement on behalf of the Hawaii Division of Consumer Advocacy)
Hawaii Public Service Commission – Case No. 2021-0063

50. In Re: Kalaeloa Water Company – Approval of a General Rate Increase / Adjustments for Water and Wastewater Services – 2021
(Appearance: Revenue Requirement on behalf of the Hawaii Division of Consumer Advocacy)
Hawaii Public Service Commission – Case No. 2021-0005

51. In Re: Northern States Power Company – 2021 Natural Gas Rate Increase Application
(Appearance: Revenue Requirements on behalf of the Advocacy Staff of the North Dakota Public Service Commission – Case No. PU-21-381

52. In Re: Shore Water Company – Petition for an Increase in Rates for Water Service and Other Relief
(Appearance: New Jersey Division of Rate Counsel – Accounting and Revenue Requirement)
New Jersey Board of Public Utilities – BPU Docket No. WR21091141

53. In Re: Atlantic City Sewerage Company – Petition for an Increase in Rates for Sewerage Service and other Tariff Changes
(Appearance: New Jersey Division of Rate Counsel – Accounting and Revenue Requirement)
New Jersey Board of Public Utilities – BPU Docket No. WR21071006

54. In Re: Gordon's Corner Water Company – Petition for an Increase in Rates and Charges for Water Service
(Appearance: New Jersey Division of Rate Counsel – Accounting and Revenue Requirement)
New Jersey Board of Public Utilities – BPU Docket No. WR21070979

55. In Re: The Petition of HPBS Inc., for review and approval of Central Scheduling System (CSS) charge increase and revised CSS Schedule (2021)
(Appearance – Accounting and Revenue Requirement on behalf of the Hawaii Division of Commerce and Consumer Affairs
Hawaii DCCA – Docket No. PTP-2021-001

56. In Re: The Berkshire Gas Company, 2020 Gas System Enhancement Program Reconciliation Filing
(Appearance – Massachusetts Attorney General's Office – Accounting and Revenue Requirement)
Massachusetts Department of Public Utilities – DPU Docket No. 21-GREC-02

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57. In Re: Eversource Gas Company of Massachusetts d/b/a Eversource Energy, 2020 Gas System Enhancement Program Reconciliation Filing
(Appearance – Massachusetts Attorney General's Office – Account and Revenue Requirement)
Massachusetts Department of Public Utilities – DPU Docket No. 21-GREC-05

58. In Re: NSTAR Gas Company d/b/a Eversource Energy, 2020 Gas System Enhancement Program Reconciliation Filing
(Appearance: Massachusetts Attorney General's Office – Accounting and Revenue Requirement)
Massachusetts Department of Public Utilities – DPU Docket No. 21-GREC-06

59. In Re: Joint Petition of New Jersey Natural Gas Company and Public Service Electric and Gas Company for Authorization and Approval of a Waiver of Certain Accounting Treatment Pursuant to the Clean Energy Order
(Appearance – New Jersey Division of Rate Counsel – Accounting and Revenue Requirement.
New Jersey Board of Public Utilities – BPU Docket No. EO20030254

60. In Re: Public Service Electric and Gas Company – 2021/2022 Annual BGSS Commodity Charge Filing for its Residential Gas Customers under its Periodic Pricing Mechanism and for Changes in its Balance Charge.
(Appearance – New Jersey Division of Rate Counsel – Accounting and Revenue Requirement)
New Jersey Board of Public Utilities – BPU Docket No. GR21060878

61. In Re: Middlesex Water Company – Petition for Approval of an Increase in Rates for Water Service and Other Tariff Changes.
(Appearances – New Jersey Division of Rate Counsel – Accounting and Revenue Requirement)
New Jersey Board of Public Utilities – BPU Docket No. WR21050813

62. In Re: New Jersey Natural Gas Company – Petition for an Increase in Gas Base Rates and Changes in its Tariff for Gas Service and for a Change to Depreciation Rates for Gas Property and for Approval of a Base Rate Adjustment Pursuant to the NJ RISE and SAFE II Programs.
(Appearances: New Jersey Division of Rate Counsel – Accounting and Revenue Requirement)
New Jersey Board of Public Utilities – BPU Docket Nos. GR21030679 and GR21030680.

63. In Re: PECO Energy Company – a division of Exelon Corp., for a General Base Rate Case Filing for Electric Operations
(Appearances: Accounting and Policy on behalf of the Pennsylvania Office of the Consumer Advocate)
Pennsylvania Public Utility Commission – Docket No. R-2021-3024601

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64. In Re: The Pittsburgh Water and Sewer Authority for approval of increased rates and charges for Water, Wastewater and Stormwater services
(Appearance: Accounting and Policy, and Regulatory Policy on behalf of the Pennsylvania Office of the Consumer Advocate)
Pennsylvania Public Utility Commission – Docket Nos. R-2021-3024773 (Water) R-2021-3024774 (Wastewater) and R-2021-3024779 (Stormwater).

65. In Re: Northern States Power Company – 2021 Electric Base Rate Case Increase
(Appearance: Revenue Requirement on behalf of the Advocacy Staff of the North Dakota Public Service Commission)
North Dakota Public Service Commission – Case No. PUC-20-441

66. In Re: Public Service Electric and Gas Company – Approval of a Tax Adjustment Clause (TAC).
(Appearance; Revenue Requirement on behalf of the New Jersey Division of Rate Counsel)
New Jersey Board of Public Utilities – Docket Nos. ER20100685 and GR20100686.

67. In Re: Pike County Light and Power Company – Approval to increase base rates for Electric and Gas Service.
(Appearance: Revenue Requirement in behalf of the Pennsylvania Office of Consumer Advocate)
Pennsylvania Public Utility Commission – Docket Nos. R-2020-3022134 (Gas) and R-2020-3022135 (Electric)

68. In Re: Jersey Central Power and Light Company for Approval of JCP&L's Energy Efficiency and Conservation Plan Including Energy Efficiency and Peak Demand Reduction Programs.
(Appearance: Revenue Requirement on behalf of the New Jersey Division of Rate Counsel)
New Jersey Board of Public Utilities – Docket Nos. QO19010040 and EO20090620

69. In Re: Atlantic City Electric Company for Approval of an Energy Efficiency Program, Cost Recovery Mechanism, and Other Related Relief for Plan Years One Through Three.
(Appearance: Revenue Requirement on behalf of the New Jersey Division of Rate Counsel)
New Jersey Board of Public Utilities – Docket Nos. QO19010040 and EO20090621

70. In Re: Rockland Electric Company for Approval of Its Energy Efficiency and Peak Demand Reduction Programs.
(Appearance: Revenue Requirement on behalf of the New Jersey Division of Rate Counsel)
New Jersey Board of Public Utilities – Docket Nos. QO19010040 and EO20090623

71. In Re: Public Service Electric and Gas Company for Approval of Changes in its Electric Green Programs Recovery Charge and its Gas Green Programs Recovery Charge 2020 PSE&G Green Programs Cost Recovery filing

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(Appearance: Revenue Requirement on behalf of the NJ Division of Rate Counsel)
New Jersey Board of Public Utilities – Docket Nos. ER20060467 and GR20060468

72. In Re: Public Service Electric and Gas Company's 2020/2021 Annual BGSS Commodity Charge filing for its Residential Gas Customers under its Pricing Mechanism and for Changes in its Balance Charge
(Appearance: Revenue Requirement on behalf of the NJ Division of Rate Counsel)
New Jersey Board of Public Utilities – Docket No. GR20060379

73. In Re: Public Service Electric and Gas Company's 2020 Annual Margin Adjustment Clause (MAC)
(Appearance: Revenue Requirement on behalf of the NJ Division of Rate Counsel)
New Jersey Board of Public Utilities – Docket No. GR20060384

74. In Re: South Jersey Gas Company for Approval to Revise the Rider H Rate Associated with the Tax Cuts and Jobs Act of 2017
(Appearance: Revenue Requirement on behalf of the NJ Division of Rate Counsel)
New Jersey Board of Public Utilities – Docket No. GR20060382

75. In Re: Berkshire Gas Company -2019 Gas System Enhancement Program Reconciliation Filing
(Appearance: Revenue Requirement on behalf of the Massachusetts Office of the Attorney General)
Commonwealth of Massachusetts -Department of Public Utilities – DPU 20-GREC-02

76. In Re: Bay States Gas Company d/b/a Columbia Gas – 2019 Gas System Enhancement Program Reconciliation Filing.
(Appearance: Revenue Requirement on behalf of the Massachusetts Office of the Attorney General)
Commonwealth of Massachusetts – Department of Public Utilities – DPU 20-GREC-05

77. In Re: NSTAR Gas Company – 2019 Gas System Enhancement Program Reconciliation Filing
(Appearance: Revenue Requirement on behalf of the Massachusetts Office of the Attorney General)
Commonwealth of Massachusetts – Department of Public Utilities – DPU 20-GREC-06

78. In Re: South Jersey Gas Company for Approval of Increased Base Tariff Rates and Charges for Gas Service, Changes to Depreciation Rates and Other Tariff Revisions.
(Appearances: Revenue Requirement and Cash Working Capital) on behalf of the New Jersey Division of Rate Counsel.
New Jersey Board of Public Utilities – Docket No. GR20030243

79. In Re: Jersey Central Power & Light Company for Review and Approval of Increased in, and Other Adjustments to Rates and Charges for Electric Services and approval of Other Proposed Tariff Revisions (Appearance: Revenue Requirement, Cash Working Capital,

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Consolidated Income Taxes, LED Conversion and Reliability Roll-In) on behalf of the New Jersey Division of Rate Counsel.
New Jersey Board of Public Utilities – Docket No. ER20020146

80. In Re: The Pittsburgh Water and Sewer Authority for approval of increased rates and charges for water and wastewater service and for approval of a multi-year rate plan.
(Appearance: Accounting and Policy, Customer Service and Regulatory Policy) on behalf of the Pennsylvania Office of the Consumer Advocate)
Pennsylvania Public Utility Commission – Docket Nos. R-2020-3017951 and R-2020-3017970.

81. In Re: New Jersey-American Water Company, Inc. for approval of Increased Base Tariff Rates and Charges for Water and Wastewater Services and Other Tariff Revisions.
(Appearance: Accounting and Revenue Requirement and Cash Working Capital / Consolidated Income Taxes) on behalf of the New Jersey Division of Rate Counsel)
New Jersey Board of Public Utilities – Docket No. WR19121516

82. In Re: Hawaiian Electric Company, Inc., for approval of a General Rate Increase and Revised Rate Schedules and Rules.
(Appearance: Accounting and Revenue Requirement on behalf of the Hawaiian Division of Consumer Advocacy)
Hawaii Public Utilities Commission – Docket No. 2019-0085

83. In Re: Mount Olive Villages Water Company for approval of an Increase in Rates for Water Service and Other Tariff Changes.
(Appearance: Accounting and Consulting Services on behalf of the New Jersey Division of Rate Counsel)
New Jersey Board of Public Utilities – Docket No. WR19060770

84. In Re: Mount Olive Villages Sewer Company for approval of an Increase in Rates for Sewer Service and Other Tariff Changes.
(Appearance: Accounting and Consulting Services on behalf of the New Jersey Division of Rate Counsel)
New Jersey Board of Public Utilities – Docket No. WR19060769

85. In Re: Public Service Electric and Gas Company for approval of changes in its Electric Green Programs Recovery and its Gas Green Programs Recovery Charge (2019 PSE&G Green Programs Cost Recovery Filing).
(Appearance: Accounting and Consulting Services on behalf of the New Jersey Division of Rate Counsel)
New Jersey Board of Public Utilities – Docket Nos. ER19070764 and GR19070765

86. In Re: Proposed Amendment to N.J.A.C. 14:9- Adoption by reference to the Uniform System of Accounts for Water Utilities and Wastewater Utilities.
(Appearance: Consulting Services on behalf of the New Jersey Division of Rate Counsel)

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New Jersey Board of Public Utilities- Docket Nos. WX19050612 (Water) and WX19050613 (Wastewater)

87. In Re: Public Service Electric and Gas Company's 2019/2020 Annual BGSS Commodity Charge filing for its Residential Gas Customers Under its Periodic Pricing Mechanism and for Changes in its Balancing Charge.
(Appearance: Revenue Requirement and accounting/consulting services on behalf of the New Jersey Division of Rate Counsel)
New Jersey Board of Public Utilities – Docket No. GR190600699

88. In Re: Bay States Gas Company d/b/a Columbia Gas of Massachusetts for Approval of a 2018 Gas System Enhancement Program Reconciliation Filing
(Appearance: Revenue Requirement on behalf of the Massachusetts Office of the Attorney General)
Commonwealth of Massachusetts Department of Public Utilities – Docket No. 19-GREC-05

89. In Re: NSTAR Gas Company d/b/a Eversource Energy for Approval of a 2018 Gas System Enhancement Program Reconciliation Filing
(Appearance: Revenue Requirement on behalf of the Massachusetts Office of the Attorney General)
Commonwealth of Massachusetts Department of Public Utilities – Docket No. 19-GREC-06

90. In Re: Public Service Electric and Gas Company for Approval of Gas Rate Base Adjustments Pursuant to its Gas System Modernization Program (April 2019 GSMP)
(Appearance: Revenue Requirement on behalf of the New Jersey Division of Rate Counsel)
New Jersey Board of Public Utilities – Docket No. GR19040522

91. In Re: Kalaeloa Water Company, LLC for Approval of General Rate Case and Revised Rules, Regulations and Rates.
(Appearance: Revenue Requirement on behalf of the Hawaii Division of Consumer Advocacy)
Hawaii Public Utilities Commission – Docket No. 2019-0057

92. In Re: Elizabethtown Gas Company for Approval of an Increase in Rates and Charges for Gas Service, Changes to Depreciation Rates and Other Tariff Revisions.
(Appearance: Revenue Requirement and Other Accounting Issues on behalf of the New Jersey Division of Rate Counsel).
New Jersey Board of Public Utilities – Docket No. GR19040586

93. In Re: Petition of Peoples Natural Gas Company for Approval of an Increase in Rates for Natural Gas Distribution Service.
(Appearance: Revenue Requirement and Other Accounting Issues on behalf of the Pennsylvania Office of Consumer Advocate)
Pennsylvania Public Utility Commission – Docket No. R-2018-3006818

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94. In Re: Petition of Aqua New Jersey, Inc. for Approval of an Increase in Rates for Water Service and other Tariff Changes.
(Appearance: Revenue Requirement and other Accounting Issues on behalf of the New Jersey Division of Rate Counsel)
New Jersey Board of Public Utilities – BPU Docket No. WR18121351

95. In Re: Petition of Public Service Electric and Gas Company for Approval of its Clean Energy Future – Energy Efficiency (CEF-EE) Program on a Regulated Basis.
(Appearance: Revenue Requirement and other Accounting Issues on behalf of the New Jersey Division of Rate Counsel)
New Jersey Board of Public Utilities – BPU Docket Nos. GO18101112 and EO18101113.

96. In Re: Petition of Public Service Electric and Gas Company for Approval of its Clean Energy Future – Energy Vehicle and Energy Storage (CEF-EVES) Program on a Regulated Basis. (Appearance – Revenue Requirement and other Accounting Issues on behalf of the New Jersey Division of Rate Counsel)
New Jersey Board of Public Utilities – BPU Docket No. EO18101111.

97. In Re: Petition of New Jersey Natural Gas Company- Request for Deferred Accounting Authority for Costs Related to New Information Technology Systems. (Appearance: Impact on Revenues, prudency of costs on behalf of the New Jersey Division of Rate Counsel)
New Jersey Board of Public Utilities – BPU Docket No. GR18101096

98. In Re: Petition for Approval of An Indirect Change in Control of the New Jersey Public Utilities Subsidiaries of SUEZ Water Resources, Inc. and Other Related Approvals.
(Appearance: Impact on Rates, Service, Employees, Positive Benefits on behalf of the New Jersey Division of Rate Counsel)
New Jersey Board of Public Utilities – BPU Docket No. WM18090982

99. In Re: The Matter of the Merger of Roxbury Water Company into New Jersey American Water Company (Appearance: Impact on Rates, Service and Employees, Positive Benefits on behalf of the New Jersey Division of Rate Counsel)
New Jersey Board of Public Utilities – BPU Docket No. WM18080904

100. In Re: The Matter of the Application of Maryland-American Water Company for Authorization to Adjust its Existing Schedule of Tariffs and Rates.
(Appearance: Revenue Requirement on behalf of the Maryland Office of People's Counsel)
Maryland Public Service Commission – Case No. 9487

101. In Re: The Matter of the Joint Petition for Approval of an Increase in Rates for Water and Wastewater Service and Other Tariff Changes for SUEZ Water NJ, Inc., Toms River, Inc., Arlington Hill, Inc., West Milford, Inc., Matchaponix, Inc., and Princeton Meadows, Inc.

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(Appearance: Revenue Requirement and the development of Consolidated Income Taxes on behalf of the NJ Division of Rate Counsel)
New Jersey Board of Public Utilities – BPU Docket No. WR18050593

102. In Re: The Matter of the Application of Atlantic City Electric Company to Adjust the Level of its Rider RGGI Rate Associated with its Solar Renewable Energy Certificate Financing Program 2018 (Appearance: Revenue Requirement on behalf of the NJ Division of Rate Counsel)
New Jersey Board of Public Utilities – BPU Docket No. ER18050543

103. In Re: The Matter of the Petition of New Jersey Natural Gas Company's Approval of the Cost Recovery Associated with Energy Efficiency Programs (Appearance; Revenue Requirement on behalf of the NJ Division of Rate Counsel)
New Jersey Board of Public Utilities – BPU Docket No, GR18050585

104. In Re: The Matter of Bay States Gas Company d/b/a Columbia Gas of Massachusetts, 2017 Gas System Enhancement Reconciliation Filing (Appearance: Revenue Requirement on behalf of the Massachusetts Attorney General's Office of Ratepayer Advocacy)
Commonwealth of Massachusetts – Department of Public Utilities – Docket No. D.P.U. 18-GREC-05.

105. In Re; The Matter of NSTAR Gas Company d/b/a Eversource Energy, Gas System Enhancement Program Reconciliation Filing (Appearance: Revenue Requirement on behalf of the Massachusetts Attorney General's Office of Ratepayer Advocacy)
Commonwealth of Massachusetts – Department of Public Utilities – Docket No. D.P.U. 18-GREC-06.

106. In Re: The Matter of the Merger of SUEZ Water NJ, SUEZ Water Toms River, SUEZ Water Arlington Hills, SUEZ Water West Milford, SUEZ Water Princeton Meadows and SUEZ Water Matchaponix (Appearance: Positive Benefits related to the Merger on behalf of the NJ Division of Rate Counsel)
New Jersey Board of Public Utilities – BPU Docket No. WR18030266

107. In Re: The Matter of the Columbia Gas of Pennsylvania for a General Rate Increase in Distribution Gas Service (Appearance; Accounting Issues and Revenue Requirement on behalf of the Pennsylvania Office of Consumer Advocate)
Pennsylvania Public Utility Commission – Docket No. R-2018-2647577

108. In Re: The Matter of the New Jersey Board of Public Utilities Consideration of the Tax Cuts and Jobs Act of 2017 – Generic Proceeding (Appearance: Revenue Requirement on behalf of the NJ Division of Rate Counsel)
New Jersey Board of Public Utilities – BPU Docket No. AX18010001

109. In Re: Acquisition of Elizabethtown Gas, a Division of Pivotal Utilities Holdings, Inc. by ETG Acquisition Corp., a Division of South Jersey Industries, Inc., and Related

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Transactions. (Appearance: Customer Service Issues/Employee and Labor Relations on behalf of the NJ Division of Rate Counsel)
New Jersey Board of Public Utilities – BPU Docket No. GM17121309.

110. In Re: Middlesex Water Company – Base Rate Case Proceeding for Water Service. (Appearance: revenue requirement on behalf of the NJ Division of Rate Counsel).
New Jersey Board of Public Utilities – BPU Docket No. WR17101049.

111. In Re: Township of East Brunswick – Sewer Rate Study – (Evaluation of the existing sewer rate structure and examining and quantify costs for future expansion).

112. In Re: Montana-Dakota Utilities – Base Rate Case Proceeding for Gas Service. (Appearance: revenue requirement on behalf of the North Dakota Public Service Commission). NDPSC Docket No. PU-17-295.

113. In Re: Andover Utility Company – Base Rate Case Proceeding for Wastewater Services. (Appearance: revenue requirement on behalf of the New Jersey Division of Rate Counsel).
New Jersey Board of Public Utilities – BPU Docket No. WR17070726.

114. In Re: Public Service Electric and Gas Company- Approval of Changes in its Electric and Gas Green Programs Recovery Charges "2017 Public Service Electric & Gas Green Programs Cost Recovery Filing. (Appearance: revenue requirement on behalf of the New Jersey Division of Rate Counsel).
New Jersey Board of Public Utilities – BPU Docket Nos. ER17070724 and GR17070725.

115. In Re: Bay States Gas Company d/b/a Columbia Gas of Massachusetts, 2016 Gas System Enhancement Program Reconciliation Filing, (Appearance: revenue requirement on behalf of the Massachusetts Attorney General's Office of Ratepayer Advocacy).
Commonwealth of Massachusetts Department of Public Utilities – Docket No. D.P.U. 17-GREC-05.

116. In Re: NSTAR Gas Company d/b/a Eversource Energy, 2016 Gas System Enhancement Program Reconciliation Filing (Appearance: revenue requirement on behalf of the Massachusetts Attorney General's Office of Ratepayer Advocacy.
Commonwealth of Massachusetts Department of Public Utilities – Docket No. D.P.U. 17-GREC-06.

117. In Re: Petition of Columbia Gas of Maryland – Increase in rates for Distribution Service – (Appearance: revenue requirement on behalf of the Office of People's Counsel) Public Service Commission of Maryland – Case No. 9447

118. In Re: Petition of South Jersey Gas Company – Increase in base rates for gas services – (Appearance: revenue requirement on behalf of the NJ Division of Rate Counsel)
New Jersey Board of Public Utilities – Docket No. GR17010071

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119. In Re: Petition of UGI Penn Natural Gas – Increase in base rates for gas services – (Appearance: revenue requirement on behalf of the Pennsylvania Office of Consumer Advocate)
Pennsylvania Public Utilities Commission Docket No. R-2016-2580030

120. In Re: Petition of PJM Interconnection, LLC. – Mid-Atlantic Interstate Transmission, LLC. Formula Rate Filing. (Appearance on behalf of the Pennsylvania Office of Consumer Advocate).
FERC Docket No. ER17-211-000

121. In Re: Petition of Pivotal Utility Holdings, Inc. d/b/a Elizabethtown Gas Company for approval of Increased Base Tariff Rates and Charges for Gas Service and Other Tariff Revisions (Appearance: revenue requirement on behalf of the New Jersey Division of Rate Counsel)
New Jersey Board of Public Utilities Docket No. GR16090826

122. In Re: Petition of SUEZ Water New Jersey, et al – Approval of a Management and Services Agreement pursuant to N.J.S.A 48: 3-7.1 (Appearance on the reasonableness of contract agreements on behalf of the New Jersey Division of Rate Counsel)
New Jersey Board of Public Utilities Docket No. WO16080806

123. In Re: Petition of SUEZ Water Arlington Hills Inc. – Approval of an Increase in Rates for Wastewater Services and other Tariff Changes (Appearance: revenue requirement on behalf of the New Jersey Division of Rate Counsel)
New Jersey Board of Public Utilities Docket No. WR16050510

124. In Re: Petition of Public Service Electric and Gas Company – 2016 Marginal Adjustment Clause (MAC) (Appearance; reconciliation and rate setting on behalf of the New Jersey Division of Rate Counsel)
New Jersey Board of Public Utilities Docket No. GR16060484

125. In Re: Petition of Public Service Electric and Gas Company for Approval of Changes in its Electric Green Programs Recovery Charges and its Gas Green Program Recovery Charges 2016 PSEG Program Cost Recovery Filing
(Appearance: reconciliation and rate setting on behalf of the New Jersey Division of Rate Counsel)
New Jersey Board of Public Utilities Docket Nos. ER16070613 and GR16070614

126. In Re: Petition of the Mount Olive Village Sewer Company, Inc., for Approval of an Increase in Rates for Service (Appearance: revenue requirement on behalf of the New Jersey Division of Rate Counsel)
New Jersey Board of Public Utilities Docket No. WR16050391

127. In Re: Petition of the Mount Olive Village Water Company, Inc. for Approval of an Increase in Rates for Service (Appearance; revenue requirement on behalf of the New Jersey Division of Rate Counsel)

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New Jersey Board of Public Utilities Docket No. WR16050390

128. In Re: Petition of Fitchburg Gas and Electric Light Company d/b/a Unitil for Approval of its 2015 Gas System Enhancement Plan Reconciliation Filing (2016) - (Analysis and Advice to Counsel: computation of the revenue requirement and rate impact on behalf of the Massachusetts Attorney General Office of Ratepayer Advocacy)
MA Department of Public Utilities Docket No. D.P.U. 16-GREC-01

129. In Re: Petition of Bay State Gas Company d/b/a Columbia Gas of Massachusetts for Approval of its 2015 Gas System Enhancement Plan Reconciliation Filing (2016) - (Appearance: computation of the revenue requirement and rate impact on behalf of the Massachusetts Attorney General Office of Ratepayer Advocacy)
MA Department of Public Utilities Docket No. D.P.U. 16-GREC-05

130. In Re: Petition for Approval of Gas Infrastructure Contract Between Public Service Company of New Hampshire d/b/a Eversource Energy and Algonquin Gas Transmission, LLC (2016) - (Analysis and Advice to Counsel: compliance with statutes and regulations, review of contract, and ratemaking on behalf of the New Hampshire Office of Consumer Advocate)
NH Public Utilities Commission Docket No. DE 16-241

131. In Re: Central Maine Power Company, Annual Compliance Filing and Price Change (2016) - (Analysis and Advice to Counsel; tax normalization regulatory asset on behalf of the Maine Office of the Public Advocate)
ME Public Service Commission Docket No. 2016-00035

132. In Re: Bulletin 2015-10 Generic Proceeding to Establish Parameters for the Next Generation PBR Plans (Appearance: productivity adjustments/performance-based ratemaking on behalf of the Alberta Utilities Consumer Advocate)
Alberta Utilities Commission Proceeding 20414

133. In Re: The Matter of Request by Emera Maine for Approval of a Rate Change (2016) - (Appearance: revenue requirement on behalf of the Maine Office of the Public Advocate)
Maine Public Utilities Commission Docket No. 15-00360)

134. In Re: the Matter of the Joint Application of the Southern Company, AGL Resources Inc., and Pivotal Holdings, Inc. d/b/a Elkton Gas (2015-2016) - (Analysis and advice to counsel: customer service impacts, employee impacts, supplier diversity on behalf of the Maryland Office of People's Counsel)
MD PSC Case No. 9404

135. In Re: The Matter of the Merger of Southern Company and AGL Inc. (2015-2016) - (Appearance: customer service impacts and employee impacts on behalf of the NJ Division of Rate Counsel)
New Jersey BPU Docket No. GM15101196

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136. In Re: The Matter of the United Water New Jersey, Inc., for Approval of an Increase in Rates for Water Service and Other Tariff Changes (2015-2016) - (Appearance: revenue requirements, rate base issues and operating income on behalf of the NJ Division of Rate Counsel)
New Jersey BPU Docket No. WR15101177

137. In Re: Petition of Boston Gas Company and Colonial Gas Company d/b/a National Grid for Approval of Precedent Agreements with Millennium Pipeline Company, LLC (2015) - (Analysis: review of contract and compliance of the Gas Supply Plan on behalf of the Massachusetts Attorney General Office of Ratepayer Advocacy)
MA D.P.U. 15-130

138. In Re: Petition of Boston Gas Company and Colonial Gas Company d/b/a National Grid for Approval of Agreements for LNG or Liquefaction Services with GDF Suez Gas NA, LLC; Northeast Energy Center, LLC; Metro LNG, L.P.; and National Grid LNG (2015) - (Analysis: review of contract and compliance of the Gas Supply Plan on behalf of the Massachusetts Attorney General Office of Ratepayer Advocacy)
MA D.P.U. 15-129

139. In Re: Columbia Gas of Massachusetts CY2014 Targeted Infrastructure Reinvestment Factor (TIRF) Compliance Filing (2015) - (Appearance: computation of the revenue requirement impact on the TIRF on behalf of the Massachusetts Attorney General Office of Ratepayer Advocacy)
MA D.P.U. 15-55

140. In Re: The Matter of the Bay State Gas Company d/b/a Columbia Gas of Massachusetts for Approval of its Targeted Infrastructure Reinvestment Factor (TIRF) for CY 2013 (2014) - (Appearance: computation of the revenue requirement impact on the TIRF)
MA D.P.U. 14-83

141. In Re: The Matter of the Merger of Exelon Corporation and Pepco Holdings, Inc. (Atlantic City Electric Company) (2014-2015) - (Appearance: customer service impacts)
New Jersey BPU Docket No. EM14060581

91. In Re: Public Utilities Commission of Ohio – In the Matter of the Application of Ohio Power Company (American Electric Power Ohio) (AEP Ohio) to Adopt a Final Implementation Plan for the Retail Stability Rider – (Appearance - Accounting Issues) (2014) on behalf of the Ohio Office of Consumer Counsel (OCC)
PUCO Case No. 14-1186-EL-RDR

92. In Re: Public Utilities Commission of Ohio - In the Matter of the Application of Aqua Ohio, Inc. to Increase its Rates and Charges for its Waterworks Service. – Revenue and Rates (2014) - (Appearance: operating income, certain rate base issues and income taxes on behalf of the Ohio Office of Consumer Counsel)
PUCO Case No. 13-2124-WW-AIR

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93. In Re: New York Public Service Commission, as to the Rates, Charges, Rules and Regulations of Consolidated Edison Company of New York, Inc. Revenue Requirement (2013-2014) – (Appearance: revenue requirement, rate base issues and operating income on behalf of the Intervenor, the County of Westchester)
NYPSC Case Nos. 13-E-0030, 13-G-0031 and 13-S-0032, et al

94. In Re: North Dakota Public Service Commission, - Application of Northern States Power Company for Authority to Increase Rates for Electric Service in North Dakota, On-Going Revenue Requirement (2013) - (Appearance: revenue requirement and rate base, operating income, operating and maintenance expenses on behalf of the North Dakota Public Service Commission Staff)
North Dakota Case No. PU-12-813

95. In the Matter of the Petition of New Jersey American Water Company for Authorization to Implement a Distribution System Improvement Charge (DSIC) Order Denying Petition and Instituting Stakeholder Process (2008) - (Case manager on policy decision and revenue requirement impact on behalf of the Staff of the NJ Board of Public Utilities)
BPU Docket No. WO08050358

96. In the Matter of the Joint Petition of the City of Trenton, New Jersey and New Jersey-American Water Company, Inc. for Authorization of the Purchase and Sale of the Assets of the Outside Water Utility System ("OWUS") of the City of Trenton, New Jersey and for Other Relief Order Adopting Initial Decision, (2008) - (Case manager on the revenue requirement impact on behalf of the Staff of the NJ Board of Public Utilities)
BPU Docket No. WM08010063

97. In the Matter of the Petition of United Water New Jersey, United Water Toms River, United Water Lambertville, United Water Mid-Atlantic and Gaz de France for Approval as Need for a Change in Ownership and Control (2007) - (Case manager on customer impact, employee impact and impact on rates on behalf of the Staff of the NJ Board of Public Utilities)
BPU Docket No. WM06110767

98. In the Matter of the Petition of United Water Arlington Hills Sewerage, Inc. for an Increase in Rates for Wastewater Service and Other Tariff Changes (2009) - (Case manager on revenue requirement and overall rate proceeding on behalf of the Staff of the NJ Board of Public Utilities)
BPU Docket No. WR08100929

99. In the Matter of the Petition of United Water New Jersey Inc. for Approval of an Increase in Rates for Water Service and Other Tariff Changes, (2009) - (Case manager on revenue requirement and overall rate proceeding on behalf of the Staff of the NJ Board of Public Utilities)
BPU Docket No. WR08090710

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100. In the Matter of the Petition of United Water Toms River, Inc. for Approval of an Increase in Rates for Water Service and Other Tariff Changes (2008) - (Case manager on the revenue requirement and overall rate proceeding on behalf of the Staff of the NJ Board of Public Utilities)
BPU Docket No. WR08030139

101. In the Matter of the Joint Petitioners of New Jersey-American Water Company, Inc., S.J. Services, Inc., South Jersey Water Company, Inc. and Pennsgrove Water Supply Company, Inc. for Among Other Things Approval of a Change in Control of South Jersey Water Supply Company, Inc. and Pennsgrove Water Supply Company, Inc. (2007) - (Case manager on the overall rate proceeding on behalf of the Staff of the NJ Board of Public Utilities)
BPU Docket No. WM07020076

102. In the Matter of the Petition of Aqua, New Jersey, Inc. for Approval of an Increase in Rates for Water Service and Other Tariff Changes (2008) - (Case manager on revenue requirement and the overall rate proceeding on behalf of the Staff of the NJ Board of Public Utilities)
BPU Docket No. WR0712095

103. I/M/O the Joint Petition of Thames Water, Aqua Holdings GMBH, on Behalf of Itself and Its Parent Holdings Company, RWE Aktiengesellschaft, Thames Water Aqua US Holdings, Inc., American Water works Company Inc., Thames Water Holdings Incorporated, E 'town Corporation, New Jersey-American Water Company, Inc., Elizabethtown Water Company, the Mount Holly Water Company and Applied Wastewater Management, Inc. for Confirmation that the Board of Public Utilities Does Not Have Jurisdiction Over, or, Alternatively, for Approval of a Proposed Transaction Involving, Among Other Things, the Sale by Thames Water Aqua Holdings GMBH of Up to 100% of the Shares of the Common Stock of American Waterworks Company, Inc. in One or More Public Offerings (2007) - (Case manager on revenue requirement impacts, effect on rates and effect on service on behalf of the Staff of the NJ Board of Public Utilities)
BPU Docket No. WM06050388

104. In the Matter of the Petition of Elizabethtown Water Company for Approval of an Increase in Rates for Water Service (2007) - (Case manager on revenue requirement and overall rate proceeding on behalf of the Staff of the NJ Board of Public Utilities)
BPU Docket No. WR03070510

105. In the Matter of the Petition of New Jersey American Water Company, Inc. for Approval of Increased Tariff Rates and Charges for Water and Sewer Service; Increased Depreciation Rates and Other Tariff Revisions (2008) - (Case manager on revenue requirement and overall rate proceeding on behalf of the Staff of the NJ Board of Public Utilities)
BPU Docket No. WR08010020

106. In the Matter of Middlesex Water Company for Approval of an Increase in its Rates for Water Service and Other Tariff Changes (2007) - (Case manager on overall revenue

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requirement and overall rate proceeding on behalf of the Staff of the NJ Board of Public Utilities)
BPU Docket No. WR07040275

107. In the Matter of the Joint Petition of United Water New Jersey, Inc., United Water Arlington Hills, Inc., United Water Hampton, Inc., United Water Vernon Water Hills, Inc., and United Water Lambertville, Inc. for an Increase in Rates and Charges for Water Service and Other Tariff Changes and for Approval to Merge the Operations of the Joint Petitioners into and with United Water New Jersey, Inc. (2007) - (Case manager on revenue requirement and overall rate proceeding on behalf of the Staff of the NJ Board of Public Utilities)
BPU Docket No. WR07020135

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ARKANSAS PUBLIC SERVICE COMMISSION
APSC 23-079-U
2023 SUA RATE CASE

REQUEST NO.: AG-002-015

COMPANY NAME: **SUMMIT UTILITIES ARKANSAS**

DATE RECEIVED: **3/4/2024**

DATE DUE: **3/19/2024**

EXTENSION DATE:

INFORMATION REQUESTED:
In addition to the Company's incentive compensation proposal, are there any other variable or incentive type pay that the Company has instituted in addition to the proposed incentive compensation balance proposed in this instant filing? Please provide a detail breakdown and description of these types of pay. What is required of employees to achieve or receive this type of pay?

REQUESTED BY: **ARKANSAS ATTORNEY GENERAL**

RESPONSE:
The company does have other incentive compensation programs but is seeking recovery only for STI, Retention Bonuses and Sign-On Bonuses.

The Company has the following incentive program in addition to the proposed inventive compensation balance proposed in the instant filing:

1) LTI - The LTI is a program aimed at retaining senior leadership. LTI grants are provided to recipients and the grants begin to vest after three years. The purpose of the vesting schedule is meant to encourage retention. The vesting schedule is as follows: In the third year, one-third of the original grant is paid, in year four the second third of the grant is paid, and in year five, the final third of the grant is paid of the original grant. Each year the recipients receive a new grant so beginning in year five and beyond, the recipient is receiving one-third from three different grants. Grant amounts are determined by level in the organization.

SUA is not seeking recovery of the expenses related to LTI which is shown in the response to AG-002-002, part (c).

SPONSOR:
Sam Springer

RESPONSIVE DOCUMENTS:
None

The foregoing response to the above information request is accurate and complete, and contains no material misrepresentations or omissions based upon present facts known to the undersigned. The undersigned agrees to

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immediately inform the Requestor if any matters are discovered which would materially affect the accuracy or completeness of the information provided in response to the above information request.

/s/ Brooke South Parsons
Signature of Company Representative

DATE PROVIDED: MARCH 19, 2024

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Summit Utilties Arkansas, Inc.
Test Year Ending 12/31/2023

AR Public Service Commission
Docket No. 23-079-U

INCENTIVE COMPENSATION SUMMARY
Short Term Incentive (STI)

	Weight %	Company Proposed	Adjustments	AGO Recommended	References
2023 Scorecard					
Goals and Performance Measures					
SUI Safety	15.000%	$ 655,212	$ -	$ 655,212	
Corporate Excellence	50.000%	$ 2,184,042	$ (1,310,558)	$ 873,484	
PEAKS	10.000%	$ 436,808	$ -	$ 436,808	AG-002-013
SUI Financial	25.000%	$ 1,091,356	$ (1,091,356)	$ -	
Total	**100.000%**	**$ 4,368,083**	**$ (2,401,913)**	**$ 1,965,505**	AG-002-006
2024 Scorecard					
SUI Safety	15.000%	$ 681,421	$ -	$ 681,421	
Corporate Excellence	50.000%	$ 2,271,404	$ (1,362,842)	$ 908,562	
PEAKS	10.000%	$ 454,281	$ -	$ 454,281	
SUI Financial	25.000%	$ 1,135,702	$ (1,135,702)	$ -	
Total	**100.000%**	**$ 4,542,807**	**$ (2,498,543)**	**$ 2,044,264**	
Difference		$ 174,724	$ (96,630)	$ 78,759	

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Summit Utilities Arkansas, Inc.
Test Year Ending 12/31/2024

AR Public Service Commission
Docket No. 23-079-U

RETENTION BONUSES
SIGN ON BONUSES

	(1) Retention Costs	Sign On Bonuses	Adjustments	AGO Recommended
Capitalized Costs	$ 84,884	$ 51,951	$ (136,835)	$ -
O&M Costs	$ 86,762	$ 53,100	$ (139,862)	$ -
Total	**$ 171,646**	**$ 105,051**		
Total		**$ 276,697**	**$ (276,697)**	$ -

(1) AGO-002-005

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ARKANSAS PUBLIC SERVICE COMMISSION
APSC 23-079-U
2023 SUA RATE CASE

REQUEST NO.: AG-002-020

COMPANY NAME: **SUMMIT UTILITIES ARKANSAS**

DATE RECEIVED: **3/4/2024**

DATE DUE: **3/19/2024**

EXTENSION DATE:

INFORMATION REQUESTED:
Refer to Mr. Springer's testimony at page 9. What is the amount of STI that the Company is requesting recovery in this instant filing?

REQUESTED BY: **ARKANSAS ATTORNEY GENERAL**

RESPONSE:
The Company is requesting an estimated amount of $4,542,807 in STI costs in the pro forma year in this filing. For test year STI please refer to AG 002-002.

SPONSOR:
Phillip Gillam, Jen Fallon

RESPONSIVE DOCUMENTS:
None

The foregoing response to the above information request is accurate and complete, and contains no material misrepresentations or omissions based upon present facts known to the undersigned. The undersigned agrees to immediately inform the Requestor if any matters are discovered which would materially affect the accuracy or completeness of the information provided in response to the above information request.

/s/ Brooke South Parsons
Signature of Company Representative

DATE PROVIDED: **MARCH 19, 2024**

ARKANSAS FILED Time: 7/10/2024 11:02:38 AM: Recvd 7/10/2024 11:00:36 AM: Docket 23-079-U-Doc. 105

ARKANSAS PUBLIC SERVICE COMMISSION
APSC 23-079-U
2023 SUA RATE CASE

REQUEST NO.: AG-002-002

COMPANY NAME: **SUMMIT UTILITIES ARKANSAS**

DATE RECEIVED: **3/4/2024**

DATE DUE: **3/19/2024**

EXTENSION DATE:

INFORMATION REQUESTED:
Please provide a schedule of total payroll costs breaking down the components by the following:

a. Base Salary
b. Short-Term Incentive
c. Long-Term Incentive
d. Restricted Stock Awards
e. Other Incentive Type Pay
f. Allocated from Corporate (Summit Utilities, Inc.)

REQUESTED BY: **ARKANSAS ATTORNEY GENERAL**

RESPONSE:
Test Year Payroll Cost Breakdown:

a. Base Salary - $45,227,323.19
b. Short-Term Incentive for SUA employees - $2,467,783.30
c. SUA is not seeking recovery of Long-Term Incentive in the current proceeding. Additionally, Long-Term Incentive is not allocated to SUA. However, SUI's Long-Term Incentive total is - $13,236,923.81
d. SUA does not have Restricted Stock Awards.
e. SUA does not have direct charged other incentive type pay in the test year.
f. Allocated Salary, STI and other Incentive Type Pay from Corporate - $14,420,886.29, of which $1,900,300.54 is STI.

SPONSOR:
Jen Fallon, Tiffany Brazle, Margaret Sanchez

RESPONSIVE DOCUMENTS:
None

The foregoing response to the above information request is accurate and complete, and contains no material misrepresentations or omissions based upon present facts known to the undersigned. The undersigned agrees to immediately inform the Requestor if any matters are discovered which would materially affect the accuracy or

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completeness of the information provided in response to the above information request.

/s/ Brooke South Parsons
Signature of Company Representative

DATE PROVIDED: MARCH 19, 2024

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ARKANSAS PUBLIC SERVICE COMMISSION
APSC 23-079-U
2023 SUA RATE CASE

REQUEST NO.: AG-002-006

COMPANY NAME: SUMMIT UTILITIES ARKANSAS

DATE RECEIVED: 3/4/2024

DATE DUE: 3/19/2024

EXTENSION DATE:

INFORMATION REQUESTED:
Refer to the response to APSC-009 #5 and #6. Please explain what "Incentive by FERC" and "Incentive by Target" represent? Please show and provide a side-by side comparison of costs under each Incentive.

REQUESTED BY: ARKANSAS ATTORNEY GENERAL

RESPONSE:
The amounts on the Incentive by FERC and Incentive by Target should be the same. The Incentive by Target is using the Incentive by FERC amounts to calculate what portion of each target/goal on the corporate scorecard the SUA incentives are made up of. There was a miscalculation due to the incorrect corporate scorecard being used. The original scorecard totaled 105%, but it should have totaled 100%. The Peaks Renewables target was 10%, not 15%. Please see the attached "Updated 2023 Corporate Scorecard" and "Updated Incentive by Target."

SPONSOR:
Jen Fallon, Sam Springer

RESPONSIVE DOCUMENTS:
AG-002-006 Updated 2023 Corporate Scorecard.JPG
AG-002-006 Updated Incentives by Targets.xlsx

The foregoing response to the above information request is accurate and complete, and contains no material misrepresentations or omissions based upon present facts known to the undersigned. The undersigned agrees to immediately inform the Requestor if any matters are discovered which would materially affect the accuracy or completeness of the information provided in response to the above information request.

/s/ Brooke South Parsons
Signature of Company Representative

DATE PROVIDED: MARCH 19, 2024

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SUASTI as % of Corp Scorecard

2023		
Goal	Goal %	Amount
SUI Safety	15%	655,112.75
Corporate Excellence	50%	2,183,709.15
Peaks Renewables	10%	436,741.83
SUI Financial	25%	1,091,854.58
	Total	4,367,418.30

2022		
Goal	Goal %	Amount
SUI Safety	5%	187,376.96
Corporate Excellence	5%	187,376.96
SUI Growth & Value Creation	15%	562,130.88
SUI Financial	25%	936,884.80
SUA & SUO Integration	50%	1,873,769.61
	Total	3,747,539.22

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Note: STI amounts provided through November 2023. December 2023 will be provided once finalized.

2023 SUA Incentives by FERC

	SUA-Direct	Corp-Alloc	
FERC	STI	STI	Total
10700	809,451.57	529,908.63	1,339,360.20
18400	(53,869.34)	-	(53,869.34)
25400	1,305.05	-	1,305.05
87400	461,660.11	-	461,660.11
87500	661.70	-	661.70
87600	28,051.90	-	28,051.90
87800	241,944.94	-	241,944.94
87900	101,836.49	-	101,836.49
88000	4,688.55	-	4,688.55
88100	279.48	-	279.48
88500	33.75	-	33.75
88600	161.08	-	161.08
88700	240,623.99	-	240,623.99
88900	39,092.40	-	39,092.40
89000	18,777.76	-	18,777.76
89100	47.11	-	47.11
89200	94,640.52	-	94,640.52
89300	30,282.90	-	30,282.90
89400	19,476.35	-	19,476.35
90200	18,153.97	-	18,153.97
90300	133,573.50	103,564.58	237,138.08
92000	310,839.82	1,144,005.20	1,454,845.02
92100	40,288.08	-	40,288.08
92300	1.37	-	1.37
92600	21.53	-	21.53
92800	-	47,915.31	47,915.31
	2,542,024.58	1,825,393.72	4,367,418.30

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Note: STI amounts provided through December 2022.

2022 SUA Incentives by FERC

FERC	SUA-Direct STI	Corp-Alloc STI	Total
10700	170,703.58	772,811.78	943,515.36
18400	(71,917.61)		(71,917.61)
25400	2,388.07		2,388.07
87400	(383.63)		(383.63)
87600	44,891.17		44,891.17
87800	659.56		659.56
87900	258,668.34		258,668.34
88000	20,496.57		20,496.57
88100	140,628.45		140,628.45
88500	108,269.69		108,269.69
88600	34,058.76		34,058.76
88700	-		-
88900	42,647.42		42,647.42
89000	52.39		52.39
89200	179,063.78		179,063.78
89300	15,285.27		15,285.27
89400	11,008.83		11,008.83
90200	34,284.44		34,284.44
90300	25,907.40		25,907.40
92000	23,364.45	622,045.22	645,409.66
92100	18,495.40		18,495.40
92300	17,053.77		17,053.77
92600	104,493.72		104,493.72
41700	(263.55)		(263.55)
87000	3,301.32		3,301.32
87100	200,462.17		200,462.17
90100	126,532.94		126,532.94
90800	842,103.70		842,103.70
91600	6.00		6.00
92500	(2.37)		(2.37)
93200	422.22		422.22
	2,352,682.22	1,394,857.00	3,747,539.22

STI as % of Corp Scorecard

Goal	Goal %	Amount
Safety	5%	187,376.96
Corporate Excellence	5%	187,376.96
Growth & Value	15%	562,130.88
Financial	25%	936,884.80
Integration	50%	1,873,769.61
	Total	3,747,539.22

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2023 Corporate Scorecard

WEIGHT	CORPORATE GOALS	MEAS TARGET
15%	**SAFETY** • Personal Injuries • Vehicle Accidents • Pipeline Replacement – AR/OK • Pipeline Damages	TRIR = 1.57 VIR = 2.46 120 miles 6.0/1,000 locates
50%	**CORPORATE EXCELLENCE** • Environmental, Social, Governance • Customer Facing Order Completion • Emergency Response Time • Audited Financial Statements Issued • Monthly Financial Reports Issued (Days)	ESG Scorecard 97.5% 30 mins April 30 16 / 14 / 12 / 16
10%	**PEAKS RENEWABLES** • RNG Digester Operation Date • Peaks Development Pipeline (Final Stage)	April 30 2
25%	**FINANCIAL** • EBITDA • Dividend Yield	$163.5M 5.2% ($132M)

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ARKANSAS PUBLIC SERVICE COMMISSION
APSC 23-079-U
2023 SUA RATE CASE

REQUEST NO.: AG-002-014

COMPANY NAME: **SUMMIT UTILITIES ARKANSAS**

DATE RECEIVED: **3/4/2024**

DATE DUE: **3/19/2024**

EXTENSION DATE:

INFORMATION REQUESTED:
Refer to Mr. Springer's testimony at page 6. In the past five years, has the Company's incentive compensation or compensation philosophy resulted in the attraction, retention, retaining and encouraging of personnel and professional development at SUI? Please explain.

REQUESTED BY: **ARKANSAS ATTORNEY GENERAL**

RESPONSE:
The Company's total employment package inclusive of the incentive compensation program(s) contributes to its ability to attract talent that advances the interests of customers, the Company and other stakeholders in a competitive employment market. In recent years, SUI's attrition rate has remained below the industry and broader market at roughly 10%. The company also encourages personal and professional development at all levels and commits resources to these efforts, including courses within the Company's learning management system which contributes to learning and development to the benefit of customers, the Company and stakeholders.

SPONSOR:
Sam Springer

RESPONSIVE DOCUMENTS:
None

The foregoing response to the above information request is accurate and complete, and contains no material misrepresentations or omissions based upon present facts known to the undersigned. The undersigned agrees to immediately inform the Requestor if any matters are discovered which would materially affect the accuracy or completeness of the information provided in response to the above information request.

/s/ Brooke South Parsons
Signature of Company Representative

DATE PROVIDED: **MARCH 19, 2024**

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ARKANSAS PUBLIC SERVICE COMMISSION
APSC 23-079-U
2023 SUA RATE CASE

REQUEST NO.: AG-002-017

COMPANY NAME: SUMMIT UTILITIES ARKANSAS

DATE RECEIVED: 3/4/2024

DATE DUE: 3/19/2024

EXTENSION DATE:

INFORMATION REQUESTED:
Refer to Mr. Springer's testimony at page 8. Has the Company realized increased retention levels for executive level employees related to its STI? Please provide the results for the past five years.

REQUESTED BY: ARKANSAS ATTORNEY GENERAL

RESPONSE:
SUA began operations in January 2022. The Company has not experienced any voluntary turnover at the executive officer level. The Company attributes this to the STI program and a number of other factors.

SPONSOR:
Sam Springer

RESPONSIVE DOCUMENTS:
None

The foregoing response to the above information request is accurate and complete, and contains no material misrepresentations or omissions based upon present facts known to the undersigned. The undersigned agrees to immediately inform the Requestor if any matters are discovered which would materially affect the accuracy or completeness of the information provided in response to the above information request.

/s/ Brooke South Parsons
Signature of Company Representative

DATE PROVIDED: MARCH 19, 2024

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ARKANSAS PUBLIC SERVICE COMMISSION
APSC 23-079-U
2023 SUA RATE CASE

REQUEST NO.: AG-002-013

COMPANY NAME: **SUMMIT UTILITIES ARKANSAS**

DATE RECEIVED: **3/4/2024**

DATE DUE: **3/19/2024**

EXTENSION DATE:

INFORMATION REQUESTED:
Refer to Company witness Mr. Springer's testimony at page 4. Please provide a breakdown of costs of the Merit Increases included in 2023 and in the test year 2024 by the following programs (PEAKS), and please explain briefly what these programs represent and which employees are eligible to receive these merit increases.

a. Pioneering
b. Excellence
c. Agility
d. Kindness
e. Safety

REQUESTED BY: **ARKANSAS ATTORNEY GENERAL**

RESPONSE:
The Company's performance management program aligned to merit runs from July 1 to June 30 every year. All employees are eligible for a merit increase unless they are subject to a collective bargaining agreement. This program assesses employee utilization of the Company's PEAKS values in the accomplishment of their work. The definition of each PEAKS value is provided below.

The test year 2023 merit budget was set at an average of 4.2% which resulted in a total merit budget of $3.02MM. The 2024 merit budget has not been finalized, but the filing includes a 4% increase to O&M and Corporate payroll for anticipated merit increases.

PEAKS Value Definitions:

PIONEERING: Passionately seek and embrace innovative ideas, dedicated to development and continuous improvement with a focus on the future.

EXCELLENCE: Reliably deliver superior results through teamwork, integrity, accountability and taking ownership of their actions, while welcoming diversity of thought and keeping a customer-centric focus.

AGILITY: Always embrace a culture of change, pursuing continual growth through collaboration, adapting to a changing environment, and valuing diversity.

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KINDNESS: Honor our customers, the communities we serve, and each other through a dedication to inclusion and by making respect, safety, excellence and satisfaction a priority.

SAFETY: Make the safety of our colleagues, customers and communities a priority while performing our duties, demonstrating a commitment to prevention and taking responsibility for one another.

SPONSOR:
Sam Springer, Phillip Gillam

RESPONSIVE DOCUMENTS:
None

The foregoing response to the above information request is accurate and complete, and contains no material misrepresentations or omissions based upon present facts known to the undersigned. The undersigned agrees to immediately inform the Requestor if any matters are discovered which would materially affect the accuracy or completeness of the information provided in response to the above information request.

/s/ Brooke South Parsons
Signature of Company Representative

DATE PROVIDED: MARCH 19, 2024

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ARKANSAS PUBLIC SERVICE COMMISSION
APSC 23-079-U
2023 SUA RATE CASE

REQUEST NO.: AG-002-005

COMPANY NAME: SUMMIT UTILITIES ARKANSAS

DATE RECEIVED: 3/4/2024

DATE DUE: 3/19/2024

EXTENSION DATE:

INFORMATION REQUESTED:
Please provide a schedule breaking down the costs for each of the Company's Incentive Compensation the Company has included in this instant filing, both before capitalization and after capitalization (expensed). Please provide the associated metric or performance goal resulting in the balance. Please also provide the number of employees eligible under each plan. Please also include the benefits to ratepayers in implementing these payments and recovering these payments from ratepayers:

a. STI-Union and Non-Union / Officer and Non-Officer
b. LTI- Union and Non-Union / Officer and Non-Officer
c. Restricted Stock Awards – Union and Non-Union / Officer and Non-Officer
d. Bonuses – Union and Non-Union / Officer and Non-Officer
e. Other Incentive Type Pay
f. Allocated from Corporate (Summit Utilities, Inc.)

REQUESTED BY: ARKANSAS ATTORNEY GENERAL

RESPONSE:
SUA does not have any union employees.

Please see Direct Testimony of Sam Springer pages 2, 6-8 and DRs AG 002-014, AG 002-016, and AG 002-017 for the benefits to ratepayers in implementing these payments.

a. Please see the attachment, "Incentive Capitalization" for all STI Non-Union/Non-Officer costs booked to capital and expense through November 2023. Summit Utilities Arkansas does not have any STI-Union or STI-Officer costs. December 2023 costs will be provided once available. 475 SUA and 390 SUI employees were eligible for STI in 2023.

b. LTI is recorded at the Corporate level and is not allocated to its subsidiaries. Summit Utilities Arkansas does not have any costs related to LTI nor is it seeking recovery on LTI in this proceeding. 46 employees were eligible for LTI in 2023.

c. Summit Utilities Arkansas does not pay out Restricted Stock Awards.

d. Other bonuses Summit Utilities, Inc. currently pays to employees includes sign-on bonuses and retention bonuses. Summit Utilities Arkansas did not pay out any of these bonuses to SUA

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employees in the test year. 15 SUI employees received a sign on bonus in 2023 and 24 SUI employees received a retention bonus in 2023.

e. Summit Utilities Arkansas does not have any other incentive type pay in the test year.

f. Summit Utilities, Inc. allocates a portion of STI, sign on bonuses and retention bonuses to its subsidiaries. Please see attachment, "Incentive Capitalization" for total Corporate Allocated incentives through December 2023 test year.

SPONSOR:
Sam Springer, Andy Hagler, Jen Fallon

RESPONSIVE DOCUMENTS:
AG-002-005 Incentive Capitalization.xlsx

The foregoing response to the above information request is accurate and complete, and contains no material misrepresentations or omissions based upon present facts known to the undersigned. The undersigned agrees to immediately inform the Requestor if any matters are discovered which would materially affect the accuracy or completeness of the information provided in response to the above information request.

/s/ Brooke South Parsons
Signature of Company Representative

DATE PROVIDED: MARCH 19, 2024

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Summit Utilities Arkansas, Inc

AG-002-005

Direct & Indirect Incentive Compensation Capitalization

**Note: STI Direct Incentive amounts provided through November 2023. December 2023 will be provided once finalized.*

2023 SUA STI Capitalization as of 11/30/2023

	SUA-Direct	
	STI	
Capital	809,451.57	
Expense	1,785,137.31	
Other Deferred	(52,564.29)	
	2,542,024.58	*

2023 Incentives Allocated from Corporate as of 12/31/23

	Corp-Alloc			
	STI	Sign-On Bonus	Retention Bonus	Total
Capital	585,026.42	51,951.17	84,883.85	721,861.44
Expense	1,315,274.12	53,100.47	86,761.72	1,455,136.30
	1,900,300.54	105,051.64	171,645.57	2,176,997.75

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ARKANSAS PUBLIC SERVICE COMMISSION
APSC 23-079-U
2023 SUA RATE CASE

REQUEST NO.: AG-003-005

COMPANY NAME: **SUMMIT UTILITIES ARKANSAS**

DATE RECEIVED: **4/3/2024**

DATE DUE: **4/18/2024**

EXTENSION DATE:

INFORMATION REQUESTED:
Refer to the response to AG-002-015. Please provide the projected dollar amounts included in the filing related to Retention Bonuses and Sign-On Bonuses. Please provide a detailed breakdown and description for each.

REQUESTED BY: **ARKANSAS ATTORNEY GENERAL**

RESPONSE:
The Company has projected that the 2024 retention and sign-on bonuses will be the same or similar to the 2023 actual amounts.

Sign-On Bonus: A sign-on bonus is a sum of money paid to a new employee as an incentive to join the Company. The Company utilizes them as a way of making the Company's compensation package more attractive to the employee (e.g., if the annual salary is lower than they desire). It lowers the risk to the Company as it is a one-time payment; for example, if the employee does not meet expectations, the Company has not committed to a higher salary. To encourage employees to stay and perform after receiving this bonus, the Company utilizes repayment agreements in the event the employee quits or is terminated for cause prior to completing a specified period.

Retention Bonus: A retention bonus is a sum of money paid to an existing employee as an incentive to remain with the Company. This form of bonus is utilized when an organization is going through a disruptive period of organizational change (i.e. mergers/acquisitions, restructuring, etc.) or when a key employee with specialized skills is at risk of being lured away by other employers. In the event the employee quits or is terminated for cause prior to completing the required retention period, the Company utilizes repayment agreements for this form of bonus as well.

SPONSOR:
Sam Springer, Phillip Gillam

RESPONSIVE DOCUMENTS:
None

The foregoing response to the above information request is accurate and complete, and contains no material

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misrepresentations or omissions based upon present facts known to the undersigned. The undersigned agrees to immediately inform the Requestor if any matters are discovered which would materially affect the accuracy or completeness of the information provided in response to the above information request.

/s/ Brooke South Parsons
Signature of Company Representative

DATE PROVIDED: APRIL 18, 2024

CERTIFICATE OF SERVICE

I, Clay Layson, hereby certify that on July 10, 2024, I filed a copy of the foregoing utilizing the Commission's Electronic Filing System, which caused a copy to be served upon all parties of record via electronic mail.

/s/ Clay Layson
Clay Layson

APSC FILED Time: 7/10/2024 11:35:35 AM: Recvd 7/10/2024 11:33:32 AM: Docket 23-079-u-Doc. 113

BEFORE THE
ARKANSAS PUBLIC SERVICE COMMISSION

IN THE MATTER OF THE APPLICATION OF SUMMIT UTILITIES ARKANSAS, INC. FOR A GENERAL CHANGE OR MODIFICATION IN ITS RATES, CHARGES AND TARIFFS	))))	**DOCKET NO. 23-079-U**

DIRECT TESTIMONY
OF
RICHARD W. PORTER

ON BEHALF OF

THE OFFICE OF ARKANSAS ATTORNEY GENERAL
TIM GRIFFIN

July 10, 2024

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Richard W Porter CV	Direct Exhibit RWP-01
Response to Data Request No. AGC-002-006	Direct Exhibit RWP-02

I. INTRODUCTION AND QUALIFICATIONS

Q. WHAT IS YOUR NAME, EMPLOYER, AND BUSINESS ADDRESS?

A. My name is Richard W. Porter. I am employed by Rod Walker & Associates Consultancy, Inc. ("RWA") as an Associate. RWA is located at P.O. Box 956399, Marietta, GA 30066.

Q. WHAT DOES YOUR POSITION WITH RWA ENTAIL?

A. RWA is a technical advisory and management consulting firm. I periodically provide regulatory advisory services to the firm's natural gas utility clients. I am responsible for the development, direction, supervision, and preparation of advisory projects for our clients.

Q. WOULD YOU PLEASE OUTLINE YOUR EDUCATIONAL BACKGROUND?

A. I graduated from Louisiana State University in Baton Rouge, Louisiana in 1976 with a Bachelor of Science Degree in Economics.

Q. WOULD YOU PLEASE BRIEFLY DESCRIBE YOUR WORK EXPERIENCE?

A. From 1977 to 1979, I was employed at Allied Bank of Texas as an Assistant to the Portfolio Manager of the Trust Department where, among other things, I participated in various investment decisions. From 1979 to 1986, I worked at Panhandle Eastern Pipeline Company, an interstate natural gas pipeline, in the Regulatory Affairs Department in various positions, including Assistant Manager of Rates. From 1986 to 1992, I was employed by Arkla Energy Resources as Manager of Rates. From 1992 to 2001, I was employed by ANR Pipe Line Company (a subsidiary of Coastal Corporation). My last position at ANR was as Assistant Vice President of Rates. From 2001 to 2004, I remained with ANR Pipe Line Company (as a subsidiary of El Paso

Corporation). From 2004 to 2009, I was employed by Enterprise Products Partners as Director of Natural Gas Rates. From 2010 to 2011, I formed The Pythia Group, LLC to provide regulatory consulting solutions. From 2011 to 2016, I was employed by Black & Veatch Management Consulting, LLC as a Director in the oil, gas, and mining business sector. From 2016 to 2017, I was employed by FTI Consulting, Inc. as a Senior Managing Director of the Houston Energy Group where I directed a team of fifteen offering regulatory consulting and litigation support. In 2018, I reconstituted The Pythia Group, LLC to continue providing regulatory and strategic advisory services. Additional details about my experience are included in my curriculum vitae in Direct Exhibit RWP-01.

Q. WOULD YOU BRIEFLY DESCRIBE YOUR EXPERIENCE WITH NATURAL GAS UTILITIES?

A. I have:

- substantial experience in natural gas pipeline and distribution company matters;
- personally assembled and negotiated rate proposals and filings before regulatory commissions;
- directed teams in the assembly of the terms and conditions of operations for greenfield pipeline projects and filed for and received regulatory permits for the projects;
- drafted policy documents, interventions, comments on rulemaking proceedings, tariff revisions, greenfield pipeline tariffs, and other documents;
- been part of the review process of both onshore and offshore transportation service negotiations;

- prepared strategic plans for distribution companies, including new services and tariff structures;
- testified on behalf of distribution companies on the prudency of gas purchases;
- testified as an expert witness before regulatory agencies on various matters including cost of service and its various components; cost classification, cost allocation, and rate design; surcharges and trackers; management fees; and tariffs and operating agreements; and
- testified on behalf of gas pipelines in civil proceedings as an expert witness on rate design and pipeline operating agreements.

Q. ON WHOSE BEHALF ARE YOU TESTIFYING IN THIS MATTER?

A. I am testifying on behalf of the Office of Arkansas Attorney General Tim Griffin ("AG").

Q. HAVE YOU PREVIOUSLY TESTIFIED AS AN EXPERT BEFORE THE ARKANSAS PUBLIC SERVICE COMMISSION?

A. Yes. I provided testimony on behalf of the AG in Arkansas Public Service Commission ("APSC" or "Commission") Docket No. 23-074-U.[1] I have also testified in APSC Docket Nos. 87-071-U and 91-093-U.

II. PURPOSE OF TESTIMONY

Q. WHAT IS THE PURPOSE OF YOUR TESTIMONY?

A. My purpose is to provide an expert opinion to the Commission on the Base Rate Case ("BRC") filing made by Summit Utilities Arkansas, Inc. ("SUA" or the "Company") on

[1] In the Matter of the Application of Black Hills Energy Arkansas, Inc. for Approval of a General Change in Rates and Tariffs.

January 25, 2024. SUA's BRC filing consists of an application and supporting testimonies from eleven witnesses. Specifically, my testimony will address:

1) SUA's proposed expansion of its System Safety Enhancement Rider ("SSER") to include additional costs, including reliability costs.

2) SUA's cost allocation methodology with its reliance on factors with a bias toward allocation of costs focused on customer and peak concerns.

III. SUMMARY OF CONCLUSIONS AND RECOMMENDATIONS

Q. WHAT IS SUA REQUESTING WITHIN ITS FILING?

A. Among other things, the Company proposes to shift interim financial risk to its ratepayers through an expanded SSER, including reliability costs as a component. SUA also requests a base rate increase of $104.7 million from its ratepayers. This increase will primarily impact the residential class which will pay for approximately $67.1 million or about 64.19% of the increase. As a result of this rate increase, residential customers will collectively pay about $195.9 million or 70.02% of the total SUA revenue requirement. SUA produces this somewhat prejudicial result though the use of allocation factors which tilt costs to the residential class.

Q. WHAT ARE YOUR OVERALL CONCLUSIONS REGARDING SUA'S APPLICATION?

A. The SUA proposals are designed to reduce its financial risk by a) minimizing or eliminating Regulatory Lag associated with, among other things, unspecified reliability capital spending programs which SUA should perform in compliance with its obligation to provide natural gas in its service territory and b) cost shifting to the residential class

as a consequence of a cost allocation methodology biased to customer and peak concerns and which is generally prejudicial to relatively low load factor customers such as the typical residential customer.

Q. WHAT ARE YOUR RECOMMENDATIONS?

A. My recommendations are as follows:

1) The proposal to add reliability and other costs to the SSER is a request for a new rider. The Commission should reject this request as unsupported and inconsistent with Commission policy. However, I believe that should SUA choose to eliminate the proposed collection of reliability costs from the new SSER, then the new SSER proposal is less problematic.
2) In recognition of the dual purpose of the utility, SUA should modify its cost allocators to reflect that utilities are built to serve a combination of peak-period and annual customer requirements.

IV. THE REGULATORY ENVIRONMENT

Q. WHAT IS THE REGULATORY STRUCTURE IN WHICH SUA OPERATES?

A. Utilities are granted the right to provide services to residents and businesses of the state in that utility's service area. This grant carries an obligation to continually maintain and safely operate the utility system while providing reliable service. In return for the consistency of service provided under Commission oversight, the utility is granted the opportunity to earn a fair return. This *quid pro quo*, i.e., the provision of safe and reliable service for the opportunity to earn a fair return, is the cornerstone of the regulatory process and is often referred to as the Regulatory Compact. Equally important is the

utility's obligation to provide safe and reliable service to residents and businesses within its service area, which is also a key aspect of the Regulatory Compact.

Q. IN YOUR OPINION, HOW DOES THE COMMISSION VIEW ITS OBLIGATIONS UNDER THE REGULATORY COMPACT?

A. On its website, the Commission states its commitment to the Regulatory Compact. For example, in the Commission History section of the Homepage, the Commission succinctly states the essentials of the Compact.

> … The Commission's primary responsibilities involve ensuring that service is safe and adequate and that rates are just and reasonable. **Regulation of public utilities requires a balancing of interests – the APSC must allow the utility an opportunity to earn a fair return on investment, but must likewise see that the public does not pay more than necessary to provide that fair return.**[2]

Thus, in my opinion, the Commission believes that it is required by the legislature[3] to balance the interests of the parties. Since the Commission is required to strike a balance, this means that the process may not be formulaic. While standard methodologies and practices may guide results, the Commission must sometimes make policy decisions regarding how to achieve the appropriate outcome.

Q. HOW DOES REGULATORY LAG IMPACT THE REGULATORY COMPACT?

A. Regulation is an imperfect model, theoretically designed to result in utility earnings and customer service rates that are comparable to those achievable in a naturally competitive market. One imperfection that utilities and regulators strive to balance is the time lag between a utility's incurrence and recovery of cost. Known as "Regulatory Lag," these

[2] Emphasis added. *See* https://apsc.arkansas.gov/commission-info/commission-history/.
[3] *See* Ark. Code. Ann. § 23-2-304(a) (granting the Commission the power to, among other things, "[f]ind and fix just, reasonable, and sufficient rates…")

time lags may rise to a level that requires adjustment within the regulatory process. The ability of a utility to efficiently manage operations and costs between rate cases enhances the utility's earnings and promotes customer rate stability.

Utilities historically were responsible for the impact of internally controlled costs such as operating expenses, corporate overheads, and routine capital maintenance to deliver natural gas safely and reliably within a service area. The utilities are responsible for those costs because they are normally within their control. Conversely, the utility has limited ability to control costs which are imposed upon it between rate cases, such as those required to implement safety and integrity management programs mandated by legislative or regulatory action. When external forces impinge on the effectiveness of the Regulatory Compact, this may require regulatory adjustments to restore the balance. These regulatory adjustments require that the Commission use its judgement and establish policies to ensure the appropriate balance in the execution of its authority. This is one reason why in some cases the Commission has allowed externally driven costs from large capital spending programs resulting from legislative or regulatory action to be recovered outside of base rates.

Q. DO ARKANSAS GAS UTILITES EXPERIENCE REGULATORY LAG?

A. All utilities suffer to varying degrees from the impact of Regulatory Lag. The lag time can span the period between the last approved rates and the effective date of the next approved schedule of rates. It can also cover the period from the point the utility files for an increase to the date the Commission approves a resulting rates adjustment. In either case, there is a lag between the date the costs were incurred and the date the costs are eligible to be recovered. Indeed, Company Witness Adams notes that, "This case is about

extinguishing regulatory lag…."[4] Witness Adams also notes that, "…approximately 82% of the requested increase in base rates is the result of eliminating the regulatory lag…."[5] However, state commissions, including this Commission, have eliminated significant portions of Regulatory Lag and, accordingly, financial risk.

Q. HOW HAS THE COMMISSION ELIMINATED SIGNIFICANT PORTIONS OF REGULATORY LAG?

A. Regulatory Lag can result from costs expended by utilities a) on their own initiative or as a fundamental requirement of their utility obligations or b) due to compliance obligations imposed by legislative or regulatory action. It is the passage of federal legislation that created new safety and integrity obligations for utilities to manage expansive investments in a compressed period that exacerbated the issue of Regulatory Lag for natural gas utilities.[6]

The requirement to fund safety and integrity projects requires significant accelerated capital spending programs by utilities. This spending would normally be temporarily stranded from immediate recovery through rate adjustments due to Regulatory Lag. However, the Commission has recognized that these mandates created obligations that were, among other things, both significant and outside the control of the utility and responded to restore balance to the Regulatory Compact.

Q. IS REDUCING OR ELIMINATING REGULATORY LAG A REGULATORY PRIVILEGE?

[4] *See* Direct Testimony of Kurt W. Adams, p. 3, lines 5-6 [Doc. No. 19].
[5] *Id.,* p. 3, lines 14-16.
[6] *See, e.g.,* the Integrity Management Program for Gas Distribution Pipelines Rule, commonly referred to as the "DIMP Rule," implemented by The Pipeline and Hazardous Materials Safety Administration ("PHMSA"), at 49 Code of Federal Regulations Part 192, Subpart P.

A. Yes. The decision by a regulator to minimize or eliminate Regulatory Lag is providing the utility with what I call a Regulatory Privilege, or in other words, providing cost recovery in a manner that is a privilege, within the normal regulatory process. A Regulatory Privilege permits a utility to recover costs in the interim period between rate proceedings, reducing or eliminating Regulatory Lag and reducing financial risk. Still, it is a privilege granted within the confines of the regulatory model; it is not a right. Absent legislative or regulatory mandate, no utility has a right to automatic recovery of costs through riders or trackers which may preempt the ability or right of a commission, other parties, or the public to participate and protect their interests. In fact, the Commission has explicitly noted that riders are granted at its discretion. "Approval of riders is within the discretion of the Commission and utilities have no legal entitlement to recovery through automatic riders."[7] Overextending this Regulatory Privilege eventually eviscerates the regulatory process, eliminating the very safeguards designed to protect consumers of the utility's services.

Q. WHAT IS THE NORMAL FORM OF A REGULATORY PRIVLEGE?

A. A Regulatory Privilege normally takes the form of a tariff rider.

Q. DOES THE PROVISION OF A REGULATORY PRIVILEGE CHANGE THE *QUID PRO QUO* OF THE REGULATORY COMPACT?

A. No. Granting a Regulatory Privilege does not change the *quid pro quo* when it is judiciously used as the granting of such a privilege does not change the responsibility of

[7] *See,* In the Matter of the Application of Southwestern Electric Power Company for Approval to Acquire a Wind Generating Facility and to Construct a Dedicated Generation Tie Line, Docket No. 17-038-U, Doc. No. 147, Order No. 11, p. 87, n. 11 "Riders under ARK. CODE ANN. § 23-18-703(a)(4) are plainly discretionary," citing Docket No. 06-101-U, Order No. 10 at p. 127-128.

either the utility or its customers. Despite receiving cost recovery relief from Regulatory Lag through the grant of the Regulatory Privilege, the utility remains obligated to provide reliable service. When requests for rider relief are properly vetted by the Commission, the rider *maintains* rather than changes the Regulatory Compact. As discussed later in my testimony, the Commission has explained the criteria used to evaluate the need for a Regulatory Privilege. This is one of numerous reasons, explained more fully below, why costs that are incurred for the generic purpose of "reliability" should not be considered for inclusion in a rider. These costs are a fundamental obligation of the utility as part of the *quid pro quo* of the Regulatory Compact.

Q. HAS THE COMMISSION APPROVED RIDERS FOR SUA?

A. Yes. Table 1 below is a list of all the riders currently in effect and proposed to be effective on the SUA system. The currently effective riders permit SUA to manage costs which the Commission has determined meet the criteria for recovery through this type of mechanism. It is worth noting the scale of rate adjustments which SUA is permitted under existing mechanisms and how rate recovery could expand under the proposals. The current adjustments include the costs of gas supply, safety and integrity projects, modifications to taxes, fees, and energy efficiency programs. In short, the existing riders already represent a significant reduction in Regulatory Lag and potential automatic realignment of cost responsibility to ratepayers. The ability to collect these costs outside of base rates represents a substantial benefit to SUA.

Table 1: Currently Active and Proposed SUA Riders

Class of Service	Rider Schedule Name	Rider Schedule No.	Description
CURRENT[8]			
RS-1, SCS-1, SCS-2, SCS-3, LCS-1, GL-1	Gas Supply Rate (GSR)	1	To recover the cost of acquiring, transporting, and storing natural gas supplies
RS-1, SCS-1, SCS-2, SCS-3, LCS-1	System Safety Enhancement Rider (Rider SSER)	2	"…to provide for the timely recovery of Mains and Associated Services replaced in compliance with the Company's DIMP and TIMP…"
RS-1, SCS-1, SCS-2, SCS-3, LCS-1, GL-1	Municipal Tax Adjustment Clause (TA)	3	to recover "…all privilege, occupation, franchise meter, gross receipts or other tax or assessment of whatever kind and by whatever name (except ad valorem taxes) now and at any time hereafter levied on, the Company by any Municipality. …"
RS-1, SCS-1, SSO	Weather Normalization Adjustment (WNA)	4	To reflect "…the impact of heating degree day variations from normal levels which were used to set rates under the applicable rate schedules."
RS-1, SCS-1, SCS-2, SCS-3, LCS-1, GL-1	Energy Efficiency Cost Recovery Rider (EECR)	5	"…recover its energy efficiency program costs approved by the Commission …"
RS-1, SCS-1, SCS-2, SCS-3, LCS-1	Customer Credit Rider	6	To apply credits "…approved in the final Order in Docket No. 21-060-U and continuing for a period of three (3) years."
RS-1, SCS-1, SCS-2, SCS-3, LCS-1	Government Mandated Expenditure Surcharge Rider (GMES)	7	To "…reflect expenditures related to governmental mandates and are imposed pursuant to the provisions of A.C.A"
PROPOSED[9]			
RS-1, SCS-1, SCS-2, SCS-3, LCS-1, GL-1	System Safety Enhancement Rider (Rider SSER)	2	"…primary purpose of the System Safety Enhancement Rider ("SSER") is to support the expedited recovery of the …Qualifying Projects."[10]
RS-1, SCS-1, SCS-2, SCS-3	Billing Determinant Rate Adjustment Tariff (BDA)	8	"…to account for a decline in billing determinants, which results in a decline in Non-Gas Base Revenues ("Base Revenues"), System Safety Enhancement Rider ("SSER") revenues and Government Mandated Expenditures Surcharge Rider ("GMES") revenues…"

[8] *See* Currently Effective APSC Gas Tariff, Part IV, Sheet Nos. 4-1 through 4-7.
[9] *See* SUA Rider Schedule No. 2, System Safety Enhancement Rider, Original Sheet No. 2 and Rider Schedule No. 8, Billing Determinant Rate Adjustment, APSC Docket No. 23-079-U, Document No. 18.
[10] Proposed "Qualifying Projects" includes, among other things, projects for TIMP, DIMP, facilities relocations, Act 310, and reliability.

V. THE CURRENT SSER

Q: WHAT IS SUA REQUESTING FROM THE COMMISSION REGARDING ITS SSER RIDER?

A: As I explain more fully below, SUA proposes to modify the existing SSER and include, among other things, costs associated with reliability projects. However, I will first explain the limited cost recovery permitted in the currently effective SSER.

Q. WHAT TYPES OF COSTS ARE CURRENTLY INCLUDED IN THE SSER?

A. Currently, the SSER includes integrity program costs that are expended as a requirement of legislative and regulatory initiatives.

> The primary purpose of the System Safety Enhancement ("SSER") is to provide for the timely recovery of Mains and Associated Services replaced in compliance with the Company's Distribution Integrity Management Program ("DIMP") and Transmission Integrity Management Program ("TIMP") on file with the Arkansas Public Service Commission ("Commission"). Subject Mains and Associated Services shall include all mains and associated services replaced in compliance with the Company's DIMP and TIMP on file with the Commission.[11]

The existing rider is also limited to recovery of certain costs associated with safety and integrity programs, specifically including language requiring that the SSER only provides "...a return on the net investment (gross plant less accumulated depreciation) in new Mains and Associated Services…."[12] Importantly the rider language also provides that recovery is permitted for costs incurred in "…compliance with the Company's

[11] *See,* In the Matter of the Joint Application of Centerpoint Energy Resources Corp. and Summit Utilities Arkansas, Inc. to Acquire the Arkansas Assets of Centerpoint Energy Resources Corp. and for Approval of a Certificate of Public Convenience and Necessity for Summit Utilities Arkansas, Inc., Docket 21-060-U, Doc. 143, Part No. 2, SUA, Rider Schedule No. 2, System Safety Enhancement Rider, Original Sheet No. 4-2., p 1, § 2.1, ¶ 1. [Document page 137].
[12] *Id.*, ¶ 2.

DIMP and TIMP on file with the Commission."[13] In other words, the Commission has essentially pre-approved the rider projects through the establishment of an existing Commission monitored integrity management program.

Q. IS THERE A COMMONALITY TO THE COSTS THAT ARE INCLUDED FOR RECOVERY IN THE EXISTING SSER?

A. Yes. The capital dollars incurred under the DIMP and the TIMP programs are the result of safety and integrity obligations imposed on the utility as the result of legislative or regulatory action. These obligations were formalized by the appropriate regulatory agencies, such as the Pipeline and Hazardous Materials Safety Administration ("PHMSA"). The obligation to establish these integrity programs required that utilities expend whatever capital was necessary to comply with the regulations.

This obligation to comply, at whatever the cost, produced a potentially extraordinary cost responsibility for the utility. Thus, all cost burdens on the utility flowed from this initial obligation, a mandate to implement a program requiring potentially significant capital spending. If this mandate did not exist, then none of the aforementioned Commission policy tests can be fully satisfied as none of the capital spending is mandated and beyond the control of the utility. This is a key differentiator when determining if mandated costs should be included in a rider.

Q. HAS SUA FILED FOR RECOVERY OF COSTS UNDER ITS CURRENT SSER?

A. Yes. Since the mechanism was approved, SSER has filed monthly reports in ASPC Docket 21-060-U.

[13] *Id.*, ¶ 1.

Q. WHAT ARE YOUR OBSERVATIONS ABOUT THESE FILINGS?

A. I generally agree with the need for this type of rider filing so utilities may recover extraordinary external costs. However, these filings demonstrate the impact that automatic cost recovery mechanisms have on a utility bill in a relatively brief time. Consequently, it is important that the Commission carefully consider requests for rider filings, or even modifications to existing riders, and determine if a Regulatory Privilege is warranted.

Table 2, below, highlights the significant increase in cost responsibility attributed to the residential class due to the SSER. The data in Table 2 also shows that, in the SSER filings tendered to be effective during 2023, the revenue requirement assigned to the residential class from the SSER increased from approximately $2.538 million in the first filing (row 1, column 7), to approximately $4.807 million in the last filing of the year (row 12, column 7), an increase of about 89%.

The associated residential billing rate has increased in tandem. For the year 2023, SUA reported total SSER spending of $70.443 million.[14] SUA calculated a total revenue requirement of approximately $6.219 million associated with the $68.358 million of net invested capital and assigned $4.808 million or about 77% of the adjustment to the residential class.[15]

Q. WHAT DO YOU CONCLUDE FROM THE DATA IN TABLE 2?

A. The data in Table 2 demonstrates the order of magnitude and fiscal impact that the automatic passthrough of rider costs has on the residential class. I raise this issue to show

[14] *See,* Docket No. 21-060-U, Doc. No. 175, Monthly System Safety Enhancement ("SSER") Rider, Filed November 1, 2023.
[15] *Id.*, Exhibit B

that a grant of Regulatory Privilege requires both sufficient notice and Commission review so that impacted parties can protect their interests. I also raise it to emphasize the importance of adherence to the Commission's policy on the types of costs permitted recovery in a rider.

Table 2: Historical Impact of SSER on Residential Class[16]

Effective Date of Adjustment	Net Capital	Cost of Capital @ 5.51%	Depreciation	Adjustment per 21-060-U	Revenue Requirement	RS-1 Revenue Requirement	RS-1 Rate
(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)
	SSER Adjustments & Revenue Requirements in Millions of $						$/Ccf
SUMMARY OF MONTHLY ADJUSTMENTS							
01/01/23	$36.874	$ 2.032	$1.358	$0.106	$3.284	$2.538	$0.01301
02/01/23	36.761	2.026	1.358	0.106	3.278	2.534	0.01298
03/01/23	36.648	2.019	1.358	0.106	3.271	2.529	0.01296
04/01/23	36.535	2.013	1.358	0.213	3.158	2.442	0.01251
05/01/23	42.269	2.329	1.549	0.213	3.666	2.834	0.01452
06/01/23	42.199	2.325	1.552	0.213	3.665	2.833	0.01452
07/01/23	42.356	2.334	1.565	0.213	3.686	2.849	0.01460
08/01/23	42.889	2.363	1.583	0.213	3.733	2.886	0.01479
09/01/23	45.653	2.516	1.668	0.213	3.971	3.070	0.01573
10/01/23	54.167	2.985	2.088	0.213	4.860	3.757	0.01925
11/01/23	61.717	3.401	2.410	0.213	5.583	4.316	0.02212
12/01/23	68.358	3.767	2.665	0.213	6.219	4.808	0.02464
CALCULATION OF INCREASES							
Total Amount of Increase - January through December						$ 2.270	$0.0116
Total Percentage Increase - January through December						89%	89%

[16] *See*, APSC Docket No. 21-060-U, Docs. Nos. 158, 160, 164, 165, 166, 167, 168, 169, 170, 171, 175, 173, and 175.

Q. DOES THE SSER REDUCE REGULATORY LAG AND PROVIDE A FINANCIAL BENEFIT TO SUA?

A. Yes. The use of the SSER and other riders constitutes a significant Regulatory Privilege for the utility, enabling it to substantially reduce Regulatory Lag and financial risk. Witness Kurt Adams emphasizes the importance of eliminating Regulatory Lag several times, at one point stating that "Eliminating the regulatory lag in the recovery of a return on its investment, and the return of depreciation and amortization expense associated with that investment, is a major factor supporting SUA's rate case filing.[17]

Witness Adams later stresses that, "…at its essence, this case is about eliminating regulatory lag…".[18] He indicates that SUA invested $144.4 million in new utility plant in 2023.[19] Because of this investment, SUA realized significant increases in rate base, and depreciation and amortization expense, yet "…SUA's base rates have not been adjusted to reflect its costs of serving its customers."[20] Presumably a related impact of the increasing capital investment is the need to finance the capital itself. Witness Adams notes, "A substantial driver of the need to increase rates involves SUA's proposed capital structure and its WACC."[21]

According to James Bonbright, one of the primary functions of setting public utility rates is capital attraction.[22] As a result, the product of appropriately established rates should be a financial outcome permitting the utility to attract capital at market

[17] *See*, Direct Testimony of Kurt W. Adams, p. 4, lines 11-13. [Doc. No. 19].
[18] *Id*, p. 5, lines 2-3.
[19] *Id*, p. 20, line 7.
[20] *Id*, p. 3, lines 1-2.
[21] *Id*, p. 23, lines 1-2.
[22] James C. Bonbright, *Principles of Public Utility Rates,* (New York: Columbia University Press, 1961), p. 49.

competitive rates. Granting a Regulatory Privilege to reduce *excessive* Regulatory Lag not only restores any imbalance in the Regulatory Compact, but it also enhances the ability of a utility to attract capital.

Q. DUE TO THE REDUCTION OF REGULATORY LAG AND POTENTIAL IMPACT ON FINACIAL RISK, SHOULD THE EXPANSION OF THE SSER BE CONSIDERED WHEN EVALUATING THE COMPANY'S COST OF CAPITAL?

A. Any provision resulting in the reduction of Regulatory Lag should be considered when evaluating a public utility's cost of capital. However, I am not an expert on financial markets and would therefore defer to the opinion of AG witness Dr. Marlon Griffing on this issue.

VI. THE PROPOSED EXPANDED SSER

Q. WHAT IS THE SUA PROPOSAL TO EXPAND THE CURRENT SSER?

A. SUA proposes to modify the existing mechanism and include, among other things, costs associated with reliability projects. Costs associated with the DIMP and TIMP projects are currently included for recovery in the SSER. The Company proposes to add new categories of costs to be eligible for recovery under the new SSER. SUA Witness Gilliam describes the Company's proposed new categories:

- Other projects to comply with rules and regulations of the U.S. Department of Transportation's Pipeline and Hazardous Materials Safety Administration, including any future requirements, and corresponding provisions of the Code;
- Facility relocation projects, exclusive of all costs that have been, are being, or will be reimbursed otherwise, that are required due to

> construction or improvement of a highway, road, street, public way or other public work by or on behalf of the United States, the State of Arkansas, a political subdivision of the State of Arkansas or another entity having the power of eminent domain;

- Projects eligible for recovery under Act 310 of 1981, as amended (Ark. Code Ann. § 23-4-21 501(a)(1); and
- Reliability Improvement Projects.[23]

Q. ARE YOU OPPOSED TO ALL COSTS THAT SUA PROPOSES TO ADD TO THE SSER?

A. No. I am primarily opposed to the addition of costs associated with reliability projects. These costs are fundamentally different than those currently included in the SSER. The utility is not mandated to incur particular reliability costs and they are therefore wholly within their control. Furthermore, reliability costs do not meet the Commission's test for inclusion in a rider.

Q. HOW DOES SUA DEFINE RELIABILITY PROJECTS?

A. The Company provides a hazy definition of what constitutes a reliability project:

> A reliability improvement project is any project that is deemed to have an underlying need centered around natural gas system capacity, including the ability to deliver services in the quantity and quality demanded by customers and the ability to prevent, withstand, adapt to, and quickly recover from system damage or operational disruption. Typical projects would include projects that increase system deliverability or projects that provide redundant feeds to an area that would support customers if a feed is interrupted. Other examples include projects to relieve bottlenecks or provide additional connections to other pipelines for gas supply diversification.[24]

I have sufficient industry experience to recognize that this definition is overly broad, potentially controlled by commercial considerations, and likely includes costs well

[23] *See,* Direct Testimony of Philip B. Gilliam, p. 40, lines 13-23. [Doc. No. 21].
[24] *See,* Direct Testimony of Vernon McNully, p. 15, lines 14-19, through p.16, lines 1-2. [Doc. No. 25].

within the control of the utility. These seem to point to normal or routine operation and maintenance ("O&M") and capital replacement projects that a utility should regularly manage to provide safe and reliable service under its obligation to serve its service territory. Furthermore, when considering expending capital that could fundamentally change the physical operations and deliverability of the utility, or impact gas supply portfolios, my experience is that the ratepayers' interests are best served when the Commission has an opportunity to thoroughly review the projects and costs prior to the ratepayer being assigned cost responsibility. A rider is not the best option for a thorough project review.

Q. HOW DOES SUA DISTINGUISH RELIABILITY PROJECTS FROM OTHER PROJECTS?

A. This is one of the fundamental issues with the Company proposal. I do not dispute that safety and reliability are inseparable as the Company suggests.[25] However, there is a real chicken and egg issue with its concept of reliability projects. In other words, which came first, a) the safety and integrity project or b) the reliability project? Which is the result of which or are they one and the same? These questions raise other questions:

- Are all safety and integrity projects also reliability projects, or are all reliability projects also safety and integrity projects?
- Which is the subset of which?
- If all reliability projects involve safety and integrity, why are they not covered under one of the legislatively or regulatorily mandated programs?
- Why is a reliability project not part of a utility's routine obligation in its service territory?

[25] *See,* Direct Testimony of Vernon McNully, p.34, lines 5-10. [Doc. No. 25].

The limited insight provided by the Company into these types of issues offers little direction for the Commission to make a reasoned decision.

Q. HAS SUA PROVIDED A COST ESTIMATE OF RELIABILITY PROJECTS?

A. No. SUA did not provide any guidance in response to a data request for this information, stating that it "objects to this data request because it is overly burdensome" and that it "has not performed the requested analysis."[26] It does not seem reasonable to put ratepayers automatically at risk for so-called reliability capital costs without a thorough review by the Commission as to the need for, or at least a review of capital projects, or when the Company cannot provide cost estimates.

In addition, SUA suggests that it will be more "proactive" regarding reliability projects if the costs of the projects are included in the SSER. SUA Company Witness McNully states:

> Q. WHY SHOULD THE SSER INCLUDE RECOVERY OF RELIABILITY PROJECTS?
>
> A. Safety and reliability are inseparable… A more proactive approach to system reliability and timely recovery for these critical projects will lead to a safer system able to meet the demands of its customers.[27]

However, it is not clear that there is a link between improved cost recovery and a safer system or improved reliability. Indeed, as discussed earlier, SUA has a responsibility to provide safe and reliable service as a part of its obligation as a utility in Arkansas.

[26] *See,* Response to Request No. AGC-002-006, attached as Direct Exhibit No. RWP-02. (Emphasis added.)
[27] *See, Doc. No. 25, Direct Testimony of Vernon McNully, p.34, lines 5-10.*

Q. ARE YOU OPPOSED TO INCLUDING RELIABLITY COSTS IN THE SSER?

A. Yes. While I am not opposed to recovery of prudently incurred reliability costs through the normal rate case review process, I am opposed to doing so through the SSER. First, as I mentioned earlier, maintaining a reliable system is part of the regulatory model. It is not a cost imposed by a party outside of the model. SUA is simply attempting to preemptively shift financial risk to ratepayers by reducing Regulatory Lag.

Second, SUA effectively seeks a blank check for reliability costs. It has not provided a preliminary estimate or a proposed analytic framework to assist the Commission in evaluating such expenditures. Assuming *in arguendo* that the inclusion of reliability costs was found to be an acceptable cost category for the SSER, SUA has not demonstrated that its proposal satisfies the Commission's criteria to include such costs in a rider.

VII. COMMISSION CRITERIA FOR RIDERS

Q. DOES THE COMMISSION HAVE A POLICY WHEN EVALUATING REQUESTS FOR RIDERS?

A. The Commission has often stated its policy on riders. As utilities propose to bundle various cost recovery programs into a single rider program, it is important to be mindful of the Commission's guidance on these mechanisms. In my view, the validity of each cost component must be satisfied on its own merits. While many types of costs can be suitable for recovery through a rider, other types of costs will fail to meet the Commission's established criteria. I find that the SUA proposal to include the costs of reliability projects is not appropriate.

Q. WHAT IS THE COMMISSION'S POLICY WHEN EVALUATING REQUESTS FOR RIDERS?

A. As mentioned above, riders are generally not a right, but a privilege. When the Commission reviews riders, it determines if they are consistent with the Regulatory Compact asking, among other things, are "…the costs significant, volatile, and out of the control of the utility?"[28] Historically, the Commission provides cost recovery relief through riders when outside forces impose cost consequences on the utility, impairing the balance in the Regulatory Compact. What the Commission has not permitted is the establishment of riders to recover costs associated with the standard fulfillment of the obligation to provide service to its service area, or other unreviewed commercial decisions by Company management.

Q. HAS THE COMMISSION ESTABLISHED CRITERIA FOR RIDERS?

A. Yes. In various orders the Commission has included specific criteria that the Commission will consider in determining whether to approve a utility's request to include costs in a proposed rider.

> . . . Order No. 11 in Docket No. 17-038-U cites Order No. 10 in Docket No. 06-101-U and notes that the traditional test for supporting a rider is whether the costs are significant, volatile, and out of control of the utility. Order No. 10 in Docket No. 06-101-U discusses the following criteria when evaluating whether to approve a rider: 1) whether the rider shifts risks of costs from the utility onto customers; 2) whether there has been extreme volatility in costs; 3) whether costs are outside the utility's control; 4) what other states have done with respect to recovery of this type of cost; and 5) whether

[28] *See* In the Matter of the Application of Southwestern Electric Power Company for Approval to Acquire a Wind Generating Facility and to Construct a Dedicated Generation Tie Line, Docket No. 17-038-U, Order No. 11, p. 86, n. 10. [Doc. No. 147].

> changes in the industry or unique circumstances warrant the rider.[29] (Internal citations omitted.)

The Company witnesses do not discuss how the expansion of the SSER satisfies the existing Commission rider policy. I will discuss how the SUA proposed expansion of its SSER effectively constitutes a new rider and fails to meet the Commission criteria. I will also specifically discuss how the costs of reliability projects fail to meet the test for inclusion in a rider.

Q. HOW DOES THE PROPOSAL TO EXPAND THE CURRENT SSER EQUATE TO A PROPOSAL FOR A NEW AND DIFFERENT RIDER?

A. The SUA proposal to restructure the SSER is not simply the revision of a previous proposal or an existing mechanism but should instead be treated as the creation of a new rider. While I would not oppose the addition of legislatively or regulatorily imposed costs proposed for inclusion, the insertion of the generic reliability cost category requested by SUA ignores its fundamental obligation under the Rules of the Commission to "…operate and maintain its entire system so that service is safe, adequate, and *reliable*."[30] In other words, the basic costs to provide reliable service are a normal cost of operation that is anticipated within the regulatory model and the obligation to serve the Company's service territory.

The responsibility for normal costs belongs to SUA until the Commission can conduct a thorough review of the proposed costs. SUA should be at risk for Regulatory

[29] *See,* In the Matter of the Application of Southwestern Electric Power Company for Approval to acquire Wind Generating Facilities Pursuant to the Arkansas Clean Energy Development Act, Docket No. 19-035-U, Order No. 7, pp. 49-50 (internal citations omitted). [Doc. No. 97].
[30] *See*, Arkansas Public Service Commission, General Service Rules, Rule 8.01. Safe and Adequate Service, Revised: December 08, 2015 (emphasis added).

Lag from the routine costs associated with serving its service area, not ratepayers. The Commission is not obligated to grant a Regulatory Privilege and provide relief from Regulatory Lag. Indeed, if the Commission were to grant such Privileges for normal costs such as routine O&M costs, or routine capital replacement projects it will eventually eliminate the need for regulatory review.[31]

Q. COMMISSION POLICY REQUIREMENT ONE: DOES THE PROPOSED RIDER SHIFT THE RISK OF COSTS FROM THE UTILITY ONTO RATEPAYERS?

A. Yes. However, SUA does not explicitly recognize this benefit in its cost study. One would expect to see some recognition of the potential benefit as an adjustment to cost of equity or debt capital, as appropriate. Nevertheless, I do not find an offsetting adjustment in favor of ratepayers. Indeed, I do not see any recognition of the significant financial benefit associated with any of the SUA riders currently in effect.

Q. COMMISSION POLICY REQUIREMENT TWO: DOES THE PROPOSED RIDER PROVIDE RECOVERY WHERE THERE HAS BEEN EXTREME VOLATILITY IN COSTS?

A. No. SUA has not demonstrated that such volatility existed or will exist in the future. While SUA asserts that it will be spending more on what it currently classifies as reliability projects, it does not, however, provide a detailed explanation of how the projects are determined to be reliability projects on either a historical or a prospective basis, nor does it provide a projection of what it expects to spend on such projects in the

[31] Utilities are capital intensive entities. Assured rate base treatment through riders of expansive discretionary and non-discretionary projects may eventually eliminate voluntary rate reviews.

future. Indeed, as I mentioned above, the Company declined to respond to discovery requesting a projection of future SSER costs. One can only conclude that extreme cost volatility is not an issue.

Q. COMMISSION POLICY REQUIRMENT THREE: DOES THE PROPOSED RIDER RECOVER COSTS THAT ARE OUTSIDE THE UTILITY'S CONTROL?

A. No. For costs to be outside of the control of the utility they must be involuntary. Management determines when to incur all voluntary expenses, postponing those that are too volatile or projects that are not critical. This is part of the Company's annual budgeting and prioritizing of capital process. However, when mandatory programs are imposed on a utility, that action alters the prioritization of capital spending. Since utility management cannot fully control the capital spent to comply with mandated programs, such spending may outstrip the ability of the utility to obtain reasonable financing. Thus, regulatory commissions will sometimes intervene to provide cost recovery relief for legislatively or regulatorily mandated cost programs through a rider.

In contrast, while the utility must respond to customer and operational needs, it controls how to do so. SUA's testimony does not provide an example where reliability costs were imposed on it by an entity outside of the regulatory model. Despite an effort to shoehorn a massive capital spending obligation from a winter storm task force,[32] SUA ignores the fact that the recommendations of that task force were quite broad and directed at dealing with the primary source of storm issues which was a supply shortage, not

[32] Arkansas Energy Resources Planning Task Force, Report 2021, available at: https://portal-assets.ark.org/2116/files/AR_ERP_task_force_report.pdf.

delivery capacity. In my opinion, SUA should evaluate its reliability projects and seek cost recovery approval for them through the normal cost recovery process.

Q. COMMISSION POLICY REQUIREMENT FOUR: DOES SUA'S PROPOSED SSER REFLECT WHAT OTHER STATES HAVE DONE WITH RESPECT TO RECOVERY OF THIS TYPE OF COST?

A. The Company makes no attempt to compare or contrast the proposal to the authorities granted by any other regulatory commissions.

Q. COMMISSION POLICY REQUIREMENT FIVE: DOES THE PROPOSED RIDER ADDRESS CHANGES IN THE INDUSTRY OR UNIQUE CIRCUMSTANCES THAT WARRANT THE RIDER?

A. No. The fact that SUA has recently acquired the Arkansas assets is not a compelling reason for providing the requested SSER as proposed. Furthermore, while the increasing costs of operating and maintaining a utility may challenge the industry, increasing operating or project costs are not a unique circumstance of today's economic conditions. More importantly, such challenges do not relieve SUA of the obligation to maintain a reliable system.

Q. DOES SUA HAVE OTHER REGULATORY OPTIONS TO RECOVER COSTS SUCH AS THOSE PROPOSED IN THE EXPANDED SSER?

A. Yes. The Arkansas Legislature enacted the Formula Rate Review Act ("FRRA")[33] in 2015 under which SUA could have elected to propose a formula rate plan mechanism ("FRP") in conjunction with its BRC application in this docket that would have provided for the annual adjustment of SUA's base rates for up to ten years. The intent of the FRRA

[33] ARK. CODE ANN. §§ 23-4-1201, *et seq.*

is to establish a framework that provides "just and reasonable rates to consumers in this state and enables public utilities in this state to provide reliable service while maintaining stable rates."[34]

Q. DID SUA EXPLAIN WHY IT IS REQUESTING AN EXPANDED SSER INSTEAD OF REQUESTING AN FRP?

A. SUA suggests that the length and difficulty of the FRP processes created obstacles, stating that it "has determined not to seek an FRP in this proceeding given the complexity of conducting its first ever cost of service case as a new Arkansas utility."[35] I read this, in conjunction with the 59.7% increase in total revenues sought in this case, as an indication that SUA might believe that the maximum four percent annual rate increase allowed under the FRRA[36] is inadequate for the level of increases the Company expects to see in the coming years. However, without projections for the Company's future SSER spending it is not possible to fully evaluate this inference.

VIII. RESIDENTIAL CLASS RATES AND REVENUES

Q. HOW DOES THIS FILING IMPACT THE RATES OF THE RESIDENTIAL CLASS?

A. On an annual basis, the monthly bill for an average annual residential customer is proposed to increase by about 29% or $18.48. SUA asserts that this level of increase is primarily attributable to four major items. Company Witness Adams states that:

> … The most significant drivers of the need for increased rates are the Company's (1) level of capital investment in the system and the resulting

[34] ARK. CODE ANN. § 23-4-1202(b).
[35] *See*, Direct Testimony of Kurt W Adams, p. 22, line 19 -20. [Doc. No.19].
[36] ARK. CODE ANN. § 23-4-1207(d)(2).

increase in depreciation expense; (2) "interim rates" that understated SUA's revenue requirement at the time they were put into effect; (3) weighted average cost of capital ("WACC") and its proposed capital structure; and (4) income taxes.[37]

I prepared Table 3 below to demonstrate, on a summary level, the primary sources of the proposed increases cited by Witness Adams and their impact on the residential rate class.

Q. WILL YOU PLEASE EXPLAIN TABLE 3?

A. Columns 1 and 2 of Table 3 compare the level of costs for the test year and the pro forma year for Gas Plant in Service (which drives the depreciation, return and income taxes components of cost of service), Operation and Maintenance Expenses, and Administrative and General Expenses. The percentage change from the Test Year to the Pro Forma Year is shown in column 3. Column 4 shows the amount from the Pro Forma Year allocated to residential service. Column 5 calculates the percentage allocated to residential service for the total Pro Forma Year.

The data in Table 3 shows that the residential class is allocated approximately three-quarters of all the pro forma costs for each of the cost components. The data also shows that gas utility plant increased the most at a rate of 8.42% (row 1, column 3), impacting downstream cost of service components such as depreciation, return, and income taxes. Setting aside how the Company's use of a hypothetical capital structure and the Company's projected debt and equity costs could impact the return on rate base, the increase in gas plant most likely has the most significant impact on residential rates. Consequently, it is necessary to evaluate the methodology used to allocate fixed costs, such as utility plant costs, among rate classes.

[37] *See*, Direct Testimony of Kurt W Adams, p. 19, lines 5-9. [Doc. No.19].

There is another key takeaway from this table. The percentages in column 5 reveal that for each of these major cost components, residential customers are assigned approximately 74% or more of the cost responsibility.

Table 3: Summary Comparison of Cost Increases and Allocations to RS-1

Description	Row	Test Year	Pro Forma Year	% Change	Avg. Amount Allocated to RS-1	% Allocated to RS-1
		(1)	(2)	(3)	(4)	(5)
Gas Utility Plant in Service	1	$ 1,653.932	$ 1,793.269	**8.42%**	$ 1,326.959	74.00%
Operation & Maintenance Expense	2	$ 56.645	$ 54.578	-3.65%	$ 42.191	77.31%
Administrative & General Expense	3	$ 36.699	$ 37.612	2.49%	$ 28.799	76.57%
Source: Docket 23-079-U, Document No. 18, Schedule Nos. B-1, C-1, G-2, G-3						

Q. HOW DOES SUA ALLOCATE THE COSTS ASSOCIATED WITH UTILITY PLANT?

A. The company develops various allocation factors for purposes of allocating the plant investment and operating expenses. For example, to allocate demand related costs such as distribution mains, SUA calculates a weighted factor called the "Minimum System Customer Demand Composite" or "MAINS." While this factor is one way to measure the cost responsibility of the customers, I do not believe that it appropriately reflects system usage and ultimately cost responsibility. In fact, the current allocation method disproportionately allocates costs to the typical residential customer.

It is appropriate to allocate distribution mains costs using a methodology that recognizes the multiple uses of the utility system of providing reliable gas service to its customers on a peak and an annual basis. The use of an allocation methodology, such as the one employed by SUA, which relies solely on or is biased to customer and peak concerns is generally prejudicial to relatively low-load factor customers such as the typical residential customer.

Q. HOW DOES SUA CALCULATE THE MAINS FACTOR?

A. SUA utilizes information from its minimum system study to weight the average number of customers by class and the design day by class. The result, as shown in Table 4, is a set of allocation percentages used to allocate, among other things, distribution mains.

Table 4: SUA Minimum System Customer Demand Composite Allocation Factors Per Schedule G-4[38]

Description	Reference	Total	Residential	SCS-1	SCS-2	SCS-3	LCS-1
		(1)	(2)	(3)	(4)	(5)	(6)
Minimum-System Customer-Demand Composite							
Avg. Number of Customers - Proforma	a	100.00%	88.80%	10.99%	0.16%	0.00%	0.05%
Minimum System Customer Related Percentage	b	54.04%	47.99%	5.94%	0.09%	0.00%	0.03%
Design-Day Demand - Proforma (b)	c	100.00%	48.92%	30.96%	0.17%	0.01%	19.94%
Minimum System Demand Related Percentage	d	45.96%	22.48%	14.23%	0.08%	0.00%	9.16%
% Allocation Factor	MAINS	100.00%	70.47%	20.17%	0.17%	0.00%	9.19%

[38] *See*, Doc. 18, Schedule G-4, p. 2, lines 32-37.

Q. HOW DOES SUA CALCULATE THE FACTORS IN COLUMNS TWO THROUGH SIX OF TABLE 4?

A. The factors on the Reference row MAINS each represent the sum of the factors calculated on rows b and d. The Minimum System Customer Related Percentage factors in row b are calculated as the product of a) the 54.04% Percentage of Mains that are customer related (row b, column 1) and b) the factor for the average number of customers for each rate class (row a, columns 2 through 6). The result is the Minimum System Customer Related Percentage factors shown for each rate class in row b, columns 2 through 6.

The Minimum System Demand Related Percentage is calculated in a similar fashion. The factors in row d are calculated by multiplying a) the Percentage of Mains that are demand related (45.96%) in row d, column 1, by b) each of the Design-Day Demand Proforma percentages for the various rate classes (row c, lines 2 through 6). Adding the Minimum System Customer Related Percentages (row b) and the Minimum System Demand Related Percentage (row d) for each rate class produces the allocations factors shown in MAINS.

Q. WHAT CONCERNS DO YOU HAVE WITH THIS METHODOLOGY?

A. The SUA method utilizes two key inputs which directly and indirectly drive a significant portion of cost of service. The use of both a) number of customers and b) design day demand heavily bias allocation of costs toward the residential class.

Cost allocation is based on theoretical principles of cost causation. However, the process is not an exact science. Regulators have often struggled with the appropriate allocation of cost responsibility. While some may hold the belief that utilities are built

purely to serve a design day need, others contend that utilities are built to deliver gas volumes to customers, and that demand or capacity costs are incurred to serve a combination of peak-period and annual customer requirements. I agree with SUA that design day is one indicator of cost responsibility. However, I disagree that the number of customers is the next best measure of cost responsibility for this purpose. This finding is supported by the actual usage of the system.

Q. WHY IS NUMBER OF CUSTOMERS NOT THE BEST MEASURE OF COST RESPONSIBILTY?

A. A review of the data filed by SUA shows that while the number of residential customers may outnumber all commercial customers collectively, these commercial customers use more gas as a group and use more gas per customer than does the residential class. I replicated the data included in Figure 3, from the direct testimony of Timothy S. Lyons at page 8, in Table 5 to demonstrate this point.

Table 5: Comparison of Number of Customers and Usage by Rate Class and per Customer

Rate Class	Number of Customers	% of Customers	Usage (Ccf)	% of Usage	Usage per Customer	% Usage per Customer
	(1)	(2)	(3)	(4)	(5)	(6)
RS-1	366,114	88.80%	195,664,213	30.90%	534	0.04%
SCS-1	45,315	10.99%	158,811,577	25.08%	3,505	0.24%
SCS-2	658	0.16%	3,728,172	0.59%	5,666	0.40%
SCS-3	7	0.00%	135,905	0.02%	19,415	1.36%
LCS-1	196	0.05%	274,957,939	43.42%	1,402,847	97.97%
TOTAL	412,290	100.00%	633,297,806	100.00%	1,431,967	100.00%
Source: Testimony of Timothy S. Lyons, Page 8, Fig. 3						

Q. WHAT DOES THE DATA IN TABLE 5 DEMONSTRATE?

A. Table 5 reflects data used by SUA to develop allocation factors. For example, the number of customers in column 1 is used to derive the percentages in column 2 which are used in the calculation of the MAINS allocation factor in Table 4. This allocation factor assumes that the residential class should contribute 88.80% of the relevant costs.[39] What the use of this allocator ignores is that annual usage for the residential class is only 30.90% of total annual deliveries (column 4) and 0.04% of total usage per customer (column 6).[40] Even assuming that peak usage is an important component of cost incurrence (and therefore cost responsibility), one cannot ignore the demands placed on the utility system by the annual user.

Q. HOW HAVE REGULATORS RECOGNIZED THE MUTLIPLE USES OF THE UTILITY WHEN ALLOCATING COSTS?

A. Since regulators have wrestled with the allocation and classification of costs between fixed or variable and demand or usage related categories, they have also grappled with the most appropriate way to assign these costs to the rate classes. The Federal Energy Regulatory Commission (FERC) at one point adopted a method that put less importance on the peak use of the system and adopted the United Method which generally allocated 25% of the fixed costs to the demand rate and 75% to the usage rate.[41] Previously, the FERC gave equal weight to both peak and annual usage, espousing the theory that the utility was built to equally serve both peak and annual needs. To recognize the multiple

[39] The number of customers is also used in the development of the CUSTOMER Allocation percentage.
[40] The Pro Forma Annual Usage is used to calculate the ENERGY Allocation percentage. SUA does not use this percentage to allocate costs.
[41] *See*, United Gas Pipe Line Co., 50 FPC 1348 (1973)

uses of the system the FERC used the Seaboard Method, assigning 50% of the fixed costs to the demand rate and 50% to the usage rate.[42] In either instance the effect of using the United Method or Seaboard Method is to provide a balancing of the allocation of costs representing the peak and annual usage of the utility.

Q. DOES THE FERC CURRENTLY USE EITHER SEABOARD OR UNITED?

A. FERC adopted the Straight Fixed-Variable method (SFV), a process assuming all fixed costs are considered demand related and all variable costs are usage related.[43] However, assigning all fixed costs to the demand charge was not directly related to customer peak utilization. Rather, it was a recognition by the regulator that significant cost differences in usage rates could inhibit gas on gas competition. Thus the primary purpose of fully allocating fixed costs to the demand rate was to encourage the development of a competitive natural gas market. I do not believe that to be a requirement of the SUA cost allocation.

Q. WHAT OTHER FACTORS SUPPORT THE RECOGNITION OF ANNUAL USAGE?

A. One argument for assignment of cost responsibility using design day and customer count is that certain customers dictated the design of the system, indeed the design day of the system. However, there are some operations of SUA which should be considered when evaluating if allocators should be solely focused on design day or if they should consider other factors. Figure 1 is a graphical depiction of the data in Schedule G-4-1,

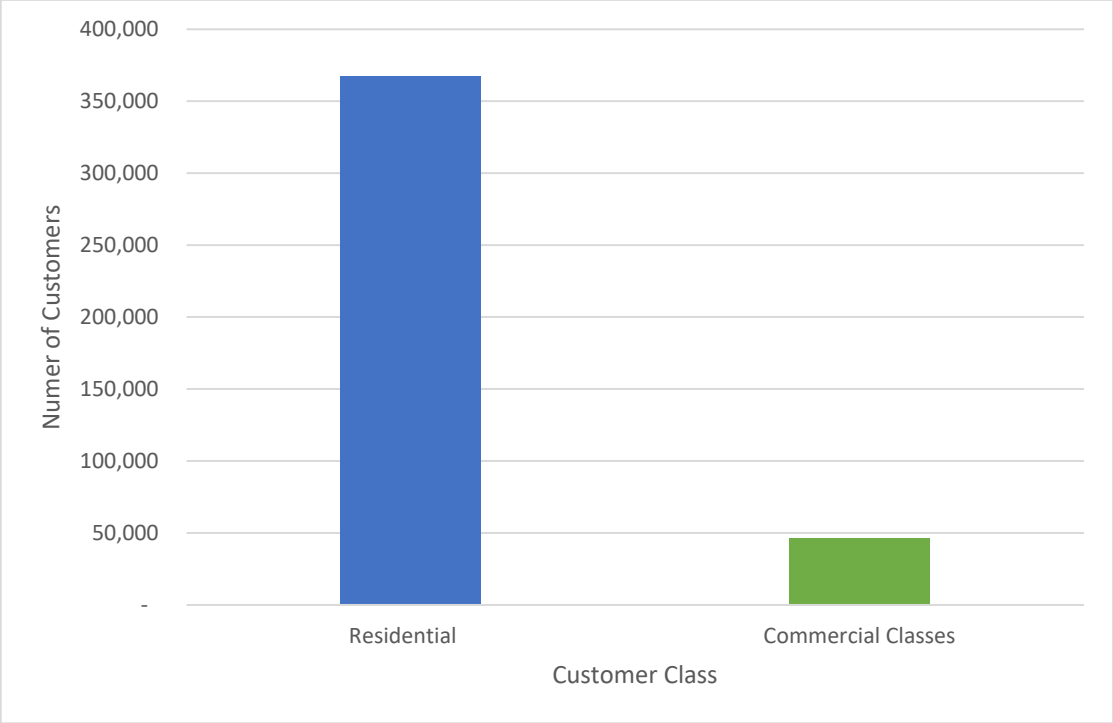
[42] *See*, Atlantic Seaboard Corp. et al., 11 FPC 43 (1952)
[43] *See*, Pipeline Service Obligations and Revisions to Regulations Governing Self-Implementing Transportation; and Regulation of Natural Gas Pipelines After Partial Wellhead Decontrol, Order No. 636, 57 Fed. Reg. 13,267 (April 16, 1992),

Development of Design Day Demand Allocation Factor, where SUA compares the number of customers by class.

Q. WHAT INFORMATION IS CONTAINED IN FIGURE 1?

A. A review solely of this graphic in Figure 1, below, suggests that residential customers, who far outnumber the commercial users, are primarily responsible for the design costs of the utility. If customer count were the sole allocator, residential customers would be responsible for most of the costs of the utility. However, additional analysis of the SUA system demonstrates that the commercial customer classes of the utility heavily utilize the system, both at the peak and on an annual basis. Consequently, it is important to explore further and examine both design day usage and annual usage for the residential and commercial classes.

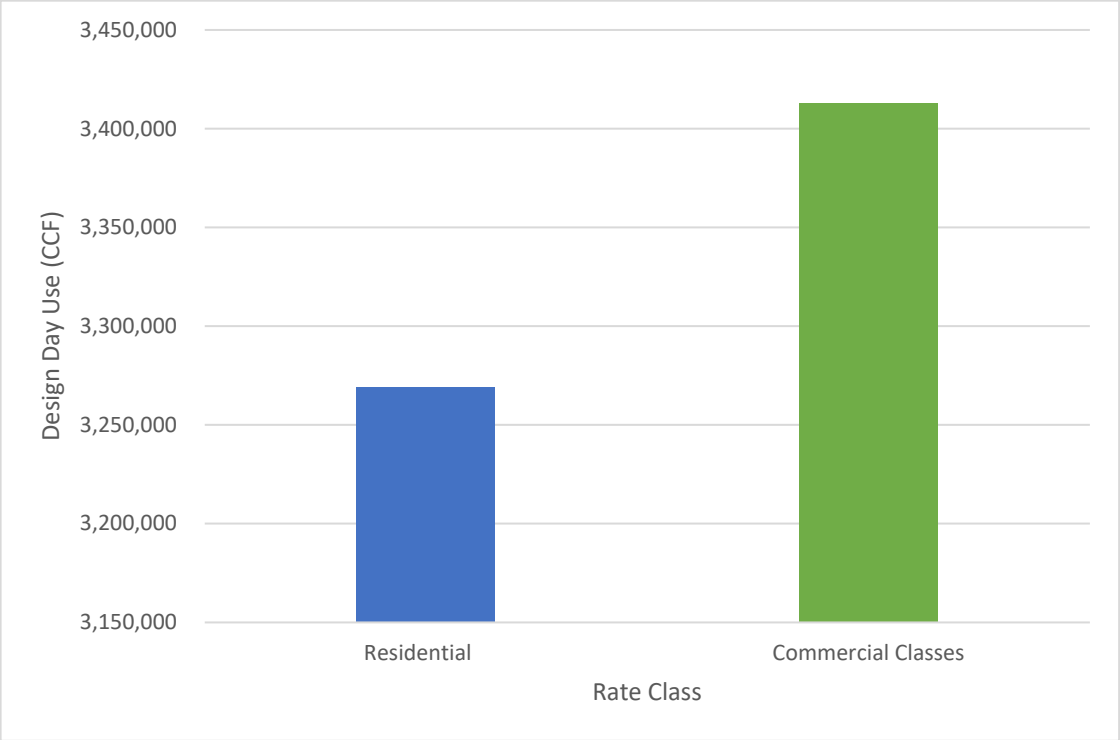
Figure 1: Comparison of Number of Residential v Commercial Customers on Design Day



Q. WHAT IS THE RESULT WHEN CONSIDERING DESIGN DAY USAGE?

A. A review of design day usage demonstrates that collectively the commercial customers take more gas supplies on the design day than do residential customers. Even allowing for the fact that utility residential customers consist of a historically low-load factor, high peaking load, the commercial load exceeds the residential load on the design day on the SUA system. This phenomenon is illustrated in Figure 2, below, which compares design day use between the residential and all commercial classes. The graph depicts the 3,268,891 Ccf of natural gas delivered to residential customers and compares it to the 3,412,978 Ccf of natural gas delivered to commercial customers. Since this demonstrates that approximately 51.08% of the design day deliveries are to commercial customers, it is not plausible to consider that the residential class is solely responsible for the peak day requirements of the system. Since design day/peak day is an input to the numerous demand related costs, and in particular distribution mains, it does not seem reasonable to assign the demand costs / distribution mains solely based on factors which are biased against residential load.

Figure 2: Design Day Usage by Rate Classes

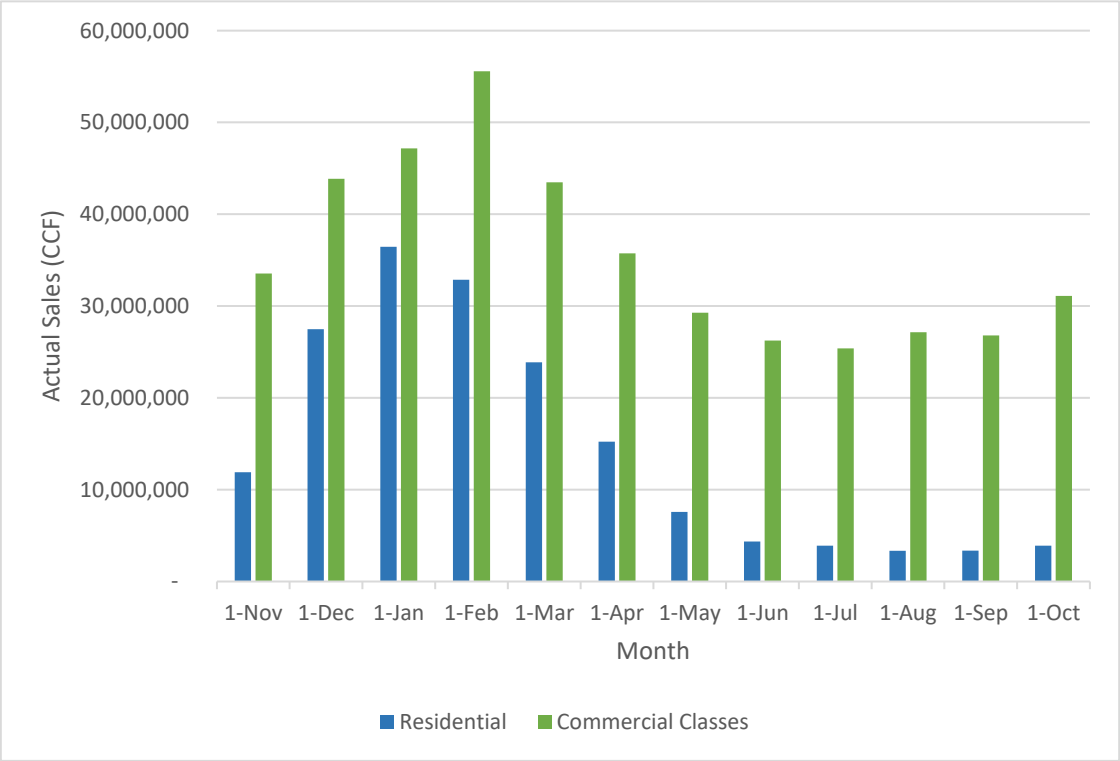


Q. HOW DOES ANNUAL USAGE COMPARE BY CUSTOMER CLASS?

A. Figure 3, below, shows that monthly annual usage for the commercial classes far exceeds the usage by the residential class. In every month, quantities delivered to the commercial classes exceed those delivered to residential customers. This further confirms that all customers use the utility for not just peaking, but also average daily needs. It also confirms that commercial use exceeds residential use both on a monthly and on a design day basis. Consequently, I contend that the allocation of costs should recognize the way the system is used, since utilization is a driver of cost incurrence. However, since investment in the utility plant in service would not have been made based on the potential for utilization alone, it is important to recognize that both the annual usage and the overall design day of the system are contributors to cost responsibility. As I discussed

earlier, the process of cost allocation is not an exact science, and it does require some judgement. My judgement is that, given the information provided by the Company, for the Commission to appropriately recognize the characteristics of the SUA system, certain of the allocation factors used in the COSS need to be revised.

Figure 3: Comparison of Monthly Deliveries to Residential and Commercial Classes



Q. WHAT CHANGES DO YOU RECOMMEND TO THE CALCULATION OF THE ALLOCATION FACTORS?

A. Key SUA allocation factors assume that the residential class is primarily responsible for the system, assigning cost responsibility using percentages which are biased toward the residential class. I propose to allocate certain costs using a methodology that recognizes that the utility system provides reliable gas service to its customers on both a peak and an annual basis. Therefore, I recommend that SUA change the calculation of the factors labeled "DEMAND" and "MAINS." I also recommend that any factors that rely on these factors, or are the result of allocations using these factors, be changed to reflect the impact of these adjustments.

Table 6, below, shows the calculation of my recommended change to the DEMAND and Table 7, below, shows the calculation of my recommended change to the MAINS allocation percentages to reflect the current cost incurrence experience of the SUA system. Each table also provides a comparison of the recommended DEMAND and MAINS allocation percentages to those filed by SUA.

Q. HOW IS THE RECOMMENDED DEMAND ALLOCATION FACTOR CALCULATED?

A. Table 6 shows the calculation of the DEMAND factor. To recognize the annual usage characteristics of the customers, I substituted the ENERGY factor for the number of customers.[44] Since the ENERGY factor is developed using annual customer deliveries, this substitution ensures that consideration is given to the annual use of the system.

[44] *See*, Doc. 18., Schedule G-4, p.1, lines 6 – 8. The ENERGY allocation factor is developed using Pro-Forma customer annual deliveries.

However, to recognize that fully providing equal consideration for peak and annual allocation of demand related costs may impose undue rate instant burdens on certain rate classes, I propose to initially weight the ENERGY by 25%.

Weighting the allocation of costs to annual usage is consistent with the approach followed in the United and Seaboard methods as it assigns some measure of cost responsibility to annual usage. It also mitigates the initial impact of the appropriate cost allocation. This adjustment results in the weighted average ENERGY percentages of 7.73%, 6.27%, 0.15%, 0.01%, and 10.86%.

I used the Peak Design Day generated by SUA and weighted that percentage by 75% to provide a measured consideration to usage at peak. The weighted Peak Design Day produced is 36.69%, 23.22%, 0.13%, 0.01%, 14.96%. I then summed the weighted average ENERGY percentages and the weighted Peak Design Day for each rate class to produce the recommended DEMAND Percentages. Like the weighting of the ENERGY factor, the 75% weighting of the Peak Design Day to calculate the DEMAND percentage is consistent with both the United and Seaboard methods. This is because it recognizes that while the utility provides a peaking service, it does not constitute 100% of the service and therefore does not drive 100% of the cost responsibility.

For purposes of comparison, I inserted the SUA DEMAND percentages in the row below the recommended percentages. It can be seen from comparing the recommended and the SUA percentages, that the change is relatively small. For example,

the residential class allocation factor changes from a factor of 48.92% to a factor of 44.42% or a change of 4.5%.

Table 6: Calculation of Recommended Demand Allocation Factors

Description	Total	Residential	SCS-1	SCS-2	SCS-3	LCS-1
Calculation of DEMAND Factor						
ENERGY Percentage	***100.00%***	***30.90%***	***25.08%***	***0.58%***	***0.02%***	***43.42%***
Weighted Avg ENERGY Percentage	***25.00%***	***7.73%***	***6.27%***	***0.15%***	***0.01%***	***10.86%***
Avg Peak Design Day	100.00%	48.92%	30.96%	0.17%	0.01%	19.94%
Weighted Avg Peak Design Day	***75.00%***	***36.69%***	***23.22%***	***0.13%***	***0.01%***	***14.96%***
Recommended DEMAND Percentage	***100.00%***	***44.42%***	***29.49%***	***0.27%***	***0.01%***	***25.81%***
SUA Demand Percentage	***100.00%***	***48.92%***	***30.96%***	***0.17%***	***0.01%***	***19.94%***

Q. HOW IS THE RECOMMENDED MAINS ALLOCATION FACTOR CALCULATED?

A. Table 7 shows the calculation of the proposed MAINS factor. The first adjustment with the MAINS factor was determining the fine-tuning to the weighting of the allocation percentages. To develop the MAINS percentage, SUA weighted the factor using the percentages associated with customer usage and demand calculated in the Company's mains studies.[45] The current weighting of 54.04% customer and 45.96% demand related

[45] SUA developed a zero intercept and minimum system study.

reflects that study. Since I have not prepared an alternative study, they are good ratios to use at this time.

Next, as I did in the development of the DEMAND factor, I recognized that it was necessary to consider that the system provides reliable gas service to its customers on both a peak and an annual basis. Since the number of customers does not sufficiently recognize annual usage characteristics, I substituted the ENERGY Factor and weighted it by the Minimum System Customer Related Percentage of 54.04%. This produces Minimum System ENERGY Percentages of 16.70%, 13.55%, 0.31%, 0.01%, and 23.46%.

Table 7: Calculation of Recommended Mains Allocation Factors

Description	Total	Residential	SCS-1	SCS-2	SCS-3	LCS-1
Calculation of MAINS Factor						
Minimum-System Customer-Demand Composite						
ENERGY Percentage	***100.00%***	***30.90%***	***25.08%***	***0.58%***	***0.02%***	***43.42%***
Minimum System ENERGY Percentage	***54.04%***	***16.70%***	***13.55%***	***0.31%***	***0.01%***	***23.46%***
Weighted Avg Peak Design Day	100.00%	48.92%	30.96%	0.17%	0.01%	19.94%
Minimum System Demand Related Percentage	45.96%	22.48%	14.23%	0.08%	0.00%	9.16%
Recommended MAINS Allocation Factor	***100.00%***	***39.18%***	***27.78%***	***0.39%***	***0.01%***	***32.63%***
SUA MAINS Allocation Factor	***100.00%***	***70.47%***	***20.17%***	***0.17%***	***0.00%***	***9.19%***

Using the SUA peak design day, I weighted it by the Minimum System Demand Related Percentage of 45.96%, producing percentages of 22.48%, 14.23%, 0.08%, 0.00%, and 9.16%. When I summed the Minimum System ENERGY Percentages and

the Minimum System Demand Related Percentages by rate class, the result was the recommended MAINS factors of 39.18%, 27.78%, 0.39%, 0.01%, and 32.63%. The SUA MAINS factors are shown in the final row of Table 6 for purposes of comparison. As an example, the residential class factor changes from 70.47% to 39.18% or a reduction of 31.29%.

IX. CONCLUSIONS & RECOMMENDATIONS

Q. WHAT ARE YOUR RECOMMENDATIONS BASED ON YOUR REVIEW AND ANALYSIS?

A. My recommendations are as follows:

1. The Commission should reject the proposal for a new and expanded SSER to, among other things, add reliability costs to the SSER, as it is a request for a new rider, it is unsupported, and it is inconsistent with Commission policy. However, I believe that SUA could be allowed to implement an appropriately structured SSER. This requires that SUA eliminate the proposed inclusion of reliability costs from the proposed expanded SSER.
2. SUA should modify its cost allocators to recognize that utility demand or capacity costs are incurred to serve a combination of peak-period and annual customer requirements. Consequently, SUA should modify its allocation factors to recognize the dual purpose of the utility. Specifically, SUA should modify the DEMAND and MAINS factors in the manner I describe herein.

Q. DOES THIS CONCLUDE YOUR TESTIMONY?

A. Yes.

CERTIFICATE OF SERVICE

I, Clay Layson, hereby certify that on July 10, 2024, I filed a copy of the foregoing utilizing the Commission's Electronic Filing System, which caused a copy to be served upon all parties of record via electronic mail.

/s/ Clay Layson
Clay Layson

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BEFORE THE
ARKANSAS PUBLIC SERVICE COMMISSION

IN THE MATTER OF THE APPLICATION OF SUMMIT UTILITIES ARKANSAS, INC., FOR A GENERAL CHANGE OR MODIFICATION IN ITS RATES, CHARGES AND TARIFFS	))))	**DOCKET NO. 23-079-U**

DIRECT TESTIMONY

OF

MICHAEL J. MAJOROS

ON BEHALF OF

THE OFFICE OF ARKANSAS ATTORNEY GENERAL
TIM GRIFFIN

July 10, 2024

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TABLE OF EXHIBITS

Exhibit MJM-1	**SKM Computation of Recommended Depreciation Rates**
Exhibit MJM-2	**Response to AG-001-002**
Exhibit MJM-3	**Response to AG-001-007**
Exhibit MJM-4	**Response to AG-001-012**
Exhibit MJM-5	**Copies of 2 Watson Life Study Charts for Account 376-Mains**
Exhibit MJM-6	**Copies of all Watson Life Study Charts for Account 380**
Exhibit MJM-7	**Geometric Mean Turnover Analysis of Account 380-Services**
Exhibit MJM-8	**SKM Recommended Remaining Lives for Accounts 376 and 380**
Exhibit MJM-9	**Response to AG-001-034**
Exhibit MJM-10	**Response to AG-001-029**
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I. INTRODUCTION

Q. PLEASE STATE YOUR NAME, EMPLOYER, AND BUSINESS ADDRESS.

A. My name is Michael J. Majoros, Jr. I am president of Snavely King Majoros & Associates, Inc. ("SKM"), an economic consulting firm specializing in public utility and telecommunications costs and rates. My business address is P.O. Box 727, Millersville, MD 21108.

Q. PLEASE BRIEFLY DESCRIBE YOUR EDUCATIONAL BACKGROUND AND WORK EXPERIENCE.

A. I hold a Bachelor of Science in accounting from the University of Baltimore. I worked at Ernst & Ernst as an auditor for three years and I passed the CPA exam (although I do not practice as a CPA) prior to beginning my consulting career which has spanned 46 years.

I started my consulting career in 1978 with Van Scoyoc & Wiskup, Inc., a public utility consulting firm in Washington D.C. I conducted and assisted in various management and regulatory consulting projects in the public utility field, including preparation of electric system load projections for a group of municipally and cooperatively owned electric systems in Arkansas; preparation of a system of accounts and reporting of gas and oil pipelines to be used by a state regulatory commission; and accounting system analysis and design for rate proceedings involving electric, gas, and telephone utilities. I provided onsite management accounting and controllership assistance to a municipal electric and water utility. I also assisted in an antitrust proceeding involving a major electric utility. I submitted expert testimony in Federal Energy Regulatory Commission ("FERC") Docket No. RP79-12 (El Paso Natural Gas Company), and co-authored a study

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entitled Analysis of Staff Study on Comprehensive Tax Normalization that was submitted to FERC in Docket No. RM 80-42.

In 1981, I accepted a position as Senior Consultant with SKM, also in Washington D.C. I provide consultation specializing in accounting, financial, and management issues. I have testified as an expert witness or negotiated on behalf of clients in more than 130 federal and state regulatory proceedings involving telephone, electric, gas, water, and sewer companies. My testimony has encompassed a wide array of complex issues including taxation, divestiture accounting, prudency, revenue requirements, rate base, nuclear decommissioning, plant lives, and capital recovery. I also provided consultation to the U.S. Department of Justice and appeared before the U.S. EPA and the Maryland State Legislature on matters regarding the accounting and plant life effects of electric plant modifications and the financial capacity of public utilities to finance environmental controls.

Q. DO YOU HAVE EXPERTISE IN THE SUBJECT OF PUBLIC UTILITY DEPRECIATION?

A. Yes. I have testified on scores of occasions concerning public utility issues. These include appearances before federal courts, federal and state regulatory agencies, and state legislatures. Many of these appearances involved depreciation and depreciation-related matters. In addition, I have authored several papers and articles and sat on many panels addressing various matters including depreciation. Appendix A is a brief description of my qualifications and experience. It also contains a listing of my appearances before state and federal regulatory bodies.

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Q. WHAT IS THE PURPOSE OF YOUR TESTIMONY?

A. I present recommendations on behalf of the Office of the Arkansas Attorney General Tim Griffin ("AG") regarding Summit Utilities, Inc.'s ("SUA" or "Company") depreciation requests in this proceeding. I have focused on SUA's Distribution Plant accounts. I recommend the depreciation rates shown in Exhibit MJM-1.

II. SUA'S DEPRECIATION REQUESTS

Q. PLEASE SUMMARIZE THE COMPANY'S APPLICATION AS IT RELATES TO DEPRECIATION.

A. The Company is requesting a $279,949,398 revenue requirement[1] and calculates that its "total revenue deficiency… after adjustments for known and measurable changes, is approximately $104.7 million on an annual basis."[2] This "will increase an average residential customer's bill by $18.48, which is approximately a 29.40% increase in the average customer's bill, including gas costs."[3]

The Company says the "primary factor driving the need for this rate filing is the (1) level of capital investment in the system and the resulting increase in depreciation expense."[4] Three other items are listed but are not relevant to my testimony. The $279,949,398 proposed revenue requirement includes $65,307,762 of depreciation expense which is composed of $58,085,030 in Distribution Plant depreciation and $7,222,732 in General Plant depreciation.[5] The Company indicates that CenterPoint Energy Arkansas

[1] Application Cover sheet.
[2] Application, p. 2, ¶ 9.
[3] *Id*., p. 3.
[4] *Id*., p. 2. (Emphasis added.)
[5] Exhibit MJM-2, SUA's Response to AG-001-002.

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Gas's (SUA's predecessor) 2020 formula rate plan depreciation expense "was $46,454,323 compared to the $65,307,762 requested by SUA in this case, for a proposed depreciation expense increase of $18,853,439."[6]

Q. DID THE COMPANY FILE A NEW DEPRECIATION STUDY TO SUPPORT ITS REQUESTS?

A. Yes. SUA witness Mr. Dane A. Watson conducted a new depreciation study. He recommends an annualized depreciation expense for SUA of approximately $58 million which he says "represents an increase of approximately $357 thousand over the annualized depreciation calculated on year-end 2022 investment using the current depreciation rates."[7,8]

The difference between Mr. Watson's proposed $357 thousand 2022 increase and the Company's $18.8 million proposed increase appears to be caused by 2023 and 2024 plant additions. The Company indicates that "[f]or 2023 capital expenditures, a little over 67% of the expenditures were associated with projects that replaced existing plant. The majority of these replacements are associated with Rehabilitation/System Maintenance/Improvements or Public Improvement projects."[9] This 67 percent replacement ratio is significant as I will discuss later in my testimony.

Q. HOW DID MR. WATSON CALCULATE HIS PROPOSED DEPRECIATION RATES?

[6] Exhibit MJM-3, SUA's Response to AG-001-007, ¶ b.
[7] Direct Testimony of Dane A. Watson ("Watson Direct"), ES-1, Executive Summary.
[8] Mr. Watson is proposing a $397.8 thousand decrease for SUA's Distribution accounts which is offset by his other recommendations to arrive at the $357 thousand increase in depreciation expense addressed in his testimony. *See,* Direct Exhibit DAW-1 Appendix B, p.2.
[9] Exhibit MJM-3 SUA's Response to AG-001-007, p. 2, ¶ e. (Emphasis added.)

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A. Mr. Watson used the straight-line remaining life method to calculate the proposed depreciation rates. The remaining life method incorporates accumulated depreciation and cost of removal into the numerator of the equation while the denominator is the estimated remaining life of the asset. The formula is as follows:

Remaining Life Depreciation Rate

Rate% = (PIS100%)-(AccDep%)-(NS or COR%)/RL

Where:
Rate = Depreciation Rate
PIS = Plant in Service
AccDep = Accumulated Depreciation
NS or COR= Net Salvage or Cost of Removal
RL = Remaining Life

Q. PLEASE EXPLAIN ACCUMULATED DEPRECIATION FROM THE ABOVE FORMULA.

A. Accumulated depreciation is a contra (offsetting) account to plant in service. Depreciation expense increases accumulated depreciation and retirements reduce accumulated depreciation. SUA also reduces its accumulated depreciation to record cost of removal relating to retired plant.

III. SUMMARY OF RECOMMENDATIONS

Q. WHAT ARE YOUR RECOMMENDATIONS?

A. I recommend the following:

1. I recommend that the Commission approve my proposed depreciation rates. My proposed rates will reduce the 2022 Distribution Plant depreciation expense by $26.7 million to $23.6

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million.[10] Also supporting my recommendation that depreciation rates should be reduced is the fact that the Company has a $191 million excess in its accumulated depreciation account resulting from its current and prior depreciation rates.

2. I recommend that the Commission adopt longer lives for the Company's Distribution Mains and Services accounts, which are fully supported by the life analyses in Mr. Watson's study.

3. I reiterate and explain the significance of Mr. Watson's explanation that when SUA replaces a section of Main or a Service, it does not actually remove anything as contemplated in the FERC Uniform System of Accounts (USOA.)

4. Mr. Watson proposes inflated cost-of-removal ratios to calculate depreciation rates for the Company's plant accounts. I recommend the Commission only approve the uninflated cost of removal ratios. Otherwise, it will be condoning an unnecessary practice that charges current ratepayers for frontloaded, future inflation that may not occur.

5. I recommend that the Commission instruct SUA to stop the practice of allocating or assigning to accumulated depreciation any portion of the project expenditures relating to plant replacements. This is particularly important with respect to pipes in the ground.

6. I recommend that the Commission require SUA file a new depreciation study within three years that includes net salvage studies with a separation of cost of removal between the amounts derived from replacement additions costs and those derived from final non-replaced retirements, along with a complete explanation of how cost of removal from replacements were calculated.

[10] *See,* Exhibit MJM-1, *supra*.

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IV. IMPORTANCE OF DEPRECIATION

Q. WHY IS DEPRECIATION IMPORTANT?

A. Public utility prices are based on their costs which include depreciation expense. Depreciation expense is an *estimated* cost included in a public utility's revenue requirement and, because public utilities are capital intensive, depreciation is generally a large component of a public utility's revenue requirement. Since it is estimated, depreciation calculations involve complex analytical methods, procedures, techniques, calculations, and a certain amount of personal judgment to make the estimate. From the ratepayers' perspective, depreciation expense is an increase to their natural gas bills. From SUA's perspective, depreciation is a source of incremental cash flow.

Q. HOW WOULD YOU SUMMARIZE THE KEY REASONS THAT DEPRECIATION IS SO IMPORTANT TO THE RATEMAKING PROCESS?

Depreciation is important because:

1. Depreciation is a large expense.
2. Depreciation is an estimated non-cash expense involving a substantial amount of personal judgment.
3. The ratemaking process passes depreciation dollar-for-dollar through to a utility's ratepayers.

V. EXCESSIVE DEPRECIATION

Q. WHAT IS EXCESSIVE DEPRECIATION?

A. Excessive depreciation stems from excessive depreciation rates. An excessive depreciation rate is one that is greater than necessary to return the cost of a company's capital asset over

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the life of the asset. The concept of excessive depreciation is not new and in fact was explained by the U.S. Supreme Court in a landmark 1934 decision:

> If the predictions of service life were entirely accurate and retirements were made when and as these predictions were precisely fulfilled, the depreciation reserve would represent the consumption of capital, on a cost basis, according to the method which spreads that loss over the respective service periods. But if the amounts charged to operating expenses and credited to the account for depreciation reserve are excessive, to that extent subscribers for the telephone service are required to provide, in effect, capital contributions, not to make good losses incurred by the utility in the service rendered and thus to keep its investment unimpaired, but to secure additional plant and equipment upon which the utility expects a return.
>
> Confiscation being the issue, the company has the burden of making a convincing showing that the amounts it has charged to operating expenses for depreciation have not been excessive. That burden is not sustained by proof that its general accounting system has been correct. The calculations are mathematical, but the predictions underlying them are essentially matters of opinion. They proceed from studies of the "behavior of large groups" of items. These studies are beset with a host of perplexing problems. Their determination involves the examination of many variable elements and opportunities for excessive allowances, even under a correct system of accounting, [are] always present. The necessity of checking the results is not questioned. The predictions must meet the controlling test of experience.[11]

As stated above, excessive depreciation rates produce excessive depreciation expenses. Since depreciation expense flows dollar-for-dollar into the revenue requirement, ratepayers are forced to pay for excessive depreciation.

Due to double-entry accounting, when utilities collect excessive depreciation cash from ratepayers, the other side of the entry flows dollar-for-dollar into the companies' accumulated depreciation reserve accounts. This can result in a depreciation reserve exceeding the gross plant balance because the depreciation rate is higher than what is

[11] *Lindheimer v. Illinois Bell Tel. Co.*, 292 U.S. 151, 168–70, 54 S. Ct. 658, 665–66 (1934). (Internal citations omitted.)

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necessary to fully depreciate the plant. This is what the Court was referring to in *Lindheimer*. This results in an accumulated depreciation account which, at the end of the asset's life, *exceeds* the original cost in the plant account.

Q. ARE SUA'S DEPRECIATION RATES EXCESSIVE?

A. Yes. SUA's depreciation rates are and have been excessive. SUA has a $191 million depreciation reserve excess in its accumulated depreciation account, which I will explain later in my testimony.

VI. SERVICE LIVES

Q. THE DEPRECIATION RATE FORMULA ABOVE SHOWS THAT THE DENOMINATOR IS THE REMAINING LIFE OF THE ASSET. HOW IS THAT CALCULATED?

A. One makes an average, whole-life estimate for an account and then subtracts the weighted-average age to estimate the future, average remaining life. The shorter the remaining life, the higher the depreciation rate.

Q. WHAT ARE THE COMPANY'S LARGEST PLANT ACCOUNTS?

A. Distribution accounts 376000A – Mains and 380000A – Services are by far the Company's largest plant accounts.

Q. WHAT ARE THE CURRENT AVERAGE DEPRECIATION LIVES FOR THESE TWO ACCOUNTS AND WHAT ARE MR. WATSON AND YOU PROPOSING?

A. The current and Mr. Watson's proposed average depreciation lives for the Company's two largest accounts, along with my proposed lives, are shown in the table below.

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Average Depreciation Service Life Curves

Account	Watson Current	Majoros Proposed[12]
376 – Mains	65-R2.5	70
380 – Services	38-R4.0	50

The initial numbers represent the average whole-life estimates for each account. The letter "R" and subsequent numbers refer to Iowa curves which are in turn empirical patterns of anticipated retirements around the average service lives developed at Iowa State University. Collectively, these describe the estimated patterns of retirements around the average lives.

Q. HOW DID MR. WATSON STUDY THESE ACCOUNTS?

A. The Company indicates that Mr. Watson "utilizes a visual fitting technique (that Mr. Watson believes is a more informative technique than simply using a single best fit statistic) as his primary fitting technique."[13] In other words, Mr. Watson ran statistical regression analyses around several average life assumptions for each of the various Iowa curves to find the best fit for each life/curve combination. He then conducted visual fittings of the results of his studies and then applied judgement based on his observations and discussions with Company personnel to make his final selections.

Q. IS MR. WATSON'S APPROACH NORMAL IN THE INDUSTRY?

A. Yes.

[12] Curve shape is not necessary because I used direct-weighted age/life calculation of remaining life. *See* Exhibit MJM-8.
[13] *See,* Exhibit MJM-4, SUA's Response to AG-001-012, *supra*.

Q. DO YOU TAKE ISSUE WITH MR. WATSON'S PROPOSALS FOR THESE ACCOUNTS?

A. Yes. As noted above, Mains and Services are the Company's largest accounts and thus the costliest for ratepayers. Remember, we are dealing with estimates relating to sunk capital costs. When using Mr. Watson's visual approach, the judgement should cut in favor of ratepayers, if it is reasonable, since it is ratepayers who are paying these sunk costs.

Q. CAN YOU GIVE AN EXAMPLE?

A. Yes. For the Mains account, Mr. Watson states "[v]isual matching across most of the bands show a 65 R2.5 to be a good fit. However, there are some fits where a longer life is indicated."[14] I reviewed Mr. Watson's graphs and discovered that, as he says, several of them support a longer life. Exhibit MJM-5 contains two of Mr. Watson's graphs for the Mains account showing 70-year and 72-year lives. Based on his testimony and these graphs, I recommend a 70-year life for SUA's Mains account.

Q. DO YOU ALSO DISAGREE WITH MR. WATSON'S PROPOSAL FOR ACCOUNT 380 – SERVICES?

A. Yes. With regard to the Services account, Mr. Watson's study states "[v]arious placement and experience bands were generated and analyzed, which consistently show a 38 R4 to be a good fit and is consistent with the approved 38 R4."[15]

Q. DO ALL HIS STATISTICAL STUDIES SUPPORT RETENTION OF A 38-YEAR LIFE FOR THE SERVICES ACCOUNT?

[14] Watson Direct Exhibit DAW-1, p.23.
[15] *Id.*, p.28.

A. No. Exhibit MJM-6 contains all of Mr. Watson's charts for SUA's Services account. A few of his curve shape charts indicate slightly shorter lives such as 36 and 37 years and several indicate 38-year lives. In explaining why he proposes to retain the current 38-year average service life instead of recommending a shorter life, Mr. Watson states the following:

> Discussions with Company personnel revealed that the service life of these assets continues to be impacted by the expedited replacement of certain facilities through the Company's System Safety Enhancement Rider ("SSER"). While these factors had little effect on the service lives of mains, the change had a much greater impact on the life of certain services assets. However, the expectation is the life will increase once the program is complete, so the study retained the existing life instead of reducing the life based on the indications from the actuarial analysis."[16]

Q. DO YOU BELIEVE THAT THE 38-YEAR LIFE FOR ACCOUNT 380 – SERVICES SHOULD BE ADJUSTED?

A. Yes. As I explain below, the life should not be decreased nor maintained at the *status quo*; it should instead be increased.

Q. SINCE MR. WATSON BELIEVES THAT THE SERVICES LIFE WILL INCREASE ONCE THE SSER "PROGRAM" IS COMPLETE, DOES IT FOLLOW THAT HE ALSO BELIEVES THAT THE SSER CAUSED THE SHORTER LIFE INDICATIONS?

A. In my opinion, Mr. Watson is indicating that the SSER caused the Service's life indications to decrease. That is evident in his 38-year and shorter life charts. These charts reveal that fitting to the tails of the curves is what draws down (shortens) the life indications. The

[16] Watson Direct, p.11, lines 4–10. (Emphasis added.)

drop in the tails of the curves is driven by recent retirements driven by the SSER. Retirements weigh heavily in Mr. Watson's 38-year life studies.

Q. DO YOU THEREFORE HAVE CONCERNS WITH MR. WATSON'S 38-YEAR RECOMMENDATION?

A. Yes. Notice that the two charts at the front of Exhibit MJM-6 indicating a 52-year life do not emphasize retirements, even though they are drawn from the same database, albeit different bands of data.

Q. DID YOU CONDUCT AN INDEPENDENT ANALYSIS TO BETTER UNDERSTAND THE IMPACT OF THE SSER?

A. Yes. I conducted a geometric mean turnover analysis ("GMT") using the life study data Mr. Watson provided. It is attached as Exhibit MJM-7.

Q. WHAT IS A GEOMETRIC MEAN TURNOVER ANALYSIS?

A. A GMT is a method to evaluate the average turnover rate of a series of data over a period of time. In this case, my analysis evaluates the average rate of turnover of dollars recorded in SUA's Services account. The method is discussed on pages 90–92 of the National Association of Regulatory Utility Commissioners' August 1996 Public Utility Practices Manual.

The GMT compares annual additions ratios and annual retirement ratios to make annual average-life estimates based on these ratios. Over time, if either the additions ratio or the retirement ratio increases, the resulting life indications will decline. On the other hand, decreasing additions ratios or retirements ratios will result in longer life indications.

Q. WHAT INFORMATION DOES THE GMT PROVIDE?

A. My GMT is shown on pages 1 to 3 of Exhibit MJM-7. It reveals that the average turnover of dollars in the Services account has been about 40 years. The trend of these results for the 1993 to 2022 band is shown on page 4 titled "Life Indications." The life indications during that band were as long as 83 years and as short as 33 years with an average of approximately 40 years. Absent further investigation, this would seemingly tend to support Mr. Watson's 38-year proposal.

However, the chart on page 5 of my Exhibit-MJM-7 titled "Adds & Rets Ratios" is the most telling. It demonstrates why it would have been more appropriate for Mr. Watson to propose his 52-year life indication instead of a 38-year life using his visual fitting approach for the Services account.

The chart on page 5 shows that during the 1993 to 2022 period, retirement ratios are immaterial relative to the additions ratios. And yet Mr. Watson's 38-year selection placed heavy emphasis on retirements rather than recognizing the magnitude of the additions. When Mr. Watson says the life is expected to increase once the SSER program is complete, he is acknowledging that it was primarily additions, not retirements, that drove the life down to 38 years. That is why I am recommending a 50-year life based on Mr. Watson's two life studies that do not place heavy emphasis on immaterial retirements for SUA's Services account.

Q. WHAT DO YOU RECOMMEND?

A. For the reasons stated above, I recommend a 70-year life for SUA's Account 376-Mains and a 50-year life for SUA's Account 380-Services.

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Q. DID YOU CALCULATE REMAINING LIVES FOR THE MAINS AND SERVICES ACCOUNTS?

A. Yes. In Exhibit MJM-8, I subtracted the direct weighted average ages from my recommended lives to determine the remining lives I used in my depreciation rates and theoretical reserve calculations.

VII. COST OF REMOVAL

Q. DOES MR. WATSON INCLUDE NET SALVAGE IN HIS PROPOSED DEPRECIATION RATES?

A. Yes.

Q. WHAT IS NET SALVAGE?

A. Mr. Watson explains net salvage as "the difference between the gross salvage (what the asset was sold for upon removal) and the removal cost (cost to remove and dispose of the asset)."[17]

Q. DO YOU AGREE WITH MR. WATSON'S EXPLANATION?

A. Yes.

Q. WHAT IS THE PRIMARY NET SALVAGE ISSUE IN THIS CASE?

A Cost of removal is the primary net salvage issue in this case. Mr. Watson has included a component for estimated cost of removal in the numerator of his remaining life

[17] Watson Direct, p. 14 (3), lines 19-20. Please note that the page numbering of Mr. Watson's direct testimony starts over on page 12, resulting in what should be pages 12 through 20 instead numbered as 1 through 9. For citations to these pages, I refer to the correct page number and include in parentheses the incorrect page number as reflected on the face of the page.

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depreciation rates. Mr. Watson's cost of removal estimates inflate the resulting depreciation rates to exorbitant and unreasonable levels.

Q. WHAT IS COST OF REMOVAL?

A. As defined by the USOA, "*Cost of removal* means the cost of demolishing, dismantling, tearing down or otherwise removing gas plant, including the cost of transportation and handling incidental thereto. It does not include the cost of removal activities associated with asset retirement obligations that are capitalized as part of tangible long-lived assets that give rise to the obligation."[18]

Q. HOW DO YOU INTERPRET USOA DEFINITION 10?

A. The USOA definition of cost of removal clearly states that a gas utility must physically remove an asset and haul it away to incur cost of removal. Furthermore, USOA defines "replacing" or "replacement" as "the construction or installation of gas plant in place of property retired, together with the removal of the property retired."[19] In light of these definitions, it is notable that the Company does not remove anything when it replaces mains and services.

Q. DOES MR. WATSON EXPLAIN WHAT HE BELIEVES ARE THE MAIN FACTORS IMPACTING COST OF REMOVAL?

A. Yes. Mr. Watson states that "The activities related to retirement costs (generally including cutting, capping, and purging of gas for the abandonment of pipe) continue to be factors in costs that the Company incurs."[20] Mr. Watson further indicates that:

[18] FERC Uniform System of Accounts ("USOA") for Gas Utilities, Definition 10.
[19] FERC USOA for Gas Utilities, Definition 32. (Emphasis added.)
[20] Watson Direct, p. 16 (5), lines 5-9. (Emphasis added.)

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> The costs related to retirement activities (generally including cutting, capping, and purging of gas for the abandonment of pipes) have increased over time. Removal from service of the underground assets involves increased labor costs due to inflation and the need to use specialized skill and equipment in the removal process, more restrictive municipal ordinances for performing these projects, and environmental disposal costs.[21]

Q. DO YOU AGREE WITH MR. WATSON?

A. No. In response to a discovery request, the Company could not identify the assets that are removed thus giving rise to cost of removal, stating that "[c]ost of removal relates to cost of removal from service, not necessarily physically removed."[22] I believe the "cutting, capping, and purging of gas for the abandonment of pipe" referenced in Mr. Watson's definition are not removal costs unless they relate to a final retirement-only retirement of a section of pipe. And, even in those circumstances, there is no cost of removal, because nothing is removed; at best, such costs might be referred to as "retirement-only costs" rather than removal costs for final retirements.

Q. WHY DO YOU STRESS FINAL RETIREMENT-ONLY RETIREMENTS?

A. I stress final "retirement-only" retirements because most pipe retirements are caused by the need to replace them rather than removing them from service without replacement.

VIII. INFLATION

Q. DOES MR. WATSON EXPLAIN HIS APPROACH TO ESTIMATING COST OF REMOVAL?

[21] *Id.*, p. 18 (7), lines 12-16. (Emphasis added.)
[22] Exhibit MJM-9, SUA's Response to AG-001-034.

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A. Yes. Mr. Watson explains his approach and how that approach results in an inflated cost of removal estimate. Mr. Watson begins by explaining that "[s]alvage and removal cost percentages are calculated by dividing the current cost of salvage or removal by the original installed cost of the asset."[23] He indicates that "[w]hen removal exceeds salvage (negative net salvage), the negative net salvage increases the amount to be depreciated."[24] Further, "[p]lant assets can experience significant negative removal cost percentages due to the amount of removal cost and the timing of the addition versus the retirement."[25] Mr. Watson goes on to use an example in an attempt to explain why he believes the cost of removal component of net salvage should be inflated:

> For example, a Distribution asset in FERC Account 376 [Mains] with a current installed cost of $500 (2022) would have had an installed cost of $20.61 [fn 3: Using the Handy-Whitman Bulletin No. 198, G-4, line 44, $20.61 = $500 x 51/1237.] in 1957. A removal cost of $50 for the asset calculated (incorrectly) on current installed cost would only have a -10% removal cost ($50/$500). The correct removal cost calculation would show a -243% removal cost for that asset ($50/$20.61), thus ignoring the significant inflation that occurred between installation and removal.[26]

Q. WHAT IS THE HANDY-WHITMAN BULLETIN TO WHICH MR. WATSON REFERS?

A. The Handy-Whitman Bulletin is also called the Handy-Whitman Index ("HWI"). It measures public utility plant cost trends throughout several regions of the United States. Arkansas is in the South-Central Region. The statistics in the HWI reflect price changes over time by USOA plant account. They are used to measure inflation in plant costs.

[23] Watson Direct, p. 14 (3), line 20 through p. 15 (4), line 1.
[24] *Id.*, p. 15 (4), lines 2-4.
[25] *Id.*, lines 4-5.
[26] *Id.*, lines 10-16. (Emphasis added.)

Q. DO YOU AGREE WITH MR. WATSON'S USE OF THE HWI?

A. I agree that the HWI measures historical inflation over time as Mr. Watson demonstrates. I disagree with Mr. Watson's projection of past inflation into the future to increase current depreciation rates. Mr. Watson further explains why he believes the inflated -243% cost of removal ratio is correct:

> In the example above, a -243% removal cost rate accurately reflects the cost necessary to remove the asset 65 years after it was originally installed. A rate of -10% clearly would not. Inflation from the time of installation of the asset until the time of its removal must be considered in the calculation of the removal cost percentage because the depreciation rate, which includes the removal cost percentage, will be applied to the original installed cost of assets. Regulators in Arkansas and other states have correctly adopted this calculation methodology in previous cases."[27]

Q. WHAT IS THE EFFECT OF MR. WATSON'S INFLATED COST OF REMOVAL APPROACH?

A. The effect is to charge current ratepayers for un-incurred future inflation. In his example, ratepayers in 2024 would be paying for inflation that may not be incurred at all, but if it is, that will not occur for 65 more years.

Q. WHAT IS THE IMPACT OF MR. WATSON'S APPROACH?

A. Mr. Watson's DAW-1[28] demonstrates the impact. Mr. Watson's life proposals result in a 34.45 composite remaining life for the Distribution Plant function.[29] He is proposing a total of $872,842,797 for future cost of removal.[30] That means he is proposing to charge current ratepayers $25,336,510 a year for inflation that has not been incurred.[31]

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[27] Watson Direct, p.15 (4), line 18 through p. 16 (5), line 4.
[28] *See,* Watson Direct Exhibit DAW-1, Appendix A1.
[29] Total of column (j) divided by total of column (l) = 34.45 composite remaining life.
[30] Total of column (i).
[31] Total of column (i) divided by 34.45 = $25,336,511 per year.

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Q. IS THIS A REASONABLE METHOD TO ESTIMATE NET SALVAGE TO INCREASE DEPRECIATION RATES?

A. No. Notwithstanding Mr. Watson's references to *Depreciation Systems*, by Drs. Fitch and Wolf and the National Association of Regulatory Utility Commissioners' *Public Utility Depreciation Practices*, this is not a reasonable method given its outrageous results as demonstrated by Mr. Watson's example. Certainly, ratepayers should pay for the cost of prudently incurred capital investments, including the cost to remove them when they are finally retired, but it is not reasonable to inflate the estimated costs to exorbitant levels.

Q. WHAT DO YOU RECOMMEND?

A. I recommend that Mr. Watson's future inflation be removed from the depreciation rates. I have used the weighted average ages and the HWI to remove the inflation from the cost of removal estimates. The results of my calculations can be found in my Exhibit MJM-11, Column (n). I recommend that the Commission use these calculations as the basis for removal.

Q. HAVE YOU MADE ANY OTHER ADJUSTMENTS TO THE DEFLATED RATIOS?

A. Yes. I limited the ratios for accounts 376-Mains and 380-Service to 33 percent of the deflated ratios to account for retirement-only retirements/non-replacement retirements.[32] These adjustments are shown in columns (o) and (p) of Exhibit MJM-11.

Q. HAVE YOU USED MR. WATSON'S DEFLATED AND ADJUSTED RATIOS TO CALCULATE YOUR RECOMMENDED DEPRECIATION RATES?

[32] As explained earlier, the Company stated that 67 percent of the company's retirements are replacements.

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A. Yes.

IX. REPLACEMENTS

Q. WHAT IS THE PLANT REPLACEMENT ISSUE IN THIS CASE?

A. Most pipe retirements are driven by the need to replace the pipe to continue to provide service and earn revenues. They do not involve the "demolishing, dismantling, tearing down or otherwise removing gas plant, including the cost of transportation and handling thereto" as contemplated in USOA Definition 10. Instead, they are *replacement costs*. Mr. Watson explains further:

> Removal cost is booked to accumulated depreciation on a project level through the accounting system. There are two types of projects: retirement-only projects and replacement projects. Retirement-only projects charge all labor costs associated with the project to removal cost. In replacement projects, only a portion of the project is booked to removal cost while the rest are considered installation costs of the new (replacement) assets. Two methods are used in the utility industry: direct charge of labor costs or using an allocated percentage of labor cost. In a direct-charged project, the project manager determines what portion of the total project is booked to removal cost. The percentage of labor cost method allocates a percentage of the labor cost associated with a replacement project based on an allocation percentage of the total labor cost in the project. SUA allocates a fixed percentage of labor cost to removal when retiring an asset with replacement.[33]

Q: HAS MR. WATSON CONDUCTED OTHER SIMILAR STUDIES?

A: Yes. Exhibit MJM-10 confirms that Mr. Watson has conducted other similar studies.

Q. DO YOU AGREE WITH THESE ALLOCATION APPROACHES?

A. No. In my view, the primary purpose of the cost of removal allocation study prepared for SUA by Mr. Watson's firm is first to convince the Commission that allocating a percentage

[33] Watson Direct, p. 18 (7), line 18 through p. 19 (8), line 6.

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of a replacement project to cost of removal is a reasonable approach. Then, those allocated amounts are inflated in net depreciation studies just as Mr. Watson explains in his testimony in this case.

Q. IS THERE A FLAW IN MR. WATSON'S APPROACH?

A. Yes. In my opinion, Mr. Watson's allocation approach is precluded by the FERC USOA.

Q. WHAT IS THE BASIS FOR YOUR OPINION?

A. I have already explained the USOA Definition 10 of removal cost and the fact that the Company does not remove anything when it replaces its pipes. Additionally, as previously mentioned, USOA Definition 32 defines replacement as: "the construction or installation of gas plant in place of property retired, together with the removal of the property retired." (Emphasis added.)

Q. WHAT DOES USOA DEFINITION 32 MEAN?

A. FERC USOA Definition 32 means that neither SUA nor any other utility should be allocating any portion of replacement asset costs to cost of removal or accumulated depreciation. USOA Definition 32 means that 100 percent of a replacement project should be assigned to plant-in-service with none of it allocated to cost of removal. That is the accounting approach that is consistent with economic cost causation principles and the matching principle in accounting. It depreciates 100 percent of the cost of the replacement addition over its service life. The USOA Definition 32 approach recognizes the purpose of a replacement is to continue to provide service and earn revenues over the asset's life.

Q. WHAT DO YOU RECOMMEND?

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A. I recommend the Company follow USOA Definition 32 and discontinue allocating portions of replacement costs to cost of removal. The Commission should require SUA to file another depreciation study which separates the actual cost of removal relating to "retirement-only" projects from cost of removal associated with replacement projects, to demonstrate it is following USOA definitions and requirements.

Q. DO NON-REGULATED COMPANIES RECORD A PORTION OF THE COST OF A REPLACEMENT PLANT ASSET IN ACCUMULATED DEPRECIATION?

A. Non-regulated companies generally record 100 percent of the cost of a new asset to plant. That is because the reason they replace an asset is to continue to earn revenues, so they match the depreciation of the full cost of the replacement asset to the future revenues.

X. EXCESS EMBEDDED IN SUA'S ACCUMULATED DEPRECIATION ACCOUNT

Q. WHAT DID YOU MEAN BY YOUR EARLIER STATEMENT THAT THE COMPANY HAS A $191 MILLION EXCESS IN ITS ACCUMULATED DEPRECIATION ACCOUNT DUE TO ITS CURRENT AND PRIOR EXCESSIVE DEPRECIATION RATES?

A. As I explained earlier, SUA uses its approved depreciation rates to calculate its annual depreciation expense and records it in its accumulated depreciation account. Depreciation expense increases the accumulated depreciation, thus if the depreciation rates are based on lives which are too short or the cost of removal factors are too negative (or both), the resulting depreciation rates and expense will be too high, and ultimately the accumulated depreciation account will be excessive.

Q. IS THERE A WAY TO MEASURE THE ADEQUACY OF ACCUMULATED DEPRECIATION ACCOUNTS FOR UTILITIES?

A. Yes. Utilities often conduct theoretical reserve studies. A theoretical reserve is a computation of the amount required in the book accumulated depreciation account assuming all future accruals are calculated using the currently estimated depreciation rates. This theoretical reserve can be compared to the actual amount recorded in the book accumulated depreciation account to assess the propriety of past depreciation rates. If the actual recorded amount exceeds the theoretical reserve, the book accumulated depreciation contains an excess resulting from the use of excessive depreciation rates in the past. Mr. Watson explains the calculation on page 11 of his depreciation study.[34]

Q. DID MR. WATSON CALCULATE THEORETICAL RESERVES FOR SUA'S PLANT ACCOUNTS USING HIS PROPOSED DEPRECIATION RATES?

A. Appendices A1 and A2 of Mr. Watson's Direct Exhibit DAW-1 show his calculated theoretical reserves for six General Plant accounts, but he does not show his theoretical reserves for the Distribution Plant accounts which contain most of the Company's plant investment.

Q. DID YOU CALCULATE THEORETICAL RESERVE REFLECTING YOUR RECOMMENDATIONS FOR SUA'S DISTRIBUTION ACCOUNTS?

A. Yes. In Exhibit MJM-12, I calculated theoretical reserves using Mr. Watson's uninflated cost of removal ratios with retirement-only adjustments to the Mains and Services ratios. I also used 70-year and 50-year lives curves for accounts 376-Mains and 380-Services,

[34] Watson Direct Exhibit DAW-1, p. 11.

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respectively. My calculation indicates that SUA's accumulated depreciation for its Distribution Plant accounts contains a $191 million depreciation excess.[35]

XI. CONCLUSION

Q. PLEASE SUMMARIZE YOUR TESTIMONY.

A. Mr. Watson's depreciation rates are not reasonable because they are excessive. The implementation of such excessive rates will overcharge ratepayers for understated lives for the Company's two largest distribution accounts and for inflated cost of removal ratios. While it is true the cost of removal of a non-replaced asset should be recorded as cost of removal, the FERC USOA indicates that the original cost of a replacement addition includes the cost of removal associated with the replaced asset. This is consistent with cost causation and matching principles because the reason for a replacement is to continue to provide service, and capitalization of 100 percent of the cost will spread that cost over the asset's life. Nevertheless, these allocations provide the inputs to the data and analysis Mr. Watson uses to support charging ratepayers for future inflation that has not occurred. The best solution is to discontinue the practice of allocating replacement costs to cost of removal. If the practice is to continue, the cost of removal estimates should not charge current ratepayers for future inflation to these allocated amounts. My proposed depreciation rates are based on reasonable lives for SUA's two largest accounts and remove the future inflation Mr. Watson included in his proposed cost of removal ratios.

[35] *See,* Exhibit MJM-12, *supra.*

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Q. DO YOUR RECOMMENDATIONS PERMIT FULL CAPITAL RECOVERY TO SUA?

A. Yes. All my recommendations will provide full capital recovery to SUA.

Q. DOES THIS CONCLUDE YOUR DIRECT TESTIMONY?

A. Yes, it does.

Experience

Analytica94, Inc.
Chairman and Founder (2013 to present)

A94 is a chartable non-profit organization founded in 2013 to provide independent research, economic models, and training to evaluate the effectiveness of economic regulation of U.S. industries.

Snavely King Majoros & Associates, Inc.
President (2010 to present)
Vice President and Treasurer (1988 to 2010)
Senior Consultant (1981-1987)

Mr. Majoros provides consultation specializing in accounting, financial, and management issues. He has testified as an expert witness or negotiated on behalf` of clients in more than one hundred thirty regulatory federal and state regulatory proceedings involving telephone, electric, gas, water, and sewerage companies. His testimony has encompassed a wide array of complex issues including taxation, divestiture accounting, prudency, revenue requirements, rate base, nuclear decommissioning, plant lives, and capital recovery. Mr. Majoros has also provided consultation to the U.S. Department of Justice and appeared before the U.S. EPA and the Maryland State Legislature on matters regarding the accounting and plant life effects of electric plant modifications and the financial capacity of public utilities to finance environmental controls. He has estimated economic damages suffered by black farmers in discrimination suits.

Van Scoyoc & Wiskup, Inc.*, Consultant (1978-1981)*

Mr. Majoros conducted and assisted in various management and regulatory consulting projects in the public utility field, including preparation of electric system load projections for a group of municipally and cooperatively owned electric systems; preparation of a system of accounts and reporting of gas and oil pipelines to be used by a state regulatory commission; accounting system analysis and design for rate proceedings involving electric, gas, and telephone utilities. Mr. Majoros provided onsite management accounting and controllership assistance to a municipal electric and water utility. Mr. Majoros also assisted in an antitrust proceeding involving a major electric utility. He submitted expert testimony in FERC Docket No. RP79-12 (El Paso Natural Gas Company), and he co-authored a study entitled Analysis of Staff Study on Comprehensive Tax Normalization that was submitted to FERC in Docket No. RM 80-42.

Handling Equipment Sales Company, Inc.
Controller/Treasurer (1976-1978)

Mr. Majoros' responsibilities included financial management, general accounting and reporting, and income taxes.

Ernst & Ernst, ***Auditor (1973-1976)***

Mr. Majoros was a member of the audit staff where his responsibilities included auditing, supervision, business systems analysis, report preparation, and corporate income taxes.

University of Baltimore - ***(1971-1973)***

Mr. Majoros was a full-time student in the School of Business.

During this period Mr. Majoros worked consistently on a part-time basis in the following positions: Assistant Legislative Auditor – State of Maryland, Staff Accountant – Robert M. Carney & Co., CPA's, Staff Accountant – Naron & Wegad, CPA's, Credit Clerk – Montgomery Wards.

Central Savings Bank, ***(1969-1971)***

Mr. Majoros was an Assistant Branch Manager at the time he left the bank to attend college as a full-time student. During his tenure at the bank, Mr. Majoros gained experience in each department of the bank. In addition, he attended night school at the University of Baltimore.

Education

University of Baltimore, School of Business, B.S. – Concentration in Accounting

Professional Affiliations

American Institute of Certified Public Accountants
Maryland Association of C.P.A.s
Society of Depreciation Professionals

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Publications, Papers, and Panels

"Analysis of Staff Study on Comprehensive Tax Normalization," FERC Docket No. RM 80-42, 1980.

"Telephone Company Deferred Taxes and Investment Tax Credits – A Capital Loss for Ratepayers," Public Utility Fortnightly, September 27, 1984.

"The Use of Customer Discount Rates in Revenue Requirement Comparisons," Proceedings of the 25th Annual Iowa State Regulatory Conference, 1986

"The Regulatory Dilemma Created By Emerging Revenue Streams of Independent Telephone Companies," Proceedings of NARUC 101st Annual Convention and Regulatory Symposium, 1989.

"BOC Depreciation Issues in the States," National Association of State Utility Consumer Advocates, 1990 Mid-Year Meeting, 1990.

"Current Issues in Capital Recovery" 30th Annual Iowa State Regulatory Conference, 1991.

"Impaired Assets Under SFAS No. 121," National Association of State Utility Consumer Advocates, 1996 Mid-Year Meeting, 1996.

"What's 'Sunk' Ain't Stranded: Why Excessive Utility Depreciation is Avoidable," with James Campbell, Public Utilities Fortnightly, April 1, 1999.

"Local Exchange Carrier Depreciation Reserve Percents," with Richard B. Lee, Journal of the Society of Depreciation Professionals, Volume 10, Number 1, 2000-2001

"Rolling Over Ratepayers," Public Utilities Fortnightly, Volume 143, Number 11, November, 2005.

"Asset Management – What is it ?" American Water Works Association, Pre-Conference Workshop, March 25, 2008.

"Main Street Gold Mine," with Dr. K. Pavlovic and J. Legieza, Public Utilities Fortnightly, October, 2010

Appendix A (cont)
Appearances

Michael J. Majoros, Jr.

Date	Jurisdiction / Agency	Docket	Utility
		Federal Courts	
2005	US District Court, Northern District of AL, Northwestern Division 55/56/57/	CV 01-B-403-NW	Tennessee Valley Authority
		State Legislatures	
2006	Maryland General Assembly 61/	SB154	Maryland Healthy Air Act
2006	Maryland House of Delegates 62/	HB189	Maryland Healthy Air Act
		Federal Regulatory Agencies	
1979	FERC-US 19/	RP79-12	El Paso Natural Gas Co.
1980	FERC-US 19/	RM80-42	Generic Tax Normalization
1996	CRTC-Canada 30/	97-9	All Canadian Telecoms
1997	CRTC-Canada 31/	97-11	All Canadian Telecoms
1999	FCC 32/	98-137 (Ex Parte)	All LECs
1999	FCC 32/	98-91 (Ex Parte)	All LECs
1999	FCC 32/	98-177 (Ex Parte)	All LECs
1999	FCC 32/	98-45 (Ex Parte)	All LECs
2000	EPA 35/	CAA-00-6	Tennessee Valley Authority
2003	FERC 48/	RM02-7	All Utilities
2003	FCC 52/	03-173	All LECs
2003	FERC 53/	ER03-409-000, ER03-666-000	Pacific Gas and Electric Co.
2017	FERC 53/	ER16-2320-002	Pacific Gas and Electric Company
		State Regulatory Agencies	
1982	Massachusetts 17/	DPU 557/558	Western Mass Elec. Co.
1982	Illinois 16/	ICC81-8115	Illinois Bell Telephone Co.
1983	Maryland 8/	7574-Direct	Baltimore Gas & Electric Co.
1983	Maryland 8/	7574-Surrebuttal	Baltimore Gas & Electric Co.
1983	Connecticut 15/	810911	Woodlake Water Co.
1983	New Jersey 1/	815-458	New Jersey Bell Tel. Co.
1983	New Jersey 14/	8011-827	Atlantic City Sewerage Co.
1984	Dist. Of Columbia 7/	785	Potomac Electric Power Co.

Michael J. Majoros, Jr.

1984	Maryland 8/	7689	Washington Gas Light Co.
1984	Dist. Of Columbia 7/	798	C&P Tel. Co.
1984	Pennsylvania 13/	R-832316	Bell Telephone Co. of PA
1984	New Mexico 12/	1032	Mt. States Tel. & Telegraph
1984	Idaho 18/	U-1000-70	Mt. States Tel. & Telegraph
1984	Colorado 11/	1655	Mt. States Tel. & Telegraph
1984	Dist. Of Columbia 7/	813	Potomac Electric Power Co.
1984	Pennsylvania 3/	R842621-R842625	Western Pa. Water Co.
1985	Maryland 8/	7743	Potomac Edison Co.
1985	New Jersey 1/	848-856	New Jersey Bell Tel. Co.
1985	Maryland 8/	7851	C&P Tel. Co.
1985	California 10/	I-85-03-78	Pacific Bell Telephone Co.
1985	Pennsylvania 3/	R-850174	Phila. Suburban Water Co.
1985	Pennsylvania 3/	R850178	Pennsylvania Gas & Water Co.
1985	Pennsylvania 3/	R-850299	General Tel. Co. of PA
1986	Maryland 8/	7899	Delmarva Power & Light Co.
1986	Maryland 8/	7754	Chesapeake Utilities Corp.
1986	Pennsylvania 3/	R-850268	York Water Co.
1986	Maryland 8/	7953	Southern Md. Electric Corp.
1986	Idaho 9/	U-1002-59	General Tel. Of the Northwest
1986	Maryland 8/	7973	Baltimore Gas & Electric Co.
1987	Pennsylvania 3/	R-860350	Dauphin Cons. Water Supply
1987	Pennsylvania 3/	C-860923	Bell Telephone Co. of PA
1987	Iowa 6/	DPU-86-2	Northwestern Bell Tel. Co.
1987	Dist. Of Columbia 7/	842	Washington Gas Light Co.
1988	Florida 4/	880069-TL	Southern Bell Telephone
1988	Iowa 6/	RPU-87-3	Iowa Public Service Company
1988	Iowa 6/	RPU-87-6	Northwestern Bell Tel. Co.
1988	Dist. Of Columbia 7/	869	Potomac Electric Power Co.
1989	Iowa 6/	RPU-88-6	Northwestern Bell Tel. Co.
1990	New Jersey 1/	1487-88	Morris City Transfer Station
1990	New Jersey 5/	WR 88-80967	Toms River Water Company
1990	Florida 4/	890256-TL	Southern Bell Company
1990	New Jersey 1/	ER89110912J	Jersey Central Power & Light
1990	New Jersey 1/	WR90050497J	Elizabethtown Water Co.
1991	Pennsylvania 3/	P900465	United Tel. Co. of Pa.
1991	West Virginia 2/	90-564-T-D	C&P Telephone Co.
1991	New Jersey 1/	90080792J	Hackensack Water Co.
1991	New Jersey 1/	WR90080884J	Middlesex Water Co.
1991	Pennsylvania 3/	R-911892	Phil. Suburban Water Co.

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1991	Kansas 20/	176, 716-U	Kansas Power & Light Co.
1991	Indiana 29/	39017	Indiana Bell Telephone
1991	Nevada 21/	91-5054	Central Tele. Co. – Nevada
1992	New Jersey 1/	EE91081428	Public Service Electric & Gas
1992	Maryland 8/	8462	C&P Telephone Co.
1992	West Virginia 2/	91-1037-E-D	Appalachian Power Co.
1993	Maryland 8/	8464	Potomac Electric Power Co.
1993	South Carolina 22/	92-227-C	Southern Bell Telephone
1993	Maryland 8/	8485	Baltimore Gas & Electric Co.
1993	Georgia 23/	4451-U	Atlanta Gas Light Co.
1993	New Jersey 1/	GR93040114	New Jersey Natural Gas. Co.
1994	Iowa 6/	RPU-93-9	U.S. West – Iowa
1994	Iowa 6/	RPU-94-3	Midwest Gas
1995	Delaware 24/	94-149	Wilm. Suburban Water Corp.
1995	Connecticut 25/	94-10-03	So. New England Telephone
1995	Connecticut 25/	95-03-01	So. New England Telephone
1995	Pennsylvania 3/	R-00953300	Citizens Utilities Company
1995	Georgia 23/	5503-0	Southern Bell
1996	Maryland 8/	8715	Bell Atlantic
1996	Arizona 26/	E-1032-95-417	Citizens Utilities Company
1996	New Hampshire 27/	DE 96-252	New England Telephone
1997	Iowa 6/	DPU-96-1	U S West – Iowa
1997	Ohio 28/	96-922-TP-UNC	Ameritech – Ohio
1997	Michigan 28/	U-11280	Ameritech – Michigan
1997	Michigan 28/	U-112 81	GTE North
1997	Wyoming 27/	7000-ztr-96-323	US West – Wyoming
1997	Iowa 6/	RPU-96-9	US West – Iowa
1997	Illinois 28/	96-0486-0569	Ameritech – Illinois
1997	Indiana 28/	40611	Ameritech – Indiana
1997	Indiana 27/	40734	GTE North
1997	Utah 27/	97-049-08	US West – Utah
1997	Georgia 28/	7061-U	BellSouth – Georgia
1997	Connecticut 25/	96-04-07	So. New England Telephone
1998	Florida 28/	960833-TP et. al.	BellSouth – Florida
1998	Illinois 27/	97-0355	GTE North/South
1998	Michigan 33/	U-11726	Detroit Edison
1999	Maryland 8/	8794	Baltimore Gas & Electric Co.
1999	Maryland 8/	8795	Delmarva Power & Light Co.
1999	Maryland 8/	8797	Potomac Edison Company
1999	West Virginia 2/	98-0452-E-GI	Electric Restructuring

Appendix A (cont)
Appearances

Michael J. Majoros, Jr.

1999	Delaware 24/	98-98	United Water Company
1999	Pennsylvania 3/	R-00994638	Pennsylvania American Water
1999	West Virginia 2/	98-0985-W-D	West Virginia American Water
1999	Michigan 33/	U-11495	Detroit Edison
2000	Delaware 24/	99-466	Tidewater Utilities
2000	New Mexico 34/	3008	US WEST Communications, Inc.
2000	Florida 28/	990649-TP	BellSouth -Florida
2000	New Jersey 1/	WR30174	Consumer New Jersey Water
2000	Pennsylvania 3/	R-00994868	Philadelphia Suburban Water
2000	Pennsylvania 3/	R-0005212	Pennsylvania American Sewerage
2000	Connecticut 25/	00-07-17	Southern New England Telephone
2001	Kentucky 36/	2000-373	Jackson Energy Cooperative
2001	Kansas 38/39/40/	01-WSRE-436-RTS	Western Resources
2001	South Carolina 22/	2001-93-E	Carolina Power & Light Co.
2001	North Dakota 37/	PU-400-00-521	Northern States Power/Xcel Energy
2001	Indiana 29/41/	41746	Northern Indiana Power Company
2001	New Jersey 1/	GR01050328	Public Service Electric and Gas
2001	Pennsylvania 3/	R-00016236	York Water Company
2001	Pennsylvania 3/	R-00016339	Pennsylvania America Water
2001	Pennsylvania 3/	R-00016356	Wellsboro Electric Coop.
2001	Florida 4/	010949-EL	Gulf Power Company
2001	Hawaii 42/	00-309	The Gas Company
2002	Pennsylvania 3/	R-00016750	Philadelphia Suburban
2002	Nevada 43/	01-10001 &10002	Nevada Power Company
2002	Kentucky 36/	2001-244	Fleming Mason Electric Coop.
2002	Nevada 43/	01-11031	Sierra Pacific Power Company
2002	Georgia 27/	14361-U	BellSouth-Georgia
2002	Alaska 44/	U-01-34,82-87,66	Alaska Communications Systems
2002	Wisconsin 45/	2055-TR-102	CenturyTel
2002	Wisconsin 45/	5846-TR-102	TelUSA
2002	Vermont 46/	6596	Citizen's Energy Services
2002	North Dakota 37/	PU-399-02-183	Montana Dakota Utilities
2002	Kansas 40/	02-MDWG-922-RTS	Midwest Energy
2002	Kentucky 36/	2002-00145	Columbia Gas
2002	Oklahoma 47/	200200166	Reliant Energy ARKLA
2002	New Jersey 1/	GR02040245	Elizabethtown Gas Company
2003	New Jersey 1/	ER02050303	Public Service Electric and Gas Co.
2003	Hawaii 42/	01-0255	Young Brothers Tug & Barge
2003	New Jersey 1/	ER02080506	Jersey Central Power & Light
2003	New Jersey 1/	ER02100724	Rockland Electric Co.

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Michael J. Majoros, Jr.

2003	Pennsylvania 3/	R-00027975	The York Water Co.
2003	Pennsylvania 3/	R-00038304	Pennsylvania-American Water Co.
2003	Kansas 20/ 40/	03-KGSG-602-RTS	Kansas Gas Service
2003	Nova Scotia, CN 49/	EMO NSPI	Nova Scotia Power, Inc.
2003	Kentucky 36/	2003-00252	Union Light Heat & Power
2003	Alaska 44/	U-96-89	ACS Communications, Inc.
2003	Indiana 29/	42359	PSI Energy, Inc.
2003	Kansas 20/ 40/	03-ATMG-1036-RTS	Atmos Energy
2003	Florida 50/	030001-E1	Tampa Electric Company
2003	Maryland 51/	8960	Washington Gas Light
2003	Hawaii 42/	02-0391	Hawaiian Electric Company
2003	Illinois 28/	02-0864	SBC Illinois
2003	Indiana 28/	42393	SBC Indiana
2004	New Jersey 1/	ER03020110	Atlantic City Electric Co.
2004	Arizona 26/	E-01345A-03-0437	Arizona Public Service Company
2004	Michigan 27/	U-13531	SBC Michigan
2004	New Jersey 1/	GR03080683	South Jersey Gas Company
2004	Kentucky 36/	2003-00434,00433	Kentucky Utilities, Louisville Gas & Electric
2004	Florida 50/ 54/	031033-EI	Tampa Electric Company
2004	Kentucky 36/	2004-00067	Delta Natural Gas Company
2004	Georgia 23/	18300, 15392, 15393	Georgia Power Company
2004	Vermont 46/	6946, 6988	Central Vermont Public Service Corporation
2004	Delaware 24/	04-288	Delaware Electric Cooperative
2004	Missouri 58/	ER-2004-0570	Empire District Electric Company
2005	Florida 50/	041272-EI	Progress Energy Florida, Inc.
2005	Florida 50/	041291-EI	Florida Power & Light Company
2005	California 59/	A.04-12-014	Southern California Edison Co.
2005	Kentucky 36/	2005-00042	Union Light Heat & Power
2005	Florida 50/	050045 & 050188-EI	Florida Power & Light Co.
2005	Kansas 38/ 40/	05-WSEE-981-RTS	Westar Energy, Inc.
2006	Delaware 24/	05-304	Delmarva Power & Light Company
2006	California 59/	A.05-12-002	Pacific Gas & Electric Co.
2006	New Jersey 1/	GR05100845	Public Service Electric and Gas Co.
2006	Colorado 60/	06S-234EG	Public Service Co. of Colorado
2006	Kentucky 36/	2006-00172	Union Light, Heat & Power
2006	Kansas 40/	06-KGSG-1209-RTS	Kansas Gas Service
2006	West Virginia 2/	06-0960-E-42T, 06-1426-E-D	Allegheny Power

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Michael J. Majoros, Jr.

2006	West Virginia 2/	05-1120-G-30C, 06-0441-G-PC, et al.	Hope Gas, Inc. and Equitable Resources, Inc.
2007	Delaware 24/	06-284	Delmarva Power & Light Company
2007	Kentucky 36/	2006-00464	Atmos Energy Corporation
2007	Colorado 60/	06S-656G	Public Service Co. of Colorado
2007	California 59/	A.06-12-009, A.06-12-010	San Diego Gas & Electric Co., and Southern California Gas Co.
2007	Kentucky 36/	2007-00143	Kentucky-American Water Co.
2007	Kentucky 36/	2007-00089	Delta Natural Gas Co.
2007	Maine 71/	2007-00215	Central Maine Power
2008	Kansas 40/	08-ATMG-280-RTS	Atmos Energy Corporation
2008	New Jersey 1/	GR07110889	New Jersey Natural Gas Co.
2008	North Dakota 37/	PU-07-776	Northern States Power/Xcel Energy
2008	Pennsylvania 3/	A-2008-2034045 et al	UGI Utilities, Inc. / PPL Gas Utilities Corp.
2008	Washington 63/	UE-072300, UG-072301	Puget Sound Energy
2008	Pennsylvania 3/	R-2008-2032689	Pennsylvania-American Water Co. - Coatesville
2008	New Jersey 1/	WR08010020	NJ American Water Co.
2008	Washington 63/ 64/	UE-080416, UG-080417	Avista Corporation
2008	Texas 65/	473-08-3681, 35717	Oncor Electric Delivery Co.
2008	Tennessee 66/	08-00039	Tennessee-American Water Co.
2008	Kansas	08-WSEE-1041-RTS	Westar Energy, Inc.
2009	Kentucky 36/	2008-00409	East Kentucky Power Coop.
2009	Indiana 29/	43501	Duke Energy Indiana
2009	Indiana 29/	43526	Northern Indiana Public Service Co.
2009	Michigan 33/	U-15611	Consumers Energy Company
2009	Kentucky 36/	2009-00141	Columbia Gas of Kentucky
2009	New Jersey 1/	GR00903015	Elizabethtown Gas Company
2009	District of Columbia 7/	FC 1076	Potomac Electric Power
2009	New Jersey 1/	GR09050422	Public Service Gas & Electric Co.
2009	Kentucky 36/	2009-00202	Duke Energy Kentucky Co.
2010	Kentucky 36/	2009-00549	Louisville Gas and Electric Co.
2010	Kentucky 36/	2009-00548	Kentucky Utilities Co.
2010	New Jersey 1/	GR10010035	Southern New Jersey Gas Co.
2010	Hawaii 42/	2009-0286	Maui Electric Co.
2010	Hawaii 42/	2009-0321	Hawaii Electric Light Co.

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Michael J. Majoros, Jr.

2010	Hawaii 42/	2010-0053	Hawaiian Electric Co.
2010	Lancaster 3/	R-2010-2179103	Lancaster Water Fund
2011	Kansas 40/	11-KCPE-581-PRE	Kansas City Power and Light Co.
2011	Delaware 24/	11-207	Artesian
2012	Kentucky 36/	2012-00221	Kentucky Utilities Company
2012	Kentucky 36/	2012-00222	Louisville Gas and Electric Company
2012	Massachusetts 67/	DPU 12-25	Bay State Gas Company
2012	District of Columbia 7/	FC 1093	Washington Gas Light Company
2012	New Jersey 1/	WR11070460	New Jersey American Water
2012	New Jersey 1/	ER11080469	Atlantic City Electric Company
2013	Michigan 33/	U-16769	Michigan Consolidated Gas
2013	New Jersey 1/	ER12111052	Jersey Central Power & Light
2013	Alberta 68/	2322	ATCO Pipelines
2013	North Dakota 37/	PU-12-813	Northern States Power
2013	Massachusetts 67/	D.P.U 13-07	New England Gas Company
2013	Wyoming 69/	20000-427-EA-13	Rocky Mountain Power
2013	New York 70/	13-E-0030	Consolidated Edison
2013	Maine 71/	2013-00168	Central Maine Power
2014	Alberta 68/	2739	Enmax Power Company
2014 2014 2015 2015 2015	West Virginia 2/ West Virginia 2/ Maryland 8/ Maryland 8/ West Virginia 2/	14-0701-E-D 14-1151-E-D 9319 9385 15-0674-WS-D	Monongahela Power Company APCO Potomac Edison PEPCO WV American Water Company
2016	Pennsylvania 3/	R2016-2529660	Columbia Gas of Pa.
2017	Hawaii 42/	2016-0431	Hawaiian Electric
2018	New Jersey 1/	14251-20175	New Jersey American Water
2019	North Dakota 37/	PU-18-403	NSPS Prudence of Mankato
2019	Arizona 72/	E-01933A-19-0028	Tucson Electric Production Plant
2023	West Virginia 2/	23-0030-E-D	Potomac Edison
2023	Tennessee 73/	23-00050	Atmos Energy

PARTICIPATION AS NEGOTIATOR IN FCC TELEPHONE DEPRECIATION RATE REPRESCRIPTION CONFERENCES

Appendix A (cont)
Appearances

Michael J. Majoros, Jr.

COMPANY	YEARS	CLIENT
Diamond State Telephone Co. 24/	1985 + 1988	Delaware Public Service Comm
Bell Telephone of Pennsylvania 3/	1986 + 1989	PA Consumer Advocate
Chesapeake & Potomac Telephone Co. - Md. 8/	1986	Maryland People's Counsel
Southwestern Bell Telephone – Kansas 20/	1986	Kansas Corp. Commission
Southern Bell – Florida 4/	1986	Florida Consumer Advocate
Chesapeake & Potomac Telephone Co.-W.Va. 2/	1987 + 1990	West VA Consumer Advocate
New Jersey Bell Telephone Co. 1/	1985 + 1988	New Jersey Rate Counsel
Southern Bell - South Carolina 22/	1986 + 1989 + 1992	S. Carolina Consumer Advocate
GTE-North – Pennsylvania 3/	1989	PA Consumer Advocate

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Michael J. Majoros, Jr.

PARTICIPATION IN PROCEEDINGS WHICH WERE SETTLED BEFORE TESTIMONY WAS SUBMITTED

STATE	DOCKET NO.	UTILITY
Maryland 8/	7878	Potomac Edison
Nevada 21/	88-728	Southwest Gas
New Jersey 1/	WR90090950J	New Jersey American Water
New Jersey 1/	WR900050497J	Elizabethtown Water
New Jersey 1/	WR91091483	Garden State Water
West Virginia 2/	91-1037-E	Appalachian Power Co.
Nevada 21/	92-7002	Central Telephone - Nevada
Pennsylvania 3/	R-00932873	Blue Mountain Water
West Virginia 2/	93-1165-E-D	Potomac Edison
West Virginia 2/	94-0013-E-D	Monongahela Power
New Jersey 1/	WR94030059	New Jersey American Water
New Jersey 1/	WR95080346	Elizabethtown Water
New Jersey 1/	WR95050219	Toms River Water Co.
Maryland 8/	8796	Potomac Electric Power Co.
South Carolina 22/	1999-077-E	Carolina Power & Light Co.
South Carolina 22/	1999-072-E	Carolina Power & Light Co.
Kentucky 36/	2001-104 & 141	Kentucky Utilities, Louisville Gas and Electric
Kentucky 36/	2002-485	Jackson Purchase Energy Corporation
Kentucky 36/	2009-00202	Duke Energy Kentucky
New Jersey 1/	ER09080664	Atlantic City Electric Co.
New Jersey 1/	ER09080668	Rockland Electric Co.

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Michael J. Majoros, Jr.

Clients

1/ New Jersey Rate Counsel/Advocate	36/ Kentucky Attorney General
2/ West Virginia Consumer Advocate	37/ North Dakota Public Service Commission
3/ Pennsylvania OCA	38/ Kansas Industrial Group
4/ Florida Office of Public Advocate	39/ City of Witchita
5/ Toms River Fire Commissioner's	40/ Kansas Citizens' Utility Rate Board
6/ Iowa Office of Consumer Advocate	41/ NIPSCO Industrial Group
7/ D.C. People's Counsel	42/ Hawaii Division of Consumer Advocacy
8/ Maryland's People's Counsel	43/ Nevada Bureau of Consumer Protection
9/ Idaho Public Service Commission	44/ GCI
10/ Western Burglar and Fire Alarm	45/ Wisc. Citizens' Utility Rate Board
11/ U.S. Dept. of Defense	46/ Vermont Department of Public Service
12/ N.M. State Corporation Comm.	47/ Oklahoma Corporation Commission
13/ City of Philadelphia	48/ National Assn. of State Utility Consumer Advocates
14/ Resorts International	49/ Nova Scotia Utility and Review Board
15/ Woodlake Condominium Association	50/ Florida Office of Public Counsel
16/ Illinois Attorney General	51/ Maryland Public Service Commission
17/ Mass Coalition of Municipalities	52/ MCI
18/ U.S. Department of Energy	53/ Transmission Agency of Northern California
19/ Arizona Electric Power Corp.	54/ Florida Industrial Power Users Group
20/ Kansas Corporation Commission	55/ Sierra Club
21/ Public Service Comm. – Nevada	56/ Our Children's Earth Foundation
22/ SC Dept. of Consumer Affairs	57/ National Parks Conservation Association, Inc.
23/ Georgia Public Service Comm.	58/ Missouri Office of the Public Counsel
24/ Delaware Public Service Comm.	59/ The Utility Reform Network
25/ Conn. Ofc. Of Consumer Counsel	60/ Colorado Office of Consumer Counsel
26/ Arizona Corp. Commission	61/ MD State Senator Paul G. Pinsky
27/ AT&T	62/ MD Speaker of the House Michael Busch
28/ AT&T/MCI	63/ Washington Office of Public Counsel
29/ IN Office of Utility Consumer Counselor	64/ Industrial Customers of Northwestern Utilities
30/ Unitel (AT&T – Canada)	65/ Steering Committee of Cities
31/ Public Interest Advocacy Centre	66/ City of Chattanooga
32/ U.S. General Services Administration	67/ Massachusetts Attorney General
33/ Michigan Attorney General	68/ Alberta Office of the Utilities Consumer Advocate
34/ New Mexico Attorney General	69/ Wyoming Industrial Energy Consumers
35/ Environmental Protection Agency Enforcement Staff	70/ New York State Department
	71/ Maine Office of Public Advocate
	72/ Western Resource Advocates
	73/ Tennessee Attorney General

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Michael J. Majoros, Jr.

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CERTIFICATE OF SERVICE

I, Clay Layson, hereby certify that on July 10, 2024, I filed a copy of the foregoing utilizing the Commission's Electronic Filing System, which caused a copy to be served upon all parties of record via electronic mail.

/s/ Clay Layson
Clay Layson

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BEFORE THE
ARKANSAS PUBLIC SERVICE COMMISSION

IN THE MATTER OF THE APPLICATION	**)**	
OF SUMMIT UTILITIES ARKANSAS, INC	**)**	**DOCKET NO. 23-079-U**
FOR APPROVAL OF A GENERAL CHANGE	**)**	
IN RATES AND TARIFFS	**)**	

DIRECT EXHIBITS
OF
MICHAEL J. MAJOROS

ON BEHALF OF

THE OFFICE OF ARKANSAS ATTORNEY GENERAL
TIM GRIFFIN

July 10, 2024

APSC FILED Time: 7/10/2024 11:50:36 AM: Recvd 7/10/2024 11:49:53 AM: Docket 23-079-U-Doc. 118

Exhibits List

Exhibit	Description	Page
MJM-1	SKM Computation of Recommended Depreciation Rates	3
MJM-2	Response to AG-001-002	4
MJM-3	Response to AG-001-003	5
MJM-4	Response to AG-001-012	7
MJM-5	Copies of 2 Watson Life Study Charts for Account 376-Mains	8
MJM-6	Copies of all Watson Life Study Charts for Account 380	9
MJM-7	Geometric Mean Turnover Analysis of Account 380-Services	25
MJM-8	SKM Recommended Remaining Lives for Accounts 376 and 380	30
MJM-9	Response to AG-001-034	31
MJM-10	Response to AG-001-029	32
MJM-11	Remove Inflation from Watson Accrual Rates and Adjust 376 and 380 for Retirement-Only Percentages	34
MJM-12	SKM Computation of Reserve Excess	35

Summit Utilities - Arkansas Assets **Exhibit___(MJM-1)**
SKM Computation of Recommended Depreciation Accrual Rates
Using Average Life Group Depreciation
As of December 31, 2022

New Asset Group	New Account	Old Account	Sub FCA	Description	Plant Balance	Book Reserve	Net Salvage %	Net Salvage Amount	Unaccrued Balance	Average Remaining Life		Annual Accrual Amount	Proposed Annual Accrual Rate
(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)=(h)*(f)	(j)=(f)-(g)-(i)	(k)		(l)=(j)/(k)	(m)=(l)/(f)
	Distribution Plant												
3742	D374200A	G37402	Multi	Land Rights	$ 4,020,565.65	$1,013,488.53	0.00%	$ -	$3,007,077.12	49.69		$60,516.75	1.51%
3751	D375100A	G37501	6900	City Gate Main Line M/R Structures	224,807.59	143,969.21	0.00%	-	80,838.38	30.04		2,691.02	1.20%
3753	D375300A	G37502	6910	Meas & Dist Reg Sta Structures	400,508.13	179,759.46	0.00%	-	220,748.67	30.17		7,316.83	1.83%
3754	D375400A	G37503	6920	Other Structures- Distribution	10,189,841.76	4,866,930.30	0.00%	-	5,322,911.46	35.38		150,449.73	1.48%
3755	D375500A	G37503	6930	Other Structures- Distribution Imp	5,244,325.19	1,851,926.56	-2.84%	(148,745.04)	3,541,143.67	31.13		113,753.41	2.17%
3760	D376000A	G37601	6940	Mains	858,698,342.45	260,324,249.11	-5.11%	(43,882,739.02)	642,256,832.36	55.11	2	11,654,088.77	1.36%
3780	D378000A	G37801	6980	Mea/ Reg Sta Equipment- General	14,120,321.49	2,518,068.38	-29.08%	(4,105,623.70)	15,707,876.81	31.24		502,812.96	3.56%
3783	D378300A	G37801	7000	Other Equipment- Odorizing Equip.	1,111,690.19	814,031.95	0.00%	-	297,658.24	8.02		37,114.49	3.34%
3790	D379000A	G37901	7010	Mea Reg Sta Equipment City Gate	2,422,516.99	1,447,967.07	-1.15%	(27,920.88)	1,002,470.80	26.74		37,489.56	1.55%
3800	D380000A	G38001	7020	Services	395,610,297.61	235,262,527.64	-25.22%	(99,790,575.20)	260,138,345.17	36.68	2	7,092,103.19	1.79%
3811	D381100A	G38101	7050	Meters- Domestic	30,121,837.85	19,337,459.49	0.00%	-	10,784,378.36	18.49		583,254.64	1.94%
3812	D381200A	G39703	7420	Meters - ERTS	29,222,228.15	20,078,076.53	0.00%	-	9,144,151.62	7.37		1,240,726.14	4.25%
3813	D381300A	G38101	7060	Meters - Industrial	14,561,884.43	9,134,489.65	0.00%	-	5,427,394.78	14.98		362,309.40	2.49%
3820	D382000A	G38201	7080	Meter Installation - Domestic	21,184,765.09	7,071,081.02	-3.36%	(712,340.45)	14,826,024.52	28.62		518,030.21	2.45%
3831	D383100A	G38301	7120	Regulators- Domestic	18,504,773.29	8,167,660.43	0.00%	-	10,337,112.86	19.35		534,217.72	2.89%
3832	D383200A	G38301	7130	Regulators- Industrial	12,758,397.10	6,320,197.46	0.00%	-	6,438,199.64	18.27		352,391.88	2.76%
3850	D385000A	G38501	7150	Industrial Meas and Reg Stat Equip.	7,450,385.75	781,229.37	-1.13%	(84,540.65)	6,753,697.03	35.83		188,492.80	2.53%
3851	D385100A	G38201	7090	M&R Station Equipment - Other	12,964,151.12	8,605,387.79	-6.46%	(836,848.27)	5,195,611.60	24.57		211,461.60	1.63%
				Total Distribution Plant	1,438,811,639.83	587,918,499.95		-149,589,333.21	1,000,482,473.09			23,649,221.10	1.64%
	General Plant - Depreciated												
3901	D390100A	G39001	7200	General Plant Structures	8,316,933.37	167,576.30	0.00%	0	8,149,357.07	41.71		195,370.48	2.35%
3920	D392000A	G39201	7300	Transportation Equipment-Autos	25,034,296.44	8,102,533.25	18.00%	4,506,173.36	12,425,589.83	5.47		2,273,313.16	9.08%
3960	D396000A	G39601	7380	Power Operated Equipment	5,112,178.99	2,521,062.51	20.00%	1,022,435.80	1,568,680.68	9.46		165,767.60	3.24%
				Total General Plant Depreciated	38,463,408.80	10,791,172.06		5,528,609.16	22,143,627.58			2,634,451.24	6.85%

1/ Uninflated N/S Cor Ratios - Mains and Services adjusted to reflect non-replaced retirements
2/ SKM Recommended Remaining Life

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ARKANSAS PUBLIC SERVICE COMMISSION
APSC 23-079-U
2023 SUA RATE CASE

REQUEST NO.: AG-001-002

COMPANY NAME: **SUMMIT UTILITIES ARKANSAS**

DATE RECEIVED: **3/4/2024**

DATE DUE: **3/19/2024**

EXTENSION DATE:

INFORMATION REQUESTED:
Refer to Application Schedule: A-1. What portion of the $279,949,398 Revenue Requirement is caused by depreciation expense. Provide the calculation of the number and a narrative description of each element of the calculation. If rate base impacts should be included, please identify, and explain each of those impacts.

REQUESTED BY: **ARKANSAS ATTORNEY GENERAL**

RESPONSE:
The depreciation expense included in the revenue requirement of $279,949,398 is $65,307,762. The calculation can found in MFR Schedule F-1.3, column (13). It is comprised of Distribution Plant depreciation expense of $58,085,030 and General Plant depreciation expense of $7,222,732. Depreciation expense is based on the projected plant-in-service balance by FERC Plant Account at December 31, 2024.

SPONSOR:
Phillip Gillam

RESPONSIVE DOCUMENTS:
None

The foregoing response to the above information request is accurate and complete, and contains no material misrepresentations or omissions based upon present facts known to the undersigned. The undersigned agrees to immediately inform the Requestor if any matters are discovered which would materially affect the accuracy or completeness of the information provided in response to the above information request.

/s/ Brooke South Parsons
Signature of Company Representative

DATE PROVIDED: **MARCH 19, 2024**

APSC FILED Time: 7/10/2024 11:50:36 AM: Recvd 7/10/2024 11:49:53 AM: Docket 23-079-U-Doc. 118

ARKANSAS PUBLIC SERVICE COMMISSION
APSC 23-079-U
2023 SUA RATE CASE

REQUEST NO.: AG-001-007

COMPANY NAME: **SUMMIT UTILITIES ARKANSAS**

DATE RECEIVED: **3/4/2024**

DATE DUE: **3/19/2024**

EXTENSION DATE:

INFORMATION REQUESTED:
Refer to the Direct Testimony of Kurt W. Adams:

a. How did the Docket No. 21-060-U settlement agreement affect depreciation rates, plant balances, accumulated depreciation, and regulatory liabilities?
b. At page 3, Mr. Adams states, "The primary drivers of the proposed rate increase are increases in rate base, and depreciation and amortization expenses." Please identify and explain specifically the increases in depreciation expenses to which M. Adams refers.
c. At page 4, Mr. Adams states "The Company also needs to recover its increased depreciation expenses, which alone represent approximately 38% of the operating expenses…." Provide and explain the source of these numbers.
d. Provide the source and calculation of the $19.4 million Dep & Amort driver shown in the table on page 19.
e. Do most of the new plant additions to the company's plant in service result from replacements of old plant? Please explain.

REQUESTED BY: **ARKANSAS ATTORNEY GENERAL**

RESPONSE:
a. There were no changes in depreciation rates as a result of the Docket No. 21-060-U Settlement Agreement. The plant balances, accumulated depreciation, and regulatory liabilities were transferred to SUA's books with the balances at January 10, 2022 from CNP's books.

b. The depreciation expense increases specifically referred to in Mr. Adams testimony is a comparison of the depreciation expense from CNP's 2020 FRP and the depreciation expense requested in this case. The CNP 2020 FRP depreciation expense was $46,454,323 compared to the $65,307,762 requested by SUA in this case, for a proposed depreciation expense increase of $18,853,439.

c. The Company has requested depreciation expense of $65,307,762 and amortization expense of $3,3470,778 for a total depreciation and amortization expense of $68,778,540. Total operating expenses requested is $177,797,261. The actual percentage of depreciation and amortization expense to total expenses requested is 38.68%.

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d. Please see the response (b) above, and additionally the amortization expense increase is $570,548, which is comprised of the CNP 2020 FRP amortization expense of $2,900,230 compared to the requested amortization expense of $3,470,778.

e. Yes. For 2023 capital expenditures, a little over 67% of the expenditure totals were associated with projects that replaced existing plant. The majority of these replacements are associated with Rehabilitation/System Maintenance/Improvements or Public Improvement projects. Please see AG-001-008 for additional detail.

SPONSOR:
Andy Hagler, Phillip Gillam, Vernon McNully

RESPONSIVE DOCUMENTS:
None

The foregoing response to the above information request is accurate and complete, and contains no material misrepresentations or omissions based upon present facts known to the undersigned. The undersigned agrees to immediately inform the Requestor if any matters are discovered which would materially affect the accuracy or completeness of the information provided in response to the above information request.

/s/ Brooke South Parsons
Signature of Company Representative

DATE PROVIDED: MARCH 19, 2024

APSC FILED Time: 7/10/2024 11:50:36 AM: Recvd 7/10/2024 11:49:53 AM: Docket 23-079-U-Doc. 118

ARKANSAS PUBLIC SERVICE COMMISSION
APSC 23-079-U
2023 SUA RATE CASE

REQUEST NO.: AG-001-012

COMPANY NAME: **SUMMIT UTILITIES ARKANSAS**

DATE RECEIVED: **3/4/2024**

DATE DUE: **3/19/2024**

EXTENSION DATE:

INFORMATION REQUESTED:
For any accounts where Mr. Watson did not base his service life/curve selection on the best-fit life/curve combination, explain why he did not.

REQUESTED BY: **ARKANSAS ATTORNEY GENERAL**

RESPONSE:
Please refer to Mr. Watson's testimony Direct Exhibit DAW-1, in the life analysis section where a discussion and illustrative graph are provided to support his recommendation. Mr. Watson utilizes a visual fitting technique (that Mr. Watson believes is a more informative technique than simply using a single best fit statistic) as his primary fitting technique. It is a common and preferred life analysis method in the industry. Direct Exhibit DAW-1, page 15 explains the actuarial analysis process used. All visual fits have been provided in the study workpapers "Actuarial 2022" folder and within each account the information would be found in the "Graphs" folder. Please see response to AG-001-001 for workpapers provided with the Company's filing.

SPONSOR:
Dane Watson

RESPONSIVE DOCUMENTS:
None

The foregoing response to the above information request is accurate and complete, and contains no material misrepresentations or omissions based upon present facts known to the undersigned. The undersigned agrees to immediately inform the Requestor if any matters are discovered which would materially affect the accuracy or completeness of the information provided in response to the above information request.

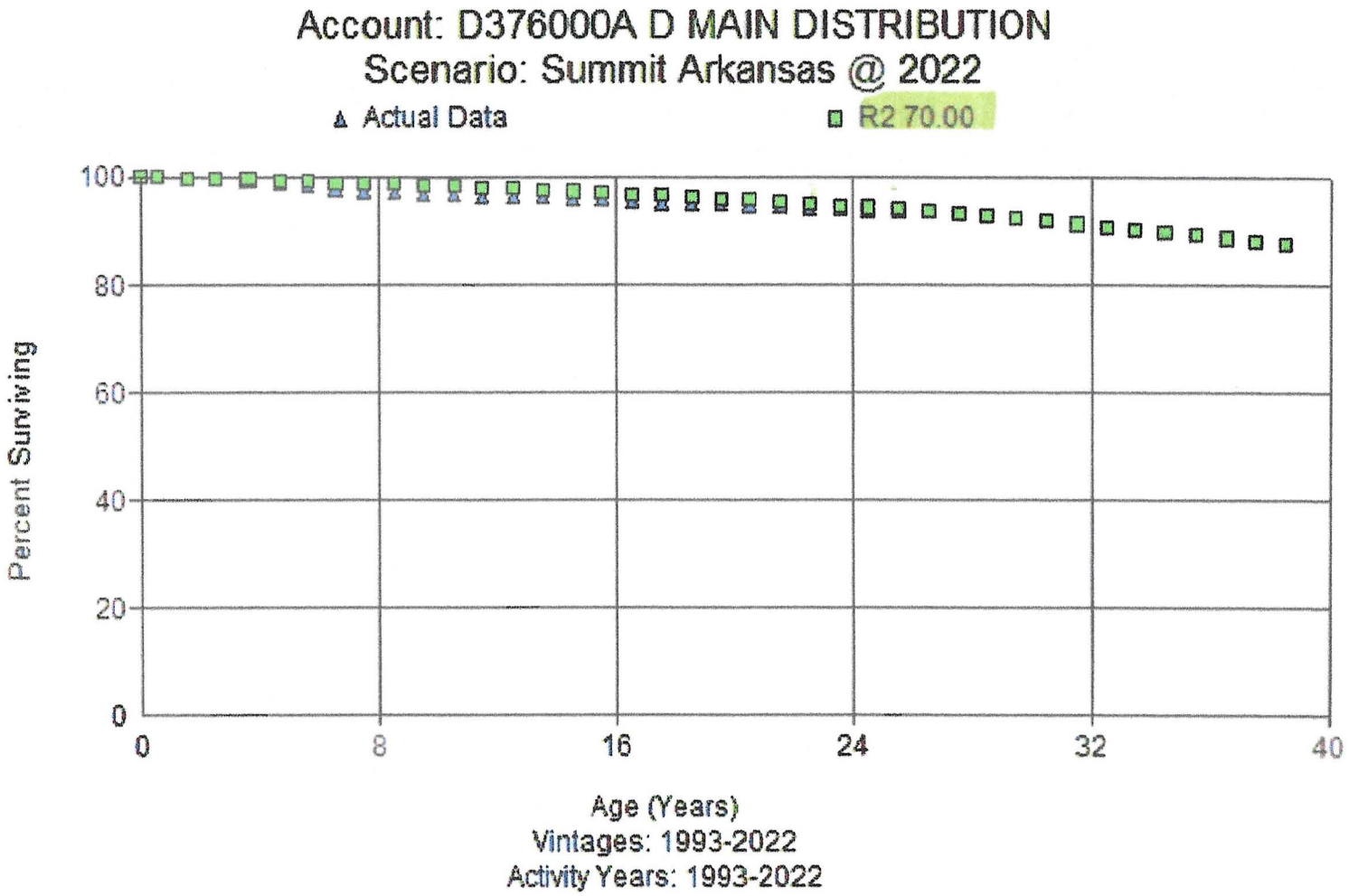
/s/ Brooke South Parsons
Signature of Company Representative

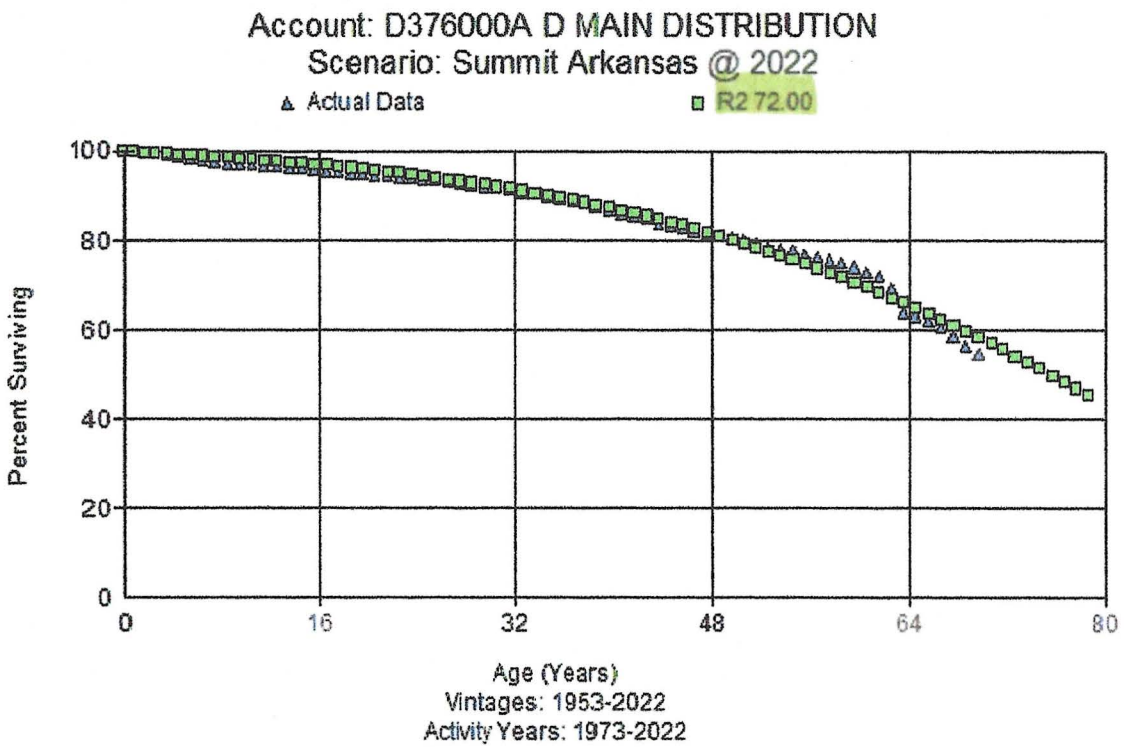
DATE PROVIDED: **MARCH 19, 2024**

ACCEPTED Date: 7/10/2024 11:50:36 AM: Recvd 7/10/2024 11:49:53 AM: Docket 23-079-U-Doc. 118

Exhibit___(MJM-5)

COPIES OF SELECTED SUA LIFE CHARTS
ACCOUNT 376 - MAINS

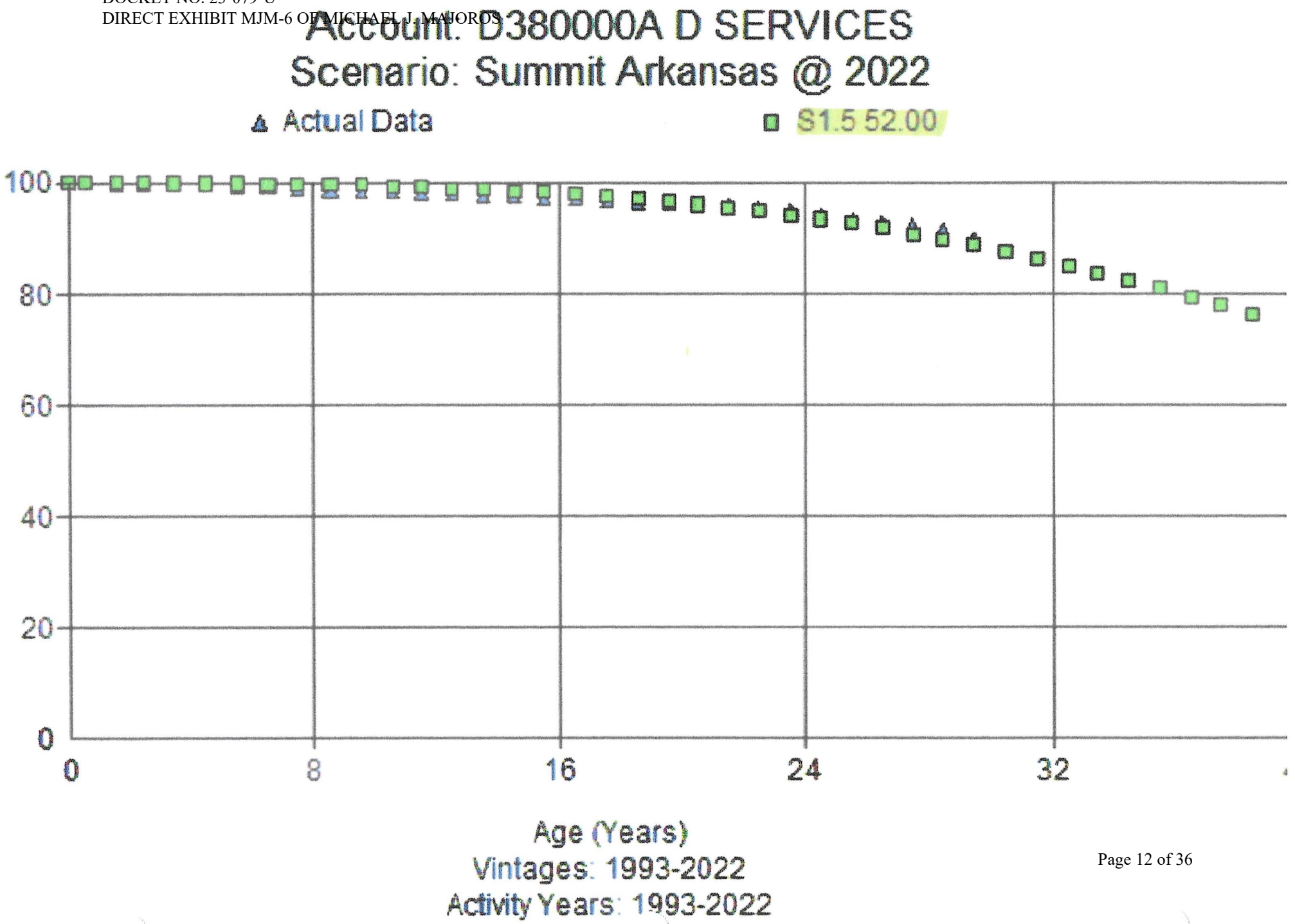

Account: D376000A D MAIN DISTRIBUTION
Scenario: Summit Arkansas @ 2022
Actual Data
R2 70.00
Percent Surviving
100
80
60
40
20
0
0
8
16
24
32
40
Age (Years)
Vintages: 1993-2022
Activity Years: 1993-2022

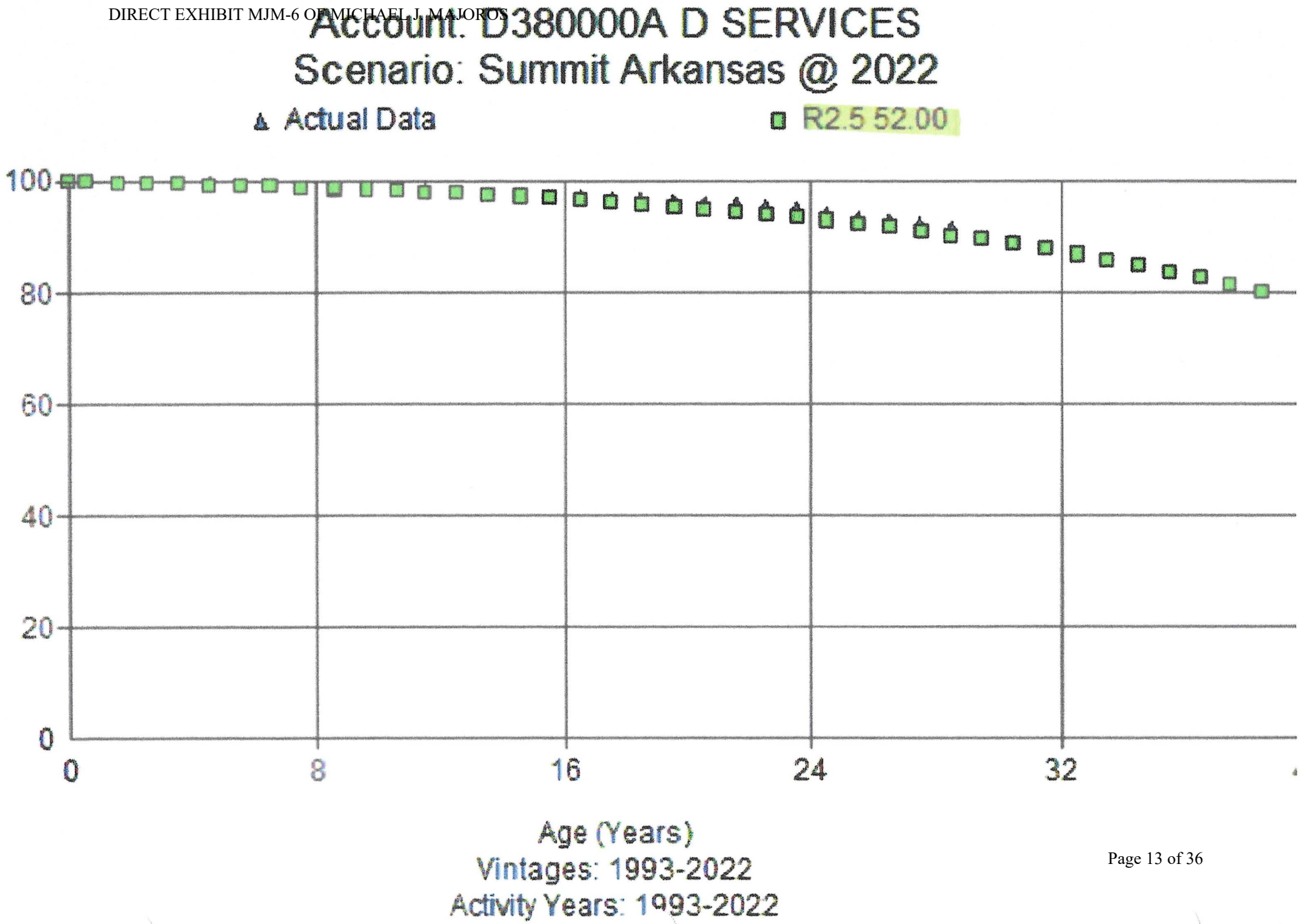

Account: D376000A D MAIN DISTRIBUTION
Scenario: Summit Arkansas @ 2022
Actual Data
R2 72.00
Percent Surviving
100
80
60
40
20
0
0
16
32
48
64
80
Age (Years)
Vintages: 1953-2022
Activity Years: 1973-2022

ARSC Date: 7/10/2024 11:50:36 AM: Recvd 7/10/2024 11:49:53 AM: Docket 23-079-U-Doc. 118

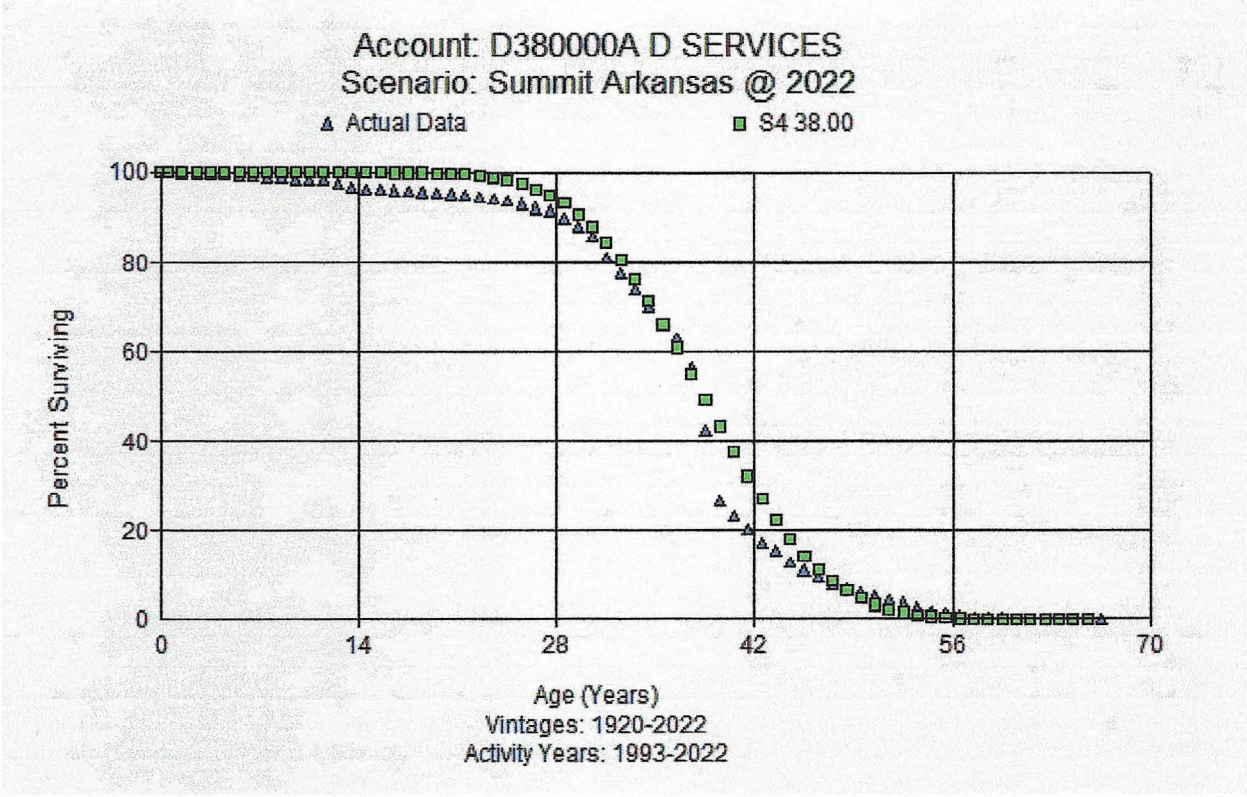
Exhibit___(MJM-6)

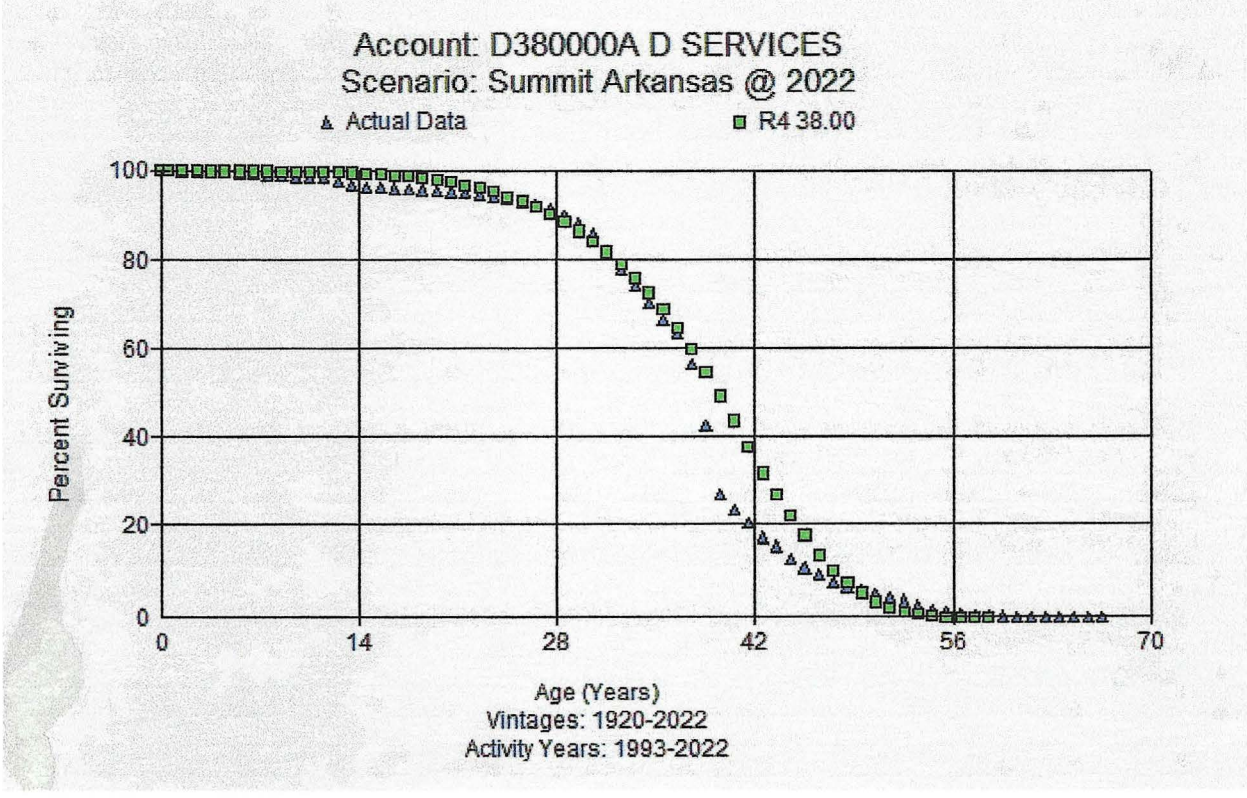
COPIES OF ALL SUA LIFE CHARTS
ACCOUNT 380 - SERVICES


Account: D380000A D SERVICES
Scenario: Summit Arkansas @ 2022
Actual Data
S1.5 52.00
100
80
60
40
20
0
0
8
16
24
32
Age (Years)
Vintages: 1993-2022
Activity Years: 1993-2022

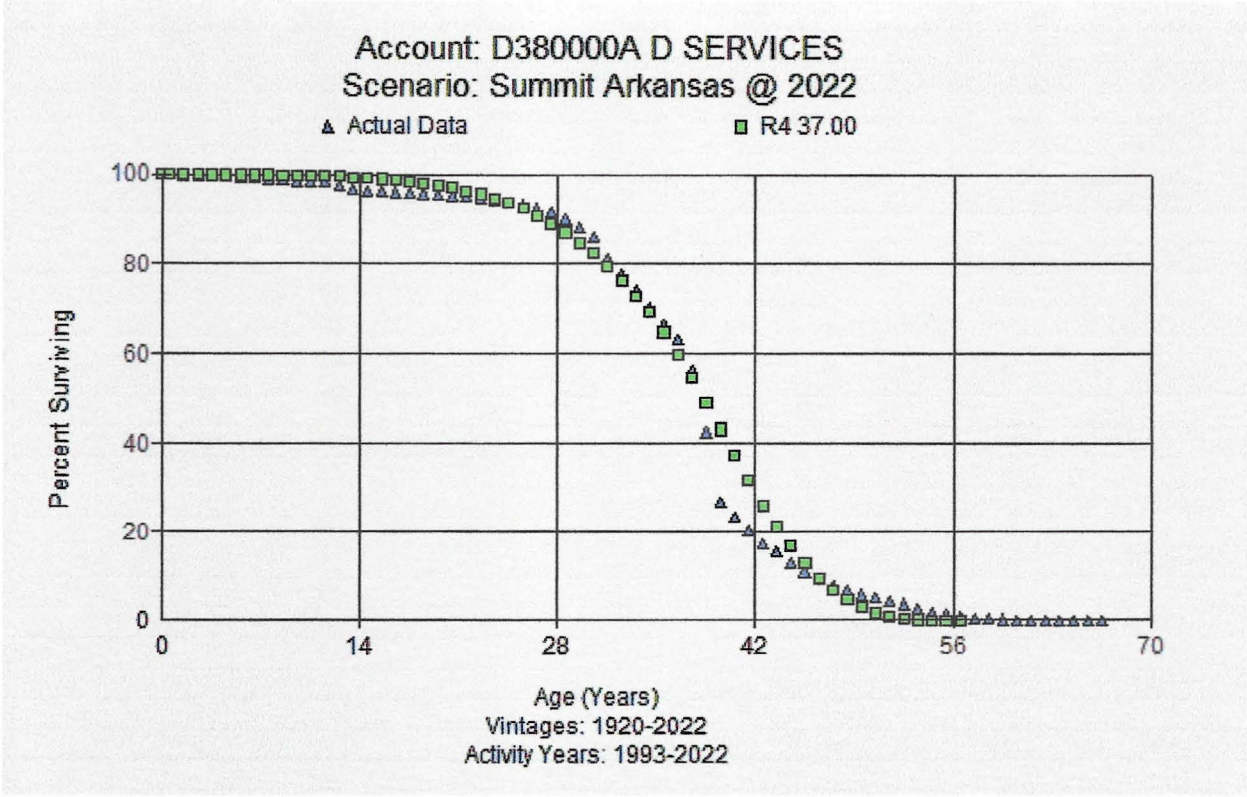

Account: D380000A D SERVICES
Scenario: Summit Arkansas @ 2022
Actual Data
R2.5 52.00
100
80
60
40
20
0
0
8
16
24
32
Age (Years)
Vintages: 1993-2022
Activity Years: 1993-2022

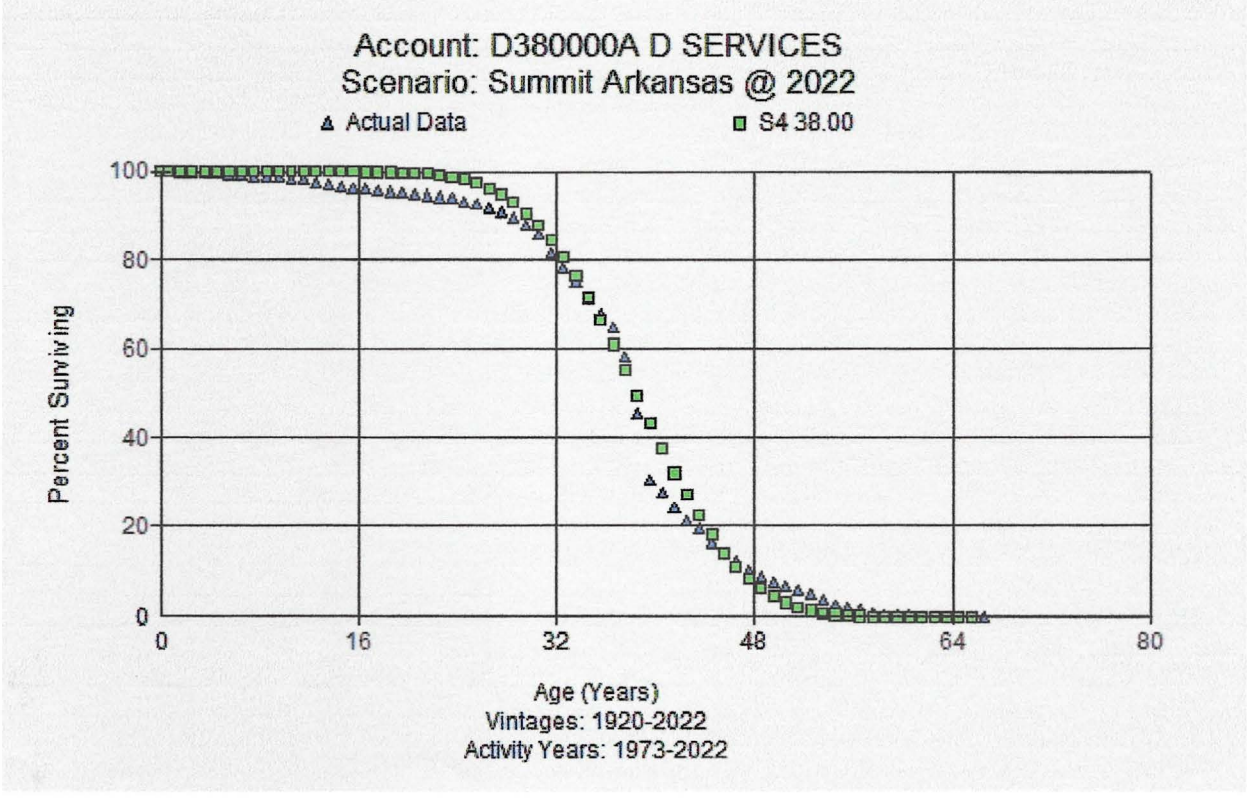
APSC FILED Time: 7/10/2024 11:50:36 AM: Recvd 7/10/2024 11:49:53 AM: Docket 23-079-U-Doc. 118



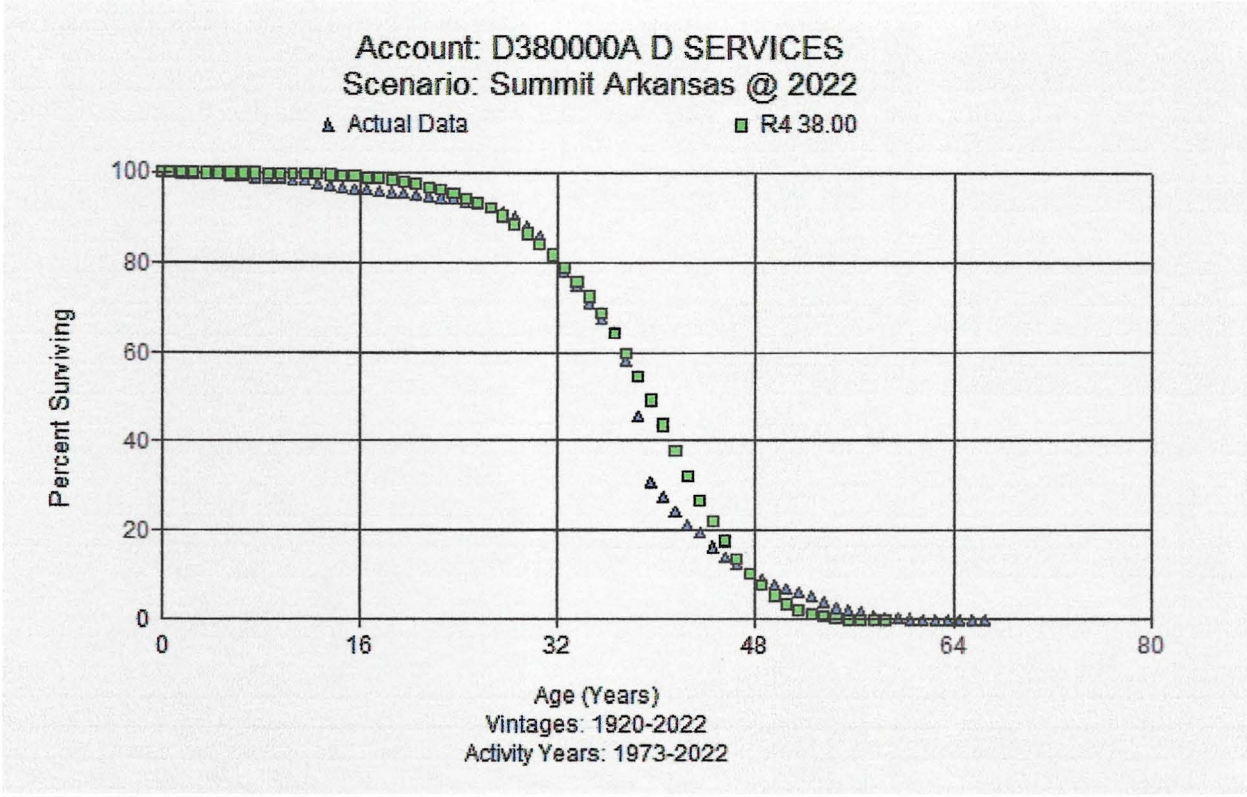


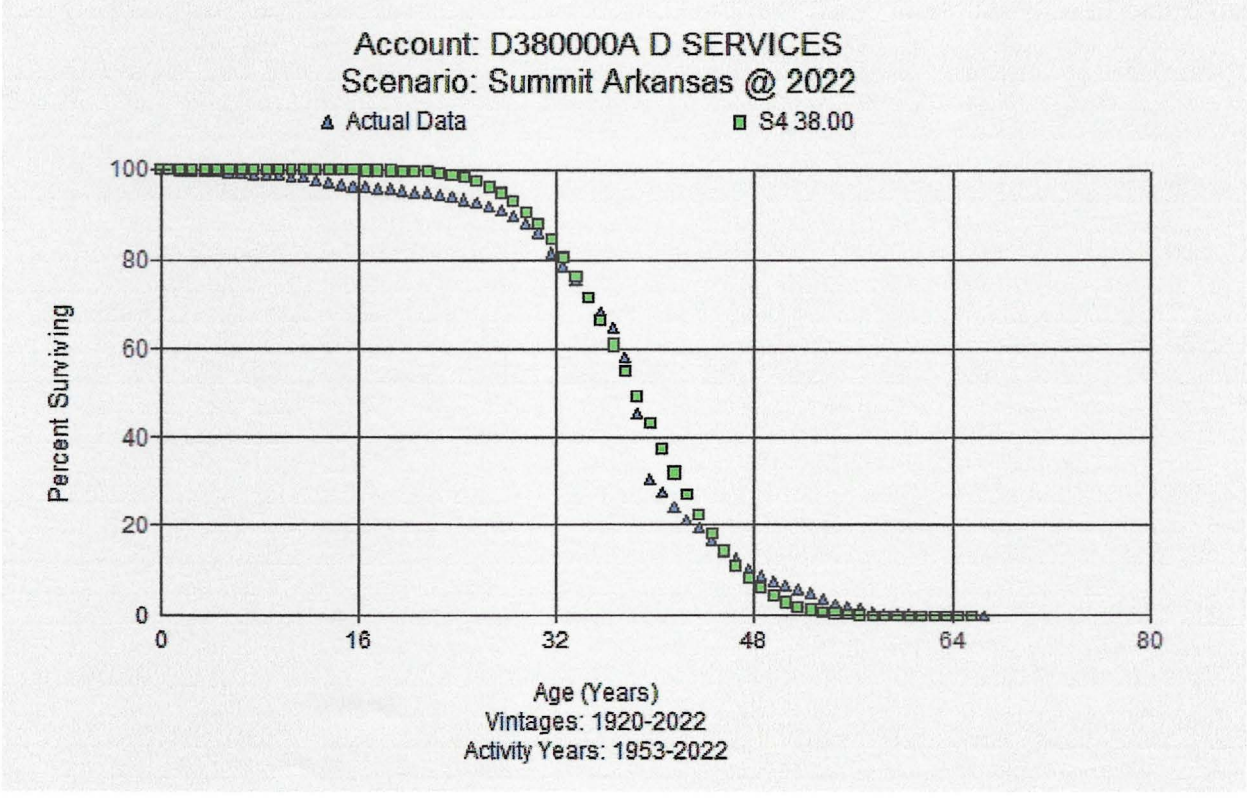
AP SC FILED Time: 7/10/2024 11:50:36 AM: Recvd 7/10/2024 11:49:53 AM: Docket 23-079-U-Doc. 118



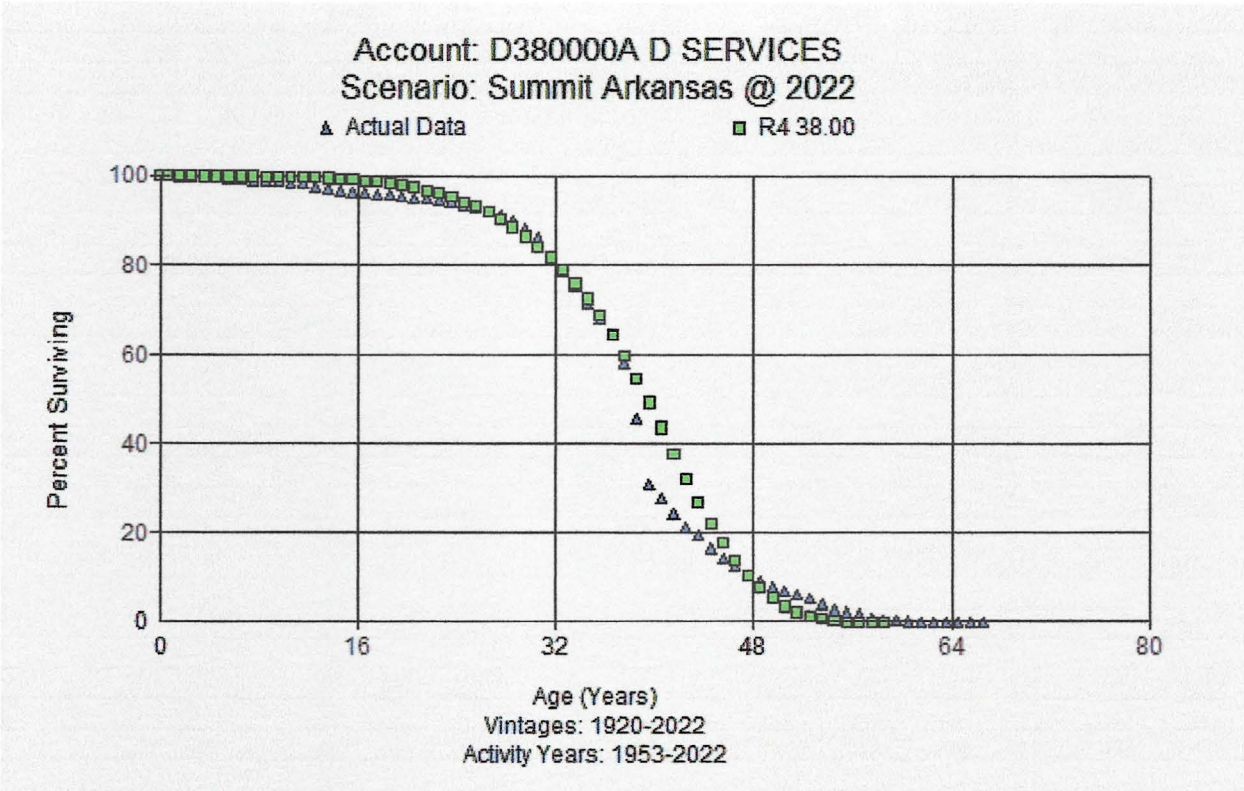


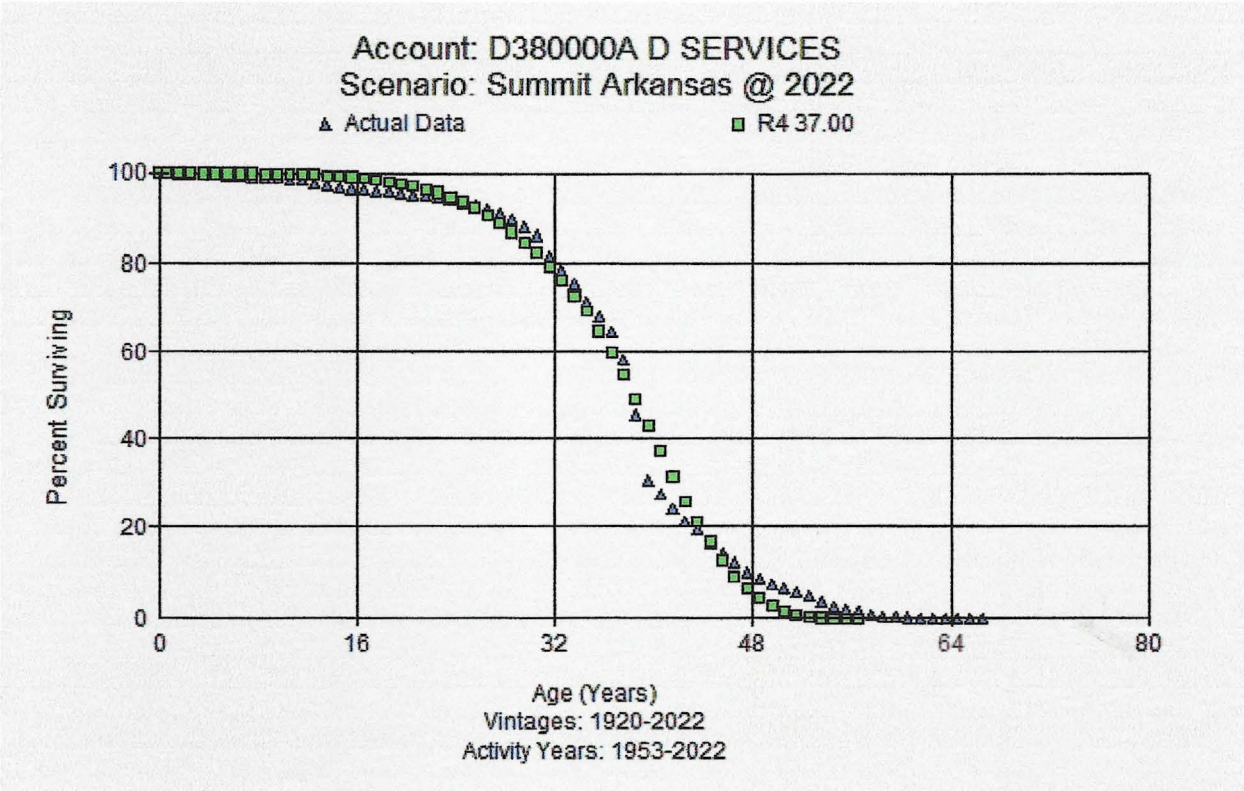
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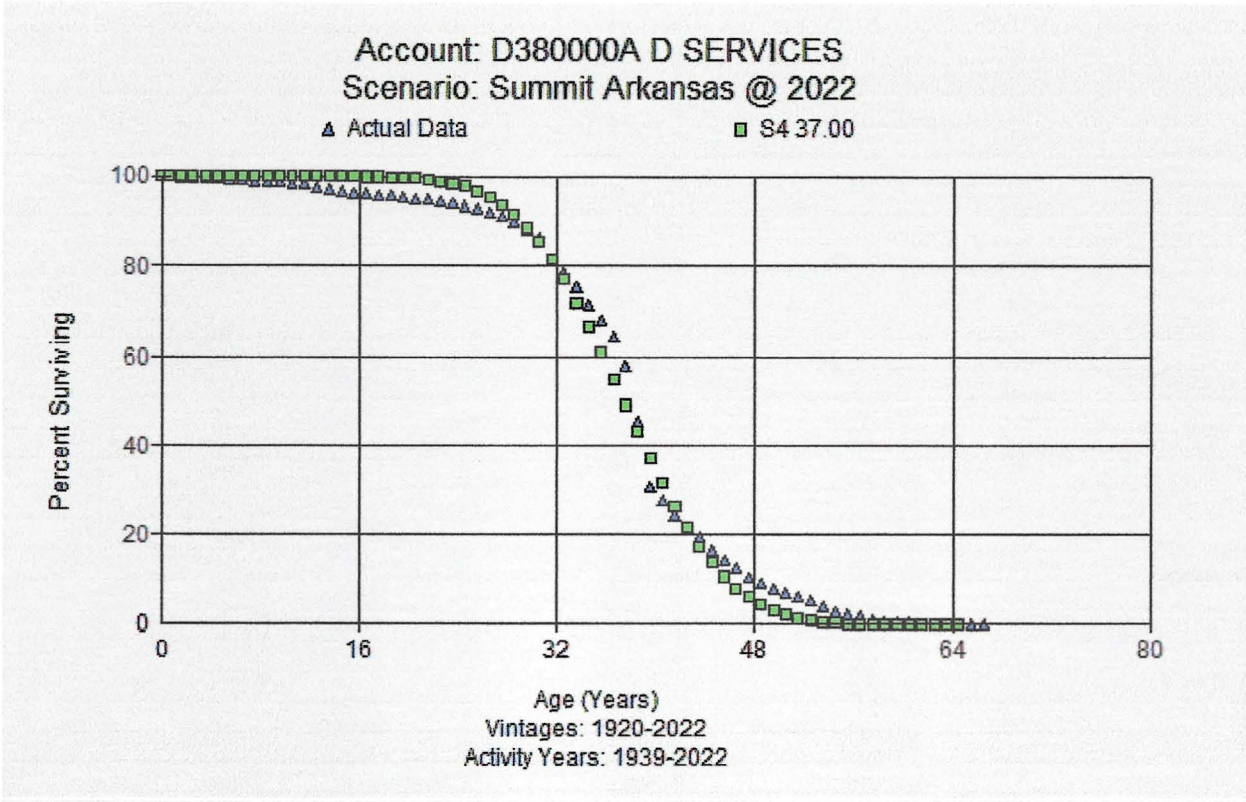


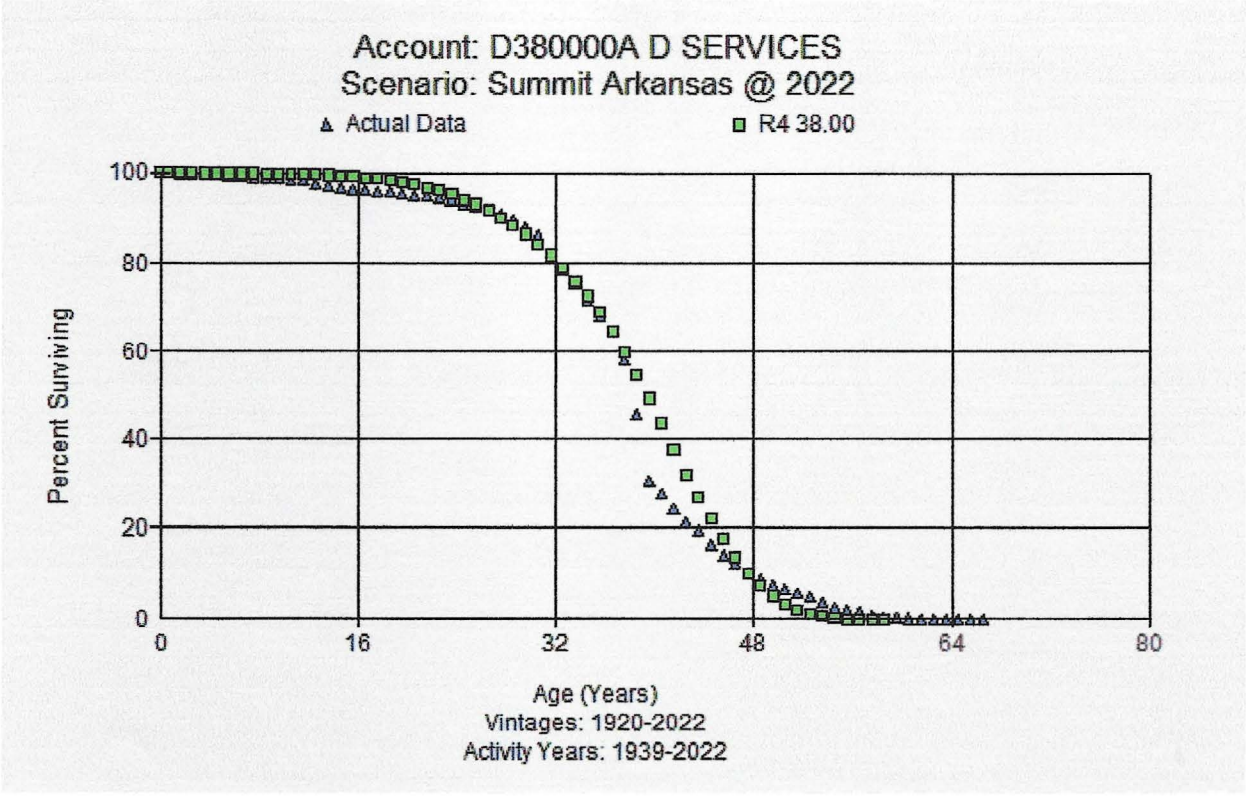
ARKANSAS PUBLIC SERVICE COMMISSION 7/10/2024 11:50:36 AM: Recvd 7/10/2024 11:49:53 AM: Docket 23-079-U-Doc. 118



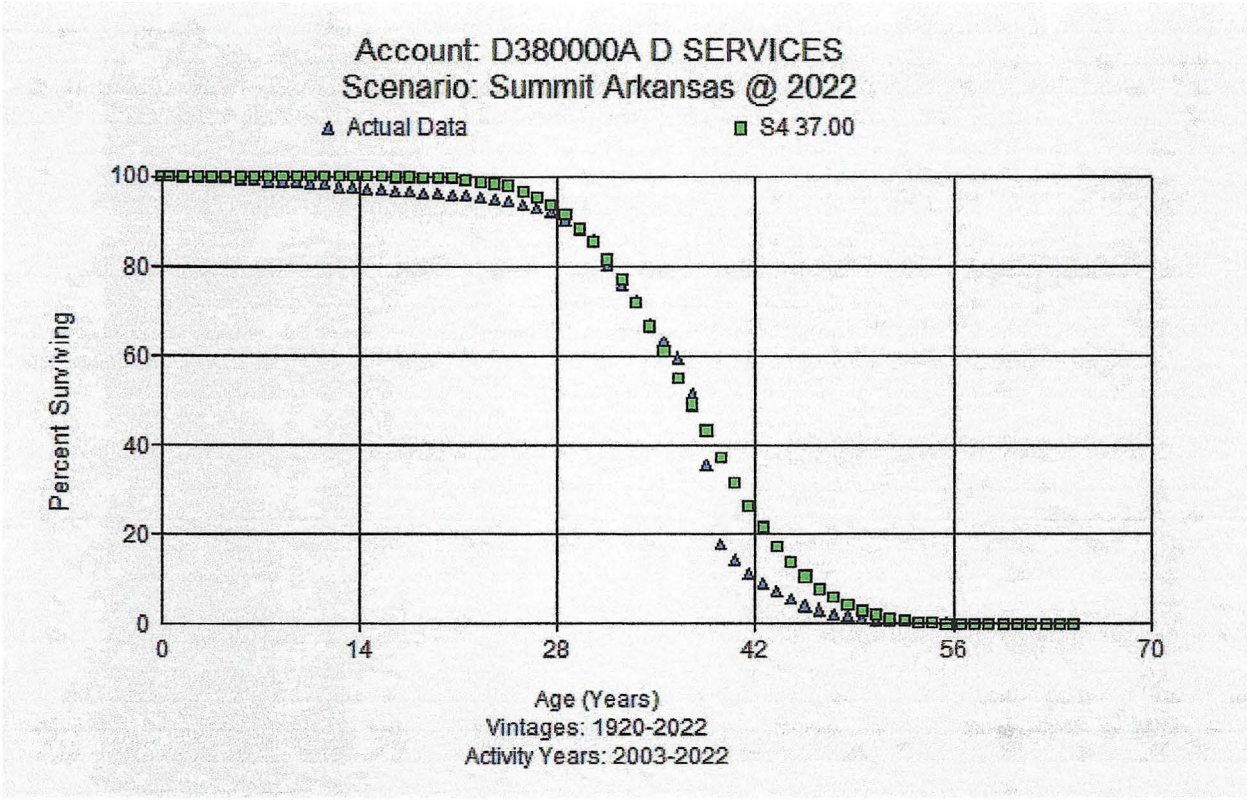


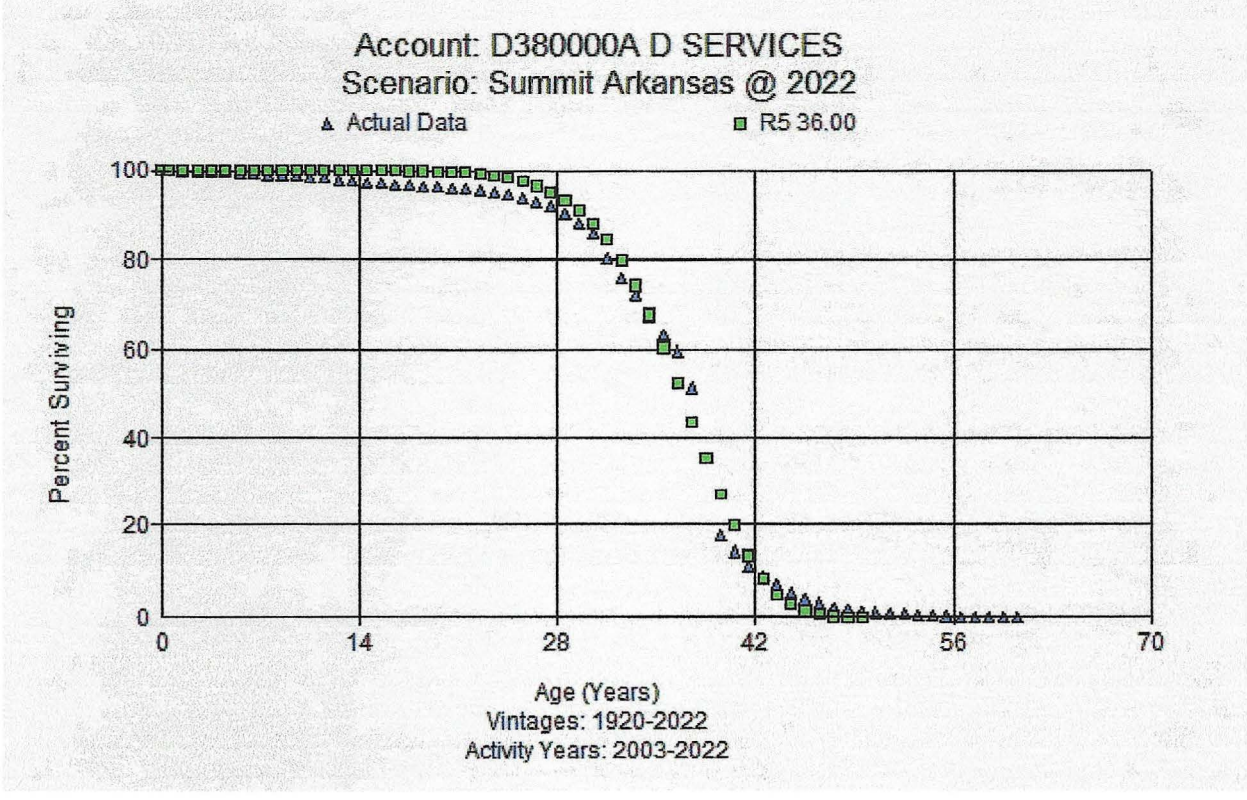
ARSC FILED Time: 7/10/2024 11:50:36 AM: Recvd 7/10/2024 11:49:53 AM: Docket 23-079-U-Doc. 118



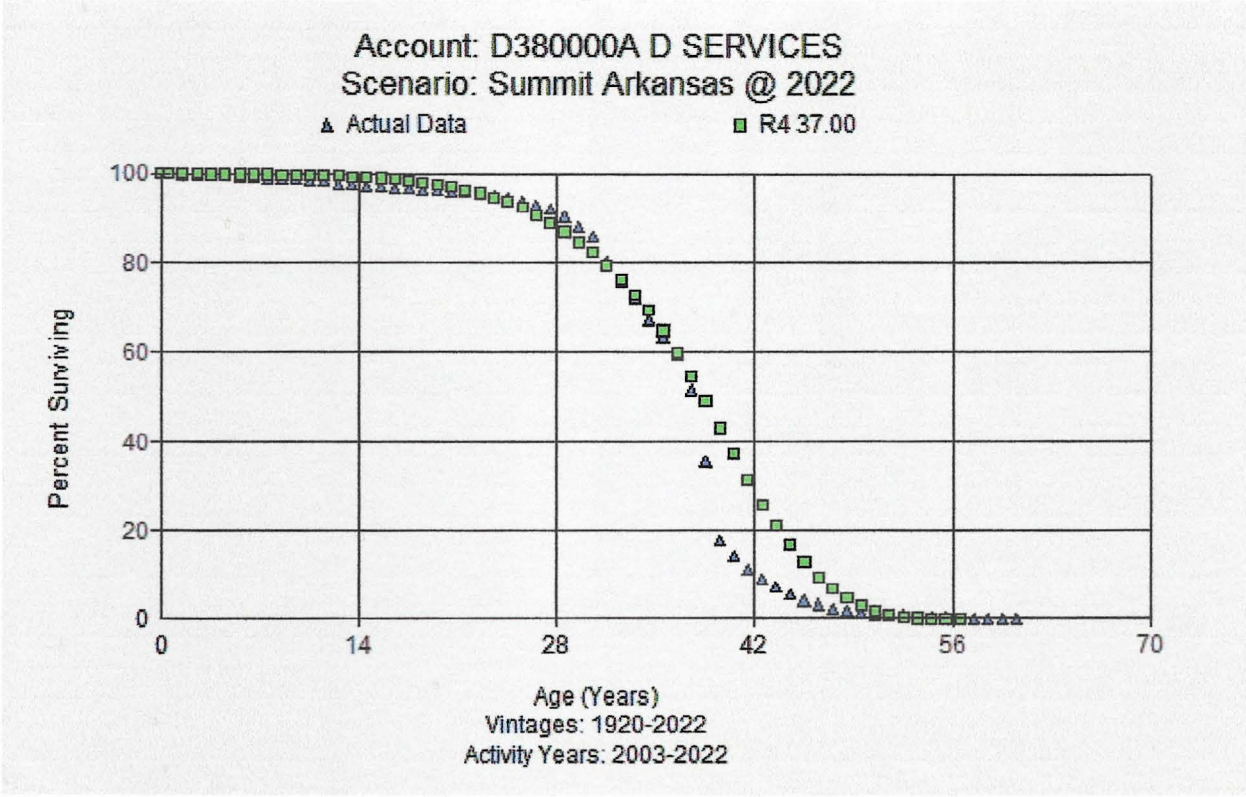


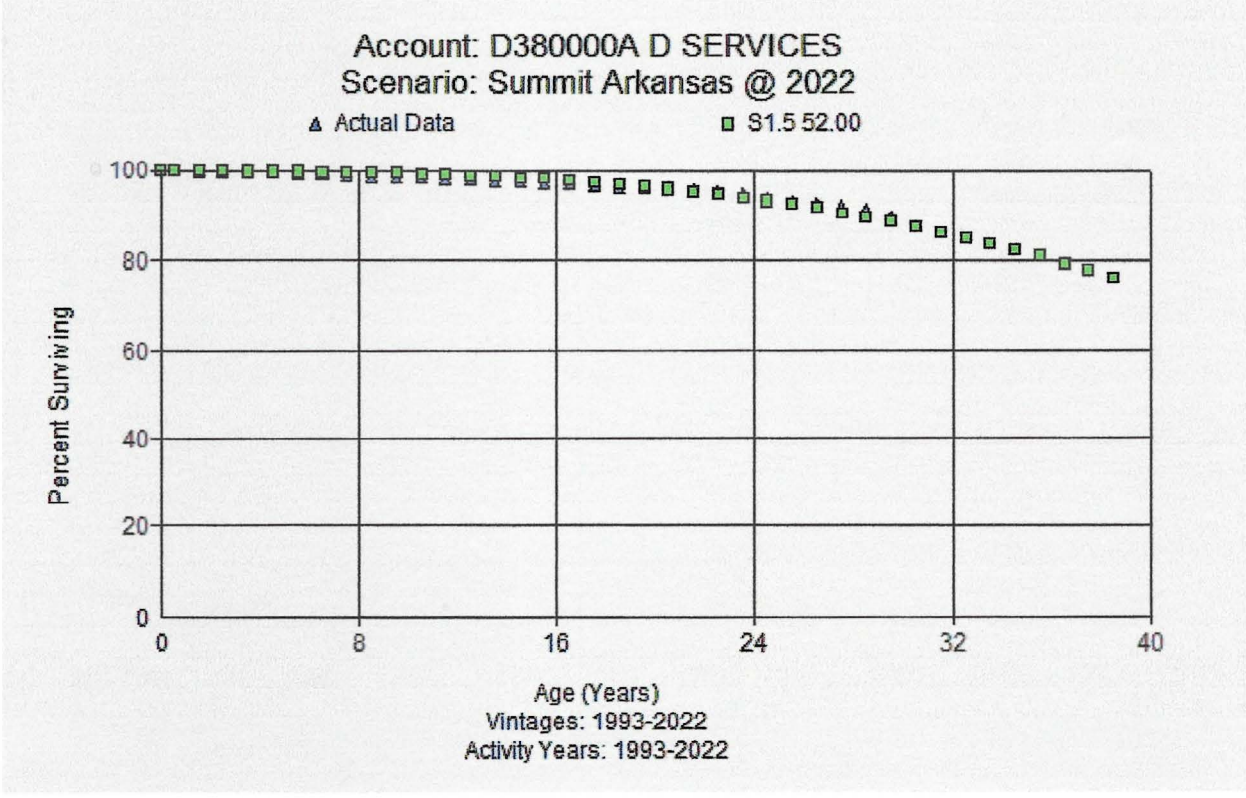
APSC FILED Time: 7/10/2024 11:50:36 AM: Recvd 7/10/2024 11:49:53 AM: Docket 23-079-U-Doc. 118



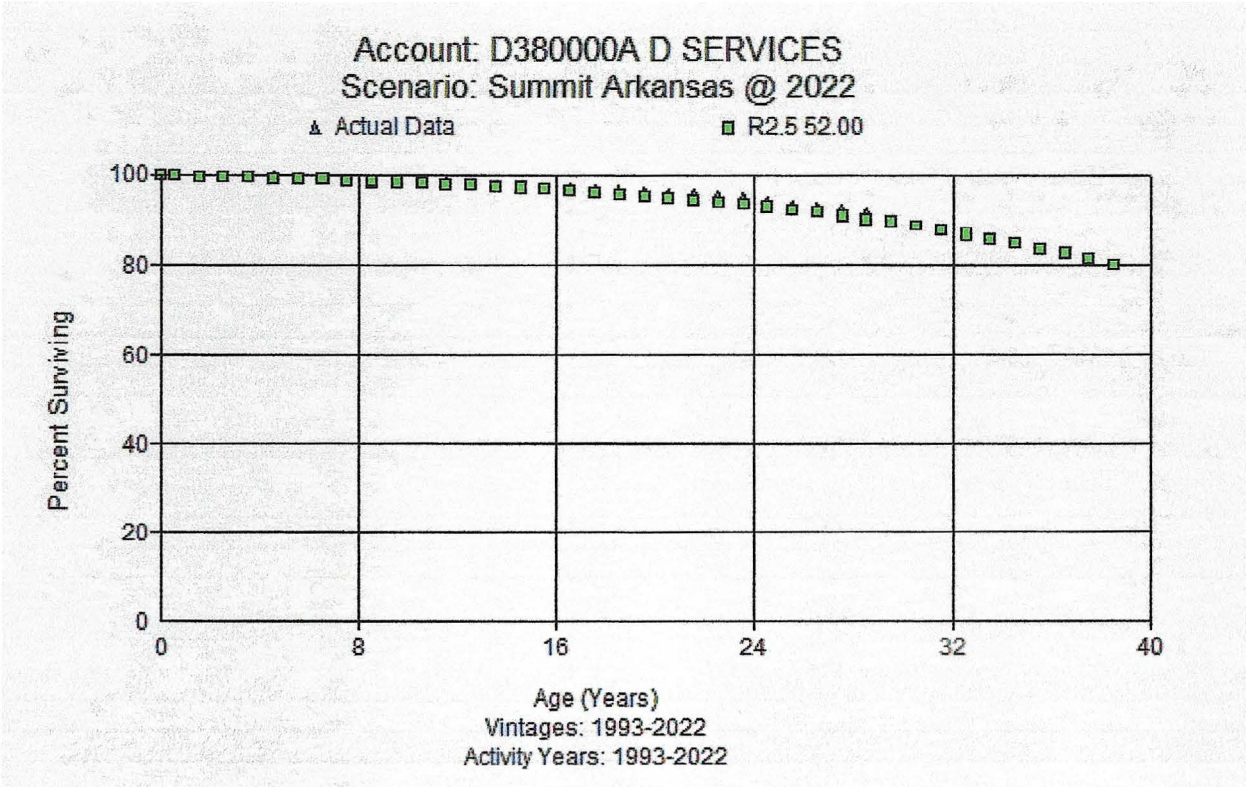


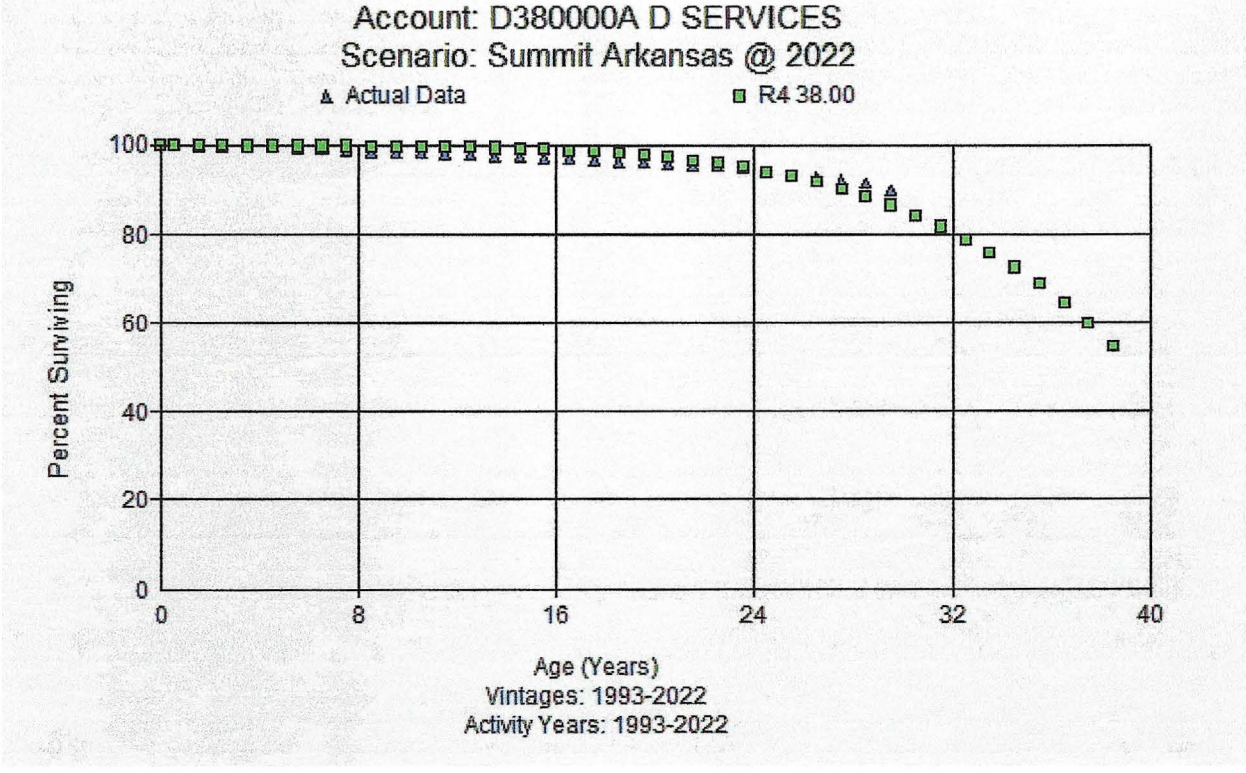
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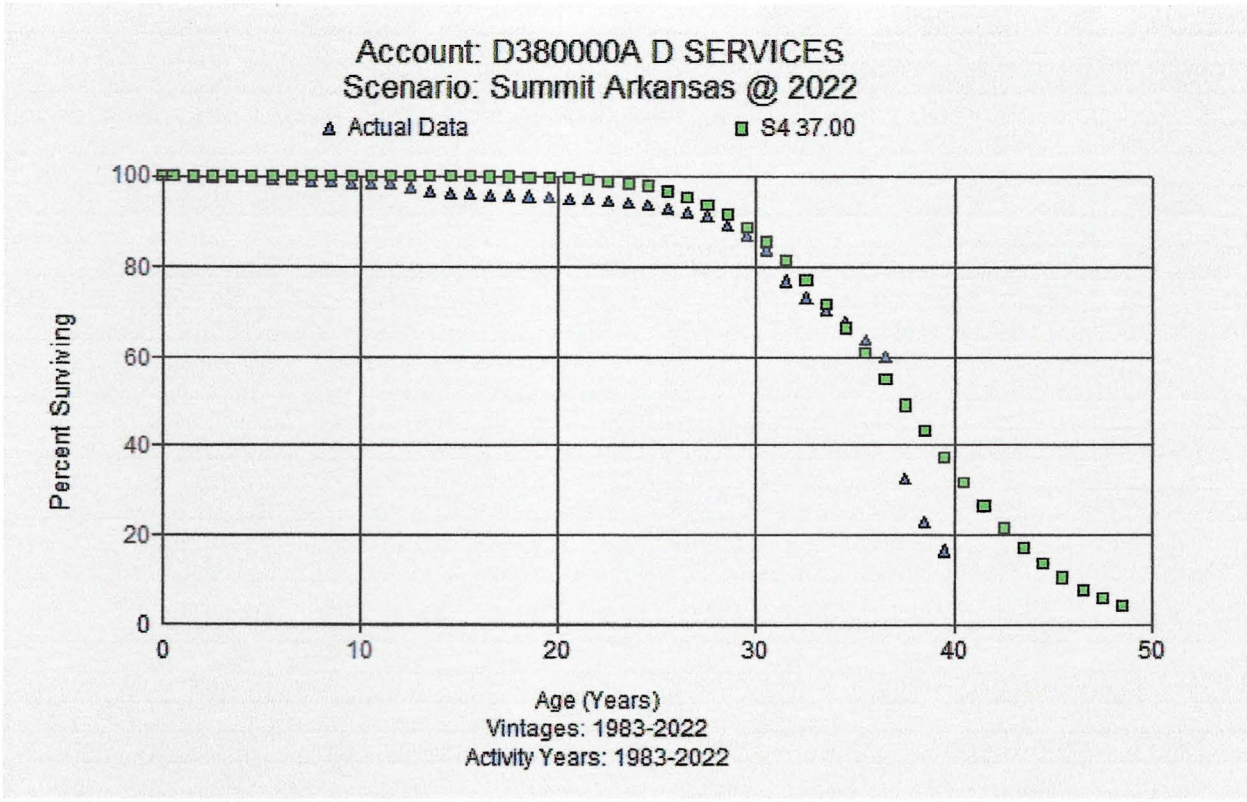


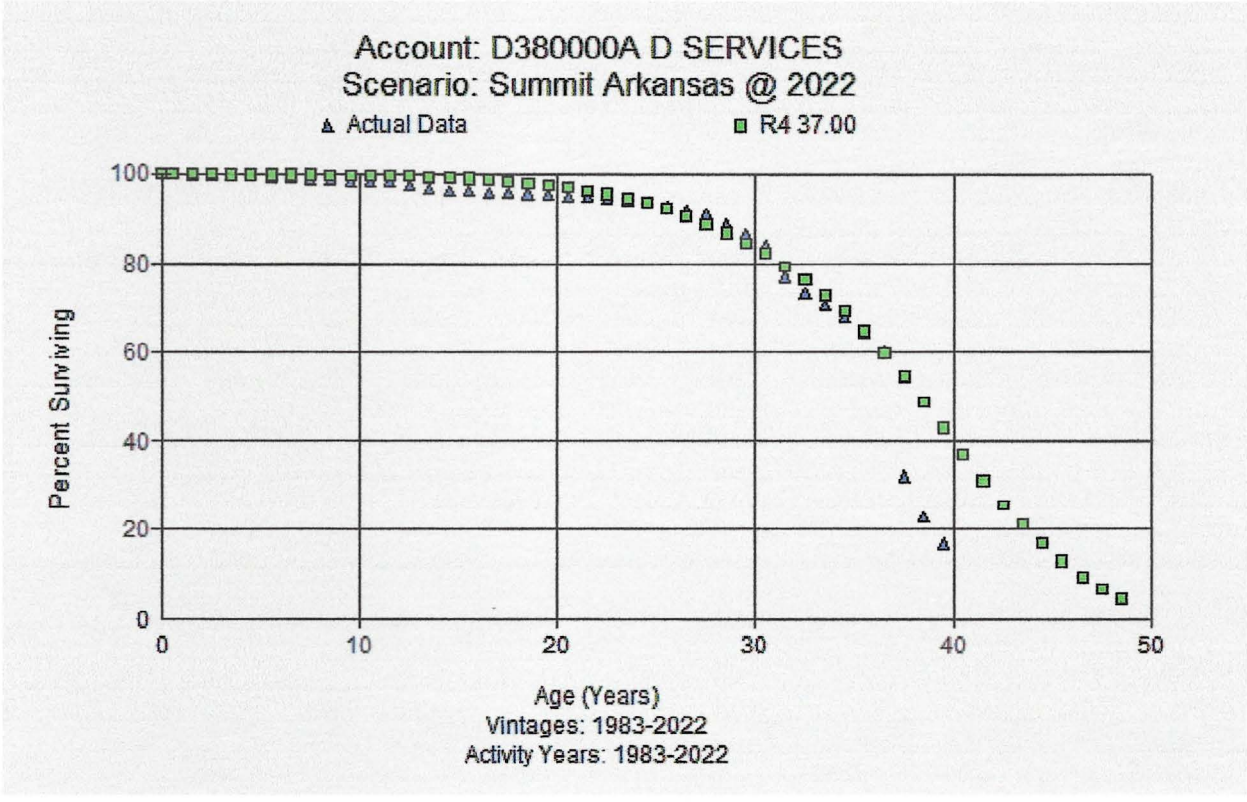
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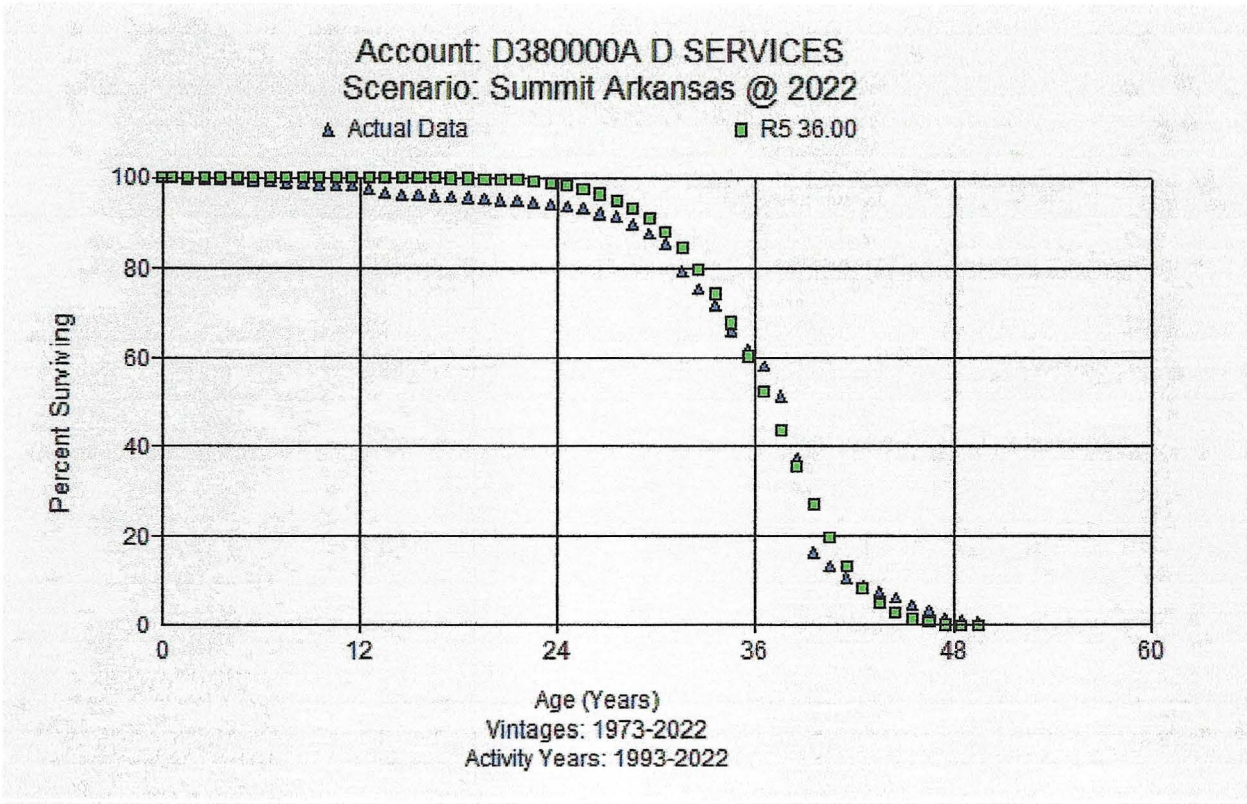


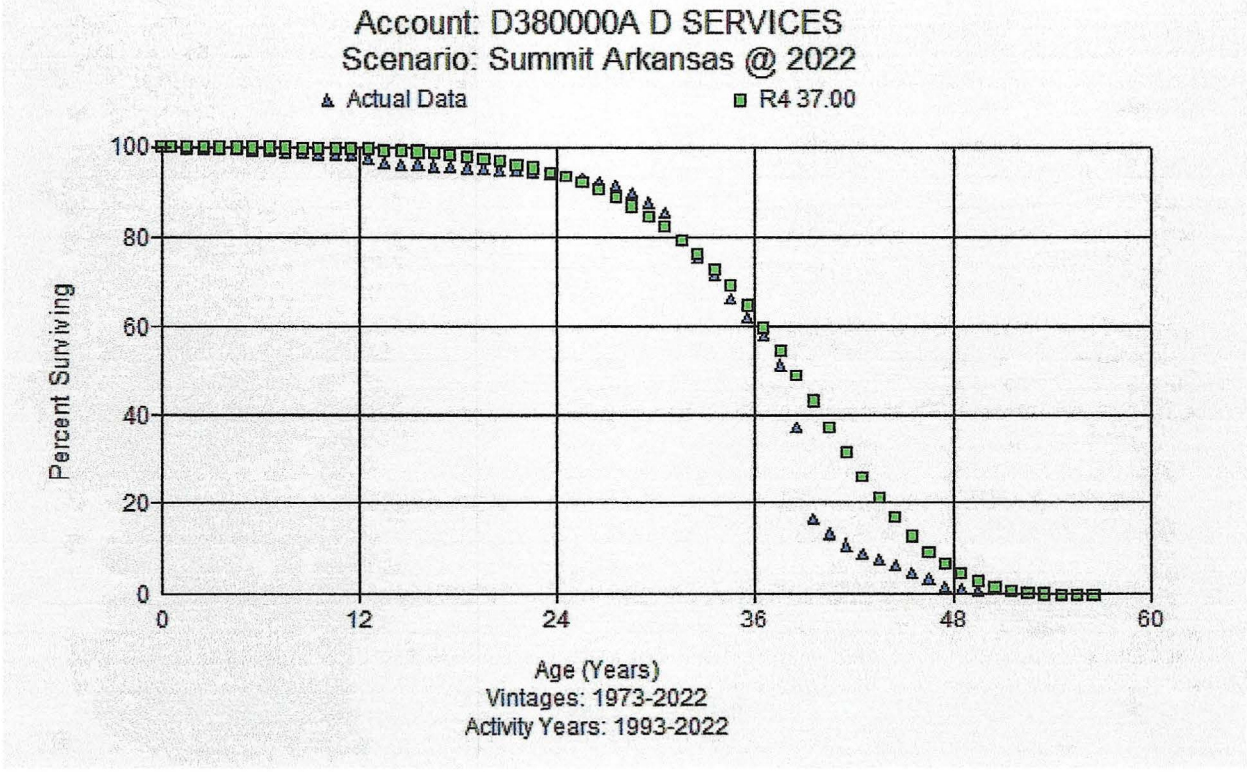
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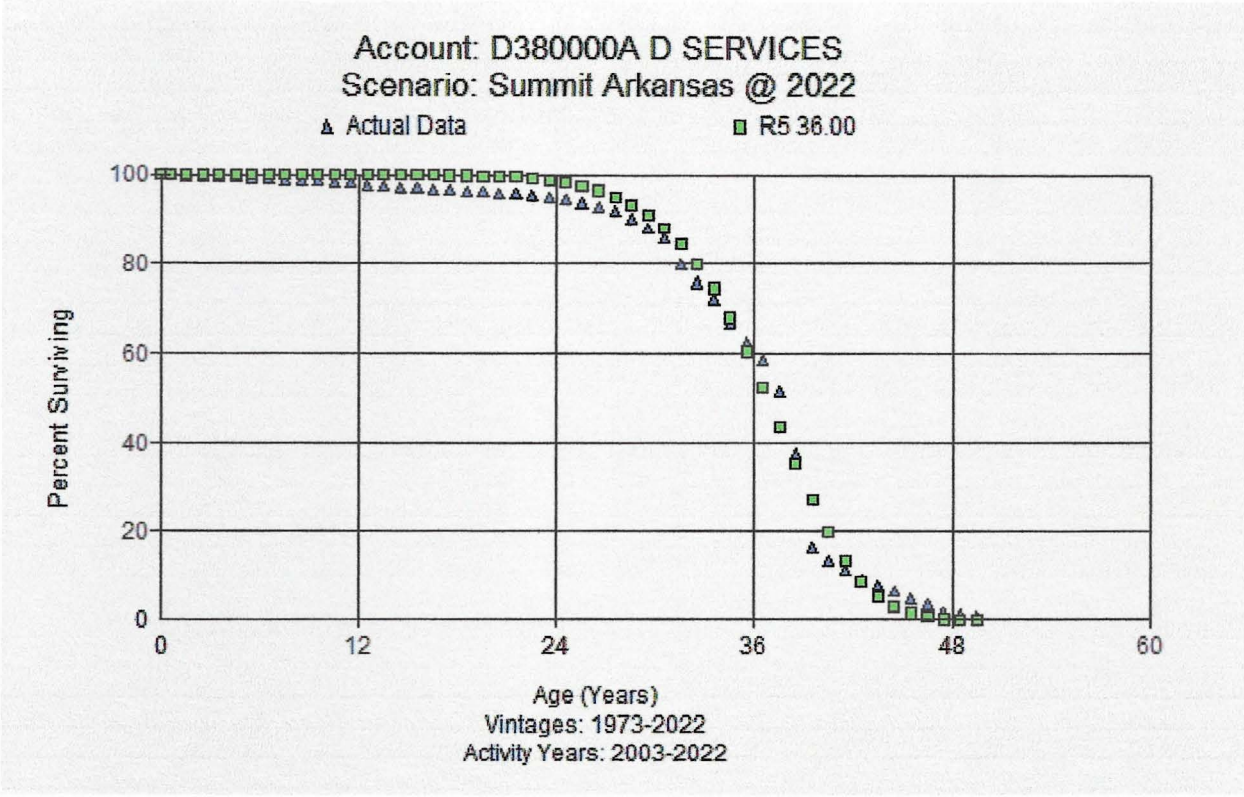


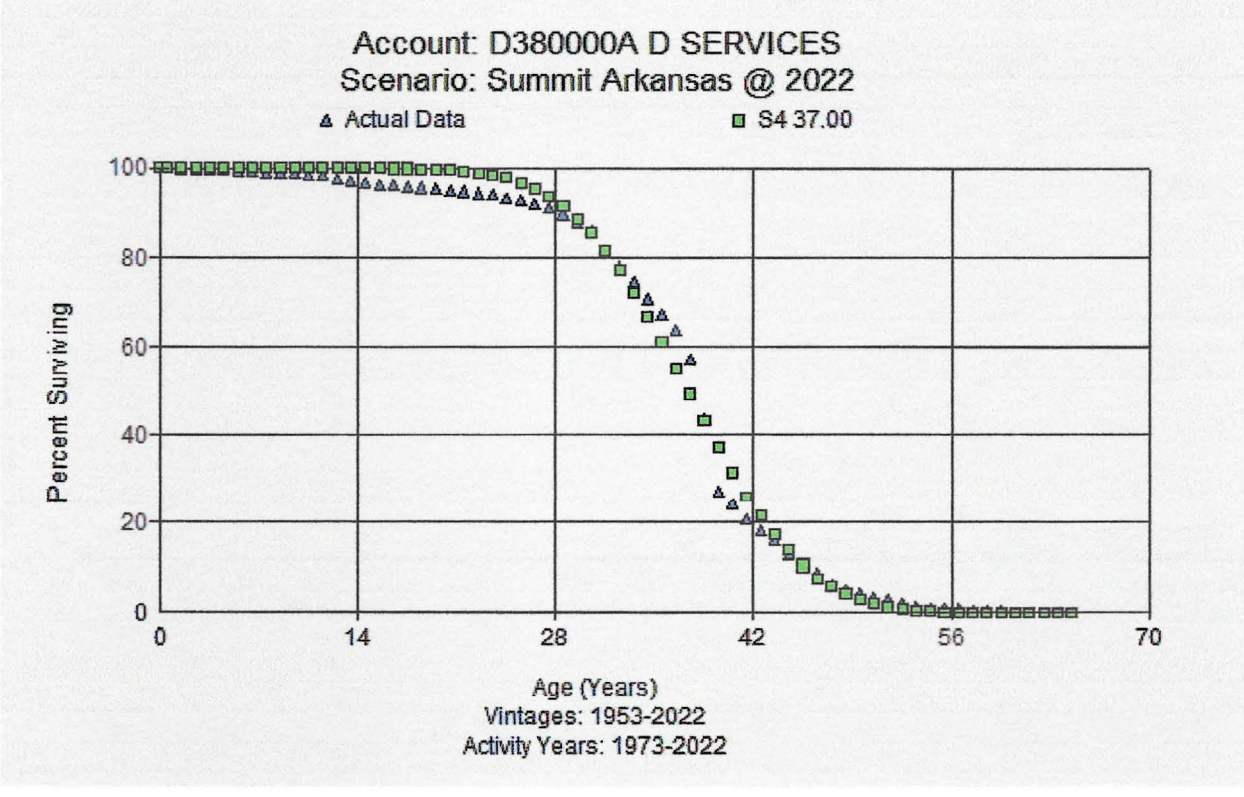


APSC FILED Time: 7/10/2024 11:50:36 AM: Recvd 7/10/2024 11:49:53 AM: Docket 23-079-U-Doc. 118






Account: D380000A D SERVICES
Scenario: Summit Arkansas @ 2022
Actual Data
R5 36.00
Percent Surviving
100
80
60
40
20
0
0
12
24
36
48
60
Age (Years)
Vintages: 1973-2022
Activity Years: 2003-2022


Account: D380000A D SERVICES
Scenario: Summit Arkansas @ 2022
Actual Data
S4 37.00
Percent Surviving
100
80
60
40
20
0
0
14
28
42
56
70
Age (Years)
Vintages: 1953-2022
Activity Years: 1973-2022

Summit Utilities-Arkansas
Geometric Mean Turnover Analysis
Account 380- Services

									3 Year Band					
Year	BOY Plant Balance	Avg. Plant Balance	Single Year Additions	Single Year Retirements	Addition Ratio	Retirement Ratio	Geometric Mean Life Estimate	3 Year Band	Avg. Plant Balance	Additions	Retirements	Addition Ratio	Retirement Ratio	Geometric Mean Life Estimate
	a	b=(a+prev a)/2	c	d	e = c/b	f = d/b	g = 1/sqrt(e*f)	h	i	j	k	l = j/i	m = k/i	n = 1/sqrt(l*m)
1920			26		#DIV/0!	#DIV/0!	#DIV/0!	1919-17	-	26	-	-	-	-
1921	26	13			0.00000	0.00000	-	1920-18						
1922	26	26			0.00000	0.00000	-	1921-19		-	-	-	-	-
1923	26	26			0.00000	0.00000	-	1922-20	66	-	-	-	-	-
1924	26	26			0.00000	0.00000	-	1923-21	79	-	-	-	-	-
1925	26	26			0.00000	0.00000	-	1924-22	79	-	-	-	-	-
1926	26	26			0.00000	0.00000	-	1925-23	79	-	-	-	-	-
1927	26	26			0.00000	0.00000	-	1926-24	79	-	-	-	-	-
1928	26	26			0.00000	0.00000	-	1927-25	79	-	-	-	-	-
1929	26	26			0.00000	0.00000	-	1928-26	79	-	-	-	-	-
1930	26	26			0.00000	0.00000	-	1929-27	79	-	-	-	-	-
1931	26	26	21		0.78887	0.00000	-	1930-28	79	21	-	0.26296	-	-
1932	47	37			0.00000	0.00000	-	1931-29	89	21	-	0.23240	-	-
1933	47	47			0.00000	0.00000	-	1932-30	110	21	-	0.18858	-	-
1934	47	47			0.00000	0.00000	-	1933-31	130	-	-	-	-	-
1935	47	47			0.00000	0.00000	-	1934-32	141	-	-	-	-	-
1936	47	47			0.00000	0.00000	-	1935-33	141	-	-	-	-	-
1937	47	47	9		0.19727	0.00000	-	1936-34	141	9	-	0.06576	-	-
1938	56	52			0.00000	0.00000	-	1937-35	145	9	-	0.06366	-	-
1939	56	56	461,172	499	8205.91317	8.87206	0.00	1938-36	155	461,182	499	2,980.94228	3.22287	0.01
1940	460,730	230,393	35,253	36	0.15301	0.00016	203.25	1939-37	230,501	496,425	535	2.15368	0.00232	14.14
1941	495,946	478,338	54,539	33	0.11402	0.00007	355.80	1940-38	708,787	550,964	568	0.77733	0.00080	40.06
1942	550,452	523,199	26,926	22	0.05146	0.00004	674.74	1941-39	1,231,930	116,718	92	0.09474	0.00007	376.11
1943	577,356	563,904	74,194	15	0.13157	0.00003	540.33	1942-40	1,565,442	155,659	70	0.09943	0.00004	473.74
1944	651,535	614,446	25,010	39	0.04070	0.00006	621.91	1943-41	1,701,549	126,130	76	0.07413	0.00004	549.43
1945	676,506	664,021	73,218	59	0.11026	0.00009	318.81	1944-42	1,842,371	172,421	113	0.09359	0.00006	417.46
1946	749,664	713,085	54,100	51	0.07587	0.00007	429.21	1945-43	1,991,552	152,327	149	0.07649	0.00007	417.61
1947	803,713	776,689	156,487	112	0.20148	0.00014	185.87	1946-44	2,153,795	283,805	222	0.13177	0.00010	271.43
1948	960,089	881,901	156,301	289	0.17723	0.00033	131.20	1947-45	2,371,675	366,888	452	0.15470	0.00019	184.24
1949	1,116,101	1,038,095	458,937	501	0.44210	0.00048	68.45	1948-46	2,696,685	771,726	902	0.28618	0.00033	102.22
1950	1,574,537	1,345,319	235,410	553	0.17498	0.00041	117.90	1949-47	3,265,315	850,648	1,343	0.26051	0.00041	96.60
1951	1,809,394	1,691,966	285,614	46	0.16881	0.00003	468.17	1950-48	4,075,380	979,961	1,100	0.24046	0.00027	124.13
1952	2,094,962	1,952,178	429,576	4,906	0.22005	0.00251	42.52	1951-49	4,989,463	950,600	5,505	0.19052	0.00110	68.97
1953	2,519,632	2,307,297	547,679	5,369	0.23737	0.00233	42.55	1952-50	5,951,441	1,262,869	10,321	0.21220	0.00173	52.13
1954	3,061,942	2,790,787	406,915	1,538	0.14581	0.00055	111.55	1953-51	7,050,262	1,384,170	11,814	0.19633	0.00168	55.13
1955	3,467,318	3,264,630	278,425	816	0.08529	0.00025	216.59	1954-52	8,362,714	1,233,019	7,724	0.14744	0.00092	85.69
1956	3,744,927	3,606,123	362,883	368	0.10063	0.00010	312.14	1955-53	9,661,539	1,048,222	2,722	0.10849	0.00028	180.87
1957	4,107,442	3,926,185	386,079	4,765	0.09833	0.00121	91.54	1957-54	10,796,937	1,027,387	5,949	0.09516	0.00055	138.11
1958	4,488,756	4,298,099	390,134	1,499	0.09077	0.00035	177.74	1957-55	11,830,406	1,139,096	6,632	0.09629	0.00056	136.11
1959	4,877,391	4,683,074	593,552	626	0.12674	0.00013	242.96	1958-56	12,907,357	1,369,765	6,890	0.10612	0.00053	132.86
1960	5,470,317	5,173,854	404,073	107	0.07810	0.00002	786.67	1959-57	14,155,027	1,387,759	2,232	0.09804	0.00016	254.35
1961	5,874,284	5,672,301	1,130,807	587	0.19936	0.00010	220.09	1960-58	15,529,228	2,128,432	1,320	0.13706	0.00009	292.94
1962	7,004,503	6,439,393	833,572	376	0.12945	0.00006	363.78	1961-59	17,285,548	2,368,452	1,070	0.13702	0.00006	343.31
1963	7,837,699	7,421,101	558,032	678	0.07520	0.00009	381.44	1962-60	19,532,795	2,522,411	1,642	0.12914	0.00008	303.55
1964	8,395,053	8,116,376	639,207	2,507	0.07876	0.00031	202.75	1963-61	21,976,871	2,030,811	3,561	0.09241	0.00016	258.43
1965	9,031,753	8,713,403	1,041,379	4,377	0.11951	0.00050	129.06	1964-62	24,250,881	2,238,618	7,563	0.09231	0.00031	186.38
1966	10,068,755	9,550,254	720,710	6,915	0.07547	0.00072	135.28	1965-63	26,380,034	2,401,296	13,799	0.09103	0.00052	144.92
1967	10,782,550	10,425,652	1,446,766	2,916	0.13877	0.00028	160.52	1966-64	28,689,310	3,208,855	14,208	0.11185	0.00050	134.36
1968	12,226,400	11,504,475	1,302,554	5,022	0.11322	0.00044	142.24	1967-65	31,480,382	3,470,030	14,853	0.11028	0.00047	138.67
1969	13,523,932	12,875,166	1,311,116	19,562	0.10183	0.00152	80.39	1968-66	34,805,294	4,060,436	27,500	0.11666	0.00079	104.16
1970	14,815,486	14,169,709	1,757,667	40,504	0.12404	0.00286	53.11	1969-67	38,549,351	4,371,338	65,088	0.11340	0.00169	72.27
1971	16,532,650	15,674,068	1,195,665	39,064	0.07628	0.00249	72.53	1970-68	42,718,944	4,264,449	99,130	0.09983	0.00232	65.70
1972	17,689,252	17,110,951	1,035,285	92,203	0.06050	0.00539	55.38	1971-69	46,954,729	3,988,617	171,770	0.08495	0.00366	56.73

Summit Utilities-Arkansas
Geometric Mean Turnover Analysis
Account 380- Services

									3 Year Band					
Year	BOY Plant Balance	Avg. Plant Balance	Single Year Additions	Single Year Retirements	Addition Ratio	Retirement Ratio	Geometric Mean Life Estimate	3 Year Band	Avg. Plant Balance	Additions	Retirements	Addition Ratio	Retirement Ratio	Geometric Mean Life Estimate
	a	b=(a+prev a)/2	c	d	e = c/b	f = d/b	g = 1/sqrt(e*f)	h	i	j	k	l = j/i	m = k/i	n = 1/sqrt(l*m)
1920			26		#DIV/0!	#DIV/0!	#DIV/0!	1919-17	-	26	-	-	-	-
1973	18,632,333	18,160,793	1,165,751	20,042	0.06419	0.00110	118.81	1972-70	50,945,812	3,396,701	151,309	0.06667	0.00297	71.06
1974	19,778,042	19,205,188	929,804	32,889	0.04841	0.00171	109.82	1973-71	54,476,931	3,130,839	145,134	0.05747	0.00266	80.82
1975	20,674,957	20,226,500	1,880,682	23,495	0.09298	0.00116	96.22	1974-72	57,592,480	3,976,236	76,426	0.06904	0.00133	104.47
1976	22,532,144	21,603,551	1,899,062	25,834	0.08791	0.00120	97.54	1975-73	61,035,238	4,709,547	82,217	0.07716	0.00135	98.09
1977	24,405,372	23,468,758	1,752,370	44,454	0.07467	0.00189	84.09	1976-74	65,298,809	5,532,113	93,783	0.08472	0.00144	90.66
1978	26,113,288	25,259,330	2,152,682	38,151	0.08522	0.00151	88.14	1977-75	70,331,639	5,804,113	108,439	0.08252	0.00154	88.65
1979	28,227,819	27,170,553	1,902,974	14,171	0.07004	0.00052	165.46	1978-76	75,898,641	5,808,026	96,776	0.07652	0.00128	101.24
1980	30,116,622	29,172,220	2,035,062	1,575	0.06976	0.00005	515.23	1979-77	81,602,103	6,090,718	53,897	0.07464	0.00066	142.42
1981	32,150,108	31,133,365	2,273,123	133,253	0.07301	0.00428	56.57	1980-78	87,476,138	6,211,159	148,999	0.07100	0.00170	90.93
1982	34,289,979	33,220,044	1,706,690	44,710	0.05138	0.00135	120.26	1981-79	93,525,629	6,014,875	179,538	0.06431	0.00192	90.00
1983	35,951,959	35,120,969	1,716,204	101,581	0.04887	0.00289	84.12	1982-80	99,474,378	5,696,017	279,544	0.05726	0.00281	78.83
1984	37,566,582	36,759,271	1,926,013	192,229	0.05240	0.00523	60.41	1983-81	105,100,283	5,348,907	338,520	0.05089	0.00322	78.11
1985	39,300,366	38,433,474	1,790,229	378,034	0.04658	0.00984	46.72	1984-82	110,313,713	5,432,446	671,844	0.04925	0.00609	57.74
1986	40,712,561	40,006,463	5,373,324	368,465	0.13431	0.00921	28.43	1985-83	115,199,208	9,089,565	938,728	0.07890	0.00815	39.44
1987	45,717,420	43,214,990	6,140,582	322,097	0.14209	0.00745	30.73	1986-84	121,654,928	13,304,134	1,068,596	0.10936	0.00878	32.26
1988	51,535,904	48,626,662	5,851,925	318,768	0.12034	0.00656	35.60	1987-85	131,848,116	17,365,830	1,009,330	0.13171	0.00766	31.49
1989	57,069,061	54,302,483	5,937,359	352,894	0.10934	0.00650	37.51	1988-86	146,144,135	17,929,865	993,759	0.12269	0.00680	34.62
1990	62,653,525	59,861,293	6,641,666	251,556	0.11095	0.00420	46.31	1989-87	162,790,438	18,430,949	923,218	0.11322	0.00567	39.46
1991	69,043,635	65,848,580	6,439,950	306,327	0.09780	0.00465	46.88	1990-88	180,012,356	19,018,975	910,777	0.10565	0.00506	43.25
1992	75,177,258	72,110,447	5,895,399	281,763	0.08176	0.00391	55.95	1991-89	197,820,321	18,977,015	839,646	0.09593	0.00424	49.56
1993	80,790,894	77,984,076	5,916,498	393,975	0.07587	0.00505	51.08	1992-90	215,943,104	18,251,846	982,064	0.08452	0.00455	51.01
1994	86,313,417	83,552,156	7,106,265	367,926	0.08505	0.00440	51.67	1993-91	233,646,679	18,918,161	1,043,663	0.08097	0.00447	52.58
1995	93,051,756	89,682,587	6,655,060	164,904	0.07421	0.00184	85.61	1994-92	251,218,819	19,677,823	926,805	0.07833	0.00369	58.83
1996	99,541,912	96,296,834	6,415,636	193,068	0.06662	0.00200	86.52	1995-93	269,531,577	20,176,961	725,898	0.07486	0.00269	70.43
1997	105,764,480	102,653,196	8,115,662	202,080	0.07906	0.00197	80.16	1996-94	288,632,617	21,186,357	560,053	0.07340	0.00194	83.79
1998	113,678,061	109,721,270	9,345,115	447,675	0.08517	0.00408	53.64	1997-95	308,671,301	23,876,413	842,824	0.07735	0.00273	68.81
1999	122,575,501	118,126,781	8,324,437	330,538	0.07047	0.00280	71.21	1998-96	330,501,248	25,785,215	980,293	0.07802	0.00297	65.74
2000	130,569,401	126,572,451	8,455,457	882,052	0.06680	0.00697	46.35	1999-97	354,420,503	26,125,009	1,660,265	0.07371	0.00468	53.81
2001	138,142,806	134,356,103	15,084,521	1,729,985	0.11227	0.01288	26.30	2000-98	379,055,336	31,864,415	2,942,574	0.08406	0.00776	39.15
2002	151,497,342	144,820,074	12,582,591	1,408,140	0.08688	0.00972	34.40	2002-00	405,748,628	36,122,569	4,020,177	0.08903	0.00991	33.67
2003	162,671,793	157,084,568	13,713,023	1,765,129	0.08730	0.01124	31.93	2003-01	436,260,745	41,380,136	4,903,254	0.09485	0.01124	30.63
2004	174,619,687	168,645,740	9,033,575	1,293,225	0.05357	0.00767	49.34	2004-02	470,550,382	35,329,190	4,466,494	0.07508	0.00949	37.46
2005	182,360,038	178,489,863	11,600,730	1,462,049	0.06499	0.00819	43.34	2005-03	504,220,171	34,347,329	4,520,402	0.06812	0.00897	40.47
2006	192,498,719	187,429,379	9,250,329	7,427,102	0.04935	0.03963	22.61	2006-04	534,564,982	29,884,634	10,182,376	0.05590	0.01905	30.64
2007	194,321,946	193,410,333	10,553,199	2,060,291	0.05456	0.01065	41.48	2007-05	559,329,575	31,404,258	10,949,442	0.05615	0.01958	30.16
2008	202,814,853	198,568,400	8,343,082	1,552,390	0.04202	0.00782	55.18	2008-06	579,408,111	28,146,610	11,039,784	0.04858	0.01905	32.87
2009	209,605,546	206,210,200	7,399,381	1,236,801	0.03588	0.00600	68.17	2009-07	598,188,932	26,295,661	4,849,482	0.04396	0.00811	52.97
2010	215,768,125	212,686,836	8,279,161	1,661,741	0.03893	0.00781	57.34	2010-08	617,465,435	24,021,624	4,450,932	0.03890	0.00721	59.72
2011	222,385,545	219,076,835	9,035,175	1,890,626	0.04124	0.00863	53.01	2011-09	637,973,870	24,713,716	4,789,168	0.03874	0.00751	58.64
2012	229,530,094	225,957,820	9,527,593	2,239,339	0.04217	0.00991	48.92	2012-10	657,721,490	26,841,928	5,791,706	0.04081	0.00881	52.75
2013	236,818,348	233,174,221	11,691,690	2,162,893	0.05014	0.00928	46.37	2013-11	678,208,876	30,254,458	6,292,858	0.04461	0.00928	49.15
2014	246,347,145	241,582,746	11,821,479	2,510,539	0.04893	0.01039	44.35	2014-12	700,714,787	33,040,762	6,912,772	0.04715	0.00987	46.36
2015	255,658,084	251,002,614	14,160,318	2,294,695	0.05642	0.00914	44.03	2015-13	725,759,582	37,673,487	6,968,127	0.05191	0.00960	44.79
2016	267,523,708	261,590,896	12,411,191	2,095,610	0.04745	0.00801	51.29	2016-14	754,176,257	38,392,988	6,900,844	0.05091	0.00915	46.33
2017	277,839,289	272,681,498	20,032,590	3,316,033	0.07347	0.01216	33.46	2017-15	785,275,009	46,604,099	7,706,338	0.05935	0.00981	41.44
2018	294,555,846	286,197,567	14,899,717	2,565,146	0.05206	0.00896	46.29	2018-16	820,469,961	47,343,498	7,976,789	0.05770	0.00972	42.22
2019	306,890,417	300,723,131	22,288,832	3,394,604	0.07412	0.01129	34.57	2019-17	859,602,197	57,221,138	9,275,783	0.06657	0.01079	37.31
2020	325,784,644	316,337,530	18,059,857	3,278,502	0.05709	0.01036	41.11	2020-18	903,258,229	55,248,406	9,238,252	0.06117	0.01023	39.98
2021	340,565,999	333,175,322	25,778,926	3,234,037	0.07737	0.00971	36.49	2021-19	950,235,983	66,127,614	9,907,143	0.06959	0.01043	37.12
2022	363,110,888	351,838,443	33,203,306	3,612,305	0.09437	0.01027	32.13	2022-20	1,001,351,295	77,042,089	10,124,844	0.07694	0.01011	35.85
1920 to 2022	**6,973,286,935**	**6,791,731,491**	**453,364,537**	**60,662,648**	**0.06675**	**0.00893**	**40.95**	**←Full Band**						
1940 to 2022	**6,973,286,253**	**6,791,730,837**	**452,903,308**	**60,662,149**	**0.06668**	**0.00893**	**40.97**							

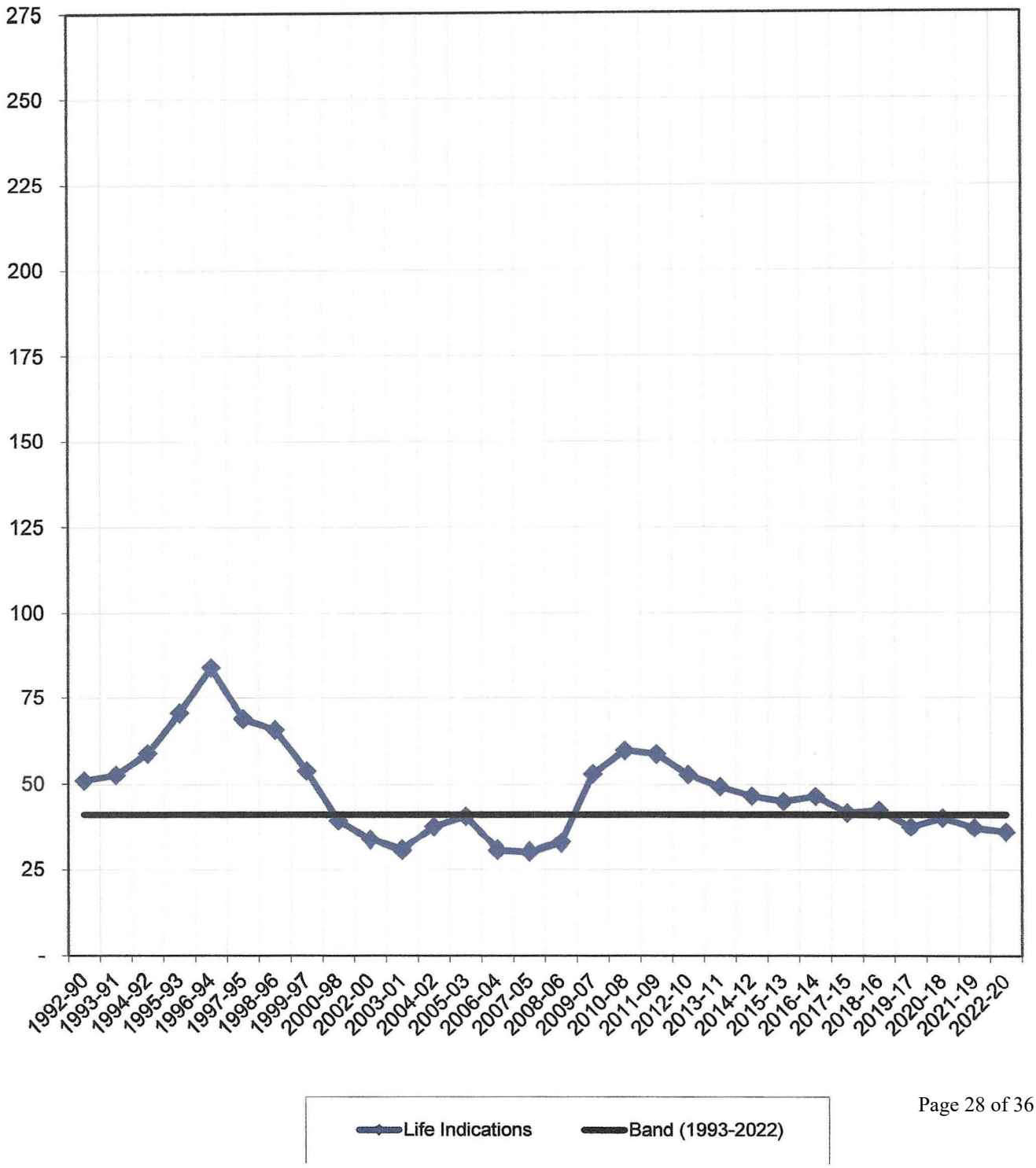
Summit Utilities-Arkansas
Geometric Mean Turnover Analysis
Account 380- Services

Year	BOY Plant Balance	Avg. Plant Balance	Single Year Additions	Single Year Retirements	Addition Ratio	Retirement Ratio	Geometric Mean Life Estimate	3 Year Band	3 Year Band: Avg. Plant Balance	3 Year Band: Additions	3 Year Band: Retirements	3 Year Band: Addition Ratio	3 Year Band: Retirement Ratio	3 Year Band: Geometric Mean Life Estimate
	a	b=(a+prev a)/2	c	d	e = c/b	f = d/b	g = 1/sqrt(e*f)	h	i	j	k	l = j/i	m = k/i	n = 1/sqrt(l*m)
1920			26		#DIV/0!	#DIV/0!	#DIV/0!	1919-17	-	26	-	-	-	-
1953 to 2022	**6,960,765,266**	**6,780,257,303**	**450,837,744**	**60,655,487**	**0.06649**	**0.00895**	**41.00**							
1983 to 2022	**6,538,324,558**	**6,373,914,103**	**416,797,044**	**60,047,114**	**0.06539**	**0.00942**	**40.29**							
1993 to 2022	**6,023,596,286**	**5,879,629,471**	**369,084,395**	**57,173,400**	**0.06277**	**0.00972**	**40.48**							

ARSC FILED Time: 7/10/2024 11:50:36 AM: Recvd 7/10/2024 11:49:53 AM: Docket 23-079-U-Doc. 118

Exh.___(MJM-7) 4
Account: 380
Category: SUA Services

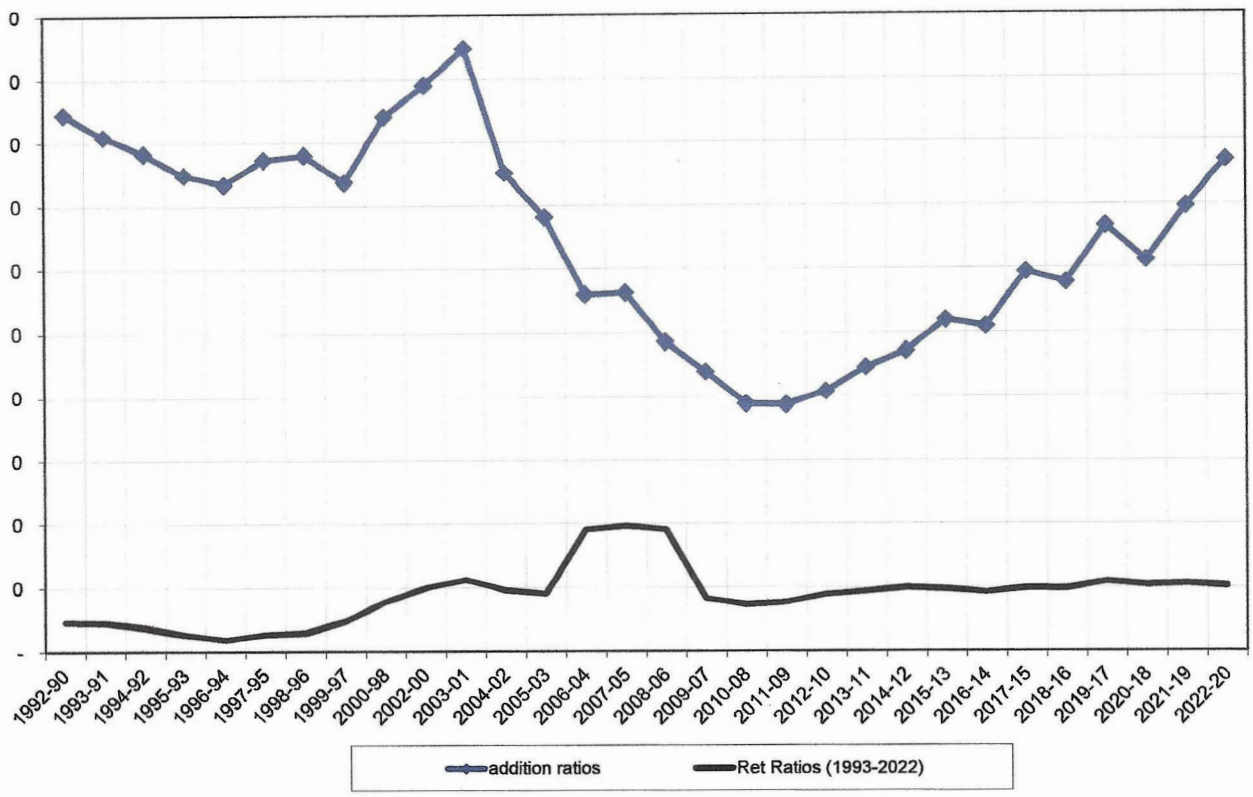
Geometric Mean Rolling Band Analysis
Life Indications - Account 380- Services



ARSC FILED Time: 7/10/2024 11:50:36 AM: Recvd 7/10/2024 11:49:53 AM: Docket 23-079-U-Doc. 118

Exh.___(MJM-7, p.5
Account: 380
Category: SUA Services

Geometric Mean Rolling Band Analysis
Adds & Rets Ratios - Account 380- Services



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Summit Utilities - Arkansas Assets **Exhibit___(MJM-8)**

SKM Recommended Remaining Lives
for accounts 376 Mains and 380 Services
As of December 31, 2022

Description

Account #	Account Name	Recommended Average Life 1/	Weighted Average Age 2/	Average Remaining Life
(1)	(2)	(3)	(4)	(5)=(3)-(4)
376	Distribution Mains	70	14.89	55.11
380	Distribution Services	50	13.32	36.68

1/ Based on visual inspection ot Mr. Watson's Graphs
2/ From Watson's Native Files

ACCEPTED Date: 7/10/2024 11:50:36 AM: Recvd 7/10/2024 11:49:53 AM: Docket 23-079-U-Doc. 118

ARKANSAS PUBLIC SERVICE COMMISSION
APSC 23-079-U
2023 SUA RATE CASE

REQUEST NO.: AG-001-034

COMPANY NAME: **SUMMIT UTILITIES ARKANSAS**

DATE RECEIVED: **3/4/2024**

DATE DUE: **3/19/2024**

EXTENSION DATE:

INFORMATION REQUESTED:
Refer to the 2nd page 5 (page 19 of 24 of the .pdf file) of Mr. Watson's Direct Testimony, lines 7 to 9.

a. Explain the difference between retirement costs and removal costs as used in that paragraph.
b. For each plant account in Mr. Watson's study, please identify the assets that are physically removed thus giving rise to cost of removal.

REQUESTED BY: **ARKANSAS ATTORNEY GENERAL**

RESPONSE:
a. The term retirement cost and removal cost are used interchangeably.

b. The Company does not track physically removed versus abandoned. Cost of removal relates to cost of removal from service, not necessarily physically removed.

SPONSOR:
Dane Watson, Peter Hobbs

RESPONSIVE DOCUMENTS:
None

The foregoing response to the above information request is accurate and complete, and contains no material misrepresentations or omissions based upon present facts known to the undersigned. The undersigned agrees to immediately inform the Requestor if any matters are discovered which would materially affect the accuracy or completeness of the information provided in response to the above information request.

/s/ Brooke South Parsons
Signature of Company Representative

DATE PROVIDED: **MARCH 19, 2024**

ARKANSAS PUBLIC SERVICE COMMISSION 7/10/2024 11:50:36 AM: Recvd 7/10/2024 11:49:53 AM: Docket 23-079-U-Doc. 128

ARKANSAS PUBLIC SERVICE COMMISSION
APSC 23-079-U
2023 SUA RATE CASE

REQUEST NO.: AG-001-029

COMPANY NAME: **SUMMIT UTILITIES ARKANSAS**

DATE RECEIVED: **3/4/2024**

DATE DUE: **3/19/2024**

EXTENSION DATE:

INFORMATION REQUESTED:
The cover page of Mr. Watson's Direct indicates he is Managing Partner of Alliance Consulting Group. Is Mr. Watson familiar with the following studies prepared for Atmos Energy by the Alliance Consulting Group: 2014 Removal Cost Study, 2016 Measuring and Regulating Time and Motion Study?

a. Were these studies prepared by Mr. Watson's firm? If yes, what was the extent of Mr. Watson's involvement?
b. Has Mr. Watson's firm conducted any similar studies for any other Companies? If yes, please identify those studies.
c. Has Mr. Watson made any presentations, taught any courses, or authored any article relating to the subject matter of those studies? If yes, please provide copies.

REQUESTED BY: **ARKANSAS ATTORNEY GENERAL**

RESPONSE:
a. Yes. Mr. Watson was directly involved in leading these studies.

b. Yes. Besides Atmos Energy referenced in the question, Mr. Watson recalls studies for CenterPoint Energy, both gas and electric. Mr. Watson believes there is a limited number of these types of studies he has conducted, but he does not maintain a separate list. Therefore, this may not be all inclusive of such engagements.

c. Mr. Watson did not make any presentations, teach any courses, or author articles directly relating to the specific subject matter of those studies. Mr. Watson is a routine instructor for The Society of Depreciation Professionals and EEI/AGA and teaches about net salvage and removal cost in principle but does not teach any course specifically on Time and Motion Studies.

SPONSOR:
Dane Watson

RESPONSIVE DOCUMENTS:

APSC FILED Time: 7/10/2024 11:50:36 AM: Recvd 7/10/2024 11:49:53 AM: Docket 23-079-U-Doc. 118

None

The foregoing response to the above information request is accurate and complete, and contains no material misrepresentations or omissions based upon present facts known to the undersigned. The undersigned agrees to immediately inform the Requestor if any matters are discovered which would materially affect the accuracy or completeness of the information provided in response to the above information request.

/s/ Brooke South Parsons
Signature of Company Representative

DATE PROVIDED: MARCH 19, 2024

Summit Utilities - Arkansas Assets **Exhibit__(MJM-11)**
Remove Inflation from Watson COR Ratios
And Adjust Mains and Services for Retirement-Only percentages
As of December 31, 2022

						Watson's			Uninflated Cost of Removal Ratios						SKM Recommendations	
									South Central Region 2/							
New Asset Group	New Account	Old Account	Sub FCA	Description	Plant Balance	Inflated Net Salvage %	Weighted Average Age 1/	Average Year of Installation	HW Index		Index	% Change	Deflator	N/S %	Non-Replaced Pipe Retirements	Recommended
(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)=2022-(h)	(j)		(k)	(l)=(k)/(j)	(m)=(j)/(k)	(n)=(m)*(g)	(o)	(p)=(o)*(n)
	Distribution Plant															
3742	D374200A	G37402	Multi	Land Rights	$ 4,020,565.65	0%	25.32	1996.68	N/A		N/A			0.00%		0.00%
3751	D375100A	G37501	6900	City Gate Main Line M/R Structures	224,807.59	0%	35.02	1986.98	219		617	282%	35.5%	0.00%		0.00%
3753	D375300A	G37502	6910	Meas & Dist Reg Sta Structures	400,508.13	0%	35.23	1986.77	219		617	282%	35.5%	0.00%		0.00%
3754	D375400A	G37503	6920	Other Structures- Distribution	10,189,841.76	0%	13.47	2008.53	368		617	168%	59.6%	0.00%		0.00%
3755	D375500A	G37503	6930	Other Structures- Distribution Imp	5,244,325.19	-5%	14.52	2007.48	350		617	176%	56.7%	-2.84%		-2.84%
3760	D376000A	G37601	6940	Mains	858,698,342.45	-40%	14.89	2007.11	470	3/	1214	258%	38.7%	-15.49%	33%	-5.11%
3780	D378000A	G37801	6980	Mea/ Reg Sta Equipment- General	14,120,321.49	-65%	11.77	2010.23	518		1158	224%	44.7%	-29.08%		-29.08%
3783	D378300A	G37801	7000	Other Equipment- Odorizing Equip.	1,111,690.19	0%	13.47	2008.53	490		1158	236%	42.3%	0.00%		0.00%
3790	D379000A	G37901	7010	Mea Reg Sta Equipment City Gate	2,422,516.99	-5%	32.16	1989.84	275		1193	434%	23.1%	-1.15%		-1.15%
3800	D380000A	G38001	7020	Services	395,610,297.61	-130%	13.32	2008.68	411	4/	699	170%	58.8%	-76.44%	33%	-25.22%
3811	D381100A	G38101	7050	Meters- Domestic	30,121,837.85	0%	21.02	2000.98	202		580	287%	34.8%	0.00%		0.00%
3812	D381200A	G39703	7420	Meters - ERTS	29,222,228.15	0%	7.28	2014.72	341		580	170%	58.8%	0.00%		0.00%
3813	D381300A	G38101	7060	Meters - Industrial	14,561,884.43	0%	17.02	2004.98	183		580	317%	31.6%	0.00%		0.00%
3820	D382000A	G38201	7080	Meter Installation - Domestic	21,184,765.09	-10%	15.23	2006.77	653		1942	297%	33.6%	-3.36%		-3.36%
3831	D383100A	G38301	7120	Regulators- Domestic	18,504,773.29	0%	12.14	2009.86	412		769	187%	53.6%	0.00%		0.00%
3832	D383200A	G38301	7130	Regulators- Industrial	12,758,397.10	0%	13.57	2008.43	387		769	199%	50.3%	0.00%		0.00%
3850	D385000A	G38501	7150	Industrial Meas and Reg Stat Equip.	7,450,385.75	-2%	4.72	2017.28	657	5/	1158	176%	56.7%	-1.13%		-1.13%
3851	D385100A	G38201	7090	M&R Station Equipment - Other	12,964,151.12	-25%	27.92	1994.08	299	5/	1158	387%	25.8%	-6.46%		-6.46%
				Total Distribution Plant	1,438,811,639.83											

1/ Watson Native Files - Weighted Averages - Weighted Average Ages
2/ Handy-Whitman Index of Public Utility Cost Trend Tables 1912 to January 1, 2024.
3/ Average of Cast Iron, Steel and Plastic
4/ Average of Steel and Plastic
5/ Used account 378 Index

Summit Utilities - Arkansas Assets **Exhibit__(MJM-12)**
SKM Computation of Reserve Excess
As of December 31, 2022

New Asset Group	New Account	Old Account	Sub FCA	Description	Plant Balance	Book Reserve	Uninflated Net Salvage % 1/	ASL	RL	Theoretical Reserve	Reserve Excess (Deficiency)
(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)=(1-(h)-(1-(h)/(i))*(j))*(f)	(l)=(g)-(k)
	Distribution Plant										
3742	D374200A	G37402	Multi	Land Rights	$ 4,020,565.65	$1,013,488.53	0.00%	75	49.69	$ 1,356,806.89	$ (343,318.36)
3751	D375100A	G37501	6900	City Gate Main Line M/R Structures	224,807.59	143,969.21	0.00%	65	30.04	120,911.90	23,057.31
3753	D375300A	G37502	6910	Meas & Dist Reg Sta Structures	400,508.13	179,759.46	0.00%	62	30.17	205,615.71	(25,856.25)
3754	D375400A	G37503	6920	Other Structures- Distribution	10,189,841.76	4,866,930.30	0.00%	48	35.38	2,679,079.23	2,187,851.07
3755	D375500A	G37503	6930	Other Structures- Distribution Imp	5,244,325.19	1,851,926.56	-2.84%	38	31.13	975,010.33	876,916.23
3760	D376000A	G37601	6940	Mains	858,698,342.45	260,324,249.11	-5.11% 1.	70	55.11 2/	191,991,197.93	68,333,051.18
3780	D378000A	G37801	6980	Mea/ Reg Sta Equipment- General	14,120,321.49	2,518,068.38	-29.08%	40	31.24	3,991,482.00	(1,473,413.62)
3783	D378300A	G37801	7000	Other Equipment- Odorizing Equip.	1,111,690.19	814,031.95	0.00%	13	8.02	425,862.86	388,169.09
3790	D379000A	G37901	7010	Mea Reg Sta Equipment City Gate	2,422,516.99	1,447,967.07	-1.15%	57	26.74	1,300,881.58	147,085.49
3800	D380000A	G38001	7020	Services	395,610,297.61	235,262,527.64	-25.22% 1.	50	36.68 2/	131,970,088.39	103,292,439.25
3811	D381100A	G38101	7050	Meters- Domestic	30,121,837.85	19,337,459.49	0.00%	36	18.49	14,650,927.24	4,686,532.25
3812	D381200A	G39703	7420	Meters - ERTS	29,222,228.15	20,078,076.53	0.00%	14	7.37	13,838,812.33	6,239,264.20
3813	D381300A	G38101	7060	Meters - Industrial	14,561,884.43	9,134,489.65	0.00%	30	14.98	7,290,650.14	1,843,839.51
3820	D382000A	G38201	7080	Meter Installation - Domestic	21,184,765.09	7,071,081.02	-3.36%	41	28.62	6,611,857.72	459,223.30
3831	D383100A	G38301	7120	Regulators- Domestic	18,504,773.29	8,167,660.43	0.00%	30	19.35	6,569,194.52	1,598,465.91
3832	D383200A	G38301	7130	Regulators- Industrial	12,758,397.10	6,320,197.46	0.00%	31	18.27	5,239,174.03	1,081,023.43
3850	D385000A	G38501	7150	Industrial Meas and Reg Stat Equip.	7,450,385.75	781,229.37	-1.13%	40	35.83	785,516.08	(4,286.71)
3851	D385100A	G38201	7090	M&R Station Equipment - Other	12,964,151.12	8,605,387.79	-6.46%	48	24.57	6,736,612.83	1,868,774.96
				Total Distribution Plant	1,438,811,639.83	587,918,499.95				396,739,681.69	191,178,818.26
	General Plant - Depreciated										
3901	D390100A	G39001	7200	General Plant Structures	8,316,933.37	167,576.30	0%				
3920	D392000A	G39201	7300	Transportation Equipment-Autos	25,034,296.44	8,102,533.25	18%				
3960	D396000A	G39601	7380	Power Operated Equipment	5,112,178.99	2,521,062.51	20%				
				Total General Plant Depreciated	38,463,408.80	10,791,172.06					

1/ Uninflated N/S Cor Ratios adjusted to reflect non-replaced retirements
2/ SKM Recommended Life & Remaining Life

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CERTIFICATE OF SERVICE

I, Clay Layson, hereby certify that on July 10, 2024, I filed a copy of the foregoing utilizing the Commission's Electronic Filing System, which caused a copy to be served upon all parties of record via electronic mail.

/s/ Clay Layson
Clay Layson

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BEFORE THE ARKANSAS
PUBLIC SERVICE COMMISSION

IN THE MATTER OF THE APPLICATION OF	**)**	
SUMMIT UTILITIES ARKANSAS, INC. FOR	**)**	
A GENERAL CHANGE OR MODIFICATION	**)**	**DOCKET NO. 23-079-U**
IN ITS RATES, CHARGES AND TARIFF	**)**	

DIRECT TESTIMONY

OF

MARLON F. GRIFFING, PH.D.

ON BEHALF OF

THE OFFICE OF ARKANSAS ATTORNEY GENERAL
TIM GRIFFIN

July 10, 2024

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I. INTRODUCTION

Q. PLEASE STATE YOUR NAME, OCCUPATION, AND BUSINESS ADDRESS.

A. My name is Dr. Marlon F. Griffing. I am a Senior Consultant with the economic consulting firm of PCMG & Associates Inc. ("PCMG"). My business address is 22 Brookes Drive, Gaithersburg, MD 20877.

Q. WHAT DOES PCMG DO?

A. PCMG was founded in 2015 to conduct research on a consulting basis into the rates, revenues, costs, and economic performance of regulated firms and industries. The firm has a professional staff of four with expertise in economics, accounting, and cost analysis. Most of its work involves the development, preparation, and presentation of expert witness testimony before federal and state regulatory agencies.

Q. HAVE YOU PREPARED A SUMMARY OF YOUR QUALIFICATIONS AND EXPERIENCE, INCLUDING COST-OF-CAPITAL TESTIMONY IN REGULATORY PROCEEDINGS?

A. Yes. Exhibit MFG-1 is a summary of my qualifications, experience, and testimony given before state regulatory agencies regarding cost of capital.

Q. HAVE YOU PREVIOUSLY TESTIFIED BEFORE THE ARKANSAS PUBLIC SERVICE COMMISSION ("APSC" OR "COMMISSION")?

A. Yes. I submitted written testimony on behalf of the Arkansas Attorney General's Office in the prior general rate cases of Black Hills Energy Arkansas ("BHEA") in APSC Docket No. 17-071-U and APSC Docket No. 23-074-U.

Q. ON WHOSE BEHALF ARE YOU APPEARING IN THIS PROCEEDING?

A. I am appearing on behalf of the Office of Arkansas Attorney General Tim Griffin ("AG").

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

A. My responsibility is to determine a fair rate of return on common equity capital and a fair overall cost of capital for Summit Utilities Arkansas ("SUA" or "Company"). SUA is part of Summit Utilities, Inc.[1] Summit Utilities, Inc.'s ultimate parent is JPMorgan Chase & Co.[2,3] Of these entities, only JPMorgan Chase & Co. ("JP Morgan") is publicly traded. SUA provides natural gas distribution service in Arkansas. The Company is seeking an increase in its Arkansas natural gas rates in this docket. SUA witness Dylan W. D'Ascendis testifies regarding return on equity ("ROE"), capital structure, and rate of return ("ROR").[4] I respond to Mr. D'Ascendis's Direct Testimony.

Q. HOW DO YOU ADDRESS RECOMMENDED RATES FOR THE COMPANY?

A. To arrive at recommended rates for common equity capital and overall cost of capital, I analyze the Company's capital structure and the costs for each component of that structure, including the return on equity and cost of debt.

Q. HOW IS YOUR TESTIMONY ORGANIZED?

A. My testimony is organized in the following way:

[1] https://www.summitutilitiesinc.com/who-we-are.
[2] *See,* Exhibit MFG-2.
[3] The chain of ownership above SUA is not clear. SUA witness Dylan W. D'Ascendis testifies that the Company is a wholly owned subsidiary of Southern Col Midco, LLC, and that unit is a wholly owned subsidiary of Southern Col Holdco LLC. Direct Testimony of Dylan W. D'Ascendis, (hereinafter "D'Ascendis Direct"), page 12, lines 11-14. These names do not appear at the Summit Utilities website.
[4] Direct Testimony of Dylan W. D'Ascendis ("D'Ascendis Direct"), page 2, lines 1-5.

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- First, I discuss economic considerations and legal precedents underlying the cost of equity in regulatory proceedings.
- Second, I provide an overview of the return on equity analysis.
- Third, I explain how I selected the members of the Comparison Group of companies used in my analysis.
- Fourth, I perform discounted cash flow ("DCF") model analysis and Capital Asset Pricing Model ("CAPM") analysis for the Comparison Group, recommended an ROE for the Company, and checked the ROE for reasonableness.
- Fifth, I recommend a capital structure and overall cost of capital for the Company.
- Sixth, I critique the Company's cost of capital analysis.
- Seventh, I summarize my testimony and recommendations.

Q. WHAT ARE YOUR CONCLUSIONS REGARDING THE COMPANY'S ROE AND OVERALL COST OF CAPITAL?

A. I recommend an ROE of 9.80 percent for the Company. For SUA's capital structure, I used a hypothetical capital structure. My analysis shows ratios of 46 percent long-term debt, 8 percent short-term debt, and 46 percent common equity are appropriate. When my recommended ROE is incorporated into the foregoing capital structure along with SUA's proposed cost of long-term debt of 4.18 percent and my hypothetical short-term debt cost of 5.55 percent, the result is an overall rate of return of 5.78 percent for SUA.

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II. THE COST OF EQUITY IN THE REGULATORY ENVIRONMENT

A. The Role of Economic Theory

Q. WHAT IS THE BASIS IN ECONOMIC THEORY FOR REGULATING CERTAIN INDUSTRIES?

A. According to economic theory, the forces of supply and demand interacting in a competitive environment produce an allocation of resources that yields an optimal mix of goods and services. Firms and individuals maximize profits and satisfaction given the prices and incomes that the interplay of market forces generates. This outcome is described as economically efficient. Put simply, there is no better output of goods and services that can be produced with the available resources.

Q. DOES THE ECONOMICALLY EFFICIENT OUTCOME OCCUR IN ALL INDUSTRIES?

A. No. Several conditions must be present for the economically efficient outcome to occur in an industry. These conditions include many buyers and sellers, identical products, perfect information about prices, and so forth. If these conditions exist, then price is the only way for providers of goods and services to compete in markets. If the conditions for competition do not exist, however, then letting supply and demand work unfettered will not produce the socially desired efficient outcome.

Q. ARE THERE LEGAL OBSTACLES TO COMPETITION IN PUBLIC UTILITY MARKETS?

A. Yes. Even if a firm is willing and able to raise the capital needed to be a viable natural gas distribution company, state and local governments typically have permitting processes that

govern where and when utilities can build facilities. Thus, high start-up costs are not the only barrier that must be overcome.

Q. ARE THERE OTHER ASPECTS OF A NATURAL GAS DISTRIBUTION UTILITY'S COSTS THAT RESULT IN FEW SELLERS?

A. Yes. The natural gas utility industry is what is typically known as a declining-cost industry.

Q. WHAT IS A DECLINING-COST INDUSTRY?

A. A declining-cost industry is one where the average cost-of-service declines over the range of effective demand.

Q. IS A DECLINING AVERAGE COST OF SERVICE SUFFICIENT FOR AN INDUSTRY TO BE TERMED "DECLINING COST?"

A. No. In fact, average costs decline in most industries as production and sales increase. However, in the typical industry, the average cost eventually rises and does so at a sales level that is smaller than the total demand for the product in a given industry. As a consequence, a few to several firms share the market because beyond the sales volume at which average costs rise, firms lose, rather than gain, cost advantage.

Q. ARE PUBLIC UTILITIES DECLINING-COST INDUSTRIES?

A. Yes. With their high fixed costs, public utilities have high initial average costs, but as their sales increase, the average cost drops. This fact alone does not make public utilities declining-cost industries. In most industries, average costs fall as sales increase. However, in most industries, average costs start to rise at sales levels that are much less than the total demand for the product produced in any given industry. Therefore, the number of firms sharing the market ranges from a few to many. What sets public utilities apart is that their

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average costs continue to decline over very high volumes of sales, up to and beyond total, or effective, market demand. A declining-cost industry creates market failure—that is, when the market produces an outcome that is inefficient. In this case, the inefficiency is caused by the market leading to a monopoly provider.

Q. HOW DOES BEING A DECLINING-COST INDUSTRY CREATE A MARKET FAILURE?

A. As a utility increases its sales and market share, its average costs decline, and continue to do so. Thus, the firm with the largest market share has an increasing advantage over competitors. In effect, there is not enough room in the market for another distributor. The logical result is a market with one producer—often referred to as a natural monopoly—not the many firms envisioned in the theory of competition.

Q. HOW HAS SOCIETY RESPONDED TO THE ABSENCE OF COMPETITION IN PUBLIC UTILITY MARKETS?

A. Because sufficient competition does not exist in the markets for public utilities, including the gas utility industry, to ensure low prices and adequate service, society has typically turned to regulation to achieve these goals. The government regulators generally are charged with pursuing an outcome that approximates the efficient outcome of the competitive model. Regulation thus is viewed as a way to decrease prices and increase services provided by a natural monopoly. A challenge for regulators is to set policies which ensure that the regulated firm provides an appropriate supply of services at reasonable rates. A reasonable rate enables a public utility not only to recover its operating expenses, depreciation, and taxes but also to earn a reasonable rate of return on its capital.

B. Standards for Finding a Fair Rate of Return

Q. DO ANY STANDARDS EXIST FOR DETERMINING A REASONABLE RATE OF RETURN?

A. Yes. Two United States Supreme Court cases are the basis for rate of return regulation in the United States. They are the *Bluefield Water Works* [5] and the *Hope Natural Gas* [6] cases. In *Hope*, the Court established the following standards for the return on equity that must be allowed a regulated public utility to provide for a reasonable return:

> …[T]he return to the equity owner should be commensurate with the returns on investments in other enterprises having corresponding risks. That return, moreover, should be sufficient to assure confidence in the financial integrity of the enterprise, so as to maintain its credit and to attract capital.[7]

It can be seen from this excerpt that there are essentially three standards for determining an appropriate return on equity from the standpoint of the equity owners of a regulated utility. The first is the "comparable earnings" standard, i.e., that the earnings must be "commensurate with the returns on investments in other enterprises having corresponding risks." The second is that earnings must be sufficient to assure "confidence in the financial integrity of the enterprise." The third is that earnings must allow the utility to attract capital.

Q. CAN THE COMPARABLE EARNINGS STANDARD BE APPLIED IN ESTIMATING THE RATE OF RETURN ON EQUITY CAPITAL?

A. No. There is circularity to the comparable earnings standard because the competitive nature of the capital markets virtually ensures that the returns to *all* enterprises are comparable

[5] *Bluefield Water Works & Improvement Co. v. Pub. Serv. Comm'n of W. Va.,* 262 U.S. 679 (1923).
[6] *Fed. Power Comm'n v. Hope Nat. Gas Co.,* 320 U.S. 591 (1944).
[7] *Hope,* 320 U.S. at 603.

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with each other. Investors establish the price of each traded stock based on that stock's present and prospective earnings and perceived risk. The prices for common equity for companies with high earnings are bid up, while the prices for companies with low earnings are bid down. If earnings were the only concern, the ratio of earnings to share prices, the return for investors, would become equal for all companies. However, investors recognize relative risk as they buy and sell common equity shares. For companies with high risk, share prices will be lower; for companies with low risk, share prices will be higher. Thus, the comparable earnings test becomes a nullity. All returns, because they are adjusted for risk, are comparable with all other returns.

Q. HOW IS THIS CIRCULARITY TYPICALLY RESOLVED IN PUBLIC UTILITY REGULATION?

A. In public utility regulation, the conventional procedure for resolving this circularity is to identify the required equity return for a utility's stock. That return is combined with the cost of debt, and the blended return to total capital is then applied to a rate base reflective of the book value of the utility's investment. The book value is the accountant's quantification of the depreciated original cost of the utility's assets adjusted for ratepayer contributions such as deposits and deferred taxes. Under this procedure, the market price of a stock is used only to determine the return that investors expect from that stock. That expectation is then applied to the book value of the utility's investment to identify the level of earnings that regulation will allow the utility's common shareholders to recover.

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Q. HOW CAN THE FINANCIAL INTEGRITY AND CAPITAL ATTRACTION STANDARDS ENUNCIATED IN *HOPE* BE APPLIED IN ESTIMATING THE RATE OF RETURN ON EQUITY CAPITAL?

A. If a utility can earn a return on its investment comparable to that required by enterprises of comparable risk, then it should have no difficulty in attracting capital and maintaining credit. Investors would have no reason to pass on purchasing the common equity of such a utility in favor of other investment opportunities. Thus, if the comparable earnings test is met, then the financial integrity and capital attraction standards are met as well.

Q. WHAT IS RISK?

A. Risk is the chance of a loss or less-than-expected return on an investment. A business, for example, may introduce a new product with the expectation that it will sell well. There is, of course, no guarantee that consumers will purchase the product. The risk investors attach to the company varies inversely with their view as to the probability of the product doing well. In general, the greater the risk of an investment, the greater the return required to attract investors, and vice versa.

Q. WHAT SHOULD THE COMMISSION CONSIDER IN SETTING AN APPROPRIATE RATE OF RETURN?

A. The Commission should look to current market conditions as it balances investor and consumer interests. The rate of return should reflect the condition of the capital markets in which SUA will have to compete with other firms for funding. Historically allowed rates and historical performances are not the most reliable inputs in this forward-looking approach. This statement does not mean that historical rates and performance are irrelevant.

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They are factors because they affect investors' views of a company's prospects and, therefore, the investors' willingness to purchase its common equity shares.

Q. HOW DO THE METHODS YOU USED TO DETERMINE THE COST OF COMMON EQUITY CAPITAL REFLECT CURRENT MARKET CONDITIONS?

A. I used a market-oriented approach to determine the common equity cost for the Company. I analyzed the equity return that investors currently expect to receive from investing in companies with risks similar to risk of the Company. Many factors influence these investor expectations, among them: past performance of the companies, estimates of how the companies will perform in the future, possible technological change, tax rates, and predicted general economic conditions. As investors decide where to place their funds among the investment options available to them, they weigh the information they have. Then they decide how to pay to acquire common equity shares, or to turn to the other side of the question, what price will lead them to sell the shares. Either way, the factors are reflected in current prices in capital markets. Thus, my analysis is forward-looking because it relies on investors' current assessment of what is likely to happen with their investments.

Q. WHAT IS THE ROLE OF OPPORTUNITY COSTS IN YOUR ANALYSIS?

A. An opportunity cost is the value of the next best choice forgone as the result of making a decision. Opportunity costs are central to my analysis. As investors decide where to place their assets, they have many opportunities from which to choose in the financial markets. Economic theory says they will choose the opportunity they think will provide them the best return, taking into account the level of risk with which they are comfortable. Thus, for a

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company to attract capital, its forward-looking fair rate of return must at least equal the expected rate of return for the best alternative opportunity with similar risk.

III. OVERVIEW OF THE RETURN ON EQUITY ANALYSIS

Q. HOW DO YOU KNOW WHAT EQUITY RATE OF RETURN THE COMPANY MUST OFFER TO INVESTORS TO BE AN ATTRACTIVE OPPORTUNITY?

A. No one knows with certainty what specific rate of return the Company must offer to investors that is just sufficient to make the Company an attractive opportunity. However, various methods based on finance theory have been derived for reliably estimating what investors currently think that rate is.

Q. WHAT METHODS HAVE YOU ADOPTED IN YOUR ROE ANALYSIS?

A. I use the Discounted Cash Flow ("DCF") method, which is widely used in utility general rate cases in determining rate of return. I also include the results of the Capital Asset Pricing Model ("CAPM"), combining them with the DCF results for my recommended ROE. I use recently authorized returns for natural gas utility operating companies in U.S. jurisdictions as a check on the reasonableness of the ROE outcome.

Q. WHAT IS THE DCF METHOD?

A. The DCF method uses the current dividend yield and the expected growth rate of this yield to determine a required rate of return on an investment opportunity. The required rate of return from a DCF analysis is derived from a formula for determining the net present value, or price, of a share of stock. There are several variations of DCF, but the constant-growth form I have selected assumes that dividends ("D") are received at the end of each year, the annual growth rate of dividends ("g") is constant to forever, and the discount rate for

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dividends ("k") is constant to infinity. The equation form of this constant-growth DCF model is the following:

$$k = \frac{D_1}{P_0} + g$$

Where:

k is the discount rate, which also is the fair rate of return for equity;

D_1 is the annual dividend one year from the present;

P_0 is the current price of a stock share; and

g is the expected growth rate of the dividend.

Q. HOW IS THE ANNUAL DIVIDEND ONE YEAR FROM THE PRESENT CALCULATED?

A. The annual dividend one year from now is derived by applying the growth-rate estimate ("g") to the actual current annual dividend ("D_0"). The equation form is:

$$D_1 = D_0 * (1 + g)$$

Q. WHAT ARE THE ELEMENTS OF THE DCF MODEL?

A. The first element of the DCF model is the dividend-yield component, while the second element is the dividend growth-rate component. The sum of these two components produces the required ROE for a company.

Q. WHAT IS THE CAPM METHOD?

A. The premise of the CAPM method is that any risk which is company-specific can be diversified away by investors. Therefore, the only risk that matters is the systematic risk of the stock. This systematic risk is measured by beta ("β∀). Expressed simply, the CAPM assumes the following form:

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$$k = r + \beta (k_m - r)$$

Where:

k is the required rate of return for the subject stock;

β is beta, the measure of systematic risk;

r is the rate of return on a riskless asset; and

k_m is the required rate of return on the broad market.

[$(k_m - r)$ is known as the "market risk premium"]

Q. HOW WOULD YOU CHARACTERIZE THE CAPM METHOD?

A. In the CAPM, the required ROE for a company also is the sum of two components. The first of these is the return on a riskless asset. To this base value, a return is added that reflects the additional rate of return earned by other companies in the broad equity market adjusted for the risk of the subject company relative to the risk of an average company in the market. The subsequent amount thus reflects the risk of the subject company.

Q. DOES YOUR EQUITY RATE OF RETURN ANALYSIS USE FINANCIAL INFORMATION FOR SUA?

A. No. As noted, SUA is an operating subsidiary of Summit Utilities. SUA is not publicly traded, so common equity share price information is unavailable. Therefore, a direct DCF analysis cannot be performed on the Company.

Q. DOES YOUR EQUITY RATE OF RETURN ANALYSIS USE SUA INFORMATION?

A. Yes, indirectly. Summit Utilities' ultimate owner is JP Morgan. JP Morgan has a Standard & Poor's ("S&P") credit rating of A-.[8] This credit rating reflects S&P's evaluation of the risk for the company. Because SUA is an indirect subsidiary of JP Morgan, I use the JP Morgan's credit rating as a risk measure for the Company. JP Morgan's credit rating is one criterion that was applied in selecting natural gas utilities that are similar in risk to SUA.

Q. HOW DO YOU USE THE ROE ANALYSIS TO ESTIMATE THE COMPANY'S REQUIRED RATE OF RETURN?

A. I performed an ROE analysis on a group of natural gas utilities comparable to SUA that are publicly traded and have similar investment risk, as discussed below. The estimated rates of return for members of this group form the basis for my estimate of a fair rate of return for the Company.

IV. SELECTING THE COMPARISON GROUP

Q. WHAT PROCEDURE DID YOU USE FOR SELECTING THE COMPARISON GROUP?

A. I set out to find a group of companies that are, from the perspective of investors, like SUA. Thus, I wanted firms that are natural gas utility companies that represent approximately the same investment risk as the Company.

[8] Exhibit MFG-2.

Q. HOW DID YOU FIND SUITABLE CANDIDATE COMPANIES FOR THE COMPARISON GROUP?

A. I looked at Value Line, a widely used investor service, for companies that Value Line classifies as part of the Natural Gas Utility Industry. The edition of the *Value Line Investment Survey* available at the Value Line website on June 17, 2024, included 12 companies in this category.[9]

Q. WAS SUA OR SUMMIT UTILITIES ONE OF THE 12 COMPANIES IN THE VALUE LINE NATURAL GAS INDUSTRY?

A. No.

Q. WHAT WAS THE NEXT STEP IN YOUR SELECTION PROCESS?

A. I applied screens to the initial set of Value Line natural gas utility companies to ensure that the companies included in my Comparison Group were similar in risk to the risk of the Company.[10]

Q. WHAT CRITERIA DID YOU APPLY IN THE SELECTION OF THE COMPARISON GROUP?

A. I applied the following screens to the initial set of natural gas utility companies:

1. U.S.-based firm;
2. shares publicly traded on a stock exchange;
3. a stable record of paying dividends;
4. not be expected to sell, merge into or be acquired by another company or be engaged in an unusual regulatory proceeding;

[9] Exhibit MFG-3.
[10] Exhibit MFG-4.

5. have a Standard & Poor's ("S&P") credit rating of BBB- (investment grade) or better;
6. have positive growth-rate projections from expert analysts; and
7. have 65 percent or more of the three-year average of net operating income, net income, or operating revenue be derived from regulated natural gas operations.

Q. WHAT IS THE PURPOSE OF APPLYING THE CRITERION THAT THE COMPANIES BE BASED IN THE CONTINENTAL UNITED STATES?

A. I sought companies that face a business environment like that in which SUA operates. The Company's operating utility in this case is in Arkansas and subject to state regulation, statutes, and rules that are similar to those found in the rest of the United States. All the companies are U.S.-based.

Q. WHAT PURPOSE IS SERVED BY REQUIRING THAT THE COMPANIES BE PUBLICLY TRADED?

A. One analytical tool that I used for finding a company's ROE, the DCF model,[11] requires information about common equity share prices, dividends, and growth-rate projections. The requirement that companies be publicly traded ensures that their common equity share prices are available. All the Value Line Natural Gas Utility companies were publicly traded.[12]

[11] As will be seen in a later section, the forward-looking Value-Line-based CAPM I have applied incorporates a DCF analysis and, thus, also relies on publicly traded companies.
[12] Exhibit MFG-4.

Q. WHAT PURPOSE IS SERVED BY REQUIRING THAT THE COMPANIES HAVE A STABLE RECORD OF PAYING DIVIDENDS?

A. The DCF model requires dividends as an input. If a company is not paying dividends or has a record of cutting dividends, then its DCF analysis is not reliable. All the companies still under consideration have been consistently paying dividends.[13]

Q. WHY IS IT IMPORTANT THAT COMPANIES INVOLVED IN SALES, MERGERS, OR ACQUISITIONS BE EXCLUDED FROM YOUR ANALYSIS?

A. The share prices of companies involved in sales, mergers, or acquisitions can be volatile. Extreme increases in the share prices of companies that are part of sales, mergers, or acquisitions drive down the ROE results in DCF analysis, while extreme decreases in the share prices drive up the ROE results. Neither outcome yields meaningful DCF results. Therefore, it is usually appropriate to exclude such companies from the analysis.

Q. WERE ANY COMPANIES IN THE INITIAL SET INVOLVED IN SALES, MERGERS, OR ACQUISITIONS?

A. Yes. Southwest Gas Holdings is in the process of spinning off its Centuri infrastructure construction unit. The transaction has reached the stage where shares in Centuri Group, the name of the new company, have been sold in a public offering. Southwest Gas Holdings common equity share prices surged upward after the offering but stabilized thereafter. The company's shares no longer are volatile because uncertainty about the spinoff has been removed and investors have internalized the spinoff in their decisions. Therefore, I continued to consider the company for the Comparison Group.[14]

[13] Exhibit MFG-4.
[14] Exhibit MFG-5.

Q. WHAT IS THE PURPOSE OF USING THE S&P CREDIT RATING AS A SCREEN?

A. S&P's experts incorporate financial risk and business risk into a firm's credit rating. Within these risk categories, S&P assesses such factors for public utilities as competitive advantage and operating efficiency. S&P also assesses scale, scope, and diversity which include the effects of a utility's markets, service territories, and customer diversity on the company's cash-flow stability, and in turn on its risk level. After considering all the factors, S&P assigns a credit rating to a company. If companies have identical or similar credit ratings as determined by expert analysts, then their relative risks are similar. As S&P states:

> Creditworthiness is a multi-faceted phenomenon. Although there is no "formula" for combining the various facets, our credit ratings attempt to condense their combined effects into rating symbols along a simple, one-dimensional scale. Indeed, as discussed below, the relative importance of the various factors may change in different situations.[15]

Q. HOW DID YOU APPLY THE S&P CREDIT RATING SCREEN?

A. A credit rating of BBB- or better is termed "investment grade." This level rating is an important threshold and gets its name from the fact that some institutional investors will not purchase the stock of a company if it does not have an investment-grade credit rating. By applying this screen, I ensure that there is a robust market for the common equity of companies. Please note that the credit rating screen does not require that companies have exactly the same credit rating as the subject company. The credit rating need only be similar to that of the subject company.

[15] *General Criteria: Understanding S&P Global Ratings' Rating Definitions*, Exhibit MFG-6, p. 2.

Q. WHAT WAS THE RESULT OF YOUR APPLICATION OF THE CREDIT RATING SCREEN IN THIS DOCKET?

A. Of the remaining utilities, Adams Resources & Energy, RGC Resources Inc., Star Group L.P, and UGI Corp. did not have an S&P credit rating, nor did any of their units or subsidiaries. Hence, the four companies were excluded.

Q. ARE THERE NATURAL GAS UTILITIES WITHOUT S&P CREDIT RATINGS THAT YOU CONTINUED TO CONSIDER?

A. Yes. Neither Chesapeake Utilities nor New Jersey Resources has a credit rating from S&P. They qualify for retention through equivalent ratings. Chesapeake Utilities has ratings of "2B" and "2A" from the National Association of Insurance Commissioners.[16] These ratings are equivalent to a BBB credit rating (or higher) from S&P.[17] As for New Jersey Resources, Moody's has a credit rating for New Jersey Natural Gas, a subsidiary of New Jersey Resources, of A1.[18] This Moody's credit rating is equivalent to an S&P credit rating of A+.[19]

Q. WHAT IS THE RANGE OF THE CREDIT RATINGS FOR THE REMAINING COMPANIES?

A. The eight remaining companies have S&P credit ratings (or an equivalent rating) ranging from BBB to A+. Thus, the credit ratings of these public utilities are investment grade.

[16] See, Annual Statement of the Metropolitan Life Insurance Company (December 31, 2023), Schedule D, Part 1, (e.g.) at 1334. https://s201.q4cdn.com/280976757/files/doc_downloads/statutory-filings/metropolitan/2023/2023-mlic-annual-statement-includes-investment-schedules.pdf.
[17] Exhibit MFG-7.
[18] Exhibit MFG-8.
[19] See, Exhibit MFG-7, *supra*.

Q. YOU REQUIRED THAT THE NATURAL GAS UTILITIES HAVE POSITIVE EARNINGS PER SHARE ("EPS") GROWTH-RATE FORECASTS TO BE INCLUDED IN THE COMPARISON GROUP. WHAT PURPOSE DOES THIS SCREEN SERVE?

A. If the growth-rate projections are negative or missing, then any DCF analysis performed on them is not meaningful. All eight companies still under consideration for the Comparison Group had at least two positive EPS growth-rate forecasts.[20]

Q. WHAT IS THE PURPOSE OF THE SCREEN REQUIRING MORE THAN 65 PERCENT OF A COMPANY'S THREE-YEAR AVERAGE OF AN INCOME OR REVENUE INDICATOR BE DERIVED FROM REGULATED NATURAL GAS UTILITY OPERATIONS?

A. For the firms to have similar risks, they must operate in similar business environments. The Company is predominantly a regulated natural gas utility operation, so the firms considered for the Comparison Group also must have predominantly regulated operations. This criterion ensures that most of the Comparison Group firms' operations are in the same environment as that of the Company.

Q. WHAT WAS THE OUTCOME OF YOUR APPLICATION OF THIS SCREEN?

A. I included seven of the remaining companies in the Comparison Group after applying the operating income/net income/operating revenue screen.[21] New Jersey Resources is eliminated with a natural gas operating income ratio of 52.2 percent.[22]

[20] *See,* Exhibit MFG-4, *supra*.
[21] Exhibit MFG-9.
[22] Exhibit MFG-10.

Q. WHAT WAS THE COMPOSITION OF THE COMPARISON GROUP AFTER YOUR SCREENING?

A. The Comparison Group is composed of Atmos Energy, Chesapeake Utilities, NiSource, Northwest Natural Holding Co., ONE Gas, Southwest Gas Holdings, and Spire, Inc.[23]

Q. HOW DOES THE MEMBERSHIP OF MR. D'ASCENDIS'S PROXY GROUP COMPARE WITH THE MEMBERSHIP OF YOUR COMPARISON GROUP?

A. Mr. D'Ascendis's Proxy Group includes five of the seven natural gas utilities in my Comparison Group. He does not include Chesapeake Utilities or Southwest Gas Holdings.[24]

V. DCF MODEL OVERVIEW

Q. WHAT IS THE PURPOSE OF A DCF ANALYSIS?

A. The goal of this analysis was to estimate an appropriate, forward-looking rate of return on equity. A DCF analysis requires a determination of expected growth rates and dividend yields in order to estimate this return.

Q. HOW ARE EXPECTED GROWTH RATES USED?

A. Because a DCF analysis is forward-looking, I estimate the expected growth rate of dividends. Historical growth rates are good indicators of the expected growth rate if both of the following are true:

- the dividend payout ratio and the realized rate of return on equity capital were constant in the past and could be assumed to remain constant in the future; and

[23] Exhibit MFG-11.
[24] D'Ascendis Direct, page 14, lines 9-11.

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- any growth in book equity was attributable solely to retained earnings.

If, in practice, these conditions held, then EPS, dividends per share ("DPS"), and book value per share ("BPS") would all grow at the same rate, and the past growth rates for these factors would be the rate at which they would grow in the future.

Q. DO YOU USE HISTORICAL GROWTH RATES IN YOUR ANALYSIS?

A. No. The conditions necessary for historical growth rates to be good indicators of future growth rates are rarely satisfied. Most utilities' returns on equity and payout ratios have not remained constant over time. Further, growth in book value has occurred not only due to retained earnings, but also due to the issuance of new shares of common stock. Consequently, past growth rates of earnings, dividends, and book equity are frequently unequal. Moreover, an industry may face a changed business environment, thereby making the past a poor basis for projecting the future. Historical growth rates can differ significantly from forward-looking projected growth rates due to such factors as inflation rates, tax rates, the role of an industry in the economy, and the regulatory environment.

Q. WHAT ESTIMATES OF GROWTH RATES DO YOU RELY ON RATHER THAN USING HISTORICAL GROWTH RATES?

A. In view of the limitations of using historical growth rates, I based my estimated growth rates on projected growth rates as publicly provided by (1) Zacks Investment Research ("Zacks"), a respected investor services company, (2) Thomson Financial Network estimates provided on Yahoo! Finance, and (3) The Value Line Investment Survey.

Q. WHAT DIVIDEND YIELDS WERE USED IN YOUR DCF ANALYSIS?

A. To estimate the required rate of return on equity capital today, I estimated the expected dividend yield, D_1/P_0 where P_0 is the price of a share of common equity today and D_1 is the dividend in the next period. To find the dividends expected a year from now, I multiplied the current annual dividends paid by one plus the EPS growth rates for each company. The use of this dividend yield assumes that dividends are distributed at the end of each period (year). Since the current equity share price incorporates all market information considered relevant by investors, generally speaking, non-recent historical prices should be avoided in calculating the dividend yield. However, since share prices are volatile in the short run, it is desirable to use a period long enough to avoid short-term aberrations in the capital market.

Q. WHAT COMMON EQUITY SHARE PRICES DID YOU USE IN YOUR DCF ANALYSIS?

A. I used the average of four weeks of share prices for each natural gas utility. This period achieves the goals of using current information and avoiding cases where short-run volatility causes common-equity share prices to be unrepresentative of the value investors place on a company.

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VI. DCF ANALYSIS FOR THE COMPARISON GROUP

A. Constant-Growth DCF Analysis

Q. HOW WAS THE REQUIRED RATE OF RETURN FOR THE COMPARISON GROUP DETERMINED?

A. To estimate the required rate of return for the group, I found the expected growth rate, *g*, and the expected dividend yield, D_1/P_0, for each Comparison Group company. I applied the DCF model to the inputs to find an ROE for each natural gas utility. Finally, I averaged the ROEs to find my DCF ROE for SUA.

Q. WHAT PERIOD DID YOU USE TO ESTABLISH AVERAGE COMMON EQUITY SHARE PRICES FOR THE COMPANIES IN THE COMPARISON GROUP?

A. I used the average common equity share prices from May 6, 2024, through May 31, 2024.[25] This four-week period is long enough to dampen any short-term aberrations in the capital market. It was also close to the July 10, 2024, date of this Testimony, thus making the results timely. I used closing prices for the Comparison Group member companies obtained at Yahoo! Finance.[26]

Q. HOW DID YOU DETERMINE THE DIVIDENDS FOR THE COMPARISON GROUP COMPANIES?

A. I used the dividends that each Comparison Group member company is currently paying as reported by Value Line on May 24, 2024, and by Zacks on June 20, 2024. I used the greater of these two options in my DCF analysis. The dividends were equal from the two sources.[27]

[25] There are 19 days of price observations in the four weeks. Financial markets were closed May 27, 2024.
[26] Exhibit MFG-12.
[27] Exhibit MFG-13.

Q. WHAT ASSUMPTION IS MADE ABOUT THE EXPECTED GROWTH RATE IN THE CONSTANT-GROWTH DCF MODEL?

A. In the constant-growth DCF model, it is assumed that current EPS growth rates continue to infinity. I used, as is commonly done, forecasts of EPS growth rates for five years, and assumed those growth rates will continue.

Q. WHAT DID YOU USE TO DETERMINE THE EXPECTED GROWTH RATE FOR THE COMPARISON GROUP?

A. As noted above, it is appropriate in this proceeding to use only the forecasted growth rates to estimate the expected growth rate to be used in the DCF analysis. Zacks and Yahoo! Finance provide five-year growth-rate projections for EPS, and Value Line provides five-year growth rate projections for EPS, DPS, and BPS. To maintain consistency across the sources, I used only the EPS estimates from Value Line.

Q. WHAT INFORMATION DID YOU USE FROM VALUE LINE?

A. I used the Value Line EPS five-year growth projections for the individual firms in the Comparison Group as reported by Value Line in its Investment Surveys of May 24, 2024.[28]

Q. WHAT INFORMATION DID YOU USE FROM ZACKS?

A. I used the Zacks EPS five-year growth projections available June 20, 2024, for the individual firms in the Comparison Group.[29]

[28] Exhibit MFG-14, Schedule 1.
[29] *Id.*

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Q. WHAT INFORMATION DID YOU USE FROM YAHOO! FINANCE?

A. I used the Yahoo! Finance EPS five-year growth projections available June 20, 2024, for the individual firms in the Comparison Group.[30]

Q. HOW DID YOU COMBINE THE ZACKS, YAHOO! FINANCE, AND VALUE LINE ESTIMATES?

A. I weighted the Zacks, Yahoo! Finance, and Value Line EPS values equally to find my best estimate of the expected growth rate for each company in the Comparison Group.

Q. HOW DID YOU CALCULATE THE EXPECTED DIVIDEND YIELD FOR THE COMPARISON GROUP?

A. The appropriate dividend to use in the constant-growth DCF model is the annual dividend rate at the beginning of the next period (year). I began my estimation of the expected dividend yield by finding the dividends that each Comparison Group member company was currently paying, as noted above.

Next, I adjusted the annualized dividends for expected growth. The dividends of all the companies in the Comparison Group are expected to increase over the next year. I applied a full year's growth rate for a firm to the annualized dividend and added the product to the annualized dividend yield to transform it into the expected dividend yield.[31] The equation for this operation is:

$$\frac{D_1}{P_0} = \frac{D_0}{P_0}(1+g)$$

[30] *Id.*
[31] I also followed this rule of applying a full year's growth to the current dividend in my CAPM analysis.

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Applying this equation to the dividend yield for each company yielded the D_1 values that I used in my estimates.[32]

Q. IS IT APPROPRIATE TO APPLY A MINIMUM STANDARD TO ROE RESULTS PRODUCED BY THE ROE MODELS?

A. Yes. Investors demand a higher return from common equity than from debt to compensate for the greater risk of common equity. The Federal Energy Regulatory Commission ("FERC") uses a minimum standard of the yield for Moody's 10-Year Baa Corporate Bonds plus 20 percent of the CAPM risk premium as a minimum ROE threshold. Investors faced with an ROE for a company below that threshold would choose the less-risky debt over common equity investment in the company. Thus, SUA would not be competing with these companies for capital.

Q. DID YOU REMOVE ANY COMPANIES FROM THE DCF ANALYSIS BECAUSE THEY HAD ROE RESULTS THAT WERE UNREASONABLY LOW?

A. No. The average yield for the Moody's 10-year Baa Corporate Bond Yield Index was 5.94 percent over May 6, 2024-May 31, 2024,[33] while the mean of 20 percent of the CAPM risk premium for the two CAPM approaches was 1.21 percent.[34] The sum of the two components of the minimum threshold was 7.15 percent. All the ROEs in the analysis exceeded that value.

[32] Exhibit MFG-14, Schedule 1.
[33] Exhibit MFG-15 Schedule 5.
[34] Exhibit MFG-15, Schedule 8.

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Q. WHAT ROE DID YOU FIND FOR YOUR CONSTANT-GROWTH DCF ANALYSIS?

A. For the seven companies, the mean ROE was 10.09 percent. The median ROE also was 10.09 percent.[35]

B. Multistage DCF Analysis

Q. WHAT ASSUMPTION IS MADE ABOUT THE EXPECTED GROWTH RATE IN THE MULTISTAGE DCF MODEL?

A. In the multistage DCF model it is assumed that the current growth rates are replaced by other growth rates covering intervals subsequent to the present period. There are several possible approaches to a multistage analysis, but in many of the variations a long-run gross domestic product ("GDP") growth rate is adopted after the first stage.

Q. WHAT LOGIC SUPPORTS ADOPTING GDP GROWTH RATES AFTER THE FIRST STAGE OF A MULTISTAGE DCF ANALYSIS?

A. The logic for adopting a long-run GDP growth rate after the first stage of a multistage analysis is that a company cannot sustain growth faster than the growth rate of the economy as a whole over the long run.

Q. WHAT LONG-RUN GDP GROWTH RATES DID YOU USE?

A. It was my opinion that the second-stage EPS growth rates will be similar to the long-run GDP growth rate forecasts of the Social Security Administration ("SSA") and the Energy Information Administration ("EIA"). I calculated long-run GDP growth rates from 2030-

[35] *See,* Exhibit MFG-14, Schedule 1, *supra*.

2050 from information published by these two agencies.[36] The SSA rate was 4.04 percent,[37] while the EIA rate was 4.33 percent.[38]

Q. WHAT TYPE OF MULTISTAGE DCF ANALYSIS DID YOU USE?

A. I applied what is sometimes called a blended approach as my multistage DCF analysis. In this approach, all inputs other than the EPS growth rates are the same as in the constant-growth DCF analysis. I continued to use the five-year EPS forecasts in the first stage but used the weighted long-run GDP growth rate as my second-stage EPS input. At that point I blended the two growth rates by weighting the average of the five-year EPS forecasts two-thirds and the long-run weighted GDP growth rate one-third. This approach is set forth in a widely used regulatory handbook.[39]

Q. WHAT IS THE RESULT OF YOUR MULTISTAGE DCF ANALYSIS?

A. For the seven companies, the mean ROE was 9.45 percent. The median ROE was 9.30 percent.[40]

VII. CAPM ANALYSIS FOR THE COMPARISON GROUP

Q. WHAT ARE THE STRENGTHS AND WEAKNESSES OF THE CAPM?

A. The CAPM is theoretically sound, but its application raises some issues. The analysis using CAPM selects a riskless asset, beta, and market risk premium. The ROE analysis can vary considerably depending on the analyst's choices for these variables. Thus, what at first may

[36] The SSA and EIA GDP growth rates include inflation.
[37] *See,* Exhibit MFG-14, Schedule 2, *supra*.
[38] *See,* Exhibit MFG-14, Schedule 3, *supra*.
[39] *See*, Exhibit MFG-14, Schedule 4; Morin, Roger, *New Regulatory Finance (2006)*, Public Utilities Reports, Inc., Vienna, Virginia, page 309, *supra*.
[40] *See,* Exhibit MFG-14, Schedule 5, *supra*.

seem like a model that is straightforward depends heavily on the particular input values used by an analyst.

Q. WHAT INSTRUMENT DID YOU USE AS YOUR RISKLESS ASSET?

A. The analyst must select the riskless asset. Short-term assets such as 90-day Treasury Bills are considered to be virtually riskless; the default risk is next to nothing, and the inflation risk is negligible. Equity investors, however, typically have a longer planning horizon than the 90-day maturity of these instruments, so the return on these bills is not suitable for this CAPM process. Long-Term Treasury bonds, on the other hand, match the planning horizon and have yields that are closer to common equity returns. But these instruments are subject to substantial inflation risk and, therefore, are not riskless. Nevertheless, I adopted the 30-year U.S. Treasury yield as my risk-free rate. Its favorable characteristics outweigh its unfavorable characteristics.

Q. WHAT PERIOD DID YOU USE FOR THE 30-YEAR TREASURY YIELD IN YOUR CAPM ANALYSIS?

A. I used the average yield on a 30-year Treasury bond for May 6, 2024, to May 31, 2024, as my riskless asset rate. This average yield was 4.60 percent.[41] This approach to calculating the risk-free rate is consistent with how I found common-equity share prices within the DCF model.

[41] *See*, Exhibit MFG-15, Schedule 1, *supra*.

Q. WHY DID YOU USE THE RECENT 30-YEAR TREASURY YIELD IN YOUR CAPM ANALYSIS?

A. Current yields on the 30-year Treasury bond are the best risk-free rate for the CAPM analysis. Much like current common equity share prices reflect all information about factors affecting the value of the shares, so too do current bond yields capture the beliefs of investors as to where yields on the instruments are headed.

Q. WHAT VALUES DID YOU USE FOR BETA (β)?

A. I used the betas for each company in the Comparison Group taken from *The Value Line Investment Survey* reports of May 24, 2024.[42] These beta values are Value Line's latest assessment for each company.

Q. HOW IS BETA (β) INTERPRETED?

A. A beta of 1 indicates that a company's share price will move with the market, while a beta higher than 1 indicates that a stock will be more volatile than the market, and a beta lower than 1 indicates that a stock will be less volatile than the market.

Q. WHAT DID YOU USE AS THE MARKET RISK PREMIUM?

A. I used two approaches to the determine the market risk premium. In one case, I adopted the estimate of the risk premium that companies currently require as they consider future returns on investment. In the other case I used S&P 500 inputs to find the market return for that broad market return.

[42] *See,* Exhibit MFG-15, Schedule 2, *supra*.

Q. WHAT SOURCE DID YOU USE FOR AN EXPERT ESTIMATE OF THE CURRENT MARKET RISK PREMIUM?

A. I used Kroll's equity risk premium (equivalent to the MRP) estimate of 5.5 percent.[43] Kroll is currently publisher of a financial statistical volume[44] previously published by Duff & Phelps and before that by Ibbotson and Associates. The company also provides financial advice. This value reflects the opinion of the company's corporate risk experts.

Q. WHAT WAS THE NEXT STEP IN CALCULATING THE KROLL CAPM ROE?

A. I multiplied the MRP by the beta for each Comparison Group company to find that company's risk premium (RP).[45]

Q. WHAT WAS THE FINAL STEP IN CALCULATING THE KROLL CAPM ROE?

A. I added the RP for each Comparison Group company to the MRP to find a specific company's CAPM ROE.[46]

Q. WHAT WAS THE RESULT OF THE KROLL CAPM ANALYSIS?

A. The mean ROE for my Kroll CAPM analysis was 9.35 percent and the median ROE was 9.28 percent.[47]

[43] *See,* Exhibit MFG-15, Schedule 4, Kroll, *Cost of Capital in the Current Environment*, June 2023 Update, *supra.*
[44] *Stocks, Bonds, Bills, and Inflation Yearbook,* by Roger G. Ibbotson and Rex Sinquefield, updated annually. https://www.kroll.com/en/cost-of-capital/stocks-bonds-bills-inflation-sbbi-yearbook.
[45] Exhibit MFG-15, Schedule 5.
[46] *Id.*
[47] *Id.*

Q. WHAT SOURCE DID YOU USE FOR THE CALCULATION OF YOUR S&P 500 MARKET RISK RETURN?

A. Under Opinion 569,[48] FERC starts with the S&P 500 as its base for determining the broad market return. FERC requires that companies included in the market return analysis be paying dividends, an essential part of any DCF analysis. Companies with EPS estimates less than zero percent and greater than 20 percent are excluded, thereby handling the problem of outliers at either end of the spectrum.

Q. WHAT DID YOU USE AS THE SOURCE OF DIVIDENDS AND SHORT-TERM EPS FORECASTS?

A. FERC has accepted Value Line's short-term EPS forecasts in the CAPM.[49] Therefore, I used Value Line's EPS forecasts for the companies in Value Line's S&P 500. Value Line also provides dividend yields for S&P 500 companies.

Q. WHAT ELSE WAS INVOLVED IN YOUR CALCULATION?

A. The term within parentheses in the CAPM equation is called the "market risk premium." It is the difference between the return on a broad market measure and the risk-free rate of return. In other words, the premium that investors require in order to take on risk. As noted above, I already had the risk-free rate. Therefore, I needed to calculate a market rate of return.

[48] *See, Ass'n of Bus. Advocating Tariff Equity v. Midcontinent Indep. Sys. Operator, Inc.*, Opinion No. 569, 171 FERC ¶ 61,129, ¶¶ 58 (2019).
[49] *See, Ass'n of Bus. Advocating Tariff Equity v. Midcontinent Indep. Sys. Operator, Inc.*, Opinion No. 569-A, 171 FERC ¶ 61,154, ¶¶ 58 (2020).

Q. WHAT PROCEDURE DID YOU USE TO FIND THE MARKET RETURN?

A. As stated, I use the S&P 500 inputs in finding my market risk premium. I downloaded these values on April 1, 2024.[50] I applied Value Line growth rates[51] to the dividend yields to find the expected dividend yield, adding a full year's growth.

Q. WHAT WERE THE NEXT STEPS IN FINDING THE S&P CAPM RETURN ON EQUITY?

A. I applied the dividend-paying rule, and the minimum and maximum threshold rules of less than or equal to zero percent and greater than 20 percent to the set of S&P 500 companies.[52] I then weighted the remaining ROEs by the market capitalization for each company. The sum of those individual ROEs is the market return. The value for the Value Line set was 11.24 percent.[53] The market risk premium was calculated by subtracting the 4.60 percent return on the 30-year Treasury from the market return. The result was 6.64 percent. This amount is multiplied by the beta for each Comparison Group company to find that company's CAPM ROE.[54]

Q. DOES FERC HAVE SCREENS FOR OUTLIER CAPM ROES?

A. Yes. FERC applies Low-End and High-End Test to the CAPM adjusted ROEs. My Low-End Test is the same as the minimum threshold for the DCF ROEs, the four-week average of the Moody's 10-year Baa Corporate Bond Yield Index value of 5.94 percent plus 20 percent of the CAPM risk premium. The High-End Test is 200 percent of the median value

[50] *See,* Exhibit MFG-15, Schedule 6, *supra*.
[51] *See*, Exhibit MFG-15, Schedule 7, *supra*.
[52] *See,* Exhibit MFG-15, Schedule 6, *supra*.
[53] *See*, Exhibit MFG-15, Schedule 3, *supra*.
[54] *See,* Exhibit MFG-15, Schedule 7*, supra*.

of all companies included in the analysis. The values of the outlier tests are different in the Kroll and Value Line analyses because of the different market risk premiums produced. However, no CAPM ROEs were removed due to the Low-End or High-End Tests in either of my analyses. I combined the two analyses to find a mean Low-End Test of 7.15 percent.[55]

Q. DID YOU INCLUDE A SIZE ADJUSTMENT IN YOUR CAPM ANALYSES?

A. No. I did not include a size adjustment. There are studies that indicate the size adjustment is not appropriate for the CAPM. The studies show that the effect disappears for years at a time and does not manifest itself in the prices investors pay for smaller and larger stocks.[56] Further, the studies that have shown a size effect may be examples of data mining: e.g., start and stop periods for the data to be studied that show a size effect, but the finding cannot be replicated when the span of the study has different beginnings and ends.[57] The studies recommend not making adjustments for an effect that may be transitory, at best, and not one that investors demand in the prices they pay for common equity.

Q. DID YOU INCLUDE A CREDIT-RISK ADJUSTMENT IN YOUR CAPM ANALYSIS?

A. No. By using credit rating as one of the proxy group selection criteria and making the A- credit rating of SUA's ultimate parent JPMorgan Chase the centerpiece of that screen, I accounted for different credit risks. The companies selected for the proxy group range from

[55] *See,* Exhibit MFG-15, Schedule 8, *supra.*
[56] Damodaran, Aswath, "The Small Cap Premium: Where is the Beef?" Business Valuation Review, Volume 34, Number 4 (2015).
[57] Ang, Clifford S., "The Absence of a Size Effect Relevant to the Cost of Equity." Business Valuation Review, Volume 37, Number 3 (2018).

A to BBB-, a relatively tight grouping. As noted previously, companies that are close in credit rating have similar risk, so no credit-rating adjustment is necessary.

VIII. RECOMMENDED ROE

Q. PLEASE SUMMARIZE YOUR ROE RESULTS.

A. I performed four ROE analyses: (1) constant-growth DCF, (2) multistage DCF, (3) Kroll MRP estimate CAPM, and (4) S&P 500 CAPM for Value Line. The resulting ROE values are:

DCF ROE Mean and Median Results

	Constant growth	Multistage
Mean	**10.09%**	**9.45%**
Median	**10.09%**	**9.30%**

CAPM ROE Mean and Median Results

	Kroll	Value Line
Mean	**9.35%**	**10.34%**
Median	**9.28%**	**10.24%**

Q. WHAT ARE YOUR THOUGHTS ABOUT THE DCF ROE RESULTS?

A. The DCF constant-growth ROE result was higher than the multistage counterpart ROE. The multistage approach incorporates the steadier long-run growth rates. Both results were within the 8.80-10.50 percent range of authorized ROEs from January 1, 2021, to

December 31, 2023, for U.S. natural gas utilities as reported by Regulatory Research Associates ("RRA"), a unit of S&P Global IQ Pro.[58]

Q. PLEASE COMMENT ON THE CAPM ROE RESULTS.

A. The Value Line CAPM ROE was the highest of the results. On the other hand, the Kroll CAPM ROE was the lowest of the four results. Both analyses produced results at least within the edge of the range of recent authorized ROEs.

Summary of ROE Awards for 2021-2023

Year	No. of Cases	Mean ROE	Median ROE	ROE Range
2021	43	9.56	9.60	8.80-10.24
2022	33	9.53	9.60	9.20-10.20
2023	37	9.60	9.55	9.25-10.50

Q. HOW DID YOU ARRIVE AT A RECOMMENDED ROE FOR SUA?

A. The four ROE results, as noted, lie within the U.S. authorized ROEs range of 8.80 percent to 10.50 percent. I weighted these four results equally, producing a mean ROE of 9.81 percent and a median ROE of 9.73 percent. My recommended ROE for SUA is 9.80 percent, reflecting the mean and median ROEs.[59]

IX. REASONABLENESS CHECK OF THE RECOMMENDED ROE

Q. HOW DID YOU CHECK THE REASONABLENESS OF YOUR ROE RESULTS?

A. I checked the reasonableness of my analyses' outcomes by comparing the ROEs with recent ROEs authorized in natural gas rate cases across the United States.

[58] Exhibit MFG-16.
[59] Exhibit MFG-17, Schedule 1.

Q. HOW DO YOU USE THIS SET OF AUTHORIZED ROES?

A. I use the recently authorized ROEs as a basis for evaluating the reasonableness of my ROE results. I did not use it as a substitute for those analyses.

Q. WHY ARE PAST AUTHORIZED ROES NOT A GOOD SUBSTITUTE FOR CURRENT, FORWARD-LOOKING ROE ANALYSES?

A. Recently authorized ROEs reflect the results of rate cases conducted in a variety of environments and at different times. Test years, conditions in capital markets, general economic indicators such as inflation rates, and so forth for previous rate cases can be different and become outdated when compared with these factors for a current rate case. Therefore, recently authorized ROEs should serve only to establish whether a current ROE result is reasonably close to what has happened, not be a substitute for forward-looking analysis based on current conditions.

Q. WHAT DID YOU CONCLUDE REGARDING YOUR ROE ANALYSIS AND THE RESULTS FOR THE 2021-2023 AUTHORIZED NATURAL GAS ROES?

A. My recommended ROE of 9.80 percent marginally exceeds the annual mean ROEs (9.53 percent to 9.60 percent) and median ROEs (9.55 percent to 9.60 percent) for the 2021-2023 authorized natural gas ROEs.[60] My analysis reflects the most recent trends in common equity prices, dividends, EPS growth rate estimates, beta values, and U.S. Treasury bond yields. The 9.80 percent ROE reflects these trends.

[60] *Id.*

A. Summit's Proposed Expanded SSER

Q. DID YOU CONSIDER SUMMIT'S PROPOSED EXPANSION OF ITS SYSTEM SAFETY ENHANCEMENT RIDER ("SSER") AS YOU SET YOUR RECOMMENDED SUMMIT ROE?

A. No. The proposed SSER expansion is speculative, so I did not consider it.[61]

Q. HOW DOES SUMMIT PROPOSE TO EXPAND ITS EXISTING SSER?

A. Summit proposes that it be allowed to include all system improvement, including integrity and reliability projects and public improvement expenditures in the expanded SSER.[62]

Q. DO YOU HAVE AN OPINION AS TO HOW THE SSER WOULD AFFECT THE RISK PROFILE OF SUMMIT?

A. Yes. The SSER would reduce the risk of Summit. The current version of the SSER already puts Summit in a position of reduced financial risk by allowing it to recover certain capital expenditures on an accelerated basis. The proposed expanded version of the SSER would allow Summit to accelerate recovery of, among other additional categories, reliability projects.

Q. HOW WOULD THE EXPANDED SSER AFFECT THE TREATMENT OF SUMMIT IN FINANCIAL MARKETS?

A. The expanded SSER would reduce the risk of Summit in financial markets. The expanded SSER would allow the Company to recover more capital costs shortly after they are incurred through a tariff rather than waiting for them to be put into the Summit rate base at

[61] Attorney General witness Richard W. Porter discusses the proposed Summit expansion of its SSER in depth in his direct testimony.
[62] Direct Testimony of Kurt W. Adams, ("Adams Direct"), page 12, lines 3-5.

the Company's next base rate case. The reduction in recovery time could be several years. Earlier recovery of capital expenditures reduces a utility's risk, which can lead to an improvement in its credit ratings from agencies such as S&P.

Q. IS THERE A LINK BETWEEN CREDIT RATINGS AND A UTILITY'S ROE?

A. Yes. There is an inverse correlation between credit ratings and authorized ROEs. As credit ratings improve, ROEs tend to fall. The ROE decrease occurs because investors require lower returns from companies with lower risk.

Q. ARE YOU FAMILIAR WITH AN ACCELERATED RECOVERY PROGRAM IN ANOTHER STATE?

A. Yes. I have participated in several dockets in New Jersey in which utilities have requested approval of infrastructure investment programs ("IIPs").[63]

Q. IS CAPITAL EXPENDITURE RECOVERY UNDER THE SSER RIGOROUS COMPARED WITH CAPITAL EXPENDITURE RECOVERY UNDER THE NEW JERSEY IIPS?

A. No. The New Jersey IIPs require pre-approval of amounts that can be recovered and allow recovery of only amounts above a company's baseline spending on eligible capital expenditures. Utilities submit reports on IIP projects completed, typically, during a six-month period. These amounts in these reports are reviewed by the New Jersey Board of

[63] For example, *In the Matter of the Verified Petition of Jersey Central Power & Light Company for Approval of an Infrastructure Investment Program II,* New Jersey Board of Public Utilities Docket No. EO23110793; *In the Matter of Petition of Atlantic City Electric Company for Approval of Powering the Future, an Infrastructure Investment Program and Related Cost Recovery Mechanism*, New Jersey Board of Public Utilities Docket No. ER22100666; *In the Matter of the Petition of Rockland Electric Company for Approval of an Infrastructure Investment Program, and Related Cost Recovery Mechanism*, New Jersey Board of Public Utilities Docket No. ER22030198.

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Public Utilities before they are allowed to be included in rates, which happens after another three months.

In contrast, under the SSER there is no baseline, all spending on projects identified by Summit as improving reliability would be recoverable, and reports on capital expenditure spending are submitted monthly with the lag between submission of the reports and the spending being reflected in customer rates being as short as one day.[64] Thus, the proposed SSER expansion is much less rigorous than the IIPs in effect in New Jersey. If approved, the expanded Summit SSER would dramatically improve the credit profile of the Company compared with the effect of the IIPs on the credit profiles of New Jersey utilities. The improved credit profile of BHEA would translate into lower risk and a lower ROE required by investors buying its common-equity shares.

Q. DO YOU HAVE A RECOMMENDATION AS TO HOW THE COMMISSION COULD IMPLEMENT A LOWER ROE FOR THE PROPOSED EXPANDED SSER IF IT IS APPROVED?

A. Yes. As discussed in the testimony of Richard W. Porter, the AG does not support expanding the SSER to include reliability projects. However, if the rider is expanded despite that objection, the Commission could apply a lower ROE to only the expanded amounts subject to the SSER. This approach makes sense as the accelerated recovery under the SSER would reduce the risk on the additional eligible projects. I conducted analyses in the New Jersey dockets, cited above, that indicated an ROE reduction of 10-15 basis points was justified. I expect an analysis in the current docket would produce a similar result. This

[64] Phillip B. Gilliam, Direct Exhibit PBG-1, at 3.

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reduced ROE would reflect an estimated improvement in the credit rating of the Company due to the expanded SSER.

X. RECOMMENDED CAPITAL STRUCTURE AND OVERALL RATE OF RETURN

Q. WHAT DEBT COSTS DID SUA PROPOSE IN THIS DOCKET?

A. SUA proposed a cost of long-term debt of 4.18 percent. This cost of long-term debt is based on the SUA's Pro Forma period ending December 31, 2024.[65] The capital structure proposed by Mr. D'Ascendis does not include any short-term debt.[66] Therefore, SUA does not propose a cost of short-term debt.

Q. WHAT IS YOUR POSITION REGARDING SUA'S PROPOSED LONG-TERM DEBT COST?

A. I accept the proposed 4.18 percent long-term debt cost for this docket. This debt cost is reasonable.

Q. WHAT CAPITAL STRUCTURE DID YOU RECOMMEND FOR SUA?

A. I recommended a capital structure of 46.00 percent long-term debt, 8.00 percent short-term debt, and 46.00 percent common equity.[67]

Q. HOW DID YOU DETERMINE YOUR RECOMMENDED SUA CAPITAL STRUCTURE?

A. To find a recommended capital structure for SUA, I turned to the Comparison Group companies. Recall that they have risk profiles similar to that of SUA. Therefore, The Company's capital structure ratios should be, not identical, but close to the average ratio

[65] SUA Schedule D-1.3-Holdco.
[66] D'Ascendis Direct, Schedule DWD-1.
[67] *See*, Exhibit MFG-16, Schedule 2, *supra*.

values for the group. To that end, I calculated the average long-term debt, short-term debt, and common equity proportions for the seven natural gas utilities in the Comparison Group. These average ratios reflected the dollar amount by company for each of the eight quarters from the second quarter of 2022 to the first quarter of 2024. The source of the amounts upon which the company ratios were based is S&P Global Market Intelligence.

Q. WHY DID YOU SELECT THESE EIGHT QUARTERS FOR YOUR CAPITAL STRUCTURE ANALYSIS?

A. I used two years of data to smooth the effects of any quarter that was an outlier. Using two years of data also mitigated any seasonal effects on the capital structures. The first quarter of 2024 is the most recent quarter for which data were available. Therefore, I began my analysis with data from the second quarter of 2023.

Q. WHAT WAS THE OUTCOME OF YOUR CAPITAL STRUCTURE ANALYSIS?

A. For the Comparison Group set of seven natural gas utilities over the eight quarters, the long-term debt proportion was 45.95 percent, the short-term debt proportion was 10.80 percent, and the common-equity proportion was 43.24 percent. SUA requested a capital structure of 44.41 percent long-term debt, and common equity of 55.59 percent.[68]

Q. DID YOU PERFORM AN ADDITIONAL CAPITAL STRUCTURE ANALYSIS?

A. Yes. I removed ONE Gas and Spire Inc. from the analysis. These public utilities have, respectively, short-term debt averages of 18.56 percent and 15.41 percent. The values are outliers. The capital structure that resulted from these deletions is 47.55 percent long-term debt, 8.33 percent short-term debt, and 44.11 percent common equity.

[68] D'Ascendis Direct, Schedule DWD-1

Q. PLEASE DISCUSS YOUR CAPITAL STRUCTURE ANALYSIS.

A. The Comparison Group's common-equity ratio remains about 11 percent below the SUA request of a ratio of 55.59 percent even with the short-term debt heavy ONE Gas and Spire Inc. capital structures removed. This disparity indicates that SUA's requested capital structure includes an excessive amount of common equity.

Q. WHAT IS YOUR RESPONSE TO THE COMPANY'S CAPITAL STRUCTURE REQUEST IN LIGHT OF THE MEAN CAPITAL STRUCTURE RATIOS FOR THE COMPARISON GROUP?

A. The long-term debt ratios of the Company and the group average are close to one another, so I made 46.00 percent my recommended proportion. On the other hand, the Company is requesting no short-term debt, which is well below the mean ratio for the group, and a much higher proportion of common equity than the group mean. The SUA request would mean higher rates for its ratepayers if granted. Considering these factors, I set my recommended capital structure proportions at 8.00 percent for short-term debt and 46.00 percent for common equity.

Q. WHAT DID YOU USE AS THE COST OF SHORT-TERM DEBT?

A. SUA did not include short-term debt in its requested capital structure. Therefore, I had to develop a short-term debt cost. I used 5.55 percent, which is the cost of short-term debt being used for Black Hills Energy Arkansas ("BHEA") in Docket No. 23-074-U. BHEA and SUA are natural gas distribution companies operating in Arkansas. It seems reasonable to assume that they would have similar costs of short-term debt.

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Q. WHAT IS THE OVERALL ROR THAT YOU RECOMMENDED FOR THE COMPANY?

A. When my recommended ROE of 9.80 percent is included with my recommended capital structure and the Company's debt costs in the modified balance sheet, the ROR is 5.78 percent.[69]

XI. REVIEW OF THE COMPANY'S ROE ANALYSIS

A. Summary of SUA ROE Analysis

Q. WHAT METHODS DID MR. D'ASCENDIS USE TO ARRIVE AT HIS RECOMMENDED ROE?

A. Mr. D'Ascendis used a constant-growth DCF model, a risk premium approach, the CAPM,[70] and the empirical CAPM ("ECAPM"). He stated that he further corroborates his utility quantitative analyses by applying the DCF model, Risk Premium approach, and CAPM to a group of non-utility firms.[71]

Q. WHAT WAS THE ROE RECOMMENDED BY MR. D'ASCENDIS FOR SUA?

A. Mr. D'Ascendis recommended an ROE of 11.00 percent.[72] He identified a range of 10.42 percent to 12.92 percent as indicated for SUA by his application of the various ROE methods. From this range he stated that 11.00 percent is an appropriate ROE for SUA.[73]

[69] Exhibit MFG-17, Schedule 3.
[70] D'Ascendis Direct, p. 18, lines 3-4.
[71] *Id*., at pp. 38 – 41, line 9 through line 16, respectively.
[72] *Id*., at p. 3, line 6.
[73] *Id*., at p. 47, lines 10 - 13.

B. DCF Analysis

Q. DID MR. D'ASCENDIS APPLY THE DCF MODEL IN HIS ROE ANALYSIS?

A. Yes.

Q. DID MR. D'ASCENDIS APPLY A MINIMUM THRESHOLD SCREEN IN HIS DCF MODEL ANALYSIS?

A. It appears that if Mr. D'Ascendis had a minimum threshold screen in mind, it was low enough that none of the individual or company ROE values were excluded by it.

Q. DID MR. D'ASCENDIS ADJUST HIS DCF ROES FOR GROWTH?

A. Yes. Mr. D'Ascendis adjusted the dividends in his DCF model analysis for growth. He applied a half year's growth, whereas I applied a full year's growth. Thus, my adjustment was larger than his adjustment.

Q. WHAT WAS THE RESULT OF MR. D'ASCENDIS'S DCF ANALYSIS?

A. The result for Mr. D'Ascendis's DCF ROE analysis was 10.32 percent. This value is at the high end of recent authorized ROEs in the U.S.

C. Risk-Premium Approach

Q. WHAT IS THE RISK-PREMIUM METHOD?

A. The risk-premium method is a historical approach to ROE analysis. The inputs to the method are authorized ROEs and U.S. Treasury yields from the past. Thus, the regression model developed by Mr. D'Ascendis finds only what has happened in certain circumstances, not what investors, signaling through their willingness to pay certain prices for common-equity shares, tell the market they expect will happen. The DCF model and

the CAPM, as applied by both Mr. D'Ascendis and me, are forward-looking models and are preferred to the risk-premium method for that reason.

Q. HOW IS THE RISK-PREMIUM METHOD CALCULATED?

A. Prior authorized utility ROEs and the bond yields in effect at the time the authorized ROEs are ordered are inputs into the risk-premium method. The values for the variables are used in statistical analysis that develops a relationship between the risk-free bonds and the authorized ROEs. The differences between the two variables' values when aggregated in the statistical analysis produce a risk premium. The outcome of the analysis is an equation in which current bond values are used to produce a risk premium and a current ROE for a public utility in a base rate case.

Q. HOW DOES THE RISK-PREMIUM METHOD INTRODUCE CIRCULARITY INTO ROE ANALYSIS?

A. The ROE for a current case becomes an input in any following risk-premium approach ROE analyses, setting up a circularity loop of references from one rate case to the next. Eventually, the current authorized ROE becomes part of the set of historical authorized ROEs that serve as inputs into the risk-premium analysis that can be part of the ROE analysis for the subject utility. The current views of investors regarding the subject company are not part of the risk-premium approach.

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Q. DO INVESTORS TAKE PREVIOUS AUTHORIZED ROES INTO ACCOUNT AS THEY MAKE DECISIONS ABOUT BUYING AND SELLING NATURAL GAS UTILITY COMMON-EQUITY SHARES?

A. Yes. Previous authorized ROEs for a subject utility and other companies are an element that investors consider in making decisions.

Q. HOW IS THIS CONSIDERATION OF PREVIOUS AUTHORIZED ROES BY INVESTORS DIFFERENT THAN USING PREVIOUS AUTORIZED ROES IN THE RISK-PREMIUM METHOD?

A. When investors include previous authorized ROEs, and other inputs into their decisions, they make judgments as to how much weight to give to each variable. Further, they also include their assessments of the prospects of a subject utility and other companies in the same industry in their process. These expectations of the future are not part of the risk-premium method. As for the previous authorized ROEs, the relationship between them and bond yield values is rigid in risk-premium analysis.

Q. WHAT WAS THE RESULT OF MR. D'ASCENDIS'S RISK-PREMIUM ANALYSIS?

A. Mr. D'Ascendis obtained an ROE of 11.38 percent from his risk-premium analysis.[74] This value is about 88 basis points greater than any ROE authorized for a U.S. natural gas utility in the period 2021 to 2023. It is not a reasonable ROE.

D. CAPM Analysis

[74] D'Ascendis' Direct, p. 4, Table 2.

Q. DID MR. D'ASCENDIS APPLY THE CAPM IN HIS ROE ANALYSIS?

A. Yes. Mr. D'Ascendis applied the CAPM and the ECAPM, a variation of the CAPM, in his ROE analysis.

Q. WHAT WERE THE RESULTS OF HIS CAPM AND ECAPM ANALYSES?

A. The mean results for his ROE analyses were 12.24 percent for the CAPM and 12.75 percent for the ECAPM. The median ROEs were 12.30 percent and 12.79 percent. Mr. D'Ascendis combined the two sets of results to arrive at a CAPM ROE value of 12.52 percent.[75]

Q. ARE THESE ROE VALUES REASONABLE?

A. No. The highest authorized ROE for a natural gas utility from 2021-2023 was 10.50 percent.[76] Mr. D'Ascendis's combined CAPM and ECAPM ROE value is 2.02 percent greater. Therefore, it does not represent a reasonable value for SUA's ROE analysis and should be given no weight.

E. Non-Price Regulated Companies Analysis

Q. HOW DID MR. D'ASCENDIS PERFORM HIS COMPARABLE RISK ANALYSIS?

A. Mr. D'Ascendis asserted that the comparable risk standard for determining an ROE for a regulated utility such as SUA can be applied to non-price regulated companies if they are comparable in risk to the subject utility. He formed a proxy group for such companies using Value Line betas and standard errors as screening criteria. The betas and standard errors had to fall within two standard deviations of the values of the same parameters for the natural gas utility Proxy Group companies. He then applied the DCF model, risk

[75] D'Ascendis Direct, Schedule DWD-5, page 1 of 2.
[76] D'Ascendis Direct, p. 36.

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premium model, and CAPM to the resulting proxy group of 45 companies. He argued that the ROEs derived were indicators of the level of return required by SUA because the risks were similar.[77]

Q. WHAT ROLE DOES VOLATILITY OF CASH FLOW PLAY IN THE CREDIT RATINGS THAT COMPANIES RECEIVE?

A. Price regulated companies such as the natural gas utilities used by Mr. D'Ascendis and me in our proxy groups tend to have cash flow that is less volatile than the cash flow of non-price regulated companies. S&P considers both level and volatility of profits as it assigns leverage ratings to companies. Firms with lower leverage ratings receive better credit ratings. Therefore, companies with less volatile cash flow receive better credit ratings. S&P explains in an excerpt from its publication "Key Credit Factors for the Regulated Public Utilities Industry" that in assessing the adequacy of cash flow of a regulated utility that S&P analysts take into account volatility of cash flow, just as they do for other corporate issuers. One measure of volatility is the percentage of cash flow from regulated activities. Utilities, with a higher percentage of their cash flow coming from regulated activities, typically are regarded as less volatile.[78]

Q. HOW DOES S&P COMBINE VOLATILITY RATINGS WITH CASH FLOW IN RATING COMPANIES?

A. S&P includes three tables of different volatility ratings in its credit rating discussion publication "General: Corporate Methodology." The tables show that for a company, regulated or not, to receive a certain leverage rating, it must demonstrate that it meets

[77] D'Ascendis Direct, p. 40, line 13 – p. 41, line 5.
[78] Exhibit MFG-18, Schedule 1, Pages 1-2.

certain thresholds for core ratios, coverage ratios, and payback ratios. Companies rated low in volatility do not have to meet levels as stringent as companies rated medial or standard in volatility do to receive the same leverage rating.[79]

The standard for a company with a low volatility rating to receive a "minimal leverage" rating for the funds from operations ("FFO")-to-debt ratio is 35 percent or better. In contrast, a company with a standard volatility rating must have an FFO-to-debt ratio of 60 percent or better to receive the same "minimal leverage" rating.[80] Recall that lower volatility is associated with better credit ratings.

Q. PLEASE DESCRIBE HOW HAVING TO MEET A LOWER RATIO TO RECEIVE THE SAME LEVERAGE RATING ADDRESSES RISK LEVELS OF PRICE REGULATED COMPANIES.

A. The FFO-to-debt ratio is one of seven indicators that S&P considers in assigning an overall leverage rating in its credit rating process. A "minimal leverage" rating is associated with higher credit ratings. Thus, a price regulated public utility with its tendency to receive a low volatility rating because a "vast majority"[81] of its cash flow comes from regulated activities will, all other things equal, receive a better leverage rating and better credit rating than will a non-price regulated company. A non-price regulated company by definition does not have a substantial percentage of cash flow coming from regulated activities.

[79] See paragraphs 76-77 of Exhibit MFG-19, Schedule 2, pp. 1-2.
[80] See the shaded areas in the FFO/Debt columns of Table 17 and Table 19 in Exhibit MFG-19, Schedule 2, pages 1-2.
[81] See paragraph 78 of Exhibit MFG-19, Schedule 1, page 2.

Q. HOW CAN NON-PRICE REGULATED FIRMS RECEIVE A CREDIT RATING IDENTICAL TO THAT OF PRICE REGULATED UTILITIES?

A. Firms with less desirable volatility ratings, such as the volatility rating a typical non-price regulated firm is likely to receive, can make up for their greater cash flow uncertainty with higher FFO-to-debt ratios, to name one compensating factor. These firms can achieve higher ratios if they have greater cash flow than price regulated firms. Higher rates of return to equity can produce greater cash flow. Hence, higher return to equity enables the non-price regulated firms to receive credit ratings equal to the credit ratings of their price regulated counterparts.

Q. DOES IT FOLLOW THAT A NON-PRICE REGULATED COMPANY WITH THE SAME CREDIT RATING AS A PRICE REGULATED UTILITY IS A GOOD PROXY FOR THE PRICE REGULATED UTILITY?

A. No. Non-price regulated companies with greater cash flow volatility tend to require greater return on equities than their price-regulated counterparts. As shown above, greater return on equity is a way non-price regulated firms can attain equality in S&P volatility ratings with price regulated utilities and take a step toward the same credit rating. Hence, the non-price regulated firms do not make good proxies for price regulated utilities because of their tendency toward higher rates of return.

Q. DO THESE OBSERVATIONS ABOUT CREDIT RATINGS AND RETURN ON EQUITY ALSO APPLY TO BETA VALUES?

A. Yes. Mr. D'Ascendis states that beta coefficients reflect the market's assessment of market/systematic risk. Further, he says that beta coefficients are derived from regression

analyses of market prices.[82] If a non-price regulated firm and a price regulated firm with the same beta value are alike in all operational aspects other than volatility of earnings, logic indicates that the non-price regulated firm must be equally appealing to investors due to a higher rate of return. Therefore, the ROEs for the companies in Mr. D'Ascendis's proxy group of 45 non-price regulated companies are biased upward relative to the ROEs for natural gas utilities in proxy groups. It is not surprising that they are higher.

XII. CONCLUSION

Q. WHAT ARE THE CRITERIA THE COMMISSION SHOULD CONSIDER IN SETTING THE COMPANY'S ROE AND COST OF CAPITAL?

A. The Commission should only consider whether the ROE and overall cost of capital meet the *Bluefield* and *Hope* criteria for a fair return. Recounting, these criteria include returns commensurate with returns being earned on other investments with equivalent risks, rate of return sufficient to enable the utility to attract capital and returns sufficient to enable the regulated company to maintain its credit rating and financial integrity. The interpretation of the *Hope* and *Bluefield* criteria is that a company should be given the opportunity to earn an ROE and overall cost of capital sufficient to meet these standards.

Q. WHAT IS YOUR RECOMMENDED RETURN ON EQUITY AND OVERALL COST OF CAPITAL?

A. I recommend an ROE of 9.80 percent and an overall cost of capital of 5.78 percent.

Q. DOES THIS CONCLUDE YOUR TESTIMONY?

A. Yes. However, I reserve the right to update this testimony as may be necessary.

[82] D'Ascendis Direct, p. 39, lines 7-10, 21.

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CERTIFICATE OF SERVICE

I, Clay Layson, hereby certify that on July 10, 2024, I filed a copy of the foregoing utilizing the Commission's Electronic Filing System, which caused a copy to be served upon all parties of record via electronic mail.

/s/ Clay Layson
Clay Layson

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BEFORE THE ARKANSAS
PUBLIC SERVICE COMMISSION

IN THE MATTER OF THE APPLICATION OF	**)**	
SUMMIT UTILITIES ARKANSAS, INC. FOR	**)**	
A GENERAL CHANGE OR MODIFICATION	**)**	**DOCKET NO. 23-079-U**
IN ITS RATES, CHARGES AND TARIFF	**)**	

DIRECT EXHIBITS
OF
MARLON F. GRIFFING, PH.D.

ON BEHALF OF

THE OFFICE OF ARKANSAS ATTORNEY GENERAL
TIM GRIFFIN

July 10, 2024

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PCMG and Associates LLC

MARLON GRIFFING, Ph.D.

Education

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Senior Consultant – PCMG and Associates	2015 – present
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Utilities Financial Analyst – Minnesota Department of Commerce	2003 – 2013
Senior Consultant – QSI Consulting	2000 – 2002
Economic Analyst – Nebraska Public Service Commission	1998 – 2000

Professional Experience

Dr. Griffing holds bachelors, masters, and doctoral degrees in economics. Dr. Griffing is well versed in microeconomics, cost/benefit analysis and econometric analysis. He has 23 years' experience as an expert witness and consultant, primarily addressing the cost of capital and capital structure for electric, natural gas, and water utilities. He has also made appearances regarding rate design, the competitive effect of mergers, reliability and supply adequacy, and oil-pipeline companies in certificate of need cases. In addition, he managed testimony in two oil-pipeline certificate-of-need cases and arbitrated a telecommunications dispute for the Nebraska Public Service Commission. Dr. Griffing has appeared more than 60 times in cost of capital dockets and other matters before the regulatory agencies of Arkansas, California, Hawaii, Maine, Maryland, Minnesota, Nebraska, New Jersey, New Mexico, North Dakota, Oklahoma, Pennsylvania, South Dakota, Wyoming, and the Federal Energy Regulatory Commission.

PCMG and Associates LLC

Regulatory Projects and Appearances

1. In the Matter of the FirstEnergy Pennsylvania Base Rate Case (2024) (Appearance: cost of capital on behalf of the Pennsylvania Office of Consumer Advocate)
   Pennsylvania Public Utility Commission – Docket No. R-2024-3047068

2. Application of Northern States Power Company for Authority to Increase Rates for Natural Gas Service in North Dakota (2024) – (Appearance: cost of capital on behalf of the North Dakota Public Service Commission Advocacy Staff)
   North Dakota Public Service Commission Docket No. PU-23-367

3. Application of Otter Tail Power Company for Authority to Increase Electric Rates in North Dakota (2024) – (Appearance: cost of capital on behalf of the North Dakota Public Service Commission Advocacy Staff)
   North Dakota Public Service Commission Docket No. PU-23-342

4. Application of Montana-Dakota Utilities Company for Authority to Increase Rates for Natural Gas Service in North Dakota (2024) – (Appearance: cost of capital on behalf of the North Dakota Public Service Commission Advocacy Staff)
   North Dakota Public Service Commission Docket No. PU-23-341

5. In the Matter of the Verified Petition of Jersey Central Power & Light Company for Approval of an Infrastructure Investment Program II ("EnergizeNJ") (2023) – (Appearance: cost of capital on behalf of the New Jersey Division of Rate Counsel)
   New Jersey Board of Public Utilities Docket No. EO23110793

6. In the Matter of the Petition of Veolia Water New Jersey Inc. for Approval of an Increase in Rates for Water/Sewer Service and Other Tariff Changes (2023) – (Appearance: rate of return and cost of capital on behalf of the New Jersey Division of Rate Counsel)
   New Jersey Board of Public Utilities Docket No. WR23110790

7. In the Matter of the Petition of the Application of Black Hills Wyoming Gas, LLC d/b/a Black Hills Energy for Approval of a General Rate Increase of $19,262,41 to the Retail Gas Rates Effective for Usage on and After February 1, 2023 and Extension of the Wyoming Integrity Rider (2023) – (Appearance: cost of capital on behalf of the Wyoming Office of Consumer Advocate)
   Wyoming Public Service Commission Docket No. 30026-78-GR-23

8. In the Matter of the Petition of Middlesex Water Company for Approval of an Increase in Rates for Water Service and Other Tariff Services (2023) – (Appearance: cost of capital on behalf of the New Jersey Division of Rate Counsel)
   New Jersey Board of Public Utilities Docket No. WR23050292

PCMG and Associates LLC

9. In the Matter of the Petition of Jersey Central Power and Light Company for Authority to Issue and Sell Up to $700,000,000 Aggregate Principal Amount of Senior Notes in One or More Series and to Make, Execute and Deliver One or More Supplemental Indentures in Connection Therewith (2023) – (Appearance: debt issuance petition on behalf of the New Jersey Division of Rate Counsel)
   New Jersey Board of Public Utilities Docket No. EF23060339
   c
10. In the Matter of the Pittsburgh Water and Sewer Authority Base Rate Case (2023) (Appearance: Cash Flow and Bond Ratings on behalf of the Pennsylvania Office of Consumer Advocate)
   Pennsylvania Public Utility Commission – Docket Nos. R-2023-3039920, R-2023-3039921, R-2023-303991

11. In the Matter of the Application of Hawaii Water Service Co. for Approval of a General Rate Increase for Its Pukalani Wastewater Division and Certain Tariff Changes (2022) (Appearance: Cost of Capital on behalf of the Hawaii Division of Consumer Advocacy)
   Hawaii Public Service Commission – Case No. 2022-0186

12. In the Matter of the Philadelphia Gas Works Base Rate Case (2023) (Appearance: Cash Flow and Bond Ratings on behalf of the Pennsylvania Office of Consumer Advocate)
   Pennsylvania Public Utility Commission – Docket No. R-2023-3037933

13. In the Matter of the Application of Lanai Water Company, Inc. for Review and Approval of Rate Increases; Revised Rate Schedules; and Changes to its Tariff (2022) (Appearance: Cost of Capital on behalf of the Hawaii Division of Consumer Advocacy)
   Hawaii Public Service Commission – Case No. 2022-0233

14. Application of Southern Maryland Electric Cooperative, Inc., for Authority to Revise Its Rates and Charges for Electric Service and Certain Rate Design Changes (2023) – (Appearance: cost of capital on behalf of the Maryland Office of the People's Counsel)
   Maryland Public Service Commission Case No. 9688

15. In the Matter of Petition of Atlantic City Electric Company for Approval of Powering the Future, an Infrastructure Investment Program and Related Cost Recovery Mechanism, Pursuant to *N.J.A.C.* 14:3-2A.1 et. seq. (2022) – (Appearance: cost of capital on behalf of the New Jersey Division of Rate Counsel)
   New Jersey Board of Public Utilities Docket No. ER22100666

16. Application of San Diego Gas & Electric Company (U902M) for Authority to Establish Its Authorized Cost of Capital for Utility Operations for 2023 and to Reset the Annual Cost of Capital Mechanism (2022) - (Appearance: cost of equity, cost of debt, capital structure, overall rate of return on behalf of the United Consumer Action Network)
   California Public Utilities Commission Proceeding A.22-04-008

PCMG and Associates LLC

17. In the Matter of the Petition of Rockland Electric Company for Approval of an Infrastructure Investment Program, and Related Cost Recovery Mechanism (2022) – (Appearance: cost of capital on behalf of the New Jersey Division of Rate Counsel)
    New Jersey Board of Public Utilities Docket No. ER22030198

18. Application of the Empire District Electric Company, a Kansas Corporation, for an Adjustment in Its Rates and Charges for Electric Service in the State of Oklahoma (2021) – (Appearance: return on equity, cost of capital on behalf of the Office of the Oklahoma Attorney General)
    Oklahoma Commerce Commission Cause No. PUD 202100163

19. In the Matter of the Application of Oklahoma Gas and Electric Company for an Order of the Commission Authorizing Applicant to Modify Its Rates, Charges, and Tariffs for Retail Electric Service in Oklahoma (2022) - (Appearance: return on equity, cost of capital on behalf of the Office of the Oklahoma Attorney General)
    Oklahoma Commerce Commission Cause No. PUD 202100164

20. In the Matter of the Application of Northern States Power Co. for Authority to Increase Rates for Natural Gas Service in North Dakota (2022) – (Appearance: cost of equity, cost of debt, capital structure, overall rate of return on behalf of the North Dakota Public Service Commission Advocacy Staff)
    ND Public Service Commission Case No. PU-21-381

21. In the Matter of the Petition of Public Service Electric and Gas Company for Approval of an Infrastructure Advancement Program Pursuant to N.J.A.C. 14:3-2A.1 *et. seq.* (2021) – (Appearance: cost of capital on behalf of the New Jersey Division of Rate Counsel)
    New Jersey Board of Public Utilities Docket Nos. EO21111211 and GO21111212

22. In Re: Hawaii-American Water Company – Approval of Rate Increases and Revised Rate Schedules for Wastewater Services (2021) (Appearances: Cost of Capital on behalf of the Hawaii Division of Consumer Advocacy)
    Hawaii Public Service Commission – Case No. 2021-0063

23. In Re: Kalaeloa Water Company – Approval of a General Rate Increase / Adjustments for Water and Wastewater Services (2021) (Appearance: Cost of Capital on behalf of the Hawaii Division of Consumer Advocacy)
    Hawaii Public Service Commission – Case No. 2021-0005

24. In the Matter of Application of San Diego Gas & Electric Company for Authority to Establish Its Authorized Cost of Capital for Utility Operations for 2022 and to Reset the Annual Cost of Capital Mechanism (2021) – (Appearance: cost of equity, cost of debt, capital structure, overall rate of return on behalf of the Utility Consumers' Action Network)
    CA Public Utilities Commission Application 21-08-014

PCMG and Associates LLC

25. In the Matter of the Petition of Gordon's Corner Water Company for an Increase in Rates and Charges for Water Service (2021) – (Appearance: cost of capital on behalf of the New Jersey Division of Rate Counsel)
    New Jersey Board of Public Utilities Docket No. WR21070979

26. Maine Water Company, Application for Approval of Rate Increase and Rate Smoothing Mechanism for the Biddeford and Saco Division (2021) – (Appearance: cost of equity, cost of debt, capital structure, overall rate of return on behalf of the Maine Office of the Public Advocate)
    Maine Public Utilities Commission Docket No. 2021-00289

27. In the Matter of the Petition of New Jersey Natural Gas Company for Approval of an Increase in Gas Base Rates and for Changes in its Tariff for Gas Service Pursuant to N.J.S.A. 48:2-21 and N.J.S.A. 48:2-21.1, and for Changes to Depreciation Rates for Gas Property Pursuant to N.J.S.A. 48:2-18 (2021) – (Appearance: cost of capital on behalf of the New Jersey Division of Rate Counsel)
    New Jersey Board of Public Utilities Docket No. ER21030679

28. In the Matter of the Application of Oklahoma Natural Gas Company, a Division of ONE Gas, Inc., for a Review and Change or Modification in Its Rates, Charges, Tariffs and Terms and Conditions of Service (2021) – (Appearance: return on equity, cost of capital on behalf of the Office of the Oklahoma Attorney General)
    Oklahoma Commerce Commission Cause No. PUD 202100063

29. Application of Public Service Company of Oklahoma, An Oklahoma Corporation, for An Adjustment in Its Rates and Charges and the Electric Service Rules, Regulations and Conditions for Service in the State of Oklahoma and to Approve a Performance-Based Rate Proposal (2021) – (Appearance: return on equity, cost of capital on behalf of the Office of the Oklahoma Attorney General)
    Oklahoma Commerce Commission Cause No. PUD 202100055

30. Versant Power f/k/a Emera Maine, Proposed Increase in Distribution Rates (2021) – (Appearance: cost of equity, cost of debt, capital structure, overall rate of return on behalf of the Maine Office of the Public Advocate)
    Maine Public Utilities Commission Docket No. 2020-00316

31. In the Matter of the Verified Petition of Atlantic City Electric Company for Approval of Amendments to its Tariff to Provide for an Increase in Rates and Charges for Electric Service Pursuant to N.J.S.A. 48:2-21 and N.J.S.A. 48:2-21.1, and for Other Appropriate Relief (2021) – (Appearance: cost of capital on behalf of the New Jersey Division of Rate Counsel)
    New Jersey Board of Public Utilities Docket No. ER201020746

PCMG and Associates LLC

32. In the Matter of the Petition of Elizabethtown Gas Company to Issue Long-Term Debt and Security Therefor and for Authority to Issue and Sell Short-Term Indebtedness, all through December 31, 2023 (2021) – (Appearance: debt issuance petition on behalf of the New Jersey Division of Rate Counsel)
    New Jersey Board of Public Utilities Docket No. GF20120749

33. Northern States Power Minnesota 2021 Electric Rate Increase Application (2021) – (Appearance: cost of equity, cost of debt, capital structure, overall rate of return on behalf of the North Dakota Public Service Commission Staff)
    ND Public Service Commission Case No. PU-20-441

34. Pike County Light & Power Company 2020 General Base Rate Increase (2020) – (Appearance: Cost of Capital on behalf of the Pennsylvania Office of Consumer Advocate)
    Pennsylvania Public Utility Commission – Docket Nos. R-2020-3022134 (Gas) and R-2020-3022135 (Electric)

35. Water Rate Case Consultant for the Maine Public Advocate (2020) – (Appearance: cost of capital on behalf of the Maine Office of Public Advocate in selected cases)
    Maine Public Utilities Commission Docket No. 2021-00053

36. In the Matter of the Petition of South Jersey Gas Company for Approval of Increased Base Tariff Rates and Charges for Gas Service, Changes to Depreciation Rates and Other Tariff Revisions (2020) – (Appearance: cost of capital on behalf of the New Jersey Division of Rate Counsel)
    New Jersey Board of Public Utilities Docket No. GR20030243

37. In the Matter of the Verified Petition of Jersey Central Power & Light Company for Review and Approval of Increases in, and Other Adjustments to, its Rates and Charges for Electric Service, and for Approval of Other Proposed Tariff Revisions in Connection Therewith (2020) – (Appearance: cost of equity on behalf of the New Jersey Division of Rate Counsel)
    New Jersey Board of Public Utilities Docket No. ER20020146

38. In the Matter of the Federal Power Act Rule 206 Complaint Against Public Service Electric and Gas Company (2020) – (Appearance: cost of equity on behalf of the New Jersey Division of Rate Counsel)
    Federal Energy Regulatory Commission Docket No. ER09-1257-000

39. In the Matter of the Petition of New Jersey-American Water Company for Approval of Increase Base Tariff Rates and Charges for Water and Wastewater Service and Other Tariff Changes (2019) – (Appearance: cost of equity on behalf of the New Jersey Division of Rate Counsel)
    New Jersey Board of Public Utilities Docket No. WR19121516

PCMG and Associates LLC

40. In the Matter of the Petition of Jersey Central Power & Light Company for Approval of Its Transmission Rates and Transmission Enhancement Charge for Interconnection with PJM Interconnection, L.L.C. (2019) – (Appearance: cost of equity on behalf of the New Jersey Division of Rate Counsel)
    Federal Energy Regulatory Commission Docket No. ER20-227-000

41. Request for Approval of Rate Change, Northern Utilities, Inc. (2019) - (Appearance: cost of equity, cost of debt, capital structure, overall rate of return on behalf of the Maine Office of the Public Advocate)
    Maine Public Utilities Commission Docket No. 2019-00092

42. Application of San Diego Gas & Electric Company (U902M) for Authority to: (i) Adjust its Authorized Return on Common Equity, (ii) Adjust its Authorized Embedded Costs of Debt and Preferred Stock, (iii) Adjust its Authorized Capital Structure; (iv) Modify its Adopted Cost of Capital Mechanism Structure, and (v) Revise its Electric Distribution and Gas Rates Accordingly, and for Related Substantive and Procedural Relief (2019) - (Appearance: cost of equity, cost of debt, capital structure, overall rate of return on behalf of the Utility Consumers' Action Network)
    California Public Utilities Commission Proceeding A.19-04-017

43. In the Matter of the Application of the Empire District Electric Company, a Kansas Corporation, for an Adjustment in its Rates and Charges for Electric Service in the State of Oklahoma (2019) - (Appearance: cost of equity, cost of debt, capital structure, overall rate of return on behalf of the Office of the Oklahoma Attorney General)
    Oklahoma Commerce Commission Cause No. PUD 201800133

44. In the Matter of the Petition of New Jersey Natural Gas Company for Approval of an Increase in Gas Base Rates and for Changes in its Tariff for Gas Service, Pursuant to **N.J.S.A. 48:2-21** and **48:2-21.1** and for Changes to Depreciation Rates for Gas Property Pursuant to **N.J.S.A. 48:2-18** (2019) - (Appearance: cost of equity, cost of debt, capital structure, overall rate of return on behalf of the New Jersey Division of Rate Counsel)
    New Jersey Board of Public Utilities Docket No. GR19030420

45. In the Matter of the Petition of Pivotal Utility Holdings d/b/a Elizabethtown Gas Company to Implement an Infrastructure Investment Program (IIP) and Associated Recovery Mechanism (2019) - (Appearance: cost of equity, cost of debt, capital structure, overall rate of return on behalf of the New Jersey Division of Rate Counsel)
    New Jersey Board of Public Utilities Docket No. GR18011197

46. Commission-Initiated Investigation into Rates and Revenue Requirements Pertaining to Emera Maine, Inc. (2019) - (Appearance: cost of equity, cost of debt, capital structure, overall rate of return on behalf of the Maine Office of the Public Advocate)
    Maine Public Utilities Commission Docket No. 2019-00019

PCMG and Associates LLC

47. In the Matter of Petition of Aqua New Jersey, Inc. for Approval of an Increase in Rates for Water Service and Other Tariff Changes (2018) - (Appearance: return on equity, cost of capital on behalf of the New Jersey Division of Rate Counsel)
New Jersey Board of Public Utilities Docket No. WR18121351

48. Application of Oklahoma Gas and Electric Company for an Order of the Commission Authorizing Applicant to Modify Its Rates, Charges, and Tariffs for Retail Electric Service in the State of Oklahoma (2018) - (Appearance: return on equity, cost of capital on behalf of the Office of the Oklahoma Attorney General)
Oklahoma Commerce Commission Cause No. PUD 201800140

49. Commission-Initiated Investigation into Rates and Revenue Requirements Pertaining to Central Maine Power Company (2018) - (Appearance: cost of equity, cost of debt, capital structure, overall rate of return on behalf of the Maine Office of the Public Advocate)
Maine Public Utilities Commission Docket No. 2018-00194

50. Application of Public Service Company of Oklahoma, An Oklahoma Corporation, for An Adjustment in Its Rates and Charges and the Electric Service Rules, Regulations and Conditions for Service in the State of Oklahoma and to Approve a Performance-Based Rate Proposal (2018) - (Appearance: return on equity, cost of capital on behalf of the Office of the Oklahoma Attorney General)
Oklahoma Commerce Commission Cause No. PUD 201800097

51. In Re: The Matter of the Application of Maryland American Water Co. for Authority to Increase Rates and Charges (2018) – (Appearance: Cost of capital on behalf of the Maryland Office of the People's Counsel)
Maryland Public Service Commission – Case No. 9487

52. In the Matter of Petition of Atlantic City Electric Co. for Approval of Amendments to Its Tariff to Provide for an Increase in Rates and Charges for Electric Service and for Other Appropriate Relief (2018) - (Appearance: return on equity, cost of capital on behalf of the New Jersey Division of Rate Counsel)
New Jersey Board of Public Utilities Docket No. ER18060638

53. In the Matter of Petition of SUEZ Water New Jersey, Inc. for Approval of an Increase in Rates for Water/Sewer Service and Other Tariff Changes (2018) - (Appearance: return on equity, cost of capital on behalf of the New Jersey Division of Rate Counsel)
New Jersey Board of Public Utilities Docket No. WR18050593

54. In Re: The Matter of the Application of Columbia Gas of Maryland, Inc. for Authority to Increase Rates and Charges (2018) – (Appearance: Cost of capital on behalf of the Maryland Office of the People's Counsel)
Maryland Public Service Commission – Case No. 9480

PCMG and Associates LLC

55. In Re: The Matter of the Columbia Gas of Pennsylvania for a General Rate Increase in Distribution Gas Service (2018) – (Appearance: Cost of Capital on behalf of the Pennsylvania Office of Consumer Advocate)
Pennsylvania Public Utility Commission – Docket No. R-2018-2647577

56. In the Matter of the Application of Black Hills Energy Arkansas, Inc. for Approval of a General Tariff Change in Rates and Tariffs (2018) – (Appearance: return on equity, cost of capital on behalf of the Office of the Arkansas Attorney General)
Arkansas Public Service Commission Docket 17-071-U

57. In the Matter of the Petition of Atlantic City Electric Company for Approval of an Infrastructure Investment Program and Related Cost Recovery Mechanism (2018) – (Appearance: cost of equity, cost of debt, capital structure, overall rate of return on behalf of the New Jersey Division of Rate Counsel)
New Jersey Board of Public Utilities Docket No. EO18020196

58. In the Matter of the Application of Oklahoma Gas and Electric Company for an Order of the Commission Authorizing Applicant to Modify Its Rates, Charges, and Tariffs for Retail Electric Service in Oklahoma (2018) - (Appearance: return on equity, cost of capital on behalf of the Office of the Oklahoma Attorney General)
Oklahoma Commerce Commission Cause No. PUD 201700496

59. Application of Fayson Lake Water Company for the Approval of an Increase in Rates and Other Appropriate Relief (2017) – (Appearance: cost of equity, cost of debt, capital structure, overall rate of return on behalf of the New Jersey Division of Rate Counsel)
New Jersey Board of Public Utilities Docket No. WR17101041

60. Petition of Middlesex Water Company for Approval of an Increase in its Rates for Water Service and Other Tariff Changes, and an Order Authorizing Special Accounting Treatment of Income Tax Refund Proceeds and Future Income Tax Deductions (2017) – (Appearance: cost of equity, cost of debt, capital structure, overall rate of return on behalf of the New Jersey Division of Rate Counsel)
New Jersey Board of Public Utilities Docket No. WR17101049

61. In the Matter of the Petition of New Jersey-American Water Company, Inc. for Approval of an Increased Tariff Rates and Charges for Water and Sewer Service, Change in Depreciation Rates, and Other Tariff Modifications (2017) – (Appearance: cost of equity, cost of debt, capital structure, overall rate of return on behalf of the New Jersey Division of Rate Counsel)
New Jersey Board of Public Utilities Docket No. WR17090985

62. Montana-Dakota Utilities Co., Application to Increase Natural Gas Rates (2017) - (Appearance: cost of equity, cost of debt, capital structure, overall rate of return on behalf of the North Dakota Public Service Commission Staff)
ND Public Service Commission Case No. PU-17-295

PCMG and Associates LLC

63. In the Matter of the Petition of Andover Utility Company, Inc. for Approval of an Increase in Rates for Wastewater Service (2017) – (Appearance: cost of equity, cost of debt, capital structure, overall rate of return on behalf of the New Jersey Division of Rate Counsel)
    New Jersey Board of Public Utilities Docket No. WR17070726

64. Application of Public Service Company of Oklahoma, An Oklahoma Corporation, for An Adjustment in Its Rates and Charges and the Electric Service Rules, Regulations and Conditions for Service in the State of Oklahoma (2017) - (Appearance: return on equity, cost of capital on behalf of the Office of the Oklahoma Attorney General)
    Oklahoma Commerce Commission Cause No. PUD 201700151

65. In the Matter of the Petition of SUEZ Water Arlington Hills, Inc. for Approval of an Increase in Rates for Wastewater Service and Other Tariffs (2016) - (Appearance: cost of equity, cost of debt, capital structure, overall rate of return on behalf of the New Jersey Division of Rate Counsel)
    New Jersey Board of Public Utilities Docket No. WR16060510

66. In the Matter of Request by Emera Maine for Approval of a Rate Change (2016) - (Appearance: cost of equity, cost of debt, capital structure, overall rate of return on behalf of the Maine Office of the Public Advocate)
    Maine Public Utilities Commission Docket No. 15-00360

67. ENMAX Energy Corporation (EEC) Regulated Rate Option Non-Energy Tariff Application (2015-2016) - (Analysis: cost of capital, risk element identification on behalf of the Alberta Utilities Consumer Advocate)
    Alberta Utilities Commission Proceeding 20480

68. Pennsylvania Public Utilities Commission vs. West Penn Power Co., Pennsylvania Electric Co., Pennsylvania Power Co., and Metropolitan Edison Co. (2014-2015) - (Appearance: cost of equity, cost of debt, capital structure, overall rate of return behalf of the Office of the Pennsylvania Consumer Advocate)
    PA Docket Nos. R-2014-2428742-R-2014-2428745

69. In the Matter of the Application of Minnesota Energy Resources Corporation for Authority to Increase Rates for Natural Gas Service in Minnesota (2010-2012) - (Appearance: cost of equity, cost of debt, capital structure, overall rate of return on behalf of the Minnesota Department of Commerce)
    MN Docket No. G007,011/GR-10-977

70. In the Matter of the Application of Otter Tail Power Company for Authority to Increase Rates for Electric Utility Service in Minnesota (2010-2011) - (Appearance: cost of equity, cost of debt, capital structure, overall rate of return on behalf of the Minnesota Department of Commerce)
    MN Docket No. E017/GR-10-239

PCMG and Associates LLC

71. In the Matter of the Petition of Northern States Power Company, a Minnesota Corporation, for Authority to Increase Rates for Natural Gas Service in Minnesota (2009-2010) - (Appearance: cost of equity, cost of debt, capital structure, overall rate of return on behalf of the Minnesota Department of Commerce)
    MN Docket No. G002/GR-09-1153

72. In the Matter of an Application by CenterPoint Energy Resources Corp., D/B/A CenterPoint Minnesota Gas to Increase Natural Gas Rates in Minnesota (2008-2009) - (Appearance: cost of equity, cost of debt, capital structure, overall rate of return on behalf of the Minnesota Department of Commerce)
    MN Docket No. G008/GR-08-1075

73. In the Matter of Minnesota Energy Resources Corporation's Application for Authority to Increase Natural Gas Rates in Minnesota (2008-2009) - (Appearance: cost of equity, cost of debt, capital structure, overall rate of return on behalf of the Minnesota Department of Commerce)
    MN Docket No. G007,011/GR-08-835

74. In the Matter of the Petition of Northern States Power Company, a Minnesota Corporation and Wholly Owned Subsidiary of Xcel Energy Inc., for Authority to Increase Rates for Natural Gas Service in Minnesota (2006-2007) - (Appearance: cost of equity, cost of debt, capital structure, overall rate of return on behalf of the Minnesota Department of Commerce)
    MN Docket No. G002/GR-06-1429

75. In the Matter of the Application of CenterPoint Energy Resources Corp., D/B/A CenterPoint Energy Minnesota Gas, for Authority to Increase Natural Gas Rates in Minnesota (2005-2006) - (Appearance: cost of equity, cost of debt, capital structure, overall rate of return on behalf of the Minnesota Department of Commerce)
    MN Docket No. G008/GR-05-1380

76. In the Matter of a Petition by Interstate Power and Light Company for Authority to Increase Electric Rates in Minnesota (2005) - (Appearance: cost of equity, cost of debt, capital structure, overall rate of return on behalf of the Minnesota Department of Commerce)
    MN Docket No. E001/GR-05-748

77. In the Matter of the Petition of Northern States Power Company dba Xcel Energy Request for General Rate Increase (2004-2005) - (Appearance: cost of equity, cost of debt, capital structure, overall rate of return on behalf of the Minnesota Department of Commerce)
    MN Docket No. G002/GR-04-1511

78. In the Matter of the Petition of Great Plains Natural Gas Company's Request for General Rate Increase (2004-2005) - (Appearance: cost of equity, cost of debt, capital structure, overall rate of return on behalf of the Minnesota Department of Commerce)
    MN Docket No. G004/GR-04-1487

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79. In the Matter of the Petition of CenterPoint Energy Minnegasco, A Division of CenterPoint Resources Corp. for Authority to Increase Natural Gas Rates in Minnesota (2004-2005) - (Appearance: cost of equity, cost of debt, capital structure, overall rate of return on behalf of the Minnesota Department of Commerce)
    Docket No. G008/GR-04-901

PCMG and Associates LLC

Advance Prudence/Certificates of Need

80. In the Matter of the Application Northern States Power Company for an Advance Determination of Prudence for the Big Stone South – Alexandria – Big Oaks 345 kV Transmission Line Project (2023) – (Appearance: Need, necessity and conformance with North Dakota Statutes and Regulation on behalf of the North Dakota Public Service Commission Advocacy Staff)
North Dakota Public Service Commission Docket No. PU-23-329

81. In the Matter of the Application Northern States Power Company for an Advance Determination of Prudence for the Proposed 345 kV Brookings County – Lyon County and Helena – Hampton Second-Circuit Project (2023) – (Appearance: Need, necessity and conformance with North Dakota Statutes and Regulation on behalf of the North Dakota Public Service Commission Advocacy Staff)
North Dakota Public Service Commission Docket No. PU-23-295

82. In the Matter of the Application Northern States Power Company for an Advance Determination of Prudence for the Lyon County to Sherburne County 345 kV Transmission Line (2023) – (Appearance: Need, necessity and conformance with North Dakota Statutes and Regulation on behalf of the North Dakota Public Service Commission Advocacy Staff)
North Dakota Public Service Commission Docket No. PU-23-142

83. In re: Petition of NSTAR Gas Company d/b/a Eversource Energy for Approval of its 2016 Gas System Enhancement Plan Reconciliation Filing (2017) - (Appearance: prudence/used and useful and plant accounting on behalf of the Massachusetts Attorney General Office of Ratepayer Advocacy)
MA Department of Public Utilities Docket No. D.P.U. 17-GREC-06

84. In re: Petition of Bay State Gas Company d/b/a Columbia Gas of Massachusetts for Approval of its 2016 Gas System Enhancement Plan Reconciliation Filing (2017) - (Appearance: prudence/used and useful and plant accounting on behalf of the Massachusetts Attorney General Office of Ratepayer Advocacy)
MA Department of Public Utilities Docket No. D.P.U. 17-GREC-05

85. In re: Northern Illinois Gas Company d/b/a Nicor Gas Company Proposed General Increase in Gas Rates (2017) – (Appearance: prudence/used and useful and plant accounting on behalf of the Citizens Utility Board of Illinois)
IL Commerce Commission Docket No. 17-0124

86. In re: Petition of Fitchburg Gas and Electric Light Company d/b/a Unitil for Approval of its 2015 Gas System Enhancement Plan Reconciliation Filing (2016) - (Analysis and Assistance to Counsel: prudence/used and useful and plant accounting on behalf of the Massachusetts Attorney General Office of Ratepayer Advocacy)
MA Department of Public Utilities Docket No. D.P.U. 16-GREC-01

PCMG and Associates LLC

87. In re: Petition of Bay State Gas Company d/b/a Columbia Gas of Massachusetts for Approval of its 2015 Gas System Enhancement Plan Reconciliation Filing (2016) - (Analysis and Assistance to Counsel: prudence/used and useful and plant accounting on behalf of the Massachusetts Attorney General Office of Ratepayer Advocacy)
MA Department of Public Utilities Docket No. D.P.U. 16-GREC-05

88. In re: Petition for Approval of Gas Infrastructure Contract Between Public Service Company of New Hampshire d/b/a Eversource Energy and Algonquin Gas Transmission, LLC (2016) - (Analysis and Advice to Counsel: forecasting and cost/benefit on behalf of the New Hampshire Office of Consumer Advocate)
NH Public Utilities Commission Docket No. DE 16-241

89. In the Matter of the Application of Enbridge Energy, Limited Partnership and Enbridge Pipelines (Southern Lights) LLC for a Certificate of Need for the Alberta Clipper and Southern Lights Diluent Pipeline Projects (2007-2008) - (Case Manager: economic impact, public interest and impact on society, advice to counsel, assist on brief on behalf of the Minnesota Department of Commerce)
MN Docket No. PL-9/CN-07-465

90. In the Matter of the Application of Enbridge Energy (Southern Lights) LLC for a Certificate of Need for a Crude Oil Pipeline for the Southern Lights Project (2007-2008) - (Case Manager: economic impact, public interest and impact on society, advice to counsel, assist on brief on behalf of the Minnesota Department of Commerce)
MN Docket No. PL-9/CN-07-464

91. In the Matter of the Application of Minnesota Pipeline Company for a Certificate of Need for a Crude Oil Pipeline (2006-2007) - (Appearance: economic impact on behalf of the Minnesota Department of Commerce)
MN Docket No. PL-5/CN-06-02

92. In the Matter of the Petition of Northern States Power Company dba Xcel Energy dba Xcel Energy Certificate Need to Establish an Independent Spent Fuel Storage Installation at the Monticello Generating Plant (2005-2006) - (Appearance: license renewal, economic impact on behalf of the Minnesota Department of Commerce)
MN Docket No. E002/CN-05-123

93. In the Matter of a Certificate of Need Application for Great River Energy's Cambridge Station (2005) - (Appearance: economic impact on behalf of the Minnesota Department of Commerce)
MN Docket No. ET2/CN-05-347

PCMG and Associates LLC

Mergers

94. In. re: The Merger of the Southern Company and AGL Resources Inc. - Joint Application of the Southern Company, AGL Resources Inc., and Pivotal Utility Holdings, Inc., d/b/a Elkton Gas (2015-2016) - (Analysis: cost of capital, credit ratings, affiliate relationships on behalf of the Maryland Office of People's Counsel)
    MD Public Service Commission Case No. 9404

95. In the Matter of a Request of Great Plains Natural Gas Co. for the Approval of the Acquisition by MDU Resources Group, Inc., of Intermountain Gas Company (2008) (Appearance: rule variance, sharing savings, regulatory authority, cost of capital on behalf of the Minnesota Department of Commerce)
    MN Docket No. G004/PA-08-813

96. In the Matter of a Request for the Approval of the Acquisition by MDU Resources Group, Inc., and Its Division, Great Plains Natural Gas Co., of Cascade Natural Gas Corporation (2006-2007) (Appearance: sharing savings, regulatory authority, cost of capital on behalf of the Minnesota Department of Commerce)
    MN Docket No. G004/PA-06-1585

Regulatory Projects and Appearances

97. Massachusetts Electric Company and Nantucket Electric Company, each d/b/a National Grid: Storm Cost Recovery for Fourteen 2020 Qualifying Events (2022) (Appearance: prudence/used and useful on behalf of the Massachusetts Attorney General Office of Ratepayer Advocacy)
    Massachusetts Department of Public Utilities – Docket No. D.P.U. 22-43

98. In Re: Township of East Brunswick – Sewer Rate Study – (2017) - (Evaluation of the existing sewer rate structure and examining and quantify costs for future expansion).

99. In re: Bulletin 2015-10 Generic Proceeding to Establish Parameters for the Next Generation PBR Plans (Appearance: productivity adjustments/performance based ratemaking on behalf of the Alberta Utilities Consumer Advocate)
    Alberta Utilities Commission Proceeding 20414

100. In re: Petition of Boston Gas Company and Colonial Gas Company d/b/a National Grid for Approval of Precedent Agreements with Millennium Pipeline Company, LLC (2015-2016) - (Analysis: gas-supply model review, forecasting on behalf of the Massachusetts Attorney General Office of Ratepayer Advocacy)
    MA D.P.U. 15-130

PCMG and Associates LLC

101. In re: Petition of Boston Gas Company and Colonial Gas Company d/b/a National Grid for Approval of Agreements for LNG or Liquefaction Services with GDF Suez Gas NA, LLC; Northeast Energy Center, LLC; Gaz Metro LNG, L.P.; and National Grid LNG (2015-2016) - (Analysis: gas-supply model review, forecasting, large customer loss and retention on behalf of the Massachusetts Attorney General Office of Ratepayer Advocacy)
MA D.P.U. 15-129

Rate Design

102. In re: The Application of Potomac Electric Power Company for Adjustments to Its Retail Rates for the Distribution of Electric Energy (2017) – (Appearance: cost of service and rate design on behalf of the Maryland Office of People's Counsel)
MD Public Service Commission Case No. 9443

103. In re: The Application of Delmarva Power and Light Company for Adjustments to Its Retail Rates for the Distribution of Electric Energy (2016) – (Analysis and Assistance to Counsel: cost of service and rate design on behalf of the Maryland Office of People's Counsel)
MD Public Service Commission Case No. 9424

104. In re: The Application of Potomac Electric Power Company for Adjustments to Its Retail Rates for the Distribution of Electric Energy (2016) – (Analysis and Assistance to Counsel: cost of service and rate design on behalf of the Maryland Office of People's Counsel)
MD Public Service Commission Case No. 9418

105. In the Matter of Otter Tail Corporation dba Otter Tail Power Company's Application for Authority to Increase Rates for Electric Service in Minnesota (2007-2008) - (Appearance: rate design, revenue requirement on behalf of the Minnesota Department of Commerce)
MN Docket No. E017/GR-07-1178

Capital Structure

106. In the Matter of the Petition of Greater Minnesota Gas Inc. for Approval of 2011 Capital Structure Petition and Permission to Issue Securities (2011) - (Appearance: capital structure on behalf of the Minnesota Department of Commerce)
MN Docket No. G022/S-11-535

107. In the Matter of the Petition of Otter Tail Power Company for Approval of 2011 Capital Structure and Permission to Issue Securities (2011) - (Appearance: capital structure on behalf of the Minnesota Department of Commerce)
MN Docket No. G007,011/S-11-392

108. The Petition of Otter Tail Power Company for Approval of 2010 Capital Structure and Permission to Issue Securities (2010) - (Appearance: capital structure on behalf of the Minnesota Department of Commerce)
MN Docket No. E017/S-10-292

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PCMG and Associates LLC

109. In the Matter of the Greater Minnesota Gas Inc.'s Capital Structure Petition and Compliance with Financial Integrity Order (2010) - (Appearance: capital structure on behalf of the Minnesota Department of Commerce)
MN Docket No. G022/S-10-281

110. Interstate Power and Light Company's petition for approval of its proposed capital structure (2009) - (Appearance: capital structure on behalf of the Minnesota Department of Commerce)
MN Docket No. E,G001/S-09-607

111. A petition of Interstate Power and Light Company for approval of its proposed capital structure (2008) - (Appearance: capital structure on behalf of the Minnesota Department of Commerce)
MN Docket No. E,G001/S-08-540

112. In the Matter of the Annual Capital Structure Filing of Minnesota Energy Resources Corporation (2008) - (Appearance: capital structure on behalf of the Minnesota Department of Commerce)
MN Docket No. G007,011/SA-08-329

113. In the Matter of the Annual Capital Structure Filing of Minnesota Energy Resources Corporation (2007) - (Appearance: capital structure on behalf of the Minnesota Department of Commerce)
Docket No. G007,011/S-07-352

114. In the Matter of the Annual Capital Structure Filing of Minnesota Energy Resources Corporation (2006-2007) - (Appearance: capital structure on behalf of the Minnesota Department of Commerce)
MN Docket No. G007,011/S-06-1013

115. Northern States Power Company's request for approval of its 2006 Capital Structure Prior to Issuing Securities (2005) - (Appearance: capital structure on behalf of the Minnesota Department of Commerce)
MN Docket No. E,G002/S-05-1583

116. A petition of Interstate Power and Light Company for approval of its proposed capital structure for calendar year 2005, ending March 31, 2006 (2005) - (Appearance: capital structure on behalf of the Minnesota Department of Commerce)
MN Docket No. E,G001/S-05-151

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PCMG and Associates LLC

Affiliated Interest

117. Petition of Greater Minnesota Gas, Inc. for Approval of an Affiliated Interest Agreement (2010-2011) - (Appearance: analysis of affiliated interests of closely held company, some owners also suppliers on behalf of the Minnesota Department of Commerce)
MN Docket No. G022/AI-10-1160

118. In the Matter of the Petition of Minnesota Energy Resources Corporation for Approval of Affiliated Interest Agreement (2010-2013) - (Appearance: analysis of affiliated interests agreement post-merger on behalf of the Minnesota Department of Commerce)
MN Docket No. G007,011/AI-10-783

119. In the Matter of the Annual Capital Structure Filing of Minnesota Energy Resources Corporation and Request for Approval of Affiliated Interest Agreement (2009-2010) - (Appearance: capital structure, affiliated interest lending on behalf of the Minnesota Department of Commerce)
MN Docket No. G007,011/SAI-09-1108

120. Petition for Approval of a Lending Agreement Between Interstate Power and Light Company and Alliant Energy Corporation Pursuant to Section 216B.48 of the Minnesota Statutes and Minnesota Rule 7825.2200 (2008-2009) - (Appearance: intercompany lending on behalf of the Minnesota Department of Commerce)
MN Docket No. E,G001/AI-08-1323

121. A Petition for Approval of Affiliated Services Agreement Between Interstate Power and Light Company and RMT, Inc. Pursuant to Section 216.48 of the Minnesota Statutes and Minnesota Rule 7825.2200 (2007-2008) - (Appearance: affiliated interests, engineering services on behalf of the Minnesota Department of Commerce)
MN Docket No. E,G001/AI-07-941

Depreciation

122. Otter Tail Power Company's Request for Approval of its Five-Year Depreciation Study (2008-2009) - (Appearance: depreciation analysis on behalf of the Minnesota Department of Commerce)
MN Docket No. E017/D-08-1042

123. In the Matter of the Petition of Great Plains Natural Gas Company's Request for Approval of its Five-Year Depreciation Study for 2007 (2007-2008) - (Appearance: depreciation analysis on behalf of the Minnesota Department of Commerce)
MN Docket No. G004/D-07-740

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PCMG and Associates LLC

124. In the Matter of the Petition of Great Plains Natural Gas Company's Request for Approval of its Proposed Remaining Lives, Salvage Rates, and Resulting Depreciation Rates (2006-2007) - (Appearance: depreciation analysis on behalf of the Minnesota Department of Commerce)
    MN Docket No. G004/D-06-700

Telecommunications

125. In the Matter of the Petition of Great Plains Communications, Inc. for Arbitration to Resolve Issues Relating to an Interconnection Agreement with WWC License L.L.C. (2003) – (Arbitrator: arbitrated interconnection agreement disputes on behalf of the Nebraska Public Service Commission)
    NE Application No. C-2872

126. In the Matter of the Analysis of Qwest Corporation's Compliance with Section 271(c) of the Telecommunications Act of 1999 (1999-2002) – (Appearances: evaluation of Qwest Corporation's opening its operational support systems (OSS) to competitive local exchange carriers on behalf of the Nebraska Public Service Commission, New Mexico Public Regulation Commission Advocacy Staff, and South Dakota Public Utilities Commission Staff)
    NE Application No. C-1830, NM Case No. 3269, SD Docket No. TC01-165

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S&P Capital IQ PRO

JPMorgan Chase & Co. | Credit Ratings

NYSE: JPM (MI KEY: 100201; SPCIQ KEY: 658776)

Agency S&P Global Ratings, Moody's

A-

S&P Global Ratings

Issuer Credit Rating (Foreign Currency LT)
12/2/2015

CreditWatch/Outlook: Positive
4/1/2024

A1

Moody's

Long Term Debt (Senior Unsecured Foreign)
1/24/2024

Outlook: Stable
1/24/2024

Current Ratings

S&P GLOBAL RATINGS (S&P Entity Name:JPMorgan Chase & Co.)

RATING TYPE	RATING	RATING DATE	LAST REVIEW DATE	PREVIOUS RATING	ACTION	CREDITWATCH/ OUTLOOK	CREDITWATCH/ OUTLOOK DATE
Issuer Credit Rating							
Foreign Currency LT	A-	12/2/2015	4/1/2024	A-	CreditWatch/Outlook	Positive	4/1/2024
Local Currency LT	A-	12/2/2015	4/1/2024	A-	CreditWatch/Outlook	Positive	4/1/2024
Foreign Currency ST	A-2	12/2/2015	4/1/2024	A-1	Downgrade | CreditWatch/Outlook	NM	12/2/2015
Local Currency ST	A-2	12/2/2015	4/1/2024	A-1	Downgrade | CreditWatch/Outlook	NM	12/2/2015

MOODY'S

RATING TYPE	RATING	DATE	ACTION	OUTLOOK
Ratings Summary				
Long Term Debt (Senior Unsecured Foreign)	A1	1/24/2024		Stable
Short Term Debt (Commercial Paper Domestic)	P-1	1/24/2024		
Outlook		1/24/2024		Stable
Ratings Detail				
Senior Unsecured (Domestic)	A1	1/24/2024		Stable
Senior Unsecured (Foreign)	A1	1/24/2024		Stable
Senior Unsecured MTN (Foreign)	(P)A1	1/24/2024		
Senior Unsecured MTN (Domestic)	(P)A1	1/24/2024		
LT Issuer Rating	A1	1/24/2024		Stable
Subordinate (Domestic)	A3	1/24/2024		
Subordinate MTN (Foreign)	(P)A3	1/24/2024		
Subordinate MTN (Domestic)	(P)A3	1/24/2024		
Junior Subordinate (Domestic)	Baa1	1/24/2024		
Pref. Stock Non-cumulative (Domestic)	Baa2	1/24/2024		
Senior Unsec. Shelf (Domestic)	(P)A1	1/24/2024		
Subordinate Shelf (Domestic)	(P)A3	1/24/2024		
Pref. shelf Non-cumulative (Domestic)	(P)Baa2	1/24/2024		
Commercial Paper (Domestic)	P-1	1/24/2024		
Other Short Term (Domestic)	(P)P-1	1/24/2024		
BACKED Senior Unsecured (Domestic)	WR	3/15/2015	Withdrawn	Withdrawn
Pref. Shelf (Domestic)	WR	10/11/2013	Withdrawn	
Junior Subord. Shelf (Domestic)	WR	9/20/2010	Withdrawn	
Pref. Stock (Domestic)	WR	8/19/2010	Withdrawn	

Ratings History

S&P GLOBAL RATINGS (S&P Entity Name:JPMorgan Chase & Co.)

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Our Mission

Our Mission is to deliver safe, affordable, and reliable energy solutions to our customers every day through exceptional service and a strong commitment to our communities.

About the Company

Summit Utilities, Inc. owns natural gas distribution and transmission subsidiaries that operate in Arkansas, Colorado, Maine, Missouri, Oklahoma, and Texas. The company provides safe and affordable natural gas to businesses and residents in six states through Arkansas Oklahoma Gas, Colorado Natural Gas, Summit Natural Gas of Maine, Summit Natural Gas of Missouri, Summit Utilities of Arkansas, and Summit Utilities of Oklahoma. Each of Summit's natural gas distribution and transmission subsidiaries constructs and installs natural gas distribution systems with the goal of supporting economic development by providing safe and reliable natural gas to residential and commercial customers through exceptional customer service and commitment to community. Overall, Summit entities serve approximately 625,000 customers and operate more than 23,400 miles of pipeline.

Our Values In Action. Every day we…

Put Safety First
We never compromise the safety of our colleagues, customers and/or communities

Focus on Customers
We honor our customers and communities by giving them the best of ourselves and by prioritizing their safety and satisfaction

Are Accountable
We take ownership for our actions and the resulting impact we have on our customers, communities, and financial success

Collaborate
We work as a team to effectively execute on our vision and deliver our goals

Strive for Excellence
We deliver consistent results by taking a strategic and aligned approach

Honor Diversity
We embrace the diversity of thought in finding optimal solutions for achieving our mission

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(community) (leadership) (board-of-directors)

COMMITMENT TO COMMUNITY

OUR LEADERSHIP

BOARD OF DIRECTORS

CAREERS

(careers) (environmental-stewardship)

ENVIRONMENTAL STEWARDSHIP

Summit Utilities

Fueling the future

10825 E. Geddes Ave.,
Suite 410

Centennial, CO 80112

Phone: 720-981-2123
(720-981-2123)

Fax: 303-979-7892

Email: Customer Service
(mailto:customerservice@summitnaturalgas.com)

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ROE and ROR Analysis for Summit Comparison Group
Value Line Investment Survey Natural Gas Utility Industry
Value Line Website June 17, 2024

Company	Ticker	Exchange where Publicly Traded
Adams Resources & Energy	AE	AMS
Atmos Energy	ATO	NYS
Chesapeake Utilities	CPK	NYS
New Jersey Resources	NJR	NYS
NiSource Inc.	NI	NYS
Northwest Natural	NWN	NYS
ONE Gas, Inc.	OGS	NYS
RGC Resources Inc	RGCO	NDQ
Southwest Gas Holdings	SWX	NYS
Spire Inc.	SR	NYS
Star Group L.P.	SGU	NYS
UGI Corp.	UGI	NYS
Summit Utilities Arkansas	None	None

ROE and ROR Analysis for Summit
Comparison Group
Value Line Natural Gas Utilities
***S&P Capital IQ Pro* Database, June 17, 2024**

Docket No. 23-079-U
Exhibit MFG-4

Company	Exchange	U.S.-Based	Merger or Acquisition/Sale	S&P Credit Rating BBB- or better	Paying Dividends	Postive EPS Growth Rates
Adams Resources & Energy	AMS	Yes	No	**None**	Yes	Yes
Atmos Energy	NYS	Yes	No	A-	Yes	Yes
Chesapeake Utilities*	NYS	Yes	No	2A, 2B	Yes	Yes
New Jersey Resources**	NYS	Yes	No	A1	Yes	Yes
NiSource Inc.	NYS	Yes	No	BBB+	Yes	Yes
Northwest Natural Holding Co.	NYS	Yes	No	A	Yes	Yes
ONE Gas, Inc.	NYS	Yes	No	A-	Yes	Yes
RGC Resources Inc.	NDQ	Yes	No	**None**	Yes	**No**
Southwest Gas Holdings***	NYS	Yes	Yes	BBB-	Yes	Yes
Spire Inc.	NYS	Yes	No	BBB+	Yes	Yes
Star Group L.P.	NYS	Yes	No	**None**	Yes	NA
UGI Corp.	NYS	Yes	No	**None**	Yes	Yes
Summit Utilities Arkansas****		Yes	No	A-	Yes	

*-National Association of Insurance Commissioners rating. "2A" is equivalent to a BBB+ rating and "2B" is equivalent to a BBB rating from Standard & Poor's.

**-The rating for New Jersey Resources is the Moody's rating for New New Jersey Natural Gas (NJNG), a New Jersey Resources (NJR) subsidiary. NJNG issues its own bonds. NJR does not issue bonds. Standard & Poor's (S&P) currently has No Rating for NJNG, but Moody's A1 is equivalent to an S&P rating of A+.

***-Southwest Gas Holdings recently completed its first public offering of common equity shares in the Centuri Group, the infrastructure services company it is spinning off. Therefore, I continued to consider the company for the Comparison

****-The A- S&P credit rating for Summit Utilities Arkansas is the S&P credit rating for JPMorgan Chase and Co., the ultimate owner of SUA.

Indicates not passing a screen

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SOUTHWEST GAS NYSE-SWX

RECENT PRICE 75.84 | P/E RATIO 23.0 (Trailing: 19.9 Median: 20.0) | RELATIVE P/E RATIO 1.26 | DIV'D YLD 3.3% | VALUE LINE

TIMELINESS — Suspended 11/17/23
SAFETY 2 Raised 2/23/24
TECHNICAL — Suspended 11/17/23
BETA .90 (1.00 = Market)

18-Month Target Price Range

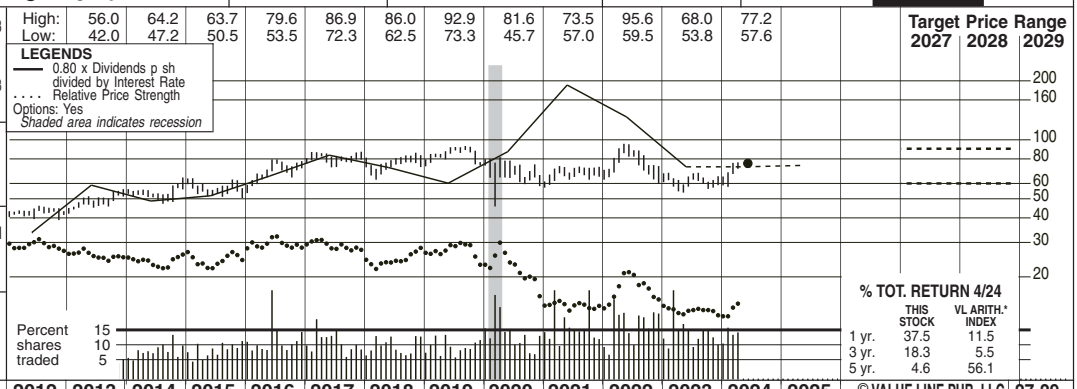
Low-High	Midpoint (% to Mid)
$62-$99	$81 (5%)

2027-29 PROJECTIONS

	Price	Gain	Ann'l Total Return
High	90	(+20%)	7%
Low	60	(-20%)	-2%

Institutional Decisions

	2Q2023	3Q2023	4Q2023
to Buy	138	103	130
to Sell	136	140	144
Hld's(000)	65230	64845	66489



2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	© VALUE LINE PUB. LLC	27-29
48.53	42.00	40.18	41.07	41.77	42.08	45.61	52.00	51.82	53.00	54.31	56.72	57.68	60.91	73.90	76.22	*69.45*	*71.90*	Revenues per sh	*73.35*
5.76	6.16	6.46	6.81	7.73	8.24	8.47	8.62	9.29	8.83	8.14	9.40	9.87	9.46	3.91	8.29	*9.55*	*10.15*	"Cash Flow" per sh	*11.00*
1.39	1.94	2.27	2.43	2.86	3.11	3.01	2.92	3.18	3.62	3.68	3.94	4.14	3.39	d3.10	2.13	*3.30*	*3.90*	Earnings per sh A	*4.20*
.90	.95	1.00	1.06	1.18	1.32	1.46	1.62	1.80	1.98	2.08	2.18	2.28	2.38	2.48	2.48	*2.48*	*2.52*	Div'ds Decl'd per sh B■†	*2.60*
6.79	4.81	4.73	8.29	8.57	7.86	8.53	10.30	11.15	12.97	14.44	17.06	14.43	11.84	12.80	12.19	*12.50*	*12.50*	Cap'l Spending per sh	*14.50*
23.49	24.44	25.62	26.66	28.35	30.47	31.95	33.61	35.03	37.74	42.47	45.56	46.77	48.89	47.95	47.72	*53.95*	*54.35*	Book Value per sh	*57.35*
44.19	45.09	45.56	45.96	46.15	46.36	46.52	47.38	47.48	48.09	53.03	55.01	57.19	60.42	67.12	71.56	*72.00*	*73.00*	Common Shs Outst'g C	*75.00*
20.3	12.2	14.0	15.7	15.0	15.8	17.9	19.4	21.6	22.2	20.6	21.3	16.8	19.9	- -	29.1	*Bold figures are Value Line estimates*		Avg Ann'l P/E Ratio	*18.0*
1.22	.81	.89	.98	.95	.89	.94	.98	1.13	1.12	1.11	1.13	.86	1.08	- -	1.68			Relative P/E Ratio	*.90*
3.2%	4.0%	3.2%	2.8%	2.8%	2.7%	2.7%	2.9%	2.6%	2.5%	2.7%	2.6%	3.3%	3.5%	3.2%	4.0%			Avg Ann'l Div'd Yield	*3.4%*
2121.7	2463.6	2460.5	2548.8	2880.0	3119.9	3298.9	3680.5	4960.0	5454.0	*5000*	*5250*	Revenues ($mill)	*5500*
141.1	138.3	152.0	173.8	182.3	213.9	232.3	200.8	d203.3	150.9	*240*	*285*	Net Profit ($mill)	*315*
35.7%	36.4%	33.9%	32.8%	25.3%	20.5%	21.6%	16.1%	NMF	21.2%	*21.0%*	*21.0%*	Income Tax Rate	*21.0%*
6.7%	5.6%	6.2%	6.8%	6.3%	6.9%	7.0%	5.5%	NMF	2.8%	*4.8%*	*5.4%*	Net Profit Margin	*5.7%*
52.4%	49.3%	48.2%	49.8%	48.3%	47.9%	50.5%	58.2%	57.8%	57.4%	*58.0%*	*58.0%*	Long-Term Debt Ratio	*57.0%*
47.6%	50.7%	51.8%	50.2%	51.7%	52.1%	49.5%	41.8%	42.2%	42.6%	*42.0%*	*42.0%*	Common Equity Ratio	*43.0%*
3123.9	3143.5	3213.5	3613.3	4359.3	4806.4	5407.2	7069.5	7621.4	8024.5	*9250*	*9450*	Total Capital ($mill)	*10000*
3658.4	3891.1	4132.0	4523.7	5093.2	5685.2	6176.1	7594.0	7024.5	7518.2	*7550*	*7750*	Net Plant ($mill)	*8000*
5.7%	5.5%	5.8%	5.8%	5.2%	5.4%	5.3%	3.5%	NMF	1.9%	*2.5%*	*3.0%*	Return on Total Cap'l	*3.0%*
9.5%	8.7%	9.1%	9.6%	8.1%	8.5%	8.7%	6.8%	NMF	4.4%	*6.0%*	*7.0%*	Return on Shr. Equity	*7.5%*
9.5%	8.7%	9.1%	9.6%	8.1%	8.5%	8.7%	6.8%	NMF	4.4%	*6.0%*	*7.0%*	Return on Com Equity	*7.5%*
5.0%	4.0%	4.1%	4.5%	3.6%	3.9%	4.0%	2.1%	NMF	NMF	*1.5%*	*2.5%*	Retained to Com Eq	*3.0%*
47%	54%	55%	53%	55%	54%	54%	69%	NMF	116%	*75%*	*65%*	All Div'ds to Net Prof	*62%*

CAPITAL STRUCTURE as of 3/31/24
Total Debt $4748.8 mill. **Due in 5 Yrs** $1008 mill.
LT Debt $4649.0 mill. **LT Interest** $275 mill.
(Total interest coverage: 1.45x) (54% of Cap'l)

Leases, Uncapitalized Annual rentals $24.9 mill.
Pension Assets-12/23 $1202.0 mill.
Oblig. $1352.2 mill.

Pfd Stock None

Common Stock 71,669,140 shs.
as of 4/26/24

MARKET CAP: $5.4 billion (Mid Cap)

CURRENT POSITION ($MILL.)	2022	2023	3/31/24
Cash Assets	123.1	106.5	104.9
Other	3584.6	1774.6	1893.6
Current Assets	3707.7	1881.1	1998.5
Accts Payable	662.1	346.9	255.3
Debt Due	1587.4	671.1	99.8
Other	1173.5	666.8	697.4
Current Liab.	1173.5	1684.8	1052.5
Fix. Chg. Cov.	265%	145%	220%

ANNUAL RATES of change (per sh)	Past 10 Yrs.	Past 5 Yrs.	Est'd '21-'23 to '27-'29
Revenues	3.5%	3.0%	*6.0%*
"Cash Flow"	4.0%	1.5%	*8.5%*
Earnings	5.5%	4.5%	*10.0%*
Dividends	8.5%	7.0%	*5.5%*
Book Value	6.5%	7.0%	*7.5%*

Calendar	QUARTERLY REVENUES ($ mill.) Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2021	885.9	821.4	888.7	1084.5	3680.5
2022	1267.4	1146.1	1125.6	1420.9	4960.0
2023	1603.3	1293.6	1169.5	1387.6	5454.0
2024	1581.0	*1000*	*1220*	*1199*	*5000*
2025	*1225*	*1275*	*1350*	*1400*	*5250*

Calendar	EARNINGS PER SHARE A D Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2021	2.03	.43	d.19	1.15	3.39
2022	1.58	d.10	d.18	d4.18	d3.10
2023	.67	.40	.04	1.02	2.13
2024	1.22	*.55*	*.20*	*1.33*	*3.30*
2025	*1.75*	*.65*	*.15*	*1.35*	*3.90*

Calendar	QUARTERLY DIVIDENDS PAID B■† Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2020	.545	.570	.570	.570	2.26
2021	.570	.595	.595	.595	2.36
2022	.595	.62	.62	.62	2.46
2023	.62	.62	.62	.62	2.48
2024	.62				

BUSINESS: Southwest Gas Holdings, Inc. is the parent holding company of Southwest Gas. Centuri Group spun-off 4/22/24. Southwest Gas is a regulated gas distributor serving 2.2 million customers in Arizona, Nevada, and California. 2023 margin mix: residential 68%; small commercial, 20%; large commercial and industrial, 8%; transportation, 4%. Total throughput: 2.2 billion therms. Southwest has 2,371 employees; Centuri 12,572. Off. & dir. own .4% of common stock; Carl C. Icahn, 15.4%; BlackRock, 13.0%; The Vanguard Group, 10.1%; (3/24 Proxy). Chairman: Michael J. Melarkey. Pres. & CEO: Karen S. Haller. Inc.: DE. Addr.: 8360 S. Durango Drive, P.O. Box 98510 Las Vegas, Nevada 89193. Telephone: 702-876-7237. Internet: www.swgas.com.

Despite missing our earnings targets, Southwest stock is up nearly 25% in price since our last review. The stock jumped significantly after the 2023 year-end earnings call when management provided insight as to the planned spin-off of the Centuri Group. Otherwise the company continued to struggle throughout the year due to higher costs and customer pushback on energy bills, though these operating results via comparisons is obscured by the significant charges from recent corporate restructuring.

The company successfully completed its initial public offering of the Centuri Group. The move, championed by activist investor Carl Icahn, aims to restore Southwest as a pure-play regulated natural gas utility. Centuri Group, the infrastructure services company, is now listed under the ticker CTRI. The stock debuted at $21 per share, a roughly $1.8 billion valuation, but quickly rose to around $25 each, where it has traded since. The company reported a $186 million loss on $2.9 billion in revenue in fiscal 2023. Southwest plans to use proceeds to reduce debt and improve cash flows.

Despite the ongoing devistiture, some catalysts should provide a near-term lift. Though Southwest is still offloading shares of the newly issued CTRI stock, operating margins reached a record in the first-quarter under the new corporate structure. Strong customer growth trends and regulatory approvals suggest a bright outlook compared with recent profit performances. Management expects a 20% to 25% increase in the authorized rate base by 2026, providing ample potential to our earnings targets late decade.

Sustainable profit growth may prove difficult in the long run. The company has been facing substantial backlash from customers for sharp increases in energy costs. While this in large part reflects commodity markets conditions, many customers are highly vocal about the company's perceived grifting which could lead to increased regulatory pressure down the line.

The stock has risen on recent developments and currently trades well within our three- to five-year target price range. The timeliness rank remains suspended pending business realignment.

Earl B. Humes *May 24, 2024*

(A) Diluted earnings. Excl. nonrec. gains (losses): '22, 10¢. Next egs. report due early August. (B) Dividends historically paid early March, June, September, and December.

■† Div'd reinvestment and stock purchase plan avail. (C) In millions.
(D) Totals may not sum due to rounding.

Company's Financial Strength	A
Stock's Price Stability	80
Price Growth Persistence	35
Earnings Predictability	10

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S&P Global
Ratings

(/en_US/web/guest/home)

General Criteria: Understanding S&P Global Ratings' Rating Definitions

03-Jun-2009 14:39 EDT

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(**Editor's Note:** We're republishing this article following our periodic review completed on Feb. 23, 2018. See the "Revisions And Updates" section for details.)

Executive Summary

S&P Global Ratings' credit ratings are designed primarily to provide relative rankings among issuers and obligations of overall creditworthiness; the ratings are not measures of absolute default probability. Creditworthiness encompasses likelihood of default, and also includes (i) payment priority, (ii) recovery, and (iii) credit stability.

In addition, our rating symbols are intended to connote the same general level of creditworthiness for issuers and bonds in different sectors and at different times. In order to promote the comparability of ratings across sectors, geographies, and over time, we are introducing stress scenarios associated with each rating category. These stress scenarios will be an important tool for calibrating our criteria to help maintain comparability. The scenarios will not become part of the rating definitions. Nor will they be the sole or primary drivers of our criteria.

S&P Global Ratings is committed to taking action to help restore confidence in ratings. As one example, over the past year, we have launched a number of initiatives designed to foster greater transparency in our analytics and processes. These initiatives have included publishing "what-if" scenario analyses discussing factors that could cause ratings to change, more

explicit discussions of the assumptions we used in forming our opinions, and changes we have made to our rating criteria for several asset classes resulting from macroeconomic developments and ongoing performance data.

By providing more information and data about ratings, we can help market participants better understand how we develop our ratings and -- whether they agree or disagree with our assessment -- act accordingly.

This article is designed to help market participants better understand what our credit ratings mean. Although the official definitions appear outwardly to be very simple, they embody multiple factors that compose the overall assessment of creditworthiness.

S&P Global Ratings has striven to maintain comparability of ratings across sectors. This has been done by relating all ratings to common default behavior and measurement and by common approaches to risk analysis. In the spirit of promoting greater transparency, S&P Global Ratings is now articulating a set of economic stress scenarios enumerated in Appendix IV, which we intend to use as benchmarks for enhancing the consistency and comparability of ratings across sectors and over time. Each scenario describes particular conditions of economic stress, which we associate with a particular rating level, as described in the appendix. Credits rated in each category are intended to be able to withstand particular conditions of economic stress without defaulting (though they might be downgraded significantly as economic stresses increase).

This publication intends to promote greater understanding of ratings and help investors attribute clearer meanings to different rating categories.

Key Attributes Of S&P Global Ratings' Credit Ratings

Rank ordering of creditworthiness

Our credit ratings express forward-looking opinions about the creditworthiness of issuers and obligations (see Appendix I for a description of "issuer" and "issue" ratings). More specifically, our credit ratings express a relative ranking of creditworthiness. Issuers and obligations with higher ratings are judged by us to be more creditworthy than issuers and obligations with lower credit ratings. (See Appendix III for a relevant excerpt from the rating definitions.)

Creditworthiness is a multi-faceted phenomenon. Although there is no "formula" for combining the various facets, our credit ratings attempt to condense their combined effects into rating symbols along a simple, one-dimensional scale. Indeed, as discussed below, the relative importance of the various factors may change in different situations.

The term creditworthiness refers to the question of whether a bond or other financial instrument will be paid according to its contractual terms. At first blush, the idea of creditworthiness seems entirely straightforward. However, delving beneath the outward simplicity reveals the true multi-dimensional nature.

Primary factor -- likelihood of default

In our view, likelihood of default is the centerpiece of creditworthiness. That means likelihood of default--encompassing both capacity and willingness to pay--is the single most important factor in our assessment of the creditworthiness of an issuer or an obligation. Therefore, consistent with our goal of achieving a rank ordering of creditworthiness, higher ratings on issuers and obligations reflect our expectation that the rated issuer or obligation should default less frequently than issuers and obligations with lower ratings, all other things being equal.

Although we emphasize the rank ordering of default likelihood, we do not view the rating categories solely in relative terms. We associate each successively higher rating category with the ability to withstand successively more stressful economic environments, which we view as less likely to occur. We associate issuers and obligations rated in the highest categories with the ability to withstand extreme or severe stress in absolute terms without defaulting. Conversely, we associate issuers and obligations rated in lower categories with vulnerability to mild or modest stress. (See Appendix IV for stress scenarios by rating level that we intend to use in promoting ratings comparability. Appendix V contains a listing of historical examples of stress conditions, including the magnitude of stress that we associate with each.)

Looking to absolute stress levels is part of how we try to achieve comparability of ratings across different types of securities, different times, different currencies, and different regions. That is, we strive to make our rating symbols correspond to the same approximate level of creditworthiness wherever they appear. Thus, when we use a given rating

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			Credit Rating Providers - Generic Rating Symbol Mapping (*) (Pursuant to the guidance in this Manual; particularly, Part One, "The Use of Credit Ratings of NRSROs in NAIC Processes," "Filing Exemptions," "Policies Applicable to Specific Asset Classes," and Part Three, "Procedure Applicable to Filing Exempt (FE) Securities and Private Letter (PL) Rating Securities")								
NAIC Designation	**NAIC Designation Modifier**	**NAIC Designation Category**	**Moody's Investor's Service**	**Standard and Poor's**	**Fitch Ratings**	**Dominion Bond Rating Service**	**A.M. Best Company**	**Morningstar Credit Ratings, LLC**	**Kroll Bond Rating Agency**	**Egan Jones Rating Company**	**HR Ratings de Mexico, S.A. de C.V.**
1	**A**	**1.A**	Aaa	AAA	AAApre, AAA	AAA, Pfd-1 (high)	aaa	AAA	AAA	AAA	HR AAA (G)
1	**B**	**1.B**	Aa1	AA+	AA+	AA (high), Pfd-1	aa+	AA+	AA+	AA+	HR AA+ (G)
1	**C**	**1.C**	Aa2	AA	AA	AA, Pfd-1 (low)	aa	AA	AA	AA	HR AA (G)
1	**D**	**1.D**	Aa3	AA-	AA-	AA (low), Pfd-1	aa-	AA-	AA-	AA-	HR AA- (G)
1	**E**	**1.E**	A1	A+	A+	A (high)	a+	A+	A+	A+	HR A+ (G)
1	**F**	**1.F**	A2	A	A	A	a	A	A	A	HR A (G)
1	**G**	**1.G**	A3	A-	A-	A (low)	a-	A-	A-	A-	HR A- (G)
2	**A**	**2.A**	Baa1	BBB+	BBB+	BBB (high), Pfd-2 (high)	bbb+	BBB+	BBB+	BBB+	HR BBB+ (G)
2	**B**	**2.B**	Baa2	BBB	BBB	BBB, Pfd-2	bbb+	BBB	BBB	BBB	HR BBB (G)
2	**C**	**2.C**	Baa3	BBB-	BBB-	BBB (low), Pfd-2 (low)	bbb-	BBB-	BBB-	BBB-	HR BBB- (G)
3	**A**	**3.A**	Ba1	BB+	BB+	BB (high), Pfd-3 (high)	bb+	BB+	BB+	BB+	HR BB+ (G)
3	**B**	**3.B**	Ba2	BB	BB	BB, Pfd-3	bb	BB	BB	BB	HR BB (G)
3	**C**	**3.C**	Ba3	BB-	BB-	BB (low), Pfd-3 (low)	bb-	BB-	BB-	BB-	HR BB- (G)
4	**A**	**4.A**	B1	B+	B+	B (high), Pfd-4 (high)	b+	B+	B+	B+	HR B+ (G)
4	**B**	**4.B**	B2	B	B	B, Pfd-4	b	B	B	B	HR B (G)
4	**C**	**4.C**	B3	B-	B-	B (low), Pfd-4 (low)	b-	B-	B-	B-	HR B- (G)
5	**A**	**5.A**	Caa1	CCC+	CCC+	CCC (high), Pfd-5 (high)	ccc+	CCC+	CCC+	CCC+	HR C+ (G)
5	**B**	**5.B**	Caa2	CCC	CCC	CCC, Pfd-5	ccc	CCC	CCC	CCC	HR C (G)
5	**C**	**5.C**	Caa3	CCC-	CCC-	CCC (low), Pfd-5 (low)	ccc-	CCC-	CCC-	CCC-	HR C- (G)
6		**6**	Ca	CC	CC	CC (high)	cc	CC	CC	CC	HR D (G)
6		**6**	C	C	C	CC	c	C	C	C	
6		**6**		D	DDD	CC (low)	d	D	D	D	
6		**6**			DD	C (high)					
6		**6**			D	C					
6		**6**				C (low)					
6		**6**				D					

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S&P Capital IQ PRO

New Jersey Natural Gas Company | Credit Ratings

(MI KEY: 4061755; SPCIQ KEY: 4233224)

Agency All

NR

S&P Global Ratings

Issuer Credit Rating (Foreign Currency LT)
5/27/2019

Not Rated | CreditWatch/Outlook: NR
5/27/2019

A1

Moody's

Long Term Rating (Senior Secured Domestic)
3/18/2020

Current Ratings

S&P GLOBAL RATINGS (S&P Entity Name:New Jersey Natural Gas Co.)

RATING TYPE	RATING	RATING DATE	LAST REVIEW DATE	PREVIOUS RATING	ACTION	CREDITWATCH/ OUTLOOK	CREDITWATCH/ OUTLOOK DATE
Issuer Credit Rating							
Foreign Currency LT	NR	5/27/2019	5/27/2019	BBB+	Not Rated | CreditWatch/Outlook	NR	5/27/2019
Local Currency LT	NR	5/27/2019	5/27/2019	BBB+	Not Rated | CreditWatch/Outlook	NR	5/27/2019
Foreign Currency ST	NR	5/27/2019	5/27/2019	A-2	Not Rated		
Local Currency ST	NR	5/27/2019	5/27/2019	A-2	Not Rated		

MOODY'S

RATING TYPE	RATING	DATE	ACTION	OUTLOOK
Ratings Summary				
Long Term Rating (Senior Secured Domestic)	A1	3/18/2020	Downgrade	
Short Term Rating (Commercial Paper Domestic)	P-2	3/18/2020	Downgrade	
Outlook		3/18/2020		Stable
Ratings Detail				

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S&P Capital IQ PRO

New Jersey Natural Gas Company | Credit Ratings

RATING TYPE	RATING	DATE	ACTION	OUTLOOK
Commercial Paper (Domestic)	P-2	3/18/2020	Downgrade	
BACKED Senior Secured (Domestic)	A1	3/18/2020	Downgrade	
Senior Secured (Domestic)	A1	3/18/2020	Downgrade	
Underlying Senior Secured (Domestic)	WR	3/16/2020	Withdrawn	
Senior Secured MTN (Domestic)	WR	1/19/2018	Withdrawn	
BACKED Other Short Term (Domestic)	WR	9/23/2014	Withdrawn	
First Mortgage Bonds (Domestic)	WR	11/30/2002	Withdrawn	
Pref. Stock (Domestic)	WR	10/30/1998	Withdrawn	
BACKED LT IRB/PC (Domestic)	WR	12/30/1997	Withdrawn	

Ratings History

S&P GLOBAL RATINGS (S&P Entity Name:New Jersey Natural Gas Co.)

RATING TYPE	RATING	RATING DATE	ACTION	CREDITWATCH/ OUTLOOK	CREDITWATCH/ OUTLOOK DATE
Foreign Currency LT					
Issuer Credit Rating	NR	5/27/2019	Not Rated | CreditWatch/Outlook	NR	5/27/2019
Issuer Credit Rating	BBB+	8/13/2018	Downgrade | CreditWatch/Outlook	Negative	8/13/2018
Issuer Credit Rating	A	4/3/2008	CreditWatch/Outlook	Negative	5/23/2018
Issuer Credit Rating	A	4/3/2008	CreditWatch/Outlook	Stable	4/30/2009
Issuer Credit Rating	A	4/3/2008	Downgrade | CreditWatch/Outlook	Negative	4/3/2008
Issuer Credit Rating	A+	9/3/2003	CreditWatch/Outlook	Negative	6/19/2006
Issuer Credit Rating	A+	9/3/2003	Upgrade | CreditWatch/Outlook	Stable	9/3/2003
Issuer Credit Rating	A	8/8/1982	CreditWatch/Outlook	Positive	12/20/1996
Issuer Credit Rating	A	8/8/1982	CreditWatch/Outlook	Stable	6/30/1992
Issuer Credit Rating	A	8/8/1982	CreditWatch/Outlook	Negative	2/17/1992
Issuer Credit Rating	A	8/8/1982	CreditWatch/Outlook	Stable	5/24/1989
Issuer Credit Rating	A	8/8/1982	Upgrade | CreditWatch/Outlook	Negative	8/8/1982
Issuer Credit Rating	A-	10/13/1976	Downgrade		
Issuer Credit Rating	A	10/8/1971	New Rating		
Local Currency LT					
Issuer Credit Rating	NR	5/27/2019	Not Rated | CreditWatch/Outlook	NR	5/27/2019
Issuer Credit Rating	BBB+	8/13/2018	Downgrade | CreditWatch/Outlook	Negative	8/13/2018
Issuer Credit Rating	A	4/3/2008	CreditWatch/Outlook	Negative	5/23/2018

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New Jersey Natural Gas Company | Credit Ratings

RATING TYPE	RATING	RATING DATE	ACTION	CREDITWATCH/ OUTLOOK	CREDITWATCH/ OUTLOOK DATE
Issuer Credit Rating	A	4/3/2008	CreditWatch/Outlook	Stable	4/30/2009
Issuer Credit Rating	A	4/3/2008	Downgrade | CreditWatch/Outlook	Negative	4/3/2008
Issuer Credit Rating	A+	9/3/2003	CreditWatch/Outlook	Negative	6/19/2006
Issuer Credit Rating	A+	9/3/2003	Upgrade | CreditWatch/Outlook	Stable	9/3/2003
Issuer Credit Rating	A	8/8/1982	CreditWatch/Outlook	Positive	12/20/1996
Issuer Credit Rating	A	8/8/1982	CreditWatch/Outlook	Stable	6/30/1992
Issuer Credit Rating	A	8/8/1982	CreditWatch/Outlook	Negative	2/17/1992
Issuer Credit Rating	A	8/8/1982	CreditWatch/Outlook	Stable	5/24/1989
Issuer Credit Rating	A	8/8/1982	Upgrade | CreditWatch/Outlook	Negative	8/8/1982
Issuer Credit Rating	A-	10/13/1976	Downgrade		
Issuer Credit Rating	A	10/8/1971	New Rating		
Foreign Currency ST					
Issuer Credit Rating	NR	5/27/2019	Not Rated		
Issuer Credit Rating	A-2	8/13/2018	Downgrade		
Issuer Credit Rating	A-1	3/28/1979	New Rating		
Local Currency ST					
Issuer Credit Rating	NR	5/27/2019	Not Rated		
Issuer Credit Rating	A-2	8/13/2018	Downgrade		
Issuer Credit Rating	A-1	3/28/1979	New Rating		

MOODY'S

RATING TYPE	RATING	DATE	ACTION	OUTLOOK
Outlook		**3/18/2020**		**Stable**
Outlook		2/7/2019		Negative
Outlook		1/19/2018		Negative
Outlook		1/30/2014		Stable
Outlook		11/8/2013		Ratings Under Review
Outlook		12/22/2009		Stable
Outlook		12/17/2008		Negative
Outlook		11/15/2003		Stable

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New Jersey Natural Gas Company | Credit Ratings

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ROE and ROR Analysis for Summit
Comparison Group
Natural Gas Distribution Company 10Ks
Operating Income unless noted otherwise

Docket No. 23-079-U
Exhibit MFG-9

	Operating Income for Natural Gas Utilities (In thousands of dollars)										
	Regulated Natural Gas Unit			Company			Regulated Natural Gas as % of Company				
Name	2023*	2022	2021	2023*	2022	2021	2023*	2022	2021	3-Year Average	10K Sources
Atmos Energy Corp.--Distribution Regulated	692,626	604,545	618,514	1,067,147	920,982	904,998	64.9%	65.6%	68.3%	66.3%	Pages 4, 26, 38
Chesapeake Utilities	126,199	115,317	106,174	150,803	142,933	131,112	83.7%	80.7%	81.0%	81.8%	Page 34
New Jersey Resources Corporation	207,528	218,873	148,993	407,000	406,475	288,350	51.0%	53.8%	51.7%	52.2%	Pages 43, 69
NiSource	901,900	915,800	617,500	1,295,500	1,265,800	1,006,900	69.6%	72.3%	61.3%	67.8%	Pages 38, 40
Northwest Natural Gas Company	170,591	152,839	147,902	184,941	167,477	163,117	92.2%	91.3%	90.7%	91.4%	Pages 9, 79, 100
ONE Gas, Inc.	377,590	349,957	310,258	377,590	349,957	310,258	100.0%	100.0%	100.0%	100.0%	Pages 7, 42
Southwest Gas Holdings, Inc.**	358,294	307,685	318,492	418,330	-24,398	369,547	85.6%	-1261.1%	86.2%	85.9%	
Southwest Gas Holdings, Inc.***	187,135	154,380	187,135	431,027	-230,290	200,779	43.4%	-67.0%	93.2%	68.3%	Pages 4, 52, 57, 97, 98
Spire Inc.****	350,800	339,900	374,000	418,600	408,200	450,200	83.8%	83.3%	83.1%	83.5%	Pages 4, 31

* - Atmos Enegy, New Jersey Resouces, and Spire, Inc. have fiscal years running from October 1 to September 30. The data for these companies is taken from their 10Ks from fiscal years ending in 2020, 2021, 2022. The remaining four companies have fiscal years running from January 1 to December 31. Data from these companies is also taken from their 10Ks for fiscal years ending in 2020, 2021, 2022.

** - Operating income. Southwest Gas Holdings, Inc. average is for 2021, 2023. Sale of pipeline in 2022 affected earnings negatively.
*** - Net income. Southwest Gas Holdings, Inc. average is for 2021, 2023. Sale of pipeline in 2022 affected earnings negatively.

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ROE and ROR Analysis for Summit Comparison Group From Operating Income Analysis in Exhibit MFG-9

Docket No. 23-079-U
Exhibit MFG-10

Company	Ticker	≥ 65 percent of operating income from regulated gas distribution operations (Companies' 2023 10Ks)
Atmos Energy Corporation	ATO	Yes
Chesapeake Utilities Corporation	CPK	Yes
New Jersey Resources	NJR	No
NiSource	NI	Yes
Northwest Natural Holding Company	NWN	Yes
ONE Gas, Inc.	OGS	Yes
Southwest Gas Holdings, Inc.	SWX	Yes
Spire Inc.	SR	Yes

Indicates not passing a screen

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Company	Ticker
Atmos Energy Corporation	ATO
Chesapeake Utilities	CPK
NiSource	NI
Northwest Natural Holding Company	NWN
ONE Gas, Inc.	OGS
Southwest Gas Holdings	SWX
Spire, Inc.	SR

Atmos Energy (ATO)			Chesapeake Utilities (CPK			NiSource (NI)		
Date		**Close**	**Date**		**Close**	**Date**		**Close**
5/6/2024	$	119.45	5/6/2024	$	109.59	5/6/2024	$	28.76
5/7/2024	$	120.34	5/7/2024	$	110.87	5/7/2024	$	29.05
5/8/2024	$	120.59	5/8/2024	$	110.53	5/8/2024	$	28.72
5/9/2024	$	119.69	5/9/2024	$	111.40	5/9/2024	$	28.90
5/10/2024	$	117.18	5/10/2024	$	111.76	5/10/2024	$	28.68
5/13/2024	$	116.33	5/13/2024	$	110.37	5/13/2024	$	28.80
5/14/2024	$	117.25	5/14/2024	$	110.75	5/14/2024	$	28.87
5/15/2024	$	117.81	5/15/2024	$	112.78	5/15/2024	$	29.13
5/16/2024	$	118.56	5/16/2024	$	113.95	5/16/2024	$	29.15
5/17/2024	$	118.64	5/17/2024	$	113.42	5/17/2024	$	29.23
5/20/2024	$	118.28	5/20/2024	$	112.40	5/20/2024	$	29.12
5/21/2024	$	118.50	5/21/2024	$	112.26	5/21/2024	$	29.21
5/22/2024	$	117.19	5/22/2024	$	110.16	5/22/2024	$	28.87
5/23/2024	$	113.99	5/23/2024	$	107.72	5/23/2024	$	28.08
5/24/2024	$	112.61	5/24/2024	$	108.36	5/24/2024	$	28.04
5/28/2024	$	112.04	5/28/2024	$	108.16	5/28/2024	$	27.90
5/29/2024	$	111.34	5/29/2024	$	106.87	5/29/2024	$	27.77
5/30/2024	$	112.59	5/30/2024	$	108.51	5/30/2024	$	27.98
5/31/2024	$	115.92	5/31/2024	$	112.01	5/31/2024	$	29.06
Mean	$	116.75	Mean	$	110.62	Mean	$	28.70

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Northwest Natural Gas (NWN)			ONE Gas, Inc. (OGS)				Southwest Gas Holdings (SWX)			Spire Inc. (SR)		
Date		Close	Date		Close		Date		Close	Date		Close
5/6/2024	$	37.86	5/6/2024	$	65.09	65.09	5/6/2024	$	75.76	5/6/2024	$	61.17
5/7/2024	$	38.37	5/7/2024	$	64.83	64.83	5/7/2024	$	76.29	5/7/2024	$	61.81
5/8/2024	$	38.47	5/8/2024	$	64.09	64.09	5/8/2024	$	75.79	5/8/2024	$	61.58
5/9/2024	$	38.36	5/9/2024	$	64.29	64.29	5/9/2024	$	76.96	5/9/2024	$	61.67
5/10/2024	$	38.64	5/10/2024	$	64.15	64.15	5/10/2024	$	76.38	5/10/2024	$	61.88
5/13/2024	$	38.48	5/13/2024	$	63.81	63.81	5/13/2024	$	75.84	5/13/2024	$	62.20
5/14/2024	$	37.99	5/14/2024	$	63.95	63.95	5/14/2024	$	74.21	5/14/2024	$	61.85
5/15/2024	$	38.15	5/15/2024	$	64.16	64.16	5/15/2024	$	76.11	5/15/2024	$	62.01
5/16/2024	$	38.49	5/16/2024	$	64.87	64.87	5/16/2024	$	77.37	5/16/2024	$	62.31
5/17/2024	$	38.54	5/17/2024	$	63.72	63.72	5/17/2024	$	77.68	5/17/2024	$	62.59
5/20/2024	$	38.71	5/20/2024	$	63.90	63.9	5/20/2024	$	77.77	5/20/2024	$	62.91
5/21/2024	$	38.75	5/21/2024	$	64.11	64.11	5/21/2024	$	78.35	5/21/2024	$	63.24
5/22/2024	$	37.98	5/22/2024	$	62.73	62.73	5/22/2024	$	77.50	5/22/2024	$	62.01
5/23/2024	$	36.73	5/23/2024	$	60.37	60.37	5/23/2024	$	76.44	5/23/2024	$	60.26
5/24/2024	$	36.23	5/24/2024	$	60.12	60.12	5/24/2024	$	76.19	5/24/2024	$	59.68
5/28/2024	$	35.67	5/28/2024	$	59.09	59.09	5/28/2024	$	76.00	5/28/2024	$	59.33
5/29/2024	$	35.38	5/29/2024	$	58.54	58.54	5/29/2024	$	73.87	5/29/2024	$	59.10
5/30/2024	$	36.93	5/30/2024	$	59.35	59.35	5/30/2024	$	75.19	5/30/2024	$	59.96
5/31/2024	$	37.42	5/31/2024	$	61.63	61.63	5/31/2024	$	77.59	5/31/2024	$	61.29
Mean	$	37.74	Mean	$	62.78		Mean	$	76.38	Mean	$	61.41

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ROE and ROR Analysis for Summit
Comparison Group
Dividends

Docket No. 23-079-U
Exhibit MFG-13

Name	Value Line	Zacks	Highest
Atmos Energy Corporation	$ 3.22	$ 3.22	$ 3.22
Chesapeake Utilities	$ 2.56	$ 2.56	$ 2.56
NiSource	$ 1.06	$ 1.06	$ 1.06
Northwest Natural Holding Company	$ 1.95	$ 1.95	$ 1.95
ONE Gas, Inc.	$ 2.64	$ 2.64	$ 2.64
Southwest Gas Holdings	$ 2.48	$ 2.48	$ 2.48
Spire, Inc.	$ 3.02	$ 3.02	$ 3.02

Value Line Gas dividends taken from May 24, 2024 Reports

Zacks Gas dividends taken from website on June 20, 2024

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ROE and ROR Analysis for Summit **Docket No. 23-079-U**
Comparison Group **Exhibit MFG-14**
Discounted Cash Flow Model Analysis **Schedule 1**
Common Equity Share Prices--May 6, 2024-May 31, 2024
Zacks, Yahoo! Finance, and Value Line Dividend Growth-Rate Estimates--May-June 2024

	A	B	C	D	E	F
Company Name	**Zacks EPS Growth Rate (%)**	**Yahoo! Finance EPS Growth Rates (%)**	**Value Line EPS Growth Rates (%)**	**Yahoo! Finance-Value Line Mean Growth**	**Average of Closing Prices**	**Annualized Dividend**
Atmos Energy Corporation	7.00%	7.40%	7.00%	7.13%	$ 116.75	$ 3.22
Chesapeake Utilities	NA	7.60%	6.50%	7.05%	$ 110.62	$ 2.56
NiSource	7.00%	6.00%	9.50%	7.50%	$ 28.70	$ 1.06
Northwest Natural Holding Company	NA	2.80%	6.50%	4.65%	$ 37.74	$ 1.95
ONE Gas, Inc.	5.00%	5.00%	3.50%	4.50%	$ 62.78	$ 2.64
Southwest Gas Holdings	6.00%	4.00%	10.00%	6.67%	$ 76.38	$ 2.48
Spire, Inc.	5.00%	6.36%	4.50%	5.29%	$ 61.41	$ 3.02
Mean	6.00%	5.59%	6.79%	6.11%		

	G	H	I	J
Company Name	**Dividend Yield (Rate/Price)**	**Expected Dividend Yield**	**Required Rate of Return on Equity**	**Exceeds 7.15% Mean of Value Line and Kroll Low-End Tests**
Atmos Energy Corporation	2.76%	2.95%	10.09%	Yes
Chesapeake Utilities	2.31%	2.48%	9.53%	Yes
NiSource	3.69%	3.97%	11.47%	Yes
Northwest Natural Holding Company	5.17%	5.41%	10.06%	Yes
ONE Gas, Inc.	4.21%	4.39%	8.89%	Yes
Southwest Gas Holdings	3.25%	3.46%	10.13%	Yes
Spire, Inc.	4.92%	5.18%	10.46%	Yes
Mean	3.76%	3.98%	10.09%	
Median			10.09%	

A: Zacks website, June 20, 2024
B: Yahoo! Finance website: June 20, 2024
C: Value Line Investment Survey reports: May 24, 202
E: Yahoo! Finance website: May 6-May 31, 2024. See Exhibit MFG-12.
F: Higher of Value Line Investment report, May 24, 2024; or Zacks website, June 20, 2024. See Exhibit MFG-13.
K: See Exhibit MFG-15, Schedule 8.

D: (A + B + C)/3 G: F/E H: G*(1+D) I: H/(1 - 0.02) J: D + H

Table VI.G6.—Selected Economic Variables, Calendar Years 2022-2095
[GDP and taxable payroll in billions]

Calendar year	Adjusted CPI [a]	Average wage index	Taxable payroll [b]	Gross domestic product	Compound new-issue interest factor [c]	Compound effective trust-fund interest factor [d]
Intermediate:						
2022	96.15	$63,467.98	$9,069	$25,422	0.9711	0.9884
2023	100.00	66,147.17	9,552	26,592	1.0000	1.0117
2024	102.53	68,627.58	9,986	27,655	1.0357	1.0356
2025	104.99	71,411.99	10,465	28,902	1.0727	1.0602
2026	107.51	74,348.48	10,944	30,177	1.1112	1.0862
2027	110.09	77,393.67	11,443	31,478	1.1530	1.1140
2028	112.73	80,510.73	11,934	32,778	1.1985	1.1442
2029	115.44	83,757.03	12,438	34,125	1.2492	1.1768
2030	118.21	87,106.49	12,954	35,521	1.3051	1.2123
2031	121.04	90,574.48	13,492	36,976	1.3656	1.2512
2032	123.95	93,995.33	14,023	38,487	1.4295	1.2946
2035	133.09	104,726.27	15,730	43,392	1.6429	1.4693
2040	149.85	125,312.66	18,992	52,850	2.0725	1.8502
2045	168.71	149,423.47	22,925	64,333	2.6144	2.3337
2050	189.95	177,750.26	27,736	78,438	3.2980	2.9438
2055	213.87	211,432.09	33,623	95,785	4.1603	3.7136
2060	240.79	251,610.19	40,795	116,988	5.2481	4.6846
2065	271.11	299,758.28	49,472	142,731	6.6204	5.9095
2070	305.24	357,187.25	59,924	173,850	8.3514	7.4546
2075	343.67	425,523.96	72,602	211,710	10.5351	9.4038
2080	386.94	506,962.67	88,194	258,358	13.2897	11.8627
2085	435.65	603,863.51	107,502	316,227	16.7646	14.9644
2090	490.50	719,124.11	131,330	387,813	21.1481	18.8772
2095	552.26	856,091.73	160,374	475,384	26.6778	23.8131
2100	621.79	1,019,162.94	195,457	581,611	33.6533	30.0396
Growth Rate 2029-2050*				4.04%		

Source: Social Security 2023 Trustees' Report

* = (2050/2030)^(1/20) - 1

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ROE and ROR Analysis for Summit
U.S Energy Information Administration Long-Term Growth Rate

Docket No. 23-079-U
Exhibit MFG-14
Schedule 3

Source: U.S. Energy Information Administration, Annual Energy Outlook 2023

Table 20. Macroeconomic Indicators

(Billions 2012 chain-weighted dollars unless otherwise noted)

	2024	2025	2026	2027	2028	2029	2030
Real Gross Domestic Product							
Reference case	20,095	20,409	20,841	21,273	21,681	22,052	22,392
Price Indices							
GDP Chain-type Price Index (2012=1.000)							
Reference case	1.35	1.38	1.41	1.44	1.47	1.51	1.54

	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040
Real Gross Domestic Product										
Reference case	22,742	23,153	23,604	24,055	24,511	24,996	25,507	26,032	26,566	27,149
Price Indices										
GDP Chain-type Price Index (2012=1.000)										
Reference case	1.58	1.61	1.65	1.69	1.73	1.77	1.81	1.85	1.89	1.93

	2041	2042	2043	2044	2045	2046	2047	2048	2049	2050	Growth Rate 2030-2050
Real Gross Domestic Product											
Reference case	27,734	28,324	28,927	29,527	30,130	30,748	31,389	32,040	32,699	33,405	2.02%
Price Indices											
GDP Chain-type Price Index (2012=1.000)											
Reference case	1.97	2.02	2.07	2.11	2.16	2.21	2.27	2.32	2.38	2.43	2.31%

Total 2030-2050 Growth Rate 4.33%

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growth than to insert a constant growth rate into the plain vanilla DCF equation. The practical challenge is to establish a reasonable growth path for future dividends. As previously discussed, an excellent starting point is security analysts' earnings growth forecasts (available from IBES, Zacks, Reuters, First Call) as a proxy for dividend forecasts. These forecasts are typically for the next five years. From the standpoint of the DCF model that extends into perpetuity, this forecasting horizon may be too short. For example, it is quite possible that a company's dividends can grow faster than the general economy for five years, but it is quite implausible for such growth to continue into perpetuity. The two-stage DCF model is based on the premise that investors expect the growth rate for the utilities to be equal to the company-specific growth rates for the next 5 years, let us say, (Stage 1 Growth), and to converge to an expected steady-state long-run rate of growth from year 6 onward (Stage 2 Growth). For example, it is quite plausible that near-term DCF growth estimates for a given company are unduly high and unsustainable over long periods, and that such growth rates are expected to decline toward a lower long-run level over time. Another example of this situation is that of companies that operate in a relatively undeveloped industry (e.g. wholesale power generation) or companies that are experiencing very high growth rates. Here again, the assumption of a constant perpetual growth rate may not be reasonable.

Blended Growth Approach

One way to account for the two stages of growth is to modify the single-stage DCF model by specifying the growth rate as a weighted average of short-term and long-term growth rates. The blended growth rate is calculated as a weighted average giving two-thirds weight to the analysts' five-year growth projections (Zacks, IBES, etc.) and one-third to historical long-term growth of the economy as a whole and/or the long-range projections of growth in Gross Domestic Product (GDP) projected for the very long term. FERC has adopted such a method in the past for determining the return on equity for gas and oil utilities.

To illustrate, two-stage DCF estimates for a group of widely traded dividend-paying diversified natural gas producers are shown on Table 9-5. Column 1 shows the spot dividend yield for each company, Column 2 shows the analyst consensus growth forecast for the next five years for each company, and column 3 shows the long-range GDP forecast of 6.5% for the U.S. economy at that time. Column 4 computes the weighed average growth, giving 2/3 weight to column 1 and 1/3 weight to column 2. Averages are shown at the bottom of the table. Adding the average blended growth rate of 9.02% to the average expected dividend yield of 2.83% shown at the bottom of Column 6 produces an estimate of equity costs of 11.85% for the group, unadjusted for flotation costs. Allowance for flotation costs to the results of Column 7 brings the return on equity estimate to 12.00%, shown in Column 7. Note

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ROE and ROR Analysis for Summit **Docket No. 23-079-U**
DCF Analysis **Exhibit MFG-14**
Common Equity Share Prices: May 6, 2024-May 31, 2024 **Schedule 5**
Multistage DCF with Zacks, Yahoo! Finance, and Value Line EPS Growth-Rate Estimates; 2023 SSA and 2023 EIA long-term growth rates

	A	B	C	D	E	F	G	H
Company Name	**Zacks EPS Growth Rate (%)**	**Yahoo! Finance EPS Growth Rates (%)**	**Value Line EPS Growth Rates (%)**	**Zacks-Yahoo! Finance-Value Line Mean Growth Rate (%)**	**Average of Closing Prices**	**Annualized Dividend**	**Dividend Yield (Rate/Price)**	**Expected Dividend Yield**
Atmos Energy Corporation	7.00%	7.40%	7.00%	7.13%	$ 116.75	$ 3.22	2.76%	2.95%
Chesapeake Utilities	NA	7.60%	6.50%	7.05%	$ 110.62	$ 2.56	2.31%	2.48%
NiSource	7.00%	6.00%	9.50%	7.50%	$ 28.70	$ 1.06	3.69%	3.97%
Northwest Natural Holding Company	NA	2.80%	6.50%	4.65%	$ 37.74	$ 1.95	5.17%	5.41%
Southwest Gas Holdings	6.00%	4.00%	3.50%	4.50%	$ 62.78	$ 2.64	4.21%	4.39%
ONE Gas, Inc.	5.00%	5.00%	10.00%	6.67%	$ 76.38	$ 2.48	3.25%	3.46%
Spire, Inc.	5.00%	6.36%	4.50%	5.29%	$ 61.41	$ 3.02	4.92%	5.18%
Mean	6.00%	5.59%	6.79%	6.11%			3.76%	3.98%

	I	J	K	L	`M	N	O	P
Company Name	**SSA Long-Run Projected EPS Growth Rate 4.04%**	**SSA Long-Run Weighted EPS Growth Rate 4.04%**	**SSA Weighted Cost of Equity, Long-Run Rate**	**EIA Long-Run Projected Growth Rate, 4.33%**	**EIA Long-Run Weighted Projected Growth Rate 4.33%**	**EIA Weighted Cost of Equity, Long-Run Rate**	**Multistage Mean Cost of Equity**	**Exceeds 7.15% Mean of Value Line and Kroll Low-End Tests**
Atmos Energy Corporation	4.04%	6.10%	9.06%	4.33%	6.20%	9.15%	9.11%	Yes
Chesapeake Utilities	4.04%	6.05%	8.52%	4.33%	6.14%	8.62%	8.57%	Yes
NiSource	4.04%	6.35%	10.32%	4.33%	6.44%	10.41%	10.37%	Yes
Northwest Natural Holding Company	4.04%	4.45%	9.86%	4.33%	4.54%	9.96%	9.91%	Yes
Southwest Gas Holdings	4.04%	4.35%	8.74%	4.33%	4.44%	8.84%	8.79%	Yes
ONE Gas, Inc.	4.04%	5.79%	9.25%	4.33%	5.89%	9.35%	9.30%	Yes
Spire, Inc.	4.04%	4.87%	10.05%	4.33%	4.97%	10.15%	10.10%	Yes
Mean		5.42%	9.40%		5.52%	9.50%	9.45%	**Mean**
Median			9.25%			9.35%	9.30%	**Median**

A: Zacks website, June 20, 2024
B: Yahoo! Finance website: June 20, 2024
C: Value Line Investment Survey reports: May 24, 2024
E: Yahoo! Finance website: May 6-May 31, 2024. See Exhibit MFG-12.
F: Higher of Value Line Investment report, May 24, 2024; or Zacks website, June 20, 2024. See Exhibit MFG-13.
I: U.S. Social Security Administration, The 2023 Annual Report of the Board of Trustees of the Federal Old-Age and Survivors Insurance and Disability Insurance Trust Funds, March 31, 2023 (OASDI Trustees Report), Table VIG6. See Exhibit MFG-14, Schedule 2.
L: U.S. Energy Information Administration,*Annual Energy Outlook 2023, Macroeconomic Indicators* (Real GDP Growth + GDP Chain-Type Index Increase 2020-2050), https://www.eia.gov/analysis/projection-data.php#annualproj. See Exhibit MFG-14, Schedule 3.
P: See Exhibit (MFG-15), Schedule 8.

D: = (A + B + C)/3 G: = F/E H: = G*(1+D) J: = 2/3*D + 1/3*J K: = H + J M: = 2/3*D + 1/3*L N: = H + M O: = (K + N)/2

ROE and ROR Analysis for Summit
CAPM Analysis
Risk-Free Rate Analysis

Docket No. 23-079-U
Exhibit MFG-15, Schedule 1

Daily Treasury Yield Curve Rates

May 6, 2024-May 31, 2024

Date	1 mo	2 mo	3 mo	4 mo	6 mo	1 yr	2 yr	3 yr	5 yr	7 yr	10 yr	20 yr	30 yr
5/6/2024	5.51	5.48	5.45	5.50	5.42	5.12	4.82	4.64	4.48	4.48	4.49	4.73	4.64
5/7/2024	5.51	5.48	5.45	5.51	5.41	5.13	4.82	4.60	4.48	4.47	4.47	4.70	4.61
5/8/2024	5.51	5.47	5.45	5.50	5.41	5.13	4.84	4.63	4.50	4.49	4.48	4.73	4.64
5/9/2024	5.51	5.48	5.46	5.50	5.41	5.12	4.80	4.60	4.47	4.46	4.45	4.70	4.6
5/10/2024	5.51	5.47	5.47	5.51	5.43	5.17	4.87	4.65	4.52	4.51	4.50	4.74	4.64
5/13/2024	5.50	5.47	5.45	5.51	5.43	5.16	4.85	4.66	4.50	4.49	4.48	4.72	4.63
5/14/2024	5.50	5.47	5.44	5.51	5.43	5.16	4.81	4.62	4.46	4.45	4.45	4.69	4.49
5/15/2024	5.49	5.46	5.45	5.50	5.40	5.10	4.73	4.51	4.35	4.35	4.36	4.61	4.52
5/16/2024	5.51	5.47	5.45	5.53	5.41	5.13	4.78	4.58	4.40	4.39	4.38	4.62	4.52
5/17/2024	5.50	5.47	5.46	5.50	5.41	5.14	4.83	4.60	4.44	4.43	4.42	4.66	4.56
5/20/2024	5.50	5.47	5.45	5.51	5.43	5.15	4.82	4.62	4.46	4.44	4.44	4.68	4.58
5/21/2024	5.50	5.47	5.45	5.51	5.42	5.14	4.82	4.61	4.43	4.42	4.41	4.65	4.55
5/22/2024	5.49	5.48	5.45	5.50	5.43	5.16	4.86	4.64	4.47	4.44	4.43	4.63	4.55
5/23/2024	5.51	5.48	5.46	5.51	5.44	5.20	4.91	4.71	4.52	4.50	4.47	4.67	4.58
5/24/2024	5.56	5.53	5.46	5.51	5.44	5.21	4.93	4.71	4.53	4.49	4.46	4.65	4.57
5/28/2024	5.50	5.48	5.46	5.51	5.43	5.21	4.94	4.75	4.56	4.56	4.54	4.74	4.66
5/29/2024	5.50	5.48	5.46	5.47	5.43	5.22	4.96	4.79	4.63	4.63	4.61	4.82	4.74
5/30/2024	5.48	5.48	5.46	5.48	5.42	5.19	4.92	4.74	4.57	4.57	4.55	4.76	4.69
5/31/2024	5.48	5.48	5.46	5.46	5.42	5.18	4.89	4.69	4.52	4.52	4.51	4.73	4.65
											Mean		4.60

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ROE and ROR Analysis for Summit
CAPM Analysis
Beta calculation for Comparison Group
Value Line Investment Survey Betas taken from reports of May 24, 2024

Docket No. 23-079-U
Exhibit MFG-15, Schedule 2

Company Name	Value Line Betas-- Comparison Group
Atmos Energy Corporation	0.85
Chesapeake Utilities	0.80
NiSource, Inc.	0.95
Northwest Natural Holding Co.	0.85
ONE Gas, Inc.	0.85
Southwest Gas Holdings	0.90
Spire Inc.	0.85

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S&P Global
Market Intelligence

Chart Builder

Entities: Moodys Bond Yield Avg - BAA Rated Corporates
Metrics: Index Value

SERIES NAME	CATEGORY	AVERAGE
Moodys Bond Yield Avg - BAA Rated Corporates-Index Value (Daily)	**Market Data**	**5.94**

Pricing Date	Moodys Bond Yield Avg BAA Rated Corporates-Index Value (Daily)
5/31/2024	5.97
5/30/2024	6.01
5/29/2024	6.08
5/28/2024	5.99
5/24/2024	5.92
5/23/2024	5.92
5/22/2024	5.89
5/21/2024	5.89
5/20/2024	5.91
5/17/2024	5.90
5/16/2024	5.85
5/15/2024	5.85
5/14/2024	5.93
5/13/2024	5.96
5/10/2024	5.98
5/9/2024	5.93
5/8/2024	5.95
5/7/2024	5.92
5/6/2024	5.96
Mean	5.94

KROLL

Cost of Capital in the Current Environment

June 2023 Update

> Although at a slower pace, major central banks are continuing to hike interest rates to tame high inflation. Headline inflation appears to have peaked, but core inflation (i.e., excluding the volatile energy and food prices) continues to be stubbornly high. Economists have upgraded real growth expectations for 2023 relative to the beginning of the year, partly due to China's reopening (after ending its zero-COVID-19 policy) and warmer weather that helped lower energy prices. Nevertheless, several countries are still expected to fall into recession in 2023 or in early 2024. In fact, Germany and the Eurozone are already in technical recession (i.e., two consecutive quarters of contraction). However, global financial markets are generally pricing a soft landing rather than a deep and prolonged recessionary period. Amidst this uncertain environment, cost of capital estimates are now similar to levels observed around the Global Financial Crisis of 2008-2009.
>
> **Carla S. Nunes, CFA – Managing Director, Kroll**

Kroll Cost of Capital Inputs

Data as of June 14, 2023

	Normalized Risk-Free Rate	Kroll-Recommended Equity Risk Premium
U.S. (in USD)	Higher of 3.5% or Spot*	5.5%
Eurozone*** (in EUR)	Higher of 3.0% or Spot**	5.5% to 6.0%

* We recommend using the spot 20-year U.S. Treasury yield as the proxy for the risk-free rate, if the prevailing yield as of the valuation date is higher than our recommended U.S. normalized risk-free rate of 3.5%. This guidance is effective when developing USD-denominated discount rates as of June 16, 2022, and thereafter.

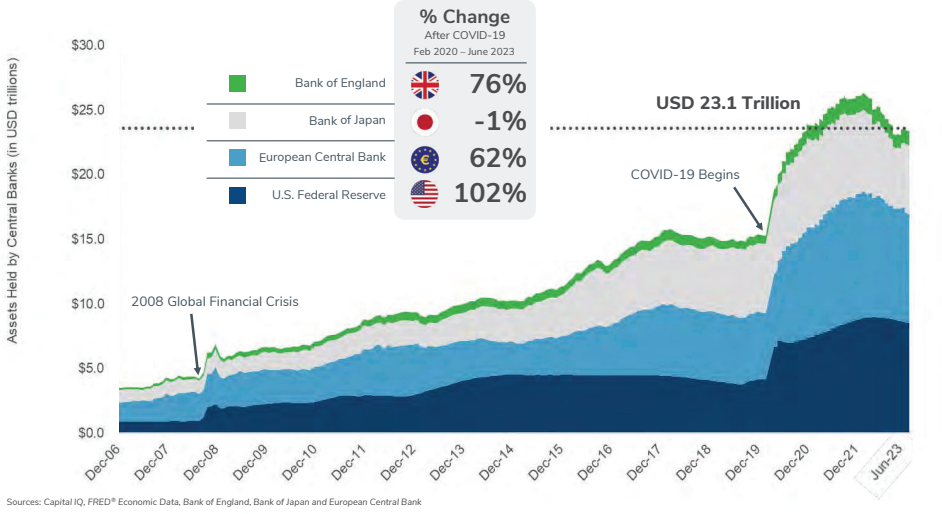
** We recommend using the spot 15-year German government bond yield as the proxy for the risk-free rate, if the prevailing yield as of the valuation date is higher than our recommended German normalized risk-free rate of 3.0%. This guidance is effective when developing EUR-denominated discount rated as of October 18, 2022, and thereafter.

*** German normalized risk-free rate and Eurozone equity risk premium (ERP) for use in EUR-denominated discount rates from a German investor perspective. Our current ERP recommendation is at the top of the range. Additional country risk adjustments may be warranted when estimating discount rates for other countries in the Eurozone.

For more information, visit: https://www.kroll.com/costofcapitalnavigator

Total Assets Held by Major Central Banks Over Time

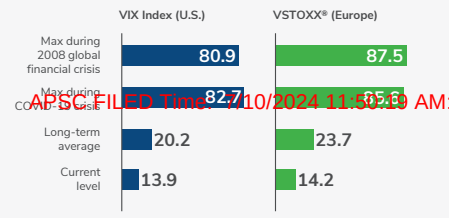
Data as of June 14, 2023



Sources: Capital IQ, FRED® Economic Data, Bank of England, Bank of Japan and European Central Bank

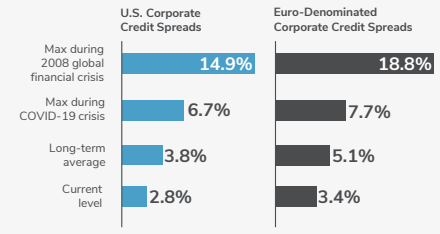
Global Market Volatility

Data as of June 14, 2023



Global Credit Spreads

Data as of June 14, 2023

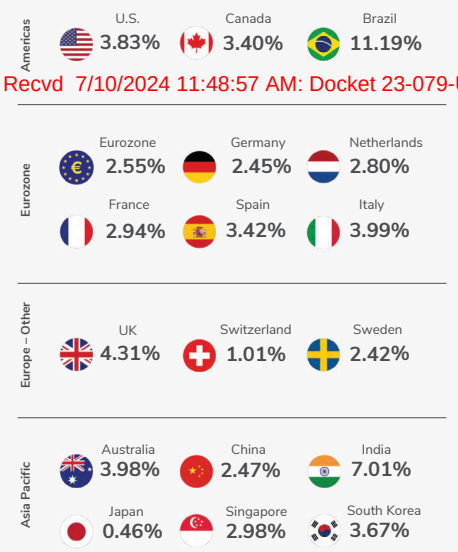


Sources: Capital IQ, FRED® Economic Data, Bloomberg

U.S. corporate credit spreads are based on the difference in effective yields between the ICE BofA U.S. High Yield Index and the ICE BofA U.S. Corporate Index. Euro-denominated corporate credit spreads are based on the difference in effective yields between the Bloomberg Pan-European High Yield Index (EUR) and the Bloomberg Euro Aggregate Corporate Bond Index. Long-term averages are based on 1995 to present for VIX daily series, 1999 to present for VSTOXX daily series, 1996 to present for U.S. credit spread daily series, and 1998 to present for EUR-denominated credit spread monthly series.

Global 10-Year Government Bond Yields

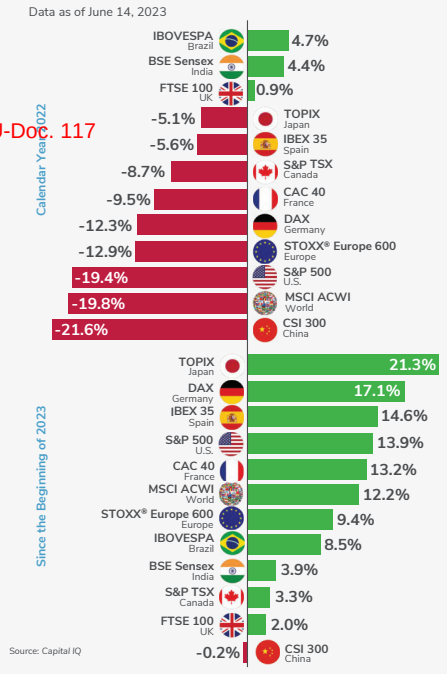
Data as of June 14, 2023



Sources: Refinitiv (Brazil, India), European Central Bank (Eurozone aggregate yield) and Capital IQ (other countries)

Stock Market Performance

Data as of June 14, 2023



Source: Capital IQ

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U.S. and Eurozone Consumer Sentiment vs. Business Confidence

Data as of June 14, 2023

	Pre-COVID-19 (February 2020)	Post-COVID-19 (June 2023)	Long-Term Avg.
Consumer Sentiment (U.S.)	101.0 ↓	59.2	(1952–2023) 85.7
Consumer Sentiment (Eurozone)	107.9 ↓	86.9	(1985–2023) 100.0
Business Confidence (U.S.)	99.0 ↓	98.9	(1950–2023) 100.0
Business Confidence (Eurozone)	100.3 ↑	101.9	(1985–2023) 100.0

Sources: Michigan University's Index of Consumer Sentiment, OECD's Business Confidence Index and European Commission business and consumer surveys [The same methodology that the European Commission uses to standardize its Economic Sentiment Indicator (ESI) was applied to the Eurozone Consumer Confidence and Business Climate Indicator series.]

U.S. vs. Eurozone Unemployment Rate

Data as of June 14, 2023

	U.S.	Eurozone
2020		
March	4.4%	7.1%
June	11.0%	8.0%
September	7.9%	8.7%
December	6.7%	8.1%
2021		
March	6.0%	8.1%
June	5.9%	7.8%
September	4.7%	7.4%
December	3.9%	7.0%
2022		
March	3.6%	6.8%
June	3.6%	6.7%
September	3.5%	6.6%
December	3.5%	6.7%
2023		
March	3.5%	6.6%
Latest Available*	3.7%	6.5%

Source: U.S. Bureau of Labor Statistics and Eurostat

* Data through May 2023 for the U.S. and April 2023 for the Eurozone.

Long-Term Inflation Expectations (Median)

Data as of May 31, 2023

U.S.

2.4%

Inflation estimates over the long term rose from 2.0% in June 2020 to 2.9% in October 2022 but declined to 2.4% at the end of December 2022 and remained at that level in May 2023.

Germany

2.6%

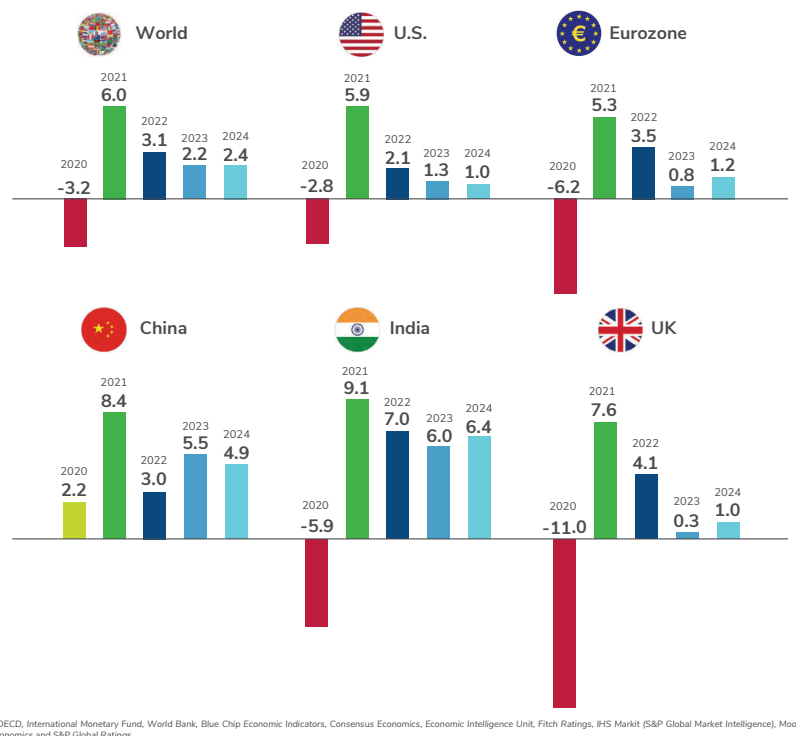
Long-term inflation expectations surged from 1.6% in June 2020 to 2.8% in October 2022 and stayed at that level at the end of December 2022 but declined to 2.6% in May 2023.

Sources of underlying U.S. data: Blue Chip Economic Indicators; Blue Chip Financial Forecasts, Consensus Economics, IHS Markit (S&P Global Market Intelligence), Federal Reserve Bank of Cleveland, Federal Reserve Bank of Philadelphia (Aruoba Term Structure of Inflation Expectations, Livingston Survey, and Survey of Professional Forecasters), Oxford Economics and the University of Michigan's Surveys of Consumers Inflation Expectations.

Sources of underlying German data: Consensus Economics, Economist Intelligence Unit, IHS Markit (S&P Global Market Intelligence), International Monetary Fund, Oxford Economics and PwC.

Real GDP Growth (%) Estimates (Median)

Data as of June 15, 2023



Sources: OECD, International Monetary Fund, World Bank, Blue Chip Economic Indicators, Consensus Economics, Economic Intelligence Unit, Fitch Ratings, IHS Markit (S&P Global Market Intelligence), Moody's Analytics, Oxford Economics and S&P Global Ratings.

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ROE and ROR Analysis for Summit
CAPM ROE Analysis--Kroll Risk Premium
Calculation for Proxy Group

Docket No. 23-079-U
Exhibit MFG-15
Schedule 5

	A	B	C	D	E	F
	Rf	MRP	Beta	RP	CAPM ROE	Filtered Results
Atmos Energy Corporation	4.60%	5.50%	0.85	4.68%	9.28%	9.28%
Chesapeake Utilities	4.60%	5.50%	0.80	4.40%	9.00%	9.00%
NiSource	4.60%	5.50%	0.95	5.23%	9.83%	9.83%
Northwest Natural Holding Co.	4.60%	5.50%	0.90	4.95%	9.55%	9.55%
Southwest Gas Holdings	4.60%	5.50%	0.85	4.68%	9.28%	9.28%
ONE Gas, Inc.	4.60%	5.50%	0.85	4.68%	9.28%	9.28%
Spire, Inc.	4.60%	5.50%	0.85	4.68%	9.28%	9.28%
				Mean	9.35%	9.35%
				Median	9.28%	9.28%

A: MFG-15, Sch 1
B: MFG-15, Sch 4
C: MFG-15 Sch 2

D: B * C
E: B + E
F: Low-end test < Column E < High-end test

Low-End Test:	Moody's 10-Year Baa Corporate Bond Index, MFG-15, Schedule 3	5.94%
	CAPM Risk Premium, Column B	5.50%
	20 percent of CAPM risk premium	1.10%
	Moody's 10-Year Baa Corporate Bond Index + 20 percent of CAPM risk	7.04%

High-End Test:	Proxy Group median, Column E	9.28%
	200 percent of Proxy Group median	18.55%

Constant-Growth DCF Analysis for S&P 500--Value Line
All companies shown
A, B, and E: Value Line Analyzer, April 1, 2024

C = B * (1 + A/100)
D = A + C
F = E/(Sum of E)
G = D * F

Companies Excluded
Companies not paying dividends
Companies with EPS ≤
Companies with EPS > 20%

EPS Market Return %	11.24

Company Name	A EPS Growth Rate (%)	B Dividend Yield (%)	C Expected Dividend Yield (%)	D Rate of Return on Equity (%)	E Market Cap $ (Mil)	F Market Cap Weight Factor	G Weighted Rate of Return on Equity (%)
Companies not paying dividends							
Adobe Inc.	14.50	0.00	0.00	14.50	236,209		
Advanced Micro Dev.	17.50	0.00	0.00	17.50	290,264		
Airbnb Inc.		0.00	0.00	0.00	105,250		
Akamai Technologies	5.00	0.00	0.00	5.00	16,575		
Align Techn.	13.50	0.00	0.00	13.50	25,208		
Alphabet Inc.	13.00	0.00	0.00	13.00	1,873,395		
Alphabet Inc. 'A'	15.98	0.00	0.00	15.98	1,853,300		
Amazon.com	19.50	0.00	0.00	19.50	1,840,289		
Amer. Airlines		0.00	0.00	0.00	9,522		
ANSYS Inc.	9.00	0.00	0.00	9.00	29,813		
Aptiv PLC	27.00	0.00	0.00	27.00	22,046		
Arch Capital Group	23.50	0.00	0.00	23.50	34,411		
Arista Networks	17.00	0.00	0.00	17.00	92,606		

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	A	B	C	D	E	F	G
Company Name	EPS Growth Rate (%)	Dividend Yield (%)	Expected Dividend Yield (%)	Rate of Return on Equity (%)	Market Cap $ (Mil)	Market Cap Weight Factor	Weighted Rate of Return on Equity (%)
Autodesk Inc.	10.00	0.00	0.00	10.00	56,160		
AutoZone Inc.	12.50	0.00	0.00	12.50	55,180		
Axon Enterprise	21.50	0.00	0.00	21.50	23,666		
Bio-Rad Labs. 'A'	9.00	0.00	0.00	9.00	9,801		
Biogen	-1.00	0.00	0.00	-1.00	31,610		
Boeing		0.00	0.00	0.00	114,455		
Booking Holdings	28.00	0.00	0.00	28.00	125,920		
Boston Scientific	12.50	0.00	0.00	12.50	98,791		
Builders FirstSource	20.00	0.00	0.00	20.00	25,496		
Cadence Design Sys.	14.00	0.00	0.00	14.00	86,206		
Caesars Entertainment		0.00	0.00	0.00	9,016		
CarMax Inc.	3.50	0.00	0.00	3.50	13,128		
Carnival Corp.		0.00	0.00	0.00	21,298		
Catalent Inc.	5.50	0.00	0.00	5.50	10,114		
CBRE Group	5.00	0.00	0.00	5.00	29,146		
Centene Corp.	10.00	0.00	0.00	10.00	41,626		
Charles River	7.00	0.00	0.00	7.00	13,756		
Charter Communic.	8.50	0.00	0.00	8.50	42,885		
Chipotle Mex. Grill	22.50	0.00	0.00	22.50	79,569		
Cooper Cos.	9.50	0.00	0.00	9.50	20,200		
Copart Inc.	9.00	0.00	0.00	9.00	54,699		
Corpay	15.50	0.00	0.00	15.50	22,122		
CoStar Group	15.00	0.00	0.00	15.00	39,301		
DaVita Inc.	9.50	0.00	0.00	9.50	12,677		
Dayforce Inc.		0.00	0.00	0.00	10,775		
Deckers Outdoor	14.00	0.00	0.00	14.00	23,474		

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	A	B	C	D	E	F	G
Company Name	EPS Growth Rate (%)	Dividend Yield (%)	Expected Dividend Yield (%)	Rate of Return on Equity (%)	Market Cap $ (Mil)	Market Cap Weight Factor	Weighted Rate of Return on Equity (%)
DexCom Inc.	24.00	0.00	0.00	24.00	51,210		
Dollar Tree Inc.	9.00	0.00	0.00	9.00	27,908		
Edwards Lifesciences	10.00	0.00	0.00	10.00	55,926		
Enphase Energy	14.00	0.00	0.00	14.00	15,432		
EPAM Systems	5.50	0.00	0.00	5.50	16,878		
Etsy Inc.	2.00	0.00	0.00	2.00	8,157		
Expedia Group		0.00	0.00	0.00	19,314		
F5 Inc.	10.50	0.00	0.00	10.50	11,144		
Fair Isaac	19.50	0.00	0.00	19.50	30,984		
First Solar Inc.	34.00	0.00	0.00	34.00	16,136		
Fiserv Inc.	9.50	0.00	0.00	9.50	93,605		
Fortinet Inc.	21.50	0.00	0.00	21.50	51,649		
Gartner Inc.	10.00	0.00	0.00	10.00	37,747		
Generac Holdings	12.50	0.00	0.00	12.50	7,116		
Hologic Inc.	-1.00	0.00	0.00	-1.00	17,600		
IDEXX Labs.	11.00	0.00	0.00	11.00	43,965		
Illumina Inc.	-6.00	0.00	0.00	-6.00	21,044		
Incyte Corp.	16.50	0.00	0.00	16.50	13,052		
Insulet Corp.	69.50	0.00	0.00	69.50	11,675		
Intuitive Surgical	12.50	0.00	0.00	12.50	137,527		
IQVIA Holdings	11.50	0.00	0.00	11.50	46,121		
Keysight Technologies	8.00	0.00	0.00	8.00	26,354		
Live Nation Entertain.		0.00	0.00	0.00	23,896		
lululemon athletica	16.50	0.00	0.00	16.50	59,212		
Match Group	13.50	0.00	0.00	13.50	9,683		
Mettler-Toledo Int'l	9.00	0.00	0.00	9.00	28,045		

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	A	B	C	D	E	F	G
Company Name	EPS Growth Rate (%)	Dividend Yield (%)	Expected Dividend Yield (%)	Rate of Return on Equity (%)	Market Cap $ (Mil)	Market Cap Weight Factor	Weighted Rate of Return on Equity (%)
MGM Resorts Int'l		0.00	0.00	0.00	15,208		
Moderna Inc.	-17.50	0.00	0.00	-17.50	39,274		
Mohawk Inds.	1.00	0.00	0.00	1.00	7,870		
Molina Healthcare	12.00	0.00	0.00	12.00	24,134		
Monster Beverage	13.00	0.00	0.00	13.00	62,640		
Netflix Inc.	14.50	0.00	0.00	14.50	274,727		
Norwegian Cruise Line		0.00	0.00	0.00	8,585		
NVR Inc.	1.50	0.00	0.00	1.50	25,427		
O'Reilly Automotive	11.00	0.00	0.00	11.00	67,656		
ON Semiconductor	13.00	0.00	0.00	13.00	32,540		
Palo Alto Networks		0.00	0.00	0.00	91,018		
PayPal Holdings	12.00	0.00	0.00	12.00	69,734		
PTC Inc.	11.00	0.00	0.00	11.00	22,668		
Qorvo Inc.	9.50	0.00	0.00	9.50	10,975		
Regeneron Pharmac.	3.00	0.00	0.00	3.00	105,205		
Royal Caribbean		0.00	0.00	0.00	34,728		
Schein (Henry)	7.50	0.00	0.00	7.50	9,665		
ServiceNow Inc.	61.00	0.00	0.00	61.00	157,138		
Super Micro Computer	39.00	0.00	0.00	39.00	50,128		
Synopsys Inc.	14.50	0.00	0.00	14.50	89,963		
Take-Two Interactive	59.00	0.00	0.00	59.00	25,307		
Teledyne Technologies	9.50	0.00	0.00	9.50	20,055		
Tesla Inc.	23.00	0.00	0.00	23.00	558,423		
TransDigm Group	21.00	0.00	0.00	21.00	67,459		
Trimble Inc.	5.50	0.00	0.00	5.50	15,712		
Tyler Technologies	10.00	0.00	0.00	10.00	17,711		

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	A	B	C	D	E	F	G
Company Name	EPS Growth Rate (%)	Dividend Yield (%)	Expected Dividend Yield (%)	Rate of Return on Equity (%)	Market Cap $ (Mil)	Market Cap Weight Factor	Weighted Rate of Return on Equity (%)
Uber Technologies		0.00	0.00	0.00	162,875		
Ulta Beauty	13.50	0.00	0.00	13.50	25,495		
Under Armour 'C'		0.00	0.00	0.00	3,101		
United Airlines Hldgs.		0.00	0.00	0.00	15,082		
VeriSign Inc.	13.00	0.00	0.00	13.00	19,236		
Vertex Pharmac.	9.50	0.00	0.00	9.50	106,254		
Warner Bros. Discovery		0.00	0.00	0.00	21,308		
Waters Corp.	5.00	0.00	0.00	5.00	20,594		
Western Digital	7.00	0.00	0.00	7.00	19,795		
Zebra Techn. 'A'	-1.00	0.00	0.00	-1.00	14,679		
Companies with EPS ≤ 0%							
AES Corp.	0.00	4.44	4.44	4.44	10,406		
Albemarle Corp.	-4.50	1.29	1.23	-3.27	14,605		
Baker Hughes	0.00	2.52	2.52	2.52	33,590		
Best Buy Co.	-0.50	4.89	4.87	4.37	16,999		
Camden Property Trust	-6.50	4.26	3.98	-2.52	10,503		
Constellation Energy	0.00	0.80	0.80	0.80	56,052		
Coterra Energy	0.00	3.10	3.10	3.10	20,843		
Delta Air Lines	0.00	0.88	0.88	0.88	29,200		
Digital Realty Trust	-5.00	3.51	3.33	-1.67	43,903		
Discover Fin'l Svcs.	0.00	2.23	2.23	2.23	31,450		
EQT Corp.	0.00	1.86	1.86	1.86	13,911		
Equity Residential	-4.50	4.23	4.04	-0.46	23,538		

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	A	B	C	D	E	F	G
Company Name	EPS Growth Rate (%)	Dividend Yield (%)	Expected Dividend Yield (%)	Rate of Return on Equity (%)	Market Cap $ (Mil)	Market Cap Weight Factor	Weighted Rate of Return on Equity (%)
Expeditors Int'l	-1.00	1.15	1.14	0.14	17,384		
Federal Rlty. Inv. Trust	0.00	4.31	4.31	4.31	7,947		
Fidelity Nat'l Info.	-3.00	2.04	1.98	-1.02	41,854		
GE HealthCare	0.00	0.13	0.13	0.13	41,375		
Host Hotels & Resorts	0.00	3.85	3.85	3.85	14,825		
Kenvue Inc.	0.00	3.92	3.92	3.92	39,085		
KeyCorp	-2.00	5.45	5.34	3.34	14,080		
Laboratory Corp.	-1.50	1.38	1.36	-0.14	17,775		
Las Vegas Sands	0.00	1.58	1.58	1.58	38,079		
LyondellBasell Inds.	0.00	4.89	4.89	4.89	33,191		
Mid-America Apt.	-11.00	4.48	3.99	-7.01	15,143		
Mosaic Company	-6.00	2.60	2.44	-3.56	10,459		
News Corp. 'B'	0.00	0.75	0.75	0.75	15,841		
Paramount Global	-2.50	1.60	1.56	-0.94	8,157		
Revvity Inc.	-2.50	0.27	0.26	-2.24	12,911		
Southwest Airlines	0.00	2.50	2.50	2.50	17,192		
Targa Resources	0.00	2.75	2.75	2.75	24,334		
Tyson Foods 'A'	-16.50	3.40	2.84	-13.66	20,599		
Ventas Inc.	0.00	4.19	4.19	4.19	17,560		
Viatris Inc.	-1.50	4.71	4.64	3.14	14,252		
Walgreens Boots	-2.00	4.74	4.65	2.65	18,183		
Weyerhaeuser Co.	-1.00	2.27	2.25	1.25	25,768		
Wynn Resorts	0.00	1.00	1.00	1.00	11,345		

Companies with EPS > 20%

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	A	B	C	D	E	F	G
Company Name	EPS Growth Rate (%)	Dividend Yield (%)	Expected Dividend Yield (%)	Rate of Return on Equity (%)	Market Cap $ (Mil)	Market Cap Weight Factor	Weighted Rate of Return on Equity (%)
Bristol-Myers Squibb	24.50	4.63	5.76	30.26	105,524		
Diamondback Energy	34.00	1.87	2.51	36.51	34,493		
Disney (Walt)	37.00	0.64	0.88	37.88	219,061		
Ford Motor	37.00	10.23	14.02	51.02	53,600		
Gen'l Electric	29.50	0.18	0.23	29.73	189,308		
Halliburton Co.	27.50	2.20	2.81	30.31	34,207		
Hilton Worldwide	37.00	0.28	0.38	37.38	54,286		
Lilly (Eli)	27.50	0.67	0.85	28.35	733,737		
Marathon Oil Corp.	25.50	1.73	2.17	27.67	15,989		
Marriott Int'l	23.00	0.82	1.01	24.01	74,996		
Molson Coors Beverage	42.00	2.63	3.73	45.73	14,257		
NVIDIA Corp.	33.00	0.02	0.03	33.03	2,226,766		
PG&E Corp.	30.00	0.31	0.40	30.40	34,563		
Schlumberger Ltd.	26.00	2.02	2.55	28.55	77,650		
Welltower Inc.	25.50	2.72	3.41	28.91	52,469		
Qualifying Companies							
3M Company	4.50	5.59	5.84	10.34	59,740	0.00186	0.0193
Abbott Labs.	4.00	1.97	2.05	6.05	193,350	0.00603	0.0365
AbbVie Inc.	3.50	3.52	3.64	7.14	311,202	0.00970	0.0693
Accenture Plc	8.50	1.36	1.48	9.98	238,533	0.00744	0.0742
Aflac Inc.	7.50	2.39	2.57	10.07	49,159	0.00153	0.0154
Agilent Technologies	8.00	0.64	0.69	8.69	43,159	0.00135	0.0117

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Company Name	EPS Growth Rate (%)	Dividend Yield (%)	Expected Dividend Yield (%)	Rate of Return on Equity (%)	Market Cap $ (Mil)	Market Cap Weight Factor	Weighted Rate of Return on Equity (%)
Air Products & Chem.	10.50	2.93	3.24	13.74	53,119	0.00166	0.0228
Alexandria Real Estate	1.00	4.03	4.07	5.07	19,939	0.00062	0.0032
Allegion plc	8.50	1.42	1.54	10.04	11,838	0.00037	0.0037
Alliant Energy	6.00	3.71	3.93	9.93	12,498	0.00039	0.0039
Allstate Corp.	11.00	2.28	2.53	13.53	42,227	0.00132	0.0178
Altria Group	5.00	8.75	9.19	14.19	79,273	0.00247	0.0351
Amcor plc	7.50	5.46	5.87	13.37	13,213	0.00041	0.0055
Amer. Elec. Power	6.50	4.31	4.59	11.09	43,549	0.00136	0.0151
Amer. Express	8.50	1.23	1.33	9.83	166,146	0.00518	0.0510
Amer. Int'l Group	9.00	1.88	2.05	11.05	54,069	0.00169	0.0186
Amer. Tower 'A'	5.50	3.33	3.51	9.01	90,729	0.00283	0.0255
Amer. Water Works	3.00	2.54	2.62	5.62	22,996	0.00072	0.0040
Ameren Corp.	6.00	3.72	3.94	9.94	18,942	0.00059	0.0059
Ameriprise Fin'l	12.50	1.34	1.51	14.01	43,708	0.00136	0.0191
AMETEK Inc.	13.00	0.61	0.69	13.69	42,513	0.00133	0.0181
Amgen	4.50	3.30	3.45	7.95	146,109	0.00456	0.0362
Amphenol Corp.	13.00	0.79	0.89	13.89	67,143	0.00209	0.0291
Analog Devices	7.50	1.89	2.03	9.53	96,365	0.00300	0.0286
Aon plc	10.00	0.86	0.95	10.95	65,475	0.00204	0.0223
APA Corp.	19.50	3.55	4.24	23.74	10,367	0.00032	0.0077
Apple Inc.	6.50	0.54	0.58	7.08	2,762,278	0.08613	0.6094
Applied Materials	10.00	0.69	0.76	10.76	170,384	0.00531	0.0572
Archer Daniels Midl'd	7.50	2.94	3.16	10.66	31,452	0.00098	0.0105
Assurant Inc.	10.50	1.60	1.77	12.27	9,525	0.00030	0.0036
AT&T Inc.	4.00	6.45	6.71	10.71	123,053	0.00384	0.0411
Atmos Energy	7.00	2.87	3.07	10.07	17,572	0.00055	0.0055

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Company Name	EPS Growth Rate (%)	Dividend Yield (%)	Expected Dividend Yield (%)	Rate of Return on Equity (%)	Market Cap $ (Mil)	Market Cap Weight Factor	Weighted Rate of Return on Equity (%)
Automatic Data Proc.	11.00	2.34	2.60	13.60	101,739	0.00317	0.0431
AvalonBay Communities	5.50	3.76	3.97	9.47	26,087	0.00081	0.0077
Avery Dennison	5.00	1.59	1.67	6.67	17,438	0.00054	0.0036
Ball Corp.	10.00	1.23	1.35	11.35	20,599	0.00064	0.0073
Bank of America	4.50	2.67	2.79	7.29	291,183	0.00908	0.0662
Bank of NY Mellon	9.00	3.08	3.36	12.36	43,183	0.00135	0.0166
Bath & Body Works	6.00	1.66	1.76	7.76	10,919	0.00034	0.0026
Baxter Int'l Inc.	4.00	2.77	2.88	6.88	21,234	0.00066	0.0046
Becton Dickinson	5.50	1.62	1.71	7.21	68,721	0.00214	0.0154
Berkley (W.R.)	16.00	0.51	0.59	16.59	22,285	0.00069	0.0115
Bio-Techne Corp.	10.00	0.44	0.48	10.48	11,295	0.00035	0.0037
BlackRock Inc.	7.50	2.69	2.89	10.39	121,819	0.00380	0.0395
Blackstone Inc.	15.00	2.51	2.89	17.89	90,745	0.00283	0.0506
BorgWarner	5.50	1.35	1.42	6.92	7,519	0.00023	0.0016
Boston Properties	0.50	6.08	6.11	6.61	10,089	0.00031	0.0021
Broadcom Inc.	17.50	1.65	1.94	19.44	590,788	0.01842	0.3581
Broadridge Fin'l	9.50	1.57	1.72	11.22	24,050	0.00075	0.0084
Brown & Brown	6.50	0.60	0.64	7.14	24,666	0.00077	0.0055
Brown-Forman 'B'	16.50	1.66	1.93	18.43	25,044	0.00078	0.0144
Bunge Global SA	1.50	2.80	2.84	4.34	14,156	0.00044	0.0019
C.H. Robinson	3.50	3.35	3.47	6.97	8,613	0.00027	0.0019
Campbell Soup	5.00	3.60	3.78	8.78	12,918	0.00040	0.0035
Capital One Fin'l	4.00	1.69	1.76	5.76	53,928	0.00168	0.0097
Cardinal Health	10.00	1.80	1.98	11.98	27,301	0.00085	0.0102
Carrier Global	13.50	1.30	1.48	14.98	49,157	0.00153	0.0230
Caterpillar Inc.	13.00	1.46	1.65	14.65	181,463	0.00566	0.0829

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Company Name	EPS Growth Rate (%)	Dividend Yield (%)	Expected Dividend Yield (%)	Rate of Return on Equity (%)	Market Cap $ (Mil)	Market Cap Weight Factor	Weighted Rate of Return on Equity (%)
Cboe Global Markets	13.00	1.20	1.36	14.36	19,338	0.00060	0.0087
CDW Corp.	7.00	0.99	1.06	8.06	33,632	0.00105	0.0085
Celanese Corp.	4.50	1.74	1.82	6.32	18,010	0.00056	0.0035
Cencora	8.00	0.86	0.93	8.93	48,244	0.00150	0.0134
CenterPoint Energy	6.00	2.85	3.02	9.02	17,737	0.00055	0.0050
CF Industries	2.00	2.32	2.37	4.37	16,211	0.00051	0.0022
Chevron Corp.	16.50	4.27	4.97	21.47	291,752	0.00910	0.1954
Chubb Ltd.	16.00	1.33	1.54	17.54	105,468	0.00329	0.0577
Church & Dwight	5.50	1.11	1.17	6.67	25,376	0.00079	0.0053
Cigna Group	12.00	1.58	1.77	13.77	103,537	0.00323	0.0445
Cincinnati Financial	10.50	2.73	3.02	13.52	18,608	0.00058	0.0078
Cintas Corp.	14.00	0.85	0.97	14.97	64,355	0.00201	0.0300
Cisco Systems	4.50	3.23	3.38	7.88	200,678	0.00626	0.0493
Citigroup Inc.	2.50	3.53	3.62	6.12	115,082	0.00359	0.0220
Citizens Fin'l Group	4.50	4.94	5.16	9.66	16,243	0.00051	0.0049
Clorox Co.	7.00	3.19	3.41	10.41	18,673	0.00058	0.0061
CME Group	7.50	2.15	2.31	9.81	76,731	0.00239	0.0235
CMS Energy Corp.	5.00	3.52	3.70	8.70	17,231	0.00054	0.0047
Coca-Cola	8.00	3.23	3.49	11.49	261,711	0.00816	0.0938
Cognizant Technology	6.50	1.60	1.70	8.20	37,650	0.00117	0.0096
Colgate-Palmolive	8.00	2.26	2.44	10.44	72,745	0.00227	0.0237
Comcast Corp.	8.00	2.88	3.11	11.11	171,078	0.00533	0.0593
Comerica Inc.	2.50	5.49	5.63	8.13	6,827	0.00021	0.0017
Conagra Brands	3.50	4.92	5.09	8.59	13,786	0.00043	0.0037
ConocoPhillips	9.00	1.97	2.15	11.15	143,622	0.00448	0.0499
Consol. Edison	6.00	3.75	3.98	9.98	30,630	0.00096	0.0095

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Constellation Brands	6.50	1.33	1.42	7.92	49,086	0.00153	0.0121
Corning Inc.	12.50	3.43	3.86	16.36	26,789	0.00084	0.0137
Corteva Inc.	9.00	1.20	1.31	10.31	39,081	0.00122	0.0126
Costco Wholesale	9.50	0.59	0.65	10.15	328,546	0.01024	0.1039
Crown Castle Int'l	6.00	5.99	6.35	12.35	45,362	0.00141	0.0175
CSX Corp.	7.00	1.28	1.37	8.37	74,322	0.00232	0.0194
Cummins Inc.	7.50	2.34	2.52	10.02	40,699	0.00127	0.0127
CVS Health	5.50	3.37	3.56	9.06	101,726	0.00317	0.0287
Danaher Corp.	7.50	0.43	0.46	7.96	186,042	0.00580	0.0462
Darden Restaurants	13.00	3.00	3.39	16.39	20,862	0.00065	0.0107
Deere & Co.	5.00	1.49	1.56	6.56	109,687	0.00342	0.0225
Dentsply Sirona	8.50	1.92	2.08	10.58	7,053	0.00022	0.0023
Devon Energy	9.50	3.62	3.96	13.46	31,159	0.00097	0.0131
Dollar General	2.00	1.51	1.54	3.54	34,254	0.00107	0.0038
Dominion Energy	0.50	5.54	5.57	6.07	40,310	0.00126	0.0076
Domino's Pizza	11.50	1.34	1.49	12.99	15,686	0.00049	0.0064
Dover Corp.	6.50	1.16	1.24	7.74	24,558	0.00077	0.0059
Dow Inc.	1.50	4.90	4.97	6.47	40,852	0.00127	0.0082
DTE Energy	6.00	3.71	3.93	9.93	22,697	0.00071	0.0070
Duke Energy	5.50	4.34	4.58	10.08	73,561	0.00229	0.0231
DuPont de Nemours	9.00	2.07	2.26	11.26	32,048	0.00100	0.0112
Eastman Chemical	5.00	3.46	3.63	8.63	10,987	0.00034	0.0030
Eaton Corp. plc	12.50	1.21	1.36	13.86	123,707	0.00386	0.0535
eBay Inc.	7.00	2.15	2.30	9.30	27,024	0.00084	0.0078
Ecolab Inc.	7.00	1.00	1.07	8.07	65,257	0.00203	0.0164
Edison Int'l	4.50	4.52	4.72	9.22	26,658	0.00083	0.0077

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Electronic Arts	17.50	0.62	0.73	18.23	35,462	0.00111	0.0202
Elevance Health	11.50	1.27	1.42	12.92	120,813	0.00377	0.0487
Emerson Electric	7.00	1.88	2.01	9.01	64,042	0.00200	0.0180
Entergy Corp.	0.50	4.39	4.41	4.91	21,928	0.00068	0.0034
EOG Resources	13.00	2.97	3.36	16.36	73,289	0.00229	0.0374
Equifax Inc.	4.50	0.59	0.62	5.12	32,636	0.00102	0.0052
Equinix Inc.	16.00	2.07	2.40	18.40	77,442	0.00241	0.0444
Essex Property Trust	1.00	4.01	4.05	5.05	14,983	0.00047	0.0024
Everest Group	10.00	1.84	2.02	12.02	16,957	0.00053	0.0064
Evergy Inc.	5.50	5.04	5.32	10.82	11,892	0.00037	0.0040
Eversource Energy	5.50	4.81	5.07	10.57	20,681	0.00064	0.0068
Exelon Corp.	2.00	4.18	4.26	6.26	36,377	0.00113	0.0071
Extra Space Storage	5.00	4.85	5.09	10.09	18,816	0.00059	0.0059
Exxon Mobil Corp.	7.00	3.36	3.60	10.60	447,779	0.01396	0.1479
FactSet Research	11.00	0.88	0.98	11.98	18,570	0.00058	0.0069
Fastenal Co.	9.00	2.01	2.19	11.19	44,420	0.00139	0.0155
FedEx Corp.	5.50	1.94	2.05	7.55	64,970	0.00203	0.0153
Fifth Third Bancorp	5.00	3.93	4.13	9.13	24,936	0.00078	0.0071
FirstEnergy Corp.	4.50	4.34	4.54	9.04	21,954	0.00068	0.0062
FMC Corp.	5.00	3.70	3.89	8.89	7,998	0.00025	0.0022
Fortive Corp.	15.00	0.37	0.43	15.43	30,178	0.00094	0.0145
Fox Corp. 'A'	8.00	1.72	1.86	9.86	14,397	0.00045	0.0044
Franklin Resources	3.00	4.53	4.67	7.67	13,531	0.00042	0.0032
Freep't-McMoRan Inc.	12.50	1.30	1.46	13.96	66,024	0.00206	0.0287
Gallagher (Arthur J.)	17.50	0.94	1.10	18.60	55,242	0.00172	0.0320
Garmin Ltd.	5.00	2.06	2.16	7.16	28,130	0.00088	0.0063

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Gen Digital Inc.	10.50	2.32	2.56	13.06	13,753	0.00043	0.0056
Gen'l Dynamics	10.00	2.01	2.21	12.21	77,306	0.00241	0.0294
Gen'l Mills	6.00	3.49	3.70	9.70	39,499	0.00123	0.0119
Gen'l Motors	8.50	1.12	1.22	9.72	59,990	0.00187	0.0182
Genuine Parts	8.50	2.58	2.80	11.30	21,676	0.00068	0.0076
Gilead Sciences	3.00	4.16	4.28	7.28	92,179	0.00287	0.0209
Global Payments	13.50	0.84	0.95	14.45	34,651	0.00108	0.0156
Globe Life Inc.	8.00	0.81	0.87	8.87	12,404	0.00039	0.0034
Goldman Sachs	1.50	2.77	2.81	4.31	129,489	0.00404	0.0174
Grainger (W.W.)	7.00	0.74	0.79	7.79	50,114	0.00156	0.0122
Hartford Fin'l Svcs.	8.50	1.86	2.02	10.52	30,582	0.00095	0.0100
Hasbro Inc.	4.50	5.16	5.39	9.89	7,531	0.00023	0.0023
HCA Healthcare	10.00	0.80	0.88	10.88	88,453	0.00276	0.0300
Healthpeak Properties	18.50	6.83	8.09	26.59	9,477	0.00030	0.0079
Henry (Jack) & Assoc.	6.50	1.28	1.36	7.86	12,495	0.00039	0.0031
Hershey Co.	9.50	2.77	3.03	12.53	40,476	0.00126	0.0158
Hess Corp.	20.00	1.17	1.40	21.40	45,867	0.00143	0.0306
Hewlett Packard Ent.	5.50	3.78	3.99	9.49	22,005	0.00069	0.0065
Home Depot	6.00	2.34	2.48	8.48	381,335	0.01189	0.1008
Honeywell Int'l	10.50	2.15	2.38	12.88	131,129	0.00409	0.0526
Hormel Foods	5.50	3.36	3.54	9.04	18,892	0.00059	0.0053
Horton D.R.	4.00	0.79	0.82	4.82	52,679	0.00164	0.0079
Howmet Aerospace	17.00	0.30	0.35	17.35	27,682	0.00086	0.0150
HP Inc.	7.00	3.74	4.00	11.00	29,086	0.00091	0.0100
Hubbell Inc.	9.00	1.20	1.31	10.31	21,850	0.00068	0.0070
Humana Inc.	8.00	1.02	1.10	9.10	42,866	0.00134	0.0122

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Hunt (J.B.)	8.50	0.88	0.95	9.45	20,119	0.00063	0.0059
Huntington Bancshs.	8.00	4.66	5.03	13.03	19,292	0.00060	0.0078
Huntington Ingalls	11.50	1.78	1.98	13.48	11,577	0.00036	0.0049
IDEX Corp.	6.00	1.12	1.19	7.19	18,242	0.00057	0.0041
Illinois Tool Works	9.50	2.08	2.28	11.78	80,867	0.00252	0.0297
Ingersoll Rand Inc.	12.50	0.09	0.10	12.60	37,786	0.00118	0.0148
Int'l Business Mach.	4.00	3.42	3.56	7.56	177,109	0.00552	0.0417
Int'l Flavors & Frag.	0.50	1.91	1.92	2.42	21,422	0.00067	0.0016
Int'l Paper	5.50	4.72	4.98	10.48	13,574	0.00042	0.0044
Intel Corp.	6.00	1.18	1.25	7.25	178,422	0.00556	0.0403
Intercontinental Exch.	6.50	1.32	1.41	7.91	77,985	0.00243	0.0192
Interpublic Group	8.50	4.02	4.36	12.86	12,868	0.00040	0.0052
Intuit Inc.	13.50	0.57	0.65	14.15	179,118	0.00559	0.0790
Invesco Ltd.	3.00	5.43	5.59	8.59	7,116	0.00022	0.0019
Invitation Homes	8.50	3.27	3.55	12.05	21,302	0.00066	0.0080
Iron Mountain	7.00	3.24	3.47	10.47	23,404	0.00073	0.0076
Jabil Inc.	15.00	0.25	0.29	15.29	16,325	0.00051	0.0078
Jacobs Solutions	9.00	0.77	0.84	9.84	18,917	0.00059	0.0058
Johnson & Johnson	3.50	3.17	3.28	6.78	374,927	0.01169	0.0793
Johnson Ctrls. Int'l plc	11.00	2.31	2.56	13.56	43,703	0.00136	0.0185
JPMorgan Chase	8.50	2.14	2.32	10.82	567,592	0.01770	0.1915
Juniper Networks	8.50	2.39	2.59	11.09	11,793	0.00037	0.0041
Kellanova	1.50	4.06	4.12	5.62	18,780	0.00059	0.0033
Keurig Dr Pepper	12.50	3.03	3.41	15.91	41,310	0.00129	0.0205
Kimberly-Clark	7.50	3.92	4.21	11.71	41,930	0.00131	0.0153
Kimco Realty	18.00	5.04	5.95	23.95	12,050	0.00038	0.0090

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Kinder Morgan Inc.	15.00	6.27	7.21	22.21	40,168	0.00125	0.0278
KLA Corp.	10.50	0.83	0.92	11.42	94,134	0.00294	0.0335
Kraft Heinz Co.	4.00	4.53	4.71	8.71	43,374	0.00135	0.0118
Kroger Co.	6.00	2.04	2.16	8.16	40,918	0.00128	0.0104
L3Harris Technologies	9.50	2.19	2.40	11.90	40,287	0.00126	0.0149
Lam Research	9.00	0.87	0.95	9.95	124,593	0.00389	0.0387
Lamb Weston Holdings	15.00	1.43	1.64	16.64	14,896	0.00046	0.0077
Lauder (Estee)	2.50	1.80	1.85	4.35	52,603	0.00164	0.0071
Leidos Hldgs.	7.50	1.19	1.28	8.78	17,362	0.00054	0.0048
Lennar Corp.	4.00	1.22	1.27	5.27	45,974	0.00143	0.0076
Linde plc	7.50	1.09	1.17	8.67	226,342	0.00706	0.0612
LKQ Corp.	7.00	2.29	2.45	9.45	14,011	0.00044	0.0041
Lockheed Martin	9.00	2.89	3.15	12.15	106,422	0.00332	0.0403
Loews Corp.	19.50	0.32	0.38	19.88	17,438	0.00054	0.0108
Lowe's Cos.	6.50	1.75	1.86	8.36	144,877	0.00452	0.0378
M&T Bank Corp.	6.50	3.77	4.02	10.52	23,789	0.00074	0.0078
Marathon Petroleum	14.50	1.67	1.91	16.41	72,772	0.00227	0.0372
MarketAxess Holdings	8.50	1.37	1.49	9.99	8,213	0.00026	0.0026
Marsh & McLennan	12.00	1.39	1.56	13.56	101,775	0.00317	0.0430
Martin Marietta	10.50	0.50	0.55	11.05	37,318	0.00116	0.0129
Masco Corp.	6.50	1.52	1.62	8.12	17,106	0.00053	0.0043
MasterCard Inc.	16.00	0.54	0.63	16.63	458,270	0.01429	0.2376
McCormick & Co.	4.50	2.44	2.55	7.05	18,443	0.00058	0.0041
McDonald's Corp.	10.00	2.40	2.64	12.64	205,572	0.00641	0.0810
McKesson Corp.	8.50	0.48	0.52	9.02	69,528	0.00217	0.0196
Medtronic plc	6.50	3.28	3.49	9.99	111,744	0.00348	0.0348

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	A	B	C	D	E	F	G
Company Name	EPS Growth Rate (%)	Dividend Yield (%)	Expected Dividend Yield (%)	Rate of Return on Equity (%)	Market Cap $ (Mil)	Market Cap Weight Factor	Weighted Rate of Return on Equity (%)
Merck & Co.	15.50	2.49	2.88	18.38	313,543	0.00978	0.1797
Meta Platforms	17.00	0.40	0.47	17.47	1,294,637	0.04037	0.7052
MetLife Inc.	7.00	2.84	3.04	10.04	54,607	0.00170	0.0171
Microchip Technology	6.00	2.13	2.26	8.26	47,738	0.00149	0.0123
Micron Technology	19.50	0.49	0.59	20.09	106,260	0.00331	0.0666
Microsoft Corp.	10.50	0.72	0.80	11.30	3,160,309	0.09855	1.1131
Mondelez Int'l	11.00	2.37	2.63	13.63	97,805	0.00305	0.0416
Monolithic Power Sys.	10.50	0.75	0.83	11.33	32,035	0.00100	0.0113
Moody's Corp.	5.50	0.79	0.83	6.33	71,202	0.00222	0.0141
Morgan Stanley	7.50	3.72	4.00	11.50	150,020	0.00468	0.0538
Motorola Solutions	10.50	1.13	1.25	11.75	57,510	0.00179	0.0211
MSCI Inc.	12.50	1.14	1.28	13.78	44,223	0.00138	0.0190
Nasdaq Inc.	7.00	1.45	1.55	8.55	29,911	0.00093	0.0080
NetApp Inc.	8.50	1.91	2.07	10.57	21,515	0.00067	0.0071
Newmont Corp.	5.00	2.91	3.06	8.06	27,234	0.00085	0.0068
News Corp. 'A'	16.00	0.77	0.89	16.89	14,805	0.00046	0.0078
NextEra Energy	8.50	3.31	3.59	12.09	127,616	0.00398	0.0481
NIKE Inc. 'B'	16.50	1.48	1.72	18.22	152,110	0.00474	0.0864
NiSource Inc.	6.00	3.84	4.07	10.07	11,102	0.00035	0.0035
Nordson Corp.	9.50	1.03	1.13	10.63	15,153	0.00047	0.0050
Norfolk Southern	9.50	2.07	2.27	11.77	58,955	0.00184	0.0216
Northern Trust Corp.	3.00	3.57	3.68	6.68	17,251	0.00054	0.0036
Northrop Grumman	8.00	1.70	1.84	9.84	70,664	0.00220	0.0217
NRG Energy	1.00	2.43	2.45	3.45	13,974	0.00044	0.0015
Nucor Corp.	2.00	1.08	1.10	3.10	47,570	0.00148	0.0046
NXP Semi. NV	10.00	1.68	1.85	11.85	62,601	0.00195	0.0231

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	A	B	C	D	E	F	G
Company Name	EPS Growth Rate (%)	Dividend Yield (%)	Expected Dividend Yield (%)	Rate of Return on Equity (%)	Market Cap $ (Mil)	Market Cap Weight Factor	Weighted Rate of Return on Equity (%)
Occidental Petroleum	15.50	1.38	1.59	17.09	55,989	0.00175	0.0298
Old Dominion Freight	8.50	0.48	0.52	9.02	47,412	0.00148	0.0133
Omnicom Group	7.00	3.18	3.40	10.40	18,657	0.00058	0.0061
ONEOK Inc.	13.50	5.07	5.75	19.25	45,980	0.00143	0.0276
Oracle Corp.	9.50	1.24	1.36	10.86	355,022	0.01107	0.1202
Otis Worldwide	11.50	1.37	1.53	13.03	40,388	0.00126	0.0164
PACCAR Inc.	14.50	3.57	4.09	18.59	63,526	0.00198	0.0368
Packaging Corp.	7.00	2.71	2.90	9.90	16,511	0.00051	0.0051
Parker-Hannifin	12.50	1.11	1.25	13.75	70,172	0.00219	0.0301
Paychex Inc.	10.00	3.14	3.45	13.45	44,255	0.00138	0.0186
Paycom Software	18.50	0.78	0.92	19.42	11,040	0.00034	0.0067
Pentair plc	12.00	1.12	1.25	13.25	13,604	0.00042	0.0056
PepsiCo Inc.	7.50	3.03	3.26	10.76	236,136	0.00736	0.0792
Pfizer Inc.	2.50	6.07	6.22	8.72	156,394	0.00488	0.0425
Philip Morris Int'l	5.00	5.55	5.83	10.83	145,364	0.00453	0.0491
Phillips 66	17.50	2.77	3.25	20.75	69,847	0.00218	0.0452
Pinnacle West Capital	2.50	4.86	4.98	7.48	8,249	0.00026	0.0019
Pioneer Natural Res.	8.50	4.03	4.37	12.87	59,265	0.00185	0.0238
PNC Financial Serv.	6.50	4.18	4.45	10.95	61,269	0.00191	0.0209
Pool Corp.	5.50	1.08	1.14	6.64	15,837	0.00049	0.0033
PPG Inds.	6.50	1.74	1.85	8.35	33,545	0.00105	0.0087
PPL Corp.	7.50	3.81	4.10	11.60	19,939	0.00062	0.0072
Price (T. Rowe) Group	1.50	4.27	4.33	5.83	26,425	0.00082	0.0048
Principal Fin'l Group	5.50	3.29	3.47	8.97	20,134	0.00063	0.0056
Procter & Gamble	5.00	2.32	2.44	7.44	381,166	0.01189	0.0884
Progressive Corp.	14.50	0.19	0.22	14.72	120,346	0.00375	0.0552

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Company Name	EPS Growth Rate (%)	Dividend Yield (%)	Expected Dividend Yield (%)	Rate of Return on Equity (%)	Market Cap $ (Mil)	Market Cap Weight Factor	Weighted Rate of Return on Equity (%)
Prologis	0.50	3.03	3.05	3.55	118,969	0.00371	0.0132
Prudential Fin'l	5.50	4.51	4.76	10.26	41,428	0.00129	0.0133
Public Serv. Enterprise	4.00	3.76	3.91	7.91	31,817	0.00099	0.0078
Public Storage	7.00	4.26	4.56	11.56	49,393	0.00154	0.0178
PulteGroup Inc.	6.50	0.72	0.77	7.27	24,229	0.00076	0.0055
Qualcomm Inc.	7.50	1.91	2.05	9.55	187,455	0.00585	0.0558
Quanta Services	15.50	0.15	0.17	15.67	36,306	0.00113	0.0177
Quest Diagnostics	1.50	2.35	2.39	3.89	14,305	0.00045	0.0017
Ralph Lauren	13.00	1.58	1.79	14.79	12,161	0.00038	0.0056
Raymond James Fin'l	12.50	1.47	1.65	14.15	25,603	0.00080	0.0113
Realty Income Corp.	5.50	5.89	6.21	11.71	31,006	0.00097	0.0113
Regency Centers Corp.	14.50	4.45	5.10	19.60	10,292	0.00032	0.0063
Regions Financial	7.50	4.96	5.33	12.83	18,235	0.00057	0.0073
Republic Services	11.00	1.14	1.27	12.27	59,176	0.00185	0.0226
ResMed Inc.	8.50	1.04	1.13	9.63	28,297	0.00088	0.0085
Robert Half Inc.	6.00	2.64	2.80	8.80	8,492	0.00026	0.0023
Rockwell Automation	10.00	1.77	1.95	11.95	32,292	0.00101	0.0120
Rollins Inc.	9.00	1.28	1.40	10.40	22,668	0.00071	0.0073
Roper Tech.	8.50	0.54	0.59	9.09	59,229	0.00185	0.0168
Ross Stores	15.00	1.00	1.15	16.15	49,525	0.00154	0.0249
RTX Corp.	12.00	2.49	2.79	14.79	125,857	0.00392	0.0580
S&P Global	8.00	0.85	0.92	8.92	134,966	0.00421	0.0375
Salesforce Inc.	18.00	0.52	0.61	18.61	297,204	0.00927	0.1725
SBA Communications	19.00	1.85	2.20	21.20	23,324	0.00073	0.0154
Schwab (Charles)	10.00	1.61	1.77	11.77	127,044	0.00396	0.0466
Seagate Technology plc	11.00	3.20	3.55	14.55	18,315	0.00057	0.0083

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Company Name	EPS Growth Rate (%)	Dividend Yield (%)	Expected Dividend Yield (%)	Rate of Return on Equity (%)	Market Cap $ (Mil)	Market Cap Weight Factor	Weighted Rate of Return on Equity (%)
Sempra Energy	6.50	3.56	3.79	10.29	44,055	0.00137	0.0141
Sherwin-Williams	11.50	0.84	0.94	12.44	87,309	0.00272	0.0339
Simon Property Group	3.50	5.15	5.33	8.83	51,063	0.00159	0.0141
Skyworks Solutions	1.50	2.75	2.79	4.29	16,911	0.00053	0.0023
Smith (A.O.)	11.50	1.46	1.63	13.13	12,929	0.00040	0.0053
Smucker (J.M.)	7.50	3.50	3.76	11.26	13,105	0.00041	0.0046
Snap-on Inc.	7.50	2.55	2.74	10.24	15,412	0.00048	0.0049
Southern Co.	6.00	4.07	4.31	10.31	76,594	0.00239	0.0246
Stanley Black & Decker	3.50	3.52	3.64	7.14	14,189	0.00044	0.0032
Starbucks Corp.	9.00	2.46	2.68	11.68	104,842	0.00327	0.0382
State Street Corp.	7.00	3.82	4.09	11.09	22,780	0.00071	0.0079
Steel Dynamics	1.50	1.29	1.31	2.81	23,333	0.00073	0.0020
STERIS plc	7.50	0.94	1.01	8.51	23,049	0.00072	0.0061
Stryker Corp.	8.50	0.92	1.00	9.50	134,248	0.00419	0.0398
Synchrony Financial	4.50	2.31	2.41	6.91	17,954	0.00056	0.0039
Sysco Corp.	16.00	2.46	2.85	18.85	40,886	0.00127	0.0240
T-Mobile US	19.50	1.64	1.96	21.46	192,716	0.00601	0.1290
Tapestry Inc.	12.50	2.95	3.32	15.82	10,874	0.00034	0.0054
Target Corp.	10.50	2.58	2.85	13.35	78,693	0.00245	0.0328
TE Connectivity	8.00	1.67	1.80	9.80	43,730	0.00136	0.0134
Teleflex Inc.	9.00	0.62	0.68	9.68	10,361	0.00032	0.0031
Teradyne Inc.	16.50	0.46	0.54	17.04	16,356	0.00051	0.0087
Texas Instruments	3.00	3.06	3.15	6.15	154,342	0.00481	0.0296
Textron Inc.	16.00	0.08	0.09	16.09	18,323	0.00057	0.0092
Thermo Fisher Sci.	5.00	0.27	0.28	5.28	224,115	0.00699	0.0369
TJX Companies	16.50	1.40	1.63	18.13	112,796	0.00352	0.0638

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Company Name	EPS Growth Rate (%)	Dividend Yield (%)	Expected Dividend Yield (%)	Rate of Return on Equity (%)	Market Cap $ (Mil)	Market Cap Weight Factor	Weighted Rate of Return on Equity (%)
Tractor Supply	11.00	1.71	1.90	12.90	27,880	0.00087	0.0112
Trane Technologies plc	14.50	1.12	1.28	15.78	67,838	0.00212	0.0334
Travelers Cos.	10.50	1.78	1.97	12.47	51,388	0.00160	0.0200
Truist Fin'l	6.00	5.87	6.22	12.22	49,106	0.00153	0.0187
U.S. Bancorp	4.50	4.51	4.71	9.21	67,710	0.00211	0.0195
UDR Inc.	2.50	4.67	4.79	7.29	12,193	0.00038	0.0028
Union Pacific	6.50	2.15	2.29	8.79	150,142	0.00468	0.0412
United Parcel Serv.	3.50	4.26	4.41	7.91	131,825	0.00411	0.0325
United Rentals	17.00	0.92	1.08	18.08	47,717	0.00149	0.0269
UnitedHealth Group	12.00	1.52	1.70	13.70	457,163	0.01426	0.1953
Universal Health `B'	6.00	0.44	0.47	6.47	12,279	0.00038	0.0025
V.F. Corp.	2.00	2.50	2.55	4.55	5,607	0.00017	0.0008
Valero Energy	6.50	2.41	2.57	9.07	57,731	0.00180	0.0163
Verisk Analytics	9.00	0.66	0.72	9.72	34,270	0.00107	0.0104
Verizon Communic.	0.50	6.63	6.66	7.16	168,669	0.00526	0.0377
VICI Properties	9.50	5.76	6.31	15.81	18,126	0.00057	0.0089
Visa Inc.	13.50	0.74	0.84	14.34	531,118	0.01656	0.2375
Vulcan Materials	8.00	0.68	0.73	8.73	35,897	0.00112	0.0098
Wabtec Corp.	12.00	0.56	0.63	12.63	25,401	0.00079	0.0100
Walmart Inc.	6.50	1.26	1.34	7.84	494,839	0.01543	0.1210
Waste Management	6.00	1.42	1.51	7.51	85,343	0.00266	0.0200
WEC Energy Group	6.50	4.15	4.42	10.92	25,411	0.00079	0.0087
Wells Fargo	10.50	2.44	2.70	13.20	208,093	0.00649	0.0856
West Pharmac. Svcs.	7.50	0.20	0.22	7.72	29,163	0.00091	0.0070
WestRock Co.	8.50	2.45	2.66	11.16	12,706	0.00040	0.0044
Williams Cos.	10.00	5.02	5.52	15.52	46,088	0.00144	0.0223

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Willis Towers Wat. plc	8.50	1.22	1.32	9.82	28,383	0.00089	0.0087
Xcel Energy Inc.	6.00	4.22	4.47	10.47	29,006	0.00090	0.0095
Xylem Inc.	15.50	1.13	1.31	16.81	27,928	0.00087	0.0146
Yum! Brands	10.50	1.90	2.10	12.60	38,223	0.00119	0.0150
Zimmer Biomet Hldgs.	4.50	0.77	0.80	5.30	26,445	0.00082	0.0044
Zoetis Inc.	8.00	1.01	1.09	9.09	78,376	0.00244	0.0222
			Totals		32,069,324	1.00	11.24

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ROE and ROR Analysis for Summit
CAPM ROE Analysis--Value Line
Calculation for Proxy Group

Docket No. 23-074-U
Exhibit MFG-15
Schedule 7

	A Market Return	B Rf	C MRP	D Beta	E RP	F CAPM ROE	G Filtered Results
Atmos Energy Corporation	11.24%	4.60%	6.64%	0.85	5.64%	10.24%	10.24%
Chesapeake Utilities	11.24%	4.60%	6.64%	0.80	5.31%	9.91%	9.91%
NiSource	11.24%	4.60%	6.64%	0.95	6.31%	10.91%	10.91%
Northwest Natural Holding Co.	11.24%	4.60%	6.64%	0.85	5.64%	10.24%	10.24%
Southwest Gas Holdings	11.24%	4.60%	6.64%	0.85	5.64%	10.24%	10.24%
ONE Gas, Inc.	11.24%	4.60%	6.64%	0.90	5.98%	10.58%	10.58%
Spire, Inc.	11.24%	4.60%	6.64%	0.85	5.64%	10.24%	10.24%
					Mean	10.34%	10.34%
					Median	10.24%	10.24%

A: MFG-15, Sch 5
B: MFG-15 Sch 1
C: A - B
D: MFG-15, Sch 2

E: C * D
F: B + E
G: Low-end test < Column F < High-end test

Low-End Test:	Moody's 10-Year Baa Corporate Bond Index, S&P Global Market Intelligence)	5.94%
	CAPM Risk Premium, Column C	6.64%
	20 percent of CAPM risk premium	1.33%
	Moody's 10-Year Baa Corporate Bond Index + 20 percent of CAPM risk premium	7.27%

High-End Test:	Proxy Group median, Column F	10.24%
	150 percent of Proxy Group median	15.37%
	200 percent of Proxy Group median	20.49%

ROE and ROR Analysis for Summit | **Docket No. 23-079-U**
CAPM ROE Analysis | **Exhibit MFG-15**
Average of Low-End Tests for Value Line and Kroll | **Schedule 8**

Value Line Low-End Test:	Moody's 10-Year Baa Corporate Bond Index, S&P Global Market Intelligence. MFG-15, Schedule 5	5.94%
	CAPM Risk Premium, Value Line, MFG-15, Schedule 7	6.64%
	20 percent of CAPM risk premium	1.33%
	Moody's 10-Year Baa Public Corporate Bond Index + 20 percent of CAPM risk premium	7.27%

Kroll Low-End Test:	Moody's 10-Year Baa Corporate Bond Index, S&P Global Market Intelligence. MFG-15, Schedule 3	5.94%
	CAPM Risk Premium, Kroll, MFG-15, Schedule 5	5.50%
	20 percent of CAPM risk premium	1.10%
	Moody's 10-Year Baa Public Corporate Bond Index + 20 percent of CAPM risk premium	7.04%

Mean of Value Line and Kroll Low-End Tests 7.15%

S&P Capital IQ PRO

Source: S&P Capital IQ Pro Regulatory Research Associates Rate Case History
Downloaded April 8, 2024

2021

State	Company	Docket	Case Type	Date of Decision	Decision Type	Return on Equity (%)	Equity Ratio (%)
Georgia	Atlanta Gas Light Co.	D-42315 (2020 review)	Distribution	1/1/2021	Fully Litigated	NA	56.00
Colorado	Black Hills Colorado Gas	D-20AL-0380G	Distribution	1/6/2021	Fully Litigated	NA	NA
Delaware	Delmarva Power & Light Co.	D-20-0150	Distribution	1/6/2021	Settled	9.60	50.37
Oregon	Cascade Natural Gas Corp.	D-UG 390	Distribution	1/6/2021	Settled	9.40	50.00
Illinois	Ameren Illinois	D-20-0308	Distribution	1/13/2021	Fully Litigated	9.67	52.00
Minnesota	CenterPoint Energy Resources	D-G-008/GR-19-524	Distribution	1/14/2021	Settled	NA	NA
Nebraska	Black Hills Nebraska Gas	D-NG-109	Distribution	1/26/2021	Settled	9.50	50.00
Montana	MDU Resources Group	D2020.06.076	Distribution	2/16/2021	Settled	NA	NA
Tennessee	Piedmont Natural Gas Co.	D-20-00086	Distribution	2/16/2021	Settled	9.80	50.50
Pennsylvania	Columbia Gas of Pennsylvania	D-R-2020-3018835	Distribution	2/19/2021	Fully Litigated	9.86	54.19
District of Columbia	Washington Gas Light Co.	FC-1162	Distribution	2/24/2021	Settled	9.25	52.10
California	Southwest Gas Corp.	A-19-08-015 (SoCal)	Distribution	3/25/2021	Settled	10.00	52.00
California	Southwest Gas Corp.	A-19-08-015 (NoCal)	Distribution	3/25/2021	Settled	10.00	52.00
California	Southwest Gas Corp.	A-19-08-015 (LkTah)	Distribution	3/25/2021	Settled	10.00	52.00
Maryland	Washington Gas Light Co.	C-9651	Distribution	4/9/2021	Fully Litigated	9.70	52.03
North Dakota	MDU Resources Group	C-PU-20-379	Distribution	5/5/2021	Settled	9.30	50.31
Washington	Cascade Natural Gas Corp.	D-UG-200568	Distribution	5/18/2021	Fully Litigated	9.40	49.10

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New York	Corning Natural Gas Corp.	C-20-G-0101	Distribution 5/19/2021	Fully Litigated	8.80	48.00
Pennsylvania	PECO Energy Co	D-R-2020-3018929	Distribution 6/17/2021	Fully Litigated	10.24	53.38
Kentucky	Louisville Gas & Electric Co.	C-2020-00350 (gas)	Distribution 6/30/2021	Settled	9.43	NA
Tennessee	Atmos Energy Corp.	D-21-00019	Distribution 7/19/2021	Settled	NA	59.88
West Virginia	Hope Gas Inc.	C-20-0746-G-42T	Distribution 7/27/2021	Fully Litigated	9.54	47.45
New Hampshire	Liberty Utilities EnergyNorth	D-DG-20-105	Distribution 7/30/2021	Settled	9.30	52.00
Wisconsin	Wisconsin Electric Power Co.	D-5-AF-107 (WEP-Gas)	Distribution 8/11/2021	NA	NA	NA
Wisconsin	Wisconsin Gas LLC	D-5-AF-107	Distribution 8/11/2021	NA	NA	NA
Wisconsin	Wisconsin Public Service Corp.	D-5-AF-107 (Gas)	Distribution 8/11/2021	NA	NA	NA
New York	KeySpan Gas East Corp.	C-19-G-0310	Distribution 8/12/2021	Settled	8.80	48.00
New York	The Brooklyn Union Gas Co.	C-19-G-0309	Distribution 8/12/2021	Settled	8.80	48.00
Oklahoma	CenterPoint Energy Resources	Ca-PUD202100054	Distribution 8/19/2021	Settled	NA	NA
Idaho	Avista Corp.	C-AVU-G-21-01	Distribution 9/1/2021	Settled	9.40	50.00
Illinois	North Shore Gas Co.	D-20-0810	Distribution 9/8/2021	Fully Litigated	9.67	51.58
Michigan	Michigan Gas Utilities Corp.	C-U-20718	Distribution 9/9/2021	Settled	9.85	NA
Virginia	Virginia Natural Gas Inc.	C-PUR-2020-00095	Distribution 9/14/2021	Settled	9.50	51.89
Arkansas*	CenterPoint Energy Resources	D-17-010-FR (2021 filing	Distribution 9/23/2021	Fully Litigated	NA	32.27
Washington	Avista Corp.	D-UG-200901	Distribution 9/27/2021	Settled	9.40	48.50
South Carolina	Piedmont Natural Gas Co.	D-2021-7-G	Distribution 9/29/2021	Settled	9.80	52.20
Massachusetts	Boston Gas Co.	DPU 20-120	Distribution 9/30/2021	Fully Litigated	9.70	53.44
Indiana	Sthrn IN Gas & Electric Co.	Ca-45447	Distribution 10/6/2021	Settled	9.70	45.74
Washington	Northwest Natural Gas Co.	D-UG-200994	Distribution 10/21/2021	Settled	NA	NA
Missouri	Spire Missouri Inc.	C-GR-2021-0108	Distribution 10/27/2021	Fully Litigated	9.37	49.86
Massachusetts	NSTAR Gas Co.	DPU 21-107	Distribution 10/29/2021	Fully Litigated	NA	NA
Indiana	Indiana Gas Co.	Ca-45468	Distribution 11/17/2021	Settled	9.80	46.21
New Jersey	New Jersey Natural Gas Co.	D-GR21030679	Distribution 11/17/2021	Settled	9.60	54.00
Georgia	Atlanta Gas Light Co.	D-42315 (2021 review)	Distribution 11/18/2021	Settled	NA	56.00
Illinois	Northern Illinois Gas Co.	D-21-0098	Distribution 11/18/2021	Fully Litigated	9.75	54.46
New York	Central Hudson Gas & Electric	C-20-G-0429	Distribution 11/18/2021	Settled	9.00	50.00

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Wisconsin	Northern States Power Co.	D- 4220-UR-125 (Gas)	Distribution	11/18/2021	Settled	10.00	52.50
Wisconsin	Wisconsin Power and Light	D-6680-UR-123 (Gas)	Distribution	11/18/2021	Settled	10.00	52.50
Wisconsin	Madison Gas and Electric	D-3270-UR-124 (Gas)	Distribution	11/23/2021	Settled	9.80	55.00
Oklahoma	Oklahoma Natural Gas Co	Ca-PUD202100063	Distribution	11/30/2021	Settled	9.40	58.55
Maryland	Columbia Gas of Maryland	C-9664	Distribution	12/3/2021	Fully Litigated	9.65	52.95
Michigan	DTE Gas Co.	C-U-20940	Distribution	12/9/2021	Fully Litigated	9.90	39.23
Colorado	Black Hills Colorado Gas	D-21AL-0236G	Distribution	12/13/2021	Settled	9.20	50.26
Pennsylvania	Columbia Gas of Pennsylvania	D-R-2021-3024296	Distribution	12/16/2021	Settled	NA	NA
Missouri	Union Electric Co.	C-GR-2021-0241	Distribution	12/22/2021	Settled	NA	NA
Iowa	Black Hills Iowa Gas Utility	D-RPU-2021-0002	Distribution	12/28/2021	Settled	9.60	50.01
Kentucky	Columbia Gas of Kentucky	C-2021-00183	Distribution	12/28/2021	Settled	9.35	52.64
Kentucky	Duke Energy Kentucky Inc.	C-2021-00190	Distribution	12/28/2021	Settled	9.38	51.34
Kansas	Black Hills Kansas Gas Utility	D-21-BHCG-418-RTS	Distribution	12/30/2021	Settled	NA	NA

*-CenterPoint Energy Arkansas case excluded from Equity Ratio. Capital Structure includes unusual

Mean	**9.56**	**51.32**
Median	**9.60**	**51.95**
Range	**8.80-10.24**	**39.23-59.88**
	n = 43	**n = 44**

2022

State	Company	Docket	Case Type	Date of Decision	Decision Type	Return on Equity (%)	Equity Ratio (%)
Kentucky	Delta Natural Gas Co.	C-2021-00185	Distribution	1/3/2022	Settled	9.25	NA
North Carolina	Piedmont Natural Gas Co.	D-G-9, Sub 781	Distribution	1/6/2022	Settled	9.60	51.60
New York	Niagara Mohawk Power	C-20-G-0381	Distribution	1/20/2022	Settled	9.00	48.00
North Carolina	Public Service Co. of NC	D-G-5 Sub 632	Distribution	1/21/2022	Settled	9.60	51.60
Nevada	Southwest Gas Corp.	D-21-09001 (Southern)	Distribution	3/22/2022	Settled	9.40	50.00
Nevada	Southwest Gas Corp.	D-21-09001 (Northern)	Distribution	3/22/2022	Settled	9.40	50.00
New York	Orange & Rockland Utlts	C-21-G-0073	Distribution	4/14/2022	Settled	9.20	48.00
Kentucky	Atmos Energy Corp.	C-2021-00214	Distribution	5/19/2022	Fully Litigated	9.23	54.50
New York	Corning Natural Gas Corp.	C-21-G-0394	Distribution	6/16/2022	Settled	9.25	48.00

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Tennessee	Atmos Energy Corp.	D-22-00010	Distribution 6/20/2022	Fully Litigated	NA	60.59
Missouri	Empire District Gas Co.	C-GR-2021-0320	Distribution 6/23/2022	Settled	NA	NA
Michigan	Consumers Energy Co.	C-U-21148	Distribution 7/7/2022	Settled	9.90	NA
New Hampshire	Northern Utilities Inc.	D-DG-21-104	Distribution 7/20/2022	Settled	9.30	52.00
Indiana	Northern IN Public Svc Co. LLC	Ca-45621	Distribution 7/27/2022	Settled	9.85	49.47
Oregon	Avista Corp.	D-UG 433	Distribution 8/2/2022	Settled	9.40	50.00
New Jersey	Elizabethtown Gas Co.	D-GR21121254	Distribution 8/17/2022	Settled	9.60	52.00
Minnesota	CenterPoint Energy Resources	D-G-008/GR-21-435	Distribution 8/18/2022	Settled	9.39	51.00
Washington	Cascade Natural Gas Corp.	D-UG-210755	Distribution 8/23/2022	Settled	9.40	47.00
Pennsylvania	UGI Utilities Inc.	D-R-2021-3030218	Distribution 9/15/2022	Settled	NA	NA
South Carolina	Piedmont Natural Gas Co.	D-2022-89-G	Distribution 9/15/2022	Settled	9.30	52.20
Massachusetts	Boston Gas Co.	DPU 22-74	Distribution 9/26/2022	Fully Litigated	NA	NA
Delaware	Delmarva Power & Light Co.	D-22-0002	Distribution 10/12/2022	Settled	9.60	49.94
Arkansas	Black Hills Energy Arkansas	D-21-097-U	Distribution 10/10/2022	Fully Litigated	9.60	45.00
Oregon	Northwest Natural Gas Co.	D-UG-435	Distribution 10/24/2022	Settled	9.40	50.00
Colorado	Public Service Co. of CO	D-22AL-0046G	Distribution 10/25/2022	Fully Litigated	9.20	53.78
Massachusetts	The Berkshire Gas Co.	DPU 22-20	Distribution 10/27/2022	Settled	9.70	54.00
North Dakota	Northern States Power Co.	C-PU-21-381	Distribution 10/27/2022	Settled	9.80	52.54
Pennsylvania	PECO Energy Co	D-R-2022-3031113	Distribution 10/27/2022	Settled	NA	NA
California	San Diego Gas & Electric Co.	A-21-08-014 (Gas)	Distribution 11/3/2022	Fully Litigated	10.20	52.00
Oklahoma	Summit Utilities Inc.	Ca-PUD202200022	Distribution 11/10/2022	Settled	NA	NA
Maryland	Columbia Gas of Maryland Inc	C-9680	Distribution 11/17/2022	Settled	9.65	52.97
Oklahoma	Oklahoma Natural Gas Co	Ca-PUD202200023	Distribution 11/29/2022	Settled	NA	NA
Missouri	Spire Missouri Inc.	C-GR-2022-0179	Distribution 11/30/2022	Settled	NA	NA
New Mexico	New Mexico Gas Co.	C-21-00267-UT	Distribution 11/30/2022	Settled	9.38	52.00
Pennsylvania	Columbia Gas of Pennsylvania	D-R-2022-3031211	Distribution 12/8/2022	Settled	NA	NA
Washington	Avista Corp.	D-UG-220054	Distribution 12/12/2022	Settled	NA	NA
California	Southern California Gas Co.	A-22-04-011	Distribution 12/15/2022	Fully Litigated	9.80	52.00

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New Jersey	South Jersey Gas Co.	D-GR22040253	Distribution	12/21/2022	Settled	9.60	54.00
Washington	Puget Sound Energy Inc.	D-UG-220067	Distribution	12/22/2022	Settled	9.40	49.00
Wisconsin	Wisconsin Public Service Corp.	D-6690-UR-127 (Gas)	Distribution	12/22/2022	Fully Litigated	9.80	53.40
Utah	Dominion Energy Inc.	D-22-057-03	Distribution	12/23/2022	Fully Litigated	9.60	51.00
Wisconsin	Wisconsin Electric Power	D-5-UR-110 (WEP-Gas)	Distribution	12/29/2022	Fully Litigated	9.80	58.22
Wisconsin	Wisconsin Gas LLC	D-5-UR-110	Distribution	12/29/2022	Fully Litigated	9.80	52.70

*-Black Hills Energy Arkansas case excluded from Equity Ratio. Capital Structure includes unusual it

Mean	**9.53**	**51.52**
Median	**9.60**	**51.80**
Range	**9.20-10.20**	**45.00-60.59**
	n = 33	**n = 32**

2023

State	Company	Docket	Case Type	Date of Decision	Decision Type	Return on Equity (%)	Equity Ratio (%)
Texas	Texas Gas Service Co.	D-OSS-22-00009896	Distribution	1/19/2023	Fully Litigated	9.60	59.74
Arizona	Southwest Gas Corp.	D-G-01551A-21-0368	Distribution	1/23/2023	Settled	9.30	50.00
Florida	Florida Public Utilities Co.	D-20220067-GU	Distribution	1/24/2023	Fully Litigated	10.25	45.16
Ohio	Columbia Gas Ohio Inc.	C-21-0637-GA-AIR	Distribution	1/26/2023	Settled	9.60	50.60
Minnesota	Northern States Power Co.	D-G-002/GR-21-678	Distribution	3/23/2023	Settled	9.57	52.50
Florida	Pivotal Utility Holdings Inc.	20220069-GU	Distribution	3/28/2023	Fully Litigated	9.50	59.60
South Dakota	MidAmerican Energy Co.	D-NG22-005	Distribution	3/28/2023	Settled	NA	NA
Colorado	Atmos Energy Corp.	D-22AL-0348G	Distribution	5/4/2023	Settled	9.30	58.00
Kansas	Atmos Energy Corp.	D-23-ATMG-359-RTS	Distribution	5/9/2023	Settled	NA	NA
Virginia	Columbia Gas of Virginia Inc	C-PUR-2022-00036	Distribution	5/15/2023	Settled	NA	NA
Pennsylvania	Natl Fuel Gas Distribution	D-R-2022-3035730	Distribution	6/15/2023	Settled	NA	NA
Idaho	Intermountain Gas Co.	C-INT-G-22-07	Distribution	6/30/2023	Settled	9.50	50.00
Oklahoma	Oklahoma Natural Gas Co	Ca-PUD2023-000012	Distribution	7/11/2023	Settled	NA	NA
New York	Consolidated Edison Company of	C-22-G-0065	Distribution	7/20/2023	Settled	9.25	48.00
Virginia	Virginia Natural Gas Inc.	C-PUR-2022-00052	Distribution	8/28/2023	Settled	NA	NA
Virginia	Washington Gas Light Co.	C-PUR-2022-00054	Distribution	8/29/2023	Settled	NA	NA

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Michigan	Consumers Energy Co.	C-U-21308	Distribution 8/30/2023	Settled	9.90	NA
Michigan	Michigan Gas Utilities Corp.	C-U-21366	Distribution 8/30/2023	Settled	9.80	NA
Idaho	Avista Corp.	C-AVU-G-23-01	Distribution 8/31/2023	Settled	9.40	50.00
Maine	Northern Utilities Inc.	D-2023-00051	Distribution 9/20/2023	Settled	9.35	52.01
South Carolina	Dominion Energy South Carolina	D-2023-70-G	Distribution 9/20/2023	Settled	9.49	54.78
Massachusetts	Boston Gas Co.	DPU 23-56	Distribution 9/28/2023	Fully Litigated	NA	NA
South Carolina	Piedmont Natural Gas Co.	D-2023-7-G	Distribution 10/5/2023	Settled	9.30	53.13
Tennessee	Chattanooga Gas Co.	D-23-00029	Distribution 10/6/2023	Settled	9.80	49.23
New York	NY State Electric & Gas	C-22-G-0318	Distribution 10/12/2023	Settled	9.20	48.00
New York	Rochester Gas & Electric Corp.	C-22-G-0320	Distribution 10/12/2023	Settled	9.20	48.00
Montana	NorthWestern Energy	D-2022-7-78 (gas)	Distribution 10/25/2023	Settled	9.55	48.02
Maryland	Columbia Gas of Maryland	C-9701	Distribution 10/26/2023	Settled	NA	NA
Minnesota	Minnesota Energy	D-G-011/GR-22-504	Distribution 10/26/2023	Settled	9.65	53.00
Oregon	Avista Corp.	D-UG-461	Distribution 10/26/2023	Settled	9.50	50.00
Massachusetts	NSTAR Gas Co.	DPU 23-94	Distribution 10/30/2023	Fully Litigated	NA	NA
Ohio	Duke Energy Ohio Inc.	C-22-0507-GA-AIR	Distribution 11/1/2023	Settled	9.60	52.32
Wisconsin	Madison Gas and Electric Co.	D-3270-UR-125 (Gas)	Distribution 11/3/2023	Fully Litigated	9.70	56.06
Wyoming	Questar Gas Co.	D-30010-215-GR-23	Distribution 11/7/2023	Settled	9.65	51.56
Florida	Peoples Gas System	D-20230023-GU	Distribution 11/9/2023	Fully Litigated	10.15	NA
Wisconsin	Northern States Power Co.	D-4220-UR-126 (Gas)	Distribution 11/9/2023	Fully Litigated	9.80	52.50
Wisconsin	Wisconsin Power and Light Co	D-6680-UR-124 (Gas)	Distribution 11/9/2023	Fully Litigated	9.80	53.70
California	Pacific Gas and Electric Co.	A-21-06-021 (Gas)	Distribution 11/16/2023	Fully Litigated	NA	NA
Illinois	Ameren Illinois	D-23-0067	Distribution 11/16/2023	Fully Litigated	9.44	50.00
Illinois	North Shore Gas Co.	D-23-0068	Distribution 11/16/2023	Fully Litigated	9.38	52.58
Illinois	Northern Illinois Gas Co.	D-23-0066	Distribution 11/16/2023	Fully Litigated	9.51	50.00
Illinois	The Peoples Gas Light & Coke C	D-23-0069	Distribution 11/16/2023	Fully Litigated	9.38	50.79
Tennessee	Piedmont Natural Gas Co.	D-23-00035	Distribution 12/4/2023	Settled	9.80	50.09
Maryland	Baltimore Gas and Electric Co.	C-9692 (GAS)	Distribution 12/14/2023	Fully Litigated	9.45	52.00
Maryland	Washington Gas Light Co.	C-9704	Distribution 12/14/2023	Fully Litigated	9.50	52.60

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District of Columbia	Washington Gas Light Co.	FC-1169	Distribution	12/15/2023	Fully Litigated	9.65	52.00
Virginia	Roanoke Gas Co.	C-PUR-2022-00205 (Ex	Distribution	12/19/2023	Settled	NA	NA
West Virginia	Mountaineer Gas Co.	C-23-0280-G-42T	Distribution	12/21/2023	Settled	9.75	NA
California	Southern California Gas Co.	Advice Letter No. 6207-(	Distribution	12/22/2023	Fully Litigated	10.50	52.00

Mean	**9.60**	**51.76**
Median	**9.55**	**50.60**
Range	**9.20-10.50**	**45.16-59.74**
	n = 37	**n = 33**

Mean	**9.56**	**51.34**
Median	**9.60**	**51.95**
Range	**8.80-10.50**	**45.16-59.74**
	n = 113	**n = 109**

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ROE and ROR Analysis for Summit
Summary of ROE Analyses and Recommended ROE

Docket No. 23-079-U
Exhibit MFG-17
Schedule 1

Analysis	Weight		ROE			Exhibit
Constant-Growth DCF		**Mean**	10.09%			Exhibit MFG-14, Schedule 1
		Median	10.09%			
Multistage DCF		**Mean**	9.45%			Exhibit MFG-14, Schedule 5
		Median	9.30%			
CAPM Kroll Market Risk Premium		**Mean**	9.35%			Exhibit MFG-15, Schedule 4
		Median	9.28%			
CAPM S&P 500 Value Line		**Mean**	10.34%			Exhibit MFG-15, Schedule 6
		Median	10.24%			
DCF and CAPM Value Line results		**Mean**	9.81%			
		Median	9.73%			
			2121	**2022**	**2023**	
Recently awarded ROEs	**Mean**		9.56	9.53	9.60	Exhibit MFG-16
	Median		9.60	9.60	9.55	
	Range		8.80-10.24	9.20-10.20	9.20-10.50	
	Cases		n = 43	n = 33	n = 37	
			Overall			
	Mean		9.56			
	Median		9.60			
	Range		8.80-10.50			
	Cases		n = 113			
Recommended ROE for Summit Utilities Arkansas				9.80%		

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S&P Capital IQ PRO

S&P Market Intelligence website, downloaded June 23, 2024
In thousands of dollars

Company Name	2024Q1	2023Q4	2023Q3	2023Q2	2023Q1	2022Q4	2022Q3	2022Q2	Average 2022Q2-2024Q1
Average Long-Term Debt for each quarter									
Atmos Energy Corporation	7,527,695	7,181,468	6,738,154	6,597,871	6,552,446	6,248,372	5,852,056	5,758,380	6,557,055
Chesapeake Utilities	1,196,312	926,233	656,084	662,861	629,587	593,794	598,210	605,826	733,613
NiSource, Inc.	11,402,950	11,046,300	11,007,050	10,633,750	9,910,100	9,538,350	9,520,700	9,350,000	10,301,150
Northwest Natural Holding Company	1,577,194	1,502,325	1,437,288	1,372,711	1,349,012	1,345,304	1,244,916	1,124,093	1,369,105
ONE Gas, Inc.	2,160,532	2,018,651	1,869,407	1,875,893	2,277,358	2,554,098	2,356,459	2,283,743	2,174,517
Southwest Gas Holdings, Inc.	4,694,173	4,987,463	5,260,192	4,931,222	4,546,128	5,190,124	5,227,023	4,574,106	4,926,304
Spire Inc.	3,334,600	3,436,000	3,588,750	3,627,900	3,429,400	3,094,250	3,120,050	3,207,600	3,354,819

Company Name	2024Q1	2023Q4	2023Q3	2023Q2	2023Q1	2022Q4	2022Q3	2022Q2	Average 2022Q2-2024Q1
Average Short-Term Debt for each quarter									
Atmos Energy Corporation	10,538	150,363	148,378	4,513	1,101,498	2,313,276	2,313,249	2,201,417	1,030,404
Chesapeake Utilities	196,079	170,871	129,552	118,152	172,161	208,764	176,167	162,066	166,726
NiSource, Inc.	2,163,500	2,663,700	1,933,000	1,465,600	1,554,300	1,549,750	947,550	585,100	1,607,813
Northwest Natural Holding Company	170,300	253,261	273,495	299,179	332,662	271,693	208,671	279,254	261,064
ONE Gas, Inc.	938,255	1,011,145	1,075,757	1,055,689	829,984	623,070	1,281,762	1,897,644	1,089,163
Southwest Gas Holdings, Inc.	694,278	400,810	78,728	283,514	1,061,331	1,017,870	963,254	1,634,546	766,791
Spire Inc.	1,298,750	1,311,700	1,041,550	890,900	1,150,600	1,404,400	1,032,800	689,350	1,102,506

Company Name	2024Q1	2023Q4	2023Q3	2023Q2	2023Q1	2022Q4	2022Q3	2022Q2	Average 2022Q2-2024Q1
Average Common Equity for each quarter									

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Atmos Energy Corporation	11,445,924	11,071,637	10,736,223	10,403,793	10,020,740	9,627,683	9,343,631	9,125,701	10,221,916
Chesapeake Utilities	1,263,504	1,056,391	865,453	861,408	845,695	823,620	815,070	810,607	917,718
NiSource, Inc.	7,201,250	6,283,200	6,068,800	6,102,750	5,970,050	5,621,650	5,446,250	5,450,250	6,018,025
Northwest Natural Holding Company	1,313,612	1,251,689	1,229,909	1,244,293	1,211,874	1,148,149	1,129,818	1,063,362	1,199,088
ONE Gas, Inc.	2,797,931	2,706,312	2,650,787	2,653,153	2,617,953	2,515,350	2,449,935	2,451,493	2,605,364
Southwest Gas Holdings, Inc.	3,333,139	3,274,391	3,250,786	3,279,491	3,177,458	3,235,837	3,435,884	3,473,967	3,307,619
Spire Inc.	2,978,550	2,742,050	2,682,900	2,717,500	2,683,300	2,599,300	2,590,200	2,601,550	2,699,419

Company Name	Average Total Capital 2022Q2-2024Q1	Long-Term Debt %	Short-Term Debt %	Common Equity %	
Atmos Energy Corporation	17,809,375	36.82%	5.79%	57.40%	100.00%
Chesapeake Utilities	1,818,057	40.35%	9.17%	50.48%	100.00%
NiSource, Inc.	17,926,988	57.46%	8.97%	33.57%	100.00%
Northwest Natural Holding Company	2,829,257	48.39%	9.23%	42.38%	100.00%
ONE Gas, Inc.	5,869,045	37.05%	18.56%	44.39%	100.00%
Southwest Gas Holdings, Inc.	9,000,714	54.73%	8.52%	36.75%	100.00%
Spire Inc.	7,156,744	46.88%	15.41%	37.72%	100.00%
Proxy Group Average %		45.95%	10.80%	43.24%	100.00%
Proxy Group w/o ONE Gas and Spire Average %		47.55%	8.33%	44.11%	100.00%
Capital structure requested by Summit Utilities Arkansas		44.41%		55.59%	100.00%

	Long-Term Debt	Short-Term Debt	Common Equity	
Recommended capital structure for Summit Utilities Arkansas	46.00%	8.00%	46.00%	100.00%

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ROE and ROR Analysis Summit
Capital Structure Analysis
Proxy Group Ratios

Summit Requested ROE and ROR

		Pro Forma ROR						
	Beginning Amount	Pro Forma Adjustments	Pro Forma Amount	Special Pro Forma Adjustments	Pro Forma Amount	Proportion	Cost	WACC
Long-Term Debt	1,163,088,203	100,992,122	1,264,080,325	(719,969,326)	544,110,999	37.2882%	4.1798%	######
Preferred Stock	-	-	-			-	-	-
Common Equity	1,084,753,299	109,981,190	1,194,734,489	(513,782,209)	680,952,280	46.6661%	#######	######
Accumulated Deferred Income Taxes	(16,817,228)	(4,120,998)	(20,938,226)	20,938,226	0	0.0000%	0.0000%	######
Excess Deferred Income Taxes	99,155,814	(3,022,298)	96,133,516		96,133,516	6.5881%	0.0000%	######
Pre-1971 ADITC	-	-	-			-	-	######
Post-1970 ADITC	-	-	-			-	-	######
Customer Deposits	5,070,887	2,200,403	7,271,290		7,271,290	0.4983%	2.5649%	######
Short-Term Debt						0.0000%	5.5500%	######
Current, Accrued and Other Liabilities	162,540,354	(31,806,060)	130,734,294		130,734,294	8.9593%	0.0000%	######
Capital Leases	-	-	-			0.0000%		
Other Capital Items	-	-	-			0.0000%		
Total	2,497,791,329	174,224,359	2,672,015,688	(1,212,813,309)	1,459,202,379	100.0000%		######

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Calculation of the Office of the Attorney General's Capital Structure Proportions

Long-Term Debt, Short-term Debt, Common Equity total Proportion of BHEA Capital Structure			83.95%
		Attorney General Proportions	
Long-Term Debt	83.95 *	46.00%	38.62%
Common Equity	83.95 *	46.00%	38.62%
Short-Term Debt	83.95 *	8.00%	6.72%
Total			83.95%

Discussion: The OAG recommended proportions are taken from Exhibit MFG-17, Schedule 2. The proportion they represent of the modified balance sheet approach is determined by multiplying each value times the total proportion for those items.

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Office of the Attorney General
Recommended ROE and ROR

	Proportion	Cost	WACC
Long-Term Debt	38.62%	4.18%	1.61%
Preferred Stock	0.00%	0.00%	0.00%
Common Equity	38.62%	9.80%	3.78%
Accumulated Deferred Income Taxes	0.00%	0.00%	0.00%
Excess Deferred Income Taxes	6.59%	0.00%	0.00%
Pre-1971 ADITC	-	-	-
Post-1970 ADITC	-	-	-
Customer Deposits	0.50%	2.56%	0.01%
Short-Term Debt	6.72%	5.55%	0.37%
Current, Accrued and Other Liabilities	8.96%	0.00%	0.00%
Capital Leases	-	-	-
Other Capital Items	-	-	-
Overall Rate of Return	100.00%		5.78%

ROE Source: The recommended common equity cost of 9.80 percent is taken from the ROE analysis in Exhibit MFG-17, Schedule 1. The cost of short-term debt is hypothetical; 5.55 percent is the cost for Black Hills Energy Arkansas, another Arkansas natural gas company, in its ongoing base rate case Docket No. 23-074-U.

Other Cost Sources: The long-term debt cost and cost of customer deposits are those proposed by Summit Utiitilities Arkansas in Schedule D-1.3. They are accepted. Any discrepancies between this exhibit and Schedule D-1.3 are due to rounding.

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Adjustment to operating income after depreciation and amortization (D&A) and EBIT: We reduce D&A related to the securitized debt, which is assumed to equal the principal payments during the period. As a result, the reduction to operating income after D&A is only for the interest portion.
Adjustment to interest expense: We remove the interest expense of the securitized debt from total interest expense.
Operating cash flows:
We reduce operating cash flows for revenues and increase for the assumed interest amount related to the securitized debt. This results in a net decrease to operating cash flows equal to the principal repayment amount.

Infrastructure renewals expenditure

72. In England and Wales, water utilities can report under either IFRS or U.K. GAAP. Those that report under U.K. GAAP are allowed to adopt infrastructure renewals accounting, which enables the companies to capitalize the maintenance spending on their underground assets, called infrastructure renewals expenditure (IRE). Under IFRS, infrastructure renewals accounting is not permitted and maintenance expenditure is charged to earnings in the year incurred. This difference typically results in lower adjusted operating cash flows for those companies that report maintenance expenditure as an operating cash flow under IFRS, than for those that report it as capital expenditure under U.K. GAAP. We therefore make financial adjustments to amounts reported by water issuers that apply U.K. GAAP, with the aim of making ratios more comparable with those issuers that report under IFRS and U.S. GAAP. For example, we deduct IRE from EBITDA and FFO.

73. IRE does not always consist entirely of maintenance expenditure that would be expensed under IFRS. A portion of IRE can relate to costs that would be eligible for capitalization as they meet the recognition criteria for a new fixed asset set out in International Accounting Standard 16 that addresses property, plant, and equipment. In such cases, we may refine our adjustment to U.K. GAAP companies so that we only deduct from FFO the portion of IRE that would not be capitalized under IFRS. However, the information to make such a refinement would need to be of high quality, reliable, and ideally independently verified by a third party, such as the company's auditor. In the absence of this, we assume that the entire amount of IRE would have been expensed under IFRS and we accordingly deduct the full expenditure from FFO.

74. Adjustment procedures:

Data requirements:
U.K. GAAP accounts typically provide little information on the portion of capital spending that relates to renewals accounting, or the related depreciation, which is referred to as the infrastructure renewals charge. The information we use for our adjustments is, however, found in the regulatory cost accounts submitted annually by the water companies to the Water Services Regulation Authority, which regulates all water companies in England and Wales.
Calculations:
EBITDA: Reduced by the value of IRE that was capitalized in the period.
EBIT: Adjusted for the difference between the adjustment to EBITDA and the reduction in the depreciation expense, depending on the degree to which the actual cash spending in the current year matches the planned spending over the five-year regulatory review period.
Cash flow from operations and FFO: Reduced by the value of IRE that was capitalized in the period.
Capital spending: Reduced by the value of infrastructure renewals spending that we reclassify to cash flow from operations.
Free operating cash flow: No impact, as the reduction in operating cash flows is exactly offset by the reduction in capital spending.

E. Cash flow/leverage analysis

75. In assessing the cash flow adequacy of a regulated utility, our analysis uses the same methodology as with other corporate issuers (see "Corporate Methodology (/en_US/web/guest/article/-/view/sourceId/8314109)"). We assess cash flow/leverage on a six-point scale ranging from ('1') minimal to ('6') highly leveraged. These scores are determined by aggregating the assessments of a range of credit ratios, predominantly cash flow-based, which complement each other by focusing attention on the different levels of a company's cash flow waterfall in relation to its obligations.

76. The corporate methodology provides benchmark ranges for various cash flow ratios we associate with different cash flow leverage assessments for standard volatility, medial volatility, and low volatility industries. The tables of benchmark ratios differ for a given ratio and cash flow leverage assessment along two dimensions: the starting point for the ratio

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range and the width of the ratio range.

77. If an industry's volatility levels are low, the threshold levels for the applicable ratios to achieve a given cash flow leverage assessment are less stringent, although the width of the ratio range is narrower. Conversely, if an industry has standard levels of volatility, the threshold levels for the applicable ratios to achieve a given cash flow leverage assessment may be elevated, but with a wider range of values.

78. We apply the "low-volatility" table to regulated utilities that qualify under the corporate criteria and with all of the following characteristics:

A vast majority of operating cash flows come from regulated operations that are predominantly at the low end of the utility risk spectrum (e.g., a "network," or distribution/transmission business unexposed to commodity risk and with very low operating risk);
A "strong" regulatory advantage assessment;
An established track record of normally stable credit measures that is expected to continue;
A demonstrated long-term track record of low funding costs (credit spread) for long-term debt that is expected to continue; and
Non-utility activities that are in a separate part of the group (as defined in our group rating methodology) that we consider to have "nonstrategic" group status and are not deemed high risk and/or volatile.

79. We apply the "medial volatility" table to companies that do not qualify under paragraph 78 with:

A majority of operating cash flows from regulated activities with an "adequate" or better regulatory advantage assessment; or
About one-third or more of consolidated operating cash flow comes from regulated utility activities with a "strong" regulatory advantage and where the average of its remaining activities have a competitive position assessment of '3' or better.

80. We apply the "standard-volatility" table to companies that do not qualify under paragraph 79 and with either:

About one-third or less of its operating cash flow comes from regulated utility activities, regardless of its regulatory advantage assessment; or
A regulatory advantage assessment of "adequate/weak" or "weak."

Part III--Rating Modifiers

F. Diversification/portfolio effect

81. In assessing the diversification/portfolio effect on a regulated utility, our analysis uses the same methodology as with other corporate issuers (see "Corporate Methodology (/en_US/web/guest/article/-/view/sourceId/8314109)").

G. Capital structure

82. In assessing the quality of the capital structure of a regulated utility, we use the same methodology as with other corporate issuers (see "Corporate Methodology (/en_US/web/guest/article/-/view/sourceId/8314109)").

H. Liquidity

83. In assessing a utility's liquidity/short-term factors, our analysis is consistent with the methodology that applies to corporate issuers (See "Methodology And Assumptions: Liquidity Descriptors For Global Corporate Issuers (/en_US/web/guest/article/-/view/sourceId/6881137)," Dec. 16, 2014) except for the standards for "adequate" liquidity set out in paragraph 84 below.

84. The relative certainty of financial performance by utilities operating under relatively predictable regulatory monopoly frameworks make these utilities attractive to investors even in times of economic stress and market turbulence compared to conventional industrials. Also, recognizing the cash flow stability of regulated utilities we allow more discretion when calculating covenant headroom. For this reason, when determining if utilities with business risk profiles of at least "satisfactory" meet our definition of "adequate" liquidity, we use slightly lower thresholds:

A ratio of sources to uses higher than 1.1x, compared with the standard 1.2x;
Positive sources over uses even if forecast EBITDA declines by 10% (compared with a 15% decline for corporate issuers);

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120. For companies undergoing a transformational event and with significant or weaker cash flow/leverage assessments, we place greater weight on near-term risk factors. That's because overemphasis on longer-term (inherently less predictable) issues could lead to some distortion when assessing the risk level of a speculative-grade company. We generally analyze a company using the arithmetic mean of the credit ratios expected according to our forecasts for the current year (or pro forma current year) and the subsequent financial year. A common example of this is when a private equity firm acquires a company using additional debt leverage, which makes historical financial ratios meaningless. In this scenario, we weight or focus the majority of our analysis on the next one or two years of projected credit measures.

3. Determining the cash flow/leverage assessment

a) Identifying the benchmark table

121. Tables 17, 18, and 19 provide benchmark ranges for various cash flow ratios we associate with different cash flow/leverage assessments for standard volatility, medial volatility, and low volatility industries. The tables of benchmark ratios differ for a given ratio and cash flow/leverage assessment along two dimensions: the starting point for the ratio range and the width of the ratio range.

122. If an industry exhibits low volatility, the threshold levels for the applicable ratios to achieve a given cash flow/leverage assessment are less stringent than those in the medial or standard volatility tables, although the range of the ratios is narrower. Conversely, if an industry exhibits medial or standard levels of volatility, the threshold for the applicable ratios to achieve a given cash flow/leverage assessment are elevated, albeit with a wider range of values.

123. The relevant benchmark table for a given company is based on our assessment of the company's associated industry and country risk volatility, or the CICRA (see section A, table 1). The low volatility table (table 19) will generally apply when a company's CICRA is 1, unless otherwise indicated in a sector's KCF criteria. The medial volatility table (table 18) will be used under certain circumstances for companies with a CICRA of 1 or 2. Those circumstances are described in the respective sectors' KCF criteria. The standard volatility table (table 17) serves as the relevant benchmark table for companies with a CICRA of 2 or worse, and we will always use it for companies with a CICRA of 2 or worse, and whose competitive position is assessed 5 or 6. Although infrequent, we will use the low volatility table when a company's CICRA is 2 for companies that exhibit or are expected to exhibit low levels of volatility. The choice of volatility tables for companies with a CICRA of 2 is addressed in the respective sector's KCF article.

Table 17

Cash Flow/Leverage Analysis Ratios--Standard Volatility

	--Core ratios--		--Supplementary coverage ratios--		--Supplementary payback ratios--		
	FFO/debt (%)	Debt/EBITDA (x)	FFO/cash interest(x)	EBITDA/interest (x)	CFO/debt (%)	FOCF/debt (%)	DCF/debt (%)
Minimal	60+	Less than 1.5	More than 13	More than 15	More than 50	40+	25+
Modest	45-60	1.5-2	9-13	10-15	35-50	25-40	15-25
Intermediate	30-45	2-3	6-9	6-10	25-35	15-25	10-15
Significant	20-30	3-4	4-6	3-6	15-25	10-15	5-10
Aggressive	12-20	4-5	2-4	2-3	10-15	5-10	2-5
Highly leveraged	Less than 12	Greater than 5	Less than 2	Less than 2	Less than 10	Less than 5	Less than 2

Table 18

Cash Flow/Leverage Analysis Ratios--Medial Volatility

	--Core ratios--		--Supplementary coverage ratios--		--Supplementary payback ratios--		
	FFO/debt (%)	Debt/EBITDA (x)	FFO/cash interest (x)	EBITDA/interest (x)	CFO/debt (%)	FOCF/debt (%)	DCF/debt (%)
Minimal	50+	less than 1.75	10.5+	14+	40+	30+	18+
Modest	35-50	1.75-2.5	7.5-10.5	9-14	27.5-40	17.5-30	11-18
Intermediate	23-35	2.5-3.5	5-7.5	5-9	18.5-27.5	9.5-17.5	6.5-11

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Significant	13–23	3.5–4.5	3–5	2.75–5	10.5–18.5	5–9.5	2.5–6.5
Aggressive	9–13	4.5–5.5	1.75–3	1.75–2.75	7–10.5	0–5	(11)–2.5
Highly leveraged	Less than 9	Greater than 5.5	Less than 1.75	Less than 1.75	Less than 7	Less than 0	Less than (11)

Table 19

Cash Flow/Leverage Analysis Ratios--Low Volatility

	--Core ratios--		--Supplementary coverage ratios--		--Supplementary payback ratios--		
	FFO/debt (%)	Debt/EBITDA (x)	FFO/cash interest (x)	EBITDA/interest (x)	CFO/debt (%)	FOCF/debt (%)	DCF/debt (%)
Minimal	35+	Less than 2	More than 8	More than 13	More than 30	20+	11+
Modest	23–35	2–3	5–8	7–13	20–30	10–20	7–11
Intermediate	13–23	3–4	3–5	4–7	12–20	4–10	3–7
Significant	9–13	4–5	2–3	2.5–4	8–12	0–4	0–3
Aggressive	6–9	5–6	1.5–2	1.5–2.5	5–8	(10)–0	(20)–0
Highly leveraged	Less than 6	Greater than 6	Less than 1.5	Less than 1.5	Less than 5	Less than (10)	Less than (20)

b) Aggregating the credit ratio assessments

124. To determine the final cash flow/leverage assessment, we make these calculations:

1) First, calculate a time series of standard core and supplemental credit ratios, select the relevant benchmark table, and determine the appropriate time weighting of the credit ratios.

Calculate the two standard core credit ratios and the five standard supplemental credit ratios over a five-year time horizon.
Consult the relevant industry KCF article (if applicable), which may identify additional supplemental ratio(s). The relevant benchmark table for a given company is based on our assessment of the company's associated industry and country risk volatility, or the CICRA.
Calculate the appropriate weighted average cash flow/leverage ratios. If the company is undergoing a transformational event, then the core and supplemental ratios will typically be calculated based on S&P Global Ratings' projections for the current and next one or two financial years.
2) Second, we use the core ratios to determine the preliminary cash flow assessment.

Compare the core ratios (FFO to debt and debt to EBITDA) to the ratio ranges in the relevant benchmark table.
If the core ratios result in different cash flow/leverage assessments, we will select the relevant core ratio based on which provides the best indicator of a company's future leverage.
3) Third, we review the supplemental ratio(s).

Determine the importance of standard or KCF supplemental ratios based on company-specific characteristics, namely, leverage, capital intensity, working capital intensity, growth rate, or industry.
4) Fourth, we calculate the adjusted cash flow/leverage assessment.

If the cash flow/leverage assessment(s) indicated by the important supplemental ratio(s) differs from the preliminary cash flow/leverage assessment, we might adjust the preliminary cash flow/leverage assessment by one category in the direction of the cash flow/leverage assessment indicated by the supplemental ratio(s) to derive the adjusted cash flow/leverage assessment. We will make this adjustment if, in our view, the supplemental ratio provides the best indicator of a company's future leverage.
If there is more than one important supplemental ratio and they result in different directional deviations from the preliminary cash flow/leverage assessment, we will select one as the relevant supplemental ratio based on which, in our opinion, provides the best indicator of a company's future leverage. We will then make the adjustment outlined above if the selected supplemental ratio differs from the preliminary cash flow/leverage assessment and the selected supplemental ratio provides the best overall indicator of a company's future leverage.
5) Lastly, we determine the final cash flow/leverage assessment based on the volatility adjustment.

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CERTIFICATE OF SERVICE

I, Clay Layson, hereby certify that on July 10, 2024, I filed a copy of the foregoing utilizing the Commission's Electronic Filing System, which caused a copy to be served upon all parties of record via electronic mail.

/s/ Clay Layson
Clay Layson

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BEFORE THE
ARKANSAS PUBLIC SERVICE COMMISSION

IN THE MATTER OF THE APPLICATION OF SUMMIT UTILITIES ARKANSAS, INC. FOR A GENERAL CHANGE OR MODIFICATION IN ITS RATES, CHARGES AND TARIFFS	))))	DOCKET NO. 23-079-U

DIRECT TESTIMONY

OF

DON MALONE, CPA, CGMA
SENIOR PUBLIC UTILITY AUDITOR
GAS AND WATER UTILITY SECTION

ON BEHALF OF THE GENERAL STAFF OF
THE ARKANSAS PUBLIC SERVICE COMMISSION

JULY 10, 2024

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INTRODUCTION

Q. Please state your name and business address.

A. My name is Don Malone. My business address is Arkansas Public Service Commission ("Commission"), 1000 Center Street, Little Rock, Arkansas 72201.

Q. By whom are you employed and in what capacity?

A. I am employed by the Commission's General Staff ("Staff") as a Senior Public Utility Auditor in the Gas and Water Utility Section.

Q. Please state your educational training and experience.

A. I have over thirty-five years of both private and public sector business experience. Prior to joining Staff, my experience includes corporate controller, plant controller, operations manager, cost accountant, and assistant controller positions in manufacturing, LTL common carrier, and cellular telephone companies. My professional career began in public accounting where I provided financial audit and income tax services for a variety of private and public clients. I am a licensed Certified Public Accountant in the State of Arkansas and a Chartered Global Management Accountant issued by the AICPA. To maintain my license, I annually complete at least 40 hours of professional education in the areas of accounting, tax, law, audit, and technology. I graduated from Arkansas State University in Jonesboro, Arkansas, with a Bachelor of Science degree in business with a major in accounting and minors in finance and economics.

I began working for the Commission as an Auditor in 1999 and was promoted to a Senior Analyst in the Financial Analysis Section in 2000. In 2004 I was transferred to the Gas and Water section and now have twenty years of

experience in the Gas and Water section. In 2022, I was promoted to Senior Public Utility Auditor.

I have participated in numerous revenue requirement, compliance, tariff, and other regulatory subject matter proceedings concerned with natural gas, water, and electric utility companies. Further, I have attended the National Association of Regulatory Utility Commissioners' Annual Regulatory Studies Program at Michigan State University and other public utility and regulatory seminars.

PURPOSE OF TESTIMONY

Q. What is the purpose of your Direct Testimony in this Docket?

A. The purpose of my Direct Testimony is to present the results of my examination of the Application for a General Change in Rates, Charges and Tariffs ("Application") of Summit Utilities Arkansas, Inc. ("SUA" or "Company") filed on January 25, 2024, with revisions to its Application filed on February 20, 2024. In its Application, SUA used a partially projected test year, whereas my adjustments are based on actual test year amounts. Specifically, I will discuss the adjustments to Current, Accrued, and Other Liabilities ("CAOL"); Accumulated Deferred Income Tax ("ADIT"), including Excess Deferred Income Taxes ("EDIT"); Working Capital Assets ("WCA"), as shown in Table 1, below; and Income Tax Expense, as shown in Table 2, below. In addition, I will discuss certain Expense adjustments the Company did not comprehend in its Application, shown below in Table 3, and Other Rate Base adjustments. I will address the Direct Testimony of Company witnesses Phillip B.

Gillam, Director of Rates & Regulatory Affairs, and Paul Schulte, Senior Tax Manager.

Table 1
Summary of Rate Base Adjustments

Staff Adj. No.	Co. Adj. No.	Description	Staff Amount[1]	SUA Amount[2]	Difference
		Test Year Balances	$343,860,152	$384,360,129	($40,499,977)
RB-11	RB-11	Adjust WCA to 13-Month Average	$46,858,397	$12,076,506	$34,781,891
		13-Month Balances	$390,718,549	$396,436,635	($5,718,086)
RB-10	RB-10	Decrease Avg. WCA to More Rep. Bal.	($294,973,140)	($277,655,455)	($17,317,685)
		Pro Forma WCA	$95,745,409	$118,781,180	($23,035,771)

Table 2
Summary of Income Tax Expense Adjustments

Staff Adj. No.	Co. Adj. No.	Description	Staff Adj. Amount[3]	SUA Adj. Amount[4]	Difference
IS-22	IS-22	Income Tax Expense:			
		Current	($5,231,235)	$0	($5,231,235)
		Deferred – Net	$250,511	($204,061)	$454,572
		Total	($4,980,724)	($204,061)	($4,776,663)

Table 3
Summary of Expense Adjustments

Staff Adj. No.	Co. Adj. No.	Description	Staff Amount	SUA Amount	Difference
IS-23	NA	Donations and Other Expenditures	($83,105)	$0	($83,105)
IS-24	NA	Vegetation Control	($212,357)	$0	($212,357)
IS-25	NA	Non-Recurring Transactions	($725,985)	$0	($725,985)
IS-28	NA	Supplemental Call Center	($489,252)	$0	($489,252)

[1] Direct Exhibits of Jeff Hilton, Direct Exhibit JH-2, line 5, columns 3-5, and Direct Testimony of Don Malone, p. 7, lines 18-21 and p. 8, lines 1-14, including Table 4, below.
[2] Application, Doc. 18, Part 2, MFR Schedule B-4, and Direct Testimony of Phillip B. Gillam, Doc. 21, p. 20, lines 14-23.
[3] Direct Testimony of Don Malone, p. 21, lines 5-23, and p. 22, lines 1-11, below.
[4] Application, Doc. 18, Part 3, filed January 25, 2024, MFR Schedule C-11.

MODIFIED BALANCE SHEET APPROACH

Q. What methodology is used to determine WCA and CAOL?

A. In Order No. 7 of Docket No. 84-199-U, the Commission directed Staff to use the Modified Balance Sheet Approach ("MBSA"), either in the absence of a lead-lag study or as a check on a lead-lag study filed by a utility.[5] Since that time, Staff has utilized the MBSA to determine WCA and CAOL with continued acceptance by the Commission. In accordance with the Commission's directive, I used the MBSA and its embodied principles to determine the Company's WCA and CAOL amounts. SUA also used the MBSA in developing its recommended WCA and CAOL.

Q. What is the MBSA methodology?

A. The MBSA requires that jurisdictional assets, other than plant assets, that are not interest bearing, are necessary in providing utility service, and are not considered elsewhere in the cost of service, to be included in a utility's rate base as WCA. Additionally, all CAOL that are a source of funds to the utility should be included in the Company's capital structure at their appropriate costs. The MBSA recognizes two basic facts: (1) a utility has investments in assets other than plant which are necessary to provide utility service and on which a return should be allowed and (2) a utility has sources of funds, other than equity and long-term debt, which should be included in the capital structure.

[5] *See* Order No. 7, Docket No. 84-199-U, Doc. 148, pp. 7-17.

Q. Why is it appropriate to include all liabilities in the capital structure?

A. The rationale for including liabilities in the capital structure is that all liabilities are sources of funds used to finance the assets of a company. This methodology is based on the basic theory of fungibility. Because liabilities represent sources of funds and because funds, by definition, are fungible (i.e., the distinction cannot be made as to which source is financing a particular asset), zero-cost liabilities should be placed in the capital structure along with all other funding sources.

The Fungibility Principle has been repeatedly recognized by the Commission as reasonable and proper for ratemaking.[6]

WORKING CAPITAL ASSETS

Q. Would you please explain the methodology SUA used to calculate its *pro forma* WCA in the amount of $118,781,180 in its Application?

A. Yes. SUA used seven months of actual WCA balances, beginning with December 31, 2022, along with the end of each of the first six months of 2023, and projected the remaining six months to calculate WCA 13-month average account balances ending December 31, 2023. SUA then adjusted its 13-month average WCA balances to representative balances in accordance with the MBSA methodology.[7]

Q. Please explain your Adjustments RB-10 and RB-11 that calculate WCA to be included in rate base.

A. To compute my recommended level of WCA to be included in rate base, I first computed a 13-month average of each WCA general ledger account using the 13

[6] Order No. 7, Docket No. 84-199-U, Doc. 148, pp.10 and 44 – 45.
[7] Direct Testimony of Phillip B. Gillam, Doc. 21, p. 18, lines 13-22.

months' balances ending December 31, 2023. As a result, my Adjustment RB-11 increases the test year WCA balances by $46,858,397. Next, I examined each potential WCA account to determine its proper inclusion or exclusion from WCA and removed accounts that do not qualify as WCA. My Adjustment RB-10 decreases WCA by $294,973,140. These two adjustments result in *pro forma* WCA in the amount of $95,745,409[8] as shown above in Table 1, above. My recommended level of *pro forma* WCA is based on actual test year balances, whereas the Company's WCA is based on projected test year balances which are greater than the actual balances used in my calculation.

Q. What specific adjustments did you make in your Adjustment RB-11 to the WCA 13-month average account balances to calculate your recommended level of WCA?

A. To calculate my recommended level of WCA, I made the following adjustments to the 13-month WCA average balances ending December 31, 2023:

TABLE 4
Staff Adjustments to the 13-Month Average WCA Balances

Remove gas costs recovered elsewhere	($242,089,743)
Remove excess ADIT included in capital structure	($25,822,703)
Remove balances related to deferred regulatory assets	($6,918,553)
Remove cash interest bearing accounts	($18,745,556)
Remove accounts not representative of a normal balance	($990,034)
Remove WNA rider balances	($746,963)
Remove clearing account balances	$340,412
Total Adjustments to the 13-Month Average WCA Balances	($294,973,140)

[8] Direct Exhibits of Jeff Hilton, Direct Exhibit JH-2, line 5, columns 3-5.

Q. Did you make any adjustments to the 13-month WCA average balances that were also made by the Company?

A. Yes. Although my adjustments differ in amount due to the use of different test years (partially projected vs. actual), I agree with the Company's adjustments to remove storage gas and unrecovered purchased gas costs totaling ($244,653,200). These gas accounts are handled through the Company's Asset Management Agreement and are recovered through the Company's Cost of Gas Rider. The Company also eliminated its deferred regulatory accounts and excess ADIT totaling ($33,002,255) which are accounted for in the Company's capital structure, riders, and amortization of deferred amounts. These adjustments total ($277,655,455), as shown in Table 1, above, as Adjustment RB-10.

I made similar adjustments as the Company totaling ($274,830,999). First was to remove storage gas and unrecovered purchased gas costs totaling ($242,089,743). Next, excess ADIT of ($25,822,703) and deferred regulatory assets of ($6,918,553), as shown in Table 4, above, were removed in a manner similar to the Company's adjustments but based on actual WCA test year balances as opposed to the Company's adjustments of ($277,655,455) which were based on partially projected test year balances.

Q. Did you make any additional WCA adjustments that the Company did not comprehend in their calculated WCA?

A. Yes. To calculate my level of WCA I made additional adjustments, as shown in Table 4, above, that the Company did not include, beginning with the removal of

cash and cash investments in the amount of ($18,745,556) which are earning a return, or interest, elsewhere as cash investments.

Next, I removed accounts not representative of a normal balance in the amount of ($990,034). This amount consisted of ($530,748) of a FERC Account 143 - Other Accounts Receivable balance that included a $360,303 liability balance with no activity and ($891,051) of accounts receivables considered not collectable. Based on my examination of prepayment amounts, I also removed ($68,801) of Prepaid Postage and Prepaid General Maintenance accounts that had no activity from FERC Sub-Accounts 165.015 and 165.017, respectively. Finally, I eliminated ($390,485) of Miscellaneous Deferred Revenues from FERC Account 186.0 that has had no activity in the test year and which dates back to claims originating from CenterPoint Energy Resources Corp. ("CERC") in 2016.

Next, I removed accrued rider revenues related to the Company's weather normalization rider ("WNA") of ($746,963) from FERC Account 173.0 - Accrued Utility Revenues that was not representative of a normal balance.

Finally, I removed clearing account balances in the amount of $340,412 consisting of FERC Account 163.0 - Stores Expense Undistributed in the amount of ($485,440) and an over-applied clearing account in FERC Account 184.0 – Clearing Accounts in the amount of $825,852 for an adjustment totaling $340,412. These clearing accounts are temporary in nature and included elsewhere in the cost of service and should have a zero balance.

These additional adjustments totaling ($20,142,141) have been removed from my WCA.

Q. What are the primary differences between your calculated WCA and the Company's WCA adjustment?

A. The difference between SUA's partially projected test year and my adjustment based on actual WCA test year balances accounted for approximately $5.7 million of the difference between SUA's and my 13-month average WCA amounts. In addition, the difference between SUA's adjustments to its 13-month average and mine are $17.3 million, which is attributed primarily to my exclusion of cash and cash investments that are earning a return elsewhere in the cost of service.

Q. Would you please summarize your *pro forma* WCA?

A. Staff's *pro forma* WCA is calculated based on actual test year balances ending December 31, 2023, resulting in *pro forma* WCA of $95,745,409, as shown above in Table 1, which is $23,035,771 less than SUA's requested amount of $118,781,180.

CURRENT, ACCRUED AND OTHER LIABILITIES

Q. What was SUA's calculated level of CAOL in its Application?

A. In its Application, SUA calculated CAOL at the Southern Colorado HoldCo, LLC ("SCHC") level based on a partially projected test year in the amount of $142,888,176 and included this amount as a zero-cost source of capital in its capital structure. SUA adjusted its partially projected test year-end balances by $13,320,547 to its 13-month average balances consisting of seven months of actual balances and six months of projections. SUA then adjusted its partially

projected test year 13-month average CAOL balances by $(137,879,970) to its requested *pro forma* level.[9]

Q. Please discuss your adjustments to calculate CAOL and how your adjustments compare to the Company's CAOL adjustments and amounts.

A. My adjustments to CAOL are based on the 13-month averages of actual balances at the Arkansas operating Company level ending December 31, 2023. Applying my adjustment of $47,573,863 to the actual test year balances results in a 13-month average CAOL balance of $223,595,739, which is $57,172.407 less than SUA's 13-month average CAOL balance.

Next, I examined the 13-month average balance for each account to determine if it is a representative balance and if it was properly included in CAOL, adjusting any account that was not representative or improperly included in CAOL. The component amounts of Staff's adjustment to the 13-month average CAOL balance are shown in Table 5, below.

TABLE 5
Staff Adjustments to the 13-Month Average CAOL Balances

Remove accumulated deferred income taxes (ADIT) *	$28,268,540
Remove interest bearing accounts *	($5,933,551)
Remove asset retirement obligations *	($2,397,667)
Remove regulated liabilities *	($120,374,003)
Amounts provided for in cost of service elsewhere *	($12,498,930)
Remove zero balance asset account	$495,319
Adjust interest payable	$3,220,056
Adjust dividends payable	$8,068,493
Total Adjustment to the 13-month average CAOL balances	($101,151,743)

* Staff's adjustments which are consistent with SUA's but differ in amount.

[9] Application, Revised Schedule D-6.1, Doc. No. 60, PDF p. 21.

My total adjustments differ from the Company's adjustments to the 13-month average balance of ($137,879,970) by $36,728,227 primarily as a result of the Company basing its adjustments on a partially projected test year at the SCHC level in its Application.

Q. Company and Staff made similar adjustments to the test year CAOL balances to determine the 13-month average balances and then made adjustments to the 13-month average balances to calculate *pro forma* year CAOL. Did you make any adjustments to the 13-month average balances that are similar to those made by the Company?

A. Yes. My adjustments to remove interest bearing accounts, the asset retirement obligation, ADIT, regulatory liabilities, and amounts provided for elsewhere in the capital structure in the total amount of $112,935,611,[10] as a decrease to CAOL, are similar to the Company's adjustments except that my adjustments are based on actual CAOL balances.

Q. Did you include any adjustments that the Company did not comprehend or differed from the Company's CAOL adjustment?

A. Yes. In my calculation of *pro forma* CAOL I included three adjustments not comprehended by the Company. The first adjustment I included was to remove an asset balance in FERC Account 228.3 - Accumulate Provision for Pensions and Benefits in the amount of $489,313 that had little to no activity and had a zero balance for the last quarter of the test year.

[10] See the specific adjustments and amounts totaling $112,935,611, each indicated by an asterisk in Table 5, above, decrease to the 13-month average CAOL balances.

Next, interest payable in the amount of $3,237,945 was provided by Staff witness Dan Daves, which I included as a component of my CAOL. Staff's interest payable is $3,334,933 less than the Company's interest payable amount of $6,572,878 as the Company's interest payable is based on partially projected test year balances and, as discussed by Staff witness Daves, Staff's is a calculated amount.

Third, I calculated and included dividends payable in the amount of $8,068,493 based on SUA's dividend payout to its parent and the number of lag days between the date the dividends were declared and the date paid. The Company did not recognize dividends payable in its level of CAOL.

These adjustments were not comprehended by SUA and increase my calculated level of CAOL by $11,783,868.

Q. What level of CAOL do you recommend and how does it compare to SUA's CAOL?

A. I recommend a CAOL balance of $122,443,996, which I provided to Staff witness Dan Daves to include in the capital structure.[11] My level of CAOL based on actual SUA level test year balances is $20,444,180 less than SUA's CAOL of $142,888,176, which was calculated using a partially projected test year based on seven months of actual balances and six months of projected liability account balances at the SCHC level.

[11] Direct Exhibits of Dan Daves, Direct Exhibit DD-2.

ACCUMULATED DEFERRED INCOME TAXES

Q. What level of *pro forma* ADIT did the Company request in its Application?

A. In its Application, the Company provided *pro forma* ADIT in the amount of $20,938,226, a net asset balance.[12]

Q. It is unusual for a public utility Company to report ADIT with a net asset balance due to the use of accelerated tax deprecation. Why does SUA have a net asset ADIT recorded in its general ledger?

A. When SUA purchased the gas distribution system jurisdictional to Arkansas, it purchased assets as opposed to purchasing company stock. In the case of an asset purchase, as opposed to a stock purchase, the ADIT associated with the assets before the sale does not transfer with the assets. Therefore, ADIT was reset to zero. In future periods with the use of accelerated depreciation methods for tax purposes, the ADIT will turn around to a net ADIT liability as tax depreciation exceeds book depreciation, creating a deferred tax liability that exceeds the current deferred tax asset in future periods.

Q. How did you treat the ADIT asset with regard to the capital structure?

A. The MBSA requires the inclusion of all sources of funds in the capital structure at their actual cost. ADIT net assets are not a zero-cost source of funds available to the Company to fund its rate base; therefore, inclusion in the capital structure would not be appropriate. I excluded the ADIT net tax assets from the capital structure as did SUA in its Application.[13]

[12] Application, Doc. 18, Part 3, MFR Schedule C-10, line 7, column 4.
[13] Direct Testimony of Phillip B. Gillam, Doc. 21, p. 35, lines 4-12.

Q. Did the Company revalue its state ADIT to recognize the reduction in state corporate income tax rates from 5.3% effective January 1, 2023, to the current 4.8% effective January 1, 2024?

A. Yes. SUA's state ADIT is valued at the current 4.8% corporation tax rate. However, on June 19, 2024, Governor Sanders signed into law a reduced 4.3% corporation income tax rate, effective January 1, 2024. The Company will revalue its *pro forma* ADIT in its rebuttal testimony to reflect the revised 4.3% tax rate.

Q. Would you please summarize your recommended ADIT to include in the capital structure?

A. Yes. Since ADIT net assets are not a source of funds to the Company, I recommend that zero ADIT be included in the capital structure. I provided Staff witness Dan Daves ADIT of $0 to include in the capital structure. I will continue to monitor the *pro forma* year components of ADIT and will update ADIT in Surrebuttal Testimony if ADIT is found to have turned around to a net liability.

EXCESS DEFERRED INCOME TAXES

Q. Is Excess Deferred Income Tax ("EDIT") included in the capital structure at zero cost?

A. Yes. EDIT is properly included in the capital structure at zero cost. The Company requested and received a Private Letter Ruling ("PLR") from the Internal Revenue Service ("IRS") to determine whether the transferred EDIT should be treated as "protected" or "unprotected" by the IRS normalization rules. The PRL confirmed that the EDIT should remain protected, and the balance should continue to be

returned to customers using the average rate assumption method ("ARAM").[14] The Company included *pro forma* EDIT of $65,878,004, net of a cost of removal ("COR") deferred income tax asset in its capital structure at zero cost in its Application.[15]

Q. Would you briefly describe what EDIT is and how EDIT originated as a zero-cost component of the capital structure?

A. The Tax Cut and Jobs Act of 2017 ("TCJA") was signed into law on December 22, 2017, and reduced the federal corporate income tax rate from 35% to 21%. ADIT represents the amount of income taxes collected through rates but not yet paid to the Department of the Treasury. Because ADIT represents a liability for taxes collected from customers but not yet paid, the change in income tax rates required a revaluation of the Company's net deferred tax liabilities at the 21% income tax rate rather than the 35% income tax rate. This revaluation has resulted in "excess" deferred tax balances (viz., the difference between the 35% rate and the 21% rate) which are grossed up for taxes and recorded as a regulatory liability and will be refunded to taxpayers or have already been refunded to taxpayers for those amounts not protected by the IRS's normalization rules. The Protected Federal EDIT, which has not yet been refunded, is included in the capital structure at zero cost.

State corporation tax rate reductions have the same effect on state ADIT as discussed above, creating excess state ADIT that should be refunded to

[14] Direct Testimony of Paul Schulte, Doc. 27, p. 3, lines 1-15.
[15] Revised Application, Doc. 60, MFR Schedule D-1.3 Holdco, line 5, column 7.

customers. However, excess state ADIT is not governed by federal tax normalization rules so state excess deferred income taxes are not "protected" and can be refunded or collected without regard to prescribed time periods. In other words, state excess deferred income taxes are unprotected and can be refunded or collected over any period of time decided by this Commission.

Q. Did SUA calculate state EDIT related to the income tax reduction from 5.3% in 2023 to 4.3% effective January 1, 2024?

A. Yes. The state corporate income tax reductions resulted in *pro forma* state unprotected EDIT in the amount of $140,337. However, since the Company's state ADIT is a net asset, the state EDIT from the income tax rate reduction resulted in a collection as opposed to a refund which is discussed later in my testimony.

Cost of Removal - Deferred Tax Asset

Q. You stated the Company adjusted its *pro forma* EDIT by a COR Deferred Income Tax Asset. Would you please describe the Deferred Income Tax Asset adjustment to EDIT?

A. Yes. SUA is relying on a PLR to another public utility which established that the cost of removal portion included in the depreciation rates is not "protected" under IRS normalization rules.[16] CERC previously included the COR portion of depreciation expense in the calculation of "protected" liabilities to be amortized and returned to customers through rates. The PLR provided that the COR portion of book verses tax excess depreciation timing differences needs to be separated

[16] Direct Testimony of Paul Schulte, Doc. 27, p. 4, lines 1-4.

from the original netted EDIT liability and from the depreciation expense used in the ARAM calculation and included as an "unprotected" deferred tax asset.[17] A deferred tax asset ("DTA"), as opposed to a deferred tax liability, is an item on a company's balance sheet that will reduce its taxable income in the future. An excess DTA ("EDTA") resulted from a decrease in tax rates, which becomes an amount to be collected from customers.

Q. What is the value of the COR related EDTA recorded on SUA's books?

SUA recorded the COR related unprotected deferred tax asset of $25,843,915 on its books, which offsets the protected deferred tax liability of ($82,590,213) recorded on SUA's books resulting in a net amount of $56,746,298 to be returned to customers. [18] The Company estimates it will take 48 years to return the $57 million to customers.[19]

Q. I agree with SUA that the EDTA is unprotected, and therefore not required to be collected over a prescribed period of time. What period of time did the Company propose the EDTA be collected?

A. The Company proposed to collect the EDTA dollar for dollar as the protected EDIT is refunded to customers. Under this proposal customers would not see a net refund until the unprotected EDTA is fully extinguished in 2037, or approximately 13 years.

[17] *Id*. at p. 4, lines 1-21.
[18] *Id*. at p. 6, lines 1-4.
[19] *Id.* at p. 6, line 12.

Q. What period of time do you recommend the unprotected EDTA be collected from customers?

A. I recommend that the unprotected EDTA be collected over the same period of time as the refunds to ratepayers under ARAM. The influx of capital into our economy through refunds to customers, due to over collection of income taxes, was an intended stimulus to our economy as a result of the TCJA. I do not find it appropriate to delay the intended stimulus to our economy by reducing the refunds of over collected income taxes to zero for 13 years. In addition, my proposed collection of the EDTA over the same approximately 48 years of refunds of EDIT would be more balanced than the proposal by SUA to completely stop the refunds for the next 13 years. My proposal would allow the Company to collect its EDTA at a rate of approximately $532,000 annually while still issuing refunds through the newly established utility rates.

Q. Did SUA refund Protected Federal EDIT using the ARAM methodology since the purchase of the Arkansas assets?

A. Yes. SUA continued to refund protected federal EDIT using the ARAM methodology

Q. What is Staff's recommended level of EDIT to include in SUA's capital structure?

A. I recommend net protected federal *pro forma* EDIT in the amount of $56,187,785 be included in the capital structure. My recommended EDIT is $9,690,219 less than what the Company included in its capital structure based on a partially projected test year in its Application. I provided my recommended level of *pro*

forma EDIT to Staff witness Dan Daves to include in his capital structure. I will continue to monitor and will update my recommended level of EDIT for the *pro forma* year in Surrebuttal Testimony.

INCOME TAX EXPENSE

Q. Would you please discuss Staff's recommended Income Tax Adjustment IS-22?

A. Staff's Income Tax Adjustment IS-22 is based on the adjusted non-gas operating income, including interest expense calculated on rate base using Staff's updated cost of capital. The Company's adjusted operating income including interest payable created a net operating loss before taxes. Applying the current federal income tax rate of 21% and state tax rate of 4.3% and eliminating deferred taxes of $250,511 resulted in a *pro forma* year federal and state income tax benefit of ($3,777,332) before amortization of state unprotected excess ADIT, federal protected excess ADIT, and cost of removal excess deferred tax asset. Because I recommend a normalized level of *pro forma* income taxes, I excluded test year deferred income taxes.

As discussed above the amortization of excess federal protected EDIT and unprotected cost of removal related excess deferred tax asset, or Net EDIT, results in a net refund to ratepayers in the amount of ($1,481,970). Discussed later in my testimony and also included is the amortization of state unprotected EDIT collection in the amount of $28,067. In order to facilitate the refund of Net EDIT and collection of state EDIT, these two amounts have been included in the income tax adjustment as an additional decrease to income tax expense resulting in a total

income tax amount of ($5,231,235). My adjustment for federal EDIT refunds decreases test year income tax expense by $2,037,800, the amount of excess protected ADIT annual amortization in recognition of the TCJA requirement to use the ARAM methodology. This amount is offset by the amortization of the COR DTA amortized over the remaining 46 years of the EDIT life, resulting in $555,830 of COR EDTA collections as an offset to the EDIT refunds, or $1,481,970 annually.

Including the current year total income tax benefit of ($3,777,332), net EDIT refunds of ($1,481,970) and state EDIT collections of $28,067 results in a total *pro forma* year net income tax benefit of ($5,231,235). The Company calculated a *pro forma* year income tax expense of $1,626,461 based on their calculated net operating income.[20]

Q. Did the Company include state EDIT resulting from the decrease in state income tax rates from 5.3% in 2023 to the 4.3% effective rate for 2024?[21]

A. Yes. The Company calculated state EDIT resulting from the recent decrease in corporation income tax rates. However, as discussed above, the state ADIT is a net asset and the calculated state unprotected EDIT is a Company benefit as opposed to a refund to customers in the amount of $140,337 as provided in response to Staff data request APSC-116.[22] I have included this amount in Staff's income tax calculation discussed above and recommend to flow it through as a

[20] Direct Testimony of Phillip B. Gillam, Doc. 21, p. 31, lines 14-17.
[21] The Arkansas 94th General Assembly, Second Extraordinary Session of 2024, passed House Bill 1001 that was signed into law on June 20, 2024, reducing the Arkansas corporate tax rate from 4.8% to 4.3%, effective retroactively to January 1, 2024.
[22] Direct Exhibits of Don Malone, Direct Exhibit DM-1.

collection over a five-year period allowing the Company to collect this amount between rate cases.

Q. Would you please summarize Staff's *pro forma* Income Tax Expense recommendation?

A. Staff's recommended Income Tax Expense reflects the federal income tax rate of 21% and the *pro forma* Arkansas state income tax rate of 4.3% resulting in income tax benefit of ($3,111,573) and ($665,759), respectively, or total normalized *pro forma* income tax benefit of ($3,777,332), which is $5,403,793 less than the Company's income tax expense of $1,626,461 in its Application. Flowing through the state EDIT collection of 28,067 and net federal protected EDIT refund of ($1,481,970) results in total income tax benefit of ($5,231,235).

OTHER RATE BASE ADJUSTMENT

Rebranding Expenditures

Q. Staff Adjustment RB-15 Rebranding Expenditures Capitalized removes $379,968 of plant-in-service expenditures. What are rebranding expenditures and why are you recommending they be removed from plant-in-service?

A. Rebranding expenditures are costs related to replacing the previous Company's logo on signs, equipment, buildings, and office products to SUA's logo. Rebranding expenditures are related to the purchase of CERC's assets and should not be the responsibility of ratepayers to fund. In response to APSC-092, the Company reported that in the test year it had capitalized rebranding expenditures

in the amount of $379,968.[23] I provided this amount to Staff witness Michael Pitts for inclusion in his PIS and depreciation expense adjustments which he discusses in his Direct Testimony.

EXPENSE ADJUSTMENTS

Donations and Other Expenditures

Q. As shown in Table 3, above, please describe your Adjustment IS-23 to remove Donations and Other Expenditures not Appropriate for Ratemaking.

A. Adjustment IS-23 removes donations and expenditures not appropriate or necessary to provide utility service such as chamber of commerce dues and donations to various charitable organizations and events.[24] My Adjustment IS-23 removes donations and other expenditures not appropriate or necessary to provide utility service in the amount of $83,105.

Q. What is your recommendation concerning donations and other expenditures?

A. I recommend the Commission disallow donations and other expenditures not appropriate or necessary to provide utility service in the amount of $83,105.

Vegetation Control Expense

Q. Would you please discuss your Adjustment IS-24 to remove $212,357 from test year Vegetation Control expense?

A. In the Company's response to Staff Data Request APSC-062 and APSC-034, the Company provided that no vegetation control expense had been incurred during

[23] Direct Exhibits of Don Malone, Direct Exhibit DM-2.
[24] Direct Exhibits of Don Malone, Direct Exhibit DM-3.

the first quarter of the *pro forma* year, but that $1,060,838 was incurred during the test year, and $636,125 for the 12 months ended December 31, 2022.[25] Since the Company had not incurred vegetation control expense for the first quarter of 2024, I averaged the test year and preceding year which resulted in *pro forma* year vegetation control expense of $848,482.

Q. What is your recommendation for Vegetation Control expense?

A. I recommend the Commission allow the Company *pro forma* vegetation control expense of $848,482 to be included in base rates.

Non-Recurring Expenditures

Q. What test year expenditures did you identify and remove in your Adjustment IS-25 Non-Recurring Expenditures?

A. During the analysis of account transactions three expenditures were identified as non-recurring and removed from the test year. The first was $32,596 of expense transactions related to legal expenses resulting from SUA's billing errors and subsequent class action lawsuit. The second was $165,824 of Transition Service Agreement expense transactions identified and removed from the test year. The third was an expense transaction removed from the cost of service in the amount of $527,565 that was paid during the test year to avoid a possible civil action that would likely have resulted in an unfavorable outcome for SUA. Expense Adjustment IS-25 removed non-recurring expenditures totaling $725,985 from the test year ending December 2023.

[25] Direct Exhibits of Don Malone, Direct Exhibit DM-4 and Direct Exhibit DM-5.

Q. What do you recommend regarding Non-Recurring Expenditures?

A. I recommend the Commission disallow $725,985 of Non-recurring Expenditures from the test year ended December 31, 2023.

Call Center Expense

Q. Would you please explain your reduction to Call Center Expense in the amount of 489,252 shown as Adjustment IS-28 in Table 3, above?

A. In my review of expense transactions a contract call center vendor was examined. The Company's response to Staff data request APSC-115 explained that due to the increased demands on the Company's call center during the conversion from the transition service agreement ("TSA"), SUA contracted with a contract call center to reduce the long wait times being experienced by SUA customers. This vendor relationship was maintained throughout the test year but was terminated in the *pro forma* year as call demand and wait times decreased.[26] I removed the test year costs associated with the contract call center since these were temporary in nature during the conversion from CERC to SUA and the contract was terminated during the pro *forma* year.

Q. What is your recommendation with regard to Call Center Expense?

A. I recommend the Commission accept my Adjustment IS-28 removing test year contract Call Center Expense in the amount of $489,252 as a non-recurring temporary expense incurred to decrease the customer call wait times during the conversion from the CERC call center to SUA's call center operations.[27]

[26] Direct Exhibits of Don Malone, Direct Exhibit DM-6.
[27] *Id.*

Q. Does this conclude your Direct Testimony?

A. Yes, it does.

CERTIFICATE OF SERVICE

I, Joshua A. Baxter, hereby certify that a copy of the foregoing has been served on all parties of record on July 10, 2024, via the Arkansas Public Service Commission's Electronic Filing System in accordance with the Commission's *Rules of Practice and Procedure*.

/s/ JOSHUA A. BAXTER
Joshua A. Baxter

APSC FILED Time: 7/10/2024 11:55:31 AM: Recvd 7/10/2024 11:55:10 AM: Docket 23-079-U-Doc. 120

BEFORE THE
ARKANSAS PUBLIC SERVICE COMMISSION

IN THE MATTER OF THE APPLICATION OF SUMMIT UTILITIES ARKANSAS, INC. FOR A GENERAL CHANGE OR MODIFICATION IN ITS RATES, CHARGES AND TARIFFS	))))	DOCKET NO. 23-079-U

REDACTED DIRECT EXHIBITS

OF

DON MALONE, CPA, CGMA
SENIOR PUBLIC UTILITY AUDITOR
GAS AND WATER UTILITY SECTION

ON BEHALF OF THE GENERAL STAFF OF
THE ARKANSAS PUBLIC SERVICE COMMISSION

JULY 10, 2024

DIRECT EXHIBIT DM-1

ARKANSAS PUBLIC SERVICE COMMISSION
APSC 23-079-U
APSC FILED Time: 7/10/2024 11:55:31 AM: Recvd 7/10/2024 11:55:10 AM: Docket 23-079-U-Doc. 120
2023 SUA RATE CASE

REQUEST NO.: APSC-116

COMPANY NAME: SUMMIT UTILITIES ARKANSAS

DATE RECEIVED: 6/20/2024

DATE DUE: 7/5/2024

EXTENSION DATE:

INFORMATION REQUESTED:
Please provide State EDIT for the pro forma year ended December 31, 2024. As of June 19, 2024 the Governor of the State of Arkansas signed into law a State Income Tax Rate Reduction which reduced the corporate tax rate from 4.8% to 4.3%.

REQUESTED BY: ARKANSAS PUBLIC SERVICE COMMISSION - DON MALONE

RESPONSE:
State EDIT for the pro forma year ended December 31, 2024 is $140,337. This is reflective of the new reduced corporate tax rate of 4.3%

SPONSOR:
Phillip Gillam, Paul Schulte

RESPONSIVE DOCUMENTS:
None

The foregoing response to the above information request is accurate and complete, and contains no material misrepresentations or omissions based upon present facts known to the undersigned. The undersigned agrees to immediately inform the Requestor if any matters are discovered which would materially affect the accuracy or completeness of the information provided in response to the above information request.

/s/ Brooke South Parsons
Signature of Company Representative

DATE PROVIDED: JULY 05, 2024

APSC FILED Time: 7/10/2024 11:55:31 AM: Recvd 7/10/2024 11:55:10 AM: Docket 23-079-U-Doc. 120

DIRECT EXHIBIT DM-2

ARKANSAS PUBLIC SERVICE COMMISSION
APSC 23-079-U
APSC FILED Time: 7/10/2024 11:55:31 AM: Recvd 7/10/2024 11:55:10 AM: Docket 23-079-U-Doc. 120
2023 SUA RATE CASE

REQUEST NO.: APSC-092

COMPANY NAME: SUMMIT UTILITIES ARKANSAS

DATE RECEIVED: 4/22/2024

DATE DUE: 5/7/2024

EXTENSION DATE:

INFORMATION REQUESTED:
Please provide the total Rebranding Expenditures by FERC account (both capital and expense), by month, for the 12 months ended December 31, 2022 and 2023. Rebranding expenditures include but are not limited to new Summit Utility signs, vehicle sings and decals, equipment signs and decals, cost of development of logos and signs, building signs and decals to replace CenterPoint Utilities signs and logos.

REQUESTED BY: ARKANSAS PUBLIC SERVICE COMMISSION - DON MALONE

RESPONSE:
The Company only has capital rebranding expenditures costs associated with rebranding CenterPoint Energy Arkansas Gas to Summit Utilities Arkansas, Inc.

The attached file APSC-092.1 Rebranding Expenditures lists monthly rebranding expenditures.

SPONSOR:
Sabrina Bradford, Ann Byrd

RESPONSIVE DOCUMENTS:
APSC-092.1 Rebranding Expenditures.xlsx

The foregoing response to the above information request is accurate and complete, and contains no material misrepresentations or omissions based upon present facts known to the undersigned. The undersigned agrees to immediately inform the Requestor if any matters are discovered which would materially affect the accuracy or completeness of the information provided in response to the above information request.

/s/ Brooke South Parsons
Signature of Company Representative

DATE PROVIDED: MAY 07, 2024

APSC FILED Time: 7/10/2024 11:55:31 AM: Recvd 7/10/2024 11:55:10 AM: Docket 23-079-U-Doc. 120

Summit Utilities Arkansas, Inc.
Docket No: AR 23-079-U
Data Request: APSC-092
Rebranding capital costs for SUA - Arkansas by month

Row Labels	SUA Rebranding Amount
202112	36,295.64
202201	13,979.54
202202	41,040.63
202203	75,011.67
202204	16,298.59
202205	99,174.47
202206	9,268.66
202207	(2,445.14)
202210	28,791.26
202211	20,281.69
202212	1,163.97
202301	24,209.53
202302	3,711.82
202303	-
202304	13,186.15
Grand Total	379,968.48

DIRECT EXHIBIT DM-3

Summit Utilities Arkansas Inc. **APSC-067 (prepared from the response to APSC-025)** **IS-23**
Donations and Other Expenditures not Appropriate or Necessary to Provide Utility Service
Docket No. 23-079-U

Payee	Amount	FERC	Expenditure Description	GL	Vendor ID	Date	DocumentNo	Expenditures not Necessary to Provide Utility Service			
								FERC Account Number			
								921.00	887.00	874.00	Total
WAMPUS CAT BOOSTER CLUB INC	483.25	9210	Donation	650080	1201204450	11/15/2023	1900017304	483.25			
ARKANSAS COUNTY 4-H COUNCIL	289.95	9210	Donation	650080	1201204486	8/2/2023	1900011543	289.95			
MARIANNA REGIONAL CHAMBER OF COMMER	55.29	9210	Club Membership Dues	650070	1201613446	6/21/2023	1900009212	55.29			
BRINKLEY CHAMBER OF COMMERCE	76.79	9210	Club Membership Dues	650070	1201209801	3/16/2023	1900008674	76.79			
DARDANELLE CHAMBER OF COMMERCE	92.15	9210	Club Membership Dues	650070	1201209801	3/16/2023	1900004492	92.15			
HEMPSTEAD COUNTY ECONOMIC	600.00	9210	Other Expenses - Annual Investmen	650350	1201206290	9/5/2023	1900013378	600.00			
Keep Little Rock Beautiful	307.15	9210	Donation	650080	1201612644	2/6/2023	1900002054	307.15			
EARLE AREA CHAMBER OF COMMERCE	92.14	9210	Club Membership Dues	650070	1201613335	5/19/2023	1900007681	92.14			
NORTHEAST ARKANSAS HOME	338.27	9210	Club Membership Dues	650070	1201206821	10/19/2023	1900015866	338.27			
CAMDEN AREA CHAMBER OF COMMERCE	966.50	9210	Club Membership Dues	650070	1201206235	11/15/2023	1900017264	966.50			
MALVERN HOT SPRINGS COUNTY CHAMBER	1,200.00	9210	Club Membership Dues	650070	1201605683	11/28/2023	1900018075	1,200.00			
SEARCY REGIONAL CHAMBER OF COMMERCE	860.02	9210	Club Membership Dues	650070	1201613076	5/2/2023	1900006700 ($1,1	860.02			
JONESBORO REGIONAL CHAMBER	1,320.75	9210	Club Membership Dues	650070	1201206810	3/16/2023	1900004460	1,320.75			
SEARCY REGIONAL CHAMBER OF COMMERCE	153.57	9210	Donation	650080	1201613076	5/2/2023	1900006708	153.57			
COGENCY GLOBAL INC	147.43	9210	Contractor Costs	630010	1201613191	4/13/2023	1900005753	147.43			
THE ARKANSAS ENVIRONMENTAL EDUCATIO	724.80	9210	Donation	650080	1201613218	9/30/2023	100705839	724.80			
THE ARKANSAS ENVIRONMENTAL EDUCATIO	25.20	9210	Donation	650080	1201613218	9/30/2023	100705839	25.20			
CONWAY AREA CHAMBER OF COMMERCE	1,597.18	9210	Club Membership Dues	650070	1201611909	3/16/2023 ; 5/1(	1900004487 ($1,6	1,597.18			
ARKANSAS STATE CHAMBER OF COMMERCE	10,000.00	9210	Club Membership Dues	650070	1201209254	2/22/2023	1900003311	10,000.00			
SOUTHERN GAS ASSOCIATION	1,755.00	9210	Marketing & Advertising	650100	1201613816	6/26/2023	1900009359	1,755.00			
ARKANSAS PBS FOUNDATION	232.08	9210	Marketing & Advertising	650100	1201615050	8/22/2023	1900012521	232.08			
ARKANSAS PBS FOUNDATION	7.92	9210	Marketing & Advertising	650100	1201615050	8/22/2023	1900012521	7.92			
PERPETUAL CORPORATION	232.08	9210	Marketing & Advertising	650100	1201616322	11/8/2023	1900016910	232.08			
PERPETUAL CORPORATION	7.92	9210	Marketing & Advertising	650100	1201616322	11/8/2023	1900016910	7.92			
PERPETUAL CORPORATION	72.52	9210	Marketing & Advertising	650100	1201616322	11/8/2023	1900016971	72.52			
PERPETUAL CORPORATION	2.48	9210	Marketing & Advertising	650100	1201616322	11/8/2023	1900016971	2.48			
Holland Girls	309.28	9210	Employee Expenses-Awards and Gif	640160	1201617039	10/2/2023	1900014812	309.28			
Pulaski County Sheriffs Prevention	483.25	9210	Donation	650080	1201617040	9/29/2023	1900014780	483.25			
Watershed Human and Community	1,933.00	9210	Donation	650080	1201617256	10/10/2023	1900015182	1,933.00			
Weekend Market at Chenal	580.20	9210	Donation	650080	1201617934	11/2/2023	1900016628	580.20			
Weekend Market at Chenal	19.80	9210	Donation	650080	1201617934	11/2/2023	1900016628	19.80			
Main Street West Memphis	483.25	9210	Donation	650080	1201617984	10/26/2023	1900016111	483.25			
United Way of Northeast Arkansas	1,594.73	9210	Donation	650080	1201618550	11/8/2023	1900016982	1,594.73			
The Little Rock Chapter of the Link	2,899.50	9210	Donation	650080	1201618927	11/8/2023	1900016903	2,899.50			
PRESCOTT-NEVADA CHAMBER OF COMMERCE	35.44	8870	Electricity	650250	1201206296	8/21/2023	1900012464		35.44		
PRESCOTT-NEVADA CHAMBER OF COMMERCE	1.23	8870	Electricity	650250	1201206296	8/21/2023	1900012464		1.23		
WAMPUS CAT BOOSTER CLUB INC	16.75	8740	Donation	650080	1201204450	11/15/2023	1900017304			16.75	
ARKANSAS COUNTY 4-H COUNCIL	10.05	8740	Donation	650080	1201204486	8/2/2023	1900011543			10.05	
DEWITT CHAMBER OF COMMERCE	500.00	8740	Donation	650080	1201205518	12/7/2023	1900018380			500.00	
MARIANNA REGIONAL CHAMBER OF COMMER	1.92	8740	Club Membership Dues	650070	1201613446	6/21/2023	1900009212			1.92	
Keep Little Rock Beautiful	10.65	8740	Donation	650080	1201612644	2/6/2023	1900002054			10.65	
BRINKLEY CHAMBER OF COMMERCE	2.66	8740	Club Membership Dues	650070	1201209801	3/16/2023	1900008674			2.66	
DARDANELLE CHAMBER OF COMMERCE	3.19	8740	Club Membership Dues	650070	1201209801	3/16/2023	1900004492			3.19	
HEART OF ARKANSAS UNITED WAY - SUMM	6,356.00	8740	Donation	650080	1201612860	3/9/2023	1900004151			6,356.00	

EARLE AREA CHAMBER OF COMMERCE	3.20	8740	Club Membership Dues	650070	1201613335	5/19/2023	1900007681			3.20
DEWITT CHAMBER OF COMMERCE	200.00	8740	Club Membership Dues	650070	1201205518	3/13/2023	1900004201			200.00
NORTHEAST ARKANSAS HOME	138.68	8740	Marketing & Advertising	650100	1201206821	8/31/2023	1900013082			138.68
NORTHEAST ARKANSAS HOME	11.73	8740	Club Membership Dues	650070	1201206821	10/19/2023	1900015866			11.73
MONTICELLO-DREW COUNTY CHAMBER OF	298.54	8740	Club Membership Dues	650070	1201206225	12/30/2022	1900003298			298.54
MARION CHAMBER OF COMMERCE	287.85	8740	Club Membership Dues	650070	1201605568	1/13/2023	1900000767			287.85
CAMDEN AREA CHAMBER OF COMMERCE	33.50	8740	Club Membership Dues	650070	1201206235	11/15/2023	1900017264			33.50
SEARCY REGIONAL CHAMBER OF COMMERCE	29.82	8740	Club Membership Dues	650070	1201613076	5/2/2023	1900006700 ($1,150)/1900006708 ($250)			29.82
LITTLE ROCK REGIONAL	346.00	8740	Donation	650080	1201611983	12/4/2023	1900018259			346.00
HEART OF ARKANSAS UNITED WAY - SUMM	1,038.00	8740	Donation	650080	1201612860	12/6/2023	1900018290			1,038.00
BENTON AREA CHAMBER OF COMMERCE	1,001.78	8740	Other Expenses	650350	1201611859	3/13/2023	1900004256			1,001.78
JONESBORO REGIONAL CHAMBER	45.79	8740	Club Membership Dues	650070	1201206810	3/16/2023	1900004460			45.79
SEARCY REGIONAL CHAMBER OF COMMERCE	5.33	8740	Donation	650080	1201613076	5/2/2023	1900006708			5.33
GOLF WITH THE BLUE	76.79	8740	Donation	650080	1201613326	5/16/2023	1900007385			76.79
GOLF WITH THE BLUE	2.66	8740	Donation	650080	1201613326	5/16/2023	1900007385			2.66
COGENCY GLOBAL INC	5.11	8740	Contractor Costs	630010	1201613191	4/13/2023	1900005753			5.11
CONWAY AREA CHAMBER OF COMMERCE	55.38	8740	Club Membership Dues	650070	1201611909	3/16/2023 ; 5/1(	1900004487 ($1,600)/ 1900007406 ($1,000)			55.38
Kevin Maxon	10.65	8740	Claims/Settlements	650120	1201613429	6/9/2023	1900008697			10.65
Renee Flesher	10.65	8740	Claims/Settlements	650120	1201613430	6/9/2023	1900008698			10.65
TOPPS	1,480.20	8740	Donation	650080	1201615464	9/14/2023	1900013884			1,480.20
Holland Girls	10.72	8740	Employee Expenses-Awards and Gif	640160	1201617039	10/2/2023	1900014812			10.72
Pulaski County Sheriffs Prevention	16.75	8740	Donation	650080	1201617040	9/29/2023	1900014780			16.75
Watershed Human and Community	67.00	8740	Donation	650080	1201617256	10/10/2023	1900015182			67.00
Watershed Human and Community	173.00	8740	Donation	650080	1201617256	12/12/2023	1900018789			173.00
Main Street West Memphis	16.75	8740	Donation	650080	1201617984	10/26/2023	1900016111			16.75
United Way of Northeast Arkansas	55.27	8740	Donation	650080	1201618550	11/8/2023	1900016982			55.27
The Little Rock Chapter of the Link	100.50	8740	Donation	650080	1201618927	11/8/2023	1900016903			100.50
Central Arkansas Firefighters	17.30	8740	Donation	650080	1201619602	12/18/2023	1900018991			17.30
Caring & Sharing Food Pantry	684.90	8740	Donation	650080	1201619802	12/19/2023	1900019067			684.90
APSC-033 Response:										
AR Summit heat fund	20,000.00	921	Donation					20,000.00		
APSC-068 Response:										
DF&A OAS - Arkansas Disaster Relief Fund	20,000.00	921	Donation					20,000.00		
							Totals	**$69,943.45**	**$36.67**	**$13,125.08**	**$83,105**

APSC FILED Time: 7/10/2024 11:55:31 AM: Recvd 7/10/2024 11:55:10 AM: Docket 23-079-U-Doc. 120

REDACTED DIRECT EXHIBIT DM-4

CONFIDENTIAL, SUBJECT TO PROTECTIVE ORDER NO. 1 ISSUED IN APSC DOCKET NO. 23-079-U

APSC FILED Time: 7/10/2024 11:55:31 AM: Recvd 7/10/2024 11:55:10 AM: Docket 23-079-U-Doc. 120

ARKANSAS PUBLIC SERVICE COMMISSION
APSC 23-079-U
2023 SUA RATE CASE

REQUEST NO.: APSC-062U

COMPANY NAME: SUMMIT UTILITIES ARKANSAS

DATE RECEIVED: 2/8/2024

DATE DUE: 5/9/2024

EXTENSION DATE:

INFORMATION REQUESTED:
1. Please provide SUA;'s vegetation control plan and budget for the test year ended 12/31/2023.

2. Please provide SUA's actual vegetation control expense, by type of vegetation control (ROW clearing, sidewall clearing, etc.), by vendor, by FERC account, by month for the test year.

3. Please provide a printout of all vegetation control invoices paid during the test year by vendor, by month.

4. Please provide vegetation control expense, by FERC, for the 12 months ended 12/31/2022 and 12/31/2021.

5. Please provide all vegetation control contracts in effect during the test year.

6. Please provide SUA;'s vegetation control plan and budget for the pro forma year ended 12/31/2024.

7. Please provide SUA's actual vegetation control expense, by type of vegetation control (ROW clearing, sidewall clearing, etc.), by vendor, by FERC account, by month for the pro forma year as available.

8. Please provide a copy of all vegetation control invoices with each monthly update for the pro forma year.

9. Please provide all vegetation control contracts in effect during the pro forma year.

REQUESTED BY: ARKANSAS PUBLIC SERVICE COMMISSION - DON MALONE

RESPONSE:
1. - 6. No update to response previously submitted in APSC-062.

7. & 8. [redacted]

9. Please see the attached contract for 2024-2025.

APSC FILED Time: 7/10/2024 11:55:31 AM: Recvd 7/10/2024 11:55:10 AM: Docket 23-079-U-Doc. 120

SPONSOR:
Teresita Trevino, Tiffany Brazle, Britney Strout

RESPONSIVE DOCUMENTS:
Confidential APSC-062U TMT ROW & Vegetation Contract 01_2024_to 12_2025.pdf

The foregoing response to the above information request is accurate and complete, and contains no material misrepresentations or omissions based upon present facts known to the undersigned. The undersigned agrees to immediately inform the Requestor if any matters are discovered which would materially affect the accuracy or completeness of the information provided in response to the above information request.

/s/ Brooke South Parsons
Signature of Company Representative

DATE PROVIDED: MAY 13, 2024

DIRECT EXHIBIT DM-5

ARKANSAS PUBLIC SERVICE COMMISSION
APSC 23-079-U
APSC FILED Time: 7/10/2024 11:55:31 AM: Recvd 7/10/2024 11:55:10 AM: Docket 23-079-U-Doc. 120
2023 SUA RATE CASE

REQUEST NO.: APSC-034U

COMPANY NAME: SUMMIT UTILITIES ARKANSAS

DATE RECEIVED: 1/25/2024

DATE DUE: 2/26/2024

EXTENSION DATE:

INFORMATION REQUESTED:

1. Please provide the cost recorded in SUA's general ledger for vegetation control and right of way clearing or right of way sidewall clearing for the 12 months ended 12/31/2021, 12/31/2022, and 12/31/2023, by FERC account.
2. Please update the response to Q.1 above when the Company updates its six months of projected data with six months of actual data for the test year.
3. Please provide all contracts with third parties for vegetation control in effect for the 12 months ended 12/31/2023. Please provide any new vegetation control contracts in effect during 2024.

REQUESTED BY: ARKANSAS PUBLIC SERVICE COMMISSION - DON MALONE

RESPONSE:
The Company submits its update to the previously provided APSC-034 modifying the grand total provided for 2023 below consistent with response to APSC-062.

1. As Summit Utilities Arkansas, Inc. ('SUA') did not commence operations until 2022, the year 2021 is not included in SUA's general ledger. For the years 2022 and 2023, the amounts have been provided by FERC account below:

FERC	2022	2023	Grand Total
8870	-	1,060,838.00	1,060,838.00
8740	636,125.40	-	636,125.40
Grand Total	636,125.40	1,060,838.00	1,696,963.40

SPONSOR:
Teresita Trevino

RESPONSIVE DOCUMENTS:

None

APSC FILED Time: 7/10/2024 11:55:31 AM: Recvd 7/10/2024 11:55:10 AM: Docket 23-079-U-Doc. 120

The foregoing response to the above information request is accurate and complete, and contains no material misrepresentations or omissions based upon present facts known to the undersigned. The undersigned agrees to immediately inform the Requestor if any matters are discovered which would materially affect the accuracy or completeness of the information provided in response to the above information request.

/s/ Brooke South Parsons
Signature of Company Representative

DATE PROVIDED: FEBRUARY 22, 2024

DIRECT EXHIBIT DM-6

ARKANSAS PUBLIC SERVICE COMMISSION
APSC 23-079-U
APSC FILED Time: 7/10/2024 11:55:31 AM: Recvd 7/10/2024 11:55:10 AM: Docket 23-079-U-Doc. 120
2023 SUA RATE CASE

REQUEST NO.: APSC-115

COMPANY NAME: SUMMIT UTILITIES ARKANSAS

DATE RECEIVED: 6/19/2024

DATE DUE: 7/3/2024

EXTENSION DATE:

INFORMATION REQUESTED:

1. Please provide the Convergent Outsourcing Inc. total expenditures for year-to-date 2024 by month, by invoice number, and provide the FERC account number where each was recorded.
2. Please provide copies of all Convergent Outsourcing Inc. invoices for year-to-date 2024 expenditures.
3. Please provide all call center expenditures by year for 2022, 2023, and 2024 year-to-date, by call center provider (both internal and external), by month, by FERC account.
4. Please provide a narrative and workpapers to explain how the call center located in Ft. Smith, Arkansas is allocated and/or direct charged to the various jurisdictions/operating companies and provide the total Ft. Smith call center expenditures by year, by month, for the years of 2022, 2023 and year-to-date 2024.
5. For the years and months of Ft. Smith call center expenditures provide in Q.3 above please provide the total amount allocated and direct charged to each jurisdiction/operating company by month and provide the allocation factor(s) used for the allocated piece by month. For the allocated and direct charged expenditures for SUA please provide the FERC account numbers the expenditures were charged.
6. Provide the same as in Q.4 and Q.5 for any other call centers that are charging expenses to SUA and identify where the call center(s) is located.

REQUESTED BY: ARKANSAS PUBLIC SERVICE COMMISSION - DON MALONE

RESPONSE:
Convergent served as an extension of our internal call center, providing the flexibility to adjust staffing levels according to call volume demands. Engaging a third party was a strategic decision that allowed us to access Convergent's surplus staffing in Guatemala, which was immediately available and bilingual—a significant advantage during the conversion period when wait times were unusually long. However, due to a decrease in call volume, our contract with Convergent ended on May 31, 2024.

SUA will supplement this response with the specific information requested as needed and requested by Staff.

SPONSOR:
Jen Fallon, Raegina Kindrix, Sheri Richard, Bryan West, Eliza Castillo

RESPONSIVE DOCUMENTS:
None

APSC FILED Time: 7/10/2024 11:55:31 AM: Recvd 7/10/2024 11:55:10 AM: Docket 23-079-U-Doc. 120

The foregoing response to the above information request is accurate and complete, and contains no material misrepresentations or omissions based upon present facts known to the undersigned. The undersigned agrees to immediately inform the Requestor if any matters are discovered which would materially affect the accuracy or completeness of the information provided in response to the above information request.

/s/ Brooke South Parsons
Signature of Company Representative

DATE PROVIDED: JULY 03, 2024

CERTIFICATE OF SERVICE

I, Joshua A. Baxter, hereby certify that a copy of the foregoing has been served on all parties of record on July 10, 2024, via the Arkansas Public Service Commission's Electronic Filing System in accordance with the Commission's *Rules of Practice and Procedure*.

/s/ JOSHUA A. BAXTER
Joshua A. Baxter