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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**

Surrebuttal Testimony and Exhibits

of

Jonathan Ly

On Behalf of

ARKANSAS GAS CONSUMERS, INC.

September 9, 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-1S	Summary of AGC’s Revised Class Cost-of-Service Study
JL-2S	AGC’s Recommended Class Revenue Allocation

GLOSSARY OF ACRONYMS

Term	Definition
Act 725	Arkansas Act 725 of 2015
AG	Office of Arkansas Attorney General
AGC	Arkansas Gas Consumers, Inc.
CCOSS	Class Cost-of-Service Study
HHEG	Hospitals and Higher Education Group
LCS-1	Large Commercial Firm Service
LCS-1 TSO	Large Commercial Firm Service – Transportation Supply Option
NARUC	National Association of Regulatory Utility Commissioners
O&M	Operation and Maintenance
Staff	General Staff of the Arkansas Public Service Commission
SUA	Summit Utilities Arkansas, Inc.

SURREBUTTAL TESTIMONY OF JONATHAN LY

Introduction

Q PLEASE STATE YOUR NAME AND BUSINESS ADDRESS.

A Jonathan Ly, 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 a regulatory consultant employed by J. Pollock, Incorporated.

Q ARE YOU THE SAME JONATHAN LY WHO PREVIOUSLY SUBMITTED DIRECT TESTIMONY ON BEHALF OF THE ARKANSAS GAS CONSUMERS, INC. (AGC) IN THIS PROCEEDING?

A Yes.

Q WHAT IS THE PURPOSE OF YOUR SURREBUTTAL TESTIMONY?

A I am responding to recommendations made by Timothy S. Lyons on behalf of Summit Utilities Arkansas, Inc. (SUA), Mark Burdette on behalf of the General Staff of the Arkansas Public Service Commission (Staff), Larry Blank on behalf of the Hospitals and Higher Education Group (HHEG), and Richard W. Porter on behalf of the Office of Arkansas Attorney General (AG) regarding SUA's proposed class cost-of-service-study (CCOSS). In addition, I also provide AGC's revised CCOSS and revised class revenue allocation incorporating certain recommendations made by these parties, as well as adjustments to SUA's revenue requirement as recommended by AGC's other witness, Ms. Billie LaConte.

Q ARE YOU ACCEPTING THE POSITIONS ON ISSUES NOT ADDRESSED IN YOUR SURREBUTTAL TESTIMONY BY THE AFOREMENTIONED WITNESSES AND/OR THE TESTIMONIES SPONSORED BY OTHER PARTIES?

A No. One should not interpret the fact that I do not address every issue raised by any party as an endorsement thereof.

Q ARE YOU SPONSORING ANY EXHIBITS TO YOUR REBUTTAL TESTIMONY?

A Yes. I am sponsoring **Exhibits JL-1S** and **JL-2S**. These exhibits were prepared by me or under my supervision and direction. In addition, I have prepared **Appendix D**, which consists of the Discovery Responses referenced in my testimony.

Summary

Q PLEASE SUMMARIZE YOUR FINDINGS AND RECOMMENDATIONS.

A My findings and recommendations are as follows:

Classification of Distribution Mains

- SUA's proposal to average the results of the minimum size main and zero-intercept methods to determine the proportion of customer-related and demand-related costs of distribution mains is not supported by Arkansas Act 725 of 2015 (Act 725).
- Further, this proposal is a departure from the methodology previously used by SUA's predecessor, CenterPoint Energy Arkansas, and unduly shifts costs from the Residential customer class to other customer classes.
- The Commission should reject SUA's proposal and instead approve a classification of distribution mains based solely on the minimum size main method.

Design Day Demand

- SUA's regression analysis demonstrates that LCS-1 and LCS-1 TSO are non-weather sensitive and, therefore, these classes should be treated as such for the purposes of calculating design day demand.

- SUA's calculation of the design day demand for each non-weather sensitive customer class should be corrected such that the total consumption over the winter months is divided by the monthly average number of customers, rather than the total number of bills over the winter months.

Allocation Factors

- Staff's recommendation to allocate Other Working Capital Assets based on net plant balances is inappropriate because this account consists entirely of cash and temporary cash investments necessary to fund day-to-day operations. Instead, it is appropriate to allocate this component of rate base on an Operations & Maintenance (O&M) expense-based allocator.
- The AG's recommendation to incorporate annual energy consumption into the design day demand and distribution main allocation factors is contrary to cost causation and should be rejected.
- Staff's recommendations to change the allocation factors for Mains and Services Operating Expense, Other Utility Operating Expense and Rents, Supervision & Engineering Maintenance Expense, Other Equipment Maintenance Expense, and Taxes Other Than Income Tax are reasonable and should be accepted.

Heating Assistance Fund

- Because the Residential customer class is the only class with customers who can receive Heating Assistance Funds, the costs for this program included in SUA's CCOSS should be directly assigned to the Residential class.

Revised Class Cost-of-Service Study and Revised Class Revenue Allocation

- The Commission should approve AGC's revised recommended CCOSS which incorporates the changes discussed above, as well as further adjustments recommended by my colleague, Ms. LaConte.
- The Commission should also approve AGC's revised recommended class revenue allocation based upon the results of the revised CCOSS and modified to incorporate certain rate smoothing adjustments.

Classification of Distribution Mains

Q PLEASE SUMMARIZE THE POSITIONS OF THE VARIOUS PARTIES REGARDING THE CLASSIFICATION OF DISTRIBUTION MAINS.

A Staff witness, Mr. Burdette, and HHEG witness, Mr. Blank, both recommend that the Commission reject SUA's proposal to classify distribution mains based on the average of results from the minimum size main method and the zero-intercept method, and instead adopt a classification based solely on the results of the minimum size main method.[1] AG witness Porter does not oppose SUA's proposal to average the results of the minimum size main and zero-intercept methods to determine the proportion of demand-related and customer-related costs of distribution mains. However, as discussed in further detail later, he recommends that in place of a customer count to allocate customer-related costs, these costs should instead be allocated based upon each class's annual energy usage.[2] Lastly, SUA witness, Mr. Lyons, maintains the proposal initially advanced in SUA's Application is appropriate and continues to recommend that distribution main costs be classified based upon the average of the two methodologies.[3]

Q WHY DO MR. BURDETTE AND MR. BLANK RECOMMEND CLASSIFYING DISTRIBUTION MAINS SOLELY BASED ON THE RESULTS OF THE MINIMUM SIZE MAIN METHOD?

A Mr. Burdette and Mr. Blank both correctly acknowledge that SUA's averaging of the

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[1] Doc. 111, Direct Testimony of Mark Burdette at 19–20; Doc. 103, Direct Testimony of Larry Blank at 12-13.

[2] Doc. 113, Direct Testimony of Richard W. Porter at 44–46.

[3] Doc. 138, Rebuttal Testimony of Timothy S. Lyons at 8.

results of the minimum size main and zero-intercept methods is a departure from the methodology CenterPoint Energy Arkansas (SUA's predecessor) used in its previous CCOSS in Docket No. 15-098-U (which was appropriately based on the minimum size main method). They also note that the validity of this revised approach is not supported by any analysis or precedent.[4] Furthermore, Mr. Burdette recognizes that the ultimate effect of SUA's unconventional classification methodology would shift costs from the Residential customer class to other customer classes.[5]

Q DO YOU AGREE WITH MR. BURDETTE AND MR. BLANK REGARDING THE CLASSIFICATION OF DISTRIBUTION MAINS?

A Yes. As I previously discussed in my direct testimony, averaging the results of the minimum size main and zero-intercept methods is not supported by Act 725.[6] Mr. Burdette's and Mr. Blank's analyses provide further justification for utilizing only the minimum size main method to classify the costs of distribution mains between their customer- and demand-related components.

Q HAS MR. PORTER PROVIDED ANY ADDITIONAL ANALYSIS SUPPORTING SUA'S PROPOSAL TO AVERAGE THE RESULTS OF THE MINIMUM SIZE MAIN AND ZERO-INTERCEPT METHODS TO CLASSIFY DISTRIBUTION MAINS?

A No. Mr. Porter states that he has not prepared an alternative study and, therefore, does not contest SUA's methodology.[7]

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[4] Doc. 111, Direct Testimony of Mark Burdette at 18; Doc. 103, Direct Testimony of Larry Blank at 12–13.

[5] Doc. 111, Direct Testimony of Mark Burdette at 19.

[6] Doc. 95, Direct Testimony and Exhibits of Jonathan Ly at 6–7.

[7] Doc. 113, Direct Testimony of Richard W. Porter at 44–45.

Q HAS MR. LYONS INTRODUCED ANY ADDITIONAL ARGUMENTS SUPPORTING USE OF THE AVERAGE RESULTS OF THE MINIMUM SIZE MAIN AND ZERO-INTERCEPT METHODS TO CLASSIFY DISTRIBUTION MAINS?

A No. Mr. Lyons states only that the minimum size main and zero-intercept studies yield different results for the customer- and demand-related portions of distribution mains and makes the claim that utilizing both approaches more accurately reflects the underlying cost of service.[8] However, he does not provide any additional analysis demonstrating how the hybrid approach more accurately reflects the cost of service relative to the minimum size main method.

Q WHAT DO YOU RECOMMEND?

A I recommend that the Commission reject SUA's proposal to average the results of the minimum size main and zero-intercept methods to classify distribution mains. Instead, I recommend that the Commission adopt the results of SUA's minimum size main method for the purpose of classifying distribution mains.

Design Day Demand

Q HAVE ANY PARTIES IDENTIFIED FLAWS WITH SUA'S CALCULATION OF THE DESIGN DAY DEMAND?

A Yes. HHEG witness, Mr. Blank, determined there were two issues with SUA's calculation of the design day demand. First, the LCS-1 customer class was treated as weather sensitive for the purposes of calculating design day demand, but it was not treated as weather sensitive for the purposes of weather normalizing revenues. Second, for classes that were not found to be weather sensitive, SUA arbitrarily chose

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[8] Doc. 138, Rebuttal Testimony of Timothy S. Lyons at 8.

February 2023, the month with the highest total maximum volume of gas deliveries, to calculate non-weather sensitive customers' contribution to design day demand.[9]

Q WHAT RECOMMENDATIONS DOES MR. BLANK MAKE TO ADDRESS THESE DEFICIENCIES?

A Mr. Blank recommends that LCS-1 and LCS-1 Transportation Supply Option (TSO) be treated as non-weather sensitive for the purposes of calculating design day demand. He also recommends that instead of using average daily usage for a single month, the daily consumption for non-weather sensitive customers should be calculated based upon an annual average.[10]

Q DO YOU AGREE WITH THE FINDING THAT LCS-1 AND LCS-1 TSO SHOULD BE TREATED AS NON-WEATHER SENSITIVE?

A Yes. SUA conducted a regression analysis to evaluate whether each customer class should be treated as weather sensitive based upon the results of an r-squared analysis, which is a statistical analysis that measures how well a dependent variable varies in relation to an independent variable. For example, an R-squared value of 1.0 indicates that changes in an independent variable perfectly explain changes in a dependent variable. Conversely, a R-squared value of 0.0 indicates that changes in an independent variable have no impact on a dependent variable. In SUA's analysis for each customer class, the dependent variable was usage per customer and the independent variable was heating degree days.[11] These results are summarized in Table 1.

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[9] Doc. 103, Direct Testimony of Larry Blank at 14–15.

[10] *Id.* at 16.

[11] WP (Input) – Weather Normalization vRebuttal, tab Vol Summary.

Table 1
Summary of SUA's R-Squared Analysis

Customer Class	R-Squared
RS-1	97.47%
SCS-1	95.74%
SCS-2	40.49%
SCS-3	2.55%
LCS-1	71.85%
SCS-1 TSO	91.78%
SCS-3 TSO	1.07%
LCS-1 TSO	55.48%

Source: WP (Input) – Weather Normalization vRebuttal, tab Vol Summary.

The value of an R-squared that indicates statistical significance between independent and dependent variables is subject to some judgment, and it is unclear what R-squared value SUA treats as the threshold to determine whether a customer class is weather sensitive. However, RS-1, SCS-1, and SCS-1 TSO all have R-squared values greater than 90%. These classes, which have R-squared values that are much greater than those of other classes, were treated as weather sensitive by SUA for the purposes of weather normalizing revenues. All other classes, including LCS-1 and LCS-1 TSO were treated as non-weather sensitive.

Q WHY THEN DID SUA TREAT LCS-1 AND LCS-1 TSO AS WEATHER SENSITIVE WHEN CALCULATING DESIGN DAY DEMANDS?

A SUA states that the r-squared values shown in Table 1 reflect the results of a regression analysis over a 6-year period. However, over the most recent 1-year period, the LCS-1 and LCS-1 TSO classes had r-squared values of 87.70% and

80.30%, respectively, which SUA determined was sufficient support to treat these classes as weather sensitive.[12]

Q DO YOU AGREE WITH SUA'S DECISION TO TREAT LCS-1 AND LCS-1 TSO AS WEATHER SENSITIVE WHEN CALCULATING DESIGN DAY DEMANDS?

A No. SUA should rely on the results of the regression analysis incorporating more years of available data to mitigate the impact of year-to-year variations. In addition, treating the same customer classes as non-weather sensitive for the purposes of normalizing revenues and weather sensitive for calculating design day demands would result in a mismatch between rate design and revenues collected.

Q HAS SUA ADOPTED MR. BLANK'S RECOMMENDATION TO CALCULATING THE DESIGN DAY DEMAND FOR NON-WEATHER SENSITIVE CLASSES?

A Yes. Mr. Lyons agreed with Mr. Blank's concern related to utilizing only February 2023 average daily consumption for non-weather sensitive classes to determine design day demand. However, instead of using average annual consumption, SUA revised Mr. Blank's recommendation and utilized average daily consumption during winter months from November 2022 to April 2023.[13]

Q DO YOU AGREE WITH SUA'S REVISED CALCULATION OF THE DESIGN DAY DEMANDS FOR NON-WEATHER SENSITIVE CLASSES?

A Yes. It is reasonable to utilize an average of the winter months from November to April since these months have historically shown greater usage than other periods of the year.

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[12] Doc. 138, Rebuttal Testimony of Timothy S. Lyons at 14.

[13] *Id.*

Q DO YOU HAVE ANY CORRECTIONS TO MAKE TO SUA'S REVISED CALCULATION OF DESIGN DAY DEMANDS?

A Yes. SUA calculated the design day demand for weather sensitive classes by dividing the total sales from November 2022 to April 2023 for each customer class by the total number of bills for each customer class over this period. This result was then divided by the number of days during this period to determine average daily use per customer. However, this amount understates the average daily use because it overstates the number of customers. Specifically, because each customer receives a monthly bill, SUA's calculation based upon the total number of bills counts each customer multiple times over the months from November 2022 to April 2023. Instead, to more accurately estimate the number of customers in each customer class, SUA should have used the average monthly bills for each customer class to prevent the same customers from being counted multiple times. The corrected average daily usage per customer for weather sensitive classes is shown in **Table 2**.

Table 2
Corrected Average
Daily Gas Consumption Per Customer of
Non-Weather Sensitive Classes
(CCF)

Customer Class	SUA	Corrected
SCS-2	0.42	2.52
SCS-3	1.98	11.86
LCS-1	319.60	1,917.62
SCS-3 TSO	17.05	102.30
LCS-1 TSO	708.44	4,250.67

Source: WP-G-4-1.

Q WHAT DO YOU RECOMMEND?

A I recommend that the Commission adopt a revised calculation of the design day demand that recognizes that the LCS-1 and LCS-1 TSO customer classes are non-weather sensitive. Furthermore, the revised calculation should be corrected to recognize the average daily gas consumption per customer for non-weather sensitive classes as shown in **Table 2.**

Allocation Factors

Q HAVE ANY PARTIES PROPOSED CHANGES TO THE ALLOCATION FACTORS USED IN SUA'S CCOSS?

A Yes. Staff witness, Mr. Burdette, recommends changes to six allocation factors used to allocate the costs of six items in SUA's CCOSS. AG witness, Mr. Porter, recommends changes to the derivation of two allocation factors.

Q PLEASE IDENTIFY STAFF'S PROPOSED ALLOCATION FACTOR CHANGES.

A Mr. Burdette recommends the following changes to allocating costs within SUA's CCOSS:

1. Allocating Other Working Capital Assets based on net plant balances;
2. Allocating Mains and Services Operating Expense (Account 874) based on an internal allocator derived from Mains (Account 376) and Services (Account 380);
3. Allocating Other Expenses (Account 880) and Rents (Account 881) based on an internal allocator derived from Operation Expense Accounts 871–879;
4. Allocating Supervision & Engineering Expense (Account 885) based on an internal allocator derived from Maintenance Expense Accounts 886–893;
5. Allocating Other Equipment (Account 894) based on an internal allocator derived from Maintenance Expense Accounts 886–893; and
6. Disaggregating Taxes Other Than Income Tax into individual items and allocating them separately.[14]

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[14] Doc. 111, Direct Testimony of Mark Burdette at 14.

Q DO YOU AGREE WITH STAFF'S RECOMMENDED ALLOCATION FACTORS?

A I agree with Staff's recommendations, with one exception. Specifically, I disagree with the recommendation to allocate Other Working Capital Assets on net plant balances.

Q WHY DOES MR. BURDETTE RECOMMEND THAT OTHER WORKING CAPITAL ASSETS BE ALLOCATED ON NET PLANT?

A SUA proposed to allocate Other Working Capital Assets using an allocation factor derived from O&M expenses. Mr. Burdette took issue with the use of an expense allocation factor for allocating Other Working Capital Assets, as this item is included as a component of rate base. Consequently, he posited that a more reasonable allocation method would be to use a plant allocation factor based on net plant balances.[15]

Q IS THE RECOMMENDATION TO ALLOCATE OTHER WORKING CAPITAL ASSETS BASED ON NET PLANT REASONABLE?

A No. Mr. Burdette is drawing a false distinction between rate base and expenses in a CCOSS. There is no requirement that items included in rate base or expenses should only be allocated based on their respective allocators. Instead, it is more reasonable to identify the cost-causative factor underlying each component of a CCOSS. In this case, Other Working Capital Assets represents the cash that a company must keep on hand to fund its day-to-day operations. In fact, the $12.1 million that SUA includes in Other Working Capital Assets consists entirely of cash and temporary cash investments.[16] Consequently, it is reasonable for SUA to allocate Other Working Capital Assets among customer classes using an O&M expense-based allocation

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[15] *Id.* at 15.

[16] SUA Rebuttal Testimony MFR Native Files and Workpapers, Schedule B-4.

factor. This is consistent with the allocation of cash used in the National Association of Regulatory Utility Commissioners (NARUC) Gas Distribution Rate Design Manual.[17]

Q PLEASE DESCRIBE THE TWO CHANGES RECOMMENDED BY MR. PORTER ON BEHALF OF THE AG.

A Mr. Porter recommends changes to the calculation of the design day demand allocator and the distribution main allocator to incorporate a component based on annual gas consumption by each customer class. For design day demand, the allocator would be based on only 75% on actual peak design day usage, and the remaining 25% would be based on annual gas consumption.[18] For distribution mains, Mr. Porter is proposing to adopt the classification methodology proposed by SUA. In addition to utilizing his recommended peak design day allocator for allocating the costs of the demand-related portion of distribution mains, he is also proposing to substitute annual gas consumption in place of the number of customers for allocating the customer-related portion for mains.[19] Thus, energy usage would be double-counted within his recommended distribution main allocator.

Q WHY DOES MR. PORTER RECOMMEND INCORPORATING ANNUAL GAS CONSUMPTION INTO THESE ALLOCATORS?

A Mr. Porter asserts that the design day demand and distribution main allocators do not appropriately reflect system usage and cost responsibility and that they disproportionately allocate costs to the residential class.[20] In recognition of the year-

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[17] NARUC, *Gas Distribution Rate Design Manual* at 42 and 47 (Jun. 1989).

[18] Doc. 113, Direct Testimony of Richard W. Porter at 44.

[19] *Id. at* 45.

[20] *Id. at* 32.

round usage of gas by the various customer classes, he recommends that these allocators be adjusted as previously described.

Q DO YOU AGREE WITH MR. PORTER'S RECOMMENDATION TO ADJUST THE CALCULATION OF THE DESIGN DAY DEMAND ALLOCATOR TO INCORPORATE ANNUAL GAS CONSUMPTION?

A No. By definition, the design day demand represents the highest gas consumption on a single day that a utility must plan for to serve its customers' needs. It is solely usage on this day that determines the size of distribution mains that a utility must install to reliably serve its customers. If a utility does not sufficiently size its system to meet design day demands, it will be unable to provide adequate service. Gas consumption throughout the rest of the year is entirely unrelated to the size of the distribution mains that a utility must install. Therefore, it is unreasonable to consider annual gas consumption in calculating the design day demand allocator.

Q IS IT REASONABLE TO ALLOCATE THE CUSTOMER-RELATED COSTS OF DISTRIBUTION MAINS BASED ON ANNUAL GAS USAGE RATHER THAN CUSTOMER COUNT AS PROPOSED BY MR. PORTER?

A No. Mr. Porter claims that because the number of customers in a customer class does not recognize annual usage characteristics, annual gas consumption should be used in place of a customer count to determine the allocation of the customer-related component of distribution mains.[21] However, this reasoning is entirely counter to the purpose and design of distribution mains.

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[21] *Id*. at 40.

First and most fundamentally, the distribution system exists to provide customers with access to natural gas service, regardless of the amount of gas consumed by each individual. Recognizing this "readiness-to-serve" function, there is necessarily a customer-related component of the distribution system that is independent of the level of a customer's peak demand and annual consumption. Second, the distribution system must be capable of meeting the peak demands of all customers of a utility. That is, a utility must size its distribution mains to be capable of delivering gas to each of its customers, reflecting a demand-related component. Both of these aspects of the distribution system are unaffected by the total gas consumed by customers over the course of a year. This is supported by the NARUC Gas Rate Design manual, which recognizes that distribution costs are functionalized only into customer-related and demand-related portions.[22]

Therefore, Mr. Porter's proposal to allocate the customer-based costs of distribution systems on annual gas consumption is unreasonable and should be rejected.

Q WHAT DO YOU RECOMMEND?

A I recommend that the Commission reject Staff's recommendation to allocate Other Working Capital Assets on net plant as well as the AG's recommendation to incorporate annual gas consumption into the design day demand and distribution main allocation factors. However, I recommend that the Commission approve Staff's five other proposed changes to the allocation factors used in SUA's CCOSS.

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

Heating Assistance Funds

Q HOW ARE COSTS RELATED TO SUA'S HEATING ASSISTANCE FUNDS ACCOUNTED FOR IN SUA'S CCOSS?

A SUA includes the costs for the Heating Assistance Funds in Accounts Receivable (Account 142), which is allocated among customer classes based on each class's proportional share of retail revenues.[23] In calendar year 2023, SUA provided customers $109,500 in Heating Assistance Funds.[24]

Q ARE ALL CUSTOMER CLASSES ELIGIBLE TO RECEIVE SUPPORT THROUGH THE HEATING ASSISTANCE FUNDS?

A No. Only residential customer classes are eligible to receive Heating Assistance Funds. Because these amounts are recorded in Accounts Receivable, however, the costs for this program are collected from all customers. It is unreasonable to collect the costs for this program from the entirety of the general customer base when only a limited subset of customers is able to participate in this program.

Q WHAT DO YOU RECOMMEND?

A I recommend that amounts related to the Heating Assistance Funds be removed from Accounts Receivable. Instead, these amounts should be recorded separately and assigned directly to the Residential customer class.

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[23] SUA Response to AGC-005-001, a copy of which is provided in **Appendix D**.

[24] SUA Response to APSC-090-2, a copy of which is provided in **Appendix D**.

Revised Class Cost-of-Service Study

Q IN ADDITION TO THE CHANGES DISCUSSED IN YOUR DIRECT TESTIMONY, 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 seven further adjustments that should be made to SUA's CCOSS:

1. SUA's rate of return should be set at 5.0719%;
2. Incentive compensation expenses should be reduced by $1.4 million and capitalized incentive compensation should be reduced by $0.5 million, as these amounts are related to SUA's financial targets;
3. Payroll taxes in the amount of $151,865 associated with SUA's Volunteer Time Off program should be removed from various expense accounts;
4. Capitalized expenses in the amount of $57,145 associated with SUA's Volunteer Time Off program should be removed from SUA's rate base;
5. Maintenance of Mains Expense should be reduced by $1.1 million;
6. Uncollectible expense in Account 904 should be reduced by $845,218 to reflect a 5-year amortization of SUA's COVID-19 regulatory asset rather than the 5-year amortization proposed by SUA; and
7. The revenue conversion factor used to calculate SUA's revenue deficiency should be based upon calculations made by Staff witness Hilton.

These adjustments are discussed in further detail in Ms. LaConte's testimony.

Q HAVE YOU PREPARED A REVISED CLASS COST-OF-SERVICE STUDY WHICH INCORPORATES THE RECOMMENDATIONS YOU SUPPORT AS WELL AS THE ADJUSTMENTS DISCUSSED BY MS. LACONTE?

A Yes. The results of my revised CCOSS are provided in **Exhibit JL-1S**. **Table 3** summarizes the results to show the resulting rates of return, relative rates of return, and cost-based increases based upon this updated CCOSS.

Table 3
Summary of AGC's Revised Recommended Class Cost-of-Service Study Results At Present Rates

Rate Class	Rate of Return	Relative Rate of Return	Cost-Based Increase
Residential	0.19%	0.19	45.4%
SCS-1	3.45%	3.38	13.2%
SCS-2	13.15%	12.89	-34.9%
SCS-3	32.28%	31.65	-61.5%
LCS-1	4.21%	4.13	6.7%
System Average	1.02%	1.00	36.3%

Q WHAT DO YOU RECOMMEND?

A I recommend that the Commission approve the results of AGC's revised CCOSS summarized in **Exhibit JL-1S** which incorporates recommendations made by AGC as well as various other parties.

Revised Class Revenue Allocation

Q HAVE YOU PREPARED A REVISED CLASS REVENUE ALLOCATION BASED UPON THE RESULTS OF AGC'S REVISED RECOMMENDED CLASS COST-OF-SERVICE STUDY?

A Yes. The results of my revised recommended class revenue allocation are shown in **Exhibit JL-2S** and summarized in Table 4, which also includes the cost-based increases resulting from AGC's revised recommended CCOSS for comparison.

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

Rate Class	Cost-Based	AGC Proposed	Proposed Relative Increase
Residential	45.4%	45.2%	1.25
SCS-1	13.2%	13.2%	0.36
SCS-2	-34.9%	0.0%	0.00
SCS-3	-61.5%	0.0%	0.00
LCS-1	6.7%	6.7%	0.18
Total	36.3%	36.3%	1.00

As I previously discussed in my direct testimony, my recommended class revenue allocation is based largely on the results of the CCOSS, but it includes rate smoothing adjustments to set the proposed revenues for SCS-2 and SCS-3 at their present revenues to mitigate the Residential rate class revenue increase, since it is the only class to experience an increase greater than the system average.

Q WHAT DO YOU RECOMMEND?

A I recommend that the Commission approve AGC's revised recommended class revenue allocation shown in **Exhibit JL-2S**.

Conclusion

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

A I recommend the Commission:

- Reject SUA's proposal and the AG's recommendation to classify distribution mains between customer- and demand-related costs based upon the average of results from the minimum size main and zero-intercept methods.
- Approve the classification of distribution mains based solely upon the results of the minimum size main method.

- Approve AGC's corrected calculation of design day demands for non-weather sensitive classes, including LCS-1 and LCS-1 TSO.
- Reject Staff's recommendation to allocate Other Working Capital Assets on net plant.
- Reject the AG's recommendation to incorporate annual gas consumption into the design day demand and distribution main allocation factors.
- Approve Staff's recommended changes to the allocation of Mains and Services Operating Expense, Other Utility Operating Expense and Rents, Supervision & Engineering Maintenance Expense, Other Equipment Maintenance Expense, and Taxes Other Than Income Taxes.
- Approve a direct allocation of costs related to the Heating Assistance Funds to the Residential customer class.
- Approve AGC's revised CCOSS as presented in **Exhibit JL-1S**.
- Approve AGC's revised class revenue allocation as presented in **Exhibit JL-2S**.

Q DOES THIS CONCLUDE YOUR SURREBUTTAL TESTIMONY?

A Yes.

APPENDIX D

Discovery Responses Relied Upon in Surrebuttal Testimony

Excerpt From Discovery Response	**Footnote/Table**	**Testimony Pg. No.**
SUA Response to AGC-005-001	Footnote 23	16
SUA Response to APSC-090-2	Footnote 24	16

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

REQUEST NO.: AGC-005-001

COMPANY NAME: **SUMMIT UTILITIES ARKANSAS**

DATE RECEIVED: **7/5/2024**

DATE DUE: **7/22/2024**

EXTENSION DATE:

INFORMATION REQUESTED:
Referring to the Direct Testimony of Kurt W. Adams at page 13, lines 13–19, please identify where in the cost-of-service study the Heating Assistance Funds are included and explain how these costs are allocated among customers.

REQUESTED BY: **ARKANSAS GAS CONSUMERS**

RESPONSE:
For information regarding the collection and application of the Heating Assistance Funds, please refer to the Company's response to APSC-090-2. The Heating Assistance Funds are included in FERC Account 142 - Accounts Receivable, which is in the Working Capital Assets section of the cost-of-service study. Accounts Receivable are allocated based on the allocation factor "RETREV" (Retail Revenues).

SPONSOR:
Wendy Clark, 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: **JULY 22, 2024**

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

REQUEST NO.: APSC-090-2

COMPANY NAME: **SUMMIT UTILITIES ARKANSAS**

DATE RECEIVED: **4/22/2024**

DATE DUE: **5/7/2024**

EXTENSION DATE:

INFORMATION REQUESTED:
3. Please provide the number of customers receiving Heating Assistance Fund (HAF) credits/proceeds by month, for the test year ended December 31, 2023.

4. Please provide journal entries or T accounts to demonstrate the accounting for HAF credits/proceeds and provide a narrative as need to explain the accounting during the test year.

5. Please provide HAF credits/proceeds by month, by FERC account (both capital and expense), for the 12 months.

REQUESTED BY: **ARKANSAS PUBLIC SERVICE COMMISSION - DON MALONE**

RESPONSE:
3. 610 customers for SUA were given $109,500.05 in assistance funds in 2023.

January	62
February	102
March	116
April	53
May	0
June	0
July	0
August	0
September	0
October	1
November	77
December	98

4. Summit pre-funds the assistance fund and sends money to the Heart of Arkansas, United Way to administer those funds. Heart of Arkansas uses specific eligibility criteria and awards funds on a first come first serve basis. Pledge amounts are then sent to Summit. Throughout the year, direct ACH are received by Summit with remittance advice to apply funds to customer accounts. Further details about the fund are here Heating Assistance Fund

(summitutilities.com)

The process for accounting and the various other departments process are in the attached H.A. Explanation document.

5. The amounts below belong to FERC 1420. The FERC for the Journal entry and the customer contributions are in the attached 101042286 - TT - Heating Assistance Match 12.2023 spreadsheet.

January	62	$11,842.45
February	102	$19,173.68
March	116	$22,108.19
April	53	$9,886.63
May	0	$0.00
June	0	$0.00
July	0	$0.00
August	0	$0.00
September	0	$0.00
October	1	$200.00
November	77	$14,596.06
December	98	$31,693.04
Total	509	$109,500.05

SPONSOR:
April Huffman, Teresita Trevino

RESPONSIVE DOCUMENTS:
APSC-090-2 1116 - 101042286 - TT - Heating Assistance Match 12.2023.xlsx
APSC-090-2 H.A. Explanation.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

Exhibit JL-1S

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 (a)**						
2	Gross Plant in Service	$ 1,816,343,222	$ 1,415,406,544	$ 314,679,134	$ 3,090,371	$ 93,451	$ 83,073,722
3	Accumulated Depreciation	686,257,276	543,776,113	113,822,826	1,343,254	41,510	27,273,573
4	Total Net Plant	$ 1,130,085,945	$ 871,630,432	$ 200,856,308	$ 1,747,116	$ 51,941	$ 55,800,148
5	Working Capital Assets	97,912,048	65,556,113	24,351,855	382,306	19,099	7,602,675
6	Other Rate Base Items	-	-	-	-	-	-
7	**TOTAL RATE BASE (A)**	**$ 1,227,997,994**	**$ 937,186,545**	**$ 225,208,163**	**$ 2,129,423**	**$ 71,040**	**$ 63,402,824**
8	**NON-FUEL OPERATING REVENUES**						
9	Present Rate Schedules/Class (c)	$ 181,561,953	$ 133,525,063	$ 36,613,817	$ 652,871	$ 41,245	$ 10,728,957
10	Other Operating Revenues	7,078,629	6,479,607	584,106	10,636	317	3,964
11	**TOTAL OPERATING REVENUES (A)**	**$ 188,640,582**	**$ 140,004,670**	**$ 37,197,922**	**$ 663,507**	**$ 41,562**	**$ 10,732,920**
12	**EXPENSES (c)**						
13	Operations and Maintenance Expense						
14	Distribution	45,274,729	34,515,819	7,912,729	70,621	2,052	2,773,508
15	Customer Accounts	15,152,491	13,917,351	1,189,137	16,912	1,320	27,771
16	Customer Services and Informational	486,204	431,821	53,385	761	8	229
17	Sales	182,548	162,130	20,044	286	3	86
18	Administrative and General	35,751,598	28,551,748	5,485,834	56,936	2,363	1,654,717
19	ETC						
20	TOTAL OPERATION & MAINTENANCE EXPENSE	$ 96,847,571	$ 77,578,869	$ 14,661,129	$ 145,515	$ 5,747	$ 4,456,311
21	Depreciation and Amortization Expense	69,635,187	56,002,116	11,113,924	126,637	4,059	2,388,450
22	Taxes Other Than Income Taxes	14,333,228	11,161,520	2,453,293	22,004	707	695,704
23	Income Taxes	(4,710,386)	(6,530,711)	1,201,633	89,364	8,115	521,212
24	**TOTAL EXPENSES (A)**	**$ 176,105,600**	**$ 138,211,794**	**$ 29,429,980**	**$ 383,520**	**$ 18,628**	**$ 8,061,678**
25	OPERATING INCOME	$ 12,534,982	$ 1,792,876	$ 7,767,943	$ 279,987	$ 22,935	$ 2,671,243
26	EARNED RETURN ON RATE BASE	1.02%	0.19%	3.45%	13.15%	32.28%	4.21%

Exhibit JL-2S

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	$133,525	$60,646	($253)	$60,393	45.2%
2	SCS-1	36,614	$4,829	$0	$4,829	13.2%
3	SCS-2	653	($228)	$228	$0	0.0%
4	SCS-3	41	($25)	$25	$0	0.0%
5	LCS-1	10,729	$721	$0	$721	6.7%
6	Total	$181,562	$65,942	$0	$65,942	36.3%

Certificate of Service

I, Shawn McMurray, hereby certify that on September 9, 2024, I served a copy of the foregoing Surrebuttal Testimony and Exhibits of Jonathan Ly upon all parties of record by electronic mail *via* the APSC's Electronic Filing System.

/s/ *M. Shawn McMurray*

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**

Surrebuttal Testimony and Exhibits

of

Billie S. LaConte

On Behalf of

ARKANSAS GAS CONSUMERS, INC.

September 9, 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**

Table of Contents

GLOSSARY OF ACRONYMS

Term	Definition
AGC	Arkansas Gas Consumers, Inc.
BDA	Billing Determinant Adjustment
CAPM	Capital Asset Pricing Model
DCF	Discounted Cash Flow
ECAPM	Empirical Capital Asset Pricing Model
FERC	Federal Energy Regulatory Commission
GMES	Government Mandated Expenditure Surcharge
MRP	Market Risk Premium
O&M	Operations and Maintenance
RCF	Revenue Conversion Factor
ROE	Return on Equity
RRA	Regulatory Research Associates
S&P	Standard and Poor’s
SSER	System Safety Enhancement Rider
SUA	Summit Utilities, Arkansas
VTO	Volunteer Time Off

SURREBUTTAL TESTIMONY OF BILLIE S. LACONTE

Introduction 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 ARE YOU THE SAME BILLIE S. LACONTE WHO PREVIOUSLY SUBMITTED DIRECT TESTIMONY ON BEHALF OF THE ARKANSAS GAS CONSUMERS, INC. (AGC) IN THIS PROCEEDING?

A Yes.

Q WHAT IS THE PURPOSE OF YOUR SURREBUTTAL TESTIMONY?

A I respond to the rebuttal testimonies of the following Summit Utilities Arkansas (SUA) witnesses:

- Mr. Dylan W. D'Ascendis regarding authorized returns on equity (ROEs), his application of the Capital Asset Pricing Model (CAPM) and Risk Premium Methods, as well as his proposed risk adjustment and credit risk adjustment;
- Mr. Craig Root on Capital Structure;
- Mr. Sam Springer on incentive compensation and Volunteer Time Off (VTO);
- Mr. Vernon McNully on Operations and Maintenance (O&M) expense; and
- Mr. Phillip Gillam on the System Safety Enhancement Rider (SSER), Billing Determinant Adjustment (BDA) Rider, and the treatment of the COVID-19 regulatory asset.

Additionally, I support a revision to the revenue conversion factor (RCF) used to gross up SUA's operating income as set forth in the direct testimony of Staff witness, Mr. Jeff Hilton.

Q ARE YOU ACCEPTING THE POSITIONS ON ISSUES NOT ADDRESSED IN YOUR SURREBUTTAL TESTIMONY BY THE AFOREMENTIONED SUA WITNESSES, THE TESTIMONIES OF OTHER SUA WITNESSES, AND/OR THE TESTIMONIES SPONSORED BY OTHER PARTIES?

A No. One should not interpret the fact that I do not address every issue raised by any party as an endorsement of any proposal.

Q ARE YOU SPONSORING ANY EXHIBITS WITH YOUR SURREBUTTAL TESTIMONY?

A Yes. I am sponsoring **Exhibits BSL-1S through BSL-4S**. These exhibits were prepared by me or under my supervision and direction.

Summary

Q PLEASE SUMMARIZE YOUR FINDINGS AND RECOMMENDATIONS.

A My findings and recommendations are as follows:

Return on Equity

- The appropriate ROE for SUA is 9.61%. This is based on the updated results of my revised ROE analyses, based on the change in my proxy group.
- The average authorized ROE for regulated natural gas utilities in 2023 was 9.6%. My revised recommended 9.61% ROE is well within the range of ROEs authorized by commissions with similar rankings to the Arkansas Public Service Commission.
- Analysts use historical and projected data when estimating the appropriate ROE and, therefore, the historical authorized ROEs are representative of market conditions at the time the ROE was authorized.
- The exclusion of certain companies when estimating the projected market return is appropriate and similar to the Federal Energy Regulatory Commission's (FERC) method of estimating the projected market risk premium used in the CAPM based on companies in the S&P 500 Index. The exclusion of certain companies from the index based on projected growth is appropriate and the betas for the companies in the proxy group should not be adjusted to reflect the exclusion.

- Interest rates alone do not determine the equity risk premium. The historical equity risk premium, estimated using the difference in historical authorized ROEs and interest rates at the time of the decision correctly captures all factors that may affect the equity risk premium, including interest rates, inflation, and other economic conditions and market conditions that commissions may consider when determining the appropriate ROE.

- SUA's risk as compared to the companies in the proxy group is lower due to the addition of the BDA and the proposed expansion of Rider SSER. These risk reducing measures, in combination with the other riders and adjustment clauses employed by SUA, reduce regulatory lag and its financial volatility, thus reducing SUA's risk.

- The size adjustment made by SUA witness D'Ascendis ignores the fact that SUA is a subsidiary of a much larger parent company that provides SUA with the same support that utility subsidiaries in the proxy group receive from their parent company. SUA does not operate in isolation. Therefore, a size adjustment is unnecessary.

Capital Structure

- SUA's equity ratio should be 44%. This is similar to the equity ratios of comparable companies and consistent with the Commission's authorization of equity ratios for other utilities in Arkansas.

Incentive Compensation

- SUA should exclude short-term incentive compensation costs based on the company meeting financial targets. SUA may continue to offer these benefits to its employees to support the gain and retention of talented employees. However, the financial targets serve to benefit SUA's shareholders and not ratepayers, and the costs associated with these benefits should be removed from rates.

Volunteer Time Off

- SUA's proposal to include VTO should be rejected. Volunteer time does not benefit ratepayers and should not be included in rates. Furthermore, VTO expense is not required to provide safe, reliable, and cost-effective service to ratepayers.

Operations and Maintenance Expense

- I have revised my recommended reduction to the operations and maintenance (O&M) expense related to maintenance of mains to $1.1 million to reflect inflation and to reflect lower maintenance costs associated with newer mains. Although new mains still require maintenance activities, the amount is reduced as compared to older mains that would require additional repairs to maintain reliable service.

Riders

- The proposed expansion of Rider SSER and the true-up of Rider SSER revenues and Rider GMES's revenues *via* the BDA Rider should be rejected. The expansion of the SSER and the proposed true-ups in Rider BDA would reduce SUA's financial risk by significantly reducing regulatory lag and shifting the risk of recovering these costs onto ratepayers.
- A cap on the amount of revenues recovered through Rider SSER should remain, based on a percentage of SUA's base rate revenues.

COVID Regulatory Asset

- SUA has approximately $6.3 million of deferred COVID-19 expenses.[1] The company proposes to amortize the recovery of the expense over three years.[2]
- The company should recover the expense over five years, to lessen the impact of the proposed rate increase on customers. If the Commission allows SUA a return on the unamortized portion of the regulatory asset, I recommend using SUA's long-term debt rate, rather than its weighted average cost of capital, to determine the carrying cost on the regulatory asset. This would serve to fulfil the Commission's desire to award SUA with a return, while limiting the impact on customers.

Revenue Conversion Factor

- SUA's RCF is incorrect because it includes outdated state income tax and uncollectible rates. The RCF should be adjusted to reflect current Arkansas state income taxes, as well as updated uncollectible expense, as supported by Staff witness Hilton.

Proxy Group

Q IS MR. D'ASCENDIS CORRECT THAT YOUR PROXY GROUP INCLUDES COMPANIES THAT ARE NOT COMPARABLE TO SUA AND WERE INCLUDED SOLELY FOR THE PURPOSE OF INCREASING THE SIZE OF YOUR PROXY GROUP?

A No. My proxy group properly comprises companies that are comparable to SUA, including Black Hills Energy. Contrary to Mr. D'Ascendis' assertion, companies were

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[1] Doc. 128, Rebuttal Testimony of Phillip B. Gillam at 18.

[2] *Id.*

not included "solely for the purpose of increasing the size of the Utility Proxy Group…"[3] The percentage of margin for Black Hills Energy's gas utilities is 51%. Furthermore, Black Hills electric utilities have $2.1 billion in rate base, whereas the gas utilities have over $2.4 billion in rate base.

However, I do agree with Mr. D'Ascendis regarding the WEC Energy Group because the total property, plant, and equipment between the electric and natural gas utilities is about even, although the electric operating margin is higher than the natural gas utilities. As such, I have updated my proxy list to omit WEC Energy Group.

Q HAVE YOU REVISED YOUR ROE ANALYSES BASED ON THE UPDATED PROXY GROUP?

A Yes. The average ROE is 9.61%, with a 9.57% midpoint, thus lowering my recommended ROE to 9.61%. The revised ROE recommendation is shown in Table 1. **Exhibits BSL-1S**, **Exhibit BSL-2S,** and **Exhibit BSL-3S** provide my revised DCF and CAPM analyses, whereas my Risk Premium results remain the same as shown in my direct testimony.

BSL Surrebuttal Table 1
Revised Estimated ROE

Component	Low	Mean	High
Constant Growth DCF	8.21%	9.52%	10.93%
Two-Stage DCF		9.43%	
CAPM Historical MRP		10.61%	
CAPM Projected MRP		9.77%	
Risk Premium		8.79%	
Average		9.61%	

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[3] Doc. 136, Rebuttal Testimony of Dylan W. D'Ascendis at 73.

Mr. D'Ascendis' Revised ROE Analysis

Q DID MR. D'ASCENDIS UPDATE HIS ROE ANALYSIS?

A Yes. Mr. D'Ascendis performed the same analyses as he did in his direct testimony, using updated information as of June 28, 2024.[4] In his direct testimony, Mr. D'Ascendis' recommended range of ROEs was 10.42% - 12.92%, which includes a 10-basis point size adjustment.[5] Based on these results, Mr. D'Ascendis recommended an 11% ROE.[6] The recommended range in his rebuttal testimony is 10.08% - 12.53%, including a lower, 5-basis point size adjustment.[7] Although his updated recommended range is about 40-basis points lower than his initial analyses, Mr. D'Ascendis continues to recommend an 11% ROE for SUA.[8]

Q DO YOU AGREE WITH MR. D'ASCENDIS' UPDATED ANALYSES?

A No. Mr. D'Ascendis' updated analyses uses the same methods he used in his direct testimony. For the reasons described in my direct testimony, I disagree with Mr. D'Ascendis' updated analyses. Furthermore, although his updated analyses produce a lower recommended range, his ROE recommendation remains at 11%. Mr. D'Ascendis' failure to adjust his recommended ROE based on his updated analyses demonstrates that his ROE recommendation is results-oriented, overstated and should be rejected.

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[4] *Id.* at 3.

[5] Doc. 34, Direct Testimony of Dylan W. D'Ascendis at 4.

[6] *Id.*

[7] Doc. 136, Rebuttal Testimony of Dylan W. D'Ascendis at 3.

[8] *Id.*

Q DO YOU AGREE WITH MR. D'ASCENDIS' STATEMENT THAT AUTHORIZED RETURNS ON EQUITY LAG BEHIND CURRENT INVESTOR REQUIRED RETURNS?

A Yes, to a degree. As noted by Mr. D'Ascendis, estimating a utility's ROE is a forward-looking exercise and analysts will use both historical and forward-looking data to estimate the appropriate ROE. Forward-looking information includes forecast earnings' growth rates, interest rates and risk premiums. Therefore, although an ROE authorized by a commission is based on data filed by a utility in its initial application, the underlying data that informs the commission's decision is also based on projections. Thus, the authorized ROEs are indicative of current investor-expectations and support my recommended 9.61% ROE.

Application of the Two-Stage Discounted Cash Flow Methodology

Q DOES MR. D'ASCENDIS DISAGREE WITH YOUR TWO-STAGE DISCOUNTED CASH FLOW (DCF) ANALYSIS?

A Yes. Mr. D'Ascendis states that the two-stage DCF model incorrectly uses GDP growth, because it is not a company specific growth rate and is not an upper bound for growth.[9] In addition, Mr. D'Ascendis states that he is not aware of any regulatory jurisdictions, outside of FERC, where the two-step DCF analysis is accepted.[10]

Q DO YOU AGREE WITH MR. D'ASCENDIS' COMMENTS REGARDING THE TWO-STAGE DCF MODEL?

A No. First, the two-stage DCF model recognizes that unusually high or low growth rates

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[9] *Id*. at 49.

[10] *Id*. at 51.

are unlikely to continue in the long term and adjusts them in the later years of the model. The two-stage DCF model uses projected earnings growth in the first stage and the projected GDP growth rate in the second stage. The GDP is not an upper bound, but is combined with the early-stage growth rate to estimate the long-term growth rate, which may be higher or lower than the projected GDP growth rate.

Second, the Minnesota Public Utilities Commission (MPUC) places its heaviest reliance on the DCF model. That Commission stated:

> The two-growth DCF model provides a fundamentally sound framework through which to analyze the Company's relative risk in relation to comparable companies, and through which to evaluate the Company's financial integrity and ability to attract investors in light of current as well as expected market conditions….And while the two-growth DCF model is not the only useful model, its strengths underscore the limitation of other models…The Commission therefore finds that the two-growth DCF analysis provided by the Company provides a reasonable basis for setting a return in this case.[11]

Furthermore, I would note that in the above quoted case, Mr. D'Ascendis provided ROE testimony on behalf of Northern States Power Company wherein he conducted a two-stage DCF analysis.[12]

Application of the Capital Asset Pricing Model

Q DOES MR. D'ASCENDIS AGREE WITH YOUR CAPITAL ASSET PRICING MODEL ANALYSES?

A No. Mr. D'Ascendis disagrees with the projected risk-free rate and projected market risk premium based on the S&P 500 I used in my CAPM analyses. He also disagrees with my "failure to include" the Empirical Capital Asset Pricing Model (ECAPM)."[13]

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[11] *In the Matter of the Application of Northern States Power Company, dba Xcel Energy, for Authority to Increase Rates for Electric Service in the State of Minnesota,* MPUC Docket No. E-002/GR-21-630, Findings of Fact, Conclusions, and Order at 89. (Jul. 17, 2023).

[12] *Id.*, Direct Testimony and Schedules of Dylan W. D'Ascendis at 29 (Oct. 25, 2021).

[13] Doc. 136, Rebuttal Testimony of Dylan W. D'Ascendis at 75.

Q PLEASE EXPLAIN MR. D'ASCENDIS CONCERNS WITH YOUR PROJECTED RISK-FREE RATE.

A Mr. D'Ascendis states that I should have included projected risk-free rates for the second through fourth quarters of 2024 instead of relying solely on the projected risk-free rate for the first three quarters of 2025. He cites Eugene F. Fama, stating that a market in which prices always fully reflect available information is called "efficient."[14] My use of the 2025 projected risk-free rate is reasonably based on the time period that new rates will go into effect for SUA, which is November 2024. The 2024 forecast risk-free rates will be out of date at the time they go into effect, therefore, it is more appropriate to use the 2025 forecast risk-free rate.

Q DO YOU AGREE WITH MR. D'ASCENDIS' CLAIM THAT SINCE YOU EXCLUDED COMPANIES WITH NEGATIVE GROWTH RATES AND GROWTH RATES ABOVE 20% WHEN ESTIMATING THE PROJECTED MARKET RISK PREMIUM, THEY SHOULD ALSO BE REMOVED FROM THE BETA CALCULATION?[15]

A No. Mr. D'Ascendis' observation is puzzling since he uses the average of two separate beta calculations in his CAPM analyses.

Mr. D'Ascendis uses Value Line betas based off of 1,700 companies in the Value Line index, as well as Bloomberg betas, which are estimated using stocks in the S&P 500 Index. The betas used in his analysis vary by as much as 44% for one company, and 29% on average.[16] Therefore, Mr. D'Ascendis' observation regarding the beta calculation is misleading.

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[14] *Id.*

[15] *Id*. at 59, 76.

[16] *Id.*, Calculated from Schedule DWD-1R.

Q **PLEASE EXPLAIN WHY YOU EXCLUDED THE ESTIMATED RETURN ON EQUITY USING THE FORECAST MARKET RISK PREMIUM BASED ON DATA FROM VALUE LINE.**

A I excluded the Value Line ROE because it is based on a high-level summary that includes companies that do not make dividend payments, as well as companies that have negative growth rates or growth rates above 20%.

Q **PLEASE EXPLAIN WHY YOU EXCLUDED THE EMPIRICAL CAPITAL ASSET PRICING MODEL FROM YOUR ROE ANALYSES.**

A As noted in my direct testimony, I excluded the ECAPM because it serves to inflate the ROE by readjusting the beta factor. The betas used in my analyses are from Value Line, which readjusts the raw betas to correct for the tendency of low betas understating risk and high betas overstating risk. Therefore, a further adjustment is unnecessary and serves to inflate SUA's ROE.

Application of the Risk Premium Method

Q **DOES YOUR RISK PREMIUM ANALYSIS CONSIDER THE IMPACT OF INTEREST RATES ON THE EQUITY RISK PREMIUM?**

A Yes. I calculated the equity risk premium based on the difference between historical authorized ROEs and historical interest rates. The variance in the equity risk premium captures not only the change in interest rates, but the change in other macroeconomic data that may also impact the equity risk premium, such as changes in market conditions and investor expectations. Commissioners often use this information when determining the appropriate ROE for a utility because interest rates alone do not dictate the appropriate ROE.

Q DID YOU BASE YOUR RISK PREMIUM ANALYSIS ON 30 YEAR LONG-TERM TREASURY BONDS?

A No. My Risk Premium analysis uses the return on A2 utility bond yields. To be consistent, I used the same yield used by Mr. D'Ascendis in his Risk Premium analysis.[17]

Risk Adjustment

Q DO YOU AGREE WITH MR. D'ASCENDIS' CONTENTION THAT SUA'S RISK IS NOT REDUCED DUE TO ITS PROPOSED BILLING DETERMINANT ADJUSTMENT AND MODIFIED SYSTEM SAFETY ENHANCEMENT RIDER?[18]

A No. SUA has several cost recovery mechanisms, including the Weather Normalization Adjustment, the Energy Efficiency Cost Recovery Rider, the Government Mandated Expenditure Surcharge (GMES), and Rider SSER, which it is proposing to expand from currently recovering approximately 29% of its capital expenditures to approximately 69% of its capital expenditures. Furthermore, SUA proposes to implement the BDA which would compensate SUA for deviations from the pro forma billing determinants, excluding those caused by the Weather Normalization Adjustment. The proposed BDA would true-up adjustments for revenues recovered through Rider SSER and the GMES. The expansion of the SSER and the proposed true-ups in Rider BDA would have lower financial risk as compared to the utilities in the proxy group if Rider SSER is expanded.

As demonstrated by Mr. D'Ascendis (Exhibit DWD-15R), which lists 29 utilities and their corresponding adjustment clauses and alternative regulation, only three have

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[17] Doc. 34, Direct Testimony of Dylan W. D'Ascendis, Schedule DWD-4 at 11.

[18] Doc. 136, Rebuttal Testimony of Dylan W. D'Ascendis at 63.

all five of the adjustment clauses listed — SUA would also have five if the Commission approves the BDA. The expansion of the SSER Rider and true-up for SSER revenues and GMES revenues shifts the risk of recovering the costs of the SSER Rider and GMES from shareholders to ratepayers. In comparison to the proxy group companies, SUA has much less risk and, therefore, my revised recommended 9.61% ROE is appropriate to recognize SUA's lower financial risk.

Q DO CREDIT RATING AGENCIES LOOK FAVORABLY UPON DECOUPLING MECHANISMS, AS WELL AS ADJUSTMENT CLAUSES?

A Yes. Moody's favorably considers a utility's ability to recover costs and earn returns when assigning a credit rating. Specifically, Moody's considers "provisions and cost recovery mechanisms for operating costs, mechanisms that allow actual operating and/or capital expenditures to be trued-up periodically into rates without having to file a rate case (this may include formula rates, riders and trackers, or the ability to periodically adjust rates for construction work in progress)…"[19] As stated above, SUA has numerous clauses and other mechanisms that improve its timeliness in recovering costs, thus reducing its financial risk.

Size Adjustment

Q MR. D'ASCENDIS CLAIMS THAT A SIZE ADJUSTMENT FOR SUA IS NECESSARY.[20] DO YOU AGREE?

A No. As noted in my direct testimony, it is inappropriate to compare the size of SUA, which is a subsidiary of Summit Utilities, Inc., to the total market capitalization of the

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[19] Moody's Investors Service, Rating Methodology, *Regulated Electric and Gas Utilities* at 12-13. (Jun. 23, 2017).

[20] Doc. 136, Rebuttal Testimony of Dylan W. D'Ascendis at 34-35.

companies in the proxy group. While I agree the companies in the proxy group should be as closely comparable to SUA as possible, a size adjustment ignores the fact that SUA, when combined with the other subsidiaries of Summit Utilities, Inc., as well as the subsidiaries of its Southern Co HoldCo, is similar in size to the proxy group companies. SUA's size does not impact its risk because it benefits from its parent company — SUA does not operate in isolation. Therefore, the size adjustment should be rejected.

Q HAS THIS COMMISSION PREVIOUSLY REJECTED A SIZE ADJUSTMENT?

A Yes. In Southwestern Electric Power Company's (SWEPCO) rate case, Docket No. 21-070-U, the Commission rejected SWEPCO's proposed size adjustment, stating:

> The Commission finds no credible evidence to support SWEPCO's contention that it faces above-average risk due to its size. The Commission agrees with Mr. Walters that SWEPCO is not a stand-alone small company, and that it receives numerous benefits as a part of AEP. The Commission finds that a size adjustment to the ROE is not appropriate.[21]

Capital Structure

Q DO YOU AGREE WITH MR. ROOT'S STATEMENT THAT IF SUA'S COMMON EQUITY RATIO IS LOWER THAN SUA'S PROPOSED 55%, THERE IS "DOCUMENTED RISK" THAT SOUTHERN COL MIDCO, LLC'S CURRENT CREDIT RATING COULD BE LOWERED?[22]

A No. Mr. Root cites as support a credit report by Fitch,[23] but the Fitch report does *not* predict a lower credit rating for Southern Col Midco in such a circumstance, and the

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[21] *In the Matter of the Application of Southwestern Electric Power Company for Approval of a General Change in Rates and Tariffs,* Docket No. 21-070-U, Doc. 323, Order No. 14 at 20-21 (May 23, 2022).

[22] Doc. 133, Rebuttal Testimony of Craig Root at 3.

[23] Doc. 141, Confidential Rebuttal Exhibit of Craig Root, Exhibit CR-1 at 2.

common equity ratio recommended by me and by the Staff is consistent with recent Arkansas outcomes.

Q WHAT ARE THE COMMON EQUITY RATIOS APPROVED BY THE ARKANSAS COMMISSION IN THE LAST TWO YEARS?

A The APSC authorized a 45% equity ratio for Black Hills in Docket No. 21-097-U on October 10, 2022.[24] In Docket No. 21-070-U, the Commission authorized a 45% equity ratio for Southwestern Electric Power Company on May 23, 2022.[25]

Q HAVE YOU REVISED YOUR CAPITAL STRUCTURE RECOMMENDATION?

A Yes. Upon review of Staff witness Daves' direct testimony, I have revised my recommended capital structure to incorporate a 44% equity ratio.

Q WHY HAVE YOU ADOPTED STAFF'S RECOMMENDED CAPITAL STRUCTURE?

A Staff's recommended capital structure is similar to those approved by the Commission in the dockets mentioned above and is supported by the equity ratios of the same risk comparable companies. In Docket No. 21-070-U the Commission found:

> [T]he Commission holds that there should be congruence between the estimated cost of equity and the DTE ratio, whereby a lower DTE ratio decreases financial risk and decreases the cost of equity. The evidence of the record supports imputing the average capital structure of companies with comparable risk to SWEPCO for the purposes of determining SWEPCO's overall cost of capital.[26]

Therefore, I support Staff's recommended 44% equity ratio as it meets the criteria set forth by the Commission as noted above. Further, it ensures that ratepayers are not burdened with excessive equity costs, as debt is cheaper than equity.

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[24] *In the Matter of the Application of Black Hills Energy Arkansas, inc., for Approval of a General Change in Rates and Tariffs*, Docket No. 21-097-U, Doc. 170, Order No. 7 at 59 (October 10, 2022).

[25] Docket No. 21-070-U, Doc. 323, Order No. 14 at 109-110 (May 23, 2022).

[26] *Id.* at 25.

Q WHAT IS YOUR RECOMMENDED RATE OF RETURN FOR SUA BASED ON YOUR REVISED ROE ANALYSES AND REVISED RECOMMENDED CAPITAL STRUCTURE?

A The recommended rate of return for SUA using my 9.61% ROE and 44% common equity ratio is 5.0719%. The impact of the lower ROE and equity ratio reduces SUA's revenue requirement by $22.9 million, as compared to SUA's requested 11% ROE and revised 54.88% equity ratio. The details of this calculation are shown in **Exhibit BSL-4S.**

Incentive Compensation

Q DOES SUA'S INCENTIVE COMPENSATION PLAN HAVE FINANCIAL TARGETS THAT THE COMPANY MUST MEET BEFORE IT PAYS EMPLOYEES A PORTION OF THEIR INCENTIVE COMPENSATION?

A Yes. Forty percent of SUA's incentive compensation plan is based on financial metrics, such as targeted Earnings Before Income Taxes, Depreciation, and Amortization, as well as the dividend yield.

Q SHOULD RATEPAYERS PAY A HIGHER PERCENTAGE OF SUA'S ANNUAL INCENTIVE COMPENSATION FOR ITS EMPLOYEES?

A No. Not all incentive compensation benefits ratepayers. SUA's incentive compensation plan includes operational targets, which do benefit ratepayers. However, financial targets serve to benefit shareholders *only*.

Q DOES SUA DISAGREE WITH YOUR DISALLOWANCE OF INCENTIVE COMPENSATION RELATED TO FINANCIAL TARGETS?

A Yes. SUA claims that incentive compensation allows the company to attract and retain talent and "…helps employees focus on goals of various types that work in tandem to benefit customers and further the Company's ability to provide quality service to customers."[27]

Q DO YOU SUPPORT INCENTIVE COMPENSATION?

A Yes. I agree that incentive compensation assists the company in attracting and retaining talented employees. However, I do not support including short-term incentive compensation tied to financial targets in rates. SUA may continue to offer incentive compensation related to financial targets to its employees, but ratepayers should not fund short-term, financially based incentive compensation because the only beneficiaries of these programs are shareholders. Therefore, I reject SUA's inclusion of short-term incentive compensation costs tied to financial targets and recommend removing $1.4 million of incentive compensation expense and $0.5 million of capitalized incentive compensation.

Volunteer Time Off

Q DOES SUA OPPOSE YOUR RECOMMENDATION TO EXCLUDE COSTS ASSOCIATED WITH VOLUNTEER TIME OFF FOR SUA'S EMPLOYEES?

A Yes. SUA claims that, similar to short-term incentive compensation, VTO benefits are reasonable and should be included in its cost of service.[28] However, this is an indirect

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[27] Doc. 135, Rebuttal Testimony of Sam Springer at 3.

[28] Doc. 128, Rebuttal Testimony of Phillip B. Gillam at 12.

benefit to customers and cannot be measured in rates. SUA may continue to support VTO among its employees, but because customers do not directly benefit from VTO, the costs should not be included in SUA's rates. Furthermore, VTO hours are not required for SUA to provide safe, reliable, and cost-effective service to ratepayers.

Q DO YOU HAVE ANY CHANGES TO YOUR RECOMMENDED ADJUSTMENTS TO SUA'S PROPOSED VOLUNTEER TIME OFF EXPENSES?

A Yes. Upon review I determined that my recommended adjustment for VTO hours excluded payroll taxes and capitalized costs associated with VTO. Therefore, I recommend reducing payroll taxes by $151,865 and capitalized VTO costs by $57,145.

Operations and Maintenance Expense

Q PLEASE COMMENT ON SUA'S RECOMMENDATION TO INCLUDE ADDITIONAL OPERATION AND MAINTENANCE EXPENSE RELATED TO MAINTENANCE OF MAINS.

A SUA opposes my recommendation to exclude certain O&M expense related to maintenance of mains. SUA claims that new mains also require maintenance activities, regardless of their age.[29]

Q DO YOU AGREE THAT NEW MAINS STILL REQUIRE MAINTENANCE ACTIVITIES?

A Yes. However, newer mains should require less O&M expense as compared to the older mains that are being replaced. Therefore, I continue to support a reduction in O&M expense related to maintenance of mains.

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[29] Doc. 131, Rebuttal Testimony of Vernon McNully at 3.

Q DO YOU HAVE ANY ADJUSTMENTS FOR YOUR RECOMMENDED REDUCTION IN OPERATIONS AND MAINTENANCE EXPENSE FOR SUA'S MAINTENANCE OF MAINS?

A Yes. SUA witness, Mr. Vernon McNully, noted that I did not make an adjustment for inflation when I recommended a $1.4 million reduction in FERC Account 887, Maintenance of Mains.[30]

Q HAVE YOU ACCOUNTED FOR INFLATION IN YOUR REVISED RECOMMENDED OPERATION AND MAINTENANCE ADJUSTMENT?

A Yes. My revised recommended adjustment includes a 2.78% inflation adjustment for 2023. This was applied to SUA's actual 2022 maintenance of mains expense, which was $8.97 million, resulting in $9.2 million of expense in 2022. The average cost per mile is $664.21, multiplied by 13,909.08 miles of main, my recommended maintenance of mains cost is $9.2 million, which is approximately $1.1 million less than SUA's proposed $10.3 million cost.

Riders

Q DO YOU AGREE WITH SUA'S CLAIMS THAT RIDER SSER SHOULD BE EXPANDED BECAUSE IT MORE CLOSELY MATCHES THE TIMING OF THESE EXPENDITURES TO THE ACTUAL COST RECOVERY?[31]

A No. Expanding Rider SSER to recover approximately 69% of SUA's capital expenditures significantly reduces regulatory lag. SUA has not proposed to recognize the reduction in regulatory lag by reducing rates for customers, such as a lower ROE.

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[30] *Id.* at 4.

[31] Doc. 128, Rebuttal Testimony of Phillip B. Gillam at 32.

Furthermore, SUA's current Rider SSER has a cap determined on an annual basis using a percentage of base rate revenues.[32]

Q DO YOU HAVE ANY OTHER COMMENTS ABOUT RIDER SSER?

A Yes. Currently, Rider SSER includes a cumulative level of savings due to the reduction in O&M expenses as a result of the capital investments. SUA claims that "[r]eplacement of facilities does not directly reduce the amount of O&M expenses."[33] Recognizing the cumulative savings in O&M expenses due to new investment is similar to my recommendation to reduce maintenance of mains expense because new mains require less maintenance. Therefore, I support the continuation of the recognition of cumulative savings in O&M due to new investment. However, my recommendation to reduce the maintenance of mains expense should not overlap with the recognition of cumulative savings in Rider SSER.

Q DO YOU SUPPORT STAFF WITNESS SWAIM'S RECOMMENDATION TO REMOVE THE TRUE-UP ADJUSTMENTS RELATED TO RIDER SSER AND RIDER GMES IN RIDER BDA?[34]

A Yes. Rider SSER and Rider GMES are not exact recovery riders and no true-up mechanism is required. However, if the Commission authorizes the true-up mechanism in Rider BDA, I recommend a reduction to SUA's ROE in the lower end of my recommended range. Allowing a true-up of these costs removes all regulatory lag related to these costs and shifts the burden of recovery to ratepayers.

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[32] Doc. 97, Direct Testimony of Jeff Hilton at 16.

[33] Doc. 128, Rebuttal Testimony of Phillip B. Gillam at 28.

[34] Doc. 110, Direct Testimony of Robert H. Swaim at 18.

COVID-19 Regulatory Asset

Q PLEASE DESCRIBE SUA'S PROPOSED TREATMENT OF ITS DEFERRED COVID-19 EXPENSE.

A SUA has a regulatory asset related to expenses incurred due to the pandemic and a moratorium on customer disconnections. The regulatory asset was authorized by the Commission in Docket No. 20-012-A.[35] SUA has accumulated $6,339,131 of expense and proposes to recover the amount from customers over three years, or $2,113,044 million per year.[36]

Q DO YOU AGREE WITH SUA'S PROPOSAL?

A No. Staff witness Hilton has proposed a five-year amortization of the expense, rather than three years.[37] I support Mr. Hilton's recommendation. A five-year amortization would reduce the annual amount recovered by SUA from customers to $1,267,826 per year, or $845,218 per year less than SUA's proposal.

Q DOES SUA SUPPORT MR. HILTON'S PROPOSAL TO RECOVER THE COVID-19 REGULATORY ASSET OVER FIVE YEARS?

A SUA does not support the recovery of the regulatory asset over five years, unless a carrying cost at SUA's weighted average cost of capital is included.[38] If the carrying cost is not included, SUA continues to support its proposed three-year amortization of the COVID-19 regulatory asset.

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[35] Doc 97, Direct Testimony of Jeff Hilton at 12.

[36] *Id.*

[37] *Id.*

[38] Doc. 128, Rebuttal Testimony of Phillip B. Gillam at 18.

Q **WHY DO YOU SUPPORT MR. HILTON'S PROPOSAL?**

A SUA is seeking a 55.7% increase in base rates, or approximately $101.2 million.[39] The LCS-1 customer class's proposed increase is 91.3%.[40] In light of SUA's proposed rate increase, amortizing the regulatory asset over five years will lessen the impact of the proposed rate increase, which is significant.

Q **DO YOU AGREE WITH SUA'S PROPOSAL TO EARN A RETURN ON THE UNAMORTIZED PORTION OF THE REGULATORY ASSET IF IT IS AMORTIZED OVER FIVE YEARS?**

A No, I do not support the inclusion of a return on the unamortized portion of the regulatory asset. However, if the Commission authorizes SUA to earn a return on the regulatory asset, then I recommend using SUA's long-term debt cost to calculate the return. This will allow the company to recover the deferred expense while being compensated for the extended amortization period.

Revenue Conversion Factor

Q **WHAT IS THE REVENUE CONVERSION FACTOR?**

A The RCF is used to gross up SUA's operating income shortfall to determine the additional income that is needed for SUA's federal and state income taxes, uncollectible accounts, and forfeited discounts. Staff revised SUA's RCF to account for the current Arkansas state income tax, as well as the correct rate for uncollectible expense.[41]

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[39] Doc. 18, Application, Schedule G-1 Cost of Service Study – Summary.

[40] *Id.*

[41] Doc. 97, Direct Testimony of Jeff Hilton at 13-14.

Q WHAT IS THE CORRECT REVENUE CONVERSION FACTOR?

A The correct RCF is 1.3253, which my colleague, Jonathan Ly, has incorporated into his class cost-of-service study.[42]

Q DOES THIS CONCLUDE YOUR SURREBUTTAL TESTIMONY?

A Yes.

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[42] *Id*. at 13-14.

Exhibit BSL-1S

SUMMIT UTILITIES

Revised Discounted Cash Flow Analysis Excluding WEC

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	Average											8.21%	9.52%	10.93%
10	Minimum											5.46%	6.86%	8.26%
11	Maximum											9.89%	11.48%	13.38%

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

Exhibit BSL-2S

SUMMIT UTILTIES

Revised Two-Stage Discounted Cash Flow Analysis Excluding WEC

Line	Company	Stock Symbol (1)	Stock Price Price (2)	Expected Annualized Dividend (3)	First Stage Growth Rate (4)	Second Stage Growth Rate (5)	ROE (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	Average						9.43%
10	Minimum						7.86%
11	Maximum						10.64%

Exhibit BSL-3S

SUMMIT UTILITIES
Revised Capital Asset Pricing Model Excluding WEC

Line	Company	Ticker (1)	Current Beta (B) (2)	Projected Risk-Free Rate (R_f) (3)	Historical Risk Premium (R_p) (4)	Historical CAPM ROE (5)	Projected Risk Premium (R_p) (6)	Projected Risk Premium CAPM ROE (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	Average		0.91			10.61%		9.77%
10	Minimum		0.85			10.18%		9.39%
11	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.

Exhibit BSL-4S

SUMMIT UTILITIES

Impact of Reducing ROE to 9.61% and Common Equity Ratio to 44%

	Proposed ROE for the Test Year Ending December 31, 2024						AGC Recommended ROE and 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	45.12%	4.81%	2.17%	1.000	2.17%	Long-Term Debt	56.00%	4.81%	2.69%	1.000	2.69%
2	Common Equity	54.88%	11.00%	6.04%	1.325	8.00%	Common Equity	44.00%	9.61%	4.23%	1.325	5.60%
3	Total	100.00%		8.21%		10.17%	Total	100.00%		6.92%		8.30%
4	Test Year Rate Base			$1,223,251,086			Impact of Change in ROE					($22,930,559)

SOURCES:
Exhibit DWD-1 at 1.
Schedule A-1.
Rebuttal Testimony of Craig Root at 2.

Certificate of Service

I, Shawn McMurray, hereby certify that on September 9, 2024, I served a copy of the foregoing Surrebuttal Testimony and Exhibits of Billie S. LaConte upon all parties of record by electronic mail *via* the APSC's Electronic Filing System.

/s/ *M. Shawn McMurray*

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**

SURREBUTTAL TESTIMONY

OF

LARRY BLANK

ON BEHALF OF

HOSPITALS AND HIGHER EDUCATION GROUP

September 9, 2024

Contents

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. DID YOU PREVIOUS PREPARE DIRECT TESTIMONY FILED IN THIS CASE?

A. Yes, I prepared direct testimony filed in this docket on July 10, 2024.

Q. ON WHOSE BEHALF ARE YOU TESTIFYING?

A. I am testifying on behalf of the Hospitals and Higher Education Group ("HHEG").

II. PURPOSE AND SUMMARY

Q. WHAT IS THE PURPOSE OF YOUR SURREBUTTAL TESTIMONY?

A. I am responding to direct and rebuttal testimonies of parties to this docket filed on July 10, 2024 and August 7, 2024, respectively. Specifically, Summit Utilities Arkansas, Inc. ("SUA" or the "Company") witness Mr. Craig Root's rebuttal testimony on the capital structure ratios for SUA, SUA witness Mr. Fred Kirkwood's rebuttal testimony suggestion that no weight be given to service performance in return on equity ("ROE") considerations, SUA witness Mr. Phillip Gillam's rebuttal testimony regarding the expansion of the System Safety Enhancement Rider, and Attorney General witness Mr. Richard W. Porter's direct testimony on cost allocation. In addition, I respond to SUA witness Mr. Timothy S. Lyons' rebuttal testimony and Arkansas Public Service Commission ("Commission") General Staff ("Staff") witness Mr. Robert H. Swaim's direct testimony regarding approaches to the design day calculations.

III. COST OF CAPITAL

Q. HAVE YOU REVIEWED THE REBUTTAL TESTIMONY OF CRAIG ROOT ON BEHALF OF THE COMPANY?

A. Yes.

Q. HAS THE COMPANY UPDATED ITS PROPOSED HYPOTHETICAL CAPITAL STRUCTURE RATIOS?

A. Yes. He states:

> The Company has updated its proposed capital structure based on the final audited balance sheet of SCHC as of December 31, 2023. The Company's updated proposed capital structure of 45% debt and 55% equity is reasonable, remains consistent with the actual planned capital structure for SCHC as of December 31, 2024, and is in-line with industry trends and standards.[1]

Q. HAVE YOU UPDATED YOUR RECOMMENDED EXTERNAL CAPITAL STRUCTURE RATIOS IN RESPONSE TO THE COMPANY'S UPDATE?

A. Yes. Based on the updated Southern Col Holdco, LLC's ("SCHC") values provided by the Company in Schedule D-1.3, I now recommend 51.82% long-term debt and 48.18% common equity for external capital ratios.

Q. PLEASE SUMMARIZE MR. ROOT'S REBUTTAL OF YOUR TESTIMONY.

A. First, Mr. Root disagrees with my observation that the removal of the Winter Storm Uri debt as a "Special Pro Forma" adjustment, as proposed by the Company, increases cost recovery for Uri beyond what the Commission has approved. This adjustment clearly is an attempt to increase cost of capital and base rates in this rate case and, thereby,

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[1] Root Rebuttal at 3:4-8.

circumvent the Commission's decision on appropriate cost recovery for Winter Storm Uri. This special adjustment should be explicitly denied by the Commission.[2]

Second, Mr. Root rebuts my position that their "Special Pro Forma" adjustment to remove goodwill from the capital structure is a mere mathematical manipulation to derive a desired hypothetical capital structure. He goes so far as to suggest that eliminating this adjustment would violate the merger settlement agreement.[3] Mr. Root's rebuttal is based on a myopic view that ratemaking and capital structure is solely related to his development of hypothetical capital structure ratios for calculation of the just and reasonable rate of return. He ignores the fact that the capital structure for SUA is actually developed by taking the hypothetical capital ratios and applying those to the pro forma rate base of SUA to derive the dollar amounts of the SUA capital structure. Because goodwill has been removed from the SUA rate base as a pro forma adjustment, goodwill has also been removed from the capital structure of SUA consistent with the merger settlement agreement. Therefore, my recommendation to deny the Company's special goodwill adjustment in the calculation of capital structure ratios is completely consistent with the merger settlement agreement. To allow the Company's proposed special goodwill adjustment would actually constitute a violation of the merger settlement agreement and a violation of the Commission's decision in that case because it is an attempt to manipulate the capital ratios to balance the equally egregious proposed special adjustment for Winter Storm Uri debt. The Company's position on this is effectively an example of attempting

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[2] Root Rebuttal at 14:3-12.

[3] *Id*. at 15:4-7.

two wrongs to make a right. Because the first wrong, the removal of Winter Storm Uri debt goes too far in producing a very high equity ratio, the Company seems to attempt to balance it with a second wrong, a fictional goodwill adjustment, to derive a mathematically contrived hypothetical capital structure.

Q. DO YOU HAVE A RESPONSE TO MR. ROOT'S CONCERN WITH YOUR USE OF THE TERM "PROXY" FOR SCHC?

A. Yes. Although SCHC may be the sole source of financial capital for SUA at this time, it does not represent the regulated utility within the Arkansas jurisdiction and is only being used as a proxy in the determination of the hypothetical capital structure ratios for SUA for the purposes of this rate case as proposed by SUA and myself. The balance sheet of SCHC may not serve well for this purpose in future rate cases. The differences in our external capital structure ratios are really limited to the two issues I have already discussed; that is, the Company's proposed special adjustments for Winter Storm Uri debt and the goodwill adjustment. To better understand the true disagreement between Mr. Root and me, I am providing a comparison in Table 1, below, in which the only change I make from the SUA-proposed ratios is the removal of these "Special Pro Forma Adjustments." Without those contrived special adjustments, my recommendation is that the actual, pro forma capital structure of SCHC is reasonable for use as a hypothetical capital structure for SUA in this case and as Mr. Root has pointed out, SCHC is the sole source of financing for SUA at this time.

Table 1. Capital Structure Comparison between Summit and HHEG*

		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	Subtotal Amount End of Pro Forma Year	Special Pro Forma Adjustments	Amount End of Pro Forma Year	External Capital Percent
1	**Summit-Proposed External**						
2	Long-Term Debt	$1,163,088,203	$ 100,992,122	$ 1,264,080,325	$ (719,969,326)	$ 544,110,999	**45.12%**
4	Common Equity	1,065,495,573	109,981,190	1,175,476,763	(513,782,209)	661,694,554	**54.88%**
5	Totals	$2,228,583,776	$ 210,973,312	$ 2,439,557,088	$ (1,233,751,535)	$1,205,805,553	100.00%
6	**HHEG-Recommend External**						
7	Long-Term Debt	$1,163,088,203	$ 100,992,122	$ 1,264,080,325	$ -	$1,264,080,325	**51.82%**
9	Common Equity	1,065,495,573	109,981,190	1,175,476,763	-	1,175,476,763	**48.18%**
10	Totals	$2,228,583,776	$ 210,973,312	$ 2,439,557,088	$ -	$2,439,557,088	100.00%
11	*Amounts come from Summit Schedule D-1.3-Holdco (updated 8-7-24). Southern Col Holdco LLC.						

Q. HOW SHOULD YOUR UPDATED RECOMMENDATION FOR THE EXTERNAL CAPITAL RATIOS BE INCORPORATED INTO THE FULL CAPITAL STRUCTURE OF SUA?

A. First, 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 51.82% long-term debt and 48.18% 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 holding company level which is influenced by other non-jurisdictional inputs.

Q. DOES SUA REBUT YOUR RECOMMENDATION TO GIVE GREATER WEIGHT TO THE LOWER RANGE OF ROE ESTIMATES BASED ON POOR SERVICE PERFOMANCE?

A. Yes. Mr. Kirkwood suggests that the performance concerns have been investigated and no violations of Commission rules have been found. Because the service concerns have been mitigated or resolved, Mr. Kirkwood suggests that no weight should be given to my ROE comments.[4]

Q. DO YOU HAVE ANY ADDITIONAL EVIDENCE IN SUPPORT OF YOUR RECOMMENDATION TO GIVE WEIGHT TO RECENT SERVICE PERFORMANCE OR CUSTOMER DISSATISFACTION?

A. Yes. A finding of no violations of Commission rules does not indicate that service quality issues do not exist. In this docket we have seen 49 comments filed by what appear to be customers of SUA mostly in opposition to the proposed rate increase. Some of these comments go directly to recent service concerns. The fact that 49 customer comments have been submitted to the Commission is indicative of some level of customer dissatisfaction. By contrast, in the recent Black Hills Energy Arkansas gas rate case, Docket 23-074-U, only two concerned customers submitted comments.

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 and management changes.

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[4] Kirkwood Rebuttal at 6:15-16.

IV. SYSTEM SAFETY ENHANCEMENT RIDER

Q. HAVE YOU REVIEWED THE REBUTTAL TESTIMONY OF PHILLIP GILLAM ON BEHALF OF SUA REGARDING THE SSER?

A. Yes. In response to my suggestion that general rate cases or an FRP with its customer protections and balancing of costs and benefits is the proper way to include capital expenditures in rates, Mr. Gillam states the following:

> The Company believes the expanded SSER is the better option at this time because it more closely matches the timing of these expenditures to the actual cost recovery. The gradual change in rates as SSER projects are completed and included in the cost recovery mechanism can serve to lessen the impact of future rate increases that potentially cause a one-time large increase until the next rate proceeding. Rate gradualism can be just as important a rate-setting concept as periodic larger rate increases.[5]

Q. DO YOU HAVE A RESPONSE TO THIS CHARACTERIZATION OF THE SSER?

A. Yes. Mr. Gillam ignores the primary concerns with the proposed SSER expansion stated in my direct testimony. First, unlike an FRP, the SSER does not include certain customer protections such as a rate cap on increases. Second, capital expenditures should also result in reductions in operation and maintenance expenses and potentially other cost savings. Unlike an FRP or a general rate case, the SSER does not provide a comprehensive look at all costs and benefits and only serves to allow cost recovery on the single issue of capital expenditures. This is known as single-issue or piecemeal ratemaking which is traditionally prohibited outside of extreme circumstances. Speeding up cost recovery through single issue ratemaking for the sake of gradualism is not an established rate-setting concept as suggested by Mr. Gillam.

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[5] Gillam Rebuttal at 32:6-11.

Q. WHAT IS YOUR RECOMMENDATION FOR THE PROPOSED EXPANSION OF THE SSER?

A. I continue to recommend the Commission deny the requested expansion and reference the FRP option available to SUA.

V. COST ALLOCATION

Q. HAVE YOU REVIEWED THE ATTORNEY GENERAL'S TESTIMONY REGARDING COST ALLOCATION FACTORS?

A. Yes, I have read the testimony of Mr. Porter.

Q. DO YOU HAVE ANY RESPONSE TO HOW HE CHARACTERIZES THE ALLOCATION METHODS UNDER CONSIDERATION IN THIS CASE?

A. Yes. Mr. Porter makes the following observation in regard to the customer count allocation factors: "[t]his allocation factor assumes that the residential class should contribute 88.80% of the relevant costs. What the use of this allocator ignores is that annual usage for the residential class is only 30.90% of total annual deliveries…"[6] This statement by Mr. Porter ignores that portions of the gas distribution utility costs are primarily caused by the number of customers on the distribution system and other costs are primarily caused by maximum customer demands on the system and, to a lesser extent, the volume of gas consumed by customers. Mr. Porter also ignores the fact that the cost of purchased gas is entirely caused by the volume of gas used by customers and the higher users of gas throughout the year pay more because they consume more gas. Cost causation is a primary consideration when

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[6] Porter Direct at 36:4-7 (internal citation omitted).

selecting a cost allocation method for a particular category of costs and not the difference between allocation factors as Mr. Porter has emphasized here.

Q. WHAT MODIFICATIONS DOES MR. PORTER RECOMMEND?

A. First, he recommends substituting the customer component of the Demand Allocation Factors with an energy consumption allocation component (weighted 25%). Second, he makes a similar substitution for the customer component in the Mains Allocation Factors with an energy consumption allocation component but weighted by the Minimum System Customer percentage.[7]

Q. WHAT CONCERNS DO YOU HAVE WITH THESE MODIFICATIONS SUGGESTED BY MR. PORTER?

A. First, volumetric energy usage is very different from number of customers and not considered a primary driver in cost causation considerations for gas distribution systems as I discuss above. Second, Mr. Porter's use of the Minimum System Customer percentage as the weight for the energy consumption allocator is a significant mismatch in concepts and approaches. Minimum System Customer percentage is not related to annual energy consumption, but instead, is related to minimum planning for customers on the system. Using a minimum system approach in combination with an energy allocation method mixes two unrelated concepts. Distribution mains are sized to meet expected maximum demands of customers on those mains but the minimum system approach attempts to identify the minimum size necessary to accommodate all the customers on the distribution main. This mismatch in approaches should be rejected by the Commission.

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[7] *See* Porter Direct at 42:3-44:3

VI. DESIGN DAY DEMAND CALCULATIONS

Q. HAVE YOU REVIEWED MR. LYON'S REBUTTAL TESTIMONY REGARDING DESIGN DAY DEMANDS?

A. Yes. Mr. Lyon's rebuttal testimony tried to explain the LCS-1 and LCS-1 TSO volumes for the proforma year were based on 6-years of data, which lacked evidence of weather sensitivity, but the design day demands were based on 1-year of data, which supported his conclusion the demands are weather sensitive.[8]

Q. WHY IS THIS LOGIC FUNDAMENTALLY FLAWED?

A. Because the design day demands are calculated off the customers' volumes and both are calculated to represent a proforma year, it is illogical to state that the design day demands are weather sensitive, but the volumes are not. This seems to be the result of differences in sample data and possibly an anomaly in only one year of data.

Q. DID STAFF'S WITNESS MR. SWAIM WEATHER NORMALIZE DESIGN DAY DEMANDS FOR LCS-1 OR LCS-1 TSO?

A. No. Mr. Swaim used the average daily volume for the month of February, normalized for the number of customers, but not for weather.

Q. DO YOU AGREE WITH MR. SWAIM'S METHOD FOR CALCULATING DESIGN DAY DEMANDS FOR LCS-1 AND LCS-1 TSO?

A. Partly, but I do have concerns regarding the use of February due to the anomaly of the February data. I provide a comparison of average monthly volumes per customer for LCS-1 TSO for years 2018-2023, below.

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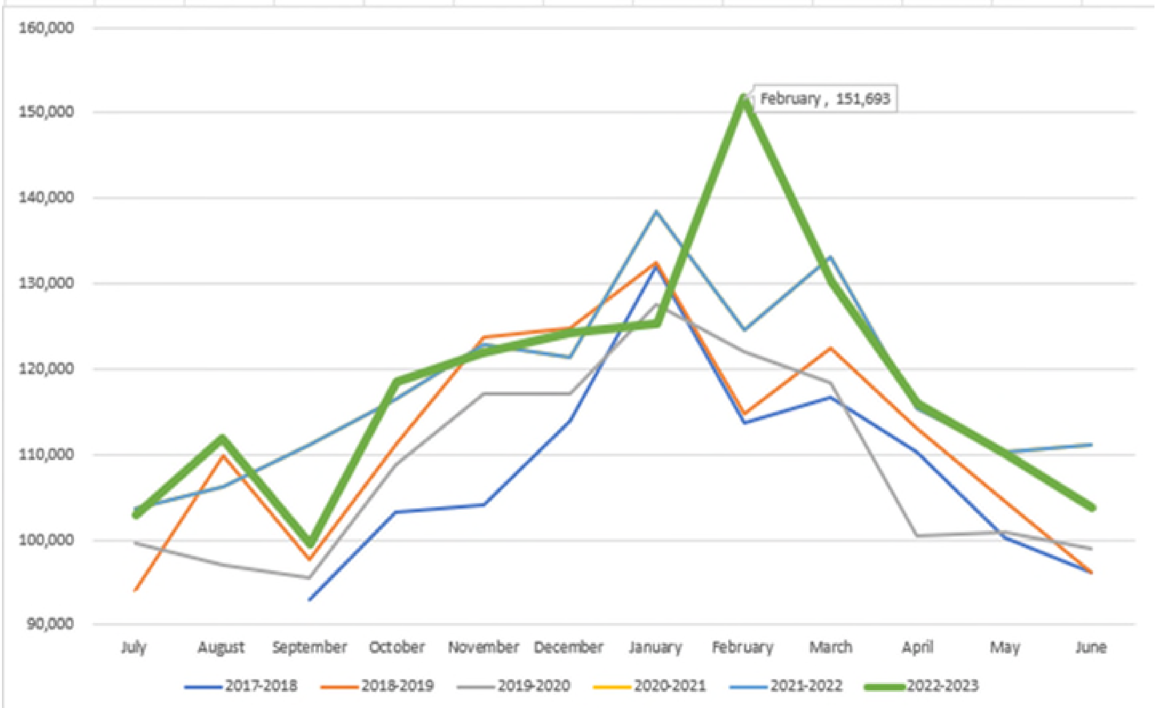
[8] *See* Lyons Rebuttal at 14:4-16.



The February 2023 monthly volumes per customer is outside of the historical normal consumption. This chart also reveals a significant decline in demand from January to February in every year except for 2023, which is a significant anomaly. I also reviewed the historical Contract Demands for LCS-1 TSO from ASPC Data Request – 085, updated through June 2024. If there was a spike in average monthly volumes equating to a 22% increase year over year, you would expect to see a similar increase in billed contract demands. Per the Company's data, Contract Demand only increased 6%. Coupling my analysis of the data with the historical billing issues the company has had, I'm concerned that the data is a misrepresentation of the proforma year's volumes for February.

Q. DO YOU CONTINUE TO RECOMMEND USING LCS-1 TSO'S AVERAGE DAILY ANNUAL CONSUMPTION?

A. Yes. Mr. Lyon's rebuttal testimony updated methodology to use the (non-weather normalized) average daily consumption from November through April is also acceptable as long as his weather normalization adjustment is rejected.

VII. <u>RATE DESIGN</u>

Q. IN HIS REBUTTAL TESTIMONY, HAS MR. LYONS ACCEPTED YOUR RECOMMENDATIONS ON RATE DESIGN?

A. Yes.[9] Mr. Lyons has accepted my recommendation to have the transportation customers and sales customers billing determinants 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 one LCS-1 rate class with additional fees for telemetry and administrative cost for transportation customers. Mr. Lyons also accepts my recommendation to hold SCS-2 and SCS-3 at present rate levels.

Q. DOES THIS CONCLUDE YOUR TESTIMONY?

A. Yes.

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[9] Lyons Rebuttal at 15.

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 9th day of September, 2024.

/s/ Randall L Bynum
Randall L Bynum, Bar No. 89194

Counsel for HHEG

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

SURREBUTTAL TESTIMONY

OF

JEFF HILTON
DIRECTOR
GAS AND WATER UTILITIES SECTION

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

SEPTEMBER 9, 2024

TABLE OF CONTENTS

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.

PURPOSE OF TESTIMONY

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

A. The purpose of my Surrebuttal Testimony is to address the Rebuttal filing made by Summit Utilities Arkansas, Inc. ("SUA" or "Company") on August 7, 2024. 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 System Safety Enhancement Rider ("SSER"). In my discussion, I will address the Rebuttal Testimonies of Company witnesses Phillip B. Gillam and Vernon McNully.

STAFF WITNESS LIST

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

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

Witness	Issue(s) Addressed
Jeff Hilton	Witness List
	Revenue Requirement
	Operating Revenue
	Operating Expenses

	Revenue Conversion Factor SSER
Don Malone	Working Capital Assets Current, Accrued, and Other Liabilities Accumulated Deferred Income Taxes Excess Accumulated Deferred Income Taxes Other Revenue Operating Expenses Income Tax Expense
Middleton Ray	Payroll and Employee-Related Benefits Incentive Compensation
Michael Pitts	Gross Plant-in-Service Accumulated Depreciation Property Taxes Depreciation Expense
Claude Robertson	Depreciation Rates and Parameters Unrecovered Reserve
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 Rebuttal case?

A. SUA's Rebuttal case used a test year ending December 31, 2023, comprised of twelve months of actual data and a *pro forma* year ending December 31, 2024.[1] SUA also updated certain schedules through April 30, 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, the same as the Company's Rebuttal, with adjustments to the *pro forma* year for known and measurable changes through December 31, 2024.

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 Surrebuttal Exhibit JH-1, Summary of Operations. As shown on Surrebuttal Exhibit JH-1, Staff's recommendations result in a Revenue Deficiency of $76,201,917 and a non-gas Revenue Requirement of $256,234,297. In contrast, SUA's proposed Revenue Deficiency is $101,194,113 with a non-gas Revenue Requirement of $289,834,695,[3] for a difference of $24,992,196 and $33,600,398 from Staff's determination, respectively. However, the

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[1] Rebuttal updated cost of service study and Minimum Filing Requirements ("MFR") schedules pursuant to Rule 8.12(d) of the Commission's Rules of Practice and Procedure, Doc. 126, Part 1, PDF p.1.

[2] Rebuttal MFR Schedules B-4, B-5, D-6.1, D-6.2, D-6.3, E-1.1, E-1.2, E-17.1.2 Doc. 126, Parts 1, 3, and 4.

[3] Rebuttal MFR Schedule A-1, Doc. 126, Part 1, PDF p. 3.

Company's Revenue Requirement is limited to its originally filed amount of $286,660,736.[4]

Also, SUA prematurely included its "Rolled-in Rider Revenue" of $10,116,448 in its Operating Revenue[5] even though the Rolled-in Rider Revenues do not become part of base rates until implementation of the rates as a result of this Docket. Whereas Staff's Operating Revenue does not include those riders because the associated Revenue Deficiency is determined by including the associated costs in Rate Base and Expense. To also include the Rider Revenue would essentially eliminate the associated deficiency. Therefore, because of the differing treatment of the Rolled-in Riders Revenue the difference in Staff's and SUA's Revenue Deficiency includes this additional difference of approximately $10,116,448. However, as discussed below, my Surrebuttal Exhibit JH-7 summarizes and reconciles the differences between Staff's and the Company's non-gas Revenue Requirements, which is only negligibly affected by the Company's differing treatment of the Rolled-in Riders Revenue.

Q. What other exhibits are you sponsoring?

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[4] The footnote to Doc. 126, Rebuttal Schedule A-1, PDF p. 3 states: "Due to changes from deficiencies in certain schedules, the Total Non-Fuel 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)."

[5] Rebuttal Testimony of Company Witness Phillip B. Gillam, Doc. 128, PDF pp. 5-6.

A. In addition to Surrebuttal Exhibit JH-1, I am sponsoring Surrebuttal 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 Surrebuttal Exhibits JH-2 and JH-3. Staff's proposed Rate Base reflects Net Plant-in-Service ("PIS") of $1,128,695,631 and Working Capital Assets ("WCA") of $86,028,019 for a Total Rate Base of $1,214,723,650. In contrast, the Company's proposed Net PIS is $1,130,492,436 with WCA of $97,912,048 for a total Rate Base of $1,228,404,484.[6] As a result, Staff's Rate Base differs from SUA's by $13,680,834, largely attributable to WCA.

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 Surrebuttal Exhibits JH-4 and JH-5, respectively. Staff's computations reflect Operating Revenues of $180,032,380 reduced by Total Expenses of $167,960,398 to derive Net Utility Operating Income of $12,071,982. SUA's proposed Operating Revenues are $188,640,582, including Rolled-in Riders Revenue of $10,116,448, and its proposed Operating Expenses are $178,517,704, yielding a Net Utility Operating Income of $10,122,877.[7]

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[6] Rebuttal MFR Schedule B-1, Doc. 126, Part 1, PDF p. 5.
[7] Rebuttal MFR Schedule C-1, Doc. 126, Part 2, PDF pp. 2-3.

Staff's income tax calculation is shown on my Surrebuttal Exhibit JH-6 and is based on the operating revenues and expenses reflected on my Surrebuttal Exhibit JH-4. Staff's weighted cost of debt of 2.04%, 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 Surrebuttal 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 $289,834,695 and makes adjustments to arrive at Staff's recommended non-gas Revenue Requirement of $256,234,297, for a total difference of $33,600,398.

SUMMARY OF ADJUSTMENTS

Table 1
Non-Contested Expense Adjustments

Adj. No.	Description	Staff Amount	Company Amount[8]	Difference*
IS-1	Cost of Gas Adjustment	(262,228,734)	(262,228,735)	1
IS-2	Misc Taxes	(8,033)	(8,033)	0
IS-5	Energy Efficiency	(10,175,378)	(10,175,378)	0
IS-9	Advertising & Marketing	(922,529)	(922,529)	0
IS-10	Other Expenses	(418,450)	(418,450)	0
IS-14	Meals & Travel	(375,037)	(375,037)	0
IS-15	Postage Expense	168,749	168,749	0
IS-17	Pipeline Locator Fees	1,166,079	1,166,079	0

*Any difference due to rounding

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[8] Rebuttal MFR Schedule C-2, Doc. 126, Part 2, PDF pp. 5-8; *see also* Rebuttal Exhibit PBG-1 of Phillip B. Gillam, Doc. 129, PDF p. 2.

Table 2
Contested Revenue and Expense Adjustments

Adj. No.	Description	Staff Amount	Company Amount[9]	Difference
IS-3	Revenue Adjustment	(273,283,597)	(265,459,431)	(7,824,166)
IS-4	Forfeited Discounts Revenue	711,158	1,495,193	(784,035)
IS-6	Bad Debt Adjustment	(8,115,740)	(6,109,401)	(2,006,339)
IS-7	Rate Case Amortization	142,866	714,940	(572,074)
IS-11	Interest - Customer Deposits	-	89,460	(89,460)
IS-20	Deferred COVID Expense Recovery	1,267,826	2,113,044	(845,218)

OPERATING 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 Surrebuttal Testimony. Staff's Adjustment IS-3 reduces SUA's actual test year revenue of $447,021,384 by $273,283,597 to *pro forma* Rate Schedule Revenue of $173,737,787. SUA's adjustment of $265,459,431, reduces its test year revenue of $447,021,384 to *pro forma* Rate Schedule Revenue of $181,561,953, which also includes SSER and the EECR's Lost Contributions from Fixed Charges ("LCFC") Revenue of $10,116,448.[10] Staff's total revenue adjustment is $7,824,166 less than SUA's revenue adjustment; however, excluding SSER and EECR-LCFC Revenue from SUA's total *pro forma* Revenue, Staff's is more than the Company's revenue by $2,292,282.

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[9] Rebuttal MFR Schedule C-2, Doc. 126, Part 2, PDF pp. 5-8;
See also Rebuttal Exhibit PBG-1 of Phillip B. Gillam, Doc. 129, PDF p. 2.

[10] SUA Rebuttal, Schedule C2-IS3, Doc. 126, Part 2, PDF p. 11.

<u>Forfeited Discounts Revenue</u>

Q. Did SUA agree with your Adjustment IS-4 for Forfeited Discounts Revenue?

A. No. SUA's primary disagreement is that I didn't explain why I considered years 2021 and 2022 as being anomalous and excluded them in determining my forfeited discounts revenue ratio. As a result, the Company recommends the use of the prescribed five-year average required by MFR C-4, rather than my three-year average.

Q. Do you agree that the Company's MFR C-4, which includes a five-year average is required in the determination of the Forfeited Discounts Revenue?

A. No. While I support the use of the most recent five-year average per the C-4, I disagree with blindly adhering to it when the data included does not appear representative of the normal on-going ratios and resulting amounts determined by those ratios.

Q. Did you make any changes to your Adjustment IS-4?

A. Yes. I used the Company's Rebuttal C-4 as my basis, which was updated to include the test year and prior four years. However, I continue to exclude the years 2020 and 2021. As shown in Table 3 below, which compares the five-year average (2019-2023) to the two years in question, both ratios clearly deviate from the norm, but this is especially true of the uncollectible ratio. Due to COVID, the uncollectible accounts written off were significantly impacted —

first in 2020 due to the moratorium on disconnections, and then in 2021, when the moratorium was ended.[11] Rather than treat the two ratios differently, I chose to exclude the years 2020 and 2021 for both the uncollectible accounts expense and the forfeited discounts revenues. This also affects my Revenue Conversion Factor ("RCF").

Table 3
Comparison of Forfeited Discounts and Uncollectible Ratios[12]

Year(s)	Arkansas Jurisdictional Operational Revenues	Arkansas Jurisdictional Uncollectible Written Off (Net of Recoveries)	Uncoll. Ratio	Arkansas Jurisdictional Forfeited Discounts	Forfeited Discount Ratio
5-Yr Avg	$398,631,139	$4,161,885	1.04%	$2,971,816	0.75%
2021	$375,712,346	$6,921,414	1.84%	$3,345,629	0.89%
2020	$327,498,029	$1,373,082	0.42%	$3,601,960	1.10%

My Adjustment IS-4 of $711,158 provides a *pro forma* level of forfeited discounts revenue of $2,187,781, which differs from SUA's *pro forma* amount of $2,971,816 by $784,035.

OPERATING EXPENSES

<u>Uncollectible Accounts Expense</u>

Q. Did SUA agree with your Adjustment IS-6 for Uncollectible Accounts Expense?

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[11] Docket No. 20-012-A, Order Nos. 1 and 18.
[12] Rebuttal MFR Schedule C-4, Doc. 126, Part 2, PDf p. 39.

A. No. Similar to the Forfeited Discounts Revenue adjustment, SUA's primary disagreement is that I didn't explain why I considered years 2021 and 2022 as being anomalous and excluded them in determining my forfeited discounts revenue ratio. As a result, the Company recommends the use of the prescribed five-year average required by MFR C-4, rather than my three-year average.

Q. Did you also update the C-4 uncollectible accounts data in the determination of your Adjustment IS-6?

A. Yes. I used the Company's updated Rebuttal C-4 as my basis, which resulted in my Adjustment IS-6 of ($8,115,740), for a *pro forma* level of $3,491,343. My recommended amount differs from the Company's *pro forma* amount of $5,497,682 by $2,006,339. The difference from the Company is due both to the updated data and to my continued use of Staff's total *pro forma* revenue reduced by Winter Storm Uri and SSER rider revenue, both of which include a level of uncollectible accounts expense.

<u>Rate Case Expense</u>

Q. Has SUA modified its rate case expense in Rebuttal?

A. No. The Company continues to base 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.[13]

Q. Please describe your revised rate case expense.

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[13] Rebuttal Schedule C2-IS7, Doc. 126, Part 2, PDF p. 15.

A. In Direct, 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. However, due to the actual invoices received to date, I now recommend a further reduction in expense to a total amount of $714,328, normalized over 5 years, or $142,866.

My Adjustment IS-7 increases expense to my recommended *pro forma* amount of rate case expense of $142,866, a difference from the Company's annual expense adjustment of $707,441 by $564,575.

Customer Deposit Interest

Q. Do you agree with SUA's request to reclassify customer deposit interest from a below-the-line account to customer accounts expense?

A. No. I disagree with moving an expense amount that the Federal Energy Regulatory Commission ("FERC") in its Uniform System of Accounts ("USOA") has classified as Other Interest Expense in order to be included in the cost of service.[14] In addition to the FERC USOA designation and the normal treatment of exclusion for ratemaking purposes, recovery is being provided for this cost, the same as other interest expense, by inclusion in the capital structure as a component of the Weighted Average Cost of Capital ("WACC"). Customer Deposits is a line item included in both the Company's and Staff's recommended WACC and reflects the *pro forma* rate approved by the

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[14] Rebuttal Schedule C2-IS11, Doc. 126, Part 2, PDF p. 19.

Commission. Therefore, I disagree with this adjustment and have removed it from Staff's recommended level of expense.

Deferred COVID-19 Expense Recovery

Q. Does SUA continue to request recovery of its deferred COVID-19 expense over three years?

A. Yes. However, in response to my recommendation in my Direct Testimony to recover the amount over five years, Company witness Gillam now suggests that unless a three-year amortization is used, the Company will propose to include carrying costs in addition to the expense amount.[15]

Q. Do you agree with SUA's adjustment?

A. No. Because the Company assumes that it is unlikely that it will avoid filing a rate case in the next five years, it has now modified its request. I disagree that the determination of the appropriate recovery period warrants additional recovery. I agree with the total amount of expense, net of savings as proposed, but I maintain that a five-year recovery period is appropriate based on the interval between SUA's last two rate cases, especially if the Commission approves a rider in this Docket. Therefore, I continue to recommend *pro forma* expense of $1,267,826.

REVENUE CONVERSION FACTOR

Q. Did the Company update its RCF?

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[15] Rebuttal Testimony of Company witness Phillip B. Gillam, Doc. 128, PDF p. 21.

A. Yes. SUA updated its RCF to include the current state income tax rate of 4.3%, the updated MFR C-4 amounts used to calculate the uncollectible accounts expense ratio, but continued to exclude the forfeited discounts revenue ratio from the RCF.[16]

Q. What is Staff's RCF?

A. For the reasons discussed above regarding uncollectible accounts expense and forfeited discounts revenue, I determined the RCF for each rate class using the three-year average of 2023, 2022 and 2019, but excluding 2020 and 2021. In addition, I included the Forfeited Discounts Ratio in my RCF. Staff's composite RCF of 1.32918 was determined in the Cost-of-Service Study as shown in Staff witness Burdette's Surrebuttal Exhibit MB-1. The impact of Staff's RCF as compared to the Company's of 1.33841 is shown in my Surrebuttal Exhibit JH-7.

SYSTEM SAFETY ENHANCEMENT RIDER

Q. Please describe SUA's response to your Direct Testimony regarding the SSER.

A. My assertions and recommendations regarding the SSER were addressed primarily by Company witnesses Gillam and McNully.

Q. Mr. Gillam disagrees that the "traditional rider test" is applicable or required, noting that the rider test has not historically been applied to safety riders. What is your response?

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[16] Rebuttal Schedule C5, Doc. 126, Part 2, PDF p. 41.

A. Evaluating the necessity of a rider should be carefully considered and fairly applied to all jurisdictional utilities. In addition, a rider should not mitigate the benefits provided through traditional rate case treatment, such as limiting rate increases, thus promoting fiscal responsibility, ensuring that all costs and revenues are considered before a rate increase is authorized rather than a single cost or issue such as the SSER, excluding costs not necessary to provide utility service and balancing the interests of all stakeholders. The traditional rider test contains specific criteria which enables both of these considerations – (1) demonstrating that a rider is in the public interest and not favoring the Company and its shareholders over ratepayers and others and (2) providing a framework that can be applied to all utilities. Capital projects by their nature can be properly planned for and the related recovery can be provided in the context of a rate case more easily than expenses that can be shown to demonstrate significant volatility, which is why capital recovery riders are and should be limited.

However, I do accept that riders related to public safety may be appropriate if limited in scope and containing adequate ratepayer protections, such as those I enumerated in my Direct Testimony.[17] In determining if the traditional rider test might be waived, a clear distinction should be made as to what is safety-related, such as Pipeline and Hazardous Materials Safety Administration ("PHMSA") and Arkansas Gas Pipeline Code ("Code") required

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[17] Direct Testimony of Jeff Hilton, Doc. 97, PDF pp. 16-18.

investments, as opposed to other desirable, but less critical expenditures, such as those deemed to be for reliability. Although the Company argues that safety and reliability should be considered the same or similar, the inclusion of reliability projects is clearly a distinct and significant request requiring evaluation as any other rider using the traditional rider test. Therefore, I continue to assert that SUA has not met the traditional rider test in regard to reliability projects and that its request should be denied.

Q. Did SUA witness McNully clarify what reliability projects entail?

A. Yes. However, he stated that all system improvements serve to enhance safety and reliability — this is broader and less helpful in making a distinction.[18] Mr. McNully continued his explanation by providing clear examples of reliability projects that are distinct from those he listed as integrity improvements. It was also clear that the two are not the same and have different purposes. Mr. McNully also noted that the current rider was an expansion over the previous Main Replacement Program ("MRP") that was in place from 2002 until the implementation of the Formula Rate Plan in 2018. The current version of the rider was put in place as an interim rider at the time of SUA's acquisition of CenterPoint Energy Arkansas, Inc. ("CEA") and along with the Customer Credit Rider ("CCR"), which limited the impact on ratepayers, it will expire at the end of this year. Therefore, it is important to carefully consider allowing the rider to

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[18] Rebuttal Testimony of Company Witness Vernon McNully, Doc. 131, PDF pp. 10-13.

continue, or be reinstated, but even more important to cautiously consider expansion.

Q. Did SUA witness McNully address your concern about possible prioritization of reliability projects?

A. Yes. Mr. McNully acknowledged my concern that a rider such as this one (which provides more favorable treatment for the Company by providing more timely recovery of projects without consideration of all revenues and expenses that might otherwise limit recovery) incentivizes the types of investments included in the rider, so that multiple types of projects or an expanded number of possible projects might reduce the incentive on the primary target of safety.[19] Mr. McNully asserted that the Company has routinely completed reliability projects while managing priorities between existing SSER criteria and the Company's commitment to operate a safe and reliable system for its customers. While I appreciate that SUA has routinely completed reliability projects, it indicates to me that there is limited need for a rider such as the current SSER, and no need for an expanded rider that would include a significant increase in the qualified projects.

Q. What was SUA witness McNully's response to your recommendation that the SSER should not include cost recovery for future PHMSA or Arkansas Gas Pipeline Code requirements?

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[19] Rebuttal Schedule C2-IS7, Doc. 126, Part 2, PDF p. 9.

A. Company witness McNully disagrees but indicates a misunderstanding of my recommendation.[20] My recommendation would limit projects to those required by PHMSA or the Code at the time of SUA's recovery request. I am not suggesting that SUA would require a tariff change to include such expenditures per the then approved PHMSA and Code requirements. This is a subtle distinction designed to avoid inclusion of projects pursuant to proposed or anticipated rule changes, not to limit projects pursuant to the rules that are in place at the time of investment. This modification was also included in the recent Black Hills Energy Arkansas, Inc. ("BHEA") Settlement in Docket No. 23-074-U, pending before the Commission as the date of this filing. As clarified, I continue to recommend this change.

Q. What was SUA witness McNully's response to your recommendation that the SSER should not include cost recovery of projects unless they have been previously approved for recovery by SUA or its predecessor under Act 310?

A. Company witness McNully disagrees with my recommended limitation, asserting that it hampers the very purpose of the rider, which is to allow the Company more timely recovery of investments of a type that the Commission and/or the Arkansas legislature have already determined deserve more timely recovery than other types of costs.[21] While I generally agree, I want recovery

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[20] Rebuttal Schedule C2-IS7, Doc. 126, Part 2, PDF pp. 16-17.
[21] Rebuttal Schedule C2-IS7, Doc. 126, Part 2, PDF p. 17.

of any project to have been previously approved by the Commission for SUA in order to limit any question as to whether a project actually qualifies for such treatment. I am also fine with excluding Act 310 projects completely since SUA has the option to request immediate recovery of these costs already.

Q. Did SUA witness Gillam agree with your other recommendations that you enumerated in Direct?

A. No. Company witness Gillam did not embrace any of my recommendations that he addressed, as listed below:[22]

- No additional monthly SSER filings would be made once the Company files an application for a general rate change.
- The Company should continue to include cumulative savings resulting from a reduction in O&M expenses due to capital investments.
- There should be an annual base rate cap of 4%.
- The Company should recognize additional Accumulated Deferred Income Tax ("ADIT") associated with capital investments being included for recovery by reducing gross plant.
- Short-Term Incentive Compensation ("STIC") and Long-Term Incentive Compensation ("LTIC") should be excluded from plant.

Q. What was SUA witness Gillam's rationale for not accepting your recommendation to discontinue the SSER filings during a rate case?

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[22] Rebuttal Testimony of Phillip B. Gillam, Doc. 128, PDF p. 30.

A. Company witness Gillam considers that discontinuation of the SSER would be contrary to the SSER's policy objective.[23]

Q. Do you agree with SUA witness Gillam?

A. No. First, to be clear, my recommendation is that SUA discontinue including additional expenditures, but not to cease recovery of the costs already incurred and filed prior to filing its rate case application. Second, Mr. Gillam ignores that any projects that can reasonably be expected to be completed and in-service by the end of the *pro forma* year will be included in plant for recovery in base rates resulting from the rate case. Third, any costs not included in base rates are subject to be included in the Company's next SSER filing. Lastly, a brief cessation of the SSER should not have much, if any, impact on the Company's incentive to address any safety concerns and is appropriate to minimize any potential issues during a rate case and to ensure that all *pro forma* plant in this and future rate cases are in service, both in total and by functional area before resuming the SSER monthly filings.

Q. What was SUA witness Gillam's rationale for not accepting your recommendation to continue to include cumulative savings resulting from a reduction in O&M expenses related to the capital investments?

A. Company witness Gillam asserted that the replacement of facilities does not directly reduce the amount of O&M expenses.[24]

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[23] Rebuttal Testimony of Phillip B. Gillam, Doc. 128, PDF p. 31.

[24] *Id.*

Q. Do you agree with SUA witness Gillam?

A. No. Mr. Gillam points to costs that will continue each year, such as leak surveying or other inspections, but ignores the variable expenses such as leak repair that will decrease as pipes are replaced. The current amount of O&M savings included in the SSER of $106,314 annually was based on the recommendation of CEA's Engineering Director in the last rate case, Docket No. 15-098-U, in regard to CEA's Main Replacement Program.[25] Also, in the context of a rider that provides recovery without consideration of all expenses and revenues that might mitigate the need for recovery, such as an earnings review or rate case, it is important to recognize any potential savings. I continue to recommend inclusion of the annual O&M savings; however, the current amount should be inflation-adjusted to $139,378.[26]

Q. What was SUA witness Gillam's rationale for not accepting your recommendation that there should be an annual base rate cap of 4%?

A. Company witness Gillam asserted that no cap is necessary due to the scope limitations of the SSER. In addition, Mr. Gillam described the circumstances that resulted in the Settlement Agreement which included the SSER and its customer protections in the Acquisition Docket No. 21-060-U.[27]

Q. Do you agree with SUA witness Gillam?

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[25] Docket No. 15-098-U, Direct Testimony of Jeffrey A. Bish, Doc. 42, PDF pp. 44-46 and Direct Exhibit JAB-8.

[26] For this calculation I referenced the resources available at https://www.usinflationcalculator.com.

[27] Rebuttal Testimony of Phillip B. Gillam, Doc. 128, PDF p. 32.

A. No. While I continue to support limiting the allowed type of projects that can be included in the SSER, I also recommend limiting the allowed level of recovery possible in order to reduce ratepayer impact. Therefore, if the scope of the allowed projects fails to limit the annual increase, the cap will accomplish this purpose. In regard to Mr. Gillam's discussion of the Settlement Agreement, I would note that it also included a Customer Credit Rider that has served to offset the SSER recovery, which is expiring at the end of the year. Therefore, without such an offset it is critical that recovery in the SSER be limited.

Q. What was SUA witness Gillam's rationale for not accepting your recommendation to recognize additional Accumulated Deferred Income Tax ("ADIT") associated with capital investments being included for recovery by reducing gross plant?

A. Company witness Gillam explained that the current ADIT asset is not being utilized by the Company in this proceeding and that he is uncertain when the current ADIT asset will become an ADIT liability. Mr. Gillam was also unclear as to how much of that change can be associated with SSER additions.[28]

Q. Do you agree with SUA witness Gillam?

A. No. The ADIT associated with the investments should be accounted for based on the accelerated tax depreciation rate less the depreciation rate being recovered as a result of this Docket. As can be seen on the Arkansas, and not the Southern Col. Holdco, LLC, balance sheet E-1.1, the ADIT has a credit

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[28] Rebuttal Testimony of Company Witness Phillip B. Gillam, Doc. 128, PDF p. 33.

balance of $14.9M as of April 30, 2024. Because this is a rider that is only considering specific investments in plant, I continue to recommend recognition of the level of ADIT accrued as a reduction to plant in determining the required return.

Q. What was SUA witness Gillam's rationale for not accepting your recommendation that STIC and LTIC should be excluded from plant?

A. Company witness Gillam had no rationale for his disagreement.[29]

Q. Do you agree with SUA witness Gillam?

A. No. Staff witness Middleton Ray is recommending disallowance of all Long-Term Incentive Compensation and 50% of Short-Term incentive Compensation, both from expense and from plant. Therefore, if the Commission approves Staff's recommendation for disallowance, the SSER should reflect the same treatment.

Q. Do you continue to recommend approval of the SSER?

A. Yes, assuming the Company accepts the ratepayer protections that I outlined in my Direct Testimony and explained further in response to the Company's Rebuttal Testimony, which excludes any reliability projects. However, without the inclusion of the ratepayer protections, I cannot support approval of the SSER as requested by SUA.

SUMMARY OF RECOMMENDATIONS

Q. What are your recommendations?

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[29] Rebuttal Testimony of Company Witness Phillip B. Gillam, Doc. 128, PDF p. 33.

A. I recommend that the Commission:

- Reject SUA's revenue requirement request and accept Staff's; and
- Reject SUA's proposed SSER Rider and accept Staff's recommended modifications.

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 September 9, 2024, via the Arkansas Public Service Commission's Electronic Filing System.

/s/ JOSHUA A. BAXTER
Joshua A. Baxter

APSC FILED Time: 9/9/2024 11:15:49 AM: Recvd 9/9/2024 11:10:14 AM: Docket 23-079-U-Doc. 154

BEFORE THE
ARKANSAS PUBLIC SERVICE COMMISSION

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

SURREBUTTAL EXHIBITS

OF

JEFF HILTON
DIRECTOR
GAS AND WATER UTILITIES SECTION

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

SEPTEMBER 9, 2024

SUMMIT UTILITIES ARKANSAS, INC.
DOCKET NO. 23-079-U
TEST YEAR ENDED DECEMBER 31, 2023
SUMMARY OF OPERATIONS

SURREBUTTAL EXHIBIT JH-1

(1)	(2)	(3)
Line No.	Description	Arkansas
1	Adjusted Rate Base	$ 1,214,723,650
2	Adjusted Operating Revenue	$ 180,032,380
3	Adjusted Operating Expense	$ 167,960,398
4	Adjusted Operating Income	$ 12,071,982
5	Current Rate of Return	0.99%
6	Required Rate of Return	5.71%
7	Required Operating Income	$ 69,402,021
8	Operating Income Deficiency/(Excess)	$ 57,330,039
9	Revenue Conversion Factor	1.3292
10	Revenue Deficiency/(Excess)	$ 76,201,917
11	Total Non-Gas Revenue Requirement	$ 256,234,297
12	Less: Other Revenues	6,294,594
13	Total Rate Schedule Revenue Requirement	249,939,704
		42.33%

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

SURREBUTTAL EXHIBIT JH-2

(1) Line No.	(2) Description	(3) Total Company December 31, 2023	(4) Staff Adjustments	(5) 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	$ (635,664,822)	$ (50,580,980)	$ (686,245,802)
3	Net Utility Plant-In-Service	$ 1,044,882,585	$ 83,813,046	$ 1,128,695,631
4	Construction Work-In-Progress	$ 21,958,399	$ (21,958,399)	$ (0)
5	Working Capital Assets	$ 344,426,738	$ (258,398,719)	$ 86,028,019
6	Non-Utility Property			$ -
7	Gas Plant Acquisition Adjustment	$ 690,091,096	$ (690,091,096)	$ -
8	Total Rate Base	$ 2,101,358,818	$ (886,635,168)	$ 1,214,723,650

SUMMIT UTILITIES ARKANSAS, INC. **SURREBUTTAL EXHIBIT JH-3**
DOCKET NO. 23-079-U
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	$ (8,857,410)	
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			$ (50,580,980)
21		Adjustments to Construction Work-In-Progress			
22	RB-7	Remove CWIP/ RWIP	Pitts		$ (21,958,399)
23		Adjustments to Working Capital Assets			
24	RB-10	Adjust 13-Month Average Balance	Malone	$ (244,463,045)	
25	RB-11	Adjust Working Capital Assets to 13 month Averge Balance	Malone	$ (13,935,674)	
26		Total Adjustments to Working Capital Assets			$ (258,398,719)
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			$ (886,635,167)

SUMMIT UTILITIES ARKANSAS, INC.

DOCKET NO. 23-079-U

TEST YEAR ENDED DECEMBER 31, 2023

STATEMENT OF INCOME AND EXPENSE

SURREBUTTAL EXHIBIT JH-4

(1) Line No.	(2) Description	(3) Total Company December 31, 2023	(4) Staff Adjustments	(5) As Adjusted By Staff
1	Operating Revenue:			
2	Sales Revenues	$ 447,021,384	$ (273,283,597)	$ 173,737,787
3	Other Operating Revenues	$ 4,970,187	$ 1,324,407	$ 6,294,594
4	Total Operating Revenue	$ 451,991,571	$ (271,959,191)	$ 180,032,380
5	Operating Expenses:			
6	Cost of Gas Purchased	$ 257,531,100	$ (257,531,100)	$ -
7	Transmission Expense	$ 4,697,634	$ (4,697,634)	$ (0)
8	Distribution Expense	$ 44,104,587	$ (593,922)	$ 43,510,665
9	Customer Accounts Expense	$ 19,931,599	$ (7,514,608)	$ 12,416,991
10	Customer Service & Information Expense	$ 10,749,843	$ (10,263,640)	$ 486,204
11	Sales Expense	$ 403,143	$ (220,595)	$ 182,549
12	General & Administrative Expense	$ 36,838,514	$ (1,487,480)	$ 35,351,034
13	Depreciation & Amortization Expense	$ 60,675,448	$ 7,176,444	$ 67,851,892
14	Taxes Other Than Income	$ 14,311,435	$ (132,286)	$ 14,179,149
15	Total Operating Expense	$ 449,243,304	$ (275,264,820)	$ 173,978,484
16	Federal & State Income Tax	$ 1,178,800	$ (7,196,886)	$ (6,018,085)
17	Total Expenses	$ 450,422,104	$ (282,461,706)	$ 167,960,398
18	Net Utility Operating Income (Loss)	$ 1,569,467	$ 10,502,515	$ 12,071,982

SUMMIT UTILITIES ARKANSAS, INC.
DOCKET NO. 23-079-U
TEST YEAR ENDED DECEMBER 31, 2023
INCOME AND EXPENSE ADJUSTMENTS

SURREBUTTAL EXHIBIT JH-5

(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	($257,531,100)	($4,697,634)	-	-	-	-
2	IS-2	Miscellaneous Taxes (Other Than Income)	Hilton	$0	$0	$0	-	-	-	-
3	IS-3	Revenue Adjustment	Hilton	($273,283,597)	$0	$0	-	-	-	-
4	IS-4	Forfeited Discount Normalization	Hilton	$711,158	$0	$0	-	-	-	-
5	IS-5	Energy Efficiency	Hilton	$0	$0	$0	-	-	(10,175,378)	-
6	IS-6	Bad Debt Adjustment	Hilton	$0	$0	$0	-	(8,115,740)	-	-
7	IS-7	Rate Case Amortization Adjustment	Hilton	$0	$0	$0	-	-	-	-
8	IS-8	Interest Income	Malone	$613,249	$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	-	-	-	-
12	IS-12	Payroll Adjustment	Ray	$0	$0	$0	(1,201,603)	(109,710)	-	-
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	-	-	-	-
24	IS-24	Vegetation Control	Malone	$0	$0	$0	(243,702)	-	-	-
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)	-	-
29		TOTAL ADJUSTMENTS		($271,959,191)	($257,531,100)	($4,697,634)	($593,922)	($7,514,608)	($10,263,640)	($220,595)

SUMMIT UTILITIES ARKANSAS, INC.
DOCKET NO. 23-079-U
TEST YEAR ENDED DECEMBER 31, 2023
INCOME AND EXPENSE ADJUSTMENTS

SURREBUTTAL EXHIBIT JH-5

(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	-	-	-	-	262,228,734
2	IS-2	Miscellaneous Taxes (Other Than Income)	Hilton	-	-	(8,033)	-	8,033
3	IS-3	Revenue Adjustment	Hilton	-	-	-	-	(273,283,597)
4	IS-4	Forfeited Discount Normalization	Hilton	-	-	-	-	711,158
5	IS-5	Energy Efficiency	Hilton	-	-	-	-	10,175,378
6	IS-6	Bad Debt Adjustment	Hilton	-	-	-	-	8,115,740
7	IS-7	Rate Case Amortization Adjustment	Hilton	142,866	-	-	-	(142,866)
8	IS-8	Interest Income	Malone	-	-	-	-	613,249
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	-	-	-	-	0
12	IS-12	Payroll Adjustment	Ray	(182,598)	-	(110,321)	-	1,604,232
13	IS-13	Benefits Adjustment	Ray	(225,834)	-	-	-	225,834
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	(172,821)	-	20,528	-	152,293
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	-	-	-	(7,196,886)	7,196,886
23	IS-23	Non-Utility Expenditures	Malone	-	-	-	-	0
24	IS-24	Vegetation Control	Malone	-	-	-	-	243,702
25	IS-25	Non-Recurring Transactions	Malone	(51,204)	-	-	-	51,204
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
29		TOTAL ADJUSTMENTS		($1,487,480)	$7,424,583	($380,425)	($7,196,886)	$10,502,515

SUMMIT UTILITIES ARKANSAS GAS
SURREBUTTAL EXHIBIT JH-6
DOCKET NO. 23-079-U
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	$ 180,032,380	$ 180,032,380
2	Less:		
3	Operating Expenses	$ 173,978,484	$ 173,978,484
4	Fixed Charges	$ 24,786,436	$ 24,786,436
5	Operating Income Before Taxes	$ (18,732,539)	$ (18,732,539)
6	State Income Tax @ 4.3%	$ (805,499)	$ (805,499)
7	Federal Taxable Income		$ (17,927,040)
8	Federal Income Tax @ 21%		$ (3,764,678)
9	Less ITC Amortization		$ -
10	Total Federal Income Tax		$ (3,764,678)
11	Total State & Federal Income Tax before EDIT (Refund)/Collection		$ (4,570,177)
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 $25,843,915 amort for 46 years		$ 561,824
16	Net Federal Protected EDIT Customer Refund		$ (1,475,976)
17	Total State & Federal Income Tax		$ (6,018,085)
18	Less: Test Year State & Federal Income Tax		$ 1,925,971
19	Adjustment		$ (7,944,057)

20	Calculation of Fixed Charges	Amount
21	Total Arkansas Rate Base	$ 1,214,723,650
22	Weighted Cost of Debt	2.04%
23	Fixed Charges	$ 24,786,436

SUMMIT UTILITIES ARKANSAS, INC.
DOCKET NO. 23-079-U
TEST YEAR ENDED DECEMBER 31, 2023
REVENUE REQUIREMENT RECONCILIATION

SURREBUTTAL EXHIBIT JH-7

Description	Expense Adjustment No.	Company Adjustments Rebuttal	Staff Adjustments Surrebuttal	Revenue Requirement Impact	Company to Staff Revenue Requirement
SUA Non-Gas Revenue Requirement					$ 289,834,695
Rate Base Impact:					
Plant-In-Service				$ (125,399)	
Working Capital Assets				$ (829,386)	
Total Rate Base Impact					$ (954,785)
Rate of Return Impact:					
Capital Structure				(5,681,263)	
Current, Accrued, and Other Liabilities				(5,993,446)	
Return on Equity				(364,417)	
Long-Term Debt Rate				(3,029,521)	
Other				(304,896)	
Total Rate of Return Impact					$ (15,373,543)
Taxes & Revenue Conversion Factor Impact:					
State & Federal Income Tax Expense		$ (4,710,386)	$ (6,018,085)	$ (1,307,699)	
Revenue Conversion Factor Impact		$ 25,586,641	$ 18,871,878	$ (6,714,763)	
Total Tax & Revenue Conversion Factor Impact					$ (8,022,462)
Operating Expense Adjustments Impact:					
Cost of Gas Adjustment	IS-1	$ (262,228,735)	$ (262,228,734)	$ 1	
Miscellaneous Taxes (Other Than Income)	IS-2	$ (8,033)	$ (8,033)	$ -	
Energy Efficiency	IS-5	$ (10,175,378)	$ (10,175,378)	$ -	
Bad Debt Adjustment	IS-6	$ (6,109,401)	$ (8,115,740)	$ (2,006,339)	
Rate Case Amortization Adjustment	IS-7	$ 714,940	$ 142,866	$ (572,074)	
Advertising & Marketing Adjustment	IS-9	$ (922,529)	$ (922,529)	$ -	
Other Expenses Adjustment	IS-10	$ (418,450)	$ (418,450)	$ -	
Interest on Customer Deposits	IS-11	$ 89,460	$ -	$ (89,460)	
Payroll Adjustment	IS-12	$ 396,911	$ (1,604,232)	$ (2,001,143)	
Benefits Adjustment	IS-13	$ 123,300	$ (225,834)	$ (349,134)	
Meals & Travel Adjustment	IS-14	$ (375,037)	$ (375,037)	$ -	
Postage Expense Adjustment	IS-15	$ 168,749	$ 168,749	$ (0)	
Property Tax Adjustment	IS-16	$ (24,501)	$ (24,501)	$ -	
Pipeline Locator Fees	IS-17	$ 1,166,079	$ 1,166,079	$ -	
Corporate Pro Forma Adjustments	IS-18	$ 537,818	$ (152,293)	$ (690,111)	
Depreciation Expense Adjustment	IS-19	$ 8,959,739	$ 8,064,458	$ (895,281)	
Deferred COVID Expense Recovery	IS-20	$ 2,113,044	$ 1,267,826	$ (845,217)	
Non-Utility Expenditures	IS-23	$ (4,581)	$ -	$ 4,581	
Vegetation Control	IS-24	$ -	$ (243,702)	$ (243,702)	
Non-Recurring Transactions	IS-25	$ (18,608)	$ (51,204)	$ (32,596)	
Volunteer Time Off	IS-26	$ -	$ (151,865)	$ (151,865)	
Transportation Depreciation Allocation	IS-27	$ -	$ (888,014)	$ (888,014)	
Call Center	IS-28	$ -	$ (489,252)	$ (489,252)	
Total Operating Expense Adjustments Impact		$ (266,015,213)	$ (275,264,820)	$ (9,249,607)	$ (9,249,607)
Staff Non-Gas Revenue Requirement					$ 256,234,297
Total Revenue Requirement Difference					$ 33,600,398

CERTIFICATE OF SERVICE

I, Joshua A. Baxter, hereby certify that a copy of the foregoing has been served on all parties of record on September 9, 2024, via the Arkansas Public Service Commission's Electronic Filing System.

/s/ JOSHUA A. BAXTER
Joshua A. Baxter

APSC FILED Time: 9/9/2024 11:18:50 AM: Recvd 9/9/2024 11:11:09 AM: Docket 23-079-U-Doc. 155

BEFORE THE
ARKANSAS PUBLIC SERVICE COMMISSION

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

SURREBUTTAL 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

SEPTEMBER 9, 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. Are you the same Don Malone who filed Direct Testimony in this Docket on July 10, 2024?

A. Yes.

PURPOSE OF TESTIMONY

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

A. The purpose of my Surrebuttal Testimony is to address the Rebuttal Testimony and Exhibits of Summit Utilities Arkansas, Inc. ("SUA" or "Company") witnesses Phillip B. Gillam, Paul Schulte, and Fred Kirkwood. Specifically, I will address the Rebuttal adjustments to Working Capital Assets ("WCA") as shown in Table 1, below; Current, Accrued, and Other Liabilities ("CAOL"); and Accumulated Deferred Income Tax ("ADIT") including Excess Deferred Income Taxes ("EDIT"). In addition, I will discuss the adjustment to income tax expense, including recent effects of the state of Arkansas income tax rate reductions, and certain revenue and expense adjustments shown below in Table 2 and Table 3, respectively.

Table 1
Summary of WCA Adjustments

Staff Adj. No.	Co. Adj. No.	Description	Staff Amount[1]	SUA Amount[2]	Difference
		Test Year Balances	$344,426,738	$344,426,738	$0
RB-11	RB-11	Adjust WCA to 13-Month Average	($13,935,674)	($13,935,674)	$0
		13-Month Balances	$330,491,064	$330,491,064	$0
RB-10	RB-10	Decrease Avg. WCA to More Rep. Bal.	($244,463,045)	($232,579,016)	($11,884,029)
		Pro Forma WCA	$86,028,019	$97,912,048	($11,884,029)

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	($7,944,057)	($6,636,357)	($1,307,700)
		Deferred – Net	$747,171	$747,171	$0
		Total	($7,196,886)	($5,889,186)	($1,307,700)

Table 3
Summary of Revenue And Expense Adjustments

Staff Adj. No.	Co. Adj. No.	Description	Staff Amount[5]	SUA Amount[6]	Difference
IS-8	IS-8	Interest Income	$613,249	$613,249	$0
IS-23	IS-23	Donations and Other Expenditures	($0)	($4,581)	$4,581
IS-24	IS-24	Vegetation Control	($817,136)	($1,060,838)	($243,702)
IS-25	IS-25	Non-Recurring Transactions	($51,204)	($18,608)	($32,596)
IS-28	IS-28	Supplemental Call Center	($489,252)	$0	($489,252)

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[1] Surrebuttal Exhibits of Jeff Hilton, Surrebuttal Exhibit JH-2, line 5, columns 3-5, and Surrebuttal Testimony of Don Malone, p. 8, lines 19-23 and p. 9, lines 1-4.

[2] SUA Rebuttal MFRs, Doc. 126, Part No. 1, Schedule B-4, pg. 30 of 49. *See also* Rebuttal Testimony of Company Witness Phillip B. Gillam, Doc. 128, p. 4, lines 5-23 and p. 5, lines 1-15.

[3] Surrebuttal Testimony of Don Malone, p. 18, lines 5-17.

[4] SUA Updated MFRs, Doc. 126, Part No. 1, Schedule C-11, p. 47 of 49.

[5] Surrebuttal Exhibits of Jeff Hilton, Surrebuttal Exhibit JH-5, line no. 8 col. 5;Line no.23, col. 16; line no. 24, col. 8; line no. 25, col. 12; and line no. 28 col. 9.

[6] SUA Rebuttal MFRs, Doc. 126, Part No. 1, Schedule C-2, col. 11, p. 5 of 49; col. 26, p. 7 of 49; col. 27, p. 7 of 49; col. 28, p. 7of 49; and IS-28 not recorded by Company.

WORKING CAPITAL ASSETS

Q. Please describe the Company's updated *pro forma* WCA discussed in the Rebuttal Testimony of Phillip B. Gillam.

A. The Company updated its adjustments to its WCA historical balances through the end of April 2024 of the *pro forma* year, as shown above in Table 1, resulting in proposed WCA in the amount of $97,912,048, as shown in SUA's Rebuttal Minimum Filing Requirement ("MFR") Schedule B-4.[7]

Mr. Gillam explained in his Rebuttal Testimony that he agreed in the most part with Staff's WCA *pro forma* adjustments but disagreed with recommended adjustments to FERC Account 143 – Other Accounts Receivable and Cash and Temporary Cash Investments,[8] in the amounts of ($530,748) and ($18,745,556), respectively.[9] Mr. Gillam states the amounts removed as inactive accounts receivable are still viable receivables that will be collected in the future.

Next, Mr. Gillam explains investment revenues have been moved to "above the line" and associated with cash and temporary cash investments. Therefore, the adjustment removing Cash and Temporary Cash Investments is no longer required.[10]

Q. Do you agree with Mr. Gillam's assertion that the $891,051 of Accounts Receivable balances you removed from FERC Account 143 – Other Accounts

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[7] SUA Rebuttal MFRs, Doc. 126, Part No. 1, Schedule B-4, p. 30 of 49.
[8] Rebuttal Testimony of Company Witness Phillip B. Gillam, Doc.128, p. 4, lines 13-23.
[9] Direct Testimony of Staff Witness Don Malone, Doc. 119, p. 9 lines 19-22 and p. 10, lines 1-6.
[10] Rebuttal Testimony of Company Witness Phillip B. Gillam, p. 4, lines 13-18 and p.5, lines 1-15.

Receivable are viable accounts that will be collected and should be included in rate base and earn a return?

A. No. These accounts Mr. Gillam briefly discusses are non-performing accounts receivable balances greater than one-year old through December 31, 2023. The Company provided no evidence to the contrary. Non-performing accounts receivable should not be accumulated on the books to earn a return from customers. However, now that the Company and Staff have updated WCA account balances through April 2024, this accounts receivable balance has reversed, becoming a credit of an approximately $450,000 accounts payable balance for the last three months of the updated period. Since the balance is now a sizable accounts payable balance for the last three months ending April 2024, I have removed the balance of this account in the amount of $625,800 as not being a representative WCA balance due to the liability balances now included in this account and for the accounts receivable balances remaining in this account. I would conclude they are non-performing balances based on the Company's accounts receivable aging report. I recommend the Commission exclude this $625,800 balance in WCA since it is comprised of non-performing accounts receivable balances and now sizable liability balances in the update to April 2024.

The second adjustment made to Other Accounts Receivable in the amount of $360,303 to remove a liability balance was not addressed by the Company. The balance is a liability sub-account recorded to FERC Account 142 – Other Accounts Receivable that has a zero balance for the last seven months of the period ending April 2024. The update to April 2024 resulted in this account value decreasing to

$333,776 from the $360,303 balance discussed in my Direct Testimony. I recommend the Commission remove this inactive liability balance with a zero balance for the last seven months of the period in the amount of $333,776 from WCA.

Q. The Company states investment revenues from cash have been included in the Company's Rebuttal case as "above the line" revenues. What amount of investment revenues did the Company move from "below the line" to operating revenues?

A. SUA included $613,249 in its Rebuttal cost-of-service as shown in Rebuttal Adjustment IS-10 – Interest Income. This amount of interest income earned on cash balances was moved from below-the-line.

Q. Do you agree your WCA adjustment to remove cash is no longer required since the Company has recognized earning from Cash and Temporary Cash investments above the line in operating revenues as discussed by Mr. Gillam?

A. No, not entirely. Staff's normal treatment is to remove cash balances other than those required to avoid a service charge; however, the Company did not provide this information. Based on the Company moving its interest revenues to the COS, which I have accepted, I recommend a cash balance be included in WCA to provide liquidity to meet daily operating requirements of SUA. However, the Company should not expect to include an unreasonable balance of cash and temporary cash investments in WCA to earn a return from customers, as the Company proposes, by including $12,063,741 of cash and cash investments in its

Rebuttal WCA. This amount of cash represents approximately fifteen days of adjusted annual operating revenues. Expecting customers to provide a return on this excessive amount of cash is not appropriate, as excess cash should be invested in other assets. In addition, allowing the Company to earn a return on excessive cash amounts in WCA would result in inflated base rates and encourage poor cash management practices to continue.

As in the prior rate case in Docket No. 15-098-U, I have recognized one day of cash revenues in my revised WCA of $471,736 that, when coupled with other working capital components included in my level of WCA in the amount of approximately $85.6 million, will provide SUA an adequate amount of working capital to meet the daily operating requirements of the Company. Expecting customers to provide a guaranteed return on a Company's entire cash balance that would be better invested in financial instruments is not responsible or prudent cash management, nor is it appropriate. I recommend the Commission accept my WCA cash adjustment of ($11,592,005) which provides the Company an adequate level of liquid WCA to meet the daily operating requirements of the Company.

Q. Did you include any adjustments in your WCA that was excluded by the Company?

A. No. The Company and I are in agreement as to the remaining WCA adjustments discussed in my Direct Testimony.

Q. Please summarize your recommended WCA and compare it to the amount proposed by the Company.

A. I have calculated WCA in the amount of $86,028,019 which is $11,884,029 less than that proposed by the Company. I addressed the differences between Staff and the Company concerning unreasonable cash levels SUA proposes to include in rate base and non-performing accounts receivable balances the Company proposes to include in rate base. I recommend the Commission accept my adjustments to WCA discussed above and shown above in Table 2 and the resulting amount of WCA to include in rate base.

CURRENT, ACCRUED, AND OTHER LIABILITIES

Q. Have you updated Staff's CAOL recommendation?

A. Yes. I have updated Staff's CAOL recommendation using updated balances as of April 2024.

Q. Would you please discuss the amount of CAOL you recommend including as a zero-cost source of funds in Staff's capital structure?

A. Yes. In my Direct Testimony I explained my amount of CAOL was calculated using the Modified Balance Sheet Approach ("MBSA") which requires that all current, accrued, and other liabilities that are a source of funds to the utility be included in the Company's capital structure at their appropriate costs. CAOL is calculated using Southern Col Holdco, LLC ("SCHC" or "Holdco") balances updated through the end of April 2024 in the amount of $154,497,558, which was provided to Staff witness Dan Daves for inclusion in the capital structure at zero cost. My amount of CAOL includes Staff's interest payable provided by Staff witness Daves in the amount of $3,617,534 and dividends payable of $18,896,438 in addition to several other adjustments in calculating *pro forma* CAOL which is discussed later in my testimony.

Q. What was SUA's proposed Rebuttal level of CAOL included in its capital structure?

A. SUA proposes CAOL in the amount of $94,403,602 calculated using SCHC historical CAOL balances through the end of April 2024 as shown on MFR Schedule D-6.1 Rebuttal, consistent with WCA.[11] SUA also included, then eliminated, $12,100,634 of Capital Lease Obligations on MFR Schedule D-1.3 Rebuttal[12] which I will discuss later in my testimony.

Q. Please summarize and compare your CAOL recommendation to the Company's proposed CAOL balance.

A. Comparing my updated CAOL adjustments to that of the Company's Rebuttal CAOL adjustments shows that we are in agreement with the 13-month average balance through April 2024. SUA and I also agree on adjustments to remove ADIT of $52,041,213; Interest Bearing Accounts of $5,842,476; Asset Retirement Obligation of $3,339,829; and Regulatory Liabilities of $21,898,966. These CAOL adjustments made by both Staff and the Company total $83,122,484 in CAOL balance reductions as shown below in Table 4.

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[11] SUA Rebuttal MFRs, Doc. 126, Part 3, Schedule D-6.1, pg. 12 of 19, line 30, column 9.
[12] *Id*. at Part 3, Schedule D-1.3 Holdco, pg. 2 of 19, line 11, column 4.

TABLE 4
Staff Adjustments to the 13-Month Average CAOL Balances

Line No.	Description	Amount
1	**Staff and Company Adjustments Agree:**	
2	**Remove accumulated deferred income tax (ADIT)**	**($52,041,213)**
3	**Remove interest bearing accounts**	**($5,842,476)**
4	**Remove asset retirement obligation**	**($3,339,829)**
5	**Remove regulated liabilities**	**($21,898,966)**
6	**Total Adjustments in Agreement (Lines 2 - 5)**	**($83,122,484)**
7	**Staff Adjustments without Agreement:**	
8	**Remove accounts with no activity**	**$9,317,975**
9	**Remove asset account**	**$23,133,048**
10	**Adjust interest payable**	**($3,619,553)**
11	**Adjust dividends payable**	**$18,896,438**
12	**Add lease obligations**	**$0**
13	**Total Adjustments not in Agreement (Lines 8 - 12)**	**$47,727,908**
14	**Adj to CAOL 13-Month Average Balances (Lines 6 + 13)**	**($35,394,576)**
15	**13-Month Average CAOL Balances**	**$189,892,134**
16	**Staff Pro Forma Year CAOL (Lines 14 + 15)**	**$154,497,558**

Q. Please discuss Staff's adjustments to the 13-Month Average CAOL balances the Company did not comprehend in its proposed CAOL.

A. Table 4 above identifies the adjustments that Staff and the Company are in agreement with and those adjustments the Company did not comprehend in its proposed CAOL (or, in the case of lease obligations, did not include in SUA's proposed CAOL).

The first adjustment (Line 8) removes accounts with no activity in the amount of $9,317,975 comprised of adjustments to FERC account 228.3 – Accumulated Provision for Pension and Benefits of $244,057, FERC account

238.0 – Dividends Declared of ($1,615,385), FERC account 242.1 – Miscellaneous Current and Accrued Liabilities I of $9,192,285, and 242.2 - Miscellaneous Current and Accrued Liabilities II of $1,496,418. The second adjustment (Line 9) in the amount of $23,133,048 removes two sub-accounts with asset balances from FERC account 242.0 – Miscellaneous Current and Accrued liabilities: the first in the amount of $23,125,176 has no activity and the second in the amount of $7,872 is a Summit Energy Outreach asset that should also be removed from CAOL.

Next, the Company removed Lease Obligations in the amount of $12,366,048 from its level of CAOL but offered no explanation other than a notation that the liabilities were provided for elsewhere in the COS. The Company did show this amount as part of its beginning capital structure but eliminated it from the *pro forma* capital structure on MFR Schedule D-1.3 Rebuttal.[13] Since all liabilities should be included in the capital structure, I restored the Lease Obligations to CAOL.

Finally, I calculated dividends payable based on the amount of dividends paid, dividends declared date, and dividends paid date, or lag, of Summit Utilities Inc. for the *pro forma* year in the amount of $18,896,438 and included the payable as a component of my CAOL as well as including interest payable provided by Staff witness Daves in the amount of $3,617,534, which is $3,619,553 less than the Company's interest payable included in CAOL.

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[13] SUA Rebuttal MFRs, Doc. 126, Part No. 3, Schedule D-1.3 Holdco, p. 2 of 19, line 11, column 4.

The adjustment to CAOL balances the Company did not include results in a CAOL balance increase of $47,727,908. This increase, when combined with the CAOL adjustments with which Company and Staff are in agreement of ($83,122,484), as discussed above, results in total adjustments of ($35,394,576) to SUA's 13-month average CAOL balances as shown above in Table 4.

Q. Please summarize and compare your amount of CAOL to SUA's and provide the Commission your recommended CAOL to be included in the capital structure as a zero cost of capital.

A. I recommend the Commission reject SUA's reduced level of CAOL and accept my *pro forma* CAOL in the amount of $154,497,558 which comprehends an additional $60,093,956 of CAOL not recognized in the Company's proposed level of CAOL. My level of CAOL is reasonable in that it adheres to Staff's practice of determining a reasonable level of CAOL for inclusion in the capital structure at a zero cost. Staff's recommendation is less likely to result in inflated base rates than the Company's proposed CAOL in the amount of $94,403,602.

ACCUMULATED DEFERRED INCOME TAXES

Q. What level of *pro forma* ADIT do you recommend be included in the capital structure?

A. I continue to recommend a zero balance for ADIT for inclusion in the capital structure for SUA for the reasons I discussed in my Direct Testimony.[14] The Company updated its *pro forma* ADIT to the amount of $22,909,825, a net asset

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[14] Direct Testimony of Don Malone, page 15, Line 5 – Line 21.

balance.[15] However, as discussed in my Direct Testimony, the MBSA requires the inclusion of all sources of funds in the capital structure at their actual cost. Therefore, I continue to recommend a zero balance for ADIT.

Q. Would you please summarize your recommended ADIT to include in the capital structure?

A. Yes. I excluded ADIT net assets from the capital structure, as did SUA, since ADIT net assets are not a source of funds to the Company. I recommend the Commission accept my *pro forma* recommendation to exclude ADIT net assets from the capital structure. I provided Staff witness Dan Daves ADIT of $0 to include in the capital structure. ADIT is expected to "turn around" in future years to a liability balance as the Company continues to invest in Plant.

EXCESS DEFERRED INCOME TAXES

Q. Would you please discuss the amount of *pro forma* EDIT you recommend to be included in the capital structure at zero cost?

A. Yes. As discussed in my Direct Testimony, SUA adjusted EDIT to recognize a cost of removal ("COR") unprotected deferred tax asset ("DTA") in the amount of $25,843,915, reducing the total protected EDIT liability to be refunded to customers. The EDIT reduction is based on a private letter ruling ("PLR")[16] from the Internal Revenue Service ("IRS") directing the recognition of the COR DTA and classifying the DTA as an unprotected tax asset.[17] I agreed with the Company's

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[15] SUA Updated MFRs, Doc. 126, Part No. 2, MFR Schedule C-10, pg. 45 of 49, line 7, column 4.

[16] Direct Testimony of Company witness Paul Schulte, p. 4, lines 1-4. The PLR referenced by SUA is issued to another utility company, not SUA.

[17] Direct Testimony of Staff Witness Malone, p. 18, lines 12-21 and p. 19, lines 1-12.

COR DTA reduction and now recommend *pro forma* EDIT in the amount of $65,217,129, which reflects the adjustment for the COR DTA. The Company and I agree with the level of zero cost EDIT to include in the capital structure but do not agree over what period of time to collect the COR DTA from customers.

Q. What period do you recommend collecting the Unprotected COR DTA from customers?

A. Company witness Mr. Paul Schulte explains that collecting the COR DTA over thirteen years as a dollar for dollar offset to the EDIT refund does not change current rates for customers and is not a cessation of a current refund.[18] However, he does not recognize that a dollar for dollar offset of the EDIT refund does nothing to lower the customer's overall cost of utility service as intended by the Tax Cut and Jobs Act of 2017 ("TCJA"). Mr. Schulte's assertion that rates will not be affected is not entirely correct since he does not discuss the fact that his proposal will increase the overall cost of utility service to customers by completely removing the TCJA refund to customers for approximately thirteen years. The average Arkansas customer would benefit greatly from this form of relief of cost reductions during a period when prices have generally been increasing. Therefore, I continue to support and recommend the unprotected COR DTA be collected over the life of the federal protected EDIT refunds, still recognizing a refund while the Company recovers their unprotected COR DTA, keeping in mind the COR DTA originated from federal protected EDIT.[19] My proposal would allow the Company

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[18] Rebuttal Testimony of Company Witness Paul Schulte, Doc. 132, p. 4, lines 8-21

[19] Direct Testimony of Company Witness Paul Schulte, Doc. 27, p. 4, lines 5-15.

to collect its COR DTA at a rate of approximately $532,000 annually while still issuing refunds through newly established utility rates.

Q. SUA recognized the State of Arkansas corporation income tax reduction to 4.3% effective January 1, 2024, by revaluing its ADIT, resulting in an unprotected state income tax deferred asset to be collected from customers in the amount of $140,337.[20] Did the Company agree with your recommended period of five years to collect the state income tax deferred asset?

A. No. The Company contends that two years is more appropriate since it will have to file for a rate increase sooner, rather than later.[21] Since this is a deferred tax asset, a five-year collection period is more reasonable than a two-year collection period in that it eliminates the risk of over-collection in the event the Company does not file a subsequent rate case in two years. Also, Staff has consistently used five years as a reasonable interval to normalize costs such as rate case expense based on the intervals between its last two rate cases; this is consistent with the five years used in Docket No. 15-098-U, the Company's last rate case. Therefore, I continue to recommend a five-year recovery of the state excess deferred tax asset.

Q. What is your recommended amount of EDIT to include in the capital structure and the related recovery period of deferred tax assets?

A. I recommend the Commission include EDIT in the amount of $65,217,129 in the capital structure at zero cost. This amount reflects the COR DTA adjustment which

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[20] Direct Testimony of Staff Witness Malone, Doc. 119, p. 18, lines 6-11.
[21] Rebuttal Testimony of Company Witness Paul Schulte, Doc. 132, p. 2, lines 16-21 and p. 3, lines 1-12.

I recommend the Commission collect over the same time period as the EDIT refunds as an adjustment to income tax expense. Finally, I recommend the Commission establish a five-year recovery period for the state income tax deferred tax asset created by the State of Arkansas corporation tax reduction to 4.3%. I provided *pro forma* EDIT of $65,217,129 to Staff witness Dan Daves for inclusion in the capital structure at zero cost.

INCOME TAX EXPENSE

Q. You explained in your Income Tax Expense discussion in your Direct Testimony that SUA has a net income tax credit as opposed to the normal debit balance of income tax expense.[22] Please discuss the amount of income tax Staff calculated as shown on Income Tax Adjustment IS-22?

A. Staff's Income Tax Adjustment IS-22 reflects the current State of Arkansas corporation income tax rate of 4.3% and the federal corporation income tax rate of 21% applied to the Company's adjusted operating deficit. Applying the current corporate income tax rates to SUA's operating deficit and eliminating deferred income taxes of ($747,171) results in a total income tax credit of ($4,570,177), comprised of the state income tax amount of ($805,499) and the federal income tax amount of ($3,764,678).

Q. How does your recommended tax amount compare to SUA's?

Staff's calculated income tax amount of ($4,570,177) before inclusion of adjustments for state EDIT collection of $28,067 and protected federal EDIT

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[22] Direct Testimony of Staff Witness Malone, Doc. 119, p. 21, lines 5-23 and p. 22, lines 1-11.

refunds net of COR DTA collection of ($1,475,976), as discussed above in the EDIT section, results in a total *pro forma* income tax benefit in the amount of ($6,018,085).[23] SUA's calculated *pro forma* income tax of ($4,710,386) includes state EDIT collections amortized over two years in the amount of $70,169, as opposed to Staff's five-year amortization of $28,067, and offsets federal protected EDIT customer refunds "dollar for dollar" with unprotected COR DTA collections, as opposed to Staff's recommended net EDIT customer refunds of $1,475,976. Staff's Income Tax Adjustment IS-22 is $1,307,699 less than SUA's and continues to provide a net refund on customer bills going forward.

Q. Would you please summarize your Income Tax recommendation?

A. Yes. I recommend the Commission accept my Income Tax Adjustment IS-22 in the amount of ($7,196,886), as shown above in Table 2, resulting in a total Income Tax credit of ($6,018,085), and reject the Company's Income Tax Adjustment. My calculated income tax allows the Company to collect its State EDIT over a five-year period to avoid the possibility of over-collection in the event the Company does not file a rate case within a two-year period. My income tax also continues to recognize a customer refund in keeping with the intentions of the TCJA. The COR DTA originated from federal protected EDIT amounts,[24] so in keeping with the Average Rate Assumption Method ("ARAM") schedule of income tax refunds it is not unreasonable to recover the COR DTA over the same schedule as the

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[23] Surrebuttal Exhibits of Jeff Hilton, Surrebuttal Exhibit JH-6, line 17, column 4.

[24] Direct Testimony of Company Witness Paul Shulte, Doc. 27, p. 4, lines 5-15.

remaining EDIT refunds. The Company's income tax adjustment proposes unreasonable results and should be rejected in its entirety.

REVENUE AND EXPENSE ADJUSTMENTS

Interest Income

Q. SUA proposed an Interest Income Adjustment – IS-8 in the amount of $613,249, moving interest investment revenues to the COS from "below the line" and restoring cash to its level of WCA to include in SUA's rate base. Did you include a similar adjustment in Staff's COS?

A. Yes, I concur with the Company's IS-8 Interest Income Adjustment in the amount of $613,249 and have included a similar adjustment in Staff's COS. The Company moved the interest income from below the line in order to restore a level of cash to its WCA included as a component of its rate base. I discuss my adjustment to cash WCA in my testimony above.

Q. What is your recommendation with regard to Adjustment IS-8 Interest Income?

A. I recommend the Commission accept Adjustment IS-8 Interest Income in the amount of $613,249 as an increase to other income.

Donations and Other Expenditures

Q. Do you agree with the Company's proposed treatment of amounts comprising Adjustment IS-23 Donations and Other Expenditures?

A. No. Company witness Gillam explained that all but $4,581 for other miscellaneous amounts was removed in the Company's Adjustment IS-10 Other Expenses and agreed to remove the additional amount.[25] These amounts are specific to the FERC accounts as shown in the adjustment and should remain in my Adjustment IS-23 as recorded. Therefore, I am recommending that no adjustment amount be reflected in the accounts until the amounts are restored to the specific FERC accounts.

Vegetation Control Expense

Q. The Company now proposes Vegetation Control Expense equal to its test year amount of $1,060,038.[26] Do you agree with the Company's proposed level of Vegetation Control Expense?

A. No, but I did include the Company's *pro forma* year vegetation control expenditures of $754,445, provide by Mr. Gillam, in my Adjustment IS-24 – Vegetation Control Expense normalization calculation, resulting in a $243,702 reduction to test year expense.

Q. What is your recommended Vegetation Control expense?

A. I recommend the Commission allow the Company's *pro forma* vegetation control expense of $817,136 which is the normalized amount of Company vegetation control expenditures.

Non-Recurring Expenditures

Q. Please discuss your revised Adjustment IS-25 Non-Recurring Expenditures

A. The Company provided additional information that resulted in a revised Non-Recurring Expenditures adjustment in the amount of ($51,204). The Company

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[25] Rebuttal Testimony of Company Witness Gillam, Doc. 128, p. 19, lines 16-22 and p.20, lines 1-3.

[26] *Id*. at p. 20, lines 16-20.

explained (1) Transition Service Agreement ("TSA") payments of $18,608 were included in the test year and (2) the Company received an insurance reimbursement in the test year offsetting the $527,565 expenditure to settle a possible civil action.[27] The Company argues the expenditures in the amount of $32,596 of test year legal expense related to billing errors should not be singled out and removed from the cost of service. Given the nature of this legal expense I continue to support that it is an abnormal non-recurring expenditure that should not be recovered in rates going forward.

Q. What do you recommend regarding Non-Recurring Expenditures?

A. Based on this new information, I recommend the Commission accept my Adjustment IS-25 removing $51,204 of abnormal non-recurring expenditures from the test year and reject the Company's assertion that the legal expense associated with SUA's billing error lawsuit defense is a component of a normal level of on-going legal expense.[28] This particular legal expense falls outside the definition of a normal recurring legal expense.

Call Center Expense

Q. Company witness Kirkwood argues the third-party temporary Call Center Expense in the amount of $489,252 is reoccurring and necessary to meet service level requirements in the most cost-efficient manner without hiring

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[27] *Id*. at p. 21, lines 17-21.
[28] *Id*. at p. 21, lines 5-10.

full-time employees.[29] Do you now agree that your Adjustment IS- 28 should be reduced or eliminated?

A. No. The Company did not explain in testimony that this expense is associated with the temporary call center ramp-up in response to calls related to the conversion from CERC's call center to SUA's and the related billing errors that overwhelmed the Company's in-house call center. I do not consider this event to be a component of a normal level of call center expenditures and thus should not be included in rates going forward as proposed by the Company.

Q. What is your recommendation with regard to Call Center Expense?

A. I recommend the Commission accept my Adjustment IS-28 removing test year temporary contract Call Center Expense in the amount of $489,252 as a non-recurring temporary expense. The Company's proposal to recover the cost of a conversion expenditure should not be borne by the Company's customers. As the Company itself provided in its response to APSC-115:

> [D]ue 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.[30]

Based on the Company's response this was clearly a cost associated with the Company's conversion processes and this temporary call center expense should be rejected.

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[29] Rebuttal Testimony of Company Witness Fred Kirkwood, Doc. 130, p. 3, lines 1-10.
[30] Direct Exhibits of Don Malone, Doc. 120, Direct Exhibit DM-6.

SUMMARY OF RECOMMENDATIONS

Q. What are your recommendations?

A. I recommend that the Commission:

- Accept my recommended WCA of $86,028,019;
- Accept my recommended CAOL of $154,497,558 to include in the capital structure at zero cost;
- Accept my recommended ADIT of $0 to include in the capital structure at zero cost;
- Accept my recommended EDIT of $65,217,129 to include in the capital structure at zero cost;
- Accept my recommended Income Tax credit amount of ($6,018,085); and
- Accept my recommended revenue and expense adjustments as discussed above.

Q. Does this conclude your Surrebuttal 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 September 9, 2024, via the Arkansas Public Service Commission's Electronic Filing System.

/s/ JOSHUA A. BAXTER
Joshua A. Baxter

APSC FILED Time: 9/9/2024 11:20:12 AM: Recvd 9/9/2024 11:12:09 AM: Docket 23-079-U-Doc. 156

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	)	
OR MODIFICATION IN RATES, CHARGES	)	
AND TARIFFS	)	

SURREBUTTAL TESTIMONY

OF

MIDDLETON RAY
MANAGER OF AUDITS

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

SEPTEMBER 9, 2024

INTRODUCTION

Q. Please state your name and business address?

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

Q. Are you the same Middleton Ray who filed Direct Testimony in this Docket on July 10, 2024, on behalf of the General Staff ("Staff") of the Commission?

A. Yes.

PURPOSE OF SURREBUTTALTESTIMONY

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

A. The purpose of my Surrebuttal Testimony is to discuss Staff's adjustments to Payroll Expense and related taxes, benefits, and Short-Term Incentive Compensation ("STIC"). In doing so, I address the respective portions of the Rebuttal Testimonies of SUA witnesses Phillip B. Gillam[1] and Sam Springer.[2] I have summarized my adjustments in Table 1, below:

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[1] Rebuttal Testimony of Company witness Phillip B. Gillam, Doc. 128.

[2] Rebuttal Testimony of Company witness Sam Springer, Doc. 135.

Table 1
Expense and Rate Base Adjustments

Adj. No.	Description	Staff Amount	Company Amount	Difference
IS-12[3]	Payroll and Payroll Tax			
	Payroll	$1,054,187	$1,054,187	$0
	STIC[4]	($928,271)	N/A	($928,271)
	Overtime	($1,619,052)	($684,577)	($934,475)
	Payroll Tax	($111,097)	$27,300	($138,398)
	Total	**($1,604,233)**	**$396,911**	**($2,001,144)**
IS-13[5]	Benefits	($225,834)	$123,300	($349,134)
IS-18[6]	Corporate Pro Forma	($152,293)	$537,818	($690,111)
IS-26[7]	Volunteer Time-Off	($151,865)	N/A	($151,865)
RB-13[8]	STIC Capitalized			
	SUA	($822,612)	N/A	($822,612)
	SUI	($926,913)	N/A	($926,913)
	Total	**($1,749,525)**	**N/A**	**($1,749,525)**

EMPLOYEE-RELATED EXPENSES

Q. Did the Company agree with your Adjustment IS-12?

A. No. Company witness Gillam in his Rebuttal Testimony partially agreed to my adjustment to overtime but did not agree to my adjustment to STIC.[9] The Company used a two-year period for normalization purposes whereas I used a five-year period that includes three years of CenterPoint Energy Resources Corp. ("CERC")

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[3] SUA Updated Cost of Service Study and Minimum Filing Requirements, Doc. 126, Part 2, C2-IS-12, PDF p. 8.

[4] Direct Exhibits of Middleton Ray, Confidential Direct Exhibit MR-1.

[5] Doc. 126, Part 2, C2-IS-13, PDF p. 8.

[6] Doc. 126, Part 2, C2-IS-18, PDF p. 8.

[7] Direct Exhibits of Middleton Ray, Confidential Direct Exhibit MR-1.

[8] *Id*.

[9] Doc. 128, PDF pp. 16-17.

data. The two years of SUA overtime hours was much higher than the three years of CERC data. My adjustment to reduce Payroll for Overtime is $1,619,052. This is greater than the Company's adjustment of $684,577.

Q. Did the Company continue to disagree with your disallowance of STIC in its Rebuttal?

A. Yes. The Company continues to state that the use of financial goals in its performance measures for STIC benefit both the ratepayers and shareholders and therefore should be allowed as an expense.[10] Staff's position remains consistent with its position from Direct, acknowledging that the Commission has recognized the shared benefit of financial incentives by both shareholders and ratepayers and the lack of ratepayer benefits associated with earnings-based incentives and has allowed 50 percent of *pro forma* STI in base rates.[11]

Q. Do you agree with the level of payroll taxes in SUA's Rebuttal?

A. No. I made an updated adjustment of $111,097 to reduce payroll tax expense as a result of my adjustments to STIC and overtime.

Q. Did the Company agree with your Adjustment IS-13 for Benefits in Rebuttal?

A. No. I updated my adjustment to decrease benefits using the Company's burden rate based on my adjustments to STIC and overtime by $225,834.

Q. Did the Company agree to your Adjustment IS-18 for Corporate *Pro Forma* Expenses in Rebuttal?

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[10] Doc. 135, PDF pp. 4-9.

[11] Order No. 12, Docket No. 19-008-U, Doc. 294, pp. 93-96 and Order No. 21, Docket No. 13-028-U,Doc. 431,pp. 54-55.

A. No. I continue to support my adjustment to reduce *pro forma* payroll and payroll tax expense related to STIC allocated from Summit Utilities Inc.(‘SUI’). My updated adjustment reduces *pro forma* payroll and payroll tax expense by $152,293 a difference of $690,111 from the Company.

Q. Did SUA agree with your Adjustment IS-26 for Volunteer Time-Off?

A. No. I continue to support my adjustment of $151,865 to reduce payroll, payroll tax, and benefits expense to remove volunteer time-off that does not provide a benefit to Arkansas ratepayers.

RATE BASE ADJUSTMENTS

Q. Do you still support a reduction to plant and related expenses for STIC?

A. Yes. For the reasons discussed in my Direct Testimony, I continue to support a reduction in Rate Base by $1,749,525 for financially based incentive compensation included since the beginning of 2022.[12] The Company presented no evidence in its rebuttal testimony to refute my assertions. Staff witness Michael L. Pitts addresses the associated reduction to plant and related depreciation, as discussed in his Surrebuttal Testimony.[13]

Q. Do you support a reduction to plant and related expenses for Volunteer Time-Off?

A. Yes. I support a reduction in Rate Base as discussed in Michael Pitts Surrebuttal Testimony.

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[12] Direct Testimony of Middleton Ray, page 7, Lines 1 – 11.
[13] Surrebuttal Testimony of Michael L. Pitts, page 4, Line 6 – 10.

SUMMARY OF RECOMMENDATIONS

Q. What are your recommendations?

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

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 September 9, 2024, via the Arkansas Public Service Commission's Electronic Filing System.

/s/ JOSHUA A. BAXTER
Joshua A. Baxter

BEFORE THE
ARKANSAS PUBLIC SERVICE COMMISSION

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

SURREBUTTAL TESTIMONY

OF

MICHAEL L. PITTS
SENIOR PUBLIC UTILITY AUDITOR
AUDITS SECTION

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

SEPTEMBER 9, 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. Are you the same Michael L. Pitts who filed Direct Testimony in this Docket on July 10, 2024, on behalf of the General Staff (“Staff”) of the Commission?

A. Yes

PURPOSE OF SURREBUTTAL TESTIMONY

Q. What is the purpose of your Surrebuttal Testimony?

A. The purpose of my Surrebuttal Testimony is to discuss my updates to the gross plant-in-service (“GPIS”) and related accumulated depreciation (“A/D”) of Summit Utilities Arkansas, Inc. (“SUA” or “Company”). I also discuss the rebuttal testimony of SUA witnesses Phillip B. Gillam and Sam Springer. In addition, I sponsor adjustments to depreciation and amortization expense. Specifically, I sponsor the adjustments shown in Table 1, which are not contested by the Company in its Rebuttal Testimony, and Table 2, which are adjustments contested by the Company in its Rebuttal Testimony. The Company presented no evidence or reasoning in its rebuttal testimony that would cause me to change my recommendations from my Direct Testimony. My Surrebuttal Testimony addresses the adjustments found in Table 2, below.

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	-
3	RB-3	Retirements	(15,826,521)	(15,824,916)	(1,605)
4	RB-4	Reclassifications	(7,773,000)	(7,773,000)	-
5	RB-12	Asset Retirement Obligation (ARO)	(2,280,944)	(2,280,944)	-
6	RB-15***	Rebranding Capital Expenditures	(379,968)	(379,968)	-
5		Accumulated Depreciation			
6	RB-1	Capital Expenditures	8,550,586	8,550,586	-
7	RB-3	Retirements	15,826,521	15,824,916	1,605
8	RB-5	RWIP/Retirements	(54,319)	-	(54,319)
9	RB-6	Depreciation Expense	(66,357,897)	(66,353,140)	(4,757)
10	RB-7	Remove CWIP/RWIP	(8,857,410)	(8,857,409)	(1)
11	RB-12	Asset Retirement Obligation (ARO)	228,094	228,094	-
12	RB-15***	Rebranding Capital Expenditures	14,500	14,500	-
13		CONSTRUCTION WORK IN PROCESS			
14	RB-1	Capital Expenditures	162,461,129	162,461,129	-
15	RB-2	CWIP Placed in Service	(162,461,129)	(162,461,129)	-
16	RB-7	Remove CWIP/RWIP	(21,958,399)	(21,958,399)	-
17		ACQUISITION ADJUSTMENT			
18	RB-9	Remove Acquisition Adjustment	(690,091,096)	(690,091,096)	-
19		Expense Adjustment			
20	IS-16	Property Tax Adjustment			
21		Test Year	10,781,927	10,781,927	-
22		Proforma Year	10,757,426	10,757,426	-
23		Adjustment	(24,501)	(24,501)	-

Table 2
Summary of Company Adjustments Contested

Line No.	Adj. No.	Description	Staff Adjustment Amount	Company Adjustment Amount	Difference
1		Plant			
2	RB-13**	Short Term Incentive Compensation (STIC)	(1,749,525)	-	(1,749,525)
3	RB-14**	Volunteer Time Off	(57,145)		(57,145)
		Accumulated Depreciation			
4	RB-13**	Short Term Incentive Compensation (STIC)	66,767		66,767
5	RB-14**	Volunteer Time Off	2,179		2,179
6		Expense Adjustment			
7	IS-19	Depreciation Expense Adjustment			
8		Test Year	60,675,448	60,675,448	-
9		Proforma Year	68,739,906	70,046,080	(1,306,174)
10		Adjustment	8,064,458	9,370,632	(1,306,174)
11		Transportation Equipment Depreciation Expense Allocation			
12	IS-27	Depreciation Expense Adjustment			
13		Test Year	-	-	-
14		Proforma Year	(888,014)		(888,014)
15		Adjustment	(888,014)	-	(888,014)

** These adjustments are addressed in the SurrebuttalTestimony of Middleton Ray

Q. Did the Company agree with the amount of your Short-Term Incentive Compensation ("STIC") adjustment?

A. Yes, SUA witness Gillam stated that my capitalized incentive compensation adjustment was calculated correctly.[1] However, the Company continues to dispute my elimination of this cost from rate base.

Q. Do you agree with the Company's position?

A. No. I continue to support my Adjustment RB-13 which removes $1,749,525 from GPIS and $66,767 from AD at the currently approved depreciation rates attributable to Plant for capitalized incentive compensation. The adjustment to STIC is addressed in Staff witness Middleton Ray's Surrebuttal Testimony. There

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[1] Rebuttal Testimony of Company Witness Phillip B. Gillam, Doc. 128, p. 11, line 8 – p. 12, line 6.

is also a corresponding depreciation expense adjustment, IS-19, discussed below.

Q. Did the Company agree with Staff's proposed adjustment RB-14, Volunteer Time Off ("VTO")?

A. No. The Company stated in its rebuttal testimony that its VTO costs are reasonable and should be included in the cost of service.[2]

Q. According to the Company, should the Commission adopt Staff's proposed adjustments to VTO for GPIS and corresponding amounts of AD?

A. No. The Company continues to assert that Staff's rate base adjustments of $57,145 for GPIS and $2,179 for AD should be rejected by the Commission. [3]

Q. Do you agree with the Company's VTO position?

A. No. I continue to support my Adjustment RB-14 which removes $57,145 from GPIS and $2,179 from AD at the currently approved depreciation rates attributable to Plant. The VTO Adjustment is addressed in Staff witness Middleton Ray's Surrebuttal Testimony. There is also a corresponding depreciation expense adjustment, IS-19, discussed below.

Q. Does SUA agree that Staff's recommended adjustments to Depreciation Expense are reasonable?

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[2] Rebuttal Testimony of Company Witness Phillip B. Gillam, Doc. 128, p. 12, lines 13-15, and Rebuttal Testimony of Company Witness Sam Springer, Doc. 135, p. 10, lines 5-6.

[3] Rebuttal Testimony of Company Witness Phillip B. Gillam, Doc. 128, p. 12, lines 7-21,

A. The Company does not contest Staff's Adjustment IS-19. However, the Company does not agree with Staff's Adjustment IS-27, because the Company claims it is based on an incorrect assumption.[4]

Q. Do you continue to support a Depreciation adjustment for your STIC adjustment RB-13 and VTO adjustment RB-14?

A. Yes, as stated above, I continue to support two adjustments to decrease Depreciation expense by $68,946 (*viz*., STIC by $66,767 and VTO by $2,179).

Q. According to the Company, why is Staff's proposed Depreciation Expense Adjustment IS-27 incorrect?

A. According to SUA, Staff references a practice by SUA's predecessor, CenterPoint Energy Resources Corp. ("CERC") d/b/a CenterPoint Energy Arkansas ("CEA"), in which transportation depreciation expense was included in fleet overhead. On page 23 of his Rebuttal Testimony, SUA witness Gillam states,

> Mr. Pitts references a practice by SUA's predecessor, CERC, in which transportation depreciation expense was included in fleet overhead. Fleet overhead was then allocated to capital and expense projects. Therefore, CERC would adjust depreciation expense to reduce the expense for the ratio that should be allocated to capital projects.[5]

Q. Do you agree with the Company?

A. No, I continue to support my adjustment IS-27 which removes $888,014 from Transportation Depreciation Expense. As stated in my Direct Testimony,[6] CEA's adjustment was necessary because transportation depreciation expense is

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[4] Rebuttal Testimony of Company Witness Phillip B. Gillam, Doc. 128, p. 22, lines 19-22.
[5] *Id.* at p. 23, lines 3-7
[6] *See* Direct Testimony of Staff Witness Michael L. Pitts, Doc. 101, p. 9, lines 3-16

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,[7] I have made a similar adjustment to the adjustment 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 ($3,014,305 X cap rate of 29.46%).[8] Therefore, this adjustment appropriately reduces expense by the capitalized portion and leaves the remainder in expense.

Q. Does this conclude your Surrebuttal Testimony?

A. Yes.

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[7] Doc. 18, Part 5, PDF p. 80.

[8] Direct Exhibit MP-4 Transportation Expense, Doc. 102, PDF p. 6.

CERTIFICATE OF SERVICE

I, Joshua A. Baxter, hereby certify that a copy of the foregoing has been served on all parties of record on September 9, 2024, via the Arkansas Public Service Commission's Electronic Filing System.

***/s/* JOSHUA A. BAXTER**
Joshua A. Baxter

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

SURREBUTTAL TESTIMONY

OF

CLAUDE ROBERTSON, CDP
SENIOR CAPITAL RECOVERY ANALYST
FINANCIAL ANALYSIS SECTION

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

SEPTEMBER 9, 2024

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. Are you the same Claude Robertson who presented Direct Testimony in this Docket on July 10, 2024, on behalf of the General Staff ("Staff") of the Commission?

A. Yes, I am.

PURPOSE OF TESTIMONY

Q. What is the purpose of your Surrebuttal Testimony?

A. The purpose of my Surrebuttal Testimony is to discuss my recommendations for my depreciation rate adjustment, unrecovered reserve for Summit Utilities Arkansas ("SUA" or "Company") and discuss the Company's proposal related to the life of certain General Account Assets and unrecovered reserve for the Company. In doing so, I respond to SUA Rebuttal witness Dane A. Watson[1] and the Direct Testimony of Arkansas Attorney General ("AG") witness Michael J. Majoros.[2]

DEPRECIATIION RATES

Depreciation Rates

Q. Did the AG file Direct Testimony in this docket?

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[1] Rebuttal Testimony of Dane A. Watson, Doc No. 139.

[2] Direct Testimony of Michael J. Majoros, Doc No. 116.

A. Yes, AG witness Majoros filed Direct Testimony in this docket. Mr. Majoros also made recommendations for depreciation-related issues in response to the Direct Testimony of Company witness Watson.[3]

<u>Account 376.0 Mains (Distribution)</u>

Q. Did Mr. Majoros give a recommendation for plant account 376.0 Mains (Distribution)?

A. Yes, Mr. Majoros recommended a life of 70 years and did not specify an Iowa Curve.[4] However, he is referencing a curve similar to my proposal which is an Iowa Curve of R2.5 with a life of 65 years, except he is recommending a life of 70 years.[5]

Q. Do you agree with the recommendations that Mr. Mojoros makes for Account 376.0 Mains?

A. No, I do not.

Q. What is your recommendation for Account 376 Mains?

. I recommend using an Iowa Curve of R2.5 65 for Account 376.0 Mains. I have attached Graph 1 below of the actual data comparing my recommendation and the recommendations of Mr. Majoros. The R2.5 65 Iowa Curve that I recommend closely illustrates an appropriate curve and life for this account as compared to the recommendation of Mr. Majoros, which is a R2.5 70 which exceeds the actual data for this account and as such should not be considered. The goal of depreciation is to align the service life of this asset with the depreciation expense related to that asset. Mr. Majoros' proposed life will exceed the usefulness of the asset.[6]

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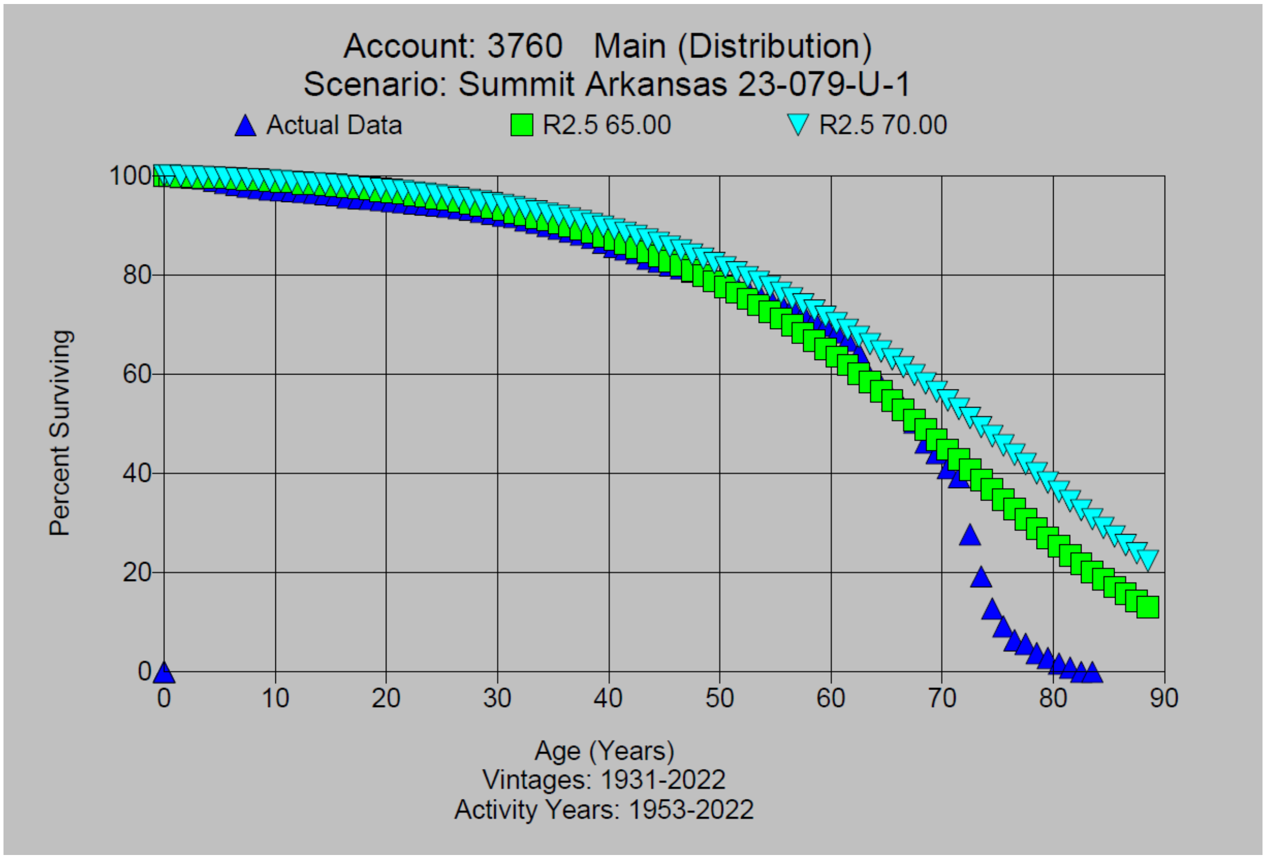
[3] Direct Testimony of Dane A. Watson, Doc No.39.
[4] Majoros Direct Testimony, Doc. No. 116, Page 13, lines 1-5.
[5] Majoros Direct Testimony, Doc. No. 116, Page 13, lines 1-5.
[6] Robertson Surrebuttal Exhibit CR-3.

GRAPH 1
ACCOUNT 376.0 MAINS



<u>Account 380.0 Services</u>

Q. What is your recommendation for Account 380.0 Services compared to Mr. Majoros?

A. Mr. Majoros recommended a 50-year life and again he does not specify an Iowa Curve.[7] For this account he is using a curve similar to a R4 curve with a 50-year life. I recommend using an Iowa Curve of R4. 38 for Account 380.0 Services. I have attached Graph 2 below of the actual data comparing my recommendation to the

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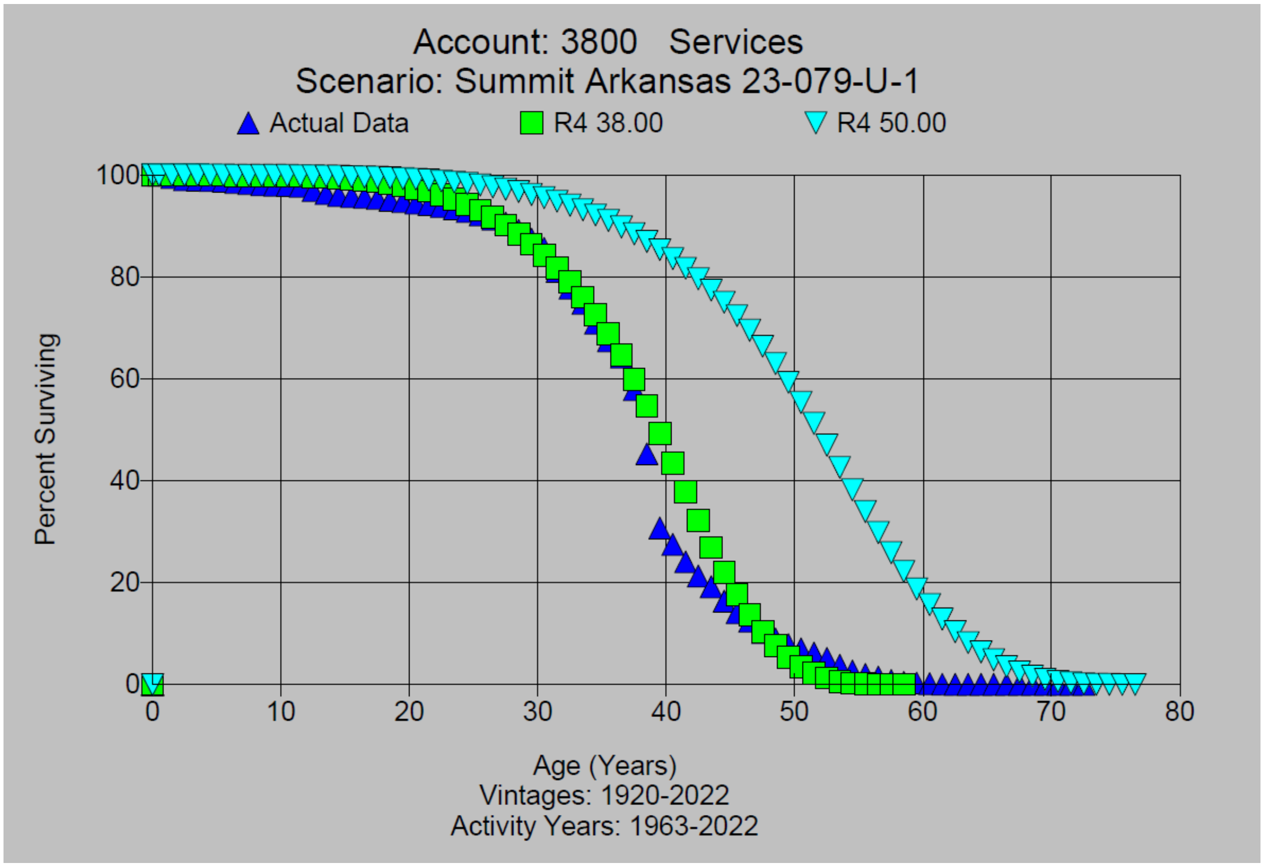
[7] Id.

recommendation made by Mr. Majoros. The R4 38 Iowa Curve that I recommend closely illustrates an appropriate curve and life for this account as compared to Mr. Majoros' R4 50 which exceeds the actual data for this account and as such should not be considered.[8]

GRAPH 2
ACCOUNT 380.0 SERVICES



Excess Depreciation

Q. Did Mr. Majoros state that the Company has excess depreciation?

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[8] Robertson Surrebuttal Exhibit CR-4.

A. Yes, in his Direct Testimony he says "SUA's depreciation rates are and have been excessive. He states that SUA has a $191 million depreciation reserve excess in its accumulated depreciation account".[9]

However, excess depreciation is not the case for SUA's assets.[10] Mr. Majoros has recommended depreciation rates that are not supported by the data being analyzed. As illustrated in Surrebuttal Exhibit CR-1 and CR-2, using my recommended depreciation rates, net salvage, and remaining life that I have proposed, excess depreciation is not a factor. My Surrebuttal Exhibit CR-5 calculates any over/under excess depreciation based upon the parameters that support my depreciation rates.[11]

Q. What is your recommendation for Mr. Majoros' proposal related to excess depreciation?

A. I recommend the Commission reject Mr. Majoros's proposal related to excess depreciation, and that the Commission use Staff's recommended depreciation rates, net salvage and remaining life as presented in my Surrebuttal Exhibits CR-1 and CR-2.

General Plant Accounts

Q. Did Mr. Watson agree with your life for Account 391.2 Computers and 394.0 Tools, Shop, Garage Equipment?

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[9] Direct Testimony of Michael J. Majoros, Doc No. 116, Page. 9, lines 1-3.
[10] Surrebuttal Exhibit CR-5.
[11] Surrebuttal Exhibit CR-5

A. No, Mr. Watson stated that, "[a]lthough Mr. Robertson's two life changes are not unreasonable, I believe that my lives are more reasonable based on the facts and circumstances."[12]

Q. What life does Mr. Watson recommend for Account 391.2 Computers?

A. Mr. Watson continues to recommend reducing the life to 4 years, based upon discussions with Subject Matter Experts ("SME's").[13]

Q. Did you do a site visit and discuss this account with SME's during your visit?

A. Yes, I did. I discussed Mr. Watson's recommendation for a 4-year life for this account with the SME's and I also sent a data request for any company policy related to the life of this account.[14]

Q. What was the results of your inquiries?

A. The meeting with the SME's and the responses to my data request did not add any information that would alter my recommendation to retain a 5-year amortization for this account. As my Surrebuttal Exhibit CR-6 indicates in years five and six the Company continues to have $2.171 million in Computers that is still in service.[15]

In response to Data Request APSC-080, the Company stated that it does not have an approved replacement policy for Account 391.2 Computers, and these are replaced as needed.[16]

Q. What is your recommendation for Account 391.2 Computers?

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[12] Surrebuttal Testimony of Dane A. Watson, Doc No. 139 page 2. Lines 5-7.

[13] Watson Rebuttal Testimony. Page 20, lines 19-23 to page 21, lines 1-12.

[14] Robertson Surrebuttal Exhibit CR-9.

[15] Robertson Surrebuttal Exhibit CR-6

[16] Robertson Surrebuttal Exhibit CR-9

A. I recommend that Mr. Watson's recommendation to reduce the life of Account 391.2 be denied and that the Commission approve my recommendation to retain the 5-year life for computers.

Q. Do you agree with Mr. Watson's assessment of SUA's conversion issues related to the data that Staff relied on to determine the life of the assets in Account 394.0 Tools, Shop, Garage Equipment?

A. No. The data I relied on was the depreciation data that was used in the Company's most recent rate case, Docket No. 15-098-U. This data was sent to Staff as Data Request APSC DR-033 and was received prior to conversion and did not go through the conversion process; the vintage year for this data runs through the vintage year 2014. Vintage year 2014 is also the year in question and I have supplied this data in my Surrebuttal Exhibit CR-7. This exhibit compares Mr. Watson's Rebuttal Exhibit DAW-2 data he labels as 2014 vintage year, with the data received from the 15-098-U rate case in response to Data Request APSC-033.[17]

Q. What is your recommendation for Account 394.0 Tools, Shop, Garage Equipment?

A. I recommend the Commission retain the current 15-year life of this account.

<u>Unrecovered Reserve</u>

Q. What was Mr. Watson's recommendation for the unrecovered reserve?

A. Mr. Watson recommended that the amount of unrecovered reserve of $1,693,565 be amortized over 10-years.[18] Further, Mr. Watson recommends that the

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[17] Robertson Surrebuttal Exhibit CR-7

[18] Watson Rebuttal Exhibit DAW-4, Page 1.

unrecovered reserve which consists of retired assets be kept in rate base and the Company receive a return of and on these assets.[19]

Q. Do you agree with Mr. Watson's recommendation?

A. I agree in part with amortizing the unrecovered reserve over 10 years. However, I disagree with the amount of the unrecovered reserve. The amount of unrecovered reserve per my Surrebuttal Exhibit CR-8 is $584,698 and should be recovered over 10 years. This is a difference of $1,108,866 compared to Mr. Watson's calculations.

Q. Does Mr. Watson agree with your proposal to move the unrecovered reserve to a Regulatory Asset and allow a return of, but not a return on the unrecovered reserve?

A. No, Mr. Watson disagreed with my proposal and discusses the Empire District Electric Docket No. 22-085-U, in which I was a witness.

Q. What was the issues involving moving retired asset to a Regulatory Asset in Docket No. 22-085-U?

A. In that docket, I agreed with the Company proposal to move stranded meters that were retired and not fully depreciated to a Regulatory Asset.[20] In Settlement Testimony Empire District Electric witness Charlotte T. Emery stated "However Liberty Empire has agreed to accept a return of, but not on, the Asbury decommissioning and retirement deferral accounting.".[21] The Commission approved this treatment of the Regulatory Asset to receive a return of, but not on the, Asbury decommissioning and retirement deferral accounting.[22]

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[19] Watson Rebuttal Testimony, Page 24, lines 3-9.
[20] Direct Testimony of Charlotte T. Emery, Docket No. 22-085-U, Doc. No. 29, p. 30, lines 6-12.
[21] Docket No. 22-085-U, Settlement Testimony of Charlotte T. Emery, Doc No. 155, p. 5, lines 10-15.
[22] Docket No. 22-085-U, Doc No. 159, Order No. 8, Page 8-9.

Q. What is your recommendation for SUA's unrecovered reserve?

A. I continue to recommend that the unrecovered reserve be put into a Regulatory Asset and receive a return of, but not a return on the unrecovered reserve.

SUMMARY OF STAFF'S RECOMMENDATIIONS

Q. Please summarize your recommendations in this docket?

A. I recommend the Commission:

- Deny SUA's proposed depreciation rates as presented in its Application Schedule F-1.3 and updated in its Rebuttal Testimony;
- Deny the Company's proposed amount of unrecovered reserve;
- Approve my depreciation rates as described in Surrebuttal Exhibits CR-1 and CR-2;
- 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;
- 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
- Approve the continued use of Vintage Accounting for Accounts 3910, 3912, 3940, 3970, 3971, and 3980.

Q. Does this conclude your Surrebuttal 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 September 9, 2024, via the Arkansas Public Service Commission's Electronic Filing System.

/s/ JOSHUA A. BAXTER
Joshua A. Baxter

APSC FILED Time: 9/9/2024 11:22:08 AM: Recvd 9/9/2024 11:15:09 AM: Docket 23-079-U-Doc. 159

BEFORE THE
ARKANSAS PUBLIC SERVICE COMMISSION

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

SURREBUTTAL EXHIBITS

OF

CLAUDE ROBERTSON, CDP
SENIOR CAPITAL RECOVERY ANALYST
FINANCIAL ANALYSIS SECTION

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

SEPTEMBER 9, 2024

STAFF RECOMMENDED DEPRECIATION RATES
SUMMIT UTILITIES ARKANSAS, INC.

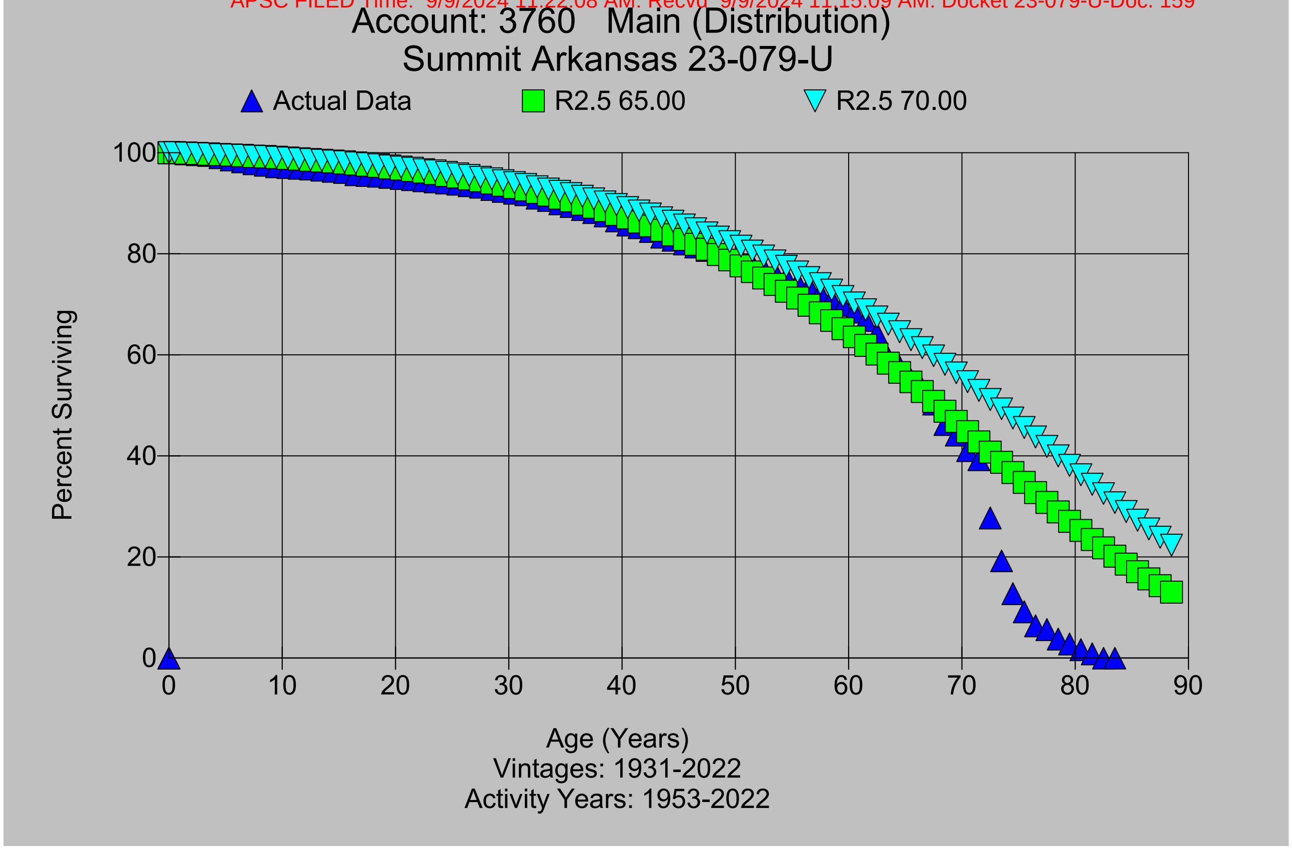
DOCKET NO. 23-079-U

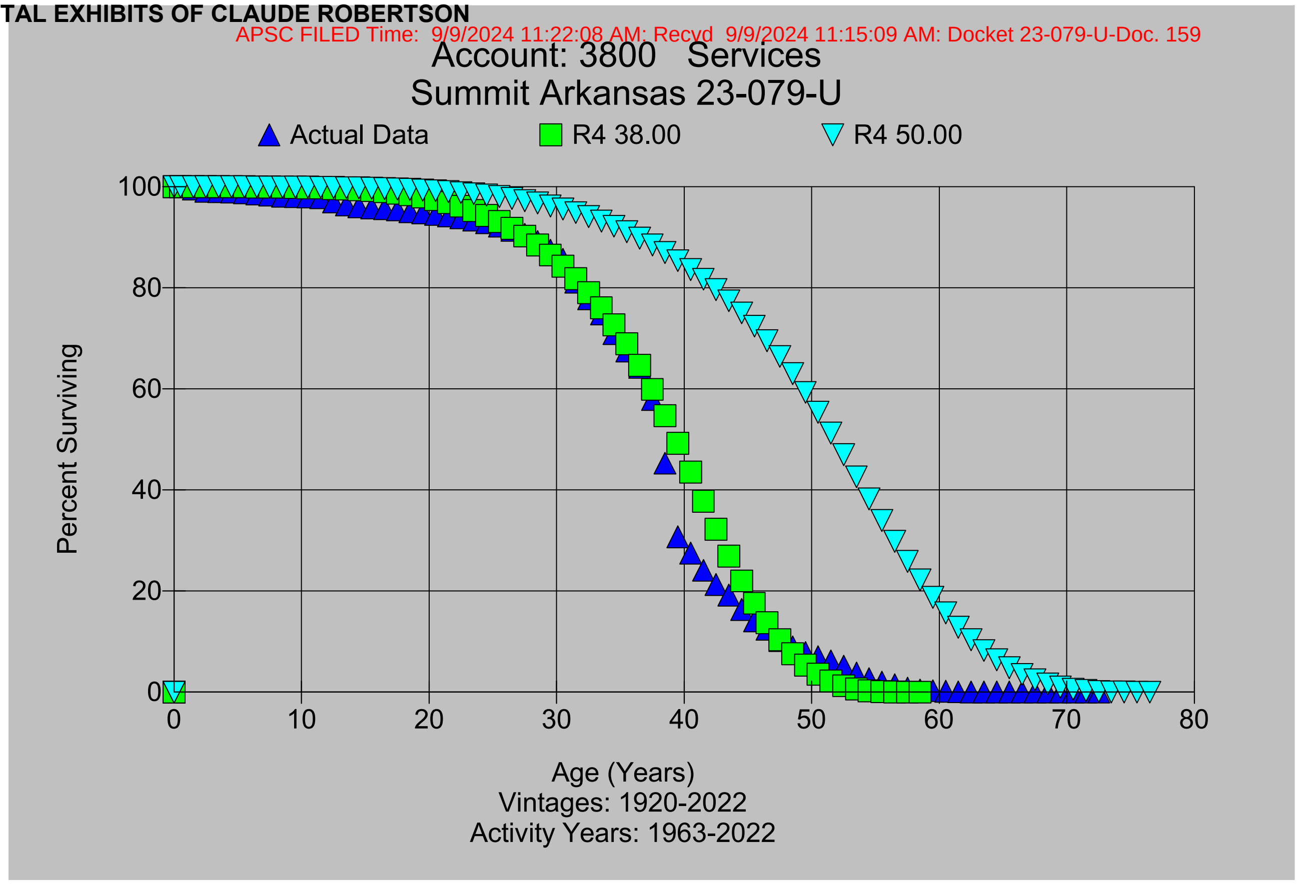
Distribution		**Staff Rate - Summit Direct**
	Intangible Plant	
302.10	PERPETUAL FRANCHISE & CONSENT	0.00%
303.00	INTANGIBLES INTERCONNECT	2.00%
303.10	INTANGIBLES MISCELLANEOUS - PICARRO	20.00%
303.20	INTANGIBLES MISCELLANEOUS	10.00%
390.20	SOFTWARE EA	10.00%
	Distribution Plant	
374.0	DISTRIBUTION 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%

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%

SURREBUTTAL EXHIBIT CR-3




Account: 3800 Services
Summit Arkansas 23-079-U
▲ Actual Data
🟩 R4 38.00
▽ R4 50.00
Percent Surviving
100
80
60
40
20
0
0
10
20
30
40
50
60
70
80
Age (Years)
Vintages: 1920-2022
Activity Years: 1963-2022

Summit Utilities Arkansas
Docket No. 23-079-U
Robertson Surrebuttal Exhibits

Robertson Surrebuttal Exhibit CR-5
Page 1 of 1

As of December 31, 2022

Account	Description	Plant at 12/31/22	Book Reserve at 12/31/2022	Remaining Life	Average Service Life	Net Salvage	Theoretical Reserve at 12/31/2022	Variance Over/(Under)
(a)	(b)	(c)	(d)	(e)	(f)		(g)	(h)
3742	Land Rights	4,020,565.65	$ 1,013,488.53	49.69	75	0.00%	1,356,807	$ (343,318.36)
3751	City Gate Main Line M/R Structures	224,807.59	143,969.21	30.04	65	0.00%	120,912	$ 23,057.31
3753	Meas & Dist Reg Sta Structures	400,508.13	179,759.46	30.17	62	0.00%	205,616	$ (25,856.25)
3754	Other Structures- Distribution	10,189,841.76	4,866,930.30	35.38	48	0.00%	2,679,079	$ 2,187,851.07
3755	Other Structures- Distribution Imp	5,244,325.19	1,851,926.56	31.13	38	-5.00%	995,525	$ 856,401.83
3760	Mains	858,698,342.45	260,324,249.11	51.94	65	-40.00%	241,545,238	$ 18,779,010.75
3780	Mea/ Reg Sta Equipment- General	14,120,321.49	2,518,068.38	31.24	40	-65.00%	5,102,378	$ (2,584,309.79)
3783	Other Equipment- Odorizing Equip.	1,111,690.19	814,031.95	8.02	13	0.00%	425,863	$ 388,169.09
3790	Mea Reg Sta Equipment City Gate	2,422,516.99	1,447,967.07	26.74	57	-5.00%	1,350,362	$ 97,605.10
3800	Services	395,610,297.61	235,262,527.64	25.29	38	-130.00%	304,338,838	$ (69,076,309.99)
3811	Meters- Domestic	30,121,837.85	19,337,459.49	18.49	36	0.00%	14,650,927	$ 4,686,532.25
3812	Meters - ERTS	29,222,228.15	20,078,076.53	7.37	14	0.00%	13,838,812	$ 6,239,264.20
3813	Meters - Industrial	14,561,884.43	9,134,489.65	14.98	30	0.00%	7,290,650	$ 1,843,839.51
3820	Meter Installation - Domestic	21,184,765.09	7,071,081.02	28.62	41	-10.00%	7,036,442	$ 34,638.80
3831	Regulators- Domestic	18,504,773.29	8,167,660.43	19.35	30	0.00%	6,569,195	$ 1,598,465.91
3832	Regulators- Industrial	12,758,397.10	6,320,197.46	18.27	31	0.00%	5,239,174	$ 1,081,023.43
3850	Industrial Meas and Reg Stat Equip.	7,450,385.75	781,229.37	35.83	40	-2.00%	792,237	$ (11,007.40)
3851	M&R Station Equipment - Other	12,964,151.12	8,605,387.79	24.57	48	-25.00%	7,910,158	$ 695,229.96
	Subtotal Distribution Plant	1,438,811,639.83	587,918,499.95				621,448,213	$ (33,529,712.57)
3901	General Plant Structures	8,316,933.37	167,576.30	41.71	43	0.00%	249,508	$ (81,931.70)
3920	Transportation Equipment	25,034,296.44	8,102,533.25	5.47	9	18.00%	8,051,586	$ 50,947.20
3960	Power Operated Equipment	5,112,178.99	2,521,062.51	9.46	15	20.00%	1,510,478	$ 1,010,584.02
	Subtotal General Depreciated	38,463,408.80	10,791,172.06				9,811,573	$ 979,599.52
	Total Plant	1,477,275,048.63	598,709,672.01				631,259,785	$ (32,550,113.05)

SUMMIT UTILITIES ARKANSAS
DOCKET NO. 23-079-u
SURREBUTTAL EXHIBITS OF CLAUDE ROBERTSON

SURREBUTTAL EXHIBIT CR-6
PAGE 1 OF 1

SUMMIT UTILITIES ARKANSAS, INC.
THEORETICAL RESERVE
AS OF DECEMBER 31, 2022

Account	Description	Vintage Year	Age	Plant Balance	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**

SUMMIT UTILITIES ARKANSAS
DOCKET NO. 23-079-U
SURREBUTTAL EXHIBIT OF CLAUDE ROBERTSON

ROBERTSON SURREBUTTAL EXHIBIT CR-7
PAGE 1 OF 1

Tools, Shop, Garage Equipment
Watson Rebuttal Exhibit   DAW 2

Asset Additional Description	**Vintage Year**	Amount
GEN - TOOLS,SHOP,GAR EQ, G-A00001	2014	138,864.76
GEN - TOOLS,SHOP,GAR EQ, G-A00001	2014	71,674.71
GEN - TOOLS,SHOP,GAR EQ, G-A00001	2014	187,241.00
GEN - TOOLS,SHOP,GAR EQ, G-A00001	2014	357,315.01
GEN - TOOLS,SHOP,GAR EQ, G-A00001	2014	248,186.77
GEN - TOOLS,SHOP,GAR EQ, G-A00001	2014	222,963.91
GEN - TOOLS,SHOP,GAR EQ, G-A00001	2014	327,325.41
GEN - TOOLS,SHOP,GAR EQ, G-A00001	2014	302,063.59
GEN - TOOLS,SHOP,GAR EQ, G-A00001	2014	702,884.57
GEN - TOOLS,SHOP,GAR EQ, G-A00001	2014	197,350.33
GEN - TOOLS,SHOP,GAR EQ, G-A00001	2014	341,951.43
GEN - TOOLS,SHOP,GAR EQ, G-A00001	2014	382,181.08
GEN - TOOLS,SHOP,GAR EQ, G-A00001	2014	186,869.78
GEN - TOOLS,SHOP,GAR EQ, G-A00001	2014	827,198.91
GEN - TOOLS,SHOP,GAR EQ, G-A00001	2015	608,087.76
GEN - TOOLS,SHOP,GAR EQ, G-A00001	2016	293,764.07
TOOLS, SHOP, GAR EQ	2017	426,335.44
GEN - TOOLS,SHOP,GAR EQ, G-A00001	2014	23,255.16
GEN - TOOLS,SHOP,GAR EQ, G-A00001	2018	771,072.10
GEN - TOOLS,SHOP,GAR EQ, G-A00001	2019	1,410,454.85
GEN - TOOLS,SHOP,GAR EQ, G-A00001	2020	764,007.61
GEN - TOOLS,SHOP,GAR EQ, G-A00001	2021	1,326,880.92
GEN - TOOLS,SHOP,GAR EQ, G-A00001	2022	1,146,621.48

Docket No. 15-098-U   **Data Response APSC-033**

FERC/Asset Class Plant Account	Description	Transaction Code	Activity Year	Vintage Year	Amount
G39401 7360	Tools Shop and	Balance	2014	2000	138,864.76
G39401 7360	Tools Shop and	Retiremen	2009	2000	36,543.36
G39401 7360	Tools Shop and	Addition	2001	2001	78,500.87
G39401 7360	Tools Shop and	Balance	2014	2001	71,674.71
G39401 7360	Tools Shop and	Retiremen	2009	2001	6,826.16
G39401 7360	Tools Shop and	Addition	2002	2002	207,593.28
G39401 7360	Tools Shop and	Balance	2014	2002	187,241.00
G39401 7360	Tools Shop and	Retiremen	2009	2002	20,352.28
G39401 7360	Tools Shop and	Addition	2003	2003	357,315.01
G39401 7360	Tools Shop and	Balance	2014	2003	357,315.01
G39401 7360	Tools Shop and	Addition	2004	2004	248,186.77
G39401 7360	Tools Shop and	Balance	2014	2004	248,186.77
G39401 7360	Tools Shop and	Addition	2005	2005	222,963.91
G39401 7360	Tools Shop and	Balance	2014	2005	222,963.91
G39401 7360	Tools Shop and Ga	Balance	2014	1996	212,942.55
G39401 7360	Tools Shop and Ga	Balance	2014	1997	146,301.71
G39401 7360	Tools Shop and Ga	Balance	2014	1998	140,099.94
G39401 7360	Tools Shop and Ga	Balance	2014	1999	349,472.40
G39401 7360	Tools Shop and	Addition	2006	2006	327,325.41
G39401 7360	Tools Shop and	Balance	2014	2006	327,325.41
G39401 7360	Tools Shop and	Addition	2007	2007	23,255.16
G39401 7360	Tools Shop and	Balance	2014	2007	23,255.16
G39401 7360	Tools Shop and	Addition	2008	2008	302,063.59
G39401 7360	Tools Shop and	Balance	2014	2008	302,063.59
G39401 7360	Tools Shop and	Addition	2009	2009	702,884.57
G39401 7360	Tools Shop and	Balance	2014	2009	702,884.57
G39401 7360	Tools Shop and	Addition	2010	2010	197,350.33
G39401 7360	Tools Shop and	Balance	2014	2010	197,350.33
G39401 7360	Tools Shop and	Addition	2011	2011	341,951.43
G39401 7360	Tools Shop and	Balance	2014	2011	341,951.43
G39401 7360	Tools Shop and	Addition	2012	2012	382,181.08
G39401 7360	Tools Shop and	Balance	2014	2012	382,181.08

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)**

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

REQUEST NO.: APSC-080

COMPANY NAME: **SUMMIT UTILITIES ARKANSAS**

DATE RECEIVED: **3/11/2024**

DATE DUE: **3/26/2024**

EXTENSION DATE:

INFORMATION REQUESTED:
Please provide the written policy for Summit Utilities Arkansas related to the General Plant Accounts (39101-7230, 39102-7260, 39401-7360, 39701-7390, 39703-7410, 39801-7450) showing the Company's length of service life for each account, before the assets are replaced with new assets, each policy should be listed by account. Please provide the documentation from management supporting when the policy was adopted and when it went into effect.

REQUESTED BY: **ARKANSAS PUBLIC SERVICE COMMISSION - DON MALONE**

RESPONSE:
The company does not have an approved replacement policy for the accounts given, these assets are replaced as needed. Under gas FERC accounting, asset service lives are not individually tracked and are retired according to FERC Accounting Release-15. Please refer to the link below.

https://www.ferc.gov/enforcement-legal/enforcement/accounting-matters/vintage-year-accounting-general-plant-accounts

SPONSOR:
Ann Byrd, 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 26, 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 September 9, 2024, via the Arkansas Public Service Commission's Electronic Filing System.

/s/ JOSHUA A. BAXTER
Joshua A. Baxter

APSC FILED Time: 9/9/2024 11:25:12 AM: Recvd 9/9/2024 11:21:07 AM: Docket 23-079-U-Doc. 160

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 SURREBUTTAL TESTIMONY

OF

DAN DAVES, CRRA
SENIOR RATE CASE ANALYST
FINANCIAL ANALYSIS SECTION

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

SEPTEMBER 9, 2024

TABLE OF CONTENTS

I. INTRODUCTION AND PURPOSE

Q. Please state your name.

A. My name is Dan Daves.

Q. Did you previously present testimony in this proceeding?

A. Yes. I filed Direct Testimony on July 10, 2024.[1]

Q. What is the purpose of your Surrebuttal Testimony?

A. The purpose of my Surrebuttal Testimony is to present Staff's updated recommendation for the overall rate of return ("ROR") for Summit Utilities Arkansas, Inc. ("SUA" or "Company"). I will address the Company's updated request of a 6.9790% ROR by specifically responding to the proposed capital structure components, the balances of those components including the relative proportion of the debt and equity external sources of funding, and the cost rates of each component.[2] Additionally, I will address the Rebuttal Testimonies of Company witnesses Craig Root and Dylan W. D'Ascendis.

II. COST OF CAPITAL UPDATE

Q. Have you evaluated the Company's Rebuttal testimonies and supporting schedules and workpapers?

A. Yes, I have. The Company filed an updated cost of service study in this docket on August 7, 2024 (Doc. 126) along with Rebuttal testimony. The Company's requested ROR, or weighted average cost of capital ("WACC"), increased from 6.7047% in Direct to 6.9790% in Rebuttal. The Company has based their request

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[1] Direct Testimony of Dan Daves, CRRA, Doc. 108.

[2] Surrebuttal Exhibit DD – 1.

on the projected balances and cost rates of its indirect parent, Southern Col Holdco, LLC ("SCHC"), as of the end of the *pro forma* year, December 31, 2024.

Q. Does SUA witness D'Ascendis provide an update to his ROE recommendation in his Rebuttal Testimony?

A. Company witness D'Ascendis updated his cost of equity models to use data through June 28, 2024.[3] SUA's updated Schedule D-1.3 utilizes a 11.00% ROE based on Company witness D'Ascendis's analysis and recommendation, which is the same as his ROE recommendation from his Direct Testimony.[4]

Q. Have you updated Staff's analysis to include the most recent growth rates published by Value Line?

A. Yes. I have updated Staff's analysis from Direct to utilize the May 24, 2024 issue of Value Line #3. As discussed in my Direct Testimony,[5] Staff's established methodology incorporates the stock prices for its proxy group for each trading day in which the price contains the Value Line growth rates used to estimate the ROE for the company being evaluated.[6] A stock's price embodies all currently-available market information, and the average of which eliminates market fluctuations.[7] This approach endeavors to comprehensively capture and incorporate into Staff's analysis both investors' expectations and the influence of macroeconomic conditions, such as inflation, on the stock prices of the market-traded entities

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[3] Rebuttal Testimony of Dylan W. D'Ascendis, p. 3, line 10.
[4] Docket No. 23-079-U, SUA Updated Cost of Service Study, Doc. 126, Part 3, Schedule D-1.3.
[5] Direct Testimony of Dan Daves, CRRA, Doc. 108, p. 40, lines 5 – 23; p. 41, lines 1 – 2.
[6] Value Line publishes new issues of each edition approximately every quarter (i.e., thirteen weeks).
[7] Direct Testimony of Dan Daves, CRRA, Doc. 108, p. 40, lines 5 – 10.

comparable in risk to SUA.

After evaluating the Company's Rebuttal testimonies, I continue to support a 9.75% ROE for SUA. The Company's witnesses provided no substantive argument or evidence in Rebuttal which would compel me to deviate from the Commission's long-standing methodology for either ROE estimation or determining the appropriate DTE ratio for ratemaking purposes, and they do not adequately refute Staff's assertions.

Q. Does Staff have an updated ROR recommendation in Surrebuttal?

A. Yes. Surrebuttal Exhibit DD – 2 shows Staff's updated ROR recommendation of 5.71% (6.92% on a pre-tax basis).

Q. Did you update the balances used in your overall ROR recommendation?

A. Yes. Surrebuttal Exhibit DD – 3 shows Staff's updated balances for the external capital components, and Staff's Surrebuttal Exhibit DD – 4 includes the DTE ratio used in arriving at those recommended balances.

Q. Did you provide an update to your cost of equity models used for your ROE recommendation?

A. Yes. Staff's updated discounted cash flow ("DCF") analysis used prices collected from May 24, 2024 through August 23, 2024[8] and growth rates from the Value Line Issue #3 from May 2024.[9] Staff's updated DCF analysis produced results of 8.2%, 9.1%, 9.2%, and 9.9%.[10] Staff's updated CAPM used the same Value Line for the

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[8] Surrebuttal Exhibit DD – 5.
[9] Surrebuttal Exhibit DD – 6.
[10] Surrebuttal Exhibit DD – 7.

beta and methodology from Direct to produce results of 10.29% and 10.52%.[11] Staff's updated risk premium model (RPM) produced results of 9.81%, 9.81%, 9.86%, and 9.88%.[12] Surrebuttal Exhibit DD – 10 indicates that the average authorized ROE in recent natural gas rate cases in surrounding jurisdictions is 9.58% and that the highest approved ROE was 10.25% (Florida Public Utilities Co.). Additionally, I would point out that of the twenty observations in DD – 10, only two of the approved ROEs in other jurisdictions were above 10% (10.15% and 10.25%). These results continue to support as reasonable Staff's recommended ROE for SUA of 9.75%.

Q. Will you explain how you updated Staff's recommended DTE ratio?

A. Yes. My Surrebuttal Testimony utilizes the most recent actual balances as of April 30, 2024 filed with the Company's Updated Cost of Service Study and Minimum Filing Requirements Schedules in support of its Rebuttal position.[13] Regarding the appropriate DTE ratio, I recommend as reasonable imputing a 55% debt (including 6.16% short-term debt) and 45% equity for ratemaking purposes based on the eight (8) quarter average of the proxy group comparable in risk to SUA as likewise used for the ROE assessment.[14] My recommendation considers the most recent eight quarterly periods for which all companies in the sample have reported, ending with the second quarter of 2024.[15] Accordingly, I have reapportioned the

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[11] Surrebuttal Exhibit DD – 8.
[12] Surrebuttal Exhibit DD – 9.
[13] Surrebuttal Exhibit DD – 3.
[14] Surrebuttal Exhibit DD – 4.
[15] *Id.*

Company's balance of external capital to reflect the most current eight-quarter average proportions of long-term debt, short-term debt, and equity of the proxy group for use in my calculation of SUA's ROR.[16]

Q. Have you updated the components of the capital structure to reflect updated information provided by other Staff witnesses?

A. Yes. Staff witness Don Malone provided updated amounts of current, accrued, and other liabilities ("CAOL") and excess deferred income taxes ("EDIT")[17] for use in Staff's WACC calculation.

Q. What was the resulting change in Staff's recommended ROR for SUA as a result of applying updated balances and cost rates?

A. Staff's recommended ROR increased from 5.58% (or 6.08% pre-tax) in Direct to 5.71% (or 6.92% pre-tax) in Surrebuttal,[18] mainly due to the changes in the capital component balances from the Company's updated cost of service study,[19] updated zero-cost liabilities balances,[20] Staff's Surrebuttal recommendation for the long-term debt cost rate, and Staff's updated DTE ratio recommendation, both of which I will explain in detail later in this testimony.

III. CAPITAL COMPONENT BALANCES

Q. Please discuss the time frame you relied upon in determining the balances in the capital structure?

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[16] Surrebuttal Exhibit DD – 2.
[17] Surrebuttal Testimony of Staff Witness Don Malone.
[18] Surrebuttal Exhibit DD – 2.
[19] Docket No. 23-079-U, Doc. 126, part 3, Schedule D-1.3.
[20] Surrebuttal Testimony of Staff Witness Don Malone.

A. Consistent with past practice before this Commission, I relied on the most recently available actual balances submitted by the Company. In Staff's Direct Testimony, Staff relied on the test-year end balances, which were as of December 31, 2023.[21] The Company's most recent submission (Doc. 126), which updates its cost of service study, contains actual balances from April 30, 2024, which I have utilized for Staff's updated ROR recommendation for SUA.[22]

Q. On what balances does the Company base its request?

A. As SUA's capital structure is composed of 100% equity,[23] the Company has based its request on the balances projected for the *pro forma* year ending December 31, 2024 for its indirect parent company, SCHC, which includes adjustments to capital components for changes that are not known nor measurable. I have used the most recent actual balances provided by the Company, consistent with Staff's past practices, as of April 30, 2024 as stated above.

IV. RELATIVE PROPORTIONS OF EXTERNAL CAPITAL COMPONENTS

Q. Have you updated Staff's analysis of the DTE ratios of the risk comparable proxy group?

A. Yes. All of the companies in the risk comparable proxy group have reported second quarter of 2024 financials, which are publicly available to investors. My

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[21] Docket No. 23-079-U, Doc. 18, Part 5, Schedule E-1.1.
[22] Docket No. 23-079-U, Doc. 126, Part 4, Schedule E-1.1.
[23] Rebuttal Testimony of Kurt Adams, p. 6, lines 14 – 15.

updated analysis is presented in Surrebuttal Exhibit DD – 4.

Q. Has Staff's recommended DTE ratio changed from its Direct Testimony?

A. Yes. Staff's Surrebuttal Testimony supports a hypothetical DTE ratio of 55% debt to 45% equity, inclusive of 6.16% in short-term debt, based on an eight-quarter average of the DTE ratios of the risk comparable sample ending with the second quarter of 2024.[24]

Q. Why is it necessary to impute SUA's capital structure?

A. As I discussed in my Direct Testimony, the Company's requested DTE ratio of 45% debt and 55% equity is out of step with observable industry trends.[25] Staff and the Company are in agreement that, because the Company is financed 100% with equity, it is necessary to impute a DTE ratio for ratemaking purposes. Staff accordingly recommends imputing the Company's capital structure based on Staff's DTE ratio recommendation, which is the eight-quarter average capital structure of the same risk-comparable sample group of companies used in determining Staff's ROE recommendation to maintain congruence between the DTE ratio and the required ROE. As the Company's requested capital structure also fails to include a proportion of short-term debt, it is necessary to use Staff's recommended DTE ratio. I will elaborate upon this further below in Section VII and VIII.

V. COST RATES

Q. Do you and the Company agree on any cost rates?

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[24] Surrebuttal Exhibit DD – 4.

[25] Direct Testimony of Dan Daves, p. 28, line 8 – p. 29, line 16.

A. Yes. The Company and I agree on the cost rate for Short-Term Debt and does not object to my Customer Deposit cost rate. The Company has accepted as reasonable my recommended short-term debt cost rate of 6.6074%.[26] The Company and I disagree on the cost rates for long-term debt and the common equity cost rate.

VI. COST OF EQUITY

Q. Do you continue to support the reasonableness of Staff's 9.75% ROE recommendation for SUA?

A. Yes. Based on the support provided in my Direct Testimony, my review of the Direct Testimony of AG Witness Dr. Griffing (whose recommended ROE for SUA is 9.80%),[27] and my review of the Rebuttal Testimony of Company witness D'Ascendis, I continue to support that 9.75% is a reasonable ROE estimate for SUA.

Q. Does Company witness D'Ascendis mischaracterize Staff's cost of equity analysis?

A. Yes. Company witness D'Ascendis asserts that Staff gives primary weight to the DCF model over other models and qualitative information.[28] Company witness D'Ascendis has inaccurately portrayed Staff's cost of equity analysis. Staff never claimed to rely on a single methodology, hence, the inclusion of other models and qualitative data, including the cost of equity analyses done

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[26] Rebuttal Testimony of Company Witness Craig Root, p. 10, lines 4 – 6.
[27] Direct Testimony of AG Witness Dr. Marlon F. Griffing, p. 57, line 19.
[28] Rebuttal Testimony of Company Witness Dylan W. D'Ascendis, p. 13, lines 18 – 21; p. 14, lines 1 – 2.

by Company witness D'Ascendis. I would point out that the average of Staff's DCF analyses is 9.12% and the median is 9.16%.[29] Additionally, three of the four DCF estimates are below Staff's recommendation of 9.75%. As stated in my Direct Testimony, the results of all models and qualitative information available at the time the analyses were performed were considered when making my required ROE recommendation.[30]

Q. Does Company witness D'Ascendis agree with you that the DCF methodology is this Commission's preferred methodology for estimating a company's cost of equity or ROE?

A. Yes.[31]

Q. What is Staff's recommended ROE for SUA?

A. Staff continues to support as reasonable an ROE of 9.75% for SUA.

Q. Did you evaluate the adequacy of your ROR recommendation?

A. Yes. As evidenced in Table 1 below, the ratios I evaluated specific to SUA using Staff's recommended ROR results are reasonable when compared to the average ratios of the companies in my risk-comparable sample. My evaluation is based on my updated calculation of: (1) earnings before interest, taxes, depreciation, and amortization (EBITDA) to interest; (2) times interest earned (TIE) ratio; and (3) total debt to EBITDA. I assessed the adequacy of my recommendations using my recommendation of 9.75%.

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[29] The average of Staff's DCF estimates of 8.2%, 9.1%, 9.2% and 9.9%.
[30] Docket No. 23-079-U, Direct Testimony of Dan Daves, CRRA, Doc. 108, p. 56, lines 11 – 18.
[31] Rebuttal Testimony of Company Witness Dylan W. D'Ascendis, p. 14, lines 5 – 6.

Table 1: Adequacy Checks

	EBITDA/Interest	**TIE Ratio**	**Debt/EBITDA**
	(1)	**(1)**	**(2)**
Recommendation - 9.75%	7.1	3.4	3.7
Sample Average	4.0	1.8	11.2

(1) Higher value is better.
(2) Lower value is better.

Q. Do you continue to support that your recommended ROE and overall ROR meet the standards set forth in the *Bluefield*[32] and *Hope*[33] decisions regarding what constitutes a reasonable rate of return?

A. Yes. These generally accepted, landmark decisions serve as guidelines for such a determination. My analysis considers the current economic and financial climate including debt costs.

VII. REBUTTAL OF COMPANY WITNESS ROOT

Q. Which of Staff's recommendations from Direct does Company witness Root respond to specifically?

A. Company witness Root responds to Staff's recommended DTE ratio and Staff's recommended long-term debt cost rate. In this section of my testimony, I attempt to address each of the Company's concerns in Company witness Root's Rebuttal Testimony, however, not addressing a particular issue should not be construed as agreement.

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[32] *Bluefield Waterworks and Improvement Co. v. Public Service Commission of the State of West Virginia*, 262 U.S. 679 (1923).

[33] *Federal Power Commission v. Hope Natural Gas Company*, 320 U.S. 591 (1944).

<u>Fitch Ratings Credit Report</u>

Q. Did you find Company witness Root's Rebuttal Testimony misleading with regard to his discussion of the Company's credit rating?

A. Yes. Company witness Root claims that SCHC has a current credit rating by Fitch of A-.[34] However, as indicated in his Confidential Rebuttal Exhibit CR-1 on page 1 of 7, [redacted] However, [redacted].[36] Neither SUA or SCHC, on which the Company has based its projected capital structure, are individually rated by Fitch.

Q. Were you able to glean any information germane to the current rate case from the report?

A. Yes. The report discusses credit supportive indicators for SUA, including key ratings drivers directly related to SUA, and Fitch's expectations of the instant rate case. I will discuss each of these in turn.

Q. Are there any credit supportive indicators in the report provided in Confidential Rebuttal Exhibit CR-1?

A. [redacted]

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[34] Rebuttal Testimony of Craig Root, p. 3, lines 18 – 20.
[35] Confidential Rebuttal Exhibit CR-1, p. 1 of 7.
[36] *Id.*

> [redacted]

> [redacted]

> [redacted]

> [redacted]

> [redacted]

[redacted] Staff's recommendation of 9.75% would no doubt be viewed favorably by Fitch Ratings. The report clearly conveys Fitch's opinion that operating in Arkansas is credit positive for natural gas utilities, including for SUA.

[redacted]

[redacted]

[redacted]

[redacted]

<u>Capital Structure</u>

Q. Is the DTE ratio inherent in the Company's request appropriate in setting its allowed ROR?

A. Absolutely not. As explained in my Direct Testimony[37] and as I will explain in detail in this section, the projected equity proportion inherent in the Company's WACC calculation used to arrive at its requested ROR is almost one-thousand (1,000) basis points (10% points) higher than the average equity proportion of the companies comparable in risk to SUA. Table 2 below illustrates the current positions of the parties and benchmarks:

Table 2: Summary of DTE Ratios

Entity	**Basis**	**Total Debt**	**Total Equity***
Company Recommendation (Rebuttal)	Projected as of December 31, 2024	45%	55%
Staff Recommendation (updated) (1)	Average of Proxy Group Actuals	55%	45%
AG Recommendation (2)	Average of Comparison Group Actuals	54%	46%

* Generally, the higher the equity ratio, the higher the overall rate of return as the cost of equity is typically the highest cost rate.

(1) Surrebuttal Exhibit DD-4. Staff's recommendation includes 6.16% in short-term debt.
(2) Direct Testimony of Marlon Griffing, p. 46, lines 14 – 16.

Q. Mr. Root suggests the capital structure imputed to CERC in its 2015 rate case is relevant to this proceeding. Do you agree?

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[37] Direct Testimony of Dan Daves, CRRA, p. 28, lines 8 – 14; p. 28, lines 1 – 16.

A. No. The Company's last rate case was filed in 2015, approximately nine (9) years ago, and Mr. Root acknowledges market conditions are substantially different now.[38] At that time the Company was authorized to have a DTE ratio of 51.5% debt (inclusive of 7.71% in short-term debt) to 48.5% common equity, based on the average capital structure of the risk comparable sample.[39] In the years since the Company's previous rate case, debt costs have generally declined with interest rates which appears to have incentivized companies to finance operations more through debt as indicated by the levels of long-term debt in the proxy group of companies in Staff's Surrebuttal Exhibit DD – 4.

Q. Why is it imperative that the capital structure be evaluated for reasonableness?

A. Evaluating and ensuring a reasonable capital structure for ratemaking purposes is an adjustment just like any other in a rate case. An imputed capital structure is used to calculate a fair rate of return to ensure that ratepayers are not burdened with excessive equity costs. However, this does not in any way imply that utility management is required to achieve such a capital structure. Just as with other ratemaking adjustments, management is free to expend the costs associated with the higher equity capital structure. Imputing a capital structure simply means that equity costs above a reasonable level may not be recovered from ratepayers.

Q. Is Staff's recommended DTE ratio out of sync with industry standards?

A. No. As found in Surrebuttal Exhibit DD – 4, Staff's recommended DTE ratio,

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[38] Rebuttal Testimony of Craig Root, p. 9, lines 2 – 4.
[39] Docket No. 15-098-U, Commission Order No. 8, Doc. 249, pp. 12 – 13.

which is an eight-quarter average of Staff's proxy group of companies updated to the second quarter of 2024, reflects the standards by which risk-comparable companies set their capital components.

Q. Is it appropriate to adjust individual company balances of individual capital components within the capital structure analysis of the risk comparable sample?

A. No. Company witness Root states that three companies in Staff's proxy group, Atmos Energy Corporation, ONE Gas, Inc., and Spire Inc., experienced higher levels of debt due to Winter Storm Uri.[40] Company witness Root implies that adjusting the debt balances of those companies by the proportions used to finance Winter Storm Uri from the capital structure recommendation maintains a consistent view with the Company's ongoing operations.[41]

Consistent with Staff's past practice before this Commission, Staff has utilized unadjusted, "as reported"[42] financial data of the market-traded risk comparable companies in its DTE ratio analysis because those proportions represent actual financing decisions by market-traded companies, who must compete for capital in the open market, at specific points in time. Observing these financing decisions "as reported" is the best way to observe "best practices" in a financial sense. The proportions of capital and cost rates

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[40] Rebuttal Testimony of Craig Root, p. 14, lines 13 – 20.

[41] *Id*. at p. 14,, lines 8 – 12.

[42] The term "as reported" means what each Company actually reported in its required quarterly or annual filing with the Securities and Exchange Commission. These reports are publicly available to all investors and are often used to inform investment decisions, especially when evaluating companies within the same industry.

together make up the capital structure and adjusting those balances creates incongruence between the required cost of equity and the recommended DTE ratio.

Q. On pages 10 of his Rebuttal Testimony, Company witness Root states that Staff's methodology for arriving at the cost of debt, cost of equity, and recommended capital structure are not congruent with one another.[43] How do you respond?

A. As I will discuss below, I partially agree with Mr. Root's observation. Staff has revised the recommended cost of debt for SUA to bring it in line with the observable debt costs of the proxy group. However, I continue to support Staff's longstanding position that congruence between the estimated ROE and the equity proportion of the capital structure are achieved when both are derived from the proxy group of market-traded companies comparable in risk to the company being evaluated.

Q. Do you support as reasonable your capital structure recommendation?

A. Yes. I recommend as reasonable the average DTE ratio of the market-traded, risk-comparable sample of 55% debt, inclusive of 6.16% short-term debt, and 45% equity for SUA for ratemaking purposes. My recommendation is based on the eight-quarter average percentage of the capital structure components of the same risk-comparable sample used to estimate my recommended ROE for SUA.

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[43] Rebuttal Testimony of Craig Root, p. 10, lines 7 – 14.

Long-Term Debt Cost Rate

Q. What is the Company's requested long-term debt cost rate?

A. The Company has requested a long-term debt cost rate of 4.1798%, which is the same long-term debt cost rate the Company requested in Direct.[44]

Q. Has Staff's recommended long-term debt cost rate recommendation changed from Direct?

A. Yes. Staff's Surrebuttal recommendation for a long-term debt cost rate of 4.11%, which is the average long-term debt cost rate of the proxy group of companies based on Company SEC filings. This long-term debt cost rate recommendation is supported by Staff's Surrebuttal Exhibit DD – 11.

Q. Why did Staff change its recommended cost rate for long-term debt?

A. Based on arguments made by Company witness Root, I reevaluated the Company's debt issuances as they appear on Schedule D-2.1. After further review, the Company's outstanding debt are all private placement issuances, which typically carry lower risk, and accordingly, lower yields than publicly issued debt. Based on that observation, I opted to implement the methodology used by Staff in the last CERC rate case to determine an appropriate cost rate for long-term debt for SUA to be used in the WACC calculation. The methodology used by Staff was to impute the average embedded cost of debt for the proxy group.[45] As shown in my Surrebuttal Exhibit DD – 11, the average cost rate for the proxy group was 4.11%.

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[44] Docket No. 23-079-U, Doc. 18, Part 4, Schedule D-2.3, PDF p. 12.
[45] Docket 15-098-U, Direct Testimony of Jerry Keever, Doc. 132, p. 28, lines 10 – 19.

VIII. REBUTTAL OF COMPANY WITNESS D'ASCENDIS

Q. What are your primary observations regarding Company witness D'Ascendis's position?

A. Company witness D'Ascendis's ROE recommendation of 11.00% did not change from his Direct to his Rebuttal Testimony. It should be noted that unlike Staff's cost of equity results, all the results from the models of Company witness D'Ascendis are over 10.00% including a 12.52% CAPM result and a 12.82% non-price regulated cost of equity result.[46] These results are two-hundred and twenty (220) basis points and two-hundred and fifty (250) basis points higher than the cost of equity result produced by his DCF model (10.32%).[47] Furthermore, as I elaborate upon later in my testimony, Company witness D'Ascendis's cost of equity analysis primarily emphasizes projected data, while Staff's ROE analysis utilizes a balance of historical and projected growth rates within all models to better inform the determination of the required ROE for SUA.

Q. Company witness D'Ascendis points out that some of the growth rates used in the DCF analysis from your Direct Testimony were inconsistent with regard to timing. How do you respond?

A. I have updated my DCF analysis for my Surrebuttal Testimony and used growth rates from Zacks Investment Research, Yahoo Finance, and Value Line, all from May 2024, to correspond with prices for my proxy group of

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[46] Rebuttal Testimony of Dylan W. D'Ascendis, p. 4, Table 2.
[47] *Id.*

companies collected between May 24, 2024 and August 23, 2024. Furthermore, my updated DCF analysis results of 8.2%, 9.1%, 9.2%, and 9.9% only provide more support for my required ROE recommendation of 9.75%.[48]

Q. Company witness D'Ascendis expresses concerns regarding the use of historical growth rates and dividend per share growth rates in your DCF analysis. How do you respond?

A. Consistent with Staff's past practice, my DCF analysis includes historical and projected growth rates to balance the cost of equity analysis. Investor expectations are based on historical trends and analysts' projections, not one or the other. As investors use both historical and projected data to make investment decisions, Staff used a more balanced approach using a combination of historical and projected growth rates in the DCF model that reflect reasonable outcomes for rational investors, which is consistent with Staff's DCF methodology in the last several rate cases before this Commission.

With respect to the use of dividends per share ("DPS") rates, investors are primarily concerned with the growth of dividends, which are paid out of earnings.[49] Therefore, to balance investors' expectations, Staff included earnings per share ("EPS") and DPS growth rates in the DCF model. Furthermore, dividends are a main concern to utilities' stockholders, as utility stocks are generally considered more conservative investments, and

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[48] Surrebuttal Exhibit DD – 7.
[49] Direct Testimony of Dan Daves, CRRA, p. 42, lines 11 – 13.

dividends provide a steady stream of income. Finally, consistent with the criterion for determining Staff's risk-comparable sample of companies, Company witness D'Ascendis also verified that no companies in his proxy group have announced a dividend cut or cut their dividend in the five years ending in 2022 or through the time of the preparation of his testimony prior to his analysis, further demonstrating the importance of dividends to utilities stock investors.[50]

Q. Do you dispute the claim by Company witness D'Ascendis that the DCF has limitations compared to other cost of equity models?

A. Yes. I would argue that the inputs in the DCF are more company specific and allow for a more granular perspective on a stock than using beta, as the current stock price embeds all market data, while beta is a historical measurement of the volatility of a stock against the market as a whole.

Q. Company witness D'Ascendis advocates for a size adjustment to your CAPM. How do you respond?

A. Adjusting the results of a cost of equity model insinuates bias into those results, which only serves to disrupt the congruence between the recommended DTE ratio and the recommended cost of equity, which are derived using market-based analyses. Furthermore, a size adjustment to any cost of equity estimate is unwarranted, as there is no substantial support for any such upward adjustment. I reiterate Staff's position that the size adjustment proposed by

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[50] Direct Testimony of Dylan W. D'Ascendis, p. 14, lines 1 – 2.

Company witness D'Ascendis is unwarranted and unsupported.[51] Further, this Commission has recently denied size adjustments to required ROEs.[52]

Q. Company witness D'Ascendis states that Staff's risk premium model uses a short period of time to calculate the average equity risk premium. How do you respond?

A. Staff's RPM uses recently-authorized ROEs and contemporaneous bond yields, thus eliminating the need to screen or adjust cost of equity estimates in the RPM. Contrary to his other cost of equity models, Company witness D'Ascendis emphasizes the use of historical data for the calculation of his equity risk premium as it relates to historical interest rates.[53] Similar to Staff's other cost of equity analyses, Staff's RPM analysis uses recent historical market data and the corresponding authorized ROEs to better inform the ROE recommendation for SUA.

Q. How do you respond to Company witness D'Ascendis reasserting the use of a non-price regulated companies in his assessment of a reasonable ROE for SUA?

A. Company witness D'Ascendis states that his group of non-price regulated companies is comparable in risk to his Utility Proxy Group, which is the same six (6) regulated natural gas utilities as Staff's risk-comparable sample.[54] Regulated utilities operate in what is essentially a monopoly environment, thus

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[51] Direct Testimony of Dan Daves, CRRA, p. 52, lines 13 – 21; p. 53, lines 1 – 2.
[52] Docket No. 21-070-U, Order No. 14, pp. 20 – 21.
[53] Rebuttal Testimony of Dylan W. D'Ascendis, p. 29; p. 30, lines 1 – 2.
[54] Rebuttal Testimony of Dylan W. D'Ascendis, p. 45, lines 2 – 4.

the need for regulation. Company witness D'Ascendis's statement that his non-price regulated group of companies is comparable in total risk to his Utility Proxy Group is a strange observation, considering the price variations and market opportunities for non-price regulated companies found in the unregulated economy. I reiterate the position from my Direct Testimony that this information should not be given any consideration in a ratemaking proceeding for determining a reasonable ROE for a regulated utility.[55]

Q. Do you believe there is substantial evidence in the record at this point to quantitatively support Company witness D'Ascendis's ROE recommendation of 11.00% for SUA?

A. No, I do not believe that there is substantial evidence on the record that supports a 11.00% ROE for SUA, quantitatively or otherwise.

Q. Does Company witness D'Ascendis mischaracterize the principle of congruence with respect to Staff's recommended capital structure?

A. Yes. On page 11 of his Rebuttal Testimony, Company witness D'Ascendis fails to recognize the importance of utilizing the same companies and maintaining a consistent methodological analysis when determining the recommended DTE ratio and required ROE. Company witness D'Ascendis erroneously conjectures that comparable earnings between the proxy group of companies is the key issue for congruence rather than maintaining a consistent methodology between the capital structure analysis and cost of equity

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[55] Direct Testimony of Dan Daves, CRRA, p. 53, lines 17 – 22; p. 54, lines 1 – 12.

models.[56] Staff's methodology for calculating a reasonable DTE ratio is consistent with Staff's past practices before this Commission in the last several rate cases. Staff's capital structure recommendation utilizes an average of the actual capital structures including proportions of long-term debt, short-term debt, and common equity of the risk-comparable sample of companies used in determining the required ROE recommendation, not unsupported projections.

Q. Company witness D'Ascendis provided a range of projected common equity ratios from Value Line on page 3 of Schedule DWD-2R. Do you have any comments on those projected common equity ratios?

A. Yes. As evidenced in Table 3 below, the average of the projected common equity ratios of the proxy group of companies provided by Company witness D'Ascendis, which includes the same companies as Staff's proxy group, do not support the Company's requested common equity ratio of 55% as reasonable.

Table 3: Value Line Projected Common Equity Ratios

		Projected Common Equity Ratio (%)		
Ticker	Company	2024	2025	2027 - 2029
ATO	Atmos	60	60	60
NJR	New Jersey Resources	42.5	43	45
NI	NiSource	40	40	37.5
NWN	Northwest Natural Holding	50	50	50
OGS	ONE Gas	55	55	49
SR	Spire	44	44	45
	AVERAGE	48.58	48.67	47.75

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[56] Rebuttal Testimony of Company witness Dylan W. D'Ascendis, p. 11, lines 9 – 15.

In fact, this data demonstrates that the Company's requested common equity ratio of 54.88% common equity is unreasonable compared to a sample of companies of similar risk. Furthermore, as evidenced in his Rebuttal Exhibit Schedule DWD-1R pages 7 through 12, Value Line only considers long-term debt and common equity for their capital structure ratios. By excluding a proportion of short-term debt, which the Company has in its requested capital structure, these capital structure ratios unnecessarily inflate the proportion of common equity, which in turn passes on unwarranted higher costs to ratepayers.

Q. Do the Value Line exhibits in Rebuttal Exhibit Schedule DWD-1R demonstrate that the Company's requested ROR is reasonable?

A. Absolutely not. On the contrary, as illustrated by the Return on Total Capital found in Schedule DWD-1R and below in Table 4 for the six proxy group companies used by Staff and Company witness D'Ascendis, the Return on Total Capital for the preceding five years is lower than the Company's request in this proceeding by approximately one-hundred and eighty (180) basis points and is trending downwards overall. Return to Total Capital is an equivalent measure to the ROR or the WACC for all capital components. The Company's requested ROR of 6.9790% is not supported by recent historical data for the proxy group of risk-comparable companies used in determining Staff's cost of capital recommendation.

Table 4: 5-Year Proxy Group Average for Return to Total Capital

	Return to Total Capital (%)					
Company	2019	2020	2021	2022	2023	AVG
ATO	6.1	5.5	5.5	5.4	5.5	5.6
NJR	6.4	5.6	6.5	5.6	5.5	5.92
NI	5.3	5.0	4.9	3.8	3.4	4.48
NWN	5.2	5.2	5.1	3.6	3.5	4.52
OGS	6.4	6.0	3.9	5.0	5.9	5.44
SR	5.1	2.9	5.8	4.9	4.8	4.7
				Proxy Group 5-Yr Avg		5.11

Q. How do you respond to the Company's use of a projected capital structure for an indirect parent while challenging the use of imputing a capital structure based on a risk-comparable proxy group of companies, consistent with the average of your sample used in assessing ROE?

A. As explained in detail in my Direct Testimony, the imputation of a reasonable capital structure is necessary due to the Company's request being out of line with industry trends. Additionally, SUA is not market-traded and is itself a wholly-owned subsidiary of a parent corporation. A public utility that operates in a monopoly environment does not have market forces operating to the same extent to balance its use of debt and equity. However, market-traded natural gas utilities do have to compete in the capital markets for external capital and are subject to the scrutiny of investors and analysts. Therefore, it is essential to review the capitalization decisions of market-traded natural gas utilities to assess the reasonableness of the Company's capital structure. This is even more important when the utility in question is itself not market-traded, as is the case with SUA. Imputing a reasonable capital structure for ratemaking purposes is an adjustment just like any other in a rate case. Imputing a methodologically consistent capital structure is required to ensure a fair rate of return to ensure that ratepayers are not burdened with excessive equity costs. The Commission has long recognized and recently affirmed[57] that congruence exists between the authorized ROE and the DTE ratio.[58]

IX. RECOMMENDATION

Q. Please summarize your recommendation to the Commission regarding the cost of capital for SUA.

A. I recommend the Commission approve a ROR of 5.71% (6.92% on a pre-tax basis) as calculated in my Surrebuttal Exhibit DD – 2, which is based on an imputed DTE ratio of 55% debt and 45% equity (including 6.16% short-term debt), an ROE of 9.75%, and the EDIT and CAOL balances provided by Staff witness Don Malone. I also recommend a weighted cost of debt of 2.04%.[59]

Q. Does this conclude your testimony?

A. Yes, it does. Thank you.

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[57] Docket No. 21-070-U, Order No. 14, p. 25; Docket No. 21-087-U, Order No. 7, p. 62.

[58] *In the Matter of the Application of SourceGas Arkansas Inc. for Approval of a General Change in Rates and Tariffs*, Docket No. 15-011-U, Order No. 10, pp. 13 – 14, *citing* Docket No. 06-101-U, Order No. 10, p. 34.

[59] Surrebuttal Exhibit DD – 12.

CERTIFICATE OF SERVICE

I, Joshua A. Baxter, hereby certify that a copy of the foregoing has been served on all parties of record on September 9, 2024, via the Arkansas Public Service Commission's Electronic Filing System.

/s/ JOSHUA A. BAXTER
Joshua A. Baxter

APSC FILED Time: 9/9/2024 11:36:18 AM: Recvd 9/9/2024 11:35:24 AM: Docket 23-079-U-Doc. 164

BEFORE THE
ARKANSAS PUBLIC SERVICE COMMISSION

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

SURREBUTTAL EXHIBITS

OF

DAN DAVES, CRRA
SENIOR RATE CASE ANALYST
FINANCIAL ANALYSIS SECTION

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

SEPTEMBER 9, 2024

Summit Utilities Arkansas, Inc.
Cost of Capital-Pro Forma Year-Southern Col Holdco LLC.
As of Pro Forma December 31, 2024

Schedule: D-1.3-Holdco
Title: Cost of Capital - Pro Forma Year
Docket No. 23-079-U

Explanation: Schedule showing elements of actual total company capital structure and the related costs at the end of the pro forma year.

		Pro Forma Year as of 12/31/2024							
(1) Line No.	(2) Description	(3) Amount Beginning of Pro Forma Year	(4) Pro Forma Adjustments	(5) Subtotal Amount End of Pro Forma Year	(6) Special Pro Forma Adjustments	(7) Amount End of Pro Forma Year	(8) Proportion (Amount/Total)	Rate %	Weighted Cost % (Col.6 x Col.7)
			①						
1	Long-Term Debt	❶ 1,163,088,203	$ 100,992,122	❶ 1,264,080,325	$ ❹ (719,969,326)	$ 544,110,999	39.6794%	❶ 4.1798%	1.6585%
2	Preferred Stock	❷ -	-	❷ -	-	-	0.0000%	❷ 0.0000%	0.0000%
3	Common Equity	❾ 1,065,495,573	109,981,190	❸ 1,175,476,763	❸ (513,782,209)	661,694,553	48.2541%	❼ 11.0000%	5.3080%
4	Accumulated Deferred Income Taxes	❻ (16,666,595)	(6,243,230)	❻ (22,909,825)	22,909,825	-	0.0000%	0.0000%	0.0000%
5	Excess Deferred Income Taxes	68,133,876	(2,916,748)	65,217,129	-	65,217,129	4.7560%	0.0000%	0.0000%
6	Pre-1971 ADITC	-	-	-	-	-	0.0000%	0.0000%	0.0000%
7	Post-1970 ADITC	-	-	-	-	-	0.0000%	0.0000%	0.0000%
8	Customer Deposits	❾ 4,871,144	971,332	❽ 5,842,476	-	5,842,476	0.4261%	❺ 2.9235%	0.0125%
9	Short-Term/Interim Debt	-	-	-	-	-	0.0000%	0.0000%	0.0000%
10	Current, Accrued, and Other Liabilities	158,859,290	(64,455,688)	94,403,602	-	94,403,602	6.8844%	0.0000%	0.0000%
11	Capital Leases	12,100,634	(12,100,634)	-	-	-	0.0000%	0.0000%	0.0000%
12	Other Capital Items	-	-	-	-	-	0.0000%	0.0000%	0.0000%
13									
14	Totals	$ 2,455,882,125	$ 126,228,344	$ 2,582,110,469	$ (1,210,841,710)	$1,371,268,759	100.0000%		6.9790%

Supporting Schedules

- ❶ D-2.3 - Rebuttal Testimony
- ❷ D-3.3 - Rebuttal Testimony
- ❸ D-1.3-SS1.1-Holdco - Rebuttal Testimony
- ❹ D-1.3-SS1.2-Holdco - Rebuttal Testimony
- ❺ D-1.3-SS1.3-Holdco - Rebuttal Testimony
- ❻ C-10 - Goodwill Excluded - Rebuttal Testimony
- ❼ D-4 - Rebuttal Testimony
- ❽ D-6.1-Holdco - Rebuttal Testimony
- ❾ E-1.2-Holdco - Rebuttal Testimony

Recap Schedules

(a) A-1 - Rebuttal Testimony

(b) Rates must be adequately cross-referenced to applicable D schedules

SURREBUTTAL EXHIBIT DD - 2

SUMMIT UTILITIES ARKANSAS, INC.
WEIGHTED AVERAGE COST OF CAPITAL

STAFF RECOMMENDATION

Component	Amount	Proportion	Rate	Weighted Cost	Pre-Tax Weighted Cost
Long-Term Debt (1) (2)	$574,073,373	41.08%	4.11%	1.69%	1.69%
Short-Term Debt (1) (3)	$72,266,779	5.17%	6.61%	0.34%	0.34%
Common Equity (1) (4)	$526,365,175	37.67%	9.75%	3.67%	4.88%
Customer Deposits (5)	4,871,144	0.35%	2.93%	0.01%	0.01%
ADIT (6)	$0	0.00%	0.00%	0.00%	0.00%
EDIT (6)	$65,217,129	4.67%	0.00%	0.00%	0.00%
CAOL (6)	$154,497,558	11.06%	0.00%	0.00%	0.00%
Totals	**$1,397,291,158**	**100.00%**		**5.71%**	**6.92%**
	RCF	**1.329180**			

Sources:
(1) Surrebuttal Exhibit DD - 3 (based on actual balances as of April 30, 2024)
(2) Surrebuttal Exhibit DD - 11
(3) Agreed by Company witness Root (Rebuttal, page 10)
(4) Direct and Surrebuttal Testimony of Dan Daves
(5) Surrebuttal Exhibit DD - 1
(6) Amount provided by Staff witness Don Malone

Summit Utilities Arkansas, Inc.
External Capital Components
Staff Recommended Capital Structure

	Short-Term Debt	Long-Term Debt	Common Equity	Total Capital
Balance as of April 30th, 2024 (1)	-	-	$ 1,862,796,423	$ 1,862,796,423
Amount of Goodwill related to Docket No. 21-060-U				$ (690,091,096)
Total External Capital Dollars				**$ 1,172,705,327**
Staff Recommended Proportions (2)	**6.16%**	**48.95%**	**44.88%**	**100.00%**
Staff Recommended Amount Total Debt-to-Total Equity	**$ 72,266,779**	**$ 574,073,373**	**$ 526,365,175**	**$ 1,172,705,327**

Sources:
(1) Rebuttal MFRs
(2) Surrebuttal Exhibit DD-4

Summit Utilities Arkansas, Inc.

Docket No. 23-079-U

Proxy Group Capital Structure - 8 Quarter Average (Q3 2022 - Q2 2024)

PROXY GROUP AVERAGE	2022 Q3	2022 Q4	2023 Q1	2023 Q2	2023 Q3	2023 Q4	2024 Q1	2024 Q2	8Qtr AVG	**8Qtr DTE**
Short-Term Debt	7.43%	8.91%	4.22%	3.94%	6.29%	5.96%	6.37%	6.18%	6.16%	
Long-Term Debt (Current and Noncurrent)	49.28%	48.24%	50.26%	51.02%	49.58%	48.77%	46.87%	47.61%	48.95%	**55.12%**
Equity (Preferred and Common)	43.29%	42.85%	45.52%	45.04%	44.13%	45.27%	46.76%	46.21%	44.88%	**44.88%**

ATO	2022 Q3	2022 Q4	2023 Q1	2023 Q2	2023 Q3	2023 Q4	2024 Q1	2024 Q2	8Qtr AVG	**8Qtr DTE**
Short-Term Debt	1.06%	0.00%	0.00%	0.00%	1.37%	0.00%	0.00%	0.00%	0.30%	
Long-Term Debt (current and non-current)	45.16%	46.94%	38.92%	38.36%	37.26%	39.92%	39.18%	39.11%	40.61%	**40.91%**
Equity (Preferred and Common)	53.78%	53.06%	61.08%	61.64%	61.37%	60.08%	60.82%	60.89%	59.09%	**59.09%**

NI	2022 Q3	2022 Q4	2023 Q1	2023 Q2	2023 Q3	2023 Q4	2024 Q1	2024 Q2	8Qtr AVG	**8Qtr DTE**
Short-Term Debt	6.95%	9.25%	6.55%	7.87%	10.56%	12.67%	5.37%	2.76%	7.75%	
Long-Term Debt (current and noncurrent)	52.10%	49.25%	52.58%	54.63%	52.49%	45.20%	51.56%	55.09%	51.61%	**59.36%**
Equity (Preferred and Common)	40.95%	41.50%	40.88%	37.49%	36.95%	42.13%	43.07%	42.15%	40.64%	**40.64%**

NJR	2022 Q3	2022 Q4	2023 Q1	2023 Q2	2023 Q3	2023 Q4	2024 Q1	2024 Q2	8Qtr AVG	**8Qtr DTE**
Short-Term Debt	8.89%	9.07%	3.79%	2.91%	4.95%	5.10%	3.76%	4.75%	5.40%	
Long-Term Debt (current and noncurrent)	53.03%	53.39%	55.77%	57.18%	55.99%	55.65%	54.52%	55.29%	55.10%	**60.50%**
Equity (Preferred and Common)	38.09%	37.55%	40.44%	39.92%	39.07%	39.25%	41.73%	39.96%	39.50%	**39.50%**

NWN	2022 Q3	2022 Q4	2023 Q1	2023 Q2	2023 Q3	2023 Q4	2024 Q1	2024 Q2	8Qtr AVG	**8Qtr DTE**
Short-Term Debt	5.42%	9.32%	2.54%	1.46%	2.44%	3.04%	3.14%	2.63%	3.75%	
Long-Term Debt (current and noncurrent)	51.46%	48.25%	53.76%	54.51%	55.59%	53.44%	52.28%	52.50%	52.72%	**56.47%**
Equity (Preferred and Common)	43.12%	42.43%	43.71%	44.04%	41.97%	43.52%	44.58%	44.87%	43.53%	**43.53%**

OGS	2022 Q3	2022 Q4	2023 Q1	2023 Q2	2023 Q3	2023 Q4	2024 Q1	2024 Q2	8Qtr AVG	**8Qtr DTE**
Short-Term Debt	7.63%	9.49%	4.99%	3.91%	5.80%	1.52%	16.00%	17.10%	8.30%	
Long-Term Debt (current and noncurrent)	48.28%	46.10%	47.79%	48.30%	47.24%	50.92%	36.50%	36.05%	45.15%	**53.45%**
Equity (Preferred and Common)	44.09%	44.41%	47.23%	47.79%	46.96%	47.56%	47.50%	46.85%	46.55%	**46.55%**

SR	2022 Q3	2022 Q4	2023 Q1	2023 Q2	2023 Q3	2023 Q4	2024 Q1	2024 Q2	8Qtr AVG	**8Qtr DTE**
Short-Term Debt	14.62%	16.35%	7.47%	7.48%	12.60%	13.42%	9.94%	9.84%	11.47%	
Long-Term Debt (current and noncurrent)	45.66%	45.48%	52.74%	53.15%	48.93%	47.48%	47.17%	47.61%	48.53%	**59.99%**
Equity (Preferred and Common)	39.72%	38.17%	39.78%	39.36%	38.47%	39.10%	42.89%	42.55%	40.01%	**40.01%**

Sources: S&P Global and SEC Filings

SURREBUTTAL EXHIBIT DD - 5

Staff Risk-Comparable Sample
Price, Dividend, and Yield

Company	**(A) 13 Week Average Price**	**(B) Current Dividend***	**(B) / (A) Dividend Yield**
Atmos	$121.16	$3.24	2.67%
NiSource	$29.89	$1.08	3.61%
New Jersey Resources	$44.11	$1.68	3.81%
NorthWest Natural	$37.51	$1.96	5.22%
ONE Gas	$64.73	$2.64	4.08%
Spire	$62.37	$3.04	4.87%

*Annualized

Source:
(1) Yahoo Finance

SURREBUTTAL EXHIBIT DD - 6

Staff Risk-Comparable Sample
Growth Rates

Company	g1	g2	g3	g4
Atmos	7.13%	7.50%	9.50%	7.00%
NiSource	7.63%	4.50%	1.50%	-0.500%
New Jersey Resources	5.50%	5.00%	5.00%	6.50%
NorthWest Natural	4.65%	0.50%	-1.00%	1.50%
ONE Gas	4.50%	2.50%	NA	NA
Spire	5.29%	4.50%	5.00%	5.00%

Notes:

g1: Average of Zack’s, Yahoo Finance, and Value Line EPS projected growth rates

g2: Value Line’s projected dividend growth

g3: Value Line's ten-year historic EPS growth

g4: Value Line's ten-year historic dividend growth

EPS - Earnings Per Share

SURREBUTTAL EXHIBIT DD - 7

Staff Risk-Comparable Sample
Cost of Equity Results

Company	k1	k2	k3	k4
Atmos	9.9%	10.3%	12.3%	9.8%
NiSource	11.4%	8.2%	5.1%	NA
New Jersey Resources	9.4%	8.9%	8.9%	10.4%
NorthWest Natural	10.0%	5.7%	NA	6.8%
ONE Gas	8.7%	6.6%	NA	NA
Spire	10.3%	9.5%	10.0%	10.0%
Cost of Equity Results	**9.9%**	**8.2%**	**9.1%**	**9.2%**

Note:
k1: Average of projected EPS growth from Zack's, Yahoo Finance, and Value Line
k2: Value Line’s projected dividend growth
k3: Value Line's ten-year historic EPS growth
k4: Value Line's ten-year historic dividend growth

EPS - Earnings Per Share

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SURREBUTTAL EXHIBIT DD - 8

STAFF CAPM RESULTS

			Risk-Comparable Sample	
	Risk Free Rate*	**Beta****	**Market Risk Premium*****	**ROE**
Value Line dates	4.19%	0.89	7.10%	**10.52%**
Prior 30-day avg.	3.96%	0.89	7.10%	**10.29%**

Sources
*Treasury.gov
**Value Line Investment Survey Issue #3 May 24, 2024
*** Kroll 2023 SBBI Yearbook

SURREBUTTAL EXHIBIT DD - 9

BOND YIELD PLUS RISK PREMIUM - Cost of Equity Results

GROUP	RISK PREMIUM
All Gas A Rated	9.86
Surrounding Jurisdiction A Rated	9.81
All Gas Baa Rated	9.81
Surrounding Jurisdiction Baa Rated	9.88

Sources: S&P Global
Mergent Bond Record - August 2024

SUMMIT UTILITIES ARKANSAS, INC.
DOCKET NO. 23-079-U
SURREBUTTALEXHIBITS OF DAN DAVES, CRRA

SURREBUTTAL EXHIBIT DD - 10

Recently-Authorized Natural Gas Distribution Rate Cases in Surrounding Jurisdictions (2022 - 2024)

Kentucky	Delta Natural Gas Co.	WTRG	C-2021-00185	Natural Gas	Distribution	1/3/2022	Settled	9.25
North Carolina	Piedmont Natural Gas Co.	DUK	D-G-9, Sub 781	Natural Gas	Distribution	1/6/2022	Settled	9.60
North Carolina	Public Service Co. of NC	D	D-G-5 Sub 632	Natural Gas	Distribution	1/21/2022	Settled	9.60
Kentucky	Atmos Energy Corp.	ATO	C-2021-00214	Natural Gas	Distribution	5/19/2022	Fully Litigated	9.23
South Carolina	Piedmont Natural Gas Co.	DUK	D-2022-89-G	Natural Gas	Distribution	9/15/2022	Settled	9.30
Arkansas	Black Hills Energy Arkansas	BKH	D-21-097-U	Natural Gas	Distribution	10/10/2022	Fully Litigated	9.60
Texas	Texas Gas Service Co.	OGS	D-OSS-22-00009896	Natural Gas	Distribution	1/19/2023	Fully Litigated	9.60
Florida	Florida Public Utilities Co.	CPK	D-20220067-GU	Natural Gas	Distribution	1/24/2023	Fully Litigated	10.25
Florida	Pivotal Utility Holdings Inc.	NEE	20220069-GU	Natural Gas	Distribution	3/28/2023	Fully Litigated	9.50
South Carolina	Dominion Energy South Carolina	D	D-2023-70-G	Natural Gas	Distribution	9/20/2023	Settled	9.49
South Carolina	Piedmont Natural Gas Co.	DUK	D-2023-7-G	Natural Gas	Distribution	10/5/2023	Settled	9.30
Tennessee	Chattanooga Gas Co.	SO	D-23-00029	Natural Gas	Distribution	10/6/2023	Settled	9.80
Florida	Peoples Gas System	EMA	D-20230023-GU	Natural Gas	Distribution	11/9/2023	Fully Litigated	10.15
Illinois	Ameren Illinois	AEE	D-23-0067	Natural Gas	Distribution	11/16/2023	Fully Litigated	9.44
Illinois	North Shore Gas Co.	WEC	D-23-0068	Natural Gas	Distribution	11/16/2023	Fully Litigated	9.38
Illinois	Northern Illinois Gas Co.	SO	D-23-0066	Natural Gas	Distribution	11/16/2023	Fully Litigated	9.51
Illinois	The Peoples Gas Light & Coke C	WEC	D-23-0069	Natural Gas	Distribution	11/16/2023	Fully Litigated	9.38
Tennessee	Piedmont Natural Gas Co.	DUK	D-23-00035	Natural Gas	Distribution	12/4/2023	Settled	9.80
Texas	Texas Gas Service Co.	OGS	D-OSS-23-00014399	Natural Gas	Distribution	1/31/2024	Settled	9.70
Texas	CenterPoint Energy Resources	CNP	D-OSS-23-00015513	Natural Gas	Distribution	6/26/2024	Settled	9.8
							AVERAGE	**9.58**

Source: S&P Global

Docket No. 23-079-U Summit Utilities Arkansas Inc. Proxy Group Weighted Cost of Long-term Debt

Ticker	Company	Long-Term Debt Balances	Cost of Debt
ATO	Atmos Energy Corp.	$ 7,460,000	4.18%
NJR	New Jersey Resources Corp.	$ 1,625,000	3.69%
NI	NiSource Inc.	$ 11,245,000	3.90%
NWN	Northwest Natural Holding Co.	$ 914,700	4.47%
OGS	ONE Gas Inc.	$ 2,150,000	4.31%
SR	Spire Inc.	$ 2,759,000	4.11%
	STAFF RECOMMENDATION		4.11%

Ticker	Issuing Company	Coupon/Rate%	Amount Out ($000)	Weighted Cost of Debt
ATO	Atmos Energy Corporation	6.67%	10,000	0.000089410
ATO	Atmos Energy Corporation	3.00%	500,000	0.002010724
ATO	Atmos Energy Corporation	6.75%	150,000	0.001357239
ATO	Atmos Energy Corporation	5.95%	200,000	0.001595174
ATO	Atmos Energy Corporation	5.50%	400,000	0.002949062
ATO	Atmos Energy Corporation	4.15%	500,000	0.002781501
ATO	Atmos Energy Corporation	4.13%	750,000	0.004147118
ATO	Atmos Energy Corporation	2.63%	500,000	0.001759383
ATO	Atmos Energy Corporation	1.50%	600,000	0.001206434
ATO	Atmos Energy Corporation	6.20%	500,000	0.004155496
ATO	Atmos Energy Corporation	5.45%	300,000	0.002191689
ATO	Atmos Energy Corporation	5.90%	400,000	0.003163539
ATO	Atmos Energy Corporation	3.38%	500,000	0.002262064
ATO	Atmos Energy Corporation	4.30%	600,000	0.003458445
ATO	Atmos Energy Corporation	2.85%	600,000	0.002292225
ATO	Atmos Energy Corporation	5.75%	500,000	0.003853887
ATO	Atmos Energy Corporation	4.13%	450,000	0.002488271
			Embedded Cost of Debt	4.18%
NJR	New Jersey Resources Corporation	3.48%	100,000	0.002141538
NJR	New Jersey Natural Gas Company	2.82%	50,000	0.000867692
NJR	New Jersey Resources Corporation	3.54%	100,000	0.002178462
NJR	New Jersey Natural Gas Company	3.15%	50,000	0.000969231
NJR	New Jersey Resources Corporation	3.96%	100,000	0.002436923
NJR	New Jersey Natural Gas Company	4.61%	55,000	0.001560308
NJR	New Jersey Natural Gas Company	3.66%	100,000	0.002252308
NJR	New Jersey Natural Gas Company	3.63%	125,000	0.002792308
NJR	New Jersey Resources Corporation	3.13%	120,000	0.002311385
NJR	New Jersey Resources Corporation	6.14%	50,000	0.001889231
NJR	New Jersey Resources Corporation	3.64%	50,000	0.001120000
NJR	New Jersey Resources Corporation	3.25%	80,000	0.001600000
NJR	New Jersey Resources Corporation	3.50%	130,000	0.002800000
NJR	New Jersey Resources Corporation	3.60%	130,000	0.002880000
NJR	New Jersey Resources Corporation	3.29%	150,000	0.003036923
NJR	New Jersey Resources Corporation	4.38%	110,000	0.002964923
NJR	New Jersey Natural Gas Company	4.01%	125,000	0.003084615
			Embedded Cost of Debt	3.69%
NI	NiSource Inc.	5.89%	265,000	0.001388039
NI	Bay State Gas Company	6.43%	10,000	0.000057181
NI	NiSource Inc.	7.99%	29,000	0.000206056
NI	NiSource Inc.	3.49%	1,000,000	0.003103602
NI	Northern Indiana Public Service Company	7.69%	53,000	0.000362446
NI	Northern Indiana Public Service Company	7.16%	5,000	0.000031836
NI	NiSource Inc.	6.78%	3,000	0.000018088
NI	Bay State Gas Company	6.26%	30,000	0.000167008
NI	NiSource Inc.	6.25%	250,000	0.001389506
NI	NiSource Inc.	5.95%	400,000	0.002116496
NI	NiSource Inc.	5.80%	250,000	0.001289462
NI	NiSource Inc.	5.25%	500,000	0.002334371
NI	NiSource Inc.	4.80%	750,000	0.003201423
NI	NiSource Inc.	5.65%	500,000	0.002512228
NI	NiSource Inc.	4.38%	1,000,000	0.003890618
NI	NiSource Inc.	0.95%	1,250,000	0.001056025
NI	NiSource Inc.	2.95%	750,000	0.001967541
NI	NiSource Inc.	5.00%	350,000	0.001556247
NI	NiSource Inc.	3.95%	750,000	0.002634504
NI	NiSource Inc.	3.60%	1,000,000	0.003201423
NI	NiSource Inc.	1.70%	750,000	0.001133837
NI	NiSource Inc.	5.20%	600,000	0.002774566
NI	NiSource Inc.	3.95%	750,000	0.002634504
			Embedded Cost of Debt	3.90%
NWN	Northwest Natural Gas Company	7.72%	20,000	0.001687985
NWN	Northwest Natural Gas Company	6.52%	10,000	0.000712802
NWN	Northwest Natural Gas Company	7.05%	20,000	0.001541489
NWN	Northwest Natural Gas Company	3.21%	35,000	0.001228654
NWN	Northwest Natural Gas Company	7.00%	20,000	0.001530556
NWN	Northwest Natural Gas Company	2.82%	25,000	0.000771291
NWN	Northwest Natural Gas Company	6.65%	19,700	0.001432218
NWN	Northwest Natural Gas Company	6.65%	10,000	0.000727014
NWN	Northwest Natural Gas Company	7.74%	20,000	0.001692358
NWN	Northwest Natural Gas Company	7.85%	10,000	0.000858205
NWN	Northwest Natural Gas Company	5.82%	30,000	0.001908823
NWN	Northwest Natural Gas Company	5.66%	40,000	0.002475128
NWN	Northwest Natural Gas Company	5.25%	10,000	0.000573959
NWN	Northwest Natural Gas Company	4.00%	50,000	0.002186509
NWN	Northwest Natural Gas Company	4.14%	40,000	0.001808680
NWN	Northwest Natural Gas Company	3.69%	75,000	0.003021482
NWN	Northwest Natural Gas Company	3.60%	150,000	0.005903575
NWN	Northwest Natural Gas Company	5.75%	100,000	0.006286214
NWN	Northwest Natural Gas Company	3.08%	130,000	0.004374549
NWN	Northwest Natural Gas Company	3.14%	50,000	0.001716956

NWN	Northwest Natural Gas Company	4.11%	50,000	0.002246638
			Embedded Cost of Debt	4.47%
OGS	ONE Gas, Inc.	4.66%	600,000	0.012999070
OGS	ONE Gas, Inc.	4.25%	300,000	0.005930233
OGS	ONE Gas, Inc.	2.00%	300,000	0.002790698
OGS	ONE Gas, Inc.	5.10%	550,000	0.013046512
OGS	ONE Gas, Inc.	4.50%	400,000	0.008372093
			Embedded Cost of Debt	4.31%
SR	Spire Alabama Inc.	3.21%	35,000	0.000407213
SR	Spire Alabama Inc.	5.32%	90,000	0.001735411
SR	Spire Alabama Inc.	2.04%	150,000	0.001109097
SR	Spire Alabama Inc.	5.41%	85,000	0.001666727
SR	Spire Alabama Inc.	3.92%	45,000	0.000639362
SR	Spire Alabama Inc.	4.64%	90,000	0.001513592
SR	Spire Alabama Inc.	4.02%	30,000	0.000437115
SR	Spire Inc.	5.80%	150,000	0.003153316
SR	Spire Alabama Inc.	2.95%	117,700	0.001258481
SR	Spire Alabama Inc.	5.61%	30,000	0.000610004
SR	Spire Alabama Inc.	3.52%	40,000	0.000510330
SR	Spire Alabama Inc.	2.84%	275,000	0.002830736
SR	Spire Alabama Inc.	4.80%	50,000	0.000869880
SR	Spire Alabama Inc.	2.88%	100,000	0.001043856
SR	Spire Alabama Inc.	4.23%	70,000	0.001073215
SR	Spire Alabama Inc.	3.30%	305,000	0.003648061
SR	Spire Alabama Inc.	4.38%	50,000	0.000793766
SR	Spire Inc.	3.13%	130,000	0.001474810
SR	Spire Inc.	3.93%	100,000	0.001424429
SR	Spire Missouri Inc.	3.40%	45,000	0.000554549
SR	Spire Missouri Inc.	7.00%	19,300	0.000489670
SR	Spire Missouri Inc.	7.90%	30,000	0.000859007
SR	Spire Inc.	5.00%	42,000	0.000761145
SR	Spire Missouri Inc.	3.68%	50,000	0.000666908
SR	Spire Missouri Inc.	6.00%	100,000	0.002174701
SR	Spire Missouri Inc.	6.15%	55,000	0.001225988
SR	Spire Alabama Inc.	5.90%	45,000	0.000962305
SR	Spire Missouri Inc.	4.63%	100,000	0.001676332
SR	Spire Inc.	4.70%	250,000	0.004258789
SR	Spire Alabama Inc.	4.31%	80,000	0.001249728
			Embedded Cost of Debt	4.11%

Source SEC Filings as of June 30, 2024

SURREBUTTALEXHIBIT DD - 12

Summit Utilities Arkansas, Inc.
Weighted Cost of Debt

Component	**Weighted Cost**
Long-Term Debt	1.69%
Short-Term Debt	0.34%
Customer Deposits	0.01%
Total	**2.04%**

Source: Surrebuttal Exhibit DD-2

CERTIFICATE OF SERVICE

I, Joshua Baxter, 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 this 9th day of September 2024.

/s/ *Joshua Baxter*
Joshua Baxter

APSC FILED Time: 9/9/2024 12:13:31 PM: Recvd 9/9/2024 12:12:44 PM: Docket 23-079-U-Doc. 165

Doyle Webb
Chairman
(501) 682-5806

Justin Tate
Commissioner
(501) 682-5806

Katie Anderson
Commissioner
(501) 682-5806

Arkansas
Public Service
Commission

UTILITIES DIVISION

Michael Marchand
Executive Director
(501) 682-1794

September 9, 2024

Ms. Karen Shook, Secretary of the Commission
Arkansas Public Service Commission
P.O. Box 400
1000 Center Street
Little Rock, AR 72203

RE: APSC Docket No. 23-079-U
Confidential Surrebuttal Testimony of Dan Daves, CRRA

Dear Ms. Shook:

Pursuant to Protective Order No. 1 in Docket No. 23-079-U, General Staff is filing under seal in the above referenced docket the enclosed Confidential Surrebuttal Testimony of Dan Daves, CRRA.

Please contact me at (501) 682-5879 if you have any questions. Thank you for your assistance.

Sincerely,

/s/ JOSHUA A. BAXTER

Joshua A. Baxter
Attorney Specialist

Enclosures

APSC FILED Time: 9/9/2024 12:13:31 PM: Recvd 9/9/2024 12:12:44 PM: Docket 23-079-U-Doc. 165

Attachment 1 – Non HSPI

(SUMMIT UTILITIES ARKANSAS)
ARKANSAS PUBLIC SERVICE COMMISSION
DOCKET NO. 23-079-U

DATE REQUESTED:
(mm/dd/yyyy)
DATA REQUEST NO.: APSC- NA

DATE PROVIDED: 08/07/2024
(mm/dd/yyyy)
COMPANY CONTACT:
NAME: BROOKE SOUTH PARSONS
PHONE: (479) 462-1178
EMAIL: bparsons@summitutilities.com

CONFIDENTIAL INFORMATION COVER SHEET

Requested Information	Company's Response
1. Document Title	CONFIDENTIAL REBUTTAL EXHIBIT OF CRAIG ROOT
2. Description of the document containing the Confidential Information	SOUTHERN COL MIDCO, LLC FITCH RATING
3. Identification of each item of Confidential Information contained in the document	ENTIRE EXHIBIT, PAGES 1-7, DEEMED CONFIDENTIAL
4. The applicable category of Confidential Information listed in the IPO under which each item of the Confidential Information falls	Paragraph D.
5. A description of why the Confidential Information within the document should be protected including the Company's reasons for claiming that each item of the Confidential Information is consistent with the description provided by the Company in its request for an IPO	THE INFORMATION, IF PUBLICLY, DISCLOSED, COULD HARM THE INTERESTS OF THE COMPANY AND ITS CUSTOMERS, AND THE COMPANY KEEPS SUCH INFORMATION CONFIDENTIAL AND DOES NOT DISCLOSE IT TO THE PUBLIC. THE PROTECTED MATERIAL IS ALSO SUBJECT TO AN AGREEMENT.
6. Has the Confidential Information been previously disclosed? If so, when and in what context?	NO.
7. What is the period of time that the Confidential Information should remain confidential?	INDEFINITELY.
8. Have both a redacted and non-redacted version of the document containing the Confidential Information been provided?	YES.

ARKANSAS PUBLIC SERVICE COMMISSION

IN THE MATTER OF THE APPLICATION)
OF SUMMIT UTILITIES ARKANSAS INC. FOR A) DOCKET NO. 23-079-U
GENERAL CHANGE OR MODIFICATION IN) ORDER NO. 1
ITS RATES, CHARGES, AND TARIFFS)

ORDER

On October 23, 2023, Summit Utilities Arkansas Inc. (SUA or the Company) filed with the Arkansas Public Service Commission (Commission) a *Motion for Protective Order of Non-Disclosure* (Motion) pursuant to Ark. Code Ann. § 23-2-316 and Rule 4.04 of the Commission's *Rules of Practice and Procedure* (RPPs) with the supporting Affidavit of Phillip Gillam (Gillam Affidavit) requesting an order precluding the public disclosure of its and its affiliates' proprietary, competitive, and confidential information.

The Motion states that on September 22, 2023, the Company filed notice in Docket No. 15-002-U of its intent to file an application for a general change or modification in its rates, charges and tariffs (Application) no sooner than 60 days and no longer than 90 days from the date of the notice. The Company's Motion states that portions of the testimony, exhibits work papers, and other documents that may be filed or otherwise provided by the Company in this proceeding, as well as portions of the information filed pursuant to the Commission's Minimum Filing Requirements, may contain confidential, proprietary and/or competitively sensitive information. The Motion further indicates that during the course of the proceeding related to the Company's Application, the General Staff (Staff) of the Commission and other parties will request certain information from the Company that is confidential, proprietary, and/or competitively sensitive, and related to the business activities of the Company or an affiliate of the Company. Motion ¶¶ 1-4 (Doc. #1).

The Motion identified the following categories of information that should be protected on an interim basis under Ark. Code Ann. § 23-2-316 and Rule 4.4 of the Commission's RPPs:

(a) Information or documents reflecting or relating to planning and strategic business, marketing or operational plans, studies or presentations; competitive bidding processes, market evaluations and program plans, plans for issuance of securities or other sources of funding and similar documents;

(b) Information or documents reflecting or relating to operating budgets, actual budgets, original budgets, revised budgets, supply or sales forecasts, demand forecasts, and similar information for any prospective or projected time periods;

(c) Income tax returns, supporting schedules and work papers, and information or documents submitted to the Internal Revenue Service by the Company;

(d) All current financial and financing information (including, but not limited to, balance sheets, financial statements, operating statements, lending facilities and credit lines) prior to its public disclosure through regular filings with state or federal securities commissions and agencies, if the disclosure of the information could cause SUA or any division, subsidiary or affiliate thereof, to suffer material damage to their competitive or financial positions, to be in violation of any financial or loan agreement or covenant, or to be in violation of any state or federal law or regulatory provision;

(e) Information or documents containing the names or personal information of individual customers, or from which individual customers could reasonably be identified, and which contain the terms of individual customer contracts, individual gas usages, individual prices, or other individual material terms associated with SUA or an affiliate's business with those customers;

(f) Information or documents of a personal nature, or containing compensation or benefit information, about any specific current or former employee or officers, unless otherwise publicly disclosed. SUA reserves the right to seek further protection with regard to information concerning any employee or officer should circumstances later occasion the need for such protection;

(g) Information regarding fees paid in connection with the recruitment of any particular employee or officer, to the extent it identifies a particular amount or particular amounts paid regarding a particular employee, officer or position;

(h) Information regarding compensation or benefit plans as well as employee specific compensation or benefit information; (i) Minutes of meetings or presentations to the Board of Directors or shareholders, owners or investors; (j) All assessments prepared by SUA or an affiliate, its advisors, accountants, or agents, of SUA's or an affiliate's actual or potential liability under gas purchase contracts, gas transportation contracts, or other contracts or pending or potential litigation;

(k) Information reflecting the terms of gas purchase or transportation contracts, or contracts related to the acquisition of renewable natural gas, carbon offsets or environmental attributes, and negotiations related to such contracts;

(l) Descriptions of work performed by attorneys on behalf of SUA or its affiliates;

(m) Information reflecting negotiations or settlements with gas suppliers, transporters, property owners, customers, or other parties;

(n) Information reflecting the location of key facilities that are critical to SUA's ability to deliver gas to its customers;

(o) Information related to Homeland Security concerns or issues or any similar information that is deemed sensitive for reasons of national security or homeland security, including, but not limited to, information deemed to be Critical Energy Infrastructure Information by the Federal Energy Regulatory Commission;

(p) Reports, work papers and other documents of internal or external auditors that contain (or to the extent they contain) any information described above; information concerning the internal controls of SUA or any division, subsidiary or affiliate thereof; or reports, work papers and other documents of external auditors that contain (or to the extent they contain) information that is proprietary or confidential to the external auditors; (q) All computer software, files or other similar information, to the extent that it either contains information or data described above or represents a proprietary product for which disclosure to a third party is constrained by contract. Disclosure of proprietary computer software, where such disclosure to third parties is prohibited by contract, will not be provided to any party, except as provided in the RPPs, even where an affidavit of nondisclosure is executed, when such proprietary program or software is available to the commercial or general public for purchase;

(r) Competitively sensitive negotiated contract prices and terms including, but not limited to, contracts containing explicit confidentiality provisions;

(s) Information regarding transactions involving the merger, acquisition, sale or purchase of any business unit by SUA or any of its affiliates, the existence and details of which have not been made public;

(t) Analyses of gas supplies, transportation capacity and storage capacity available to SUA, including projections of price and price volatility; and

(s) Documents or other information designated as Confidential or Highly Sensitive Protected Information ("HSPI") in other dockets or proceedings.

Id. ¶ 6.

The Company's Motion states that the release of the foregoing information could cause the Company and its divisions, subsidiaries or affiliates to suffer material damage to their competitive or financial position; would reveal proprietary facts and trade secrets; and would impair the public interest, due to the effect that such disclosure could have on future operations. Further, the Company's Motion states that this information has not already been publicly disclosed, and it has maintained the information as confidential while in its possession. *Id.* ¶ 6.

The Company's Motion further states that the information identified above, and other information that may be requested, may contain information for which the Company requests Highly Sensitive Protected Information (HSPI) status. The Company states that information for which it requests HSPI status is proprietary as to the Company or an affiliate (collectively, Affected Parties.) If released, the Company's Motion states that it could cause material damage to an Affected Party's competitive or financial position in its respective markets. The Company therefore requests that this information not be released to the public or to intervenors in this proceeding. *Id.* ¶ 9.

Mr. Gillam asserts that, to the best of his knowledge and belief, the information detailed in the Company's Motion has not been publicly disclosed, has been maintained as confidential while in the Company's or an affiliate's possession, and disclosure of the information would have one or more of the following consequences:

> (i) SUA or its affiliates could suffer material damage to their competitive or financial position;
> (ii) A proprietary fact or trade secret belonging to SUA or a third party would be revealed; or
> (iii) The public interest would be impaired.

Gillam Affidavit.

On November 2, 2023, Staff filed a Response to the Company's Motion (Response), stating that it does not concede that the documentation and/or information in question is sufficiently proprietary, confidential, or otherwise entitled to protected status, nor does Staff concede that the Company has provided sufficient evidence pursuant to Rule 4.04 of the Commission's *Rules of Practice and Procedure* to show that the information in question is sufficiently proprietary, confidential, or otherwise subject to protection. However, Staff states that based on the Company's representations, it does not object to the Commission entering a protective order for the information described in the Company's Motion, except as stated herein, if Staff's right to contest at a future date, upon reasonable notice, the Company's entitlement to a protective order for all or a portion of the information is preserved. Staff recommends that if the Motion is granted, the Commission direct the parties to file and abide by the terms of the Commission's standard affidavit of nondisclosure and to reproduce the protected documents only in accordance with the Commission's Orders and RPPs. Response ¶ 8-9 (Doc. #2).

<u>Discussion</u>

Arkansas Code Annotated § 23-2-316(b) provides as follows:

> (b)(1) Whenever the commission determines it to be necessary in the interest of the public or, as to proprietary facts or trade secrets, in the interest of the utility to withhold such facts and information from the public, the commission shall do so.
>
> (2) The commission may take such action in the nature of, but not limited to, issuing protective orders, temporarily or permanently sealing records, or making other appropriate orders to prevent or otherwise limit public disclosure of facts and information.

When considering a request for the entry of a protective order of non-disclosure, the Commission must carefully balance three competing needs, *i.e.*, (1) the Company's need to protect from public disclosure its proprietary facts or trade secrets, (2) the Commission's investigative need to acquire information from the Company in an expeditious and efficient manner, and (3) the public's right of access to information in the possession of the Commission.

The entry of an Interim Protective Order which allows the other official parties the right to contest at a future date the Company's continuing entitlement to the protective order efficiently addresses the first two needs. To protect the public's right of access to the maximum extent possible, the Commission directs that the Company hold to an absolute minimum the amount of information to be protected from public disclosure.

Findings and Ruling

Having considered the Company's Motion and Staff's Response thereto, the Commission grants the Motion as conditioned herein and finds, orders, and directs as follows:

1. Based upon the Company's assertions of confidentiality, the Commission finds that the categories of information identified in the Company's Motion should be protected from public disclosure on an interim basis pursuant to Ark. Code Ann. § 23-2-316 and Rule 4.04 of the Commission's RPPs (also referred to as Confidential Information). However, any information identified in the Motion which has already been made public or is information that is commonly available to the public shall not be protected from public disclosure.
2. To protect the public's right of access to the maximum extent possible, the Company shall hold to an absolute minimum the amount of data to be protected from public disclosure.
3. For each specific item of Confidential Information to be filed or submitted in this Docket by the Company, it shall affix thereto a written Confidential Information Cover Sheet in the form of Attachment 1 hereto providing detailed and complete responses to the information required thereby.
4. The following definition of HSPI shall be used for purposes of designation of Confidential Information as HSPI:

> Documents or information that are commercially sensitive in a competitive gas market that if improperly disclosed would expose the Company to an unreasonable risk of harm, including but not limited to: (1) customer-specific information; (2) contractual information pertaining to contracts that specify that their terms are confidential or which are confidential pursuant to an order entered in litigation to which the Company is a party; (3) market-sensitive price forecasts, wholesale transactions information and/or market-sensitive marketing plans; and (4) business operations or financial, cost or modeling information.

5. As to Confidential Information covered by the scope of this Order except for HSPI, the authorized reviewing representatives of an official party to this Docket shall include its counsel of record in this Docket and associated attorneys, paralegals, economists, statisticians, accountants, consultants, or other persons employed or retained by the official party and who are immediately and directly working on matters relating to the above referenced Docket on behalf of such official.

6. Access to HSPI by the authorized reviewing representatives of an official party to this Docket, other than Staff and the Attorney General, shall be restricted to those reviewing representatives (as defined in ¶ 5 above) who are not themselves participants in the competitive gas market and who do not represent others who are participants in the competitive gas market. To be granted access to HSPI, reviewing representatives must additionally certify to the Company that they are not themselves participants in the competitive gas market nor do they represent others who are participants in the competitive gas market.

7. In the event that a reviewing representative ceases to be engaged in this Docket, access to protected materials by such person shall be terminated and the reviewing

representative shall return or destroy all copies of such Confidential Information made available to him or her.

8. Confidential Information and HSPI to be provided in paper format shall be reproduced and filed or submitted on distinctive pink paper only. Confidential Information and HSPI to be provided in digital format shall be reproduced and filed or submitted on a CD that is distinctively red or pink in color or on a flash drive clearly labeled as confidential. Confidential Information provided digitally shall have a file name which includes the word "CONFIDENTIAL."

9. The Commission's standard form AFFIDAVIT OF NON-DISCLOSURE (Attachment 2 hereto) shall be executed and filed in this Docket by all official party representatives to be granted access to said Confidential Information pursuant to this Interim Protective Order.[1]

10. All official parties are hereby granted the right to contest at a future date, upon reasonable notice, the Company's continuing entitlement to protect from public disclosure all or any portions of any Confidential Information filed or submitted pursuant to this Interim Protective Order. Such Confidential Information shall be reviewed by the official parties for the express purpose of ascertaining (1) whether such Confidential Information is consistent with the description provided by the Company in its Motion; (2) whether such Confidential Information is consistent with the Confidential Information transmittal cover document; (3) whether such

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[1] A digital copy of the Attachments to this Order can be accessed through the Commission's web site at the following internet address: **https://apps.apsc.arkansas.gov/olsv2/rules_Select2.asp .** The digital copies can be filled in online and then printed for signature and filing. The standard form Attachments shall not be modified or amended in any way.

Confidential Information identified as HSPI meets the Commission's definition of HSPI; and (4) whether the scope of this Interim Protective Order has been applied too broadly by the Company. Based upon such review any official party shall promptly file an objection in this Docket if such party determines that any portion of such Confidential Information should be removed from the scope of this Interim Protective Order.

11. Further, if any official party determines that any information previously deemed to be confidential should no longer be protected from public disclosure due to the passage of time or changed circumstances, such party shall promptly file an appropriate objection in this Docket.
12. In the event of any objection filed pursuant to the terms and conditions of this Interim Protective Order, the burden of proof will rest on the Company.
13. Accordingly, the Company's Motion, as conditioned herein, is granted on an interim basis. The Company shall forthwith cause said Confidential Information to be filed and/or otherwise submitted under seal as requested.

BY ORDER OF THE COMMISSION.

This _17th_ day of November, 2023.

Doyle Webb

Doyle Webb, Chairman

Justin Tate, Commissioner

Katie Anderson

Katie Anderson, Commissioner

Karen Shook

Karen Shook, Secretary of the Commission

I hereby certify that this order, issued by
the Arkansas Public Service Commission, has been
served on all parties of record on this date by the
following method:

__ U.S. mail with postage prepaid using the mailing
addresss of each party as indicated in the official
docket file, or
X Electronic mail using the email address of each
party as indicated in the official docket file

Attachment 1a – Non-HSPI

Summit Utilities Arkansas Inc.
ARKANSAS PUBLIC SERVICE COMMISSION
DOCKET NO. 23-079-U

DATE REQUESTED: MONTH, DAY, YEAR

DATE PROVIDED: MONTH, DAY, YEAR

DATA REQUEST NO.: APSC-###

COMPANY CONTACT:
NAME
PHONE, EMAIL

CONFIDENTIAL INFORMATION COVER SHEET

Requested Information	Company's Response
1. Document Title	
2. Description of the document containing the Confidential Information	
3. Identification of each item of Confidential Information contained in the document	
4. The applicable category of Confidential Information listed in the IPO under which each item of the Confidential Information falls	
5. A description of why the Confidential Information within the document should be protected including the Company's reasons for claiming that each item of the Confidential Information is consistent with the description provided by the Company in its request for an IPO.	
6. Has the Confidential Information been previously disclosed? If so, when and in what context?	
7. What is the period of time that the Confidential Information should remain confidential?	
8. Have both a redacted and non-redacted version of the document containing the Confidential Information been provided?	

Attachment 1b – HSPI

Summit Utilities Arkansas Inc.
ARKANSAS PUBLIC SERVICE COMMISSION
DOCKET NO 23-079-U

DATE REQUESTED: MONTH, DAY, YEAR **DATE PROVIDED**: MONTH, DAY, YEAR

DATA REQUEST #: **REQUESTING PARTY:**

COMPANY CONTACT:
NAME
PHONE, EMAIL

HIGHLY SENSITIVE PROTECTED INFORMATION COVER SHEET

Requested Information	Company's Response
1. Document Title	
2. Description of the document containing the Confidential Information	
3. Identification of each item of Confidential Information contained in the document	
4. The applicable category of Confidential Information listed in the IPO under which each item of the Confidential Information falls	
5. A description of why the Confidential Information within the document should be protected including the Company's reasons for claiming that each item of the Confidential Information is consistent with the description provided by the Company in its request for an IPO	
6. A description of why any specific item of Confidential Information identified above is claimed by the Company to be Highly Sensitive Protected Information (HSPI) and how such Confidential Information fits within the Commission's definition of HSPI	
7. Has the Confidential Information been previously disclosed? If so, when and in what context?	
8. What is the period of time that the Confidential Information should remain confidential?	
9. Have both a redacted and non-redacted version of the document containing the Confidential Information been provided?	

Attachment 2

ARKANSAS PUBLIC SERVICE COMMISSION

IN THE MATTER OF THE APPLICATION)
OF SUMMIT UTILITIES ARKANSAS INC. FOR A) DOCKET NO. 23-079-U
GENERAL CHANGE OR MODIFICATION IN) ORDER NO. 1
ITS RATES, CHARGES, AND TARIFFS)

AFFIDAVIT OF NON-DISCLOSURE
PURSUANT TO INTERIM PROTECTIVE ORDER NO. 1

STATE OF ______________________)
COUNTY OF ____________________)

I, _________________________, am immediately and directly working on matters relating to the above referenced docket on behalf of _____________________. The above referenced Interim Protective Order directs that the confidential information identified therein shall be protected from public disclosure pursuant to the provisions of Ark. Code Ann. § 23-2-316 and Rule 4.04 of the Arkansas Public Service Commission's *Rules of Practice and Procedure* (Rule 4.04).

In accordance with said Interim Protective Order, I understand, agree and certify as follows:

1. That said confidential information is provided to me by the protected party pursuant to the terms of said Interim Protective Order and the provisions of Rule 4.04; that I have been provided a copy of said Interim Protective Order and Rule 4.04, and that I have read and understand the provisions of said Interim Protective Order and Rule 4.04; and that I shall fully comply with same; and

2. That said confidential information at all times shall be clearly and distinctly marked as CONFIDENTIAL – SUBJECT TO PROTECTIVE ORDER and at all times shall be maintained in a secure manner; and

3. That I shall not disclose said confidential information to any person not immediately and directly involved in the above-referenced docket, nor to any person not entitled to said confidential information by the terms of said Interim Protective Order and Rule 4.04, nor to any person who has not executed the required Affidavit of Non-Disclosure; and

4. That said confidential information shall be used solely for the purpose of pursuing the case at hand, and shall not be used for any other purpose(s) whatsoever, and most especially shall not be used for competitive business purposes; and

5. That improper disclosure of said confidential information by a party or person may result in civil liabilities or sanctions against said party or person; and

6. That I shall neither disclose nor permit to be reviewed or copied said confidential information, and any notes, memoranda, or any other form of information regarding or derived from said confidential information, by any person other than myself or other individuals who are entitled to said confidential information by the terms of said Interim Protective Order and Rule 4.04 and who have also executed the required Affidavit of Non-Disclosure; and

7. That said confidential information shall not lose its confidential status through use in this docket and that I will take all steps reasonably required to protect its confidentiality during such use; and

8. That if I have knowledge that said confidential information has been disclosed, reviewed or copied by any persons other than in the manner authorized by the Interim Protective Order, Rule 4.04, and this Affidavit of Non-Disclosure, I shall promptly notify

counsel for the protected party and make every reasonable effort to retrieve such confidential materials and to prevent further disclosure of such information; and

9. That any pleadings or other filings that incorporate, reference, or attach said confidential information shall be filed in two formats: (a) public format with said confidential information appropriately redacted, and (b) non-public under protective seal format; and

10. That neither the filing in this docket of said confidential information, nor the furnishing of said confidential information for review by the parties to this docket shall be considered a waiver of any right to object upon any grounds to the use or introduction into evidence of said confidential information during any proceeding in this docket; and

11. That, I shall return said confidential information to the protected party within thirty (30) days of the conclusion of the above referenced docket and any appeals taken therefrom. Further, I shall destroy any notes, memoranda, or any other form of information regarding or derived from said confidential information within thirty (30) days of the conclusion of said docket and any appeals taken therefrom.

12. That, if the Interim Protective Order identified hereinabove subsequently is amended and/or further Interim or Final Protective Orders are entered in this Docket, I shall be bound by the same terms herein as they relate to any additional Confidential Information which may be protected by such subsequent Protective Orders without the need for the execution of further affidavits of non-disclosure in this Docket.

AFFIANT CERTIFICATION

Dated this _____ day of ______________, 20__.

____
Signature of Affiant

____
Print name of Affiant

NOTARY CERTIFICATION

Subscribed and sworn to by the foregoing Affiant before me, a Notary Public, on this _____ day of ___________, 20__.

____
Notary Public

My Commission Expires: __________

Affix Notary Seal:

BEFORE THE
ARKANSAS PUBLIC SERVICE COMMISSION

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

SURREBUTTAL 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

SEPTEMBER 9, 2024

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. Are you the same Robert H. Swaim who filed Direct Testimony in this docket on July 10, 2024?

A. Yes, I am.

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. I will address the Rebuttal Testimony of SUA witnesses Phillip B. Gillam and Timothy S. Lyons filed on August 7, 2024, and the Direct Testimonies filed on July 10, 2024, by Jonathan Ly on behalf of the Arkansas Gas Consumers ("AGC"); by Richard W. Porter on behalf of the Office of the Arkansas Attorney General ("AG"); and by Larry Blank on behalf of the Hospitals and Higher Education Group ("HHEG").

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 Weather Normalization Adjustment ("WNA") Bases and Degree Day Factors ("DDFs") and accept those I recommend in Table 1, below;
- Reject SUA's design day (i.e., peak day demand) forecast and accept Staff's peak day forecast;
- Reject SUA's Mains allocator and accept Staff's Mains allocator;
- Reject SUA's Rate Schedule Revenue Requirement used for designing rates;
- Accept Staff's mitigated Rate Schedule Revenue Requirement; and
- Reject SUA's WNA and Billing Determinant Adjustment ("BDA") rider tariffs as filed and order SUA to refile the riders using the DDFs in Table 1.

DIRECT TESTIMONIES OF INTERVENORS

AGC Witness Jonathan Ly

Q. Does AGC witness Ly disagree with SUA's averaging of its minimum size study and its zero-intercept study for the allocation of distribution mains ("Mains") related costs?

A. Yes. AGC witness Ly disagrees with SUA's Mains allocator. He states that the National Association of Regulatory Utility Commissioners ("NARUC") *Gas Distribution Rate Design Manual* (1989) describes the zero intercept and the minimum size approaches for use as the Mains allocator as an either / or choice and does not discuss an averaging of the two results as an appropriate method as proposed by SUA.[1]

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[1] Direct Testimony of AGC Witness Jonathan Ly, Doc. 95, p. 6, line 7 – p. 7, line 22.

Q. Do you agree with Mr. Ly?

A. Yes. As pointed out in Staff witness Mark Burdette's Direct Testimony, Staff disagrees with SUA's Mains allocator methodology.[2]

<u>HHEG Witness Larry Blank</u>

Q. Does HHEG witness Blank disagree with SUA's averaging of its minimum system size study and its zero-intercept study for the allocation of Mains related costs?

A. Yes. Similar to AGC witness Ly, HHEG witness Blank disagrees with SUA's Mains allocator. He states the NARUC *Gas Distribution Rate Design Manual* (1989) describes the zero intercept and the minimum size as alternative approaches for use as the Mains allocator. He also notes that SUA's use of the average is a departure from the rate case filing in Docket No. 15-098-U in which the minimum system method was used. Witness Blank also asserts that the Company's choice of averaging classification methods is an attempt to mitigate results relative to the precedent model design.[3]

Q. Do you agree that the classification of distribution mains should be based on the minimum system method rather than the mixed method average proposed by SUA?

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[2] Direct Testimony of Staff Witness Mark Burdette, Doc. 111, p.18, line 3 – p. 20, line 3.
[3] Direct Testimony of HHEG Witness Larry Blank, Doc. 103, p. 12, line 13 – p. 13, line 9.

A. Yes. The classification of distribution mains should be based on the minimum system method rather than the mixed method average proposed by SUA. SUA has not provided substantial evidence to support the method the Company proposed.

Q. Did HHEG witness Blank raise any concern about SUA's rate design for the SCS-1 and LCS-1 customer classes?

A. Yes. HHEG witness Blank takes exception to Company witness Lyons approach of separating transportation customers from sales customers for SCS-1 and LCS-1 when calculating rates. Witness Blank notes that because SUA developed a COS for transportation customers separate and apart from sales customers, the demand and usage rates for the SCS-1 TSO and the LCS-1 TSO customers is higher than that for the sales customers. Mr. Blank asserts that "[i]t does not stand to reason that a customer should pay higher demand or usage charges solely due to the change of supplier."[4] Witness Blank recommends that the transportation customers' and sales customers' billing determinants be combined when calculating the rates for SCS-1 and LCS-1 rate classes.[5]

Q. Do you agree with HHEG witness Blank's recommendation regarding the rate design for the SCS-1 and LCS-1 sales and transportation customers?

A. For the most part. Staff's COSS combines both sales and transportation customers for SCS-1 and LCS-1 when developing a COS. Recognizing that some customers pay a demand charge while others do not and recognizing that sales customers

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[4] Direct Testimony of HHEG Witness Larry Blank, Doc. 103, p. 19, lines 5 -7.

[5] *Id*. at p. 18, line 17 – p. 19, line 15.

are typically billed based on CCFs while transportation customers are billed in MMBtus, I recommend that SUA design rates such that sales and transportation customer rates are equitable and fair such that each group pays its pro rata COS.

REBUTTAL TESTIMONIES

SUA Witness Phillip B. Gillam

Q. What are the principal assertions of Mr. Gillam?

A. Mr. Gillam asserts , among other things, that I erroneously stated that the proposed BDA Rider differs from the previously approved BDA Rider.

Q. Is Mr. Gillam correct?

A. Yes. Upon further review, the BDA Rider filed by SUA in this case is of the same form as the previously approved BDA Rider. Therefore, I recommend approval of the BDA Rider as proposed by the Company. However, I continue to recommend SUA's filed BDA and WNA Riders be updated to reflect the DDFs shown in Table 1, below, resulting from the development of my recommended *pro forma* year billing determinants.

Table 1

STAFF WNA PARAMETERS		
DDF	Residential (CCF)	SCS-1 (SSO) (CCF)
STAFF PROPOSED BASE USAGE	9.92	79.95
STAFF PROPOSED DEGREE DAY FACTOR (DDF)	0.14901	0.64803

SUA Witness Timothy S. Lyons

Q. What are the principal assertions of Mr. Lyons?

A. Mr. Lyons disagrees with Staff's findings regarding SUA's billing determinants and design day demands. He agrees that no rate class should have a rate decrease in the context of an overall rate increase.

Q. How do you respond to Mr. Lyons?

A. I reaffirm and continue to support the arguments I made in my Direct Testimony.[6] I would also like to point out that SUA's analysis utilizes inconsistent model application. For example, SUA uses a six-year regression analysis to estimate Base usage and DDFs for billing determinants; a two-year period with an arbitrarily assigned Base Usage and a hybrid application of Staff's methodology to estimate the DDFs for use in the WNA; and a one-year regression analysis to estimate the Base and DDF for the Design Day for peak cost allocation. I find his cafeteria style approach to the estimation of weather effects to be flawed. Further, neither the Company nor Staff made any weather adjustments to the sales volumes for the LCS-1 customer class, having previously concluded that this customer class does not demonstrate significant weather sensitivity. However, SUA witness Lyons chose to derive a heating factor or DDF using his regression model for use in calculating the design day demand for these customer classes. Witness Lyons also asserts that DDFs based on the one-year period of November 1, 2022, through October 31, 2023, are more appropriate because they reflect recent usage.[7] This is inconsistent with Staff's long-standing approach of relying on multiple years of

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[6] Direct Testimony of Staff Witness Robert H. Swaim, Doc. 110, p.6, line 11 – p. 13, line 9.
[7] Rebuttal Testimony of SUA Witness Timothy S. Lyons, Doc. 138, p. 10, line 17 – p. 11, line 8.

data to determine if any trends are evident in the usage patterns of each class of customers. HHEG witness Blank also finds fault with SUA's approach to developing its design day demand for the LCS-1 customer class.[8]

Q. In rebutting HHEG witness Blank, Company witness Lyons appears to make a concession regarding the calculation of its design day demand for the SCS-2, SCS-3, and SCS-3 TSO customers. Do you agree with Mr. Lyons's revision to the design day demand calculation for these customer classes?

A. No, I do not. SUA witness Lyons agrees with Mr. Blank's concern in utilizing February 2023 average daily consumption to calculate SCS-2, SCS-3, and SCS-3 TSO's contribution to the system design day demand. The Company agreed to utilize average daily consumption for the winter months as a concession to HHEG witness Blank's expressed concern.[9]

Q. Do you find Mr. Lyons change to its design day demand for SCS-2, SCS-3, and SCS-3 TSO reasonable in light of the concern expressed by HHEG witness Blank in his Direct Testimony?

A. No, I do not. Mr. Lyons suggested use of the average daily usage for all winter months for these three classes of customers appears to be a very simplistic approach which would diminish any connection between the actual consumption of these customer classes on a system peak day event. If SUA wishes to concede that its design day demand calculation for these customer classes is flawed, it

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[8] Direct Testimony of HHEG Witness Larry Blank, Doc. 103, p. 14, line 21 – p. 15, line 11.
[9] Rebuttal Testimony of SUA Witness Timothy S. Lyons, Doc. 138, p. 14, lines 13-16.

should recommend an approach that is more closely related to actual consumption under a system peak day occurrence.

Q. Has Staff made any adjustments to its design day demand or peak day calculation?

A. Yes. Staff's design day demand allocator utilized in its Direct COSS is largely unchanged from its Direct case. However, due to some slight adjustments to its billing determinants model, Staff has updated its DDFs and Base Level usages for Residential and SCS-1 customer classes to reflect the impact of these minor adjustments.

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 2, below. I also recommend that the Commission reject both SUA's regression-based model and its simplified WNA models and associated results.

Table 2

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	4,320,745	142,856	3.42%
Use Per Customer	10,581.40	10,943.21	362	3.42%
Revenue	$7,065,421	$7,242,706	$177,286	2.51%
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%)

RATE DESIGN

Rate Schedule Revenue Requirement Used in Designing Rates

Q. Have you modified your proposed billing determinants since your Direct Testimony?

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.[10] 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 Surrebuttal COSS?

A. Staff witness Burdette presents the results of Staff's Surrebuttal COSS. Staff's resulting revenue requirement by rate class forms the basis for my rate design recommendations. The result of Staff's Surrebuttal COSS, supported by Staff witness Burdette, is reflected on Line 2 of Table 3, below.

Table 3
Staff's Surrebuttal COSS Summary

Line No.	Description (1)	Total (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	173,737,787	127,027,804	35,775,053	572,868	38,535	10,323,528
2	Rate Schedule Revenue Requirement	249,939,704	191,049,324	42,979,172	478,969	13,974	15,418,264
3	Revenue Deficiency/(Surplus) (L2-L1)	76,201,917	64,021,521	7,204,119	(93,899)	(24,561)	5,094,736
4	**% Increase on Base Revenue (L3/L1)**	**43.86%**	**50.40%**	**20.14%**	**-16.39%**	**-63.74%**	**49.35%**
	Staff's Proposed Revenue Requirement after Mitigation						
5	Rate Sch. Rev. Req. before Mitigation (L2)	249,939,704	191,049,324	42,979,172	478,969	13,974	15,418,264
6	Mitigation Adjustment	-	(109,727)		93,899	24,561	(8,732)
7	Rate Sch. Rev. Req. after Mitigation (L5+L6)	249,939,704	190,939,597	42,979,172	572,868	38,535	15,409,532
8	Revenue Deficiency/(Surplus) (L7-L1)	76,201,917	63,911,793	7,204,119	-	-	5,086,004
9	**% Increase on Base Revenue (L8/L1)**	**43.86%**	**50.31%**	**20.14%**	**0.00%**	**0.00%**	**49.27%**
10	**% of System Average Increase (L9'/L9 Total)**	**100.00%**	**114.71%**	**45.91%**	**0.00%**	**0.00%**	**112.33%**

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[10] Surrebuttal Exhibit JH-5 to the Surrebuttal Testimony of Staff witness Jeff Hilton.

Q. Are the results of Staff's Surrebuttal 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 (see Line 2 of Table 3, above) should be used as the basis for designing rates. The overall increase in base rate revenue requirements, 43.86%, is shown on Line 4 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 (*viz*., for SCS-2, a 16.39% reduction, and for SCS-3, a 63.74% reduction) whereas the remaining classes are due a rate increase.

Q. What is your recommendation concerning the design of the customer, volumetric, and demand charges for each rate class?

A. I recommend that the total reduction in rates from SCS-2 and SCS-3 be allocated pro rata to the Residential and LCS-1 classes. 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 9 in Table 3, above, for the respective classes.

RECOMMENDATIONS

Q. Please summarize your recommendations.

A. Based on my analysis and conclusions, I recommend that the Commission:

- Reject SUA's COSS and accept Staff's COSS as presented in Surrebuttal Exhibit MB-1 to the Surrebuttal Testimony of Staff witness Mark Burdette;
- Reject SUA's *pro forma* billing determinants and rate schedule revenues and accept those I recommended in my Surrebuttal Testimony;

- Reject the Bases and DDFs in SUA's WNA and accept those I recommend as presented in Table 1, above;
- Accept SUA's BDA rider after it is updated to reflect the DDFs recommended in Table 1, above;
- 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 use in designing Compliance Rates in this case.

Q. Does this conclude your testimony?

A. Yes, it does.

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 September 9, 2024.

/s/ JOSHUA A. BAXTER
Joshua A. Baxter

APSC FILED Time: 9/9/2024 11:26:50 AM: Recvd 9/9/2024 11:22:21 AM: Docket 23-079-U-Doc. 162

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

SURREBUTTAL TESTIMONY

OF

MARK BURDETTE
SENIOR RATE CASE AUDITOR

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

SEPTEMBER 9, 2024

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INTRODUCTION

Q. Please state your name and business address.

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

Q. Are you the same Mark Burdette who filed Direct Testimony and Exhibits in this docket?

A. Yes, I filed Direct Testimony and Exhibits on behalf of the Commission's General Staff ("Staff") on July 10, 2024.

PURPOSE OF TESTIMONY

Q. What is the purpose of your testimony?

A. My testimony will address the Rebuttal Testimony of Summit Utilities Arkansas, Inc. ("SUA" or "Company") witness Timothy S. Lyons. I also address certain aspects of the Direct Testimonies of Arkansas Gas Consumers, Inc. ("AGC") witness Jonathan Ly, Hospitals and Higher Education Group ("HHEG") witness Larry Blank, and the Office of the Arkansas Attorney General ("AG") witness Richard W. Porter.

Q. Do you sponsor any exhibits in your Surrebuttal Testimony?

A. Yes. I am sponsoring one exhibit, Surrebuttal Exhibit MB-1, presenting Staff's Schedule G-1 which summarizes the results of Staff's Surrebuttal Class Cost of Service Study ("COSS").

Q. What were Company witness Lyons's comments regarding your Direct Testimony?

A. SUA witness Lyons mentions three components of my Direct Testimony:

> Mr. Burdette's concerns are related to the following areas: (1) derivation of current revenues; (2) overall approach to classify and allocate costs; and (3) methodology to classify and allocate certain costs.[1]

I will address each of these items in turn.

DERIVATION OF CURRENT REVENUES

Q. Does SUA witness Lyons continue to recommend the inclusion of Rider Revenues in its present rate revenues in SUA's COSS?

A. Yes. According to SUA witness Lyons:

> The Company agrees with Mr. Burdette that rolled-in rider revenues are not part of base rate revenues. However, the Company disagrees that rolled-in rider revenues should be excluded from the COSS. The Company believes including rolled-in rider revenues along with base rate revenues provides a more accurate representation of the Company's proposed rate increase because a portion of the Company's proposed revenue requirement increase is already recovered through the rider revenues.[2]

Q. Has Staff changed its recommendation regarding excluding rolled-in Rider Revenues as part of SUA's present rate revenues reflected in its COSS?

A. No. Staff maintains its position as presented in my Direct Testimony.[3] Staff's position has always been that existing base rate revenues should not be restated as if these rider revenues are somehow part of present base rates. The costs underlying these riders will become part of base rate revenues or "rolled in" to base rates when new rates go into effect. Restating the existing base rates as if these

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[1] Rebuttal Testimony of SUA Witness Timothy S. Lyons, Doc. 138, p. 1, lines 21-23.
[2] *Id*. at p. 2, lines 8-14.
[3] Direct Testimony of Mark Burdette, page 10, Lines 5 – 20.

rider revenues were included in present base rates simply allows the utility to make its base rate increase appear smaller than it is in reality. Staff presents a base rate increase and a total bill impact for full disclosure of the impact of the rate case on customer bills.

COST CLASSIFICATION AND ALLOCATION

Q. Did SUA witness Lyons address your concerns regarding its order of operation for classification and allocation of costs?

A. Yes. SUA witness Lyons provided additional discussion of the Company's methodology and classification factors that resulted in differences in SUA's COSS and Staff's.[4] However, the resolution of this issue does not change my overall recommendation.

Q. Does SUA agree with Staff's recommendation to allocate Other Working Capital Assets based on Net Plant?

A. No. SUA maintains its recommendation to classify Other Working Capital Assets as Operations and Maintenance ("O&M") Expense and allocate using the O&M Expenses composite allocator. Witness Lyons maintains that the goods and services funded by Other Working Capital Assets largely consists of O&M expenses, income taxes and taxes other than income.[5] By definition, Other Working Capital Assets are assets and as such, Staff maintains its position that it should be classified as Plant and allocated using the NetPLT composite allocator.

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[4] Rebuttal Testimony of SUA Witness Timothy S. Lyons, Doc. 138, p. 3, lines 9-11.

[5] *Id.* at p. 6, lines 10-18.

Q. Did SUA agree to Staff's classification and allocation of other accounts detailed in your Direct Testimony?

A. Yes. SUA witness Lyons agreed with my recommendations regarding the following accounts:[6]

- Account 874 (Mains and Services): allocate expense based on an internal allocator derived from plant accounts 376 (Mains) and 380 (Services);
- Account 880 (Other Distribution & Operating Expenses) and 881 (Rents): allocate expense based on an internal allocator derived from expense accounts 871-879;
- Account 885 (Supervision & Engineering Expense): allocate expense based on internal allocator derived from Distribution Maintenance Expense accounts 886-893;
- Account 894 (Other Equipment): allocate expense based on internal allocator derived from Distribution Maintenance Expense accounts 886-893; and
- Taxes Other Than Income Tax: disaggregate into individual taxes and then allocate the individual tax line items based on Staff's recommended allocator.

Q. Does SUA witness Lyons continue to recommend using an average of the Minimum-Size Study and Zero-Intercept Study for the classification and allocation of distribution mains?

A. Yes. Witness Lyons disagrees with Staff's methodology for the classification and allocation of distribution mains.[7]

Q. Does Staff continue to recommend using a Minimum-Size study only?

A. Yes. Staff has traditionally relied upon the minimum size main study when allocating distribution mains to the customer classes in its COSS, as was used in

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[6] *Id*. at p. 7, lines 1-19.

[7] *Id*. at p. 7, line 20 – p. 8, line 8.

the Company's last rate case, Docket No. 15-098-U. The Commission has generally accepted Staff's COSS as the basis for rate design.

Q. Do other witnesses in this docket disagree with SUA witness Lyons's averaging of the Minimum Size and Zero-Intercept methods to classify and allocate Distribution Mains?

A. Yes. AGC witness Ly states:

> Therefore, the costs for distribution mains in SUA's CCOSS should not be classified on a hybrid basis as is proposed by SUA. Instead, these costs should be classified based solely on the results of the minimum size study.[8]

HHEG witness Blank states:

> SUA's decision to use the average [of the minimum system and zero-inch methods] is a departure from the rate case filing in Docket No. 15-098-U in which the minimum system method was used.[9]
>
> 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.[10]

Both witnesses Ly and Blank agree with Staff's position that an averaging of these two methods to classify and allocate Distribution Mains is inappropriate.

Q. What are your comments regarding AG witness Porter's recommendation regarding the classification and allocation of distribution mains?

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[8] Direct Testimony of AGC Witness Jonathan Ly, Doc. 95, p. 7, lines 20-22.

[9] Direct Testimony of HHEG Witness Larry Blank, Doc. 103, p. 12, lines 16-19.

[10] *Id*. at p. 13, lines 1-9.

A. Witness Porter accepted the Company's averaging methodology.[11] I recommend that AG witness Porter's recommendation should be rejected for the reasons I previously stated on this matter.

COSS RESULTS

Q. What are the results of the COSS developed by SUA in its Rebuttal Testimony?

A. The results of SUA's Rebuttal COSS are summarized in Table 1, "Summary of SUA's Rebuttal COSS," below.[12] Line 9 shows the percentage increase to rate schedule revenues, excluding the Rolled-In Rider Revenues, which more accurately reflects the overall increase in base rates. The percentage increase in Total Revenue Requirement is displayed on line 20. The Total Current Revenues reported on line 17 includes Rolled-In Rider Revenues of $10.1 million as reported by SUA on its MFR Schedule G-1.

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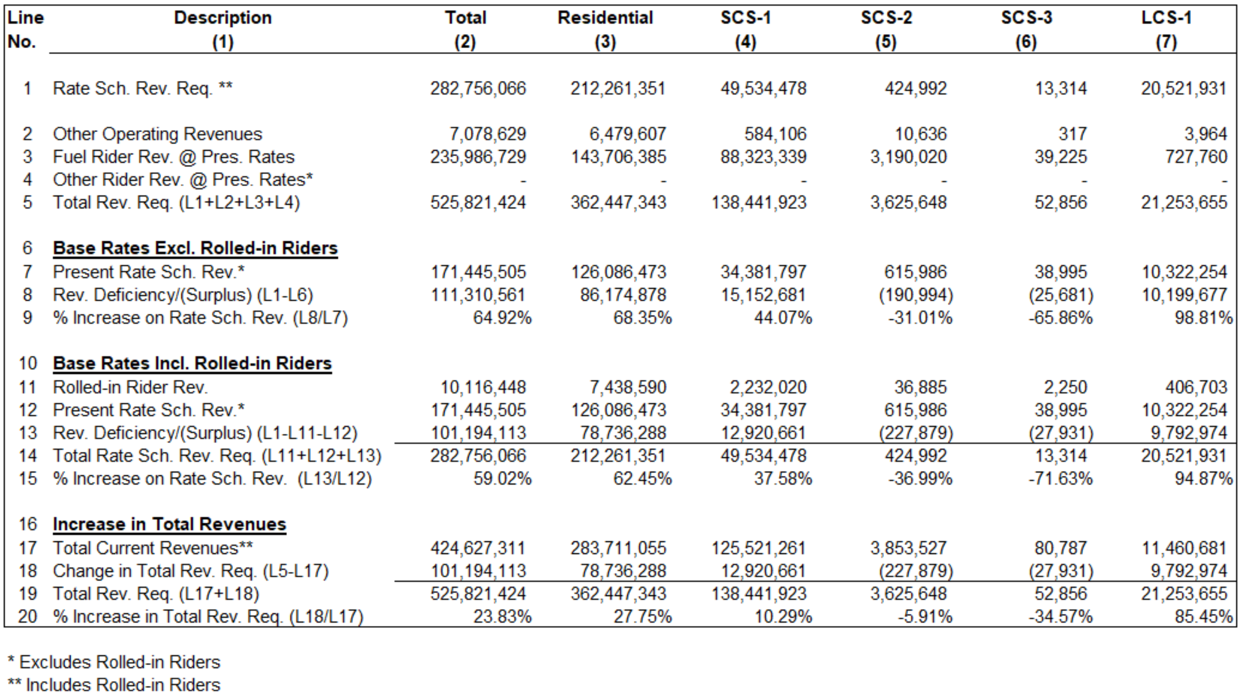
[11] Direct Testimony of AG Witness Richard W. Porter, Doc. 113, pg, 33, line 9-11.

[12] SUA's Rebuttal MFR Schedule G-1.

Table 1
Summary of SUA's Rebuttal COSS



Line No.	Description (1)	Total (2)	Residential (3)	SCS-1 (4)	SCS-2 (5)	SCS-3 (6)	LCS-1 (7)
1	Rate Sch. Rev. Req. **	282,756,066	212,261,351	49,534,478	424,992	13,314	20,521,931
2	Other Operating Revenues	7,078,629	6,479,607	584,106	10,636	317	3,964
3	Fuel Rider Rev. @ Pres. Rates	235,986,729	143,706,385	88,323,339	3,190,020	39,225	727,760
4	Other Rider Rev. @ Pres. Rates*	-	-	-	-	-	-
5	Total Rev. Req. (L1+L2+L3+L4)	525,821,424	362,447,343	138,441,923	3,625,648	52,856	21,253,655
6	**Base Rates Excl. Rolled-in Riders**						
7	Present Rate Sch. Rev.*	171,445,505	126,086,473	34,381,797	615,986	38,995	10,322,254
8	Rev. Deficiency/(Surplus) (L1-L6)	111,310,561	86,174,878	15,152,681	(190,994)	(25,681)	10,199,677
9	% Increase on Rate Sch. Rev. (L8/L7)	64.92%	68.35%	44.07%	-31.01%	-65.86%	98.81%
10	**Base Rates Incl. Rolled-in Riders**						
11	Rolled-in Rider Rev.	10,116,448	7,438,590	2,232,020	36,885	2,250	406,703
12	Present Rate Sch. Rev.*	171,445,505	126,086,473	34,381,797	615,986	38,995	10,322,254
13	Rev. Deficiency/(Surplus) (L1-L11-L12)	101,194,113	78,736,288	12,920,661	(227,879)	(27,931)	9,792,974
14	Total Rate Sch. Rev. Req. (L11+L12+L13)	282,756,066	212,261,351	49,534,478	424,992	13,314	20,521,931
15	% Increase on Rate Sch. Rev. (L13/L12)	59.02%	62.45%	37.58%	-36.99%	-71.63%	94.87%
16	**Increase in Total Revenues**						
17	Total Current Revenues**	424,627,311	283,711,055	125,521,261	3,853,527	80,787	11,460,681
18	Change in Total Rev. Req. (L5-L17)	101,194,113	78,736,288	12,920,661	(227,879)	(27,931)	9,792,974
19	Total Rev. Req. (L17+L18)	525,821,424	362,447,343	138,441,923	3,625,648	52,856	21,253,655
20	% Increase in Total Rev. Req. (L18/L17)	23.83%	27.75%	10.29%	-5.91%	-34.57%	85.45%

* Excludes Rolled-in Riders
** Includes Rolled-in Riders

Q. What are the results of Staff's COSS?

A. Staff's Surrebuttal COSS results are summarized in Table 2, below. The methods and procedures applied in Staff's COSS are generally consistent with traditional ratemaking principles and the methodology approved in SUA's most recent rate case, Docket No. 15-098-U. The results of Staff's COSS fairly and reasonably reflect the cost to serve the various customer classes and provides a sound basis for designing just and reasonable rates for each of SUA's customer classes.

Table 2
Staff's Surrebuttal COSS Results

Line No.	Description (1)	Total (2)	Residential (3)	SCS-1 (4)	SCS-2 (5)	SCS-3 (6)	LCS-1 (7)
1	Rate Sch. Rev. Req. **	260,992,090	199,802,883	44,859,013	501,727	14,199	15,814,267
2	Other Operating Revenues	6,294,594	5,735,435	543,145	9,714	789	5,510
3	Fuel Rider Rev. @ Pres. Rates	238,301,086	153,655,093	82,410,837	1,664,715	20,415	550,027
4	Other Rider Rev. @ Pres. Rates*	17,744,383	11,897,308	3,185,466	45,168	449	2,615,993
5	Total Rev. Req. (L1+L2+L3+L4)	523,332,153	371,090,718	130,998,460	2,221,325	35,852	18,985,798
6	**Base Rates Excl. Rolled-in Riders**						
7	Present Rate Sch. Rev.*	173,737,787	127,027,804	35,775,053	572,868	38,535	10,323,528
8	Rev. Deficiency/(Surplus) (L1-L6)	87,254,303	72,775,079	9,083,960	(71,140)	(24,336)	5,490,740
9	% Increase on Rate Sch. Rev. (L8/L7)	50.22%	57.29%	25.39%	-12.42%	-63.15%	53.19%
10	**Base Rates Incl. Rolled-in Riders**						
11	Rolled-in Rider Rev.	11,052,386	8,753,559	1,879,841	22,758	225	396,003
12	Present Rate Sch. Rev.*	173,737,787	127,027,804	35,775,053	572,868	38,535	10,323,528
13	Rev. Deficiency/(Surplus) (L1-L11-L12)	76,201,917	64,021,521	7,204,119	(93,899)	(24,561)	5,094,736
14	Total Rate Sch. Rev. Req. (L11+L12+L13)	260,992,090	199,802,883	44,859,013	501,727	14,199	15,814,267
15	% Increase on Rate Sch. Rev. (L13/L12)	43.86%	50.40%	20.14%	-16.39%	-63.74%	49.35%
16	**Increase in Total Revenues**						
17	Total Current Revenues**	447,130,236	307,069,198	123,794,341	2,315,223	60,413	13,891,061
18	Change in Total Rev. Req. (L5-L17)	76,201,917	64,021,521	7,204,119	(93,899)	(24,561)	5,094,736
19	Total Rev. Req. (L17+L18)	523,332,153	371,090,718	130,998,460	2,221,325	35,852	18,985,798
20	% Increase in Total Rev. Req. (L18/L17)	17.04%	20.85%	5.82%	-4.06%	-40.65%	36.68%

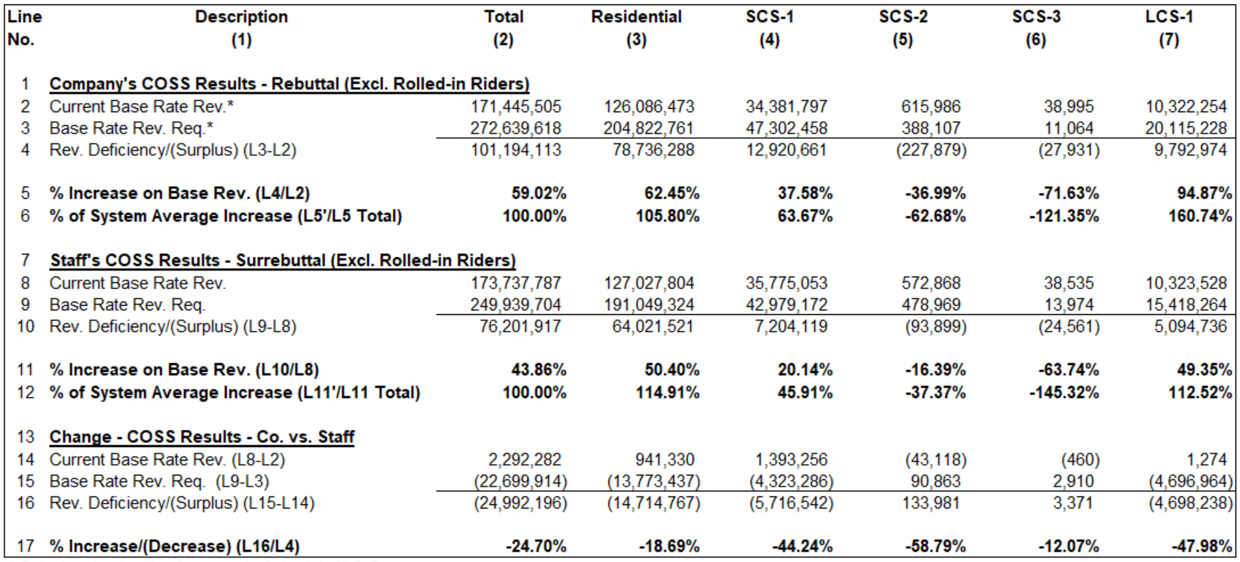
* Excludes Rolled-in Riders
** Includes Rolled-in Riders

Q. What are the primary differences between Staff's and the Company's COSS results?

A. There are two primary differences between Staff's and the Company's COSS results. They are (1) the total recommended base rate revenue requirement and (2) the external factors used to allocate costs to the customer classes derived from the billing determinants and load data (such as number of customers, volume or throughput, and peak demands) and minor differences in classification and allocation methodologies used to allocate the total recommended COSS to the customer classes.

The difference between Company's and Staff's total recommended base rate revenue requirement is addressed in the Surrebuttal Testimony of Staff witness Jeff Hilton and presented in his Surrebuttal Exhibit JH-7. The difference between the Company's and Staff's billing determinants and peak demands is addressed in the Surrebuttal Testimony of Staff witness Robert H. Swaim. Table 3, below, "SUA's COSS Results vs. Staff's COSS Results", summarizes the differences between Company's and Staff's COSS results.

Table 3
SUA's COSS Results vs. Staff's COSS Results



Line No.	Description (1)	Total (2)	Residential (3)	SCS-1 (4)	SCS-2 (5)	SCS-3 (6)	LCS-1 (7)
1	**Company's COSS Results - Rebuttal (Excl. Rolled-in Riders)**						
2	Current Base Rate Rev.*	171,445,505	126,086,473	34,381,797	615,986	38,995	10,322,254
3	Base Rate Rev. Req.*	272,639,618	204,822,761	47,302,458	388,107	11,064	20,115,228
4	Rev. Deficiency/(Surplus) (L3-L2)	101,194,113	78,736,288	12,920,661	(227,879)	(27,931)	9,792,974
5	**% Increase on Base Rev. (L4/L2)**	**59.02%**	**62.45%**	**37.58%**	**-36.99%**	**-71.63%**	**94.87%**
6	**% of System Average Increase (L5'/L5 Total)**	**100.00%**	**105.80%**	**63.67%**	**-62.68%**	**-121.35%**	**160.74%**
7	**Staff's COSS Results - Surrebuttal (Excl. Rolled-in Riders)**						
8	Current Base Rate Rev.	173,737,787	127,027,804	35,775,053	572,868	38,535	10,323,528
9	Base Rate Rev. Req.	249,939,704	191,049,324	42,979,172	478,969	13,974	15,418,264
10	Rev. Deficiency/(Surplus) (L9-L8)	76,201,917	64,021,521	7,204,119	(93,899)	(24,561)	5,094,736
11	**% Increase on Base Rev. (L10/L8)**	**43.86%**	**50.40%**	**20.14%**	**-16.39%**	**-63.74%**	**49.35%**
12	**% of System Average Increase (L11'/L11 Total)**	**100.00%**	**114.91%**	**45.91%**	**-37.37%**	**-145.32%**	**112.52%**
13	**Change - COSS Results - Co. vs. Staff**						
14	Current Base Rate Rev. (L8-L2)	2,292,282	941,330	1,393,256	(43,118)	(460)	1,274
15	Base Rate Rev. Req. (L9-L3)	(22,699,914)	(13,773,437)	(4,323,286)	90,863	2,910	(4,696,964)
16	Rev. Deficiency/(Surplus) (L15-L14)	(24,992,196)	(14,714,767)	(5,716,542)	133,981	3,371	(4,698,238)
17	**% Increase/(Decrease) (L16/L4)**	**-24.70%**	**-18.69%**	**-44.24%**	**-58.79%**	**-12.07%**	**-47.98%**

* Calculated using the Company's Schedule H-2-C

Q. What conclusions have you reached regarding the results of Staff's Surrebuttal COSS?

A. The methods and procedures applied in Staff's Surrebuttal COSS are consistent with traditional ratemaking principles and prior Commission decisions including SUA's previous rate case. The results of Staff's Surrebuttal 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. Staff's Surrebuttal COSS including rider and other revenues is presented in Table 4, below, and reflects the increase in base rates as a percentage of the total revenue requirement.

Table 4
Staff's COSS Results Including Rider and Other Revenues

Line No.	Description (1)	Total (2)	Residential (3)	SCS-1 (4)	SCS-2 (5)	SCS-3 (6)	LCS-1 (7)
1	Rate Schedule Revenue @ Present Rates *	173,737,787	127,027,804	35,775,053	572,868	38,535	10,323,528
2	Rate Schedule Revenue Requirement	249,939,704	191,049,324	42,979,172	478,969	13,974	15,418,264
3	Revenue Deficiency/(Surplus) (L2-L1)	76,201,917	64,021,521	7,204,119	(93,899)	(24,561)	5,094,736
4	**% Increase on Base Revenue**	**43.86%**	**50.40%**	**20.14%**	**-16.39%**	**-63.74%**	**49.35%**
5	**% of System Average Increase**	**100.00%**	**114.91%**	**45.91%**	**-37.37%**	**-145.32%**	**112.52%**
6	Other Revenues	6,294,594	5,735,435	543,145	9,714	789	5,510
7	Fuel Revenues	238,301,086	153,655,093	82,410,837	1,664,715	20,415	550,027
8	Other Rider Revenues	17,744,383	11,897,308	3,185,466	45,168	449	2,615,993
9	Total Retail Rev. Req. (L2+L6+L7+L8)	512,279,767	362,337,160	129,118,619	2,198,566	35,627	18,589,794
10	All Present Rate Revenues**	447,130,236	307,069,198	123,794,341	2,315,223	60,413	13,891,061
11	Total Retail Revenue Requirement (L9)	512,279,767	362,337,160	129,118,619	2,198,566	35,627	18,589,794
12	Change in Total Rev. Req.	65,149,531	55,267,962	5,324,278	(116,657)	(24,786)	4,698,733
13	**% Increase on Total Rev. Req.**	**14.57%**	**18.00%**	**4.30%**	**-5.04%**	**-41.03%**	**33.83%**

* Excludes Rolled-in Riders
** Includes Rolled-in Riders

REVENUE REQUIREMENT USED IN DESIGNING RATES

Q. Should the results of Staff's Surrebuttal COSS be used to determine rates for each of the customer classes?

A. Yes. I recommend that rates be designed based on the results of Staff's Surrebuttal COSS incorporating Staff's recommended mitigated distribution of the base rate revenue requirement as further addressed in the Surrebuttal Testimony of Staff witness Robert H. Swaim.

RECOMMENDATIONS

Q. What are your recommendations regarding SUA's COSS in this proceeding?

A. I recommend the Commission reject the Company's COSS and accept as reasonable the cost classification and allocation methodologies embedded in Staff's Surrebuttal COSS.

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 via the Arkansas Public Service Commission's Electronic Filing System on September 9, 2024.

/s/ JOSHUA A. BAXTER
Joshua A. Baxter

BEFORE THE
ARKANSAS PUBLIC SERVICE COMMISSION

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

SURREBUTTAL EXHIBIT

OF

MARK BURDETTE
SENIOR RATE CASE AUDITOR

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

September 9, 2024

SUMMIT UTILITIES OF ARKANSAS, INC.
DOCKET NO. 23-079-U
SURREBUTTAL EXHIBIT OF MARK BURDETTE

SURREBITTAL EXHIBIT MB-1

Line No.	Description (1)	Total (2)	Residential (3)	SCS-1 (4)	SCS-2 (5)	SCS-3 (6)	LCS-1 (7)
1	**RATE BASE**						
2	GROSS PLANT IN SERVICE	1,814,941,433	1,400,338,652	314,352,715	3,706,585	103,789	96,439,692
3	LESS: ACCUMULATED DEPRECIATION	686,245,802	539,821,906	113,802,010	1,514,350	44,382	31,063,154
4	**NET PLANT**	**1,128,695,631**	**860,516,746**	**200,550,705**	**2,192,235**	**59,407**	**65,376,538**
5	WORKING CAPITAL ASSETS	86,028,019	55,024,619	23,343,010	340,855	16,831	7,302,705
6	**TOTAL RATE BASE**	**1,214,723,650**	**915,541,365**	**223,893,715**	**2,533,090**	**76,238**	**72,679,243**
7	**NON-FUEL OPERATING REVENUES**						
8	RETAIL PRESENT RATE SCHEDULE REVENUES	173,737,787	127,027,804	35,775,053	572,868	38,535	10,323,528
9	OTHER OPERATING REVENUES	6,294,594	5,735,435	543,145	9,714	789	5,510
10	**TOTAL OPERATING REVENUES**	**180,032,380**	**132,763,239**	**36,318,198**	**582,582**	**39,324**	**10,329,038**
11	**EXPENSES**						
12	OPERATION & MAINTENANCE EXPENSES	91,947,443	72,152,321	13,861,467	158,508	5,305	5,769,842
13	DEPRECIATION & AMORTIZATION EXPENSES	67,851,892	51,730,234	12,056,169	131,787	3,571	3,930,131
14	TAXES OTHER THAN INCOME	14,179,149	10,808,169	2,521,879	27,551	745	820,805
15	INCOME TAXES	(6,018,086)	(6,119,297)	540,699	48,958	6,776	(495,222)
16	**TOTAL EXPENSES**	**167,960,398**	**128,571,427**	**28,980,214**	**366,804**	**16,397**	**10,025,556**
17	**OPERATING INCOME**	**12,071,982**	**4,191,812**	**7,337,984**	**215,778**	**22,927**	**303,482**
18	**PRESENT RETURN ON RATE BASE**	**0.994%**	**0.458%**	**3.277%**	**8.518%**	**30.073%**	**0.418%**
19	**COST OF SERVICE REVENUE REQUIREMENT**						
20	REQUIRED RATE OF RETURN	5.713%	5.713%	5.713%	5.713%	5.713%	5.713%
21	REQUIRED OPERATING INCOME (L6*L20)	69,402,021	52,308,540	12,791,944	144,726	4,356	4,152,456
22	OPERATING INCOME DEFICIENCY/(SURPLUS) (L21-L17)	57,330,039	48,116,729	5,453,960	(71,052)	(18,571)	3,848,974
23	REVENUE CONVERSION FACTOR	1.3292	1.3305	1.3209	1.3215	1.3225	1.3237
24	REVENUE DEFICIENCY/(SURPLUS)	76,201,917	64,021,521	7,204,119	(93,899)	(24,561)	5,094,736
25	**% INCREASE ON BASE REVENUE (L24/L8)**	**43.860%**	**50.400%**	**20.137%**	**-16.391%**	**-63.736%**	**49.351%**
26	**RATE SCHEDULE REVENUE REQUIREMENT (L8+L24)**	**249,939,704**	**191,049,324**	**42,979,172**	**478,969**	**13,974**	**15,418,264**
27	FUEL REVENUES @ PRESENT RATES	238,301,086	153,655,093	82,410,837	1,664,715	20,415	550,027
28	TOTAL RIDER REVENUES (L29+L30)	28,796,769	20,650,866	5,065,306	67,927	674	3,011,996
29	Other Rider Revenues @ Proposed Rates	17,744,383	11,897,308	3,185,466	45,168	449	2,615,993
30	Rolled-in Rider Revenues @ Present Rates	11,052,386	8,753,559	1,879,841	22,758	225	396,003
31	TOTAL REV. REQ. Excl. Rolled-in Riders (L9+L26+L27+L29)	512,279,767	362,337,160	129,118,619	2,198,566	35,627	18,589,794
32	% INCREASE IN TOTAL REV. REQ. [L24/(L31-L24)]	17.474%	21.461%	5.909%	-4.096%	-40.807%	37.753%
33	**TOTAL BILL IMPACT - COST OF SERVICE**						
34	PRESENT RATE SCHEDULE REVENUE	173,737,787	127,027,804	35,775,053	572,868	38,535	10,323,528
35	OTHER OPERATING REVENUES	6,294,594	5,735,435	543,145	9,714	789	5,510
36	GAS COST REVENUES @ PRESENT RATES	238,301,086	153,655,093	82,410,837	1,664,715	20,415	550,027
37	TOTAL RIDER REVENUES @ PRESENT RATES (L28)	28,796,769	20,650,866	5,065,306	67,927	674	3,011,996
38	**TOTAL PRESENT REV. REQ. INCL. ROLLED-IN RIDER REV. (L34+L35+L36+L37)**	**447,130,236**	**307,069,198**	**123,794,341**	**2,315,223**	**60,413**	**13,891,061**
39	REVENUE DEFICIENCY/(SURPLUS) (L24)	76,201,917	64,021,521	7,204,119	(93,899)	(24,561)	5,094,736
40	**% INCREASE IN TOTAL REV. REQ. (L39/L38)**	**17.042%**	**20.849%**	**5.819%**	**-4.056%**	**-40.655%**	**36.676%**
41	**PROPOSED REVENUE REQUIREMENT**						
42	Proposed Base Rate Rev. Req. after Mitigation	249,939,704	190,939,597	42,979,172	572,868	38,535	15,409,532
43	Revenue Deficiency/(Surplus) after Mitigation	76,201,917	63,911,793	7,204,119	-	-	5,086,004
44	**% INCREASE ON BASE REVENUE after Mitigation (L43/L8)**	**43.860%**	**50.313%**	**20.137%**	**0.000%**	**0.000%**	**49.266%**
45	**% of System Average Increase (L44'/L44 Total)**	**100.000%**	**114.712%**	**45.912%**	**0.000%**	**0.000%**	**112.325%**

CERTIFICATE OF SERVICE

I, Joshua A. Baxter, hereby 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 September 9, 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 UTILTIES ARKANSAS, INC. FOR	)	
A GENERAL CHANGE OR MODIFICATION	)	**DOCKET NO. 23-079-U**
IN ITS RATES, CHARGES, AND TARIFF	)	

SURREBUTTAL TESTIMONY

OF

MARLON F. GRIFFING, PH.D.

ON BEHALF OF

THE OFFICE OF ARKANSAS ATTORNEY GENERAL
TIM GRIFFIN

September 9, 2024

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I. INTRODUCTION

Q. PLEASE STATE YOUR NAME.

A. My name is Dr. Marlon F. Griffing.

Q. ARE YOU THE SAME DR. MARLON F. GRIFFING WHO FILED DIRECT TESTIMONY ON BEHALF OF THE OFFICE OF THE ARKANSAS ATTORNEY GENERAL ("AG") IN THIS DOCKET?

A. Yes.

Q. WHAT IS THE PURPOSE OF YOUR SURREBUTTAL TESTIMONY?

A. I respond to the Rebuttal Testimony of Company witness Dylan W. D'Ascendis and the Direct Testimony of Commission General Staff witness Dan Daves.

Q. HOW IS YOUR TESTIMONY ORGANIZED?

A. My testimony is organized in the following manner.

- First, I report on my updated return on equity ("ROE") analysis, which results in a recommended ROE of 9.59 percent for the Company.
- Second, I discuss capital structure for SUA. I continue to recommend a hypothetical capital structure of 46 percent long-term debt, 8 percent short-term debt, and 46 percent common equity are appropriate. In addition, I examine the approach of Commission witness Daves to determining a capital structure for the Company.
- Third, I respond to Mr. D'Ascendis's criticisms of my ROE analysis.
- Fourth, I summarize my testimony and recommendations.

Q. WHAT ARE YOUR CONCLUSIONS REGARDING THE COMPANY'S ROE AND ROR?

A. I recommend an ROE for the Company of 9.59 percent. When this number is included in the capital structure with cost of debt information, the ROR result for SUA is a weighted-average cost of capital of 5.40 percent.[1]

II. UPDATED RATE OF RETURN ANALYSIS

A. Return on Equity Analysis

Q. WHAT IS YOUR ROE RECOMMENDATION FOR SUA?

A. I updated my ROE analysis. The updated analysis produced an ROE of 9.63 percent for the Company. However, I reduced this value to 9.59 percent to reflect the poor performance of SUA in billing.[2] This reduction is sufficient to penalize SUA for its billing deficiencies and serve as a signal that inadequate SUA operations will result in corrective action.

Q. DID YOUR ROE ANALYTICAL APPROACH CHANGE FROM YOUR DIRECT TESTIMONY?

A. No. My ROE approach comprises two models, the discounted cash flow ("DCF") and capital asset pricing model (CAPM"). I apply two versions of each model I used the same mechanics in the application of these models as I did in my Direct Testimony.[3]

Q. WERE THERE ANY CHANGES TO THE COMPARISON GROUP?

A. No. I applied each of these four ROE approaches to the same seven proxy companies that I developed in my Direct Testimony.[4]

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[1] Exhibit MFG-S-5, Schedule 1.

[2] Direct Testimony of Marlon Griffing, (hereinafter "Griffing Direct"), page 40 through page 42.

[3] Griffing Direct, page 15, line 3 through page 18, line 13.

[4] Griffing Direct, page 18, line 14 through page 25, line 9.

Q. IN WHAT ORDER DID YOU PERFORM YOUR UPDATED ANALYSES?

A. I first updated the constant-growth DCF model. The multistage DCF model depends upon data developed for the constant-growth DCF model, so it was the next approach I updated. The multistage also includes data developed specifically for that approach. I then proceeded to update the Kroll CAPM approach, followed by the Value Line S&P 500 CAPM.

B. DCF Model Analyses

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 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 July 22, 2024, through August 16, 2024. I used closing prices for the Comparison Group member companies obtained at Yahoo! Finance.[5]

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 August 23, 2024, and by Zacks on August 26, 2024. I used the

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[5] Exhibit MFG-S-1, pages 1-2.

greater of these two options in my DCF analysis. The dividends were equal from the two sources.[6]

Q. WHAT DID YOU USE TO DETERMINE THE EXPECTED GROWTH RATE FOR THE COMPARISON GROUP?

A. In line with the producing forward-looking results, forecasted growth rates are used as the inputs for the expected dividend growth rate component of the DCF equation. I used forecasted earnings per share ("EPS") growth rates from Zacks, Yahoo! Finance, and Value Line as inputs for my analysis.

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 August 23, 2024.[7]

Q. WHAT INFORMATION DID YOU USE FROM ZACKS?

A. I used the Zacks EPS five-year growth projections available August 26, 2024, for the individual firms in the Comparison Group.[8]

Q. WHAT INFORMATION DID YOU USE FROM YAHOO! FINANCE?

A. I used the Yahoo! Finance EPS five-year growth projections available August 23, 2024, for the individual firms in the Comparison Group.[9]

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[6] Exhibit MFG-S-2.
[7] Exhibit MFG-S-3, Schedule 1.
[8] Exhibit MFG-S-3, Schedule 1.
[9] *Id.*

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. 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.[10]

Q. WHAT WAS THE RESULT FOR THE CONSTANT-GROWTH DCF MODEL UPDATE?

A. I combined the dividend growth-rate component and the expected dividend-yield component for each Comparison Group company, then averaged those values to find the constant-growth DCF model ROE. The results were a mean ROE of 9.92 percent and median ROE of 9.87 percent.[11]

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[10] I also followed this rule of applying a full year's growth to the current dividend in my CAPM analysis.

[11] Exhibit MFG-S-3, Schedule 1.

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 LONG-RUN GDP GROWTH RATES DID YOU USE IN YOUR UPDATE?

A. It is 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 2030-2050 from information published by these two agencies.[12] The SSA rate was 4.04 percent,[13] while the EIA rate was 4.33 percent.[14]

Q. DESCRIBE YOUR MULTISTAGE DCF ANALYSIS.

A. My multistage DCF analysis is the blended approach set forth in a widely used regulatory handbook.[15] In this application, 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.

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[12] The SSA and EIA GDP growth rates include inflation.

[13] Exhibit MFG-14, Schedule 2.

[14] Exhibit MFG-14, Schedule 3.

[15] Exhibit MFG-14, Schedule 4; Morin, Roger, *New Regulatory Finance (2006)*, Public Utilities Reports, Inc., Vienna, Virginia, page 309.

Q. WHAT IS THE RESULT OF YOUR UPDATED MULTISTAGE DCF ANALYSIS?

A. For the seven companies, the mean ROE was 9.27 percent. The median ROE was 9.48 percent.[16]

C. CAPM Analyses

Q. IS THE CAPM METHOD YOU USED IN YOUR UPDATED ANAYLSIS THE SAME AS THE ONE USED IN YOUR DIRECT TESTIMONY?

A. Yes.

Q. WHAT INSTRUMENT DID YOU USE AS YOUR RISKLESS ASSET?

A. I used current yields on the 30-year Treasury bond as the 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 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 July 22, 2024, to August 16, 2024, as my riskless asset rate. This average yield was 4.29 percent.[17]

Q. WHAT VALUES DID YOU USE FOR BETA (β), THE VOLATILITY INDICATOR?

A. I used the betas for each company in the Comparison Group taken from *The Value Line Investment Survey* reports of August 23, 2024.[18]

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[16] Exhibit MFG-S-3, Schedule 2.
[17] Exhibit MFG-S-4, Schedule 1.
[18] Exhibit MFG-S-4, Schedule 2.

Q. WHAT SOURCE DID YOU USE FOR AN EXPERT ESTIMATE OF THE CURRENT MARKET RISK PREMIUM?

A. I used Kroll's most recent equity risk premium (equivalent to the MRP) estimate of 5.0 percent.[19] This value is a forward-looking expert estimate of the risk premium that companies currently require as they consider future returns on investment.

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).[20]

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.[21]

Q. WHAT WAS THE RESULT OF THE UPDATED KROLL CAPM ANALYSIS?

A. The mean ROE for my Kroll CAPM analysis was 8.61 percent and the median ROE was 8.54 percent.[22]

Q. WHAT WAS YOUR SECOND SOURCE FOR CALCULATION OF THE CURRENT MARKET RISK PREMIUM FOR THE CAPM?

A. 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. These two values enabled me to calculate a market rate of return.

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[19] Exhibit MFG-S-4, Schedule 4, Kroll, *Cost of Capital in the Current Environment*, June 2024 Update.
[20] Exhibit MFG-S-4, Schedule 5.
[21] *Id.*
[22] *Id.*

Q. DID YOU ELIMINATE ANY COMPANIES IN THE VALUE LINE S&P 500 FROM FURTHER CONSIDERATION IN YOUR CALCULATIONS?

A. Yes. To be included in the market-return analysis, companies must 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 return spectrum.

Q. WHAT PROCEDURE DID YOU USE TO FIND THE MARKET RETURN?

A. I downloaded the S&P 500 EPS forecasts and dividend yields values on August 21, 2024.[23] I applied Value Line growth rates[24] to the dividend yields to find the expected dividend yield, adding a full year's growth. I added the EPS forecasts to the dividend-yield values for each company. I then weighted the 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 14.57 percent.[25]

Q. WHAT WAS THE UPDATED MARKET RISK PREMIUM?

A. The updated market risk premium was calculated by subtracting the 4.29 percent return on the 30-year Treasury from the 14.57 percent market return. The result was 10.28 percent. This amount is multiplied by the beta for each Comparison Group company to find that company's CAPM ROE.[26]

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[23] Exhibit MFG-S-4, Schedule 6.
[24] Exhibit MFG-S-4, Schedule 7.
[25] *Id.*
[26] *Id.*

Q. WHAT WAS THE RESULT OF THE UPDATED VALUE LINE S&P 500 CAPM ANALYSIS?

A. The mean ROE for my Value Line S&P 500 analysis was 13.17 percent and the median ROE was 13.03 percent.[27]

Q. DID YOU CHECK YOUR DCF AND CAPM ROE ANALYSES FOR OUTLIER RESULTS?

A. Yes. I used the same methodology as I employed in my direct testimony. I followed the Federal Energy Regulatory Commission ("FERC") standard of the yield for Moody's 10-Year Baa Corporate Bonds[28] plus 20 percent of the CAPM risk premium as a minimum ROE threshold. From there I developed low-end tests for the ROE analyses and CAPM analyses.[29] I also developed specific high-end tests for the two CAPM analyses.

Q. WHAT WAS THE RESULT OF APPLYING YOUR OUTLIER TESTS?

A. No individual companies were eliminated by either a low-end test or a high-end test.

D. <u>Updated ROE</u>

Q. HOW WOULD YOU SUMMARIZE YOUR UPDATED ROE RESULTS?

A. I performed four ROE analyses: (1) constant-growth DCF, (2) multistage DCF, (3) Kroll MRP estimate CAPM, and (4) Value Line S&P 500 CAPM for Value Line. The resulting ROE values are:

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[27] *Id.*

[28] Exhibit MFG-S-4, Schedule 3.

[29] Exhibit MFG-S-4, Schedule 8.

DCF ROE Mean and Median Results

	Constant growth	**Multistage**
Mean	**9.92%**	**9.27%**
Median	**9.87%**	**9.48%**

CAPM ROE Mean and Median Results

	Kroll	**Value Line**
Mean	**8.61%**	**13.17%**
Median	**8.54%**	**13.03%**

Q. HOW DO YOU EXPLAIN THE UPDATED ROE RESULTS?

A. The updated Kroll CAPM ROE mean and median results are less than the single lowest natural gas utility ROE authorized in the United States from 2021 to 2023.[30] The updated Value Line S&P 500 CAPM ROE mean and median results are about 2.5 percent greater than the single highest, not the average, natural gas utility ROE authorized in the United States over the same period. The CAPM ROEs do not address the actual return required to compete for capital in current financial markets. The DCF model ROE results, on the other hand, fall within the 8.80 percent to 10.50 percent range of authorized ROEs over the three years. Therefore, I exclude the updated CAPM results from consideration in determining SUA's ROE. I give equal weight to the two DCF model results, which produces a mean

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[30] Exhibit MFG-16.

ROE of 9.59 percent and a median ROE of 9.67 percent.[31] Within this range, the midpoint of 9.63 percent is the appropriate SUA ROE.

Q. WHAT IS YOUR UPDATED ADJUSTED ROE RECOMMENDATION FOR SUA?

A. My starting point is my updated ROE for SUA of 9.63 percent. I continue to recommend a downward adjustment in the recommended ROE for SUA in recognition of its poor performance in billing.[32] I believe a reduction to the bottom of the ROE range serves to penalize and signal to SUA that its performance was not acceptable. Therefore, I recommend an ROE for SUA of 9.59 percent to reflect its billing performance.[33]

Q. DO YOU CONTINUE TO SUPPORT A DECREASE IN SUA'S ROE IF SYSTEM SAFETY ENHANCEMENT RIDER ("SSER") IS EXPANDED?

A. Yes. As I stated in my direct testimony, the Commission should reduce the SUA ROE by 10 to 15 basis points if the SSER is expanded.[34]

E. Capital Structure

Q. DID YOU UPDATE YOUR CAPITAL STRUCTURE ANALYSIS FOR SUA?

A. Yes. I updated the SUA capital structure analysis I performed in my direct testimony.[35] I changed the eight calendar quarters included in the analysis from the second quarter of 2022 to the first quarter of 2024 to the third quarter of 2022 to the second quarter of 2024.[36]

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[31] Exhibit MFG-S-5, Schedule 1.
[32] APSC Docket No. 04-121-U, Document No. 286, Order No. 16, pages 94 - 104.
[33] Exhibit MFG-S-5, Schedule 1.
[34] Griffing Direct, page 45, line 12 through page 46, line 2.
[35] Exhibit MFG-17, Schedule 2.
[36] Exhibit MFG-S-5, Schedule 2.

Q. PLEASE DISCUSS THE RESULT OF THE UPDATED CAPITAL STRUCTURE ANALYSIS.

A. The updated analysis produced an average capital structure for the Comparison Group that varied slightly from the original analysis result. The long-term debt ratio increased 0.45 percent to 46.40 percent, the common equity ratio increased 0.41 percent to 43.65 percent, and short-term debt ratio decreased 0.85 percent to 9.95 percent.

Q. WHAT IS SIGNIFICANT ABOUT THE UPDATED COMPARISON GROUP CAPITAL STRUCTURE?

A. The significant value in the Comparison Group capital structure is the large short-term debt ratio, not the modest changes in the ratios for the three capital-structure elements from the original analysis. SUA requested a capital structure with no short-term debt. My analysis shows that short-term debt is a common and continuing part of the capital structures of regulated investor-owned natural gas utilities.

Q. DID YOU CHANGE YOUR RECOMMENDED CAPITAL STRUCTURE FOR SUA?

A. No. I continue to recommend a capital structure of 46.00 percent long-term debt, 8.00 percent short-term debt, and 46.00 percent common equity.[37]

Q. DO YOU HAVE A RESPONSE TO THE CAPITAL STRUCTURE ANALYSIS OF ANOTHER PARTY IN THIS DOCKET?

A. Yes. I have a response to the capital-structure analysis of General Staff witness Mr. Daves. Although our methods of finding element costs and capital-structure ratios for SUA are different, we agree the analysis for the Company should be driven by two major

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[37] Exhibit MFG-S-5, Schedule 3.

assumptions: (1) the average capital structures of the proxy group companies for SUA are the appropriate basis for evaluating the reasonableness of a capital structure for ratemaking purposes; and (2) the SUA should include short-term debt.

Q. WHY ARE PROXY-GROUP MEMBER COMPANIES APPROPRIATE AS THE BASIS FOR EVALUATING THE REASONABLENESS OF SUA'S CAPITAL STRUCTURE?

A. As I stated in my direct testimony, the Comparison Group companies have risk profiles similar to SUA's risk profile. It follows that their capital structures, reflecting this shared risk range, would be a sound basis for evaluating SUA's capital structure.[38] Mr. Daves explains why the pressure of market forces leads to reasonable capital structures for the proxy companies. Mr. Daves observes that market-traded natural gas utilities, as the proxy group companies are and SUA is not, are subject to the scrutiny of investors and analysts. The proxy group natural gas utilities must compete for capital in the financial markets, so the assessments of the investors and analysts serve to drive the companies' capital structures to ratios that balance the interests of their customers and their investors. Hence, the resulting capital-structure ratios, with risk as a major consideration of the investors, are reasonable.[39]

Q. WHY IS IT IMPORTANT TO INCLUDE SHORT-TERM DEBT IN SUA'S CAPITAL STRUCTURE?

A. Mr. Daves states that short-term debt is a normal source of funding for most companies for their ongoing operations. While short-term debt may fluctuate, it is a permanent source of

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[38] Griffing Direct, page 46, line 17 through page 47, line 1.
[39] Direct Testimony of Dan Daves ("Daves Direct"), page 21, line 2 through page 23, line 3.

funds. He notes that this fact about short-term debt is true for the proxy group companies and for SUA's parent companies.[40] Daves also states that the Commission found that it is not reasonable to exclude short-term debt from the recommended capital structure in a ratemaking proceeding.[41]

F. Cost of Long-Term Debt

Q. DO YOU HAVE AN OBSERVATION TO MAKE ABOUT ANOTHER PART OF MR. DAVES'S COST OF CAPITAL ANALYSIS?

A. Yes. Mr. Daves took steps that result in a reduction in the cost of long-term debt. He removed a revolving credit facility, which is a short-term financing tool, from the SUA long-term debt cost calculation. The facility's balance was $199,515,264 and its cost rate 6.6074 percent.[42] He also removed a term loan with a balance of $115,000,000 with a projected issuance date of December 31, 2024. This loan's projected cost rate of 6.32 percent will be in place for only the last day of the test year. Therefore, to include the term loan's annual interest cost of $7,268,000 in the calculation of long-term debt cost is inappropriate.

Q. WHAT IS MR. DAVES'S RECOMMENDED COST OF LONG-TERM DEBT?

A. Mr. Daves recommended cost of long-term debt for SUA is 3.3916 percent.[43]

Q. DO YOU AGREE WITH MR. DAVES'S LONG-TERM DEBT ACTIONS?

A. Yes. Although I accepted the SUA cost of long-term debt of 4.18 percent in my direct testimony, I conclude that Mr. Daves' removal of the two items cited above from SUA's

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[40] Daves Direct, page 24, lines 16-19.
[41] Daves Direct, page 25, lines 1-3, *citing* Order No. 7, Docket No. 21-097-U, Doc. 170, page 58.
[42] Daves Direct, page 17, lines 8-11 and page 33, lines 17-19.
[43] Daves Direct, page 33, line 7.

long-term debt were correct actions. Therefore, I accept his long-term debt cost of 3.3916 percent for inclusion in my calculation of the ROR for SUA.

Q. DO YOU DISAGREE WITH ANY OF MR. DAVES'S OTHER ACTIONS TAKEN IN CALCULATING SUA CAPITAL-STRUCTURE RATIOS AND COSTS?

A. No.

G. Rate of Return

Q. WHAT IS YOUR RECOMMENDED ROR FOR SUA?

A. When Mr. Daves' long-term debt cost is included in my ROR calculation, the value is 5.40 percent.[44]

III. RESPONSE TO MR. MCKENZIE'S CRITIQUE OF THE AG'S RETURN ON EQUITY ANALYSIS

A. Capital Structure

Q. MR. D'ASCENDIS STATES THAT THE AVERAGE CAPITAL STRUCTURE RATIOS OF THE PROXY COMPANIES SHOULD NOT BE USED TO EVALUATE THE REASONABLENESS OF SUA'S CAPITAL STRUCTURE. DO YOU AGREE?

A. No. As stated above, the proxy companies are market traded. Thus, the proxy companies are subject to the discipline imposed by the investors and analysts that participate in the financial markets. Thus, their capital structures are driven to ratios that balance the interests of their customers and their investors. Mr. D'Ascendis's preferred reference group is the utility operating company subsidiaries of the parent proxy companies. The operating

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[44] Exhibit MFG-S-5, Schedule 3, page 3.

companies do not trade in the markets and thus are not subject to the market forces to which the proxy companies are subjected.

B. Multistage Discounted Cash Flow Model

Q. MR. D'ASCENDIS CRITICIZES THE USE OF THE MULTISTAGE MODEL, ASSERTING IT APPLIES ONLY TO GROWING COMPANIES OR COMPANIES TRANSITIONING FROM A GROWTH STAGE. DO YOU AGREE?

A. No. The multistage DCF ROE analysis can be used for companies passing from high start-up growth rates to lower long-term rates. It can also be used if EPS growth rates are high enough that it is unlikely they will be continued. As the U.S. economy comes out of a period of high inflation, the EPS growth-rate forecasts for the next five years could be above the long-term EPS growth rates for the proxy companies. The multistage DCF model is a way to take this possibility into account. As for weighting the five-year EPS growth rates and the long-term GDP growth rates, my blended approach weight of two-thirds five-year rates/one-third GDP rates[45] matches what Mr. D'Ascendis states the FERC advocates for natural gas utilities.[46]

Q. IS FERC THE ONLY BODY THAT ACCEPTS THE MULTISTAGE DCF MODEL?

A. No. I included the "two-step" model, as Mr. D'Ascendis refers to the multistage DCF model, in testimony I have submitted in several states.[47]

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[45] See Morin, Roger A, *New Regulatory Finance*, Public Utilities Reports, June 1, 2006.
[46] Rebuttal Testimony of Dylan W. D'Ascendis (hereinafter "D'Ascendis Direct"), page 53, lines 15-17.
[47] E.g., Hawaii, North Dakota, Oklahoma.

Q. WHAT IS THE PURPOSE OF MR. D'ASCENDIS'S EXERCISE REGARDING WHEN AN INDUSTRY MIGHT BECOME THE ENTIRE ECONOMY?

A. I do not understand the purpose of this exercise.

C. <u>Capital Asset Pricing Model</u>

Q. MR. D'ASCENDIS ASSERTS THERE ARE SEVERAL FLAWS IN YOUR APPLICATION OF THE CAPM. WHAT ARE THOSE FLAWS?

A. Mr. D'Ascendis alleges that I do not use projected interest rates, thus making my CAPM ROE not prospective. However, current bond yields capture the views of investors regarding future interest rates. Moreover, these yields reflect actual buy and sell decisions by investors, which make them stronger predictors of future yields than speculative projections of interest rates.

Q. DO YOU AGREE WITH MR. D'ASCENDIS ASSERTION THAT KROLL DOES NOT EXPLAIN HOW IT CALCULATES ITS EQUITY RISK PREMIUM?

A. I agree that Kroll does not provide detail as to how it determines its equity risk premium ("ERP"). On the other hand, the Kroll ERP is one of the few available indicators of a market risk premium that is forward-looking, which is why I use it in my CAPM analysis. The historical approach favored by Mr. D'Ascendis presented in the *Stocks, Bonds, Bills, and Inflation Yearbook* also does not explain how the annual arithmetic mean return for individual large-company stocks is calculated. So, this value, which is necessary to calculate the market risk premium, is not only backward-looking, but opaque. I stand by my choice of the forward-looking Kroll ERP for part of my CAPM analysis.

Q. IS MR. D'ASCENDIS CORRECT WHEN HE DOES NOT AGREE WITH YOUR REMOVAL OF COMPANIES NOT PAYING DIVIDENDS, OR WITH GROWTH RATES OF 0 PERCENT OR LESS, AND GREATER THAN 20 PERCENT?

A. No. The removal of companies not paying dividends from the calculation of is a matter of mathematics. The ROE for every stock in the Value Line S&P 500, or any other broad market return, must be calculated using EPS and dividend values. The constant-growth rate DCF model calculates the price of a dividend-paying stock growing at a constant rate per the following expression: [48]

$$P = \frac{D_1}{1+K} / (1 - \frac{1+g}{1+K})$$

If the stock pays no dividends, D_1 is zero, and the price of the stock is zero. Investors cannot purchase equities for this price. Therefore, the DCF model results are not reliable for non-dividend paying companies and they must be removed from the ROE calculation.

Q. IS THERE SUPPORT FOR THE PROPOSITION THAT THE DCF MODEL CANNOT BE APPLIED TO COMPANIES NOT PAYING DIVIDENDS?

A. Yes. The following passage is from FERC Opinion No. 569:

> f. Commission Determination
> "260. We continue to find reasonable the MISO TOs' proposal to estimate the CAPM expected market return using a forward-looking approach, based on applying the DCF model to the dividend-paying members of the S&P 500. Using a DCF analysis of the dividend-paying members of the S&P 500 is a well-recognized method of estimating the expected market return for purposes of the CAPM model.[563] *The DCF analysis must be limited to the dividend-paying members of the S&P 500, rather than using all companies in the S&P 500, because a DCF analysis can only be performed on companies that pay dividends."*[49] *[Emphasis added]*

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[48] Roger A. Morin, *New Regulatory Finance*, Public Utilities Reports, Inc., Vienna, Virginia (2006), page 273.

[49] *Ass'n of Bus. Advocating Tariff Equity v. Midcontinent Indep. Sys. Operator, Inc.,* Opinion No. 569, 169 FERC ¶ 61,129 (2019), page 134.

Q. WHY DID YOU REMOVE COMPANIES WITH EPS FORECASTS OF ≤ 0 PERCENT AND > 20 PERCENT?

A. Companies with EPS forecasts of zero or less are not profitable and may be out of business within five years. Companies with EPS forecasts of greater than 20 percent are unlikely to continue to have such high growth rates long. Removing these two categories of companies deals with outliers at either end of the EPS spectrum.

Q. DO YOU HAVE ANY FURTHER RESPONSE TO MR. D'ASCENDIS'S CRITICISMS OF YOU NOT INCLUDING A SIZE ADJUSTMENT IN YOUR CAPM ANALYSIS AND NOT PERFORMING AN ECAPM ANALYSIS?

A. No. I stand by my discussion of size adjustments and the ECAPM in my direct testimony.

IV. RESPONSE TO MR. D'ASCENDIS'S REBUTTAL TESTIMONY

A. Risk Premium Approach

Q. WHAT IS YOUR RESPONSE TO MR. D'ASCENDIS ASSERTION THAT YOU FAILED TO ADDRESS THE "OVERALL AVERAGE ERPS" IN HIS RISK-PREMIUM APPROACH?

A. I may have addressed only what Mr. D'Ascendis calls his "authorized-return based ERP" in his risk-premium approach. However, if I did, it is because it is because I could find only one instance of an ROE for common equity in his risk-premium approach. That ROE is the 11.38 percent in his Schedule DWD-4, Page 1 of 11. Since the point of analysis in this docket is an ROE, I assumed that was the main product of Mr. D'Ascendis's analysis. I did see a blizzard of equity risk premiums calculated in the other 10 pages of DWD-4 that seemed to be combined into an average equity risk premium of 5.44 percent that appeared on Schedule DWD-4, Page 1 of 11. However, I did not see another ROE or a common equity cost rate.

Q. WHAT DID YOU FIND UNREASONABLE ABOUT THE 11.38 PERCENT ROE THAT WAS THE PRODUCT OF MR. D'ASCENDIS'S RISK-PREMIUM ANALYSIS?

A. As I stated in my direct testimony the risk-premium approach ROE of 11.38 percent is 88 basis points greater than the single highest ROE authorized for a natural gas utility in the United States from 2021 to 2023. Note again that Mr. D'Ascendis's risk-premium ROE exceeds the highest, not the average, ROE authorized in that period. The ROE simply is not a good guide to what is required to compete for capital in current markets.

B. <u>CAPM ROE</u>

Q. WHAT DID YOU FIND UNREASONABLE ABOUT THE ROE THAT WAS THE PRODUCT OF MR. D'ASCENDIS'S CAPM ANALYSIS?

A. Mr. D'Ascendis combined his CAPM and ECAPM analyses. The result of the combination was an ROE of 12.52 percent. This ROE exceeds the highest, not the average, natural gas utility ROE authorized in the 2021 to 2023 period by 2.02 percent. Mr. D'Ascendis CAPM ROE provides no useful information about the ROE needed for SUA to effectively compete for capital in the current markets. That conclusion is the basis for my judgment that the CAPM result is unreasonable.

Q. WHAT IS THE BASIS FOR YOUR RECOMMENDED ROE OF 9.59 PERCENT?

A. The results of my application of the DCF model and the CAPM, with a 4-basis point reduction due to SUA's poor billing performance, are the basis for my recommendation of an SUA ROE of 9.59 percent. I do not rely on the authorized natural gas ROEs from 2021-

2023 for anything other than to exclude outlier results such as the risk-premium and CAPM ROE results of Mr. D'Ascendis.

VI. SUMMARY

Q. WHAT ROE AND ROR DO YOU RECOMMEND FOR SUA?

A. I recommend an ROE of 9.59 percent and an ROR of 5.40 percent for SUA.

CERTIFICATE OF SERVICE

I, Dawn R. Kelliher, hereby certify that on September 9, 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/ Dawn R. Kelliher
Dawn R. Kelliher

APSC FILED Time: 9/9/2024 11:01:55 AM: Recvd 9/9/2024 11:00:00 AM: Docket 23-079-U-Doc. 149

BEFORE THE ARKANSAS
PUBLIC SERVICE COMMISSION

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

SURREBUTTAL EXHIBITS

OF

MARLON F. GRIFFING, PH.D.

ON BEHALF OF

THE OFFICE OF ARKANSAS ATTORNEY GENERAL
TIM GRIFFIN

September 9, 2024

SUMMIT UTILITIES ARKANSAS, INC.
DOCKET NO. 23-079-U
SURREBUTTAL EXHIBITS OF MARLON F. GRIFFING

EXHIBITS:

MFG-S-1, Pages 1-2	Updated Common Equity Share Prices for the Comparison Group Companies
MFG-S-2	Updated Dividends for the Comparison Group Companies
MFG-S-3, Schedule 1	Updated Constant-Growth DCF Model ROE Calculation
MFG-S-3, Schedule 2	Updated Multistage DCF Model ROE Calculation
MFG-S-4, Schedule 1	Updated 30-Year U.S. Treasury Bond Yield Average
MFG-S-4, Schedule 2	Update Comparison Group Value Line Beta Values
MFG-S-4, Schedule 3	Updated Moody's 10-Year Baa Corporate Bond Index
MFG-S-4, Schedule 4	Updated Kroll Estimate of Market Premium
MFG-S-4, Schedule 5	Kroll CAPM ROE Analysis
MFG-S-4, Schedule 6	S&P 500 Stocks with Updated Value Line Earnings per Share and Value Line Dividend Yields
MFG-S-4, Schedule 7	Updated Value Line CAPM ROE Analysis
MFG-S-4, Schedule 8	Updated Low-End Test Mean Calculation
MFG-S-5, Schedule 1	Updated Return on Equity Analysis
MFG-S-5, Schedule 2	Updated Capital Structure Analysis
MFG-S-5, Schedule 3	Updated Rate of Return Analysis

ROE and ROR Analysis for Summit
Comparison Group
Common Equity Share Prices
Yahoo! Finance July 22, 2024-August 16, 2024

Docket No. 23-079-U
Exhibit MFG-S-1
Page 1 of 2

Atmos Energy (ATO)		**Chesapeake Utilities (CPK**		**NiSource (NI)**	
Date	**Close**	**Date**	**Close**	**Date**	**Close**
7/22/2024	$ 123.51	7/22/2024	$ 117.93	7/22/2024	$ 30.80
7/23/2024	$ 124.54	7/23/2024	$ 119.42	7/23/2024	$ 30.56
7/24/2024	$ 125.90	7/24/2024	$ 118.15	7/24/2024	$ 31.01
7/25/2024	$ 124.93	7/25/2024	$ 117.81	7/25/2024	$ 31.08
7/26/2024	$ 126.16	7/26/2024	$ 119.46	7/26/2024	$ 31.33
7/29/2024	$ 127.04	7/29/2024	$ 117.75	7/29/2024	$ 31.33
7/30/2024	$ 128.22	7/30/2024	$ 118.50	7/30/2024	$ 31.42
7/31/2024	$ 127.88	7/31/2024	$ 118.03	7/31/2024	$ 31.25
8/1/2024	$ 130.08	8/1/2024	$ 118.31	8/1/2024	$ 31.76
8/2/2024	$ 129.99	8/2/2024	$ 119.21	8/2/2024	$ 31.81
8/5/2024	$ 127.26	8/5/2024	$ 115.09	8/5/2024	$ 30.57
8/6/2024	$ 127.52	8/6/2024	$ 114.15	8/6/2024	$ 30.94
8/7/2024	$ 128.10	8/7/2024	$ 115.01	8/7/2024	$ 31.10
8/8/2024	$ 126.95	8/8/2024	$ 115.20	8/8/2024	$ 31.05
8/9/2024	$ 128.05	8/9/2024	$ 113.90	8/9/2024	$ 31.35
8/12/2024	$ 128.64	8/12/2024	$ 113.55	8/12/2024	$ 31.56
8/13/2024	$ 128.80	8/13/2024	$ 114.00	8/13/2024	$ 31.64
8/14/2024	$ 128.66	8/14/2024	$ 113.89	8/14/2024	$ 31.84
8/15/2024	$ 129.03	8/15/2024	$ 114.74	8/15/2024	$ 31.73
8/16/2024	$ 129.21	8/16/2024	$ 114.57	8/16/2024	$ 31.90
Mean	$ 127.52	Mean	$ 116.43	Mean	$ 31.30

ROE and ROR Analysis for Summit
Comparison Group
Common Equity Share Prices
Yahoo! Finance July 22, 2024-August 16, 2024

Northwest Natural Gas (NWN)

Date		Close
7/22/2024	$	39.64
7/23/2024	$	39.79
7/24/2024	$	40.03
7/25/2024	$	40.35
7/26/2024	$	40.71
7/29/2024	$	40.59
7/30/2024	$	40.74
7/31/2024	$	39.98
8/1/2024	$	40.36
8/2/2024	$	38.92
8/5/2024	$	38.09
8/6/2024	$	38.39
8/7/2024	$	37.91
8/8/2024	$	38.20
8/9/2024	$	38.26
8/12/2024	$	37.75
8/13/2024	$	37.90
8/14/2024	$	37.85
8/15/2024	$	38.64
8/16/2024	$	38.61
Mean	$	39.14

ONE Gas, Inc. (OGS)

Date		Close
7/22/2024	$	68.66
7/23/2024	$	68.68
7/24/2024	$	69.14
7/25/2024	$	69.17
7/26/2024	$	70.49
7/29/2024	$	70.07
7/30/2024	$	70.54
7/31/2024	$	69.63
8/1/2024	$	69.67
8/2/2024	$	69.07
8/5/2024	$	66.60
8/6/2024	$	66.12
8/7/2024	$	67.18
8/8/2024	$	67.31
8/9/2024	$	67.70
8/12/2024	$	66.89
8/13/2024	$	67.36
8/14/2024	$	66.54
8/15/2024	$	66.79
8/16/2024	$	66.86
Mean	$	68.22

Southwest Gas Holdings (SWX)

Date		Close
7/22/2024	$	74.01
7/23/2024	$	75.87
7/24/2024	$	73.81
7/25/2024	$	74.66
7/26/2024	$	75.87
7/29/2024	$	72.50
7/30/2024	$	73.64
7/31/2024	$	74.16
8/1/2024	$	73.80
8/2/2024	$	74.02
8/5/2024	$	71.46
8/6/2024	$	69.92
8/7/2024	$	70.72
8/8/2024	$	71.23
8/9/2024	$	71.47
8/12/2024	$	70.90
8/13/2024	$	71.87
8/14/2024	$	71.94
8/15/2024	$	70.58
8/16/2024	$	71.25
Mean	$	72.68

Spire Inc. (SR)

Date		Close
7/22/2024	$	66.05
7/23/2024	$	66.15
7/24/2024	$	66.67
7/25/2024	$	67.13
7/26/2024	$	67.77
7/29/2024	$	67.27
7/30/2024	$	67.58
7/31/2024	$	66.59
8/1/2024	$	66.27
8/2/2024	$	66.11
8/5/2024	$	63.93
8/6/2024	$	64.22
8/7/2024	$	64.75
8/8/2024	$	64.04
8/9/2024	$	64.21
8/12/2024	$	63.48
8/13/2024	$	63.99
8/14/2024	$	63.86
8/15/2024	$	64.25
8/16/2024	$	64.72
Mean	$	65.45

ROE and ROR Analysis for Summit
Comparison Group
Dividends

Docket No. 23-079-U
Exhibit MFG-S-2

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 August 23, 2024 Reports

Zacks Gas dividends taken from website on August 26, 2024

Docket No. 23-079-U
Exhibit MFG-S-3
Schedule 1

ROE and ROR Analysis for Summit
Comparison Group
Discounted Cash Flow Model Analysis
Common Equity Share Prices--July 22, 2024-August 16, 2024
Zacks, Yahoo! Finance, and Value Line Dividend Growth-Rate Estimates--August 2024

	A	B	C	D	E	F
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**
Atmos Energy Corporation	7.00%	7.40%	7.00%	7.13%	$ 127.52	$ 3.22
Chesapeake Utilities	NA	7.60%	6.50%	7.05%	$ 116.43	$ 2.56
NiSource	6.00%	7.50%	9.50%	7.67%	$ 31.30	$ 1.06
Northwest Natural Holding Company	NA	2.80%	6.50%	4.65%	$ 39.14	$ 1.95
ONE Gas, Inc.	5.00%	5.00%	3.50%	4.50%	$ 68.22	$ 2.64
Southwest Gas Holdings	6.00%	4.00%	10.00%	6.67%	$ 72.68	$ 2.48
Spire, Inc.	5.00%	6.36%	4.50%	5.29%	$ 65.45	$ 3.02
Mean	5.80%	5.81%	6.79%	6.14%		

	G	H	I	J
Company Name	**Dividend Yield (Rate/Price)**	**Expected Dividend Yield**	**Required Rate of Return on Equity**	**Exceeds 7.26% Mean of Kroll and Value Line Low-End Tests**
Atmos Energy Corporation	2.53%	2.71%	9.84%	Yes
Chesapeake Utilities	2.20%	2.35%	9.40%	Yes
NiSource	3.39%	3.65%	11.31%	Yes
Northwest Natural Holding Company	4.99%	5.22%	9.87%	Yes
ONE Gas, Inc.	3.87%	4.04%	8.54%	Yes
Southwest Gas Holdings	3.41%	3.64%	10.31%	Yes
Spire, Inc.	4.61%	4.86%	10.14%	Yes
Mean	3.57%	3.78%	9.92%	
Median			9.87%	

A: Zacks website, August 26, 2024
B: Yahoo! Finance website: August 23, 2024
C: Value Line Investment Survey reports: August 23, 2024
E: Yahoo! Finance website: July 22, 2024-August 16, 2024. See Exhibit MFG-S-1.
F: Higher of Value Line Investment report, August 23, 2024; or Zacks website, August 26, 2024. See Exhibit MFG-S-2.
K: See Exhibit MFG-S-4, Schedule 8.

D: (A + B + C)/3 G: F/E H: G*(1+D) I: H/(1 - 0.02) J: D + H

ROE and ROR Analysis for Summit
DCF Analysis
Common Equity Share Prices: July 22, 2024-August 16, 2024

Docket No. 23-079-U
Exhibit MFG-S-3
Schedule 2

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%	$ 127.52	$ 3.22	2.53%	2.71%
Chesapeake Utilities	NA	7.60%	6.50%	7.05%	$ 116.43	$ 2.56	2.20%	2.35%
NiSource	6.00%	7.50%	9.50%	7.67%	$ 31.30	$ 1.06	3.39%	3.65%
Northwest Natural Holding Company	NA	2.80%	6.50%	4.65%	$ 39.14	$ 1.95	4.99%	5.22%
Southwest Gas Holdings	6.00%	4.00%	3.50%	4.50%	$ 68.22	$ 2.64	3.87%	4.04%
ONE Gas, Inc.	5.00%	5.00%	10.00%	6.67%	$ 72.68	$ 2.48	3.41%	3.64%
Spire, Inc.	5.00%	6.36%	4.50%	5.29%	$ 65.45	$ 3.02	4.61%	4.86%
Mean	5.80%	5.81%	6.79%	6.14%			3.57%	3.78%

	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 7.26% Mean of Kroll and Value Line Low-End Tests**
Atmos Energy Corporation	4.04%	6.10%	8.81%	4.33%	6.20%	8.90%	8.86%	Yes
Chesapeake Utilities	4.04%	6.05%	8.40%	4.33%	6.14%	8.50%	8.45%	Yes
NiSource	4.04%	6.46%	10.10%	4.33%	6.55%	10.20%	10.15%	Yes
Northwest Natural Holding Company	4.04%	4.45%	9.67%	4.33%	4.54%	9.76%	9.71%	Yes
Southwest Gas Holdings	4.04%	4.35%	8.39%	4.33%	4.44%	8.49%	8.44%	Yes
ONE Gas, Inc.	4.04%	5.79%	9.43%	4.33%	5.89%	9.53%	9.48%	Yes
Spire, Inc.	4.04%	4.87%	9.73%	4.33%	4.97%	9.83%	9.78%	Yes
Mean		5.44%	9.22%		5.53%	9.31%	9.27%	**Mean**
Median			9.43%			9.53%	9.48%	**Median**

A: Zacks website, August 26, 2024
B: Yahoo! Finance website: August 23, 2024
C: Value Line Investment Survey reports: August 23, 2024
E: Yahoo! Finance website: July 22, 2024-August 16, 2024. See Exhibit MFG-S-1.
F: Higher of Value Line Investment report, August 23, 2024; or Zacks website, August 26, 2024. See Exhibit MFG-S-2.
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-S-4, 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-S-4, Schedule 1

Daily Treasury Yield Curve Rates

July 22, 2024-August 16, 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
8/16/2024	5.53	5.40	5.33	5.21	5.02	4.49	4.06	3.87	3.77	3.81	3.89	4.26	4.15
8/15/2024	5.53	5.40	5.34	5.22	5.04	4.52	4.08	3.90	3.79	3.83	3.92	4.28	4.18
8/14/2024	5.49	5.39	5.32	5.21	5.00	4.42	3.94	3.76	3.67	3.72	3.83	4.22	4.12
8/13/2024	5.48	5.39	5.32	5.18	4.97	4.40	3.93	3.75	3.68	3.74	3.85	4.25	4.16
8/12/2024	5.53	5.40	5.33	5.20	5.02	4.47	4.01	3.82	3.75	3.80	3.90	4.30	4.19
8/9/2024	5.54	5.40	5.33	5.22	5.02	4.50	4.05	3.86	3.80	3.85	3.94	4.33	4.23
8/8/2024	5.55	5.42	5.34	5.21	5.01	4.48	4.04	3.86	3.83	3.89	3.99	4.38	4.28
8/7/2024	5.50	5.43	5.34	5.21	4.99	4.45	4.00	3.81	3.79	3.85	3.96	4.35	4.26
8/6/2024	5.50	5.43	5.34	5.18	5.00	4.46	3.99	3.76	3.73	3.79	3.90	4.28	4.18
8/5/2024	5.52	5.43	5.35	5.14	4.91	4.34	3.89	3.71	3.62	3.66	3.78	4.16	4.06
8/2/2024	5.54	5.43	5.29	5.14	4.88	4.33	3.88	3.70	3.62	3.68	3.80	4.19	4.11
8/1/2024	5.55	5.46	5.37	5.28	5.08	4.62	4.16	3.96	3.84	3.89	3.99	4.35	4.27
7/31/2024	5.49	5.51	5.41	5.32	5.14	4.73	4.29	4.10	3.97	4.00	4.09	4.44	4.35
7/30/2024	5.50	5.50	5.40	5.35	5.16	4.78	4.35	4.16	4.03	4.06	4.15	4.50	4.40
7/29/2024	5.50	5.51	5.41	5.36	5.18	4.79	4.36	4.19	4.05	4.08	4.17	4.51	4.42
7/26/2024	5.49	5.51	5.38	5.36	5.18	4.79	4.36	4.20	4.06	4.10	4.20	4.53	4.45
7/25/2024	5.49	5.52	5.39	5.37	5.19	4.83	4.41	4.26	4.13	4.18	4.27	4.59	4.50
7/24/2024	5.50	5.50	5.40	5.37	5.19	4.82	4.37	4.24	4.12	4.20	4.28	4.62	4.54
7/23/2024	5.49	5.51	5.41	5.38	5.22	4.85	4.40	4.26	4.15	4.18	4.25	4.56	4.48
7/22/2024	5.49	5.51	5.43	5.39	5.24	4.88	4.50	4.29	4.17	4.20	4.26	4.57	4.48
											Mean		4.29

Docket No. 23-079-U
Exhibit MFG-S-4
Schedule 2

ROE and ROR Analysis for Summit
CAPM Analysis
Beta calculation for Comparison Group
Value Line Investment Survey Betas taken from reports of August 23, 2024

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

ROE and ROR Analysis for Summit
CAPM Analysis
Moody's 10-Year Baa Corporate Bonds Index July 22, 2024-August 16, 2024
Downloaded August 26, 2024

Docket No. 23-079-U
Exhibit MFG-S-4
Schedule 3

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**	**5.73**

Pricing Date	Moodys Bond Yield Avg - BAA Rated Corporates-Index Value (Daily)
8/16/2024	5.58
8/15/2024	5.60
8/14/2024	5.57
8/13/2024	5.65
8/12/2024	5.68
8/9/2024	5.71
8/8/2024	5.77
8/7/2024	5.76
8/6/2024	5.68
8/5/2024	5.63
8/2/2024	5.60
8/1/2024	5.70
7/31/2024	5.77
7/30/2024	5.80
7/29/2024	5.83
7/26/2024	5.85
7/25/2024	5.89
7/24/2024	5.93
7/23/2024	5.84
7/22/2024	5.84
Mean	5.73

June 6, 2024

Kroll Lowers its Recommended U.S. Equity Risk Premium to 5.0%, Effective June 5, 2024

Executive Summary

Kroll regularly reviews fluctuations in global economic and financial market conditions that may warrant changes to our equity risk premium (ERP) and accompanying risk-free rate recommendations. The risk-free rate and ERP are key inputs used to calculate the cost of equity capital in the context of the Capital Asset Pricing Model (CAPM) and other models used to develop discount rates. We also update country risk data on a quarterly basis for 175+ countries using various models.

The Kroll Recommended U.S. ERP is decreasing from 5.5% to 5.0% when developing USD-denominated discount rates as of June 5, 2024, and thereafter, until further notice.

Notwithstanding the current recommendation, we are monitoring economic and geopolitical events that may change our views and impact our guidance toward the end of 2024 and into 2025. In particular, the U.S. Presidential Election in November 2024 has the potential to cause turmoil in U.S. and global financial markets. Of particular concern is any potential promise of a significant increase in government spending and a corresponding rise in the U.S. budget deficit, which could place upward pressure on long-term interest rates and disrupt financial markets. Other global geopolitical events that warrant close watch include, but are not limited to, the impact of general elections in other major economies (e.g., Mexico, India, UK), trade conflicts between the U.S. and China, rising tensions in the Middle East and the protracted Russia's war on Ukraine.

Background

The Kroll U.S. Recommended ERP was last changed on June 8, 2023, when it was lowered from 6.0% to 5.5%. This ERP guidance was applicable when developing USD-denominated discount rates and was to be used in conjunction with our U.S. risk-free guidance—the higher of the spot 20-year U.S. Treasury yield (prevailing as of the valuation date) and the Kroll normalized U.S. risk-free rate of 3.5%.

ROE and ROR Analysis for Summit
CAPM ROE Analysis--Kroll Risk Premium
Calculation for Proxy Group

Docket No. 23-079-U
Exhibit MFG-S-4
Schedule 5

	A	B	C	D	E	F
	Rf	**MRP**	**Beta**	**RP**	**CAPM ROE**	**Filtered Results**
Atmos Energy Corporation	4.29%	5.00%	0.85	4.25%	8.54%	8.54%
Chesapeake Utilities	4.29%	5.00%	0.80	4.00%	8.29%	8.29%
NiSource	4.29%	5.00%	0.95	4.75%	9.04%	9.04%
Northwest Natural Holding Co.	4.29%	5.00%	0.90	4.50%	8.79%	8.79%
Southwest Gas Holdings	4.29%	5.00%	0.85	4.25%	8.54%	8.54%
ONE Gas, Inc.	4.29%	5.00%	0.85	4.25%	8.54%	8.54%
Spire, Inc.	4.29%	5.00%	0.85	4.25%	8.54%	8.54%
				Mean	8.61%	8.61%
				Median	8.54%	8.54%

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-S-4, Schedule 3	5.73%
	CAPM Risk Premium, Column B	5.00%
	20 percent of CAPM risk premium	1.00%
	Moody's 10-Year Baa Corporate Bond Index + 20 percent of CAPM risk premium	6.73%

High-End Test:	Proxy Group median, Column E	8.54%
	200 percent of Proxy Group median	17.08%

Constant-Growth DCF Analysis for S&P 500--Value Line

All companies shown
A, B, and E: Value Line Analyzer, August 21, 2024

C = B * (1 + A/100)
D = A + C
F = E/(Sum of Column E)
G = D * F

Companies Excluded

- Companies not paying dividends
- Companies with EPS ≤
- Companies with EPS > 20%

EPS Market Return %	14.57

	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 (%)**
Companies not paying dividends							
Adobe Inc.	24.00	0.00	0.00	24.00	242,366		
Advanced Micro Dev.	78.50	0.00	0.00	78.50	227,734		
Airbnb Inc.	0.00	0.00	0.00	0.00	73,696		
Akamai Technologies	17.50	0.00	0.00	17.50	15,150		
Align Techn.	12.50	0.00	0.00	12.50	16,564		
Alphabet Inc. 'A'	39.00	0.00	0.00	39.00	1,976,079		
Amazon.com	32.50	0.00	0.00	32.50	1,784,349		
Amer. Airlines	0.00	0.00	0.00	0.00	6,395		
ANSYS Inc.	12.00	0.00	0.00	12.00	27,884		
Aptiv PLC	-10.50	0.00	0.00	-10.50	17,864		
Arch Capital Group	28.50	0.00	0.00	28.50	37,868		
Arista Networks	28.00	0.00	0.00	28.00	109,506		

	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.	0.00	0.00	0.00	0.00	52,937		
AutoZone Inc.	20.50	0.00	0.00	20.50	54,799		
Axon Enterprise	48.50	0.00	0.00	48.50	27,965		
Bio-Rad Labs. 'A'	30.00	0.00	0.00	30.00	9,141		
Biogen	-7.00	0.00	0.00	-7.00	29,226		
Boeing	0.00	0.00	0.00	0.00	103,717		
Boston Scientific	11.50	0.00	0.00	11.50	112,338		
Builders FirstSource	87.50	0.00	0.00	87.50	19,601		
Cadence Design Sys.	23.00	0.00	0.00	23.00	74,419		
Caesars Entertainment	0.00	0.00	0.00	0.00	7,500		
CarMax Inc.	2.00	0.00	0.00	2.00	12,110		
Carnival Corp.	0.00	0.00	0.00	0.00	18,701		
Catalent Inc.	9.50	0.00	0.00	9.50	10,692		
CBRE Group	13.00	0.00	0.00	13.00	33,862		
Centene Corp.	16.50	0.00	0.00	16.50	40,518		
Charles River	17.00	0.00	0.00	17.00	10,227		
Charter Communic.	29.50	0.00	0.00	29.50	50,586		
Chipotle Mex. Grill	43.50	0.00	0.00	43.50	70,831		
Cooper Cos.	14.00	0.00	0.00	14.00	18,202		
Copart Inc.	26.50	0.00	0.00	26.50	49,066		
Corpay	14.00	0.00	0.00	14.00	19,990		
CoStar Group	16.00	0.00	0.00	16.00	30,100		
CrowdStrike Hldgs.	0.00	0.00	0.00	0.00	62,309		
DaVita Inc.	17.50	0.00	0.00	17.50	13,057		
Dayforce Inc.	0.00	0.00	0.00	0.00	8,639		

	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 (%)**
Deckers Outdoor	28.50	0.00	0.00	28.50	23,376		
DexCom Inc.	0.00	0.00	0.00	0.00	28,069		
Dollar Tree Inc.	-9.50	0.00	0.00	-9.50	19,967		
Edwards Lifesciences	13.50	0.00	0.00	13.50	40,053		
Enphase Energy	0.00	0.00	0.00	0.00	15,049		
EPAM Systems	22.00	0.00	0.00	22.00	11,584		
Etsy Inc.	51.00	0.00	0.00	51.00	5,939		
Expedia Group	-4.00	0.00	0.00	-4.00	17,229		
F5 Inc.	-2.00	0.00	0.00	-2.00	11,153		
Fair Isaac	28.00	0.00	0.00	28.00	44,455		
First Solar Inc.	0.00	0.00	0.00	0.00	24,143		
Fiserv Inc.	20.00	0.00	0.00	20.00	94,645		
Fortinet Inc.	53.50	0.00	0.00	53.50	55,553		
Gartner Inc.	26.00	0.00	0.00	26.00	37,095		
GE Vernova Inc	0.00	0.00	0.00	0.00	50,476		
Generac Holdings	17.50	0.00	0.00	17.50	8,726		
GoDaddy Inc.	0.00	0.00	0.00	0.00	22,907		
Hologic Inc.	33.00	0.00	0.00	33.00	18,794		
IDEXX Labs.	21.50	0.00	0.00	21.50	39,360		
Incyte Corp.	0.00	0.00	0.00	0.00	13,737		
Insulet Corp.	0.00	0.00	0.00	0.00	13,429		
Intuitive Surgical	10.50	0.00	0.00	10.50	167,421		
IQVIA Holdings	16.00	0.00	0.00	16.00	43,061		
Keysight Technologies	31.00	0.00	0.00	31.00	22,221		
Live Nation Entertain.	0.00	0.00	0.00	0.00	21,531		

	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 (%)**
lululemon athletica	29.00	0.00	0.00	29.00	30,202		
Match Group	8.50	0.00	0.00	8.50	8,893		
Mettler-Toledo Int'l	16.50	0.00	0.00	16.50	29,761		
MGM Resorts Int'l	0.00	0.00	0.00	0.00	11,613		
Moderna Inc.	0.00	0.00	0.00	0.00	31,584		
Mohawk Inds.	-1.00	0.00	0.00	-1.00	10,140		
Molina Healthcare	37.00	0.00	0.00	37.00	20,014		
Monster Beverage	13.00	0.00	0.00	13.00	48,168		
Netflix Inc.	49.00	0.00	0.00	49.00	283,970		
Norwegian Cruise Line	0.00	0.00	0.00	0.00	6,620		
NVR Inc.	24.50	0.00	0.00	24.50	27,154		
O'Reilly Automotive	21.00	0.00	0.00	21.00	66,604		
ON Semiconductor	25.50	0.00	0.00	25.50	30,438		
Palo Alto Networks	0.00	0.00	0.00	0.00	109,927		
PayPal Holdings	17.00	0.00	0.00	17.00	68,257		
PTC Inc.	0.00	0.00	0.00	0.00	20,642		
Qorvo Inc.	0.00	0.00	0.00	0.00	10,305		
Regeneron Pharmac.	30.50	0.00	0.00	30.50	128,527		
Royal Caribbean	0.00	0.00	0.00	0.00	39,307		
Schein (Henry)	3.00	0.00	0.00	3.00	8,802		
ServiceNow Inc.	0.00	0.00	0.00	0.00	168,601		
Solventum Corp	0.00	0.00	0.00	0.00	9,979		
Super Micro Computer	39.50	0.00	0.00	39.50	33,790		
Synopsys Inc.	21.00	0.00	0.00	21.00	81,321		
Take-Two Interactive	0.00	0.00	0.00	0.00	24,751		

	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 (%)**
Teledyne Technologies	21.50	0.00	0.00	21.50	19,178		
Tesla Inc.	0.00	0.00	0.00	0.00	643,208		
TransDigm Group	4.00	0.00	0.00	4.00	69,826		
Trimble Inc.	27.50	0.00	0.00	27.50	13,106		
Tyler Technologies	13.00	0.00	0.00	13.00	27,982		
Uber Technologies	0.00	0.00	0.00	0.00	150,906		
Ulta Beauty	21.50	0.00	0.00	21.50	15,743		
Under Armour 'C'	-16.00	0.00	0.00	-16.00	3,398		
United Airlines Hldgs.	0.00	0.00	0.00	0.00	13,231		
VeriSign Inc.	9.50	0.00	0.00	9.50	17,143		
Vertex Pharmac.	68.50	0.00	0.00	68.50	121,639		
Warner Bros. Discovery	0.00	0.00	0.00	0.00	17,059		
Waters Corp.	9.00	0.00	0.00	9.00	19,972		
Western Digital	-20.50	0.00	0.00	-20.50	20,052		
Zebra Techn. 'A'	14.00	0.00	0.00	14.00	17,185		
<u>Companies with EPS ≤ 0%</u>							
3M Company	-22.50	2.22	1.72	-20.78	69,312		
AES Corp.	0.00	4.13	4.13	4.13	12,041		
Alexandria Real Estate	0.00	4.49	4.49	4.49	19,336		
Allstate Corp.	-7.50	2.03	1.88	-5.62	47,771		
Amcor plc	0.00	4.69	4.69	4.69	15,393		

	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 (%)**
AT&T Inc.	-3.00	5.66	5.49	2.49	140,752		
Baker Hughes	0.00	2.53	2.53	2.53	34,681		
Bath & Body Works	-2.00	2.55	2.50	0.50	7,002		
Campbell Soup	0.00	3.14	3.14	3.14	14,790		
Carrier Global	0.00	1.16	1.16	1.16	59,174		
CF Industries	0.00	2.61	2.61	2.61	14,849		
Clorox Co.	0.00	3.32	3.32	3.32	17,948		
Colgate-Palmolive	-1.50	1.96	1.93	0.43	83,490		
Constellation Energy	0.00	0.76	0.76	0.76	58,637		
Corteva Inc.	0.00	1.31	1.31	1.31	36,061		
Coterra Energy	0.00	3.51	3.51	3.51	17,979		
Delta Air Lines	-19.50	1.55	1.25	-18.25	24,971		
Disney (Walt)	-27.00	1.04	0.76	-26.24	161,640		
Dominion Energy	-2.00	4.81	4.71	2.71	46,517		
Dow Inc.	0.00	5.50	5.50	5.50	37,101		
DTE Energy	-0.50	3.34	3.32	2.82	25,263		
DuPont de Nemours	0.00	1.98	1.98	1.98	32,876		
Eastman Chemical	-0.50	3.39	3.37	2.87	11,168		
Ecolab Inc.	-2.00	0.95	0.93	-1.07	68,129		
Electronic Arts	0.00	0.55	0.55	0.55	38,958		
EQT Corp.	-25.00	2.00	1.50	-23.50	13,902		
Equity Residential	-12.50	3.79	3.32	-9.18	26,940		
Exelon Corp.	-2.50	4.11	4.01	1.51	37,030		
Federal Rlty. Inv. Trust	0.00	3.87	3.87	3.87	9,161		
FirstEnergy Corp.	-1.00	4.09	4.05	3.05	24,333		

	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 (%)**
Ford Motor	-14.00	5.89	5.07	-8.93	42,542		
Fortive Corp.	-5.00	0.47	0.45	-4.55	24,076		
Fox Corp. 'A'	0.00	1.33	1.33	1.33	18,286		
Fox Corp. 'B'	0.00	1.43	1.43	1.43			
Franklin Resources	-3.50	5.63	5.43	1.93	11,496		
GE HealthCare	0.00	0.14	0.14	0.14	38,117		
Gen'l Electric	-21.50	0.67	0.53	-20.97	183,839		
Gilead Sciences	-9.50	4.15	3.76	-5.74	92,378		
Hasbro Inc.	-2.50	4.33	4.22	1.72	8,996		
Hess Corp.	0.00	1.30	1.30	1.30	41,330		
Hormel Foods	0.00	3.50	3.50	3.50	17,679		
Host Hotels & Resorts	0.00	5.20	5.20	5.20	11,529		
Howmet Aerospace	0.00	0.53	0.53	0.53	38,292		
Ingersoll Rand Inc.	0.00	0.09	0.09	0.09	36,756		
Int'l Business Mach.	-6.50	3.47	3.24	-3.26	176,666		
Int'l Flavors & Frag.	-3.50	1.65	1.59	-1.91	24,692		
Int'l Paper	-3.00	4.01	3.89	0.89	16,021		
Intel Corp.	-5.00	2.51	2.38	-2.62	85,178		
Invesco Ltd.	-11.50	5.16	4.57	-6.93	7,413		
Invitation Homes	0.00	3.19	3.19	3.19	21,473		
Kellanova	-1.00	2.85	2.82	1.82	27,479		
Kenvue Inc.	0.00	3.78	3.78	3.78	40,560		
Kimberly-Clark	-1.00	3.46	3.43	2.43	47,456		
Kraft Heinz Co.	-3.50	4.64	4.48	0.98	41,698		
L3Harris Technologies	0.00	2.06	2.06	2.06	42,901		

	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 (%)**
Lamb Weston Holdings	0.00	2.57	2.57	2.57	8,538		
Las Vegas Sands	0.00	2.03	2.03	2.03	29,072		
Linde plc	0.00	1.23	1.23	1.23	216,871		
Marathon Oil Corp.	0.00	1.59	1.59	1.59	15,705		
Micron Technology	-9.00	0.47	0.43	-8.57	111,355		
Molson Coors Beverage	-2.00	3.39	3.32	1.32	10,885		
News Corp. 'A'	0.00	0.73	0.73	0.73	15,585		
News Corp. 'B'	0.00	0.71	0.71	0.71	16,739		
NRG Energy	0.00	1.98	1.98	1.98	17,094		
Otis Worldwide	0.00	1.48	1.48	1.48	36,964		
Paramount Global	-14.00	1.96	1.69	-12.31	6,701		
PG&E Corp.	0.00	0.22	0.22	0.22	39,308		
PPL Corp.	-14.00	3.32	2.86	-11.14	22,908		
RTX Corp.	-7.50	2.14	1.98	-5.52	156,503		
Southwest Airlines	-44.50	2.84	1.58	-42.92	15,189		
Stanley Black & Decker	-5.50	3.43	3.24	-2.26	14,685		
Targa Resources	0.00	2.32	2.32	2.32	30,719		
Trane Technologies plc	0.00	0.97	0.97	0.97	78,098		
UDR Inc.	-1.50	4.19	4.13	2.63	13,746		
Ventas Inc.	0.00	3.18	3.18	3.18	23,531		
Viatris Inc.	0.00	4.21	4.21	4.21	13,603		
Vistra Corp.	0.00	1.10	1.10	1.10	27,365		
Walgreens Boots	-2.50	9.59	9.35	6.85	9,004		
Wells Fargo	-5.00	2.98	2.83	-2.17	182,590		
Welltower Inc.	-22.00	2.28	1.78	-20.22	66,304		

	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 (%)**
Wynn Resorts	0.00	4.05	4.05	4.05	8,298		
Zimmer Biomet Hldgs.	-3.00	0.89	0.86	-2.14	22,345		

Companies with EPS > 20%

Alphabet Inc.	23.50	0.49	0.61	24.11	2,002,367		
Amer. Int'l Group	22.50	2.19	2.68	25.18	48,924		
APA Corp.	66.50	3.45	5.74	72.24	10,707		
Archer Daniels Midl'd	20.50	3.43	4.13	24.63	27,906		
Ball Corp.	23.00	1.29	1.59	24.59	19,031		
Berkley (W.R.)	24.00	0.56	0.69	24.69	22,054		
Broadcom Inc.	55.00	1.33	2.06	57.06	733,259		
Bunge Global SA	37.00	2.87	3.93	40.93	13,564		
Chevron Corp.	28.50	4.67	6.00	34.50	267,207		
ConocoPhillips	54.00	2.85	4.39	58.39	126,960		
Crown Castle Int'l	25.00	5.82	7.28	32.28	47,941		
Deere & Co.	32.50	1.67	2.21	34.71	96,802		
Devon Energy	45.00	1.98	2.87	47.87	28,162		
Diamondback Energy	38.00	1.83	2.53	40.53	35,035		

	A	B	C	D	E	F	G
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EOG Resources	46.50	3.02	4.42	50.92	72,713		
Equinix Inc.	21.00	2.03	2.46	23.46	79,861		
Expeditors Int'l	21.00	1.22	1.48	22.48	16,840		
Exxon Mobil Corp.	22.50	3.19	3.91	26.41	469,020		
Fidelity Nat'l Info.	23.00	1.84	2.26	25.26	43,965		
Healthpeak Properties	26.00	5.51	6.94	32.94	11,911		
Horton D.R.	35.50	0.69	0.93	36.43	57,032		
Intuit Inc.	21.00	0.57	0.69	21.69	177,999		
Jabil Inc.	28.50	0.31	0.40	28.90	12,260		
Keurig Dr Pepper	20.50	2.55	3.07	23.57	47,872		
Kinder Morgan Inc.	26.50	5.49	6.94	33.44	46,519		
KLA Corp.	27.00	0.73	0.93	27.93	106,947		
Lam Research	23.00	0.98	1.21	24.21	110,515		
Lennar Corp.	27.50	1.18	1.50	29.00	46,441		
Lowe's Cos.	23.50	1.94	2.40	25.90	135,930		
Marathon Petroleum	33.50	1.84	2.46	35.96	63,563		
Microsoft Corp.	22.50	0.78	0.96	23.46	3,098,520		
Monolithic Power Sys.	42.50	0.58	0.83	43.33	41,981		
Mosaic Company	45.00	3.04	4.41	49.41	8,883		
MSCI Inc.	23.00	1.15	1.41	24.41	43,654		
Nucor Corp.	39.00	1.59	2.21	41.21	33,869		
NVIDIA Corp.	42.00	0.03	0.04	42.04	2,903,587		
Occidental Petroleum	26.00	1.72	2.17	28.17	50,490		
Old Dominion Freight	26.00	0.55	0.69	26.69	41,997		
Paycom Software	32.50	0.97	1.29	33.79	8,713		

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Pool Corp.	29.50	1.39	1.80	31.30	13,173		
PulteGroup Inc.	32.50	0.66	0.87	33.37	25,337		
Quanta Services	24.00	0.14	0.17	24.17	38,584		
Revvity Inc.	27.00	0.24	0.30	27.30	14,488		
Salesforce Inc.	26.00	0.63	0.79	26.79	266,043		
SBA Communications	42.50	1.82	2.59	45.09	23,504		
Steel Dynamics	40.00	1.60	2.24	42.24	18,164		
Thermo Fisher Sci.	24.00	0.26	0.32	24.32	229,831		
Tractor Supply	21.00	1.75	2.12	23.12	28,299		
United Rentals	22.00	0.93	1.13	23.13	46,510		
Valero Energy	26.50	2.89	3.66	30.16	47,359		
VICI Properties	53.00	5.25	8.03	61.03	30,444		
West Pharmac. Svcs.	30.50	0.27	0.35	30.85	21,214		
Weyerhaeuser Co.	24.00	2.66	3.30	27.30	21,840		
Qualifying Companies							
Abbott Labs.	14.50	2.00	2.29	16.79	191,197	0.00758	0.1272
AbbVie Inc.	15.50	3.21	3.71	19.21	340,785	0.01351	0.2595
Accenture Plc	11.50	1.61	1.80	13.30	200,413	0.00794	0.1056
Aflac Inc.	10.00	2.01	2.21	12.21	59,117	0.00234	0.0286
Agilent Technologies	16.00	0.69	0.80	16.80	39,665	0.00157	0.0264
Air Products & Chem.	8.00	2.56	2.76	10.76	61,468	0.00244	0.0262

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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 (%)**
Albemarle Corp.	18.50	2.20	2.61	21.11	8,562	0.00034	0.0072
Allegion plc	9.50	1.47	1.61	11.11	11,422	0.00045	0.0050
Alliant Energy	7.00	3.40	3.64	10.64	14,487	0.00057	0.0061
Altria Group	7.50	7.66	8.23	15.73	87,925	0.00349	0.0548
Amer. Elec. Power	4.50	3.70	3.87	8.37	51,247	0.00203	0.0170
Amer. Express	10.50	0.99	1.09	11.59	175,264	0.00695	0.0805
Amer. Tower 'A'	11.50	3.20	3.57	15.07	104,242	0.00413	0.0623
Amer. Water Works	15.00	2.20	2.53	17.53	27,606	0.00109	0.0192
Ameren Corp.	7.00	3.30	3.53	10.53	21,664	0.00086	0.0090
Ameriprise Fin'l	17.00	1.41	1.65	18.65	41,838	0.00166	0.0309
AMETEK Inc.	13.00	0.69	0.78	13.78	37,388	0.00148	0.0204
Amgen	6.50	2.91	3.10	9.60	173,112	0.00686	0.0659
Amphenol Corp.	12.50	0.71	0.80	13.30	78,018	0.00309	0.0411
Analog Devices	14.00	1.71	1.95	15.95	106,845	0.00424	0.0675
Aon plc	16.50	0.82	0.96	17.46	71,893	0.00285	0.0497
Apple Inc.	19.50	0.45	0.54	20.04	3,375,079	0.13378	2.6807
Applied Materials	20.00	0.70	0.84	20.84	166,944	0.00662	0.1379
Assurant Inc.	4.00	1.55	1.61	5.61	9,675	0.00038	0.0022
Atmos Energy	9.00	2.69	2.93	11.93	19,412	0.00077	0.0092
Automatic Data Proc.	15.00	2.13	2.45	17.45	107,704	0.00427	0.0745
AvalonBay Communities	1.00	3.28	3.31	4.31	30,325	0.00120	0.0052
Avery Dennison	12.00	1.75	1.96	13.96	16,835	0.00067	0.0093
Bank of America	13.00	2.47	2.79	15.79	305,313	0.01210	0.1911
Bank of NY Mellon	6.00	2.93	3.11	9.11	47,943	0.00190	0.0173
Baxter Int'l Inc.	6.00	3.27	3.47	9.47	18,105	0.00072	0.0068

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Becton Dickinson	4.50	1.67	1.75	6.25	67,659	0.00268	0.0167
Best Buy Co.	12.00	4.53	5.07	17.07	17,917	0.00071	0.0121
Bio-Techne Corp.	16.50	0.44	0.51	17.01	11,462	0.00045	0.0077
BlackRock Inc.	10.50	2.52	2.78	13.28	127,565	0.00506	0.0672
Blackstone Inc.	12.00	2.41	2.70	14.70	97,948	0.00388	0.0571
Booking Holdings	5.00	0.98	1.03	6.03	121,704	0.00482	0.0291
BorgWarner	2.00	1.39	1.42	3.42	7,227	0.00029	0.0010
Bristol-Myers Squibb	4.50	4.96	5.18	9.68	98,127	0.00389	0.0377
Broadridge Fin'l	15.00	1.53	1.76	16.76	24,739	0.00098	0.0164
Brown & Brown	19.50	0.53	0.63	20.13	28,871	0.00114	0.0230
Brown-Forman 'B'	3.50	2.27	2.35	5.85	21,035	0.00083	0.0049
BXP Inc.	4.00	5.72	5.95	9.95	10,728	0.00043	0.0042
C.H. Robinson	7.00	2.49	2.66	9.66	11,467	0.00045	0.0044
Camden Property Trust	8.00	3.49	3.77	11.77	12,795	0.00051	0.0060
Capital One Fin'l	17.00	1.76	2.06	19.06	51,913	0.00206	0.0392
Cardinal Health	12.50	1.90	2.14	14.64	25,952	0.00103	0.0151
Caterpillar Inc.	16.50	1.67	1.95	18.45	165,174	0.00655	0.1208
Cboe Global Markets	8.00	1.07	1.16	9.16	21,586	0.00086	0.0078
CDW Corp.	18.50	1.14	1.35	19.85	28,948	0.00115	0.0228
Celanese Corp.	11.50	2.23	2.49	13.99	13,732	0.00054	0.0076
Cencora	12.50	0.86	0.97	13.47	47,405	0.00188	0.0253
CenterPoint Energy	3.50	3.10	3.21	6.71	16,543	0.00066	0.0044
Chubb Ltd.	11.50	1.36	1.52	13.02	110,591	0.00438	0.0571
Church & Dwight	9.50	1.13	1.24	10.74	24,595	0.00097	0.0105
Cigna Group	16.00	1.67	1.94	17.94	95,136	0.00377	0.0676

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Cincinnati Financial	12.50	2.58	2.90	15.40	20,356	0.00081	0.0124
Cintas Corp.	17.50	0.82	0.96	18.46	77,272	0.00306	0.0566
Cisco Systems	7.50	3.52	3.78	11.28	183,169	0.00726	0.0819
Citigroup Inc.	13.00	3.78	4.27	17.27	113,073	0.00448	0.0774
Citizens Fin'l Group	7.00	4.19	4.48	11.48	18,390	0.00073	0.0084
CME Group	1.00	2.21	2.23	3.23	74,686	0.00296	0.0096
CMS Energy Corp.	5.50	3.11	3.28	8.78	19,810	0.00079	0.0069
Coca-Cola	5.00	2.90	3.05	8.05	295,511	0.01171	0.0942
Cognizant Technology	2.00	1.65	1.68	3.68	36,967	0.00147	0.0054
Comcast Corp.	11.50	3.18	3.55	15.05	151,420	0.00600	0.0903
Conagra Brands	5.50	4.67	4.93	10.43	14,734	0.00058	0.0061
Consol. Edison	2.00	3.33	3.40	5.40	34,898	0.00138	0.0075
Constellation Brands	6.00	1.69	1.79	7.79	43,963	0.00174	0.0136
Corning Inc.	4.00	2.83	2.94	6.94	32,424	0.00129	0.0089
Costco Wholesale	16.00	0.54	0.63	16.63	382,503	0.01516	0.2521
CSX Corp.	15.00	1.47	1.69	16.69	65,216	0.00259	0.0431
Cummins Inc.	9.50	2.49	2.73	12.23	40,017	0.00159	0.0194
CVS Health	6.50	4.86	5.18	11.68	70,100	0.00278	0.0324
Danaher Corp.	17.50	0.43	0.51	18.01	194,090	0.00769	0.1385
Darden Restaurants	10.50	3.98	4.40	14.90	16,744	0.00066	0.0099
Digital Realty Trust	18.00	3.31	3.91	21.91	47,109	0.00187	0.0409
Discover Fin'l Svcs.	18.00	2.19	2.58	20.58	32,014	0.00127	0.0261
Dollar General	14.00	2.03	2.31	16.31	25,626	0.00102	0.0166
Domino's Pizza	17.00	1.41	1.65	18.65	15,391	0.00061	0.0114
Dover Corp.	14.50	1.15	1.32	15.82	24,300	0.00096	0.0152

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Duke Energy	4.50	3.65	3.81	8.31	87,591	0.00347	0.0289
Eaton Corp. plc	10.50	1.26	1.39	11.89	119,260	0.00473	0.0562
eBay Inc.	14.50	1.94	2.22	16.72	27,545	0.00109	0.0183
Edison Int'l	14.00	3.86	4.40	18.40	32,100	0.00127	0.0234
Elevance Health	20.00	1.21	1.45	21.45	125,393	0.00497	0.1066
Emerson Electric	10.00	2.05	2.26	12.26	59,207	0.00235	0.0288
Entergy Corp.	5.50	3.83	4.04	9.54	25,164	0.00100	0.0095
Equifax Inc.	5.00	0.53	0.56	5.56	36,662	0.00145	0.0081
Essex Property Trust	6.50	3.38	3.60	10.10	18,486	0.00073	0.0074
Everest Group	2.00	2.22	2.26	4.26	16,038	0.00064	0.0027
Evergy Inc.	6.50	4.41	4.70	11.20	13,597	0.00054	0.0060
Eversource Energy	5.50	4.44	4.68	10.18	23,349	0.00093	0.0094
Extra Space Storage	17.00	4.09	4.79	21.79	22,322	0.00088	0.0193
FactSet Research	15.00	1.08	1.24	16.24	15,391	0.00061	0.0099
Fastenal Co.	11.00	2.35	2.61	13.61	37,948	0.00150	0.0205
FedEx Corp.	7.00	1.95	2.09	9.09	69,722	0.00276	0.0251
Fifth Third Bancorp	7.50	3.68	3.96	11.46	27,154	0.00108	0.0123
FMC Corp.	9.00	3.94	4.29	13.29	7,667	0.00030	0.0040
Freep't-McMoRan Inc.	19.50	1.43	1.71	21.21	60,183	0.00239	0.0506
Gallagher (Arthur J.)	11.00	0.84	0.93	11.93	62,378	0.00247	0.0295
Garmin Ltd.	13.00	1.76	1.99	14.99	32,683	0.00130	0.0194
Gen Digital Inc.	5.00	2.01	2.11	7.11	15,338	0.00061	0.0043
Gen'l Dynamics	3.00	1.97	2.03	5.03	80,711	0.00320	0.0161
Gen'l Mills	6.50	3.47	3.70	10.20	39,361	0.00156	0.0159
Gen'l Motors	1.00	1.10	1.11	2.11	47,971	0.00190	0.0040

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Genuine Parts	10.50	2.99	3.30	13.80	19,117	0.00076	0.0105
Global Payments	10.00	0.95	1.05	11.05	26,809	0.00106	0.0117
Globe Life Inc.	10.50	1.02	1.13	11.63	8,840	0.00035	0.0041
Goldman Sachs	13.00	2.21	2.50	15.50	161,586	0.00640	0.0993
Grainger (W.W.)	16.50	0.86	1.00	17.50	46,570	0.00185	0.0323
Halliburton Co.	18.00	2.27	2.68	20.68	27,320	0.00108	0.0224
Hartford Fin'l Svcs.	16.50	1.72	2.00	18.50	32,533	0.00129	0.0239
HCA Healthcare	18.00	0.71	0.84	18.84	97,806	0.00388	0.0730
Henry (Jack) & Assoc.	7.50	1.34	1.44	8.94	12,013	0.00048	0.0043
Hershey Co.	10.50	2.81	3.11	13.61	40,578	0.00161	0.0219
Hewlett Packard Ent.	7.00	2.92	3.12	10.12	23,077	0.00091	0.0093
Hilton Worldwide	14.00	0.29	0.33	14.33	52,162	0.00207	0.0296
Home Depot	14.50	2.53	2.90	17.40	352,815	0.01398	0.2433
Honeywell Int'l	3.50	2.19	2.27	5.77	128,375	0.00509	0.0293
HP Inc.	17.50	3.19	3.75	21.25	33,986	0.00135	0.0286
Hubbell Inc.	12.50	1.29	1.45	13.95	20,382	0.00081	0.0113
Humana Inc.	15.00	0.99	1.14	16.14	42,944	0.00170	0.0275
Hunt (J.B.)	12.00	1.09	1.22	13.22	16,688	0.00066	0.0087
Huntington Bancshs.	8.50	4.75	5.15	13.65	19,579	0.00078	0.0106
Huntington Ingalls	1.50	1.95	1.98	3.48	10,468	0.00041	0.0014
IDEX Corp.	11.00	1.45	1.61	12.61	14,672	0.00058	0.0073
Illinois Tool Works	7.00	2.35	2.51	9.51	70,858	0.00281	0.0267
Intercontinental Exch.	11.50	1.15	1.28	12.78	89,457	0.00355	0.0453
Interpublic Group	11.50	4.45	4.96	16.46	11,583	0.00046	0.0076
Iron Mountain	9.00	2.39	2.61	11.61	31,879	0.00126	0.0147

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Jacobs Solutions	13.50	0.83	0.94	14.44	18,016	0.00071	0.0103
Johnson Ctrls. Int'l plc	0.50	2.16	2.17	2.67	45,759	0.00181	0.0048
Johnson & Johnson	9.00	3.16	3.44	12.44	381,437	0.01512	0.1882
JPMorgan Chase	14.50	2.19	2.51	17.01	603,739	0.02393	0.4070
Juniper Networks	1.00	2.27	2.29	3.29	12,618	0.00050	0.0016
KeyCorp	8.00	5.24	5.66	13.66	14,752	0.00058	0.0080
Kimco Realty	0.50	4.50	4.52	5.02	13,650	0.00054	0.0027
KKR & Co.	18.50	0.59	0.70	19.20	104,767	0.00415	0.0797
Kroger Co.	15.00	2.43	2.79	17.79	38,049	0.00151	0.0268
Labcorp Holdings	16.00	1.30	1.51	17.51	18,658	0.00074	0.0129
Lauder (Estee)	9.50	2.88	3.15	12.65	32,855	0.00130	0.0165
Leidos Hldgs.	12.00	1.03	1.15	13.15	19,905	0.00079	0.0104
Lilly (Eli)	11.00	0.56	0.62	11.62	885,472	0.03510	0.4079
LKQ Corp.	14.50	3.05	3.49	17.99	10,407	0.00041	0.0074
Lockheed Martin	13.50	2.29	2.60	16.10	133,483	0.00529	0.0852
Loews Corp.	15.50	0.32	0.37	15.87	17,247	0.00068	0.0108
LyondellBasell Inds.	1.50	0.37	0.38	1.88	31,297	0.00124	0.0023
M&T Bank Corp.	8.00	3.37	3.64	11.64	26,701	0.00106	0.0123
MarketAxess Holdings	11.00	1.23	1.37	12.37	9,141	0.00036	0.0045
Marriott Int'l	9.50	1.16	1.27	10.77	61,418	0.00243	0.0262
Marsh & McLennan	9.50	1.48	1.62	11.12	108,939	0.00432	0.0480
Martin Marietta	15.00	0.58	0.67	15.67	32,389	0.00128	0.0201
Masco Corp.	13.50	1.54	1.75	15.25	16,623	0.00066	0.0100
MasterCard Inc.	15.50	0.57	0.66	16.16	426,108	0.01689	0.2729
McCormick & Co.	5.00	2.15	2.26	7.26	20,942	0.00083	0.0060

	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 (%)
McDonald's Corp.	9.00	2.63	2.87	11.87	195,418	0.00775	0.0919
McKesson Corp.	14.50	0.49	0.56	15.06	72,421	0.00287	0.0432
Medtronic plc	2.00	3.42	3.49	5.49	107,189	0.00425	0.0233
Merck & Co.	4.50	2.71	2.83	7.33	287,664	0.01140	0.0836
Meta Platforms	16.50	0.38	0.44	16.94	1,334,283	0.05289	0.8961
MetLife Inc.	11.00	3.06	3.40	14.40	50,941	0.00202	0.0291
Microchip Technology	18.00	2.37	2.80	20.80	41,901	0.00166	0.0345
Mid-America Apt.	4.00	3.84	3.99	7.99	17,707	0.00070	0.0056
Mondelez Int'l	6.00	2.39	2.53	8.53	95,205	0.00377	0.0322
Moody's Corp.	11.00	0.73	0.81	11.81	84,879	0.00336	0.0397
Morgan Stanley	11.00	3.72	4.13	15.13	161,755	0.00641	0.0970
Motorola Solutions	12.50	0.94	1.06	13.56	69,821	0.00277	0.0375
Nasdaq Inc.	14.00	1.38	1.57	15.57	39,900	0.00158	0.0246
NetApp Inc.	13.50	1.64	1.86	15.36	26,185	0.00104	0.0159
Newmont Corp.	10.50	2.04	2.25	12.75	56,665	0.00225	0.0286
NextEra Energy	12.50	2.77	3.12	15.62	160,311	0.00635	0.0992
NIKE Inc. 'B'	8.50	1.88	2.04	10.54	118,644	0.00470	0.0496
NiSource Inc.	10.50	3.49	3.86	14.36	14,271	0.00057	0.0081
Nordson Corp.	10.50	1.15	1.27	11.77	13,543	0.00054	0.0063
Norfolk Southern	9.50	2.23	2.44	11.94	54,708	0.00217	0.0259
Northern Trust Corp.	3.00	3.54	3.65	6.65	17,101	0.00068	0.0045
Northrop Grumman	12.00	1.67	1.87	13.87	73,964	0.00293	0.0407
NXP Semi. NV	14.50	1.67	1.91	16.41	62,662	0.00248	0.0408
Omnicom Group	4.50	3.02	3.16	7.66	18,479	0.00073	0.0056
ONEOK Inc.	13.00	4.67	5.28	18.28	50,392	0.00200	0.0365

	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 (%)**
Oracle Corp.	10.50	1.18	1.30	11.80	373,578	0.01481	0.1748
PACCAR Inc.	14.50	4.66	5.34	19.84	49,118	0.00195	0.0386
Packaging Corp.	10.00	2.57	2.83	12.83	17,452	0.00069	0.0089
Parker-Hannifin	17.00	1.13	1.32	18.32	74,347	0.00295	0.0540
Paychex Inc.	11.00	3.13	3.47	14.47	45,049	0.00179	0.0258
Pentair plc	3.50	1.11	1.15	4.65	13,758	0.00055	0.0025
PepsiCo Inc.	5.50	3.15	3.32	8.82	238,678	0.00946	0.0835
Pfizer Inc.	15.50	5.82	6.72	22.22	163,663	0.00649	0.1442
Philip Morris Int'l	5.00	4.44	4.66	9.66	182,218	0.00722	0.0698
Phillips 66	13.50	3.38	3.84	17.34	57,637	0.00228	0.0396
Pinnacle West Capital	2.00	4.18	4.26	6.26	9,736	0.00039	0.0024
PNC Financial Serv.	8.50	3.80	4.12	12.62	66,937	0.00265	0.0335
PPG Inds.	1.00	2.27	2.29	3.29	28,110	0.00111	0.0037
Price (T. Rowe) Group	9.00	4.80	5.23	14.23	23,581	0.00093	0.0133
Principal Fin'l Group	5.50	3.74	3.95	9.45	17,839	0.00071	0.0067
Procter & Gamble	8.00	2.39	2.58	10.58	398,391	0.01579	0.1671
Progressive Corp.	8.00	0.17	0.18	8.18	137,253	0.00544	0.0445
Prologis	7.00	3.21	3.43	10.43	114,088	0.00452	0.0472
Prudential Fin'l	2.00	4.67	4.76	6.76	40,001	0.00159	0.0107
Public Serv. Enterprise	4.00	3.06	3.18	7.18	40,094	0.00159	0.0114
Public Storage	5.50	3.74	3.95	9.45	56,197	0.00223	0.0210
Qualcomm Inc.	19.00	2.03	2.42	21.42	186,539	0.00739	0.1583
Quest Diagnostics	14.00	2.00	2.28	16.28	16,633	0.00066	0.0107
Ralph Lauren	7.50	2.08	2.24	9.74	10,035	0.00040	0.0039
Raymond James Fin'l	17.50	1.70	2.00	19.50	23,823	0.00094	0.0184

	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 (%)**
Realty Income Corp.	1.00	5.27	5.32	6.32	35,570	0.00141	0.0089
Regency Centers Corp.	10.50	3.81	4.21	14.71	11,991	0.00048	0.0070
Regions Financial	16.00	4.79	5.56	21.56	19,156	0.00076	0.0164
Republic Services	13.50	1.06	1.20	14.70	63,569	0.00252	0.0370
ResMed Inc.	16.00	0.94	1.09	17.09	32,640	0.00129	0.0221
Rockwell Automation	9.00	1.91	2.08	11.08	29,773	0.00118	0.0131
Rollins Inc.	14.50	1.24	1.42	15.92	23,489	0.00093	0.0148
Roper Tech.	12.00	0.61	0.68	12.68	56,601	0.00224	0.0285
Ross Stores	2.00	1.09	1.11	3.11	47,197	0.00187	0.0058
S&P Global	12.50	0.74	0.83	13.33	154,200	0.00611	0.0815
Schlumberger Ltd.	10.00	2.63	2.89	12.89	62,168	0.00246	0.0318
Schwab (Charles)	10.50	1.53	1.69	12.19	119,412	0.00473	0.0577
Seagate Technology plc	3.50	2.88	2.98	6.48	20,381	0.00081	0.0052
Sempra Energy	13.50	3.21	3.64	17.14	49,817	0.00197	0.0339
Sherwin-Williams	12.50	0.84	0.95	13.45	88,848	0.00352	0.0473
Simon Property Group	1.50	5.16	5.24	6.74	51,529	0.00204	0.0138
Skyworks Solutions	10.00	2.77	3.05	13.05	16,749	0.00066	0.0087
Smith (A.O.)	8.50	1.61	1.75	10.25	11,767	0.00047	0.0048
Smucker (J.M.)	2.00	3.64	3.71	5.71	12,713	0.00050	0.0029
Snap-on Inc.	10.50	3.01	3.33	13.83	14,404	0.00057	0.0079
Southern Co.	3.50	3.30	3.42	6.92	95,435	0.00378	0.0262
Starbucks Corp.	9.00	2.49	2.71	11.71	106,398	0.00422	0.0494
State Street Corp.	5.00	3.96	4.16	9.16	23,624	0.00094	0.0086
STERIS plc	14.50	0.94	1.08	15.58	23,002	0.00091	0.0142
Stryker Corp.	12.00	0.99	1.11	13.11	126,784	0.00503	0.0659

	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 (%)**
Synchrony Financial	15.50	2.16	2.49	17.99	18,302	0.00073	0.0131
Sysco Corp.	3.00	2.68	2.76	5.76	37,923	0.00150	0.0087
T-Mobile US	20.00	1.35	1.62	21.62	229,259	0.00909	0.1965
Tapestry Inc.	9.00	3.69	4.02	13.02	8,723	0.00035	0.0045
Target Corp.	13.50	3.30	3.75	17.25	62,808	0.00249	0.0429
TE Connectivity	7.00	1.79	1.92	8.92	44,184	0.00175	0.0156
Teleflex Inc.	11.50	0.58	0.65	12.15	10,962	0.00043	0.0053
Teradyne Inc.	17.00	0.39	0.46	17.46	19,258	0.00076	0.0133
Texas Instruments	13.00	2.66	3.01	16.01	178,592	0.00708	0.1133
Textron Inc.	7.00	0.09	0.10	7.10	16,123	0.00064	0.0045
TJX Companies	9.00	1.38	1.50	10.50	123,351	0.00489	0.0514
Travelers Cos.	8.50	1.96	2.13	10.63	49,027	0.00194	0.0207
Truist Fin'l	7.50	4.96	5.33	12.83	56,066	0.00222	0.0285
Tyson Foods 'A'	3.00	3.16	3.25	6.25	22,145	0.00088	0.0055
U.S. Bancorp	5.00	4.63	4.86	9.86	66,068	0.00262	0.0258
Union Pacific	11.00	2.20	2.44	13.44	147,078	0.00583	0.0784
United Parcel Serv.	12.00	5.16	5.78	17.78	108,329	0.00429	0.0763
UnitedHealth Group	16.50	1.45	1.69	18.19	533,296	0.02114	0.3845
Universal Health `B'	6.50	0.36	0.38	6.88	14,848	0.00059	0.0041
Verisk Analytics	9.50	0.58	0.64	10.14	38,264	0.00152	0.0154
Verizon Communic.	6.00	6.58	6.97	12.97	172,169	0.00682	0.0885
Visa Inc.	14.50	0.80	0.92	15.42	499,806	0.01981	0.3054
Vulcan Materials	12.00	0.76	0.85	12.85	32,083	0.00127	0.0163
Wabtec Corp.	7.50	0.54	0.58	8.08	27,408	0.00109	0.0088
Walmart Inc.	7.50	1.21	1.30	8.80	552,644	0.02191	0.1928

	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 (%)**
Waste Management	10.00	1.45	1.60	11.60	82,767	0.00328	0.0380
WEC Energy Group	6.00	3.73	3.95	9.95	28,333	0.00112	0.0112
Williams Cos.	19.50	4.38	5.23	24.73	52,892	0.00210	0.0519
Willis Towers Wat. plc	19.50	1.27	1.52	21.02	28,618	0.00113	0.0238
Xcel Energy Inc.	6.50	3.82	4.07	10.57	32,861	0.00130	0.0138
Xylem Inc.	6.50	1.14	1.21	7.71	31,939	0.00127	0.0098
Yum! Brands	10.50	1.95	2.15	12.65	38,570	0.00153	0.0193
Zoetis Inc.	14.50	0.94	1.08	15.58	83,795	0.00332	0.0517
			Totals		25,228,241	1.00	14.57

ROE and ROR Analysis for Summit
CAPM ROE Analysis--Value Line
Calculation for Proxy Group

Docket No. 23-079-U
Exhibit MFG-S-4
Schedule 7

	A	B	C	D	E	F	G
	Market Return	**Rf**	**MRP**	**Beta**	**RP**	**CAPM ROE**	**Filtered Results**
Atmos Energy Corporation	14.57%	4.29%	10.28%	0.85	8.74%	13.03%	13.03%
Chesapeake Utilities	14.57%	4.29%	10.28%	0.80	8.22%	12.51%	12.51%
NiSource	14.57%	4.29%	10.28%	0.95	9.77%	14.06%	14.06%
Northwest Natural Holding Co.	14.57%	4.29%	10.28%	0.85	8.74%	13.03%	13.03%
Southwest Gas Holdings	14.57%	4.29%	10.28%	0.85	8.74%	13.03%	13.03%
ONE Gas, Inc.	14.57%	4.29%	10.28%	0.90	9.25%	13.54%	13.54%
Spire, Inc.	14.57%	4.29%	10.28%	0.85	8.74%	13.03%	13.03%
					Mean	13.17%	13.17%
					Median	13.03%	13.03%

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)	5.73%
	CAPM Risk Premium, Column C	10.28%
	20 percent of CAPM risk premium	2.06%
	Moody's 10-Year Baa Corporate Bond Index + 20 percent of CAPM risk premium	7.79%

High-End Test:	Proxy Group median, Column F	13.03%
	150 percent of Proxy Group median	19.54%
	200 percent of Proxy Group median	26.06%

ROE and ROR Analysis for Summit | **Docket No. 23-079-U**
CAPM ROE Analysis | **Exhibit MFG-S-4**
Average of Low-End Tests for Kroll and Value Line | **Schedule 8**

Kroll Low-End Test:	Moody's 10-Year Baa Corporate Bond Index, S&P Global Market Intelligence. MFG-15, Schedule 3	5.73%
	CAPM Risk Premium, Kroll, MFG-15, Schedule 5	5.00%
	20 percent of CAPM risk premium	1.00%
	Moody's 10-Year Baa Public Corporate Bond Index + 20 percent of CAPM risk premium	6.73%

Value Line Low-End Test:	Moody's 10-Year Baa Corporate Bond Index, S&P Global Market Intelligence. MFG-15, Schedule 3	5.73%
	CAPM Risk Premium, Value Line, MFG-15, Schedule 7	10.28%
	20 percent of CAPM risk premium	2.06%
	Moody's 10-Year Baa Public Corporate Bond Index + 20 percent of CAPM risk premium	7.79%

Mean of Value Line and Kroll Low-End Tests 7.26%

ROE and ROR Analysis for Summit
Summary of ROE Analyses and Recommended ROE

Docket No. 23-079-U
Exhibit MFG-S-5
Schedule 1

Analysis	Weight		ROE	Exhibit
Constant-Growth DCF		**Mean**	9.92%	Exhibit MFG-S-3, Schedule 1
		Median	9.87%	
Multistage DCF		**Mean**	9.27%	Exhibit MFG-S-3, Schedule 2
		Median	9.48%	
CAPM Kroll Market Risk Premium		**Mean**	8.61%	Exhibit MFG-S-4, Schedule 5
		Median	8.54%	
CAPM S&P 500 Value Line		**Mean**	13.17%	Exhibit MFG-S-4, Schedule 7
		Median	13.03%	
DCF and CAPM Value Line results		**Mean**	10.24%	
		Median	10.23%	
CAPM Kroll and Value Line results excluded		**Mean**	9.59%	
		Median	9.67%	

		2121	**2022**	**2023**
Recently awarded ROEs	**Mean**	9.56	9.53	9.60
	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

ROE Range for Summit Utilities	9.59%-9.67%
Initial ROE for Summit Utilities Arkansas	9.63%
Less: Move to Bottom of Range for Billing Practices Penalty	-0.04%
Recommended ROE for Summit Utilities Arkansas	9.59%

ROE and ROR Analysis Summit
Capital Structure Analysis
Proxy Group Ratios

S&P Capital IQ PRO

S&P Market Intelligence website, downloaded August 27, 2024
In thousands of dollars

Company Name	2024Q2	2024Q1	2023Q4	2023Q3	2023Q2	2023Q1	2022Q4	2022Q3	Average 2022Q3-2024Q2
			Average Long-Term Debt for each quarter						
Atmos Energy Corporation	7,696,287	7,527,695	7,181,468	6,738,154	6,597,871	6,552,446	6,248,372	5,852,056	6,799,293
Chesapeake Utilities	1,189,551	1,196,312	926,233	656,084	662,861	629,587	593,794	598,210	806,579
NiSource, Inc.	12,267,100	11,402,950	11,046,300	11,007,050	10,633,750	9,910,100	9,538,350	9,520,700	10,665,788
Northwest Natural Holding Company	1,651,615	1,577,194	1,502,325	1,437,288	1,372,711	1,349,012	1,345,304	1,244,916	1,435,045
ONE Gas, Inc.	2,146,642	2,160,532	2,018,651	1,869,407	1,875,893	2,277,358	2,554,098	2,356,459	2,157,380
Southwest Gas Holdings, Inc.	4,856,268	4,694,173	4,987,463	5,260,192	4,931,222	4,546,128	5,190,124	5,227,023	4,961,574
Spire Inc.	3,421,850	3,334,600	3,436,000	3,588,750	3,627,900	3,429,400	3,094,250	3,120,050	3,381,600

Company Name	2024Q2	2024Q1	2023Q4	2023Q3	2023Q2	2023Q1	2022Q4	2022Q3	Average 2022Q3-2024Q2
			Average Short-Term Debt for each quarter						
Atmos Energy Corporation	9,607	10,538	150,363	148,378	4,513	1,101,498	2,313,276	2,313,249	756,428
Chesapeake Utilities	209,741	196,079	170,871	129,552	118,152	172,161	208,764	176,167	172,686
NiSource, Inc.	956,850	2,163,500	2,663,700	1,933,000	1,465,600	1,554,300	1,549,750	947,550	1,654,281
Northwest Natural Holding Company	89,670	170,300	253,261	273,495	299,179	332,662	271,693	208,671	237,366
ONE Gas, Inc.	1,020,646	938,255	1,011,145	1,075,757	1,055,689	829,984	623,070	1,281,762	979,538
Southwest Gas Holdings, Inc.	414,482	694,278	400,810	78,728	283,514	1,061,331	1,017,870	963,254	614,283
Spire Inc.	1,085,500	1,298,750	1,311,700	1,041,550	890,900	1,150,600	1,404,400	1,032,800	1,152,025

Company Name	2024Q2	2024Q1	2023Q4	2023Q3	2023Q2	2023Q1	2022Q4	2022Q3	Average 2022Q2-2024Q1
			Average Common Equity for each quarter						
Atmos Energy Corporation	11,900,858	11,445,924	11,071,637	10,736,223	10,403,793	10,020,740	9,627,683	9,343,631	10,568,811
Chesapeake Utilities	1,285,729	1,263,504	1,056,391	865,453	861,408	845,695	823,620	815,070	977,108

ROE and ROR Analysis Summit
Capital Structure Analysis
Proxy Group Ratios

NiSource, Inc.	7,882,450	7,201,250	6,283,200	6,068,800	6,102,750	5,970,050	5,621,650	5,446,250	6,322,050
Northwest Natural Holding Company	1,345,051	1,313,612	1,251,689	1,229,909	1,244,293	1,211,874	1,148,149	1,129,818	1,234,299
ONE Gas, Inc.	2,828,429	2,797,931	2,706,312	2,650,787	2,653,153	2,617,953	2,515,350	2,449,935	2,652,481
Southwest Gas Holdings, Inc.	3,424,503	3,333,139	3,274,391	3,250,786	3,279,491	3,177,458	3,235,837	3,435,884	3,301,436
Spire Inc.	3,119,750	2,978,550	2,742,050	2,682,900	2,717,500	2,683,300	2,599,300	2,590,200	2,764,194

Company Name	**Average Total Capital 2022Q3-2024Q2**		**Long-Term Debt %**	**Short-Term Debt %**	**Common Equity %**	
Atmos Energy Corporation	18,124,532		37.51%	4.17%	58.31%	100.00%
Chesapeake Utilities	1,956,373		41.23%	8.83%	49.94%	100.00%
NiSource, Inc.	18,642,119		57.21%	8.87%	33.91%	100.00%
Northwest Natural Holding Company	2,906,711		49.37%	8.17%	42.46%	100.00%
ONE Gas, Inc.	5,789,399		37.26%	16.92%	45.82%	100.00%
Southwest Gas Holdings, Inc.	8,877,293		55.89%	6.92%	37.19%	100.00%
Spire Inc.	7,297,819		46.34%	15.79%	37.88%	100.00%
	Proxy Group	**Average %**	46.40%	9.95%	43.65%	100.00%
	w/o ONE Gas and Spire	**Average %**	48.24%	7.39%	44.36%	100.00%
Capital structure requested by Summit Utilities Arkansas			44.41%	0.00%	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%

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%	1.5586%
Preferred Stock	-	-	-			-	-	-
Common Equity	1,084,753,299	109,981,190	1,194,734,489	(513,782,209)	680,952,280	46.6661%	11.0000%	5.1333%
Accumulated Deferred Income Taxes	(16,817,228)	(4,120,998)	(20,938,226)	20,938,226	0	0.0000%	0.0000%	0.0000%
Excess Deferred Income Taxes	99,155,814	(3,022,298)	96,133,516		96,133,516	6.5881%	0.0000%	0.0000%
Pre-1971 ADITC	-	-	-			-	-	0.0000%
Post-1970 ADITC	-	-	-			-	-	0.0000%
Customer Deposits	5,070,887	2,200,403	7,271,290		7,271,290	0.4983%	2.5649%	0.0128%
Short-Term Debt						0.0000%	5.5500%	0.0000%
Current, Accrued and Other Liabilities	162,540,354	(31,806,060)	130,734,294		130,734,294	8.9593%	0.0000%	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%		6.7046%

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.

Office of the Attorney General Recommended ROE and ROR

	Proportion	Cost	WACC
Long-Term Debt	38.62%	3.39%	1.31%
Preferred Stock	0.00%	0.00%	0.00%
Common Equity	38.62%	9.59%	3.70%
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%		5.40%

ROE Source: The recommended common equity cost of 9.60 percent is taken from the ROE analysis in Exhibit MFG-S-5, Schedule 1. The cost of short-term debt is taken from Direct Exhibit DD-5 of General Staff witness Dan Daves. 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 base rate case Docket No. 23-074-U.

Other Cost Sources: The cost of customer deposits is that proposed by Summit Utiitilities Arkansas in Schedule D-1.3. Any discrepancies between this exhibit and Schedule D-1.3 are due to rounding.

CERTIFICATE OF SERVICE

I, Dawn R. Kelliher, hereby certify that on September 9, 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/ Dawn R. Kelliher
Dawn R. Kelliher

BEFORE THE
ARKANSAS PUBLIC SERVICE COMMISSION

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

SURREBUTTAL TESTIMONY
OF
MICHAEL J. MAJOROS

ON BEHALF OF

THE OFFICE OF ARKANSAS ATTORNEY GENERAL
TIM GRIFFIN

July 10, 2024

TABLE OF CONTENTS

I. INTRODUCTION

Q. PLEASE STATE YOUR NAME.

A. My name is Michael J. Majoros, Jr.

Q. ARE YOU THE SAME MICHAEL J. MAJOROS, JR. THAT FILED DIRECT TESTIMONY IN THIS MATTER?

A. Yes.

Q. WHO ARE YOU REPRESENTING 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 SURREBUTTAL TESTIMONY?

A. I am responding to Mr. Watson's rebuttal to my direct testimony.

Q. WHAT DOES MR. WATSON SAY ABOUT YOUR DIRECT TESTIMONY?

A. Mr. Watson asserts that my ".… approach is a clear departure from widely held depreciation methodologies, this Commission's prior approvals, the majority of Commissions in the country, as well as Staff's recommendations in this case."[1] He opines that my "recommendations should be disregarded in their entirety."[2]

Q. DOES MR. WATSON ASSERT OR CLAIM THAT YOUR RECOMMENDATIONS WOULD DENY THE COMPANY RECOVERY OF ITS CAPITAL EXPENDITURES?

A. No.

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[1] Document No. 139, Rebuttal Testimony of Dane A. Watson ("Watson Rebuttal"), page ES-1.

[2] *Id.*

II. THEORETICAL RESERVE CALCULATION

Q. MR. WATSON ASSERTS THAT YOU DID "NOT MAKE THE THEORETICAL RESERVE COMPUTATION CORRECTLY."[3] WHAT IS YOUR RESPONSE?

A. I correctly used the "Prospective Method" to calculate the Theoretical Reserve of $396.7 million which indicates a $191.2 million depreciation reserve excess The Prospective Method is discussed at pages 189 to 191 of the National Association of Regulatory Utility Commissioners' August 1996 Public Utility Practices Manual. The calculation can be tracked by following the formula shown at the top of page 190 of the Manual and the formula at the top of column (k) of my Exhibit MJM-12.

Q. WHY DOES MR. WATSON SAY YOUR THEORETICAL RESERVE CALCULATION IS INCORRECT?

A. Mr. Watson disagrees with my recommendations to use different service lives for the Company's Mains and Services accounts. I used alternative lives directly from Mr. Watson's studies, but they are longer than Mr. Watson proposes. Mr. Watson disagrees with the longer lives and with my calculated remaining lives using the longer service lives.

III. AVERAGE SERVICE LIVES OF MAINS AND SERVICES

Q. WHY DOES MR. WATSON DISAGREE WITH YOU RECOMMENDED SERVICE LIVES FOR MAINS AND SERVICES?

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[3] Watson Rebuttal, page 6, lines 9-10.

A. Mr. Watson proposes a 65-year average service life for the Company's Mains and a 38-year average service life for the Company's Services. I propose a 70-year average service life for Mains and a 50-year average service life for Services. Mr. Watson asserts that I did not incorporate "vital depreciation study input" about the lives of mains and services from Company personnel and Subject Matter Experts.[4] However, Mr. Watson's assertion is incorrect.

I specifically agreed with that information from Company personnel and Subject Matter Experts and in fact quoted it at page 15 of my Direct Testimony.[5] I also conducted a Geometric Mean Turnover analyses to better understand the expert information combined with Mr. Watson's statistical life studies of the Services account.[6] The Company personnel and Subject Matter Experts themselves indicate that the Company's expedited replacement program had little impact on the life of Mains and that the life of Services will increase when the program ends.

IV. GEOMETRIC MEAN TURNOVER (GMT) ANALYSIS

Q. HOW DO YOU RESPOND TO MR. WATSON'S STATEMENT THAT "GIVEN THE ABUNDANT AGED DATA AVAILABLE, IT IS UNUSUAL TO PRESENT AN UNAGED LIFE ANALYSIS APPROACH AS MR. MAJOROS HAS DONE"?[7]

A. Mr. Watson conducted several different life-analyses of the Services account. His studies indicted some very short lives and a couple of much longer lives. Given the magnitude of

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[4] Watson Rebuttal, page 5, lines 17–18.
[5] Document 116, Direct Testimony of Michael J. Majoros ("Majoros Direct"), page 15, lines 6–13.
[6] Majoros Direct pages 16-17 and Exhibit-MJM-7.
[7] Watson Rebuttal, page 19, lines 9-10.

the Services account, I conducted a Geometric Mean Turnover Analysis ("GMT") to understand the major discrepancies in Mr. Watson's results. The GMT is not antiquated as Mr. Watson infers; it is merely a different approach to life analyses. Turnover analyses are used regularly in business.

Mr. Watson prefers the visual inspection approach to selecting his proposed average service lives from his own studies. The Company informed him that when the System Safety Enhancement program (SSER) accelerated replacement programs ceases the Services life would get longer. He nonetheless adopted a short 38-year life even though he had other "smooth" studies which supported a life in the 50-year range.

I concur that the GMT is based on the turnover of annual (unaged) dollars in the Services account. At a summary level, the GMT illustrates the impact of the SSER program to date. It reduced the life of the Services account. But, I did not conduct the GMT to estimate a life, I conducted it to understand the discrepancy between Mr. Watson's 38-year studies and his 50-year studies. Visual examination of Mr. Watson's 38-year curve chart reveals that retirements at the tail end of the curve draw down (shorten) that life indication, but that does not explain why Mr. Watson's other studies indicated a life in the 50-year range.[8]

The GMT provided the answer. It revealed that the retirements resulting from the accelerated replacement program were immaterial relative to the annual additions. Thus, I concluded additions were the primary driver of life indications. Mr. Watson's 50-year life

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[8] *See*, Direct Exhibits of Michael J. Majoros, MJM-6, Copies of all Watson Life Study Charts for Account 380, pages 14-20 and 22-24.

indications did not give as much weight to recent retirements as his 38-year indications. Hence, I concluded that Mr. Watson's 50-year indication is more reasonable given: 1) his aged studies, 2) the information provided by Company personnel and Subject Matter Experts, and 3) the information provided by the GMT.

V. AVERAGE REMAINING LIVES OF MAINS AND SERVICES

Q. WHAT INACCURACIES DOES MR. WATSON CLAIM TO EXIST IN YOUR TESTIMONY?

A. I recommend different average service lives for account 376-Mains and 380-Services than Mr. Watson recommends. My recommendations are drawn directly from his own studies. I used the age/life approach to estimate the remaining lives associated with those two average service lives. Mr. Watson says my remaining lives for those two accounts are inaccurate.[9]

Q. WHAT IS THE AGE/LIFE APPROACH?

A. The age/life concept is fundamental to depreciation. Depreciation is the process of allocating the cost of a tangible asset over its useful life. The useful life of an asset is the period over which it is expected to be used by the business, and this period is critical in determining the amount of depreciation expense that will be recognized each year.

There are different methods of calculating depreciation, such as:

Straight-Line Depreciation: The asset's cost is evenly spread over its useful life.

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[9] Watson Rebuttal, page 6, lines 9–11.

Declining Balance Method: A higher depreciation expense is recorded in the earlier years of the asset's life, with the expense decreasing over time.

Units of Production Method: Depreciation is based on the asset's usage or output rather than time.

In all these methods, the useful life or age of the asset is a key factor in determining the annual depreciation expense. Therefore, the concept of age and useful life is fundamental to the depreciation process.

Q. HOW DOES ONE CALCULATE A REMAINING LIFE USING THE AGE/LIFE APPROACH?

A. The calculation is straight forward and easy to understand. Assume an asset has a 10-year life and is 6-years old; its remaining life is 4 years as calculated below:

Age/Life Approach		
Life	10	Years
Age	6	Years
Remaining Life (a. – b.)	4	Years

Q. WHAT WAS THE SOURCE OF THE LIVES AND AGES YOU USED TO IMPLEMENT THE AGE/LIFE APPROACH FOR THE COMPANY'S MAINS AND SERVICES ACCOUNT?

A. The lives and the ages are from Mr. Watson's study and workpapers.

Q. WHAT IS THE ISSUE WITH THIS APPROACH?

A. The age/life approach is an acceptable approach to estimate a remaining life. The issue here is Mr. Watson's use of understated average service lives for Mains and Services as explained in my direct testimony and above.

VI. NET SALVAGE AND COST OF REMOVAL

Q. WHAT ARE THE DIFERENCES BETWEEN YOUR AND MR. WATSON'S NET SALVAGE AND COST OF REMOVAL RECOMMENDATIONS?

A. There are two major differences between Mr. Watson's net salvage and cost of removal recommendations and my net salvage and cost of removal recommendations.

1. Mr. Watson inflates his cost of removal ratios I have removed the inflation from Mr. Watson's cost of removal ratios so that current customers are not charged for future inflation that has not been incurred. I used the same approach and reference source (The Handy-Whitman Index) that Mr. Warson used.

2. This Company allocates a portion of the original cost of replacement assets to cost of removal to provide the beginning inputs to Mr. Watson's inflation process as identified and described above.[10] I made an adjustment to remove the estimated portion of cost of removal for Mains and Services relating to replacements.

VII. REPLACING AND REPLACEMENTS

Q. WHAT IS YOUR RESPONSE TO MR. WATSON'S CRITISIM THAT YOUR "RECOMMENDATIONS REGARDING NET SALVAGE AND COST OF

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[10] Also see, Majoros Direct pages 19, 23-26, Exhibits MJM-9, MJM-10, MJM-11 Col. (o).

REMOVAL WOULD SHIFT REMOVAL COST TO BECOME A CAPITAL ITEM WHICH IS ADDED TO NEW ADDITIONS?"[11]

A. The issue is that the Company shifts replacement costs to cost of removal in contravention of the FERC Uniform System of Accounts. The Company shifts an arbitrary portion of the *original co*st of replacements to cost of removal. After the shift, Mr. Watson inflates the shifted cost of removal.

As stated in the USOA's prescribed accounting for replacement additions,[12] one hundred percent of the original cost of a replacement, including the cost to remove the replaced asset, is a capital item.[13] But this Company allocates an arbitrary portion of the cost of replacement additions to cost of removal to unjustly maximize its depreciation expense. The USOA requires that 100 percent of the original cost of replacement additions are required to be capitalized to plant in service.

Q. DID YOU MAKE AN ADJUSTMENT TO ACCOUNT FOR THE COMPANY'S SHIFT OF CAPITALIZED REPLACEMENT COSTS TO COST OF REMOVAL?

A. Yes. I reduced the deflated cost of removal ratios for the Mains and Services accounts by 33 percent to account for the Company's allocation of capital costs to cost of removal for these two major accounts.

Q. WHAT WAS MR. WATSON'S RESPONSE TO THE 33 PERCENT ADJUSTMENT?

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[11] Watson Rebuttal, page 2, lines 17–18.
[12] Majoros Direct, page 19, line 1 through page 20, line 19.
[13] Federal Energy Regulatory Commission, Unform System of Accounts (USOA) for Gas Utilities, Definitions 6, 9, 10, 26, 32 and Gas Plant Instruction 2.A

A. Mr. Watson believes the adjustment should be 67 percent which would further reduce the amount of cost of removal for these two accounts.

Q. DO YOU THINK THE ADJUSTMENT SHOULD BE HIGHER?

A. I have no objection to raising the adjustment, however, the adjustment should apply to almost all of the Company's plant accounts since most of the additions to its accounts are driven by replacements. That is why I recommended that the Company discontinue the practice of allocating capital costs to cost of removal for replacement projects. If the company were to cease that practice, most of these problems would end.

Q. WHAT IS YOUR RESPONSE TO MR. WATSON'S STATEMENT THAT "TO MY KNOWLEDGE, THE COMPANY AND THIS COMMISSION HAVE ALWAYS APPROVED TRADITIONAL NET SALVAGE, COMPUTED AS STAFF WITNESS MR. ROBERTSON AND I HAVE DONE"?[14]

A. I recommend that the Commission and Staff consider the totality of the circumstances surrounding these depreciation issues that indicate an update to methodology is warranted.

Q. DOES THIS CONCLUDE YOUR SURREBUTTAL TESTIMONY?

A. Yes, it does.

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[14] Watson Rebuttal, page 26, lines 4–5.

CERTIFICATE OF SERVICE

I, Dawn Kelliher, hereby certify that on September 9, 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/ Dawn Kelliher
Dawn Kelliher

APSC FILED Time: 9/9/2024 11:03:31 AM: Recvd 9/9/2024 11:01:46 AM: Docket 23-079-U-Doc. 151

BEFORE THE ARKANSAS
PUBLIC SERVICE COMMISSION

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

SURREBUTTAL TESTIMONY
OF
DANTE MUGRACE

ON BEHALF OF

THE OFFICE OF ARKANSAS ATTORNEY GENERAL

TIM GRIFFIN

September 9, 2024

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I. INTRODUCTION AND BACKGROUND

Q. PLEASE STATE YOUR NAME.

A. My name is Dante Mugrace.

Q. ARE YOU THE SAME DANTE MUGRACE WHO FILED DIRECT TESTIMONY IN THIS DOCKET?

A. Yes.

Q. WHAT IS THE PURPOSE OF YOUR SURREBUTTAL TESTIMONY?

A. The purpose of my surrebuttal testimony is to address the rebuttal testimony of Summit Utilities Arkansas, Inc.'s ("SUA" or "Company") witness Mr. Sam Springer with respect to the following incentive compensation costs included in the Company's base rate case proceeding:

- Incentive compensation related to SUA Employees.
- Costs related to Retention and Sign-On Bonuses.

II. RESPONSE REGARDING INCENTIVE COMPENSATION COSTS

Q. WHAT DID MR. SPRINGER STATE REGARDING YOUR EXCLUSION OF CERTAIN INCENTIVE COMPENSATION ITEMS?

A. Mr. Springer stated that:

- Incentive compensation programs as they are appropriately named, incentivizes employees to achieve high impact results;
- At SUA, these results are aimed at furthering and improving upon the Company's mission to safely provide affordable and reliable energy solutions to its customers;[1]

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[1] Document No. 135, Rebuttal Testimony of Sam Springer ("Springer Rebuttal"), page 2, line 27 through page 3, line 11.

- The incentive compensation component of the Company's total compensation package enables it to compete for talent in a challenging market;
- Including an incentive pay component in the total compensation package leads to more successful attraction and retention of talent; and
- It helps employees focus on goals of various types that work in tandem to benefit customers and further the Company's ability to provide quality service to customers.[2]

Q. WHAT IS YOUR RESPONSE?

A. I accept that incentive compensation programs are an inherent and integral part of an employee's overall compensation package. However, I believe that certain of the Company's incentive programs should not be recovered from ratepayers because they do not directly benefit ratepayers. In addition, they should not be recovered from ratepayers because they do not relate to customer-oriented service that address ratepayer utility service in the form of safety and reliability including but not limited to customer satisfaction, customer inquiries, and customer appointments.

Ratepayers should not pay those portions of earnings-based or stock value-based incentives if the company's and the ratepayers' interests are misaligned.

Q. WHAT DID MR. SPRINGER STATE REGARDING THE COMPANY'S FINANCIAL GOALS BENEFITTING CUSTOMERS?

A. Mr. Springer stated the Company must be financially stable and healthy to maintain operations, continue investing in its system, and have the workforce necessary to meet

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[2] Springer Rebuttal, page 3, lines 1-6.

customer needs and provide quality customer service. Having goals that motivate employees to focus on building and maintaining a financially strong utility is critical to meeting customer needs. He further stated that a financially strong utility is able to attract investors who provide access to capital the Company needs to operate. All employees play a role in making sure the Company's financial resources are used efficiently and effectively.[3] Mr. Springer stated that the Company's financial Scorecard goals of "Audited Financial Statements Issues" and "Monthly Financial Reports Issues" "encourage employees to focus on ensuring that the financial outcomes of specific projects and other expense across SUA are being managed responsibly and achieving the intended results."[4]

Q. WHAT IS YOUR RESPONSE?

A. The Company claims that these incentive compensation costs are necessary to meet customer needs and provide quality service to customers. However, the Company has the responsibility to provide safe and reliable utility service at all times. Absent recovery of certain incentive compensation, the Company is still responsible and still accountable to provide safe and reliable service.

Q. WHAT DID MR. SPRINGER STATE WITH RESPECT TO FINANCIAL GOALS HELPING EMPLOYEES FOCUS ON ACTIVITIES THAT SUPPORT AND FURTHER CUSTOMER INTERESTS?

A. Mr. Springer stated that identifying goals that focus employee attention on these issues leads to management and operational efficiencies that help the Company manage costs, enhance operations, and support customer service. These goals also ensure that the

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[3] Springer Rebuttal, page 4, lines 5-8, lines 9-12.

[4] Springer Rebuttal, page 5, lines 10-13.

Company is able to fulfill its regulatory obligations in a timely and accurate manner, which is also critical for a regulated utility.[5]

Q. WHAT IS YOUR RESPONSE?

A. I believe that the goals of the Company with respect to regulatory obligations, management and operational efficiencies, and managing costs are clearly within the realm of the responsibility of the Company rather than its ratepayers. The financial incentive with respect to these goals appear to be in the sphere and scope of the Company and are not the responsibility or the burden that ratepayers should be required to absorb. The regulatory compact provides public utilities with certain guarantees such as reasonable opportunities to recover costs and earn a fair rate of return on investments. Reasonable opportunities to recover costs are not guarantees of recovery, including certain costs related to financial incentive compensation. If these financial incentive costs are not recovered from ratepayers as the Company has stated, then these costs will ultimately be funded by the Company.

Q. WHAT DID MR. SPRINGER STATE REGARDING NO ALLOWANCE OF RECOVERY OF STI COSTS FOR MEETING FINANCIAL TARGETS?

A. Mr. Springer explains that my opposition to recover STI-related financial costs is because I claim that shareholders benefit from these goals and customer do not. Mr. Springer stated that my position is narrow and short-sighted.[6] His position is that customers care about how the Company manages its finance to complete projects and improve its operations because those issues affect rates and service.[7] Having a corporate goal that focuses all

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[5] Springer Rebuttal, page 5, lines 13-17.
[6] Springer Rebuttal, page 6, lines 1-2.
[7] Springer Rebuttal, page 6, lines 2-4.

employees across the Company on doing their part and linking a portion of their total compensation to financial outcomes is something that makes the Company more likely to achieve outcomes that meet these high expectations while remaining reasonable in terms of total compensation being provided to its employees.[8]

Q. WHAT IS YOUR RESPONSE?

A. Ratepayers are primarily focused on paying their bills, receiving adequate utility service. They are concerned with the increase in their utility bills.

Part of the Company's argument is that in order to provide safe and reliable service to its customers, it has to incentivize employees in order to focus on and achieve sound fiscal management. The Company claims that without appropriate financially metric-related incentive compensation, employees would not be able to perform their duties. This is contrary to what the Company is obligated to do with respect to safe and reliable utility service. I see no further information included in the filing that substantiates the claim that such financial incentive type costs benefit ratepayers in the areas of safe and reliable utility service.

Q. WHAT DID MR. SPRINGER STATE WITH RESPECT TO RELYING ON A COMBINATION OF STI GOALS INCLUDING FINANCIAL GOALS?

A. Mr. Springer stated that the goals are developed with the purpose of ensuring the Company is improving in all aspects of its business. These ongoing improvements and the evolution of the business make certain that the Company remains healthy and competitive for its

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[8] Springer Rebuttal, page 6, lines 8-12.

customers, offering them the service levels they expect.[9] Mr. Springer stated that a financially strong utility allows the Company to better serve customers.[10]

Q. WHAT IS YOUR RESPONSE?

A. The Company has the right and the opportunity to provide its employees with market-based and comparable total compensation packages. While the Company assumes that such compensation may be at a fair and reasonable level to include in rates, there should be no assumption that all these costs should be recovered. The Company has the opportunity to recover these costs for ratemaking purposes only if they are prudent and reasonable and inure to the benefit of ratepayers. It is not the responsibility of ratepayers to pay for the costs related to the STI particularly in the area of financially related metric goals; the Company has a responsibility to share the burden of these types of costs.

I am not arguing for elimination of these incentive programs. While I understand the importance of providing incentive compensation to employees, I do not believe that certain incentive compensation should be recoverable from ratepayers and should only be recoverable from ratepayers where the incentive compensation provide specific benefits in the form of customer services, satisfaction, safety, and reliability.

Q. HOW DID MR. SPRINGER RESPOND TO YOUR RECOMMENDED DISALLOWANCE OF THE ENVIRONMENTAL, SOCIAL, AND GOVERNANCE (“ESG”) METRIC COSTS?

A. Mr. Springer disagreed with my disallowance of ESG costs from the Company’s incentive compensation. His position is that ESG evaluates a company’s internal business practices

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[9] Springer Rebuttal, page 4, lines 15-18.
[10] Springer Rebuttal, page 4, lines18-19.

and the company's impact on the communities in which it operates. Managing to the high standards set by ESG produces higher quality service, more efficient operations, and promotes higher level of customer safety.[11] He said ESG companies focus on managing risks effectively and that supporting companies that follow ESG practices ensures long-term sustainability and resilience, offering financial benefits and increased safety for customers, while benefitting communities and the environment of the areas in which they operate. Mr. Springer further stated that ESG directly impacts customers in a positive way because it is purely focused on the Company being transparent and accountable to its customers in every facet of the business.[12]

Q. WHAT IS YOUR RESPONSE?

A. I continue to recommend disallowance of the Company's ESG costs included in the Company's Corporate Excellence 2024 Score Card incentive compensation. These types of costs solely benefit the Company related to its shared vision, strategies, investments in the communities, better access to capital, and attracting outside investor to invest in the Company. These initiatives are clearly within the domain and discretion of the Company, and ratepayers should not be burdened or be required to pay for these costs.

The Company has not provided any results with respect to incorporating these ESG initiatives in this proceeding. If the Company believes that there is value in implementing these costs in rates, the Company should shoulder the burden of funding these costs. ESG costs encompass data and metrics needed to inform decision-making compensation,

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[11] Springer Rebuttal, page 8, lines 7-10.
[12] Springer Rebuttal, page 8, lines 11-16.

succession planning, board management practices, and shareholder rights which are distinctly in the spectrum of the Company's responsibilities.

Q. WHAT CONSEQUENCES DID MR. SPRINGER ALLEGE WOULD RESULT IF SUA DID NOT PROVIDE STI, BUT RATHER MOVED THAT FORM OF COMPENSATION TO EMPLOYEE BASE PAY?

A. Mr. Springer alleges that employee motivation to go above and beyond in order to achieve hard-to-obtain results would be compromised if every pay day, employees would be paid the same regardless of whether they simply meet expectations or go above and beyond.[13] To carve out a percentage of every employee's reasonable, yet competitive total compensation amount and offer that compensation in the form of STI, creates no additional cost for customers, but ensures that there is an incentive for employees to go above-and-beyond because employees who do are reasonably compensated for doing so.[14]

Q. WHAT IS YOUR RESPONSE?

A. The Company has the right to provide its employees with market-based pay comparable to what other companies provide in order to stay competitive in the industry. The Company supposes that compensation packages are required to establish metrics or measurements to determine oriented results of its employees. Further, there is no expectation that all employees are will be motivated in the same manner or behave in the same fashion. There is no assumption that these compensation packages are expected to be recovered in rates through regulatory proceedings.

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[13] Springer Rebuttal, page 8, lines 22-23 through page 9, line 1.
[14] Springer Rebuttal page 9, lines 1-5.

I am not arguing for eliminating incentive compensation costs and packages. I am proposing that the costs that are not ratepayer-oriented should not be recovered from ratepayers. Non-customer-oriented costs should be the responsibility of the Company as it is the Company that reaps the benefits.

Q. DID MR. SPRINGER'S DISCUSSION OF THE RECOVERY OF FINANCIALLY RELATED INCENTIVE COMPENSATION IMPACT YOUR OPINION?

A. No. Ratepayers should not be burdened by costs that are primarily geared toward providing benefits to company shareholders. Costs are and should be based upon prudent use of ratepayer money, as well as reasonable and appropriate uses in the day-to-day operations of the Company. The Company should not expect to assume that all its proposed expenses are to be recovered in rates, but rather only those expenses that are reasonable and prudent in nature and provide specific benefits to ratepayers.

III. <u>RESPONSE REGARDING RETENTION AND SIGN-ON BONUSES</u>

Q. WHAT DID MR. SPRINGER STATE REGARDING THE NEED FOR THE RETENTION AND SIGN-ON BONUS COSTS THAT YOU PROPOSED TO DISALLOW?

A. Mr. Springer stated that the need for these costs is to ensure that critical talent is focused on staying and accomplishing critical work for the Company and also as a means to allow the Company to recruit talent. Mr. Springer stated that retention payments have been made to 1.8% of employees who are in the most critical roles with the Company. Sign-on bonuses serve a number of purposes to enable the Company to bring talent into the Company.[15]

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[15] Springer Rebuttal, page 10 lines 18-22.

Q. WHAT IS YOUR RESPONSE?

A. I continue to recommend disallowance of the Company's retention and sign-on bonuses. Although Mr. Springer stated that it has not had a single retention or sign-on bonus repaid, I believe these costs are clearly to the benefit of the Company. Ratepayers should not be required to pay for incentivizing employees to ensure that employees will stay on with the Company, maintaining a workforce, and encouraging employees to stay with the Company. These are undoubtedly human resource and personnel-related issues that should be paid for by the Company.

Q. WHAT DID MR. SPRINGER STATE WITH RESPECT TO EMPLOYEES WHO RECEIVE RETENTION AND SIGN-ON BONUSES AND THEN LEAVE THE COMPANY?

A. Mr. Springer stated that both types of compensation are accompanied by repayment agreements. [16] Mr. Springer stated that to date the Company has not had a single retention or sign-on bonus repaid which shows that these programs achieve their intended purpose of attracting and retaining employees. [17]

Q. WHAT IS YOUR RESPONSE?

A. The fact that employees do stay with the Company with the implementation of these retention and sign-on bonuses does not negate the fact that ratepayers should not shoulder the burden of paying for these human resource-related costs. These are clearly Company organizational functions and internal decisions. Although Mr. Springer stated that these retention and sign-on bonuses ensure that critical talent and key employees remain with the

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[16] Springer Rebuttal, page 11, line 10.
[17] Springer Rebuttal, page 11, lines 13-15.

Company, Mr. Springer has not identified whether such employees' responsibilities, duties and tasks are even related to customer service or customer-oriented duties and responsibilities that benefit ratepayers. As I stated previously, the Company has the right and the justification to provide its employees with market-based salaries to be competitive in the industry; however, there is no assumption that all of these types of incentive compensation costs are to be recovered in rates. I am not arguing for eliminating these types of incentive costs and packages, just that the costs that are not ratepayer-oriented should not be recovered from ratepayers.

VI. CONCLUDING REMARKS

I recommend that the Commission:

a) Allow only those costs as supported in my surrebuttal testimony related to the Company's STI.

b) Disallow all costs related to employee retention and sign on bonuses.

Q. DOES THIS CONCLUDE YOUR TESTIMONY?

A. Yes.

CERTIFICATE OF SERVICE

I, Dawn R. Kelliher, hereby certify that on September 9, 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/ Dawn R. Kelliher
Dawn R. Kelliher

APSC FILED Time: 9/9/2024 11:05:34 AM: Recvd 9/9/2024 11:02:29 AM: Docket 23-079-U-Doc. 152

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)

SURREBUTTAL TESTIMONY

OF

RICHARD W. PORTER

ON BEHALF OF

THE OFFICE OF ARKANSAS ATTORNEY GENERAL
TIM GRIFFIN

September 9, 2024

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I. INTRODUCTION

Q. PLEASE STATE YOUR NAME.

A. My name is Richard W Porter.

Q. ARE YOU THE SAME RICHARD PORTER WHO FILED DIRECT TESTIMONY IN THIS DOCKET?

A. Yes.

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. WHAT IS THE PURPOSE OF YOUR TESTIMONY?

A. I respond to various conclusions drawn from my direct testimony by Summit Utilities Arkansas, Inc. ("SUA" or "Company") witnesses Vernon McNully and Timothy Lyons. My surrebuttal testimony is limited to the issues discussed below. This limitation does not imply agreement with the positions taken by any party with respect to other issues, nor does it imply a change in position from my direct testimony.

II. SUMMARY OF SURREBUTTAL CONCLUSIONS AND RECOMMENDATIONS

Q. WHAT ARE YOUR OVERALL CONCLUSIONS REGARDING SUA'S REBUTTAL TESTIMONY?

A. SUA fails to substantiate its request for inclusion of reliability costs in a proposed, newly-restructured SSER. SUA instead opines that the rider policy requirements espoused by the Arkansas Public Service Commission ("APSC" or "Commission") are not applied on a consistent basis. The Commission's pronouncements indicate otherwise, and SUA's proposal does not satisfy the traditional criteria of the Commission specifically the criteria of cost controllability.

SUA also ignores the logical impact of its cost allocation methodology, advocating for cost allocation factors biased to customer and peak concerns which are generally prejudicial to relatively low load factor customers such as the typical residential customer.

Q. WHAT ARE YOUR RECOMMENDATIONS?

A. My recommendations are unchanged from my Direct Testimony:

a) The proposal to add an entirely new category of costs, reliability costs, to the SSER equates to a request for a new rider. In addition, SUA fails to satisfy the Commission's policy requirements for the justification of costs to be recovered outside of base rates through a rider mechanism. As such, the Commission should reject the Company's proposal. However, SUA should be allowed to retain its existing SSER.

b) SUA should modify its cost allocators to reflect that utilities are built to serve a combination of peak-period and annual customer requirements.

III. COSTS OUTSIDE OF THE CONTROL OF THE COMPANY

Q. DID SUA DEMONSTRATE THAT THE COSTS IT PROPOSES TO INCLUDE IN ITS RIDER WERE OUTSIDE OF ITS CONTROL?

A. No. Of the traditional criteria espoused by the Commission for rider approval[1], SUA only directly responds to its failure to satisfy the controllability element (costs outside of the

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[1] The Commission's traditional criteria are materiality, volatility, and controllability. *See*, APSC Docket No. 04-121-U, Document No. 286, Order No. 16, page 78. *See also*, APSC Docket No. 06-101-U, Document No. 303, Order No. 10, page 111-112, which added two additional criteria which are not relevant to my discussion.

utilities' control). SUA contends that this lack of control, among other things, justifies the inclusion of the reliability costs in a rider. Issues outside the Company's control can impact the level of the Company's reliability investment. However, the costs of the reliability projects are not outside of the utility's control for purposes of determining inclusion in a rider. Reliability costs are not appropriately included in a rider since they are ultimately discretionary costs, as to their timing and their amount. The decision regarding what amount to spend on reliability costs, and when to spend those costs, are within the control of the Company's management. As such, those costs are not appropriate for inclusion in the rider.

IV. RESIDENTIAL CLASS RATES & REVENUES

Q. DOES SUA AGREE WITH YOUR PROPOSAL TO ALLOCATE COSTS TO RECOGNIZE PEAK AND ANNUAL USAGE BY UTILITY CUSTOMERS?

A. No. In my Direct Testimony, I proposed revising the allocation of costs using the DEMAND and MAINS factors (as well as all other factors which are derivatives of these factors).[2] SUA contends that my recommended approach is not consistent with cost causation. SUA Witness Lyons states that the two drivers of cost causation can only be the number of customers and design day demand.[3] He further opines that mains costs cannot vary with energy use.

Mr. Lyons argument is a purely theoretical one without a real-world application. A utility operates in a dynamic market where its commercial operations and its capital

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[2] Document No. 113, Direct Testimony of Richard W. Porter ("Porter Direct"), pages 44 -45, Tables 6 & 7.
[3] Document No. 138, Rebuttal Testimony of Timothy S. Lyons ("Lyons Rebuttal"), page 16, lines 13-17.

requirements constantly change. Mr Lyons' methodology suggests that the utility model is static.

I could agree that in the beginning, since all or most customers were residential, the utility system was primarily designed for them and their load profile. However, over time, additional load altered both the utility operating characteristics and capital needs. These additional customers should share their portion of the cost responsibility. For example, in the SUA allocation model a) there are always a greater number of residential customers on a distribution system than any other rate class, b) the number of customers is the cost driver, and c) residential customers will always be allocated a larger share of the MAINS costs.

Q. CAN YOU EXPLAIN WHY THE SUA METHOD IS FLAWED?

A. Yes. Assume two similar distribution systems, one with a single residential customer and one with a single industrial customer. Logically, the design and operations of each of these systems will reflect the needs of each customer, not the number of customers on the system. Thus, the residential system will likely have smaller diameter pipe, operate at lower pressures, and deliver lower annual and possibly higher peak quantities. Conversely, the industrial system may be larger diameter pipe, operate at higher pressures, and deliver higher annual and higher average daily quantities. The fact that there is one customer on each system is incidental to the creation of costs on each system. In other words, the number of customers is not a driver of costs. Rather, the investment in pipe size and length to meet the load profile of each system load is a cost driver. Thus, each customer's load profile is the result of the primary cost driver, that is the pipe investment.

If these systems subsequently merge, customer count is not useful for purposes of allocating costs since, in our example, both customers are allocated an equal share of costs. For a relationship to be used to allocate costs, it must have a nexus to the cost (i.e., cost causation) to produce a meaningful allocation factor. As discussed above, the number of customers does not have a cost-based relationship to plant investment. Conversely, a residential customer's load profile and usage differs significantly from an industrial customer and is a result of the investment in gas plant for the customer class, and the entire system. Thus, where appropriate, costs to a customer class can be directly assigned or otherwise allocated on factors calculated with data that is indicative of cost causation.

Q. ARE THERE OTHER REASONS THAT YOU DON'T AGREE WITH THE SUA METHODOLGY ON COST ALLOCATION?

A. Yes. Despite the insistence that a driver of certain cost categories, such as Plant Account 376, is number of customers, SUA does not provide any studies that demonstrate this relationship. As explained above, physical and operational relationships are more indicative of cost causation than number of customers. In another vein, it seems somewhat contradictory that:

a) *on the one hand*, SUA proposes a static cost allocation methodology relying on a theory that the utility was built to serve "X" number of residential customers, and that customer class should forever bear a disproportionate share of the costs, and

b) *on the other hand*, SUA proposes a dynamic cost recovery methodology *(i.e., reliability costs in a newly revised SSER)* asserting that significant changes in

> utility markets and operations require instant reimbursement of prospective capital expenditures.

Under the SUA methodologies, residential customers will always bear a disproportionate share of allocated DEMAND and MAINS costs. However, the residential class also assumes a lopsided share of prospective reliability costs, even though it is not clear if these reliability costs will primarily benefit the residential class, or instead, other rate classes. Furthermore, it is quite unclear how the number of customers is related to any of the capital costs that might be associated with these reliability expenditures. Rather, the primary cost drivers are found in the data associated with the customer usage profiles which are the reflection of the investment in facilities.

Q. DOES THIS CONCLUDE YOUR TESTIMONY?

A. Yes.

CERTIFICATE OF SERVICE

I, Dawn Kelliher, hereby certify that on September 9, 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/ Dawn R. Kelliher
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