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

REBUTTAL TESTIMONY

OF

KURT W. ADAMS

PRESIDENT AND CHIEF EXECUTIVE OFFICER

ON BEHALF OF

SUMMIT UTILITIES ARKANSAS, INC.

Date Filed: August 7, 2024

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I. INTRODUCTION

Q. PLEASE STATE YOUR NAME, POSITION AND BUSINESS ADDRESS.

A. My name is Kurt W. Adams. I am President and Chief Executive Officer of Summit Utilities, Inc. ("SUI"). My business address is 10825 E. Geddes Ave, Suite 410, Centennial, Colorado 80112.

Q. ARE YOU THE SAME KURT W. ADAMS WHO FILED DIRECT TESTIMONY ON JANUARY 25, 2024, IN THIS PROCEEDING?

A. Yes.

Q. WHAT IS THE PURPOSE OF YOUR REBUTTAL TESTIMONY?

A. The purpose of my Rebuttal Testimony is to provide an overview of the updated cost of service requested by Summit Utilities Arkansas, Inc. ("SUA," or the "Company") as a result of the Company's adoption of various Intervenor and Arkansas Public Service Commission ("Commission") General Staff ("Staff") proposals and to provide a general response to certain positions taken by Intervenors and Staff witnesses. I also provide an overview of the various subjects addressed by SUA witnesses in rebuttal.

II. COMPANY REBUTTAL WITNESSES

Q. PLEASE PROVIDE A SUMMARY OF THE COMPANY'S WITNESSES AND THE PURPOSE OF THEIR TESTIMONY.

A. The chart below provides a summary of the Company's Rebuttal Testimony by witness.

Dylan D'Ascendis	Updates the analyses provided in his Direct Testimony to reflect current capital structure and return on equity data and responds to the Direct Testimonies of Staff, the Office of the Arkansas Attorney General Tim Griffin ("AG"), and Arkansas Gas Consumers, Inc. ("AGC") as they relate to the Company's return on common equity on its Arkansas jurisdictional rate base and appropriate capital structure.
Phillip B. Gillam	Responds to certain proposed adjustments, contentions, and recommendations of Staff, the AG, and Hospitals and Higher Education Group ("HHEG"). Also addresses recommendations related to SUA's proposed riders BDA and SSER.
Fred Kirkwood	Responds to certain proposed adjustments, contentions, and recommendations in the Direct Testimonies of Staff, and HHEG as it relates to customer service, recommended tariff revisions, and a waiver from Commission General Service Rules.
Timothy S. Lyons	Addresses concerns and recommendations regarding the class cost of service study and rate design proposed by Staff and the Intervenors.
Vernon McNully	Responds to proposed adjustments, conditions and recommendations in the Direct Testimonies of AGC, Staff, and the AG witness related to the Company's requested operations and maintenance expense for maintenance of mains and the proposed System Safety Enhancement Rider.
Craig Root	Addresses the Direct Testimonies of Staff, the AG, HHEG, and AGC related to the reasonableness of the Company's proposed capital structure.
Paul Schulte	Responds to certain recommendations in the Direct Testimonies of Staff and AGC related to Accumulated Deferred Income Tax and Excess Deferred Income Tax.
Sam Springer	Responds to proposed adjustments and recommendations in the Direct Testimonies of AGC, Staff, and the AG related to certain aspects of the Company's requested compensation and benefits costs.
Dane A. Watson	Rebuts the Direct Testimony of Staff and the AG regarding their proposed changes to the depreciation rates proposed by SUA.

III. UPDATED COST OF SERVICE

Q. HAS THE COMPANY'S REQUESTED COST OF SERVICE CHANGED AS A RESULT OF ITS REVIEW OF THE RECOMMENDATIONS MADE BY STAFF AND CERTAIN INTERVENORS?

A. Yes.

Q. HOW SO?

A. SUA understands that base rate proceedings are often contentious. In light of this understanding and in the context of its first base rate proceeding before the Commission, SUA has been intentionally committed throughout the preparation and processing of this case to careful consideration of party positions and recommendations. As a result, I am pleased to report to the Commission that the case now involves relatively few contested issues. In fact, many of the issues that remain in dispute, such as rate of return and the selection of depreciation rates, are typical areas of disagreement between Intervenors and a utility in a base rate case. Regardless, through discovery and purposeful communication with parties, necessary adjustments to SUA's cost of service have been identified. Many of these adjustments are reflected in Staff's recommendations and, as a result, where the Company can agree to certain proposed adjustments and can reduce issues in controversy, it has. For example, the Company accepted Staff's adjustments related to advertising and marketing expenses, postage expense, and certain rebranding-related capital expenditures.

Q. ARE THERE PROPOSED INTERVENOR AND STAFF ADJUSTMENTS THAT SUA IS ASKING THE COMMISSION TO REJECT?

A. There are. As reflected in the various Rebuttal Testimonies filed by the Company, certain proposed adjustments would set SUA's approved cost of service at a level that is not reflective of its current operational experience or of the conditions the Company expects to exist at the time new rates are implemented following this case. Similarly, certain capital structure recommendations would put SUA on less firm financial footing than the Commission found to be reasonable for its predecessor, CenterPoint Energy Resources Corp. ("CERC"). SUA's detailed responses on these issues are provided through its

Rebuttal Testimonies, and the Company respectfully requests that the Commission carefully consider SUA's rebuttal on the remaining contested items. The cost of service and tariffs approved by the Commission in this case will directly impact the Company's ability to provide the service expected by the Commission and SUA's customers in the years to come.

IV. GENERAL COMMENTS ON STAFF AND INTERVENOR POSITIONS AND SUMMARY OF REBUTTAL

Q. WHAT IS THE REVENUE DEFICIENCY THE COMPANY IS REQUESTING AS A RESULT OF ITS REBUTTAL CASE?

A. As further explained in Company witness Phillip Gillam's Rebuttal Testimony, SUA's updated revenue deficiency is now $101,194,113 which represents a reduction of $3,485,314 from the Company's original application.

Q. HOW DOES THE COMPANY'S DEFICIENCY IN ITS REBUTTAL CASE COMPARE TO STAFF'S DEFICIENCY FROM THEIR DIRECT CASE?

A. As noted in the Direct Testimony of Staff witness, Mr. Jeff Hilton, Staff's recommendations result in a revenue deficiency of $74,571,448. Adjusted for the recommendations that SUA has voluntarily made through its rebuttal case, the difference between Staff's position and the Company's current requested revenue requirement is $26,622,665.

Q. WHAT ARE THE PRIMARY DRIVERS OF THE DIFFERENCE BETWEEN THE COMPANY'S REQUESTED REVENUE REQUIREMENT AND THE REVENUE REQUIREMENTS PROPOSED THROUGH STAFF'S DIRECT CASE?

A. The drivers of the difference between the revenue requirement currently requested by the Company and the revenue requirement proposed by Staff relate to different views on the issues of return on rate base, base revenues and operating expenses. The largest of these drivers – the rate of return – accounts for approximately 64% of the $26,622,665 difference between what the Company is proposing and what Staff is proposing.

Q. ARE THERE ANY OTHER MAJOR DIFFERENCES BETWEEN THE COMPANY'S REQUEST IN THIS CASE AND THE FILED POSITIONS OF STAFF AND INTERVENORS?

A. One. Both Staff and certain Intervenors oppose the Company's proposal to include reliability project expenditures in the expanded System Safety Enhancement Rider ("SSER").

Q. WHY DOES SUA WANT TO EXPAND ITS CURRENT SSER TO INCLUDE RELIABILITY PROJECTS?

A. At SUA, reliability and safety go hand in hand. It is our job to make sure that our customers have natural gas service on the coldest days of the year because if they do not, their safety becomes an issue. Likewise, when a third party damages the Company's facilities such that service is limited or ceases for a time period, SUA personnel must go house by house and business by business to ensure that service is safely restored. It is only logical therefore, that the same policy reasons that support the inclusion of safety-related investment in the SSER also support the recovery of reliability investment through that mechanism as well. In my opinion, the Commission should want SUA to prioritize reliability projects. The recovery of reliability projects through the SSER better enables the Company to effectuate that prioritization.

Q. DO YOU HAVE ANY COMMENTS ON AREAS OF DISAGREEMENT BETWEEN THE INTERVENORS, STAFF AND THE COMPANY?

A. Yes. As noted in my Direct Testimony, this is the Company's first base rate filing under SUI's ownership. During the period between SUI assuming ownership to present day, the Company has continued to make necessary investments in the system without the existence of a comprehensive rate adjustment mechanism and has experienced the very real impact of regulatory lag. There have been no material safety or reliability incidents, and SUI has hired an additional 301 employees to fill *new jobs in Arkansas* in nearly every department of the Company, including senior executive and management positions. In other words, SUA has endeavored to become a best-in-class corporate partner in Arkansas and has taken on real financial risk in that effort. In this context, the results of this case serve as a foundation for SUA's future ability to meet customer expectations and to provide safe and reliable natural gas service for years to come.

To this end, as further explained in the Rebuttal Testimony of SUI's Vice President and Corporate Treasurer, Craig Root, the Company's updated requested capital structure (though not reflective of SUA's actual capital structure, which is composed of 100% equity) is an actual planned capital structure consisting of debt and equity components of 45.12% debt and 54.88% equity. Based on the target capital structure of SUA's indirect corporate parent, along with existing debt facilities and an additional planned debt issuance, the Company's proposed capital structure results in an implied investment grade credit rating that is beneficial to customers because it reduces credit risk, thereby reducing the overall cost of capital. Importantly, no Intervenor or Staff witness disputes the reduction in credit risk associated with SUA's proposal. Yet, Staff proposes a capital structure of 56% debt and 44% equity. Notably, Staff's proposed capital structure is less credit supportive than the Commission's last approved capital structure for CERC, which was approximately 51.5% debt and 48.5% equity. Simply put, the Company's capital structure request remains reasonable and is supported by good policy. The Rebuttal Testimonies of Company witness Mr. Root, and of its expert witness, Dylan D'Ascendis, also address why the Commission should adopt the Company's requested capital structure.

As I discuss above and as is further explained in the Rebuttal Testimony of Company witnesses Mr. Gillam and Mr. McNully, I would note that the Intervenors and Staff oppose the Company's request to add reliability projects to investment eligible for recovery under the SSER. A portion of this opposition appears to be based on uncertainty around which exact projects and programs will be added to those already being recovered under the SSER. SUA's Rebuttal Testimony attempts to address these concerns. SUA agrees that the Commission should have a clear understanding of which projects are eligible for recovery under the SSER and hopes that after further review, the Commission will conclude that reliability projects identified by SUA are beneficial to customers and merit interim recovery under the SSER. Finally, if the Commission approves the SSER as requested, the Company requests that no annual cap be placed on its cost recovery. The SSER, as requested, is designed to recover needed safety, reliability and public improvement projects that the Company must make on an annual basis. While the Company understands Staff's desire to limit the annual rate impact of the SSER to customers, to impose a cap on recovery would unfairly penalize SUA when it must make that necessary investment regardless of the ultimate cost.

Q. DOES THIS CONCLUDE YOUR REBUTTAL TESTIMONY?

A. Yes.

CERTIFICATE OF SERVICE

I, Brooke South Parsons, do hereby certify that a true and correct copy of the foregoing has been delivered to all Parties of Record by electronic mail via the Electronic Filing System this 7th day of August 2024.

Brooke South Parsons

Brooke South Parsons

BEFORE THE

ARKANSAS PUBLIC SERVICE COMMISSION

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

REBUTTAL TESTIMONY

OF

PHILLIP B. GILLAM

DIRECTOR OF RATES & REGULATORY AFFAIRS

ON BEHALF OF

SUMMIT UTILITIES ARKANSAS, INC.

Date Filed: August 7, 2024

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LIST OF EXHIBITS

I. INTRODUCTION

Q. PLEASE STATE YOUR NAME, POSITION AND BUSINESS ADDRESS.

A. My name is Phillip B. Gillam, and I am Director, Rates and Regulatory Affairs. I am testifying on behalf of Summit Utilities Arkansas, Inc. ("SUA," or the "Company"). My business address is 1400 Centerview Drive, Suite 100, Little Rock, Arkansas 72211.

Q. ARE YOU THE SAME PHILLIP B. GILLAM WHO FILED DIRECT TESTIMONY ON JANUARY 25, 2024, IN THIS PROCEEDING?

A. Yes.

Q. WHAT IS THE PURPOSE OF YOUR REBUTTAL TESTIMONY?

A. The purpose of my Rebuttal Testimony is to respond to certain proposed adjustments, contentions, and recommendations in the Direct Testimonies of Arkansas Public Service Commission ("Commission") General Staff ("Staff") witnesses, Mr. Don Malone, Mr. Jeff Hilton, Mr. Middleton Ray, Mr. Robert Swaim, Mr. Claude Robertson, Mr. Michael Pitts, and Mr. Dan Daves, Office of the Arkansas Attorney General ("AG") witnesses, Mr. Richard Porter, Mr. Dante Mugrace, and Dr. Marlon Griffing, Arkansas Gas Consumers, Inc. ("AGC") witness Mr. Jonathan Ly, and Hospitals and Higher Education Group ("HHEG") witness, Mr. Larry Blank.

Q. ARE YOU SPONSORING OR CO-SPONSORING ANY EXHIBITS TO YOUR TESTIMONY?

A. Yes, I sponsor the exhibits listed in the Table of Contents.

Q. HOW DOES YOUR TESTIMONY RELATE TO THE TESTIMONY OF OTHER COMPANY WITNESSES?

A. Timothy S. Lyons provides testimony supporting the Company's Rebuttal Minimum Filing Requirement ("MFR") Schedules E-11.1, E-11.2, and MFR Schedules G through H, and other Company witnesses support various numbers in the schedules and the reasonableness of the various expenses and rate base items.

II. SUMMARY OF UPDATED REVENUE REQUIREMENT AND REBUTTAL

Q. HAS THE COMPANY UPDATED ITS REVENUE REQUIREMENT AND REVENUE DEFICIENCY FOLLOWING ITS REVIEW OF STAFF AND INTERVENOR TESTIMONY?

A. Yes, SUA's updated Total Non-Fuel Revenue Requirement request is now $289,834,695. It represents a total revenue requirement increase of $3,173,959 compared to the Company's originally requested Total Non-Fuel Revenue Requirement of $286,660,736. As described in the footnote to MFR Schedule A-1, the Company seeks the original Total Non-Fuel Revenue Requirement of $286,660,736. The updated revenue deficiency is $101,194,113. It represents a revenue deficiency decrease of $3,485,314 compared to the Company's originally requested revenue deficiency of $104,679,427. A summary of Staff's proposed adjustments that have been accepted and/or contested by the Company is attached as Rebuttal Exhibit PBG-1 and Rebuttal Exhibit PBG-2. The updated revenue requirement is attached as Rebuttal Exhibit PBG-3, which is also MFR Schedule A-1.

Q. HOW DOES THE COMPANY'S UPDATED REVENUE REQUIREMENT COMPARE TO STAFF'S DIRECT TESTIMONY REVENUE REQUIREMENT?

A. SUA's updated revenue requirement was calculated using "rolled-in" revenues for the System Safety Enhancement Rider ("SSER") and the Lost Contribution from Fixed Costs ("LCFC") portion of the Energy Efficiency Cost Recovery ("EECR") Rider, while Staff's revenue requirement does not include these rolled-in revenues. The Company calculated SSER revenues of $8,716,076 and LCFC revenues of $1,400,373, while the Staff calculated SSER revenues of $9,628,361 and LCFC revenues of $1,420,671. This fundamentally means, when comparing revenue deficiency amounts, the comparison is not apples to apples. More importantly though, the revenue requirement calculated under both approaches is the same. The comparative emphasis then should be on revenue requirement and not revenue deficiency.

Q. WHY SHOULD "ROLLED-IN" REVENUES BE INCLUDED IN THE COMPANY'S REVENUE REQUIREMENT AS OPPOSED TO STAFF'S APPROACH OF NOT INCLUDING THEM?

A. In my opinion, the inclusion of "rolled-in" revenues gives a better representation of the increase that will be shown on customer's bills going forward. Using Staff's methodology, the revenue deficiency appears to be $10,116,449 higher than it really is (using the Company's calculation), and $11,049,032 higher using the Staff's calculation because of the exclusion of the "rolled-in" revenues.

Q. HOW IS THE REMAINDER OF YOUR REBUTTAL TESTIMONY ORGANIZED?

A. I first address adjustments related to working capital assets, accumulated depreciation, and other rate base items. I then address certain expense-related adjustments, flow-through adjustments, and tariff-related proposals. Some proposed adjustments of Intervenors and Staff impact both rate base and expense issues. For purposes of clarity, I address the rate base and expense issues separately in different sections. Where the Company can agree to a proposed adjustment, I affirm SUA's agreement and the adjustment is reflected in the

Company's updated cost of service. In some cases, I also identify other SUA witnesses who further support the Company's position on each contested issue.

III. PROPOSED MBSA, RATE BASE, AND RELATED ACCUMULATED DEPRECIATION ADJUSTMENTS

A. Working Capital Assets ("WCA").

Q. PLEASE DESCRIBE MR. MALONE'S PROPOSED ADJUSTMENTS TO WCA.

A. Mr. Malone proposes to make adjustments to the following WCA Accounts: FERC Account 131 – Cash; FERC Account 136 – Temporary Cash Investments; FERC Account 143 – Other Accounts Receivable; FERC Account 163 – Stores Expense Undistributed; FERC Account 165 – Prepayments; FERC Account 173 – Accrued Utility Revenues; FERC Account 184 – Clearing Accounts; and FERC Account 186 – Miscellaneous Deferred Debits.

Q. DO YOU AGREE WITH MR. MALONE'S PROPOSED ADJUSTMENTS TO WCA?

A. For the most part, yes. I disagree with his proposed adjustment to FERC Account 143 – Other Accounts Receivable, as those amounts are still viable receivables and are expected to be collected in the future. Also, as explained below, the adjustment to Cash and Temporary Cash Investments is not needed.

Q. WHAT ADJUSTMENTS SHOULD THE COMMISSION MAKE TO THE COMPANY'S FILED WCA?

A. The Commission should make the other adjustments enumerated by Mr. Malone relating to Stores Expense Undistributed, Prepayments, Accrued Utility Revenues, and Clearing Accounts.

Q. PLEASE EXPLAIN MR. MALONE'S PROPOSED ADJUSTMENTS TO CASH AND TEMPORARY CASH INVESTMENTS?

A. Appendix 8-1, Schedule B-4, of the Commission's Rules of Practice and Procedures states the WCA should "include only asset accounts that meet the following criteria (1) is necessary for providing utility service ; (2) is not included elsewhere in rate base; (3) does not accrue income that is not included in operating revenue.". Interest is earned associated with Cash and Temporary Cash Investments and recorded below the line, which is not included in operating income. The Company did not propose an adjustment to move this interest above the line into operating income in its initial filing . Therefore, Mr. Malone removed the Cash and Temporary Cash Investments from WCA.

Q. WHY IS THE ADJUSTMENT TO WCA FOR CASH AND TEMPORARY CASH INVESTMENTS NO LONGER NEEDED?

A. As part of the Company's Rebuttal MFR Schedules, it has moved the interest to include it in operating income. Therefore, the adjustment removing Cash and Temporary Cash Investments is no longer required by Mr. Malone.

Q. AGC WITNESS MR. LY EXPRESSED A CONCERN ABOUT THE TREATMENT OF HEATING ASSISTANCE FUNDS AND THEIR INCLUSION IN THE COST OF SERVICE STUDY. PLEASE ADDRESS MR. LY'S CONCERN.

A. In response to discovery request AGC-005-001 (included as Rebuttal Exhibit PBG-4), the Company responded to this concern with the statement that Heating Assistance Funds are included in FERC Account 142 – Accounts Receivable, which is in the WCA section of the cost of service study. Accounts Receivable are allocated based on the allocation factor "RETREV" (Retail Revenues).

B. Current, Accrued and Other Liabilities ("CAOL").

Q. PLEASE DESCRIBE MR. MALONE'S PROPOSED ADJUSTMENTS TO CAOL.

A. Mr. Malone proposes to make a series of adjustments to the SUA CAOL accounts in a manner similar to the Company's adjustments to the Southern Col Holdco, LLC ("Holdco") CAOL accounts, with a few exceptions related to the Accumulated provision for Pensions and Benefits, Interest Payable and Dividends Payable.

Q. DO YOU AGREE WITH MR. MALONE'S PROPOSED ADJUSTMENTS TO CAOL?

A. No. The Company's CAOL calculation is at the Holdco level, not the SUA level, and adjustments to SUA CAOL accounts are not entirely comparable to the Company's Holdco CAOL adjustments.

Q. WHAT ADJUSTMENTS SHOULD THE COMMISSION MAKE TO THE COMPANY'S FILED CAOL AND MBSA?

A. The Commission should accept the Company's filed CAOL provided in the Rebuttal MFR Schedule D-1.3 Holdco.

C. Excess Deferred Income Taxes ("EDIT") Related Adjustment to Capital Structure.

Q. WHAT IS MR. MALONE'S PROPOSAL AS IT RELATES TO RECLASSIFIED UNPROTECTED EDIT ASSOCIATED WITH THE COST OF REMOVAL?

A. Mr. Malone proposes the unprotected EDIT asset associated with the cost of removal be collected over the same time period as the refund to ratepayers under the Average Rate Assumption Method ("ARAM").

Q. HAS MR. MALONE CORRECTLY CALCULATED HIS PROPOSED ADJUSTMENT TO THE CAPITAL STRUCTURE?

A. No. The Company used its Holdco entity to determine the appropriate capital structure for this case. Mr. Malone's adjustment only contemplates using the SUA portion of Holdco, which is inconsistent with the rest of the Company's calculation.

Q. DO ANY OTHER WITNESSES TAKE ISSUE WITH USING HOLDCO BALANCES FOR CAOL, EDIT OR OTHER COST OF CAPTIAL COMPONENTS?

A. Yes. Staff witness Mr. Daves recommends the use of SUA's balances for the weighted average cost of capital (WACC) calculation and asserts that methodology is consistent with CenterPoint Energy Resources Corp.'s ("CERC") most recent rate case, Docket No. 15-098-U.

Q. WHAT BALANCES WERE UTILIZED IN THE DETERMINATION OF WACC IN DOCKET NO. 15-098-U?

A. Docket No. 15-098-U utilized balances from CenterPoint Energy Arkla ("Arkla"), which was an accounting division of CERC, in determining its WACC.

Q. WERE THE ARKLA BALANCES SPECIFIC TO ARKANSAS OPERATIONS?

A. No. The Arkla balances included operations from Oklahoma and North Louisiana in addition to the operations from Arkansas and Texarkana, Texas (now SUA).

Q. WHAT UTILITY OPERATIONS MAKE UP THE HOLDCO BALANCES?

A. Holdco consists of the utility operations from SUA (Arkansas and Texarkana TX) and Summit Utilities Oklahoma, Inc. ("SUO").

Q. IS THE COMPANY'S METHODOLOGY OF USING HOLDCO BALANCES CONSISTENT WITH THE METHODOLOGY FROM DOCKET NO. 15-098-U?

A. Yes. The Holdco balances consist of the same utility operations (SUA and SUO) that were utilized in Docket 15-098-U, except for the North Louisiana operations because the Louisiana assets were not part of the acquisition of certain CERC assets by Summit Utilities, Inc. in 2022. The remaining Holdco activities relate to debt and equity funding of SUA's and SUO's utility operations.

Q. IS STAFF'S METHODOLOGY OF USING SUA'S BALANCES CONSISTENT WITH THE METHODOLOGY FROM DOCKETNO. 15-098-U?

A. No. As noted above, Arkla's balances included operations from other jurisdictions. Staff is proposing to use only SUA's balances.

Q. WHAT IMPACT DOES MR. MALONE'S PROPOSED ADJUSTMENT HAVE ON THE COMPANY'S WEIGHTED AVERAGE COST OF CAPITAL?

A. Mr. Malone's proposed adjustment slightly increases the weighted average cost of capital calculation, when isolating this adjustment and keeping all other amounts the same.

Q. SHOULD THE COMMISSION ADOPT MR. MALONE'S PROPOSED ADJUSTMENT RELATED TO EDIT AND THE COST OF REMOVAL?

A. As noted in the Rebuttal Testimony of Company witness Mr. Paul Schulte, it is the Company's position that Mr. Malone's proposal to recover cost of removal-related EDIT over ARAM is not reasonable.

Q. IS MR. MALONE'S FIVE-YEAR COLLECTION PERIOD FOR EDIT RELATED TO THE CHANGE IN STATE CORPORATE TAX RATE REASONABLE?

A. No. SUA, like other natural gas utilities around the country and in the state, is constantly investing in its system. Accordingly, it is not likely that the Company will be able to avoid filing another rate case for five years. SUA has not requested a Formula Rate Plan, and Staff and the Arkansas Attorney General's Office ("AG") oppose the addition of reliability-related investment as well as investment related to future Pipeline and Hazardous Materials Safety Administration ("PHMSA") regulations in the Company's SSER. Going even further, Staff proposes a cap on SSER recovery. As such, SUA will need to return to the Commission for rate relief sooner, rather than later.

D. Gross Plant-in-Service ("GPIS").

Q. WHAT ADJUSTMENTS IS STAFF PROPOSING TO GPIS?

A. Staff witness Mr. Michael Pitts is proposing four adjustments to GPIS relating to Asset Retirement Obligations ("ARO"), Short-Term Incentive Compensation ("STI"), Volunteer Time Off ("VTO") and Rebranding expenditures.

Q. DOES THE COMPANY HAVE ANY OBJECTION TO STAFF'S PROPOSED ADJUSTMENTS TO GPIS AND THE CORRESPONDING IMPACT TO ACCUMULATED DEPRECIATION ("AD")?

A. Yes it does, for two of the four GPIS adjustments – STI and VTO, as explained below.

E. ARO

Q. PLEASE EXPLAIN MR. PITTS' PROPOSED ADJUSTMENT TO ARO.

A. Mr. Pitts proposes to adjust the ARO balance of $2,280,940 out of GPIS, as that amount was inadvertently included in the Company's April 11, 2024 updated MFR Schedules provided pursuant to General Service Rule 8.12(d). It was not included in the Company's initial application. Mr. Pitts' adjustment is appropriate because ARO balances should not be included in the Company's rate base.

Q. DOES THE COMPANY HAVE ANY OBJECTION TO STAFF'S PROPOSED ADJUSTMENT TO ARO AND THE CORRESPONDING IMPACT TO ACCUMULATED DEPRECIATION ("AD")?

A. No. It does not.

F. Cost Rate Customer Deposits.

Q. PLEASE EXPLAIN MR. DAVES' PROPOSED ADJUSTMENT TO THE CUSTOMER DEPOSIT COST RATE.

A. Mr. Daves proposes to use the most recent SUA customer deposit rate of 2.93%, which is different than the Holdco customer deposit rate initially filed of 2.5649%.

Q. DOES THE COMPANY OBJECT TO MR. DAVES' PROPOSAL TO UPDATE THE CUSTOMER DEPOSIT COST RATE FOR 2024?

A. No, not in the context of using SUA amounts in the overall WACC calculation. It is not materially different than the most recent Holdco customer deposit rate of 2.9235%, but the Company will continue to use Holdco amounts in its overall Weighted-Average Cost of Capital ("WACC") calculation.

G. Rebranding Costs.

Q. PLEASE DESCRIBE MR. MALONE'S AND MR. PITTS' PROPOSED ADJUSTMENT RELATED TO REBRANDING PLANT-IN-SERVICE AND THE RELATED AD.

A. Mr. Pitts and Mr. Malone propose to adjust GPIS for Rebranding Capital Expenditures of $379,968, and to adjust AD by $14,500 as a result of the Company's Settlement Agreement in Docket No. 21-060-U regarding Transition Costs.

Q. DOES THE COMPANY OBJECT TO MR. MALONE'S PROPOSED REBRANDING-RELATED ADJUSTMENT?

A. No. The Company has no objection to Mr. Malone's proposed adjustment related to rebranding plant-in-service and has reflected the adjustment in its updated cost of service.

H. Capitalized Incentive Compensation Costs.

Q. WHAT ADJUSTMENTS DO INTERVENORS AND STAFF PROPOSE AS IT RELATES TO CAPITALIZED INCENTIVE COMPENSATION AMOUNTS?

A. The treatment of STI adjustments is also discussed in the expense adjustments portion of my testimony below. For capitalized STI, the Staff proposes to eliminate STI of $1,749,525 and the related AD of $66,767.

Q. DOES THE COMPANY CAPITALIZE ANY LONG TERM INCENTIVE ("LTI") COSTS?

A. No. There are no capitalized costs associated with LTI in the Company's requested cost of service.

Q. ARE THE INTERVENOR AND STAFF ADJUSTMENTS TO CAPITALIZED INCENTIVE COMPENSATION CORRECTLY CALCULATED?

A. Yes. The Intervenor and Staff adjustments incorporated amounts provided by the Company in discovery.

Q. SHOULD THE COMMISSION ADOPT THE STAFF AND INTERVENOR PROPOSALS TO DISALLOW CAPITALIZED INCENTIVE COMPENSATION COSTS AND CORRESPONDING AMOUNTS OF AD?

A. No. As addressed in the Rebuttal Testimony of Mr. Springer, the Company's incentive compensation-related costs are reasonable and should be included in the Company's cost of service.

I. VTO.

Q. WHAT ADJUSTMENT DOES STAFF PROPOSE RELATED TO VOLUNTEER TIME OFF?

A. Staff witnesses Ray and Pitts propose to eliminate capitalized VTO and expensed payroll and related payroll taxes from rate base and from operation & maintenance ("O&M") Expenses.

Q. DO YOU AGREE WITH STAFF'S PROPOSED ADJUSTMENTS?

A. No. Similar to the issue of STI, as addressed in the testimony of Mr. Springer, the Company's VTO costs are reasonable and should be included in the Company's cost of service.

Q. SHOULD THE COMMISSION ADOPT STAFF'S PROPOSED ADJUSTMENTS TO VOLUNTEER TIME OFF AND CORRESPONDING AMOUNTS OF AD?

A. No. Mr. Pitts' rate base adjustments of $57,145 for GPIS and $2,179 for AD, along with Mr. Ray's adjustment of $151,865 to O&M expenses should be rejected by the Commission.

J. Retention and Sign-on Bonuses.

Q. PLEASE EXPLAIN MR. MUGRACE'S PROPOSED ADJUSTMENTS RELATED TO RETENTION AND SIGN-ON BONUSES.

A. Mr. Mugrace proposes to eliminate $84,884 related to capitalized retention bonuses and $51,951 related to capitalized sign-on bonuses from the Company's payroll adjustment.

Q. DID MR. MUGRACE CORRECTLY CALCULATE HIS PROPOSED ADJUSTMENTS TO TEST YEAR RETENTION AND SIGN-ON BONUS AMOUNTS?

A. Yes, these were amounts provided by the Company in discovery.

Q. SHOULD THE COMMISSION ADOPT MR. MUGRACE'S PROPOSED RETENTION AND SIGN-ON BONUS ADJUSTMENTS?

A. No. As described in the Rebuttal Testimony of Company witness Mr. Springer, SUA's requested capitalized costs associated with retention and sign-on bonuses are reasonable, necessary and should be included in the Company's cost of service.

IV. PROPOSED EXPENSE ADJUSTMENTS

A. Overtime Expense.

Q. PLEASE DESCRIBE STAFF'S PROPOSED ADJUSTMENT TO OVERTIME EXPENSE.

A. Staff witness Ray proposes to adjust payroll overtime costs by $1,619,052 based on a "normalization" of overtime costs using a five-year average.

Q. DO YOU AGREE WITH MR. RAY'S PROPOSED ADJUSTMENT?

A. Not entirely. Mr. Ray proposes to use a five-year average, which includes three years of CERC overtime cost history and only two years of SUA's overtime cost history. I recommend using the two-year average of SUA's overtime costs, which would result in an adjustment of $685,188.

Q. SHOULD THE COMMISSION ADOPT MR. RAY'S PROPOSED ADJUSTMENT TO OVERTIME EXPENSE?

A. No. The Company's proposed overtime expense amount is reasonable, reflective of SUA's operational practices, and reflects a normalized level that is likely to be incurred by SUA in the future. Therefore, SUA's proposed amount should be approved.

B. Forfeited Discounts.

Q. WHAT ADJUSTMENT DOES STAFF PROPOSE TO SUA'S REQUESTED FORFEITED DISCOUNTS EXPENSE?

A. Staff proposes to increase the amount of forfeited discount revenues by $1,537,787 by using a three-year average of actual forfeited discounts for the years 2018, 2019 and 2022. In other words, Staff's proposal excludes the years of 2020 and 2021.

Q. DO YOU AGREE WITH STAFF'S PROPOSED METHODOLOGY AND ADJUSTMENT TO FORFEITED DISCOUNTS?

A. No. Mr. Hilton states that he excluded the years of 2020 and 2021 because those years were "anomalous," but he does not offer any explanation as to why those years are anomalous. Staff's proposed methodology is a departure from the methodology required in MFR Schedule C-4, which incorporates a five-year average for the calculation of both the forfeited discount rate and the uncollectible or bad debt expense rate. Use of this methodology in turn yields forfeited discount revenue adjustment of $1,495,193, which is $42,594 lower than Staff's proposed adjustment. It also affects the uncollectible adjustment, which will be discussed later in my testimony.

Q. WHAT AMOUNT SHOULD THE COMMISSION APPROVE FOR SUA'S TEST YEAR FORFEITED DISCOUNTS REVENUE?

A. The Commission should approve an amount of $2,971,816, based on the use of the prescribed five-year average required by MFR C-4.

C. Uncollectible Expense.

Q. PLEASE EXPLAIN STAFF'S PROPOSED ADJUSTMENT TO UNCOLLECTIBLE EXPENSE.

A. Staff witness Mr. Hilton proposes to reduce uncollectible expense by $7,295,558, again based on the use of the years 2018, 2019, and 2022 to calculate a average of uncollectible expense. As with forfeited discounts, Mr. Hilton states that he excluded the years of 2020 and 2021 because those years were "anomalous," but he does not offer any explanation as to why those years are anomalous.

Q. DOES THE COMPANY AGREE WITH MR. HILTON'S PROPOSED ADJUSTMENT?

A. No.

Q. WHY NOT?

A. As discussed earlier with the forfeited discount revenue adjustment, Schedule MFR C-4 prescribes the use of a five-year average, and Mr. Hilton does not support his deviation from this schedule requirement.

Q. SHOULD THE COMMISSION APPROVE MR. HILTON'S PROPOSED ADJUSTMENT TO UNCOLLECTIBLE EXPENSE?

A. No. The Commission should approve an adjustment to uncollectible expense based on a five-year average. The Company's proposed adjustment is $6,109,401.

D. Rate Case Expense.

Q. WHAT ADJUSTMENT DOES STAFF PROPOSE TO THE COMPANY'S REQUESTED RATE CASE EXPENSE AMOUNT?

A. Mr. Hilton proposes to reduce the level of requested rate case expenses by $500,000 based on the lower end of an estimate provided by the Company's outside counsel. Mr. Hilton also proposes to extend the proposed recovery period to five years as compared to the Company's proposal of a two-year amortization.

Q. DOES THE COMPANY HAVE ANY OBJECTION TO STAFF'S PROPOSED ADJUSTMENT?

A. As the Company understands Mr. Hilton's proposed adjustment, the adjustment reduces the anticipated costs of this proceeding. Those costs could change and exceed the estimate provided by Mr. Hilton. Accordingly, SUA requests that its rate case expense amount be monitored and adjusted moving forward as those costs are incurred, and that the final and actual amount be approved for recovery. Additionally, consistent with my testimony at the end of Section III.C, above, the Company is likely to need to file another general rate case sooner rather than later, so the Company continues to propose to maintain the two-year amortization period originally proposed.

E. Incentive Compensation.

Q. WHAT POSITIONS DO STAFF AND THE INTERVENORS TAKE AS IT RELATES TO INCENTIVE COMPENSATION?

A. Staff and Intervenor witnesses have taken the position that some portion of incentive compensation should be disallowed because of its limited benefit to customers.

Q. HAVE YOU REVIEWED THE CALCULATIONS OF THE PROPOSED ADJUSTMENTS BY STAFF AND THE INTERVENORS TO INCENTIVE COMPENSATION EXPENSE?

A. Yes.

Q. DO YOU HAVE COMMENTS ON THE ACCURACY OF THOSE CALCULATIONS?

A. Yes, the calculations appear to be accurate and based on the information that was supplied by the Company in discovery.

Q. MR. MUGRACE ARGUES THAT BASIC RATEMAKING CONCEPTS DO NOT PROVIDE FULL RECOVERY FOR ALL EXPENSES, INCLUDING INCENTIVE PAY. WHAT IS YOUR RESPONSE TO THIS ARGUMENT?

A. I disagree. Basic ratemaking concepts allow for recovery of all reasonable and customary expenses. Incentive compensation costs, as further described by Mr. Springer, should be included in the Company's cost of service.

F. Retention and Sign-on Bonuses.

Q. WHAT ADJUSTMENTS ARE PROPOSED BY MR. MUGRACE TO EXPENSED RETENTION AND SIGN-ON BONUS AMOUNTS INCLUDED IN THE TEST YEAR?

A. Mr. Mugrace proposes to eliminate $86,762 related to expensed retention bonuses and $53,100 related to expensed sign-on bonuses from the Company's payroll adjustment.

Q. HAS MR. MUGRACE CORRECTLY CALCULATED HIS PROPOSED ADJUSTMENT?

A. Yes, these were amounts provided by the Company in discovery.

Q. SHOULD THE COMMISSION ADOPT MR. MUGRACES' RECOMMENDATION RELATED TO RETENTION AND SIGN-ON BONUSES?

A. No. As described in the Rebuttal Testimony of Company witness Mr. Springer, SUA's requested expensed costs associated with retention and sign-on bonuses are reasonable, necessary and should be approved.

G. Deferred COVID-19 Expenses.

Q. PLEASE DESCRIBE MR. HILTON'S PROPOSED ADJUSTMENT RELATED TO THE AMORTIZATION OF COVID-19 EXPENSES?

A. Mr. Hilton proposes to amortize SUA's deferred Covid-19 expenses of $6,339,131 over five years.

Q. DO YOU AGREE WITH MR. HILTON'S PROPOSED AMORTIZATION PERIOD?

A. No. As discussed above, it is unlikely that the Company will be able to avoid another base rate filing for the next five years. Given the size and age of this regulatory asset, it is more reasonable to amortize the asset over the three-year period originally proposed by the Company. If the Commission decides to accept Staff's proposal for a five-year amortization period, then the Company requests carrying costs on the unrecovered balance at the weighted-average cost of capital approved in this docket. The Company's Rebuttal MFR Schedules continue to include a three-year amortization of Covid-19 expenses with no return on the unrecovered balance.

H. Revenue Conversion Factor.

Q. PLEASE EXPLAIN MR. HILTON'S PROPOSED ADJUSTMENT TO THE COMPANY'S REVENUE CONVERSION FACTOR.

A. Mr. Hilton proposes to use an average of the years of 2018, 2019, and 2022, excluding the years of 2020 and 2021, uncollectibles and forfeited discounts instead of the five-year averages proposed by the Company, and to calculate the factor using the forfeited discount ratio.

Q. IS MR. HILTON'S PROPOSED ADJUSTMENT TO THE REVENUE CONVERSION FACTOR REASONABLE?

A. No.

Q. WHY NOT?

A. As discussed earlier in the Company's response to the income statement adjustments for uncollectible expense and forfeited discount revenue, Mr. Hilton's unsupported methodology average is a departure from the requirement of using a five-year average as prescribed in MFR C-4.

Q. SHOULD THE COMMISSION ADOPT MR. HILTON'S PROPOSED ADJUSTMENT TO THE REVENUE CONVERSION FACTOR?

A. No.

I. Donations.

Q. PLEASE EXPLAIN MR. MALONE'S PROPOSED ADJUSTMENT RELATED TO DONATIONS.

A. Mr. Malone proposes to adjust amounts related to donations, dues and subscriptions, and other miscellaneous administrative and general costs in the amount of $83,105.

Q. DOS SUA HAVE ANY OBJECTION TO MR. MALONE'S PROPOSED OBJECTION TO DONATIONS?

A. Yes. The donations, dues, and subscriptions amounts he proposes to adjust have already been adjusted in the Company's IS-10 Other Expenses adjustment. The Company agrees to make an adjustment of $4,581 for the other miscellaneous amounts.

J. Vegetation Control.

Q. WHAT IS STAFF'S PROPOSED ADJUSTMENT TO TEST-YEAR VEGETATION CONTROL EXPENSE?

A. Staff proposes to make an adjustment to vegetation control expense in the amount of $212,357 based on a two-year average of vegetation control expenses from 2022 and 2023.

Q. IS STAFF'S PROPOSED ADJUSTMENT TO VEGETATION CONTROL EXPENSES REASONABLE?

A. No.

Q. WHY NOT?

A. The Company is currently trending towards a higher amount of vegetation control expenses in the pro forma year 2024. As of July 2024, the Company has incurred $754,445 in vegetation control expenses.

Q. WHAT TEST YEAR AMOUNT SHOULD THE COMMISSION APPROVE FOR VEGETATION CONTROL?

A. The Commission should approve the test year amount presented in the Company's initial case, or if a new pro forma adjustment is made later in the case, approve the new adjusted amount.

K. Non-Recurring Expenses.

Q. WHAT ADJUSTMENTS DOES STAFF PROPOSE TO TEST YEAR EXPENSE FOR NON-RECURRING EXPENSES?

A. Staff proposed three adjustments: 1) transactions related to legal expenses associated with SUA billing errors; 2) Transition Service Agreement ("TSA") payments made during the test year; and 3) settlement expense paid related to a possible civil action.

Q. DO YOU AGREE WITH STAFF'S PROPOSED ADJUSTMENTS?

A. No, I do not. For adjustment item 1, legal expenses associated with SUA billing errors, it appears Mr. Malone has singled out one particular case that he deems non-recurring. This is not a reasonable approach as there are unique, non-recurring legal cases each year. An adjustment based on a normalized level of legal expense is more appropriate. The Company included actual test year expense that represented a normal level of legal expense.

For adjustment item 2, TSA payments, while the Company did incur limited TSA costs in 2023, the majority of these costs, $147,216, were accrued for and reflected in SUA's 2022 expenses, none of which are included in the test year. Therefore, Staff should not remove these costs from the test year expense as they are not reflected in 2023. However, the Company agrees with the removal of $18,608 of transition costs paid and reflected in 2023 test year expenses.

For adjustment item 3, settlement expense paid related to a possible civil action, the Company received an insurance reimbursement for the claim amount of $527,565. This insurance reimbursement offsets the claim expense, resulting in a zero cost impact in the test year. Mr. Malone's adjustment essentially double-books the reduction to expense. Therefore, Mr. Malone's decreasing expense by $527,565 should be rejected.

L. VTO.

Q. DOES COMMISSION STAFF PROPOSE AN EXPENSE ADJUSTMENT RELATED TO VTO THAT IS CONSISTENT WITH ITS POSITION ON CAPITALIZED VTO?

A. Yes. Staff witness Mr. Ray proposes to adjust O&M payroll expense by $141,906 and payroll taxes by $9,959 for VTO.

Q. WHAT IS THE COMPANY'S POSITION ON CAPITALIZED VOLUNTEER TIME, WHETHER THE COST IS INCLUDED IN PLANT-IN-SERVICE OR EXPENSE?

A. As explained in my testimony above and in the Rebuttal Testimony of Mr. Springer, the Company's request for recovery related to all VTO costs is reasonable and should be approved regardless of whether the cost is booked to plant-in-service, expense or has any flow through/attendant impacts.

M. Depreciation.

Q. PLEASE EXPLAIN THE VARIOUS ADJUSTMENTS TO DEPRECIATION EXPENSE RECOMMENDED BY MR. PITTS.

A. Staff witness Michael Pitts made two adjustments to depreciation expense: IS-19 reducing depreciation expense by $38,740 and IS-27 reducing depreciation expense by $888,014.

Q. DOES SUA AGREE THAT STAFF'S RECOMMENDED ADJUSTMENTS TO DEPRECIATION EXPENSE ARE REASONABLE?

A. The Company does not contest Mr. Pitts' adjustment IS-19. However, the Company does not agree with Mr. Pitts' adjustment IS-27, because it is based on an incorrect assumption.

Q. WHY IS STAFF'S PROPOSED DEPRECIATION ADJUSTMENT IS-27 INCORRECT?

A. 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. Mr. Pitts incorrectly assumed that SUA follows that same practice. While SUA also has fleet overhead which is applied to both capital and expense projects, depreciation expense is not a component of fleet overhead that is applied to projects. In other words, all transportation depreciation costs are expensed and not capitalized. Therefore, Mr. Pitts should not make this adjustment reducing expense.

Q. DO YOU AGREE WITH MR. ROBERTSON'S RECOMMENDATION REGARDING THE THEORETICAL RESERVE ADJUSTMENT?

A. No. As described by Company witness Watson, the theoretical reserve should not be adjusted to a regulatory asset with only a return "of" and no return "on" this asset. I agree with Mr. Watson's recommendation that the theoretical reserve should remain in the plant portion of rate base and not be adjusted out to a regulatory asset.

Q. DO YOU AGREE WITH MAJOROS' RECOMMENDATION REGARDING THE OVERALL DEPRECIATION EXPENSE THAT IS INCLUDED IN THE COMPANY'S REVENUE REQUIREMENT?

A. No. Company witness Watson effectively debunks his approach to artificially lengthening the lives of certain plant accounts and the concept that there is $191 million of excess accumulated depreciation because of the inflation inherent in customarily approved net salvage calculations. Assuming artificially lower lives and artificially low net salvage only serves to set up customers for higher depreciation rates in the future, when the next depreciation study will likely show significant under-recovery of the associated assets.

V. FLOW THROUGH/ATTENDANT IMPACT ADJUSTMENTS

A. Payroll Taxes and Benefits.

Q. HAVE YOU REVIEWED THE CALCULATIONS PROVIDED BY STAFF RELATED TO THE FLOW THROUGH/ATTENDANT IMPACTS OF THEIR PROPOSED ADJUSTMENTS TO PAYROLL TAXES AND BENEFITS?

A. Yes.

Q. HAS STAFF CALCULATED THE FLOW THROUGH/ATTENDANT IMPACTS OF THEIR PROPOSED ADJUSTMENTS CORRECTLY?

A. Yes. Staff has calculated the impacts of their proposed adjustments to payroll taxes and benefits correctly, but the only adjustment the Company is proposing to accept is the overtime adjustment at an amount lower than Staff's proposal. The related payroll taxes and benefits were also adjusted as a result.

VI. TARIFF PROPOSALS

A. Rider BDA.

Q. PLEASE EXPLAIN STAFF'S POSITION RELATED TO THE COMPANY'S BILLING DETERMINANT ADJUSTMENT ("BDA") RIDER REQUEST.

A. Staff witness Mr. Swaim contends that the proposed BDA rider differs from the previously approved BDA rider and that the Company's proposal has added two "true-up" adjustments.

Q. DID THE COMPANY INCLUDE TRUE-UP ADJUSTMENTS IN ITS PROPOSED RIDER BDA?

A. No. The BDA mechanism includes two revenue normalization adjustments similar to the BDA that was in place for CERC. The Company is not proposing any new methodology in this BDA rider.

Q. DOES THE COMPANY HAVE AN OBJECTION TO MR. SWAIM'S PROPOSED ADJUSTMENTS TO RIDER BDA?

A. Yes. Mr. Swaim's proposed elimination of the revenue normalization adjustments is contrary to the structure of CERC's last approved Rider BDA. The revenue normalization adjustments are necessary to calculate the appropriate test year base revenues for comparison to the actual revenues recorded.

Q. WHAT ACTIONS SHOULD THE COMMISSION TAKE ON SUA'S PROPOSED RIDER BDA?

A. The Commission should approve the Rider BDA as proposed by the Company.

B. SSER.

Q. DOES STAFF AGREE THAT SUA'S SSER SHOULD BE APPROVED?

A. Yes, but Mr. Hilton does not support the Company's requested SSER, inclusive of reliability projects. Mr. Hilton asserts that the Company should have applied traditional rider test factors and the additional criteria the Commission considered for an electric utility in Docket No. 19-035-U.

Q. DO YOU AGREE WITH MR. HILTON THAT THE COMPANY SHOULD HAVE APPLIED THE TRADITIONAL RIDER TEST TO THE PROPOSED SSER?

A. No. There is no requirement from the Commission that these test factors should be applied to riders nor that a consideration in one docket should apply to other docketed cases before the Commission. Additionally, this test has not historically been applied to safety riders such as SUA's requested SSER and in fact, Docket No. 19-035-U was not considering a safety rider nor a natural gas rider. In fact, these factors were not considered when the Commission approved the settlement agreement implementing the SSER in Docket No. 21-060-U.

Q. DOES THE COMPANY RECOGNIZE THAT IT IS ASKING FOR A CHANGE IN SSER'S OPERATION?

A. Yes. The request for this change was outlined in the Company's direct case. Importantly, I would note that the decision of whether to alter the type of costs collected through the SSER is a policy decision. It is the Company's belief that there is little practical difference between reliability and safety projects. If the Company experiences an issue related to reliability—say, for instance, low pressure or the loss of pressure completely on a gas line—then safety issues immediately follow. In the example of lost pressure to homes or businesses, Company personnel must go house to house, business to business before service can safely be restored. Put differently, reliability and safety go hand in hand. The Company does, however, understand Staff's request for greater clarity on the types of projects that might be added to SSER. It has attempted to provide that clarity through Mr. McNully's rebuttal testimony.

Q. WHAT RECOMMENDATIONS DOES STAFF PROPOSE WITH RESPECT TO RIDER SSER AND OTHER EXPIRING RIDERS?

A. Mr. Swaim proposes to calculate a level of SSER and Lost Contribution to Fixed Costs ("LCFC") revenue for the pro forma year using Staff's billing determinants. Additionally, Mr. Hilton recommends that the SSER be approved with the following additional recommendation:

- 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 SSER should exclude reliability projects.
- The Company should recognize additional Accumulated Deferred Income Tax ("ADIT") associated with capital investments being included for recovery by reducing gross plant.
- STI and LTI should be excluded from plant.
- The SSER should exclude future Pipeline and Hazardous Materials Safety Administration or Arkansas Gas Pipeline Code requirements.
- Only previously approved Act 310 activities should be included.
- Finally, no additional monthly SSER filings would be made once the Company files an application for a general rate change.

Q. WILL YOU BE ADDRESSING ALL OF MR. HILTON'S RECOMMENDATIONS?

A. No. I address the inclusion of cumulative savings, the annual cap, reduction of gross plant due to ADIT, excluding STI and LTI, and no additional SSER filings once an application for a general rate case has been filed. Mr. McNully addresses the remainder of Staff's concerns in his testimony.

Q. DO YOU AGREE WITH MR. SWAIM'S SSER BILLING DETERMINANT ADJUSTMENT AND EXPIRING RIDER REVENUE RECOMMENDATIONS?

A. No.

Q. WHY NOT?

A. Mr. Swaim's calculation of the SSER revenue impacts uses a different set of proposed billing determinants and the June 1, 2024 SSER rates. The Company calculates an SSER revenue impact of $8,716,076 using the Company's proposed billing determinants and the

August 1, 2024 SSER rates. For LCFC, the Company proposes a revenue impact of $1,400,373 using the same billing determinants and the LCFC portion of the EECR rates.

Q. DO YOU AGREE WITH MR. HILTON'S RECOMMENDATION THAT NO ADDITIONAL MONTHLY FILINGS IN THE SSER BE MADE ONCE THE COMPANY HAS FILED ITS APPLICATION FOR A GENERAL RATE CHANGE IN A FUTURE RATE CASE?

A. No. At this time, no one knows how the Commission will address the SSER in future proceedings. It is common for rate mechanisms to stay in place until they are replaced by other new mechanisms and new rates are implemented. Proactively ceasing a rate mechanism without clarity on its replacement would be unusual in my experience. In the case of the SSER, it would also be contrary to a policy objective of the SSER's existence while the future rate case was being processed—encouraging investment in safety. The Commission and utilities have long managed to transition between rate mechanisms without cessation during a pending rate case, and that transition can be orderly through diligent accounting and further true-up, if needed, at the time of new rate implementation.

Q. DO YOU AGREE WITH MR. HILTON'S RECOMMENDATION THAT THE COMPANY SHOULD CONTINUE TO INCLUDE CUMULATIVE SAVINGS DUE TO O&M EXPENSE REDUCTION?

A. No. Replacement of facilities does not directly reduce the amount of O&M expenses. There are still O&M expenses that must be incurred regardless of the age or condition of the facilities such as leak surveying, line locating, performing cathodic protection test point reads and rectifier inspections, field testing meters, inspecting and testing district regulator stations and over-pressure protection, etc.

Q. DO YOU AGREE WITH MR. HILTON'S RECOMMENDATION THAT THERE SHOULD BE AN ANNUAL CAP ON THE COMPANY'S SSER?

A. No. The annual cap is not necessary. The SSER defines what projects may be included and there are checks and balances in place to ensure the Company is not including projects outside the scope of the SSER. Further, many of the SSER projects are driven by replacements due to DIMP and TIMP plans, which are required by this Commission's gas code. The underlying policy behind an SSER is to allow the Company to recover these expenses in a more efficient manner, which allows the Company to reinvest the funds in the next required project. A cap does not support the intent of the SSER.

Q. HOW DO YOU DISTINGUISH THE ANNUAL CAP SET FOR THE SSER IN DOCKET NO. 21-060-U?

A. In the SSER negotiated as part of the settlement agreement in that docket, an annual revenue requirement cap for a certain dollar amount was set for the years 2022, 2023, and 2024, in conjunction with the Company's agreement to file a notice of intent to file a general rate case application no sooner than 12 months (January 2023) and no more than 24 months after the closing of the transaction (January 2024).[1][2] Such a cap was reasonable within the context of that settlement given that Summit Utilities, Inc. had just purchased CERC's Arkansas assets and SUA's future capital investment plans, although planned to be similar to those of CERC's, might be expected to differ from CERC's historical capital investment levels. Beyond those specific circumstances, for the reasons explained above,

[1] Docket No. 21-060-U, Joint Motion to Approve Settlement Agreement and to Waive Hearing, Joint Exhibit 1 at 8 (October 14, 2021).
[2] Paragraph D.3 of the Settlement Agreement states: "This Settlement Agreement shall not be used or argued as establishing precedent for any methodology or rate treatment in any future proceeding."

a cap on SSER expenditures is not necessary or reasonable now that SUA has established its operations in Arkansas for a number of years.

Q. DO YOU AGREE WITH MR. HILTON'S RECOMMENDATION THAT THE COMPANY SHOULD RECOGNIZE ADIT BEING INCLUDED FOR RECOVERY BY REDUCING GROSS PLANT?

A. No. The current ADIT asset, although part of the MBSA and the associated WACC calculation, is not being utilized by the Company in this proceeding, thereby resulting in a lower WACC compared to including the ADIT asset. It is uncertain at this time when the current ADIT asset, which is projected to be $22,909,825 at the end of the pro forma year, will become an ADIT liability. Additionally, it is unclear how much of that change can be associated with SSER additions.

Q. DO YOU AGREE WITH MR. HILTON'S RECOMMENDATION THAT STI AND LTI SHOULD BE REMOVED FROM PLANT?

A. No.

Q. HAVE YOU REVIEWED MR. PORTER'S TESTIMONY RELATED TO THE SSER?

A. Yes.

Q. DO YOU HAVE ANY GENERAL COMMENTS ON HIS CHARACTERIZATION OF THE REGULATORY ENVIRONMENT AND THE COMMISSION'S CRITERIA FOR RIDERS?

A. Yes. I do not agree with Mr. Porter's characterization of the "regulatory environment" and the request for a modification to an existing approved rider as "regulatory privilege", or his alleged "Commission's criteria" for riders. Simply put, the Commission has approved countless cost recovery and refund mechanisms over the years. Riders have been approved for a variety of "reasonable and necessary" reasons. For example, Gas Supply Riders ("GSR") were approved because of cost volatility reasons. It was unfair to either the utility company or customers to set rates for an extended period of time when fuel costs are abnormally high or abnormally low. Weather Normalization Adjustment and Billing Determinant Adjustment riders have been created to address revenue volatility after rates are set. Tax Adjustment riders have been created to address substantial changes in tax laws that either increased or decreased taxes paid by the utility and ultimately recovered from customers. Sometimes a Commission may want greater cost visibility and oversight, such as what occurs in the EECR context. Finally, riders such as the SSER and Government Mandated Expenditures Surcharge riders were developed in response to safety issues and government mandates. I am not aware of, nor can Mr. Porter point to, the Commission evaluating riders in accordance with his stated "criteria" on a consistent basis. There is no "one size fits all" ratemaking approach. Rather, it is my opinion that the Commission has simply evaluated the need for cost recovery or refund mechanisms under the traditional standard of whether the mechanism is reasonable and necessary given the facts and evidence at hand.

Q. ARE THE COMPANY'S REQUESTS RELATED TO SSER TRULY NEW OR UNIQUE?

A. No. As noted above and in Mr. McNully's testimony, reliability projects are important. They necessarily involve safety. I would also note, that if the Company had requested, and the Commission approved, a FRP mechanism in this case, the debate of whether to include reliability projects in the SSER would likely not even exist. Those projects would be included in the Company's annual FRP filing.

Q. DO YOU HAVE ANY COMMENTS ON MR. BLANK'S SUGGESTION THAT A FORMULA RATE PLAN RIDER IS A BETTER OPTION THAN AN EXPANDED SSER?

A. 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.

VII. CONCLUSION

Q. PLEASE SUMMARIZE YOUR TESTIMONY.

A. Throughout my testimony I have identified some adjustments proposed by other parties that are appropriate to make. I have also provided an explanation of why some proposed adjustments are improper and request that the Commission accept SUA's adjustments. Finally, I discuss SUA's proposed Rider BDA and SSER . Specifically, I reject Staff's recommended changes to the Rider BDA because determining revenue normalization adjustments is required for the purpose of the Rider BDA. I also explain why Staff's recommended changes to SUA's proposed SSER are not necessary and at times contradict the basic purpose of the SSER.

Q. DOES THIS CONCLUDE YOUR TESTIMONY?

A. Yes.

CERTIFICATE OF SERVICE

I, Brooke South Parsons, do hereby certify that a true and correct copy of the foregoing has been delivered to all Parties of Record by electronic mail via the Electronic Filing System this 7th day of August 2024.

Brooke South Parsons

Brooke South Parsons

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

REBUTTAL EXHIBITS

OF

PHILLIP B. GILLAM

DIRECTOR OF RATES & REGULATORY AFFAIRS

ON BEHALF OF

SUMMIT UTILITIES ARKANSAS INC.

Date Filed: August 7, 2024

Summit Utilities Arkansas, Inc
Summary of Income Statement Adjustments
Docket No. 23-079-U

Line No.	Adjustment Description	SUA Adjustment	Staff Adjustment	Difference	Position
1	IS-1 Cost of Gas Adjustment	262,228,735	268,978,147	(6,749,412)	Updated - Not Contested
2	IS-2 Miscellaneous Taxes (Other Than Income) Adjustment	8,033	8,033	-	Not Contested
3	IS-3 Revenue Adjustment	(265,459,431)	(273,642,924)	8,183,493	Contested and Updated
4	IS-4 Forfeited Discount Normalization	1,495,193	1,537,787	(42,594)	Contested and Updated
5	IS-5 Energy Efficiency Adjustment	10,175,378	-	10,175,378	Updated - Not Contested
6	IS-6 Bad Debt Adjustment	6,109,401	7,295,558	(1,186,157)	Contested and Updated
7	IS-7 Rate Case Amortization Adjustment	(714,940)	(182,976)	(531,964)	Contested
8	IS-8 Interest Income Adjustment	613,249	-	613,249	Updated
9	IS-9 Advertising & Marketing Adjustment	922,529	922,529	-	Not Contested
10	IS-10 Other Expenses Adjustment	418,450	418,450	-	Not Contested
11	IS-11 Interest on Customer Deposits	(89,460)	(89,460)	-	Not Contested
12	IS-12 Payroll Adjustment	(396,911)	1,607,440	(2,004,351)	Contested and Updated
13	IS-13 Benefits Adjustment	(123,300)	229,104	(352,404)	Contested and Updated
14	IS-14 Meals & Travel Adjustment	375,037	375,037	-	Not Contested
15	IS-15 Postage Expense Adjustment	(168,749)	(168,749)	-	Not Contested
16	IS-16 Property Tax Adjustment	24,501	24,501	-	Not Contested
17	IS-17 Pipeline Locator Fees	(1,166,079)	(1,166,079)	-	Not Contested
18	IS-18 Corporate Pro Forma Adjustments	(537,818)	204,946	(742,764)	Contested and Updated
19	IS-19 Depreciation Expense Adjustment	(8,959,739)	(8,064,458)	(895,281)	Contested and Updated
20	IS-20 Deferred COVID Expense Recovery	(2,113,044)	(1,267,826)	(845,217)	Contested
21	IS-21 Deferred Income Tax Expense - ARO	186,125	-	186,125	Not Contested
22	IS-22 Current Income Tax **	5,703,062	4,980,724	722,338	Contested and Updated
23	IS-23 Non-Utility Expenses	4,581	83,105	(78,524)	Contested
24	IS-24 Vegetation Control Expense	-	212,357	(212,357)	Contested-Not Updated
25	IS-25 Non-Recurring Transactions	18,608	725,985	(707,377)	Contested
26	IS-26 Volunteer Time Off	-	151,865	(151,865)	Contested
27	IS-27 Transportation Depreciation Allocation	-	888,014	(888,014)	Contested
28	IS-28 Call Center	-	489,252	(489,252)	Contested
		8,553,411	4,550,362		

**Includes an adjustment for deferred inc tax, utility operating

Summit Utilities Arkansas, Inc
Summary of Rate Base Adjustments
Docket No. 23-079-U

Line No.	SUA Adj. No.	Staff Adj. No.	Description	SUA Adjustments	Staff Adjustments	Difference	Position
1			Adjustments to Utility Gross Plant-In-Service				
2	RB-2	RB-2	CWIP Placed in Service Pro Forma Year	$ 162,461,129	$ 162,461,129	-	Not Contested
3	RB-3	RB-3	Pro Forma Retirements	(15,824,916)	(15,826,521)	1,605	Updated
4	RB-4	RB-4	Pro Forma Reclassifications	(7,773,000)	(7,773,000)	-	Not Contested
5	RB-12	RB-12	ARO - Adjustment	(2,280,944)	(2,280,944)	-	Not Contested
6		RB-13	STIC	-	(1,749,525)	1,749,525	Contested
7		RB-14	Volunteer Time Off	-	(57,145)	57,145	Contested
8	RB-15	RB-15	Rebranding Capital Expenditures	(379,968)	(379,968)	-	Updated
9			Total Adjustments to Utility Gross Plant-In-Service	$ 136,202,301	$ 134,394,026	1,808,275	
10			Adjustments to Accumulated Depreciation				
11	RB-1	RB-1	Pro Forma Capital Expenditures	8,550,586	8,550,586	(0)	Not Contested
11	RB-3	RB-3	Pro Forma Retirements	15,824,916	15,826,521	(1,605)	Updated
13		RB-5	Pro Forma RWIP /Retirements	-	(54,319)	54,319	Contested and Updated
14	RB-6	RB-6	Pro Forma Depreciation	(66,353,140)	(66,357,897)	4,757	Contested and Updated
15	RB-7	RB-7	Remove CWIP/ RWIP	(8,857,409)	(8,982,020)	124,611	Updated
16	RB-12	RB-12	ARO - Adjustment	228,094	228,094	-	Not Contested
17		RB-13	STIC	-	66,767	(66,767)	Contested and Updated
18		RB-14	Volunteer Time Off	-	2,179	(2,179)	Contested and Updated
19	RB-15	RB-15	Rebranding Capital Expenditures	14,500	14,500	-	Not Contested
20			Total Adjustments to Accumulated Depreciation	$ (50,592,454)	$ (50,705,590)	113,136	
21			Adjustments to Construction Work-In-Progress				
22	RB-7		Remove CWIP/ RWIP	($21,958,399)	(20,410,287)	(1,548,112)	Updated
23			Adjustments to Working Capital Assets				
24	RB-10	RB-10	Adjust 13-Month Average Balance	(232,579,016)	(294,973,142)	62,394,126	Contested and Updated
25	RB-11	RB-11	Adjust Working Capital Assets to 13 month Averge Balance	(13,935,674)	46,858,397	(60,794,071)	Contested and Updated
26			Total Adjustments to Working Capital Assets	$ (246,514,690)	$ (248,114,746)	1,600,055	
27			Other Adjustments				
28	RB-9	RB-9	Remove Acquisition Adjustment	$ (690,091,096)	(690,091,096)	-	Not Contested
29	RB-12	RB-12	ARO - Adjustment	-	-	-	
30			Total Other Adjustments	$ (690,091,096)	$ (690,091,096)		
31			Total Rate Base Adjustments	(872,954,338)	(874,927,693)		

Summit Utilities Arkansas, Inc.
Arkansas Calculation of Revenue Requirement
For The Pro Forma Test Year Ended December 31, 2024

Schedule: A - 1
Title: Calculation of Requested Increase In Revenue Requirement
Docket No. 23-079-U

Explanation: Schedule showing test year information and the calculation of Arkansas jurisdictional revenue requirement and revenue deficiency as determined by separate supporting schedules.

I. Test Year Information

1	Provide the ending date of the test year	12/31/2023
2	Specify whether the test year is completely historical or partially projected.	partially projected test year

II. Calculation of Revenue Requirement

(1) Line No.	(2) Line Item Description	(3) Arkansas Jurisdiction*
1	Adjusted Rate Base (a)	1,228,404,484
2	Adjusted Operating Revenue (a)	188,640,582
3	Adjusted Operating Expense (a)	178,517,705
4	Adjusted Operating Income (L.2 - L.3)	10,122,877
5	Current Rate of Return (L.4 / L.1)	0.8241%
6	Required Rate of Return (b)	6.9790%
7	Required Operating Income (L.1 x L.6)	85,730,349
8	Operating Income Deficiency (L.7 - L.4)	75,607,472
9	Revenue Conversion Factor (c)	1.33841
10	Revenue Deficiency (L.8 x L.9)	101,194,113
11	Total Non-Fuel Revenue Requirement (L.2 + L.10)	289,834,695
12	Adjusted Revenues Other Than Rate Schedule Revenue (a)	7,078,629
13	Rate Schedule Revenue Requirement (L.11 - L.12)	282,756,066
14	Percentage Increase in Total Revenue Requirement (L.10 / L.2)	53.6439%

Supporting Schedules
(a) G-1
(b) D-1.3-Holdco - Rebuttal Testimony
(c) C-5 - Rebuttal Testimony, or composite from G-1 if determined by rate class

* 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).

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**

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

REBUTTAL TESTIMONY

OF

FRED KIRKWOOD

CHIEF CUSTOMER OFFICER

ON BEHALF OF

SUMMIT UTILITIES ARKANSAS, INC.

Date Filed: August 7, 2024

TABLE OF CONTENTS

I. INTRODUCTION

Q. PLEASE STATE YOUR NAME, POSITION AND BUSINESS ADDRESS.

A. My name is Fred Kirkwood. I am the Senior Vice President & Chief Customer Experience Officer for Summit Utilities, Inc. ("SUI"). My business address is 1000 Fianna Way, Suite 520, Fort Smith, Arkansas.

Q. ARE YOU THE SAME FRED KIRKWOOD WHO FILED DIRECT TESTIMONY ON JANUARY 25, 2024, IN THIS PROCEEDING?

A. Yes.

Q. WHAT IS THE PURPOSE OF YOUR REBUTTAL TESTIMONY?

A. The purpose of my Rebuttal Testimony is to respond to certain proposed adjustments, contentions, and recommendations in the Direct Testimonies of Arkansas Public Service Commission ("Commission") General Staff ("Staff") witnesses, Mr. Don Malone and Mr. Jeff Hilton, and Hospitals and Higher Education Group witness, Mr. Larry Blank.

II. TEST YEAR CALL CENTER EXPENSE

Q. PLEASE SUMMARIZE MR. MALONE'S PROPOSED ADJUSTMENT TO CALL CENTER EXPENSES.

A. Mr. Malone proposes to adjust the Company's test year expense by $489,252 to remove certain vendor call center costs that were incurred by Summit Utilities Arkansas, Inc. ("SUA" or the "Company") during the conversion from the transition service agreement with CenterPoint Energy, Inc. ("CNP"). Mr. Malone argues that the call center expenses in question were temporary and are non-recurring.

Q. IS MR. MALONE'S PROPOSED ADJUSTMENT REASONABLE?

A. No. Mr. Malone is correct that the identified call center expenses were temporary in nature. The vendor, Convergent Outsourcing, Inc., served as an extension of SUA's internal call center through May 31, 2024. However, I do not agree that the use of a third-party vendor for call center support will be non-recurring.

Q. WHAT FACTORS TYPICALLY CONTRIBUTE TO CALL CENTER EXPENSE LEVELS?

A. Several factors typically contribute to the number of agents needed in a call center to answer phone calls, impacting overall expense levels. These include:

- **Call Volume:** One of the most significant factors is the number of incoming calls. Higher call volumes necessitate a larger workforce to handle the increased load, directly increasing labor costs.

- **Gas Prices:** Increases or fluctuations in gas prices which impact customer bills. As customers face higher expenses, they more likely to contact customer service for assistance or to discuss their bills, leading to an increased call volume and a need for more agents.

- **Weather:** Weather conditions can significantly impact call volumes. Colder weather or a winter storm, for instance, may lead to a higher number of calls due to an increase in heating costs. Colder weather also will increase the demand for new gas service connects and reconnects of service for disconnected customers.

- **Cost of Labor:** The expense associated with recruiting, training, and retaining call center agents is another critical factor.

Q. DOES THE COMPANY EXPECT THAT IT MAY NEED TO RETAIN THIRD-PARTY ASSISTANCE WITH CALL CENTER FUNCTIONS IN THE FUTURE?

A. Yes. The use of third-party vendors to support call centers is commonly used as a cost-effective extension of labor. The Company currently utilizes the services of a third-party vendor, First Collection Services, located in Little Rock, Arkansas.

Q. SHOULD THE COMMISSION ADOPT MR. MALONE'S PROPOSED ADJUSTMENT TO TEST YEAR CALL CENTER EXPENSE?

A. No. Mr. Malone argues that the call center expenses in question were temporary and are non-recurring. However, SUA's use of a third-party vendor for call center support will be reoccurring and necessary to meet service level requirements in the most cost-efficient manner. Strategically, using third party vendors provides the Company with the necessary flexibility to adjust staffing levels according to demand. The scalability offered by a third-party vendor also allows the Company to efficiently manage its resources, ramping up or down as needed without the long-term commitment associated with hiring full-time employees.

Q. IS THE TEST YEAR AMOUNT ASSOCIATED WITH THIRD-PARTY VENDOR COSTS REASONABLE?

A. Yes. Based on my experience, the test year call center expense amount is reasonable.

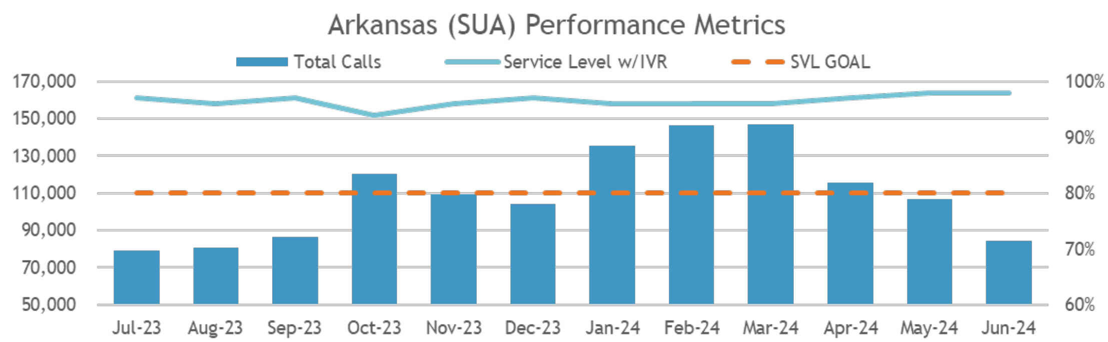
III. CUSTOMER SERVICE PERFORMANCE

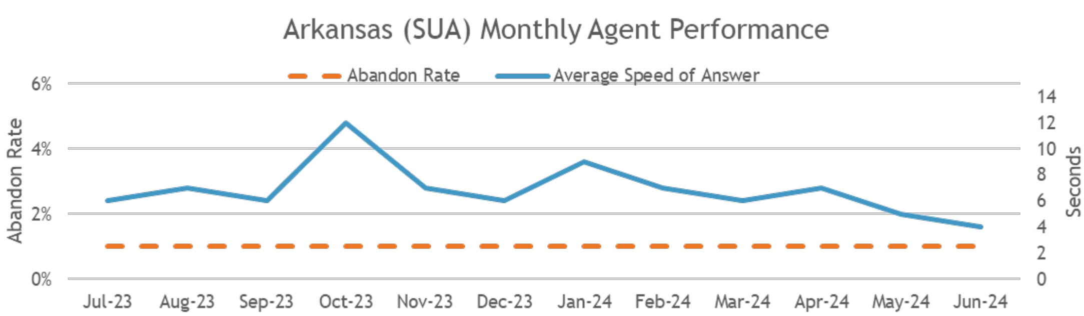
Q. MR. BLANK SUGGESTS THAT THE COMMISSION SHOULD GIVE GREATER WEIGHT TO THE LOWER END OF MR. D'ASCENDIS' RANGE OF RETURNS ON EQUITY BASED ON SUA'S RECENT PERFORMANCE. DO YOU HAVE ANY GENERAL COMMENTS ON THIS SUGGESTION?

A. Mr. Blank's suggestion lacks any support showing that SUA was acting imprudently or had "poor management and widespread customer dissatisfaction." As discussed in more detail below, in Docket No. 23-015-U, the Commission found that SUA did not violate any General Service Rules ("GSR") and added a reporting requirement to "aid the Commission and Parties in the oversight of SUA's customer service as the transition process continues and will help address whether SUA is acting in the best interest of its customers."[1] SUA has since filed these reports and demonstrated that service levels are continuing to improve and complaints have declined. Additionally, in Docket No. 07-044-U, there were two separate proceedings in which SUA, or its predecessor, CNP, was found to have acted prudently.

Q. HOW IS SUA CURRENTLY PERFORMING?

A. SUA is exceeding all service levels included in Commission Rule 2.05 D. Call Center Operations - Utility Response Requirements. The chart below, an earlier version of which was presented in my Direct Testimony, demonstrates SUA's current call center performance metrics through June of 2024.





[1] Docket No. 23-015-U, Order No. 15 at 5 (August 18, 2023).

Q. DOES THE "EVIDENCE" CITED BY MR. BLANK ACTUALLY SUPPORT HIS ARGUMENT ON ROE?

A. No, as referenced above, Mr. Blank does not provide evidence of or point to any specific wrongdoing; instead, he simply points to the fact that there was an investigation. As explained in my Direct Testimony, it is common for companies transitioning to a new billing and customer service platform to experience challenges. SUA took additional steps to voluntarily suspend late payment fees and disconnection activities to ease any burden on customers as a result of this transition. A short-term increase in calls and complaints associated with a billing and customer service platform transition, during a time of unusually high natural gas prices, is not sufficient evidence that a company is experiencing performance issues.

Q. DID THE COMMISSION DETERMINE THAT SUA VIOLATED ANY COMMISSION RULES DURING THE BILLING INVESTIGATION IN DOCKET NO. 23-015-U?

A. No. The Commission found no evidence that SUA violated any of the Commission's GSRs and further found that SUA had corrected all billing errors at issue.[2]

Q. DID SUI OWN SUA'S ARKANSAS ASSETS DURING WINTER STORM URI?

A. No, such assets were owned and operated by CNP during Winter Storm Uri.

Q. WAS SUA FOUND TO BE IMPRUDENT IN THE GSR INVESTIGATION INITIATED ON MARCH 20, 2023?

[2] Id. at 4-5.

A. No. The Commission found that "SUA's gas costs were based on its Commission approved GSR tariff and were just and reasonable, and that gas costs did rise 35 percent from 2021 to 2022."[3]

Q. FROM YOUR PERSPECTIVE, IS THERE "WIDESPREAD CUSTOMER DISSATISFACTION" AMONG SUA CUSTOMERS, AS MR. BLANK ALLEGES?

A. No. SUA anticipated and communicated with its customers, the Commission, and other stakeholders the potential for a "bumpy" start during the transition from CNP's billing platform to SUA's new system. Unfortunately, due to data migration issues encountered during the transfer of data from CNP, the transition period lasted longer than expected. Since that period, however, SUA has continuously improved upon the quality of service delivered to its customers, exceeding all service level performance requirements for the past sixteen months.

Q. HOW SHOULD THE COMMISSION VIEW MR. BLANK'S COMMENTS AS THEY RELATE TO ROE?

A. Mr. Blank's comments are not supported by actual facts. As such, SUA respectfully requests that the Commission give no weight to Mr. Blank's ROE comments.

IV. STAFF TARIFF AND REPORTING RECOMMENDATIONS

Q. HAS STAFF TAKEN ANY SUPPORTIVE POSITIONS ON TARIFF CHANGES REQUESTED BY THE COMPANY IN THIS CASE?

A. Yes. Staff witness, Mr. Hilton, recommends approval of the Company's requested tariff changes related to the Company's Municipal Tax Adjustment Clause, General Service Rule

[3] Docket No. 07-044-U, Order No. 17 at 10 (August 18, 2023).

5.08 Waiver, Pooling Service, and Telemetry Language for Large and Small Transport Customers.

Q. DOES THE COMPANY HAVE ANY GENERAL COMMENTS RELATED TO THESE STAFF RECOMMENDATIONS?

A. SUA is appreciative of Staff's diligence and consideration of the Company's requested changes. Because Staff supports the requested changes and no other party has filed a position on the Company's requests, the changes should be approved by the Commission.

Q. WHAT POSITION HAS STAFF TAKEN ON SUA'S REQUEST TO FOREGO THE FILING OF FUTURE PAYMENT CENTER REPORTS?

A. Mr. Hilton agrees that it is reasonable for the Company to discontinue the filing of Payment Center Reports. However, he recommends that SUA ensure that its website is clear as to whether a payment center is free or not and that SUA should continue to maintain the supporting data for the report, for any future requests.

Q. DOES THE COMPANY AGREE TO FOLLOW STAFF'S RECOMMENDATIONS RELATED TO ITS WEBSITE AND RETENTION OF DATA?

A. Yes. The Company has no objection to Mr. Hilton's additional recommendations. The Commission should approve SUA's request to discontinue the filing of Payment Center Reports.

Q. DOES THIS CONCLUDE YOUR REBUTTAL TESTIMONY?

A. Yes.

CERTIFICATE OF SERVICE

I, Brooke South Parsons, do hereby certify that a true and correct copy of the foregoing has been delivered to all Parties of Record by electronic mail via the Electronic Filing System this 7th day of August 2024.

Brooke South Parsons

Brooke South Parsons

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

REBUTTAL TESTIMONY

OF

PAUL SCHULTE

SENIOR TAX MANAGER

ON BEHALF OF

SUMMIT UTILITIES ARKANSAS, INC.

Date Filed: August 7, 2024

TABLE OF CONTENTS

I. INTRODUCTION

Q. PLEASE STATE YOUR NAME, POSITION AND BUSINESS ADDRESS.

A. My name is Paul Schulte. I am the Senior Tax Manager for Summit Utilities, Inc. ("SUI"), which is the ultimate parent company of Summit Utilities Arkansas, Inc. ("SUA" or "Company"). My business address is 10825 E Geddes Avenue, Suite 410, Centennial, Colorado 80112.

Q. ARE YOU THE SAME PAUL SCHULTE WHO FILED DIRECT TESTIMONY ON JANUARY 25, 2024, IN THIS PROCEEDING?

A. Yes.

Q. WHAT IS THE PURPOSE OF YOUR REBUTTAL TESTIMONY?

A. The purpose of my Rebuttal Testimony is to respond to certain recommendations in the Direct Testimonies of Arkansas Public Service Commission ("Commission") General Staff ("Staff") witness, Mr. Don Malone, and Arkansas Gas Consumers, Inc. ("AGC") witness, Ms. Billie LaConte related to Accumulated Deferred Income Tax ("ADIT") and Excess Deferred Income Tax ("EDIT").

II. REPLY TO CERTAIN STAFF EDIT POSITIONS

Q. PLEASE SUMMARIZE THE RECOMMENDATIONS OF STAFF RELATED TO EDIT THAT WILL BE ADDRESSED IN YOUR REBUTTAL.

A. My Rebuttal Testimony addresses Staff's proposal to collect EDIT associated with the change in the state's corporate income tax from 5.3% to 4.3% effective January 1, 2024, over five years and Staff's proposal to collect EDIT reflected in SUA's Cost of Removal Deferred Tax Asset using the Average Rate Assumption Method ("ARAM").

Q. IS MR. MALONE CORRECT THAT IT IS APPROPRIATE TO COLLECT EDIT ASSOCIATED WITH THE CHANGE IN ARKANSAS'S CORPORATE TAX RATE FROM CUSTOMERS?

A. Yes. Mr. Malone correctly recognizes that EDIT associated with the change in Arkansas' corporate tax rate from 5.3% to 4.3% results in a net regulatory asset that should be returned to SUA.

Q. DID EDIT ASSOCIATED WITH THE CHANGE IN THE STATE CORPORATE TAX RATE EXIST WHEN SUA ORIGINALLY FILED THIS RATE CASE?

A. No. The change in the Arkansas state corporate tax rate occurred after the Company filed its rate case application and Direct Testimony.

Q. WHY DOES MR. MALONE RECOMMEND THAT EDIT PRODUCED BY THE CHANGE IN THE ARKANSAS CORPORATE TAX RATE BE COLLECTED OVER FIVE YEARS?

A. Mr. Malone's proposed collection period appears to be tied to his speculation that five years will pass "between rate cases" for SUA.[1]

Q. IS MR. MALONE'S FIVE-YEAR COLLECTION PERIOD FOR EDIT RELATED TO THE CHANGE IN CORPORATE TAX RATE REASONABLE?

A. No. As further explained in Company witness Gillam's Rebuttal Testimony, SUA will likely need to return to the Commission for rate relief sooner, rather than later.

Q. OVER WHAT PERIOD DOES SUA PROPOSE TO COLLECT EDIT ASSOCIATED WITH THE CHANGE IN CORPORATE TAX RATE?

---

[1] Direct Testimony of Don Malone at 23, line 2 (July 10, 2024).

A. SUA proposes to collect EDIT associated with the change in Arkansas' corporate tax rate over two years.

Q. WHY IS SUA PROPOSING A TWO-YEAR RECOVERY PERIOD FOR CORPORATE TAX RATE CHANGE-RELATED EDIT?

A. A two-year recovery period is more reflective of the time that is likely to exist between rate cases for SUA. Especially because this particular EDIT asset is relatively small in amount, it makes sense to ensure that it is fully collected prior to the imposition of new rates resulting from the Company's next base rate proceeding. Otherwise, the asset will remain on SUA's books, and the Commission will have to set a new collection period for an even smaller asset in a future case. It is more efficient, under these circumstances, to ensure that the full amount is collected between rate cases so that the issue is fully resolved through the rates resulting from this proceeding.

Q. WHY DOES MR. MALONE PROPOSE TO COLLECT THE COST OF REMOVAL-RELATED EDIT ASSET OVER ARAM?

A. Mr. Malone states that the "influx of capital into our economy through refunds to customers…was an intended stimulus to our economy as a result of the TCJA."[2] He therefore takes issue with the Company's proposal to credit the cost of removal-related asset against the protected EDIT liability that is currently being returned to customers as a result of the Commission's rate orders following the passage of the TCJA.

Q. IS MR. MALONE'S RECOMMENDATION TO COLLECT COST OF REMOVAL-RELATED EDIT OVER ARAM REASONABLE?

[2] Id. at 20, lines 4-6.

A. No. Mr. Malone does not dispute that the cost of removal-related EDIT is now considered "unprotected" EDIT by the Internal Revenue Service ("IRS"). As such, and as he correctly acknowledges in the context of excess state ADIT, "unprotected" EDIT may be collected or refunded "without regard to any prescribed time periods."[3] "Protected" EDIT, on the other hand, must be returned or collected from customers over ARAM. Additionally, it appears that Mr. Malone may not understand the intended effect of SUA's proposal with respect to customers.

Q. WHY DID THE COMPANY ORIGINALLY PROPOSE TO CREDIT THE COST OF REMOVAL-RELATED EDIT ASSET AGAINST THE PROTECTED EDIT LIABILITY THAT IS BEING REFUNDED TO CUSTOMERS?

A. The Company's proposal simply decreases the amount of the TCJA-related protected EDIT liability that is already in existence and is currently being refunded to customers. Mr. Malone states that "customers would not see a net refund until the unprotected EDTA is fully extinguished in 2037."[4] The Company's proposal does not stop the return of protected EDIT to customers. Rather, it provides for a return to the Company from the cost of removal-related asset at the same rate as the refund to customers from the protected EDIT liability. It results in no change to current rates for customers—it is not a cessation of a current refund. It is not unreasonable, in this context, to credit the asset against the Company's current protected deferred tax liability such that is collected over 13 years, as opposed to the approximately 48 years of collection that would result through the use of ARAM.

[3] Id. at 18, lines 1-5.
[4] Id. at 19, lines 17-19.

Q. SHOULD THE COMMISSION ADOPT MR. MALONE'S RECOMMENDATION RELATED TO COST OF REMOVAL-RELATED EDIT?

A. No. SUA hopes to work with Staff on this issue and arrive at a common understanding of how SUA's proposal on cost of removal-related EDIT will impact customer rates in the future. Regardless, SUA's proposal is reasonable, does not keep the utility from continuing to refund EDIT in current rates, and, as such, should be approved.

III. REPLY TO STAFF'S INCOME TAX EXPENSE POSITION

Q. WHAT IS MR. MALONE'S POSITION ON INCOME TAX EXPENSE?

A. Mr. Malone proposes adjustments to the Company's income tax expense to reflect a pro forma Arkansas state income tax rate of 4.3%, interest expense, and adjustments related to his EDIT recommendations.

Q. DO YOU AGREE WITH MR. MALONE'S ADJUSTMENTS?

A. I agree with Mr. Malone's adjustments as they relate to the state income tax rate and interest expense. The Company updated its income tax expense calculations to include an imputed interest expense line item. I do not agree with Mr. Malone's proposed adjustments related to cost of removal-related EDIT for many of the same reasons detailed in my testimony above. I have not included an adjustment to income tax expense for a reduced cost of removal-related EDIT amortization, because the Company still believes it should offset the protected liability amortization at a net-zero rate for the next 13 years. Mr. Gillam has reflected the portions of Mr. Malone's income tax adjustment that the Company can agree to in SUA's updated cost of service.

IV. <u>REPLY TO AGC'S EDIT POSITION</u>

Q. PLEASE SUMMARIZE MS. LACONTE'S POSITION ON THE COMPANY'S DEFERRED TAX ASSET RELATED TO COST OF REMOVAL.

A. Ms. LaConte argues that SUA's proposal does not align with the Commission's order in Docket No. 18-006-U and that the IRS Private Letter Ruling ("PLR") provided by the Company in support of its request pertains to another utility.

Q. HOW DO YOU RESPOND TO MS. LACONTE?

A. As noted in my Direct Testimony, to avoid a normalization violation, the cost of removal portion of book versus tax depreciation timing differences needs to be separated from both the original netted EDIT liability and from the depreciation expense used in the ARAM calculation and included as an "unprotected" EDIT asset. Otherwise, the remaining protected EDIT may be returned too quickly under the ARAM calculation, which would put SUA in the position of risking a normalization violation. The Commission was well-aware of the normalization rules when it decided Docket No. 18-006-U. As such, there is no conflict between the order issued by the Commission in that proceeding and the Company's proposal aside from the fact that amounts originally thought to be "protected" EDIT have now been determined to be "unprotected" by the IRS.

Q. DOES MS. LACONTE DISPUTE THE FACT THAT A NORMALIZATION VIOLATION COULD OCCUR IF SUA DOES NOT ACT TO SEPARATE ITS COST OF REMOVAL EDIT FROM THE ORIGINAL EDIT LIABILITY AND DEPRECIATION EXPENSE USED IN THE ARAM CALCULATION?

A. No.

Q. DID THE TCJA INCLUDE LANGUAGE RELATED TO VIOLATION OF THE IRS'S NORMALIZATION RULES?

A. Yes. The law states "If the taxpayer does not use a normalization method of accounting… the taxpayer's tax for the taxable year shall be increased by the amount by which it reduces its excess tax reserve more rapidly than permitted under a normalization method of accounting and such taxpayer shall not be treated as using a normalization method of accounting for purposes of sub-sections (f)(2) and (i)(9)(C) of section 168 of the Internal Revenue Code of 1986." This penalty is in addition to the penalty under the Tax Reform Act of 1986.

Q. WHAT WOULD THE CONSEQUENCE BE IF THE COMPANY WERE REQUIRED TO VIOLATE THE IRS'S NORMALIZATION RULES?

A. The Company would be required to notify the IRS of such a violation, and it would be prohibited from using accelerated depreciation prospectively, unless corrective actions are taken to bring the Company's books back in line with the IRS normalization guidelines. Accelerated depreciation results in ADIT that is a critical source of cost-free capital. That cost-free capital benefits customers by lowering financing costs and thus directly results in lower rates. Loss of this cost-free loan from the government would significantly increase costs to Arkansas customers and would weaken the Company's financial position. Additionally, if the normalization violation was caused by refunding the protected excess tax reserve faster than allowed under ARAM, the Company would be required to pay an additional tax equal to the amount of the excess refunded. The combination of these two penalties, if imposed, would severely damage both the Company and its customers.

Q. HOW DO YOU RESPOND TO MS. LACONTE'S ARGUMENT THAT THE PLR RELIED UPON BY THE COMPANY PERTAINS TO ANOTHER UTILITY?

A. Ms. LaConte's argument ignores the fact that the IRS's guidance to the utility in the cited PLR relates to similar circumstances faced by SUA. Utilities across the country are relying on the same guidance and PLR in requests to change the tax accounting and recovery of cost of removal-related EDIT. SUA is not alone in its request. It is also commonplace and a best practice to rely on PLRs that address the same tax issue faced by different filers. Otherwise, the IRS would have to issue a PLR on any new guidance for virtually every corporate tax filer anytime it issued new guidance. Staff witness, Mr. Malone, correctly recognizes the effect of the PLR and the change in accounting necessary to avoid a normalization violation for SUA. Ms. LaConte's position should be rejected.

Q. DOES THIS CONCLUDE YOUR REBUTTAL TESTIMONY?

A. Yes.

CERTIFICATE OF SERVICE

I, Brooke South Parsons, do hereby certify that a true and correct copy of the foregoing has been delivered to all Parties of Record by electronic mail via the Electronic Filing System this 7th day of August 2024.

Brooke South Parsons

Brooke South Parsons

BEFORE THE

ARKANSAS PUBLIC SERVICE COMMISSION

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

REBUTTAL TESTIMONY

OF

CRAIG ROOT

VICE PRESIDENT AND CORPORATE TREASURER

ON BEHALF OF

SUMMIT UTILITIES ARKANSAS, INC.

Date Filed: August 7, 2024

TABLE OF CONTENTS

LIST OF EXHIBITS

I. INTRODUCTION

Q. PLEASE STATE YOUR NAME, POSITION, AND BUSINESS ADDRESS.

A. My name is Craig Root. I am the Vice President and Corporate Treasurer for Summit Utilities, Inc. ("SUI"), which is the ultimate parent company of Summit Utilities Arkansas, Inc. ("SUA" or "Company"). My business address is 1400 Centerview Drive, Suite 100, Little Rock, AR 72211.

Q. ARE YOU THE SAME CRAIG ROOT WHO FILED DIRECT TESTIMONY ON JANUARY 25, 2024, IN THIS PROCEEDING?

A. Yes.

Q. WHAT IS THE PURPOSE OF YOUR REBUTTAL TESTIMONY?

A. The purpose of my Rebuttal Testimony is to rebut portions of the Direct Testimonies of the Arkansas Public Service Commission ("Commission") General Staff ("Staff") witness Mr. Dan Daves, the Arkansas Attorney General ("AG") witness Dr. Marlon F. Griffing, Ph.D., Hospitals and Higher Educations Group ("HHEG") witness Mr. Larry Blank, and Arkansas Gas Consumers, Inc. ("AGC") witness Ms. Billie S. LaConte.

Q. ARE YOU SPONSORING OR CO-SPONSORING ANY EXHIBITS?

A. Yes, I sponsor the exhibit listed in my Table of Contents.

Q. DOES THE FACT THAT YOU MAY NOT ADDRESS AN ISSUE OR POSITION RAISED BY ANOTHER PARTY INDICATE THAT YOU AGREE WITH THEIR POSITION?

A. No, it does not.

II. CAPITAL STRUCTURE

Q. WHAT IS THE COMPANY'S REQUESTED CAPITAL STRUCTURE IN THIS CASE?

A. Based on updated numbers from the final 2023 audit, the Company is requesting a capital structure of 45.12% total debt and 54.88% equity, consistent with the actual capital structure planned for Southern Col Holdco, LLC's ("SCHC") as of December 31, 2024.

Q. WHAT HAVE THE OTHER PARTIES PROPOSED RELATING TO CAPITAL STRUCTURE?

A. The parties' capital structure positions are as follows:

- On behalf of Staff, Mr. Daves proposes a hypothetical a capital structure of 56% debt and 44% equity, with 6.23% allocated for short-term debt.[1]
- For the AG, Dr. Griffing proposes a hypothetical capital structure of 46% long-term debt, 8% short-term debt, and 46% common equity.[2]
- Testifying on behalf of HHEG, Dr. Blank recommends utilizing the long-term debt and common equity of SCHC without the pro forma adjustments to debt and equity proposed in my Direct Testimony, resulting in a hypothetical capital structure of 51.41% long-term debt and 48.59% common equity.[3]
- For AGC, Ms. LaConte recommends that the Commission lower the Company's proposed common equity ratio to no higher than 50%.[4]

[1] Direct Testimony of Dan Daves at 29 (July 10, 2024).
[2] Direct Testimony of Marlon F. Griffing, Ph.D. at 46 (July 10, 2024).
[3] Direct Testimony of Larry Blank at 8-9 (July 10, 2024).
[4] Direct Testimony of Billie S. LaConte at 34 (July 10, 2024).

Q. DO YOU HAVE ANY UPDATES TO THE COMPANY ANALYSES INVOLVED IN REACHING THE PROPOSED CAPITAL STRUCTURE IN THIS CASE THAT RESULT IN AN ALTERATION IN YOUR OPINION?

A. Yes. 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.

Q. FROM YOUR PERSPECTIVE AS TREASURER OF SUI, WHY IS THE COMPANY'S REQUESTED 55% EQUITY RATIO REASONABLE?

A. The Company's requested capital structure is consistent with the actual plan to finance SCHC as of December 31, 2024. In other words, while that capital structure may currently be considered "hypothetical" or "adjusted" or "pro forma", it reflects the actual financing plan for SUA and SCHC moving forward. That actual planned financing, using an equity ratio of 55%, has been relied upon by at least one rating agency in assessing the Company's credit profile and related risk.[5] As such, an equity ratio of 55% ensures that SUA can maintain its current cost of debt based on a target Funds From Operations to Debt ratio ("FFO / Debt") of 15%. In fact, if the Commission approves a lower equity ratio for SUA, there is documented risk that SCHC's current rating of A- by Fitch could be lowered, thereby increasing the cost of future debt for the Company.[6]

The Company's requested 55% equity ratio is also reasonable based on the range of equity ratios in the proxy group provided by Mr. D'Ascendis and is in line with recent

[5] Rebuttal Exhibit CR-1.
[6] Id. at 1.

industry trends. According to the RRA report provided by Mr. Daves as Exhibit 16,[7] average authorized equity ratios for gas utilities have risen substantially from 45.81% in 2004 to 53.86% in Q1 2024. Staff's recommendation of 44% equity is not consistent with industry trends and exposes the Company to significant and unnecessary financial risk in the form of reduced access to capital markets, higher costs of equity and debt, and less financial flexibility to withstand continued inflation or unexpected Winter Storm Uri-type events.

Q. WHY DOES A UTILITY FINANCE ITS ASSETS AND OPERATIONS WITH DIFFERENT TYPES OF CAPITAL?

A. A utility typically uses different types of capital because the various elements of capital have different risks, and, hence, different costs. Debt is generally less risky for investors than equity because debt holders are senior to equity holders in terms of having a claim on the utility's assets, and for that reason debt is generally less costly than equity. However, because debt investors have a senior claim on available cash flows and claim on the utility's assets, a higher debt ratio compared to equity ratio equates to increased financial risk to all investors. As a utility increases the proportion of debt in its capital structure, lenders increasingly demand higher returns to offset the risk of default, which increases the overall cost to access capital. Utilities, therefore, work to strike a balance that provides dependable access to capital in a cost-effective manner.

Q. DOES THE CAPITAL STRUCTURE APPROVED BY SUA'S REGULATORY AUTHORITIES HAVE AN IMPACT ON ITS COST OF DEBT?

[7] Direct Exhibits of Dan Daves, DD-16 at 6-7 (July 10, 2024).

A. Yes, because SCHC must necessarily manage its capital structure consistent with its regulatory approvals, decisions on how to manage the mix of debt and equity directly impact a company's credit rating. In general, the credit rating agencies examine the business risk and financial risk of an issuer by reviewing their cash flows and capital structure. Accordingly, the more financial leverage a company has, the worse its financial ratios and lower its credit ratings—and hence, the higher its cost of debt.

Q. PLEASE DESCRIBE THE CREDIT RATING AGENCY SCALES.

A. The rating agencies issue ratings for both the business entity as a whole and for the various debt issuances of the entity. For example, Moody's Investors Services, Inc. ("Moody's") assigns a long-term "issuer rating" that reflects the general credit risk of the business enterprise and Moody's opinion of the debt issuer's overall capacity to pay its scheduled financial obligations. The issuer rating is not a rating of individual securities but rather the core rating of the business enterprise from which ratings of individual securities are derived. In contrast, ratings on individual debt issuances reflect the likelihood that principal and interest on those specific debt issues will be paid in a timely manner and take into account the recovery prospects in the event of default. As shown below in Table 1, the ratings of the three rating agencies are similar, but not identical:

Table 1. Credit Rating Scales by Agency

Category	**Moody's***	**S&P***	**Fitch***
High Grade	Aaa	AAA	AAA
	Aa	AA	AA
Medium Grade	A	A	A
	Baa	BBB	BBB
Speculative	Ba	BB	BB
	B	B	B
Default	Caa	CCC	CCC

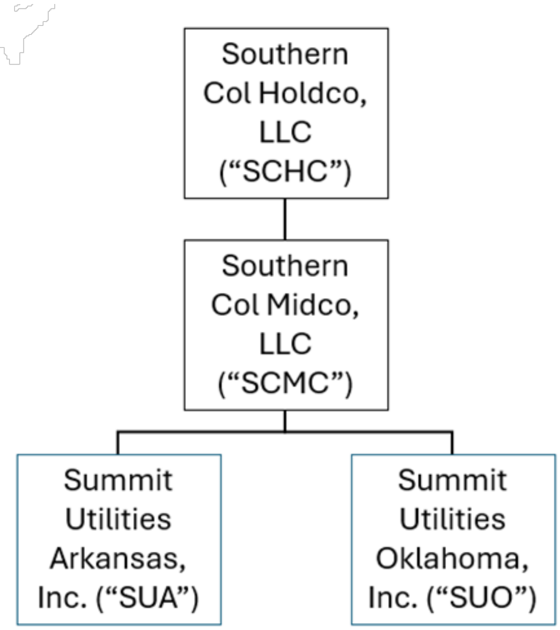
* S&P refers to its rating for the credit risk of the enterprise as a "corporate credit rating," whereas Fitch refers to its rating for the credit risk of the enterprise as an "issuer default rating." I will use the term "issuer rating" in this testimony to refer to the credit risk of the business enterprise.

The ratings are further delineated through the use of pluses or minuses by Standard & Poor's Financial Services LLC ("S&P") and Fitch Ratings ("Fitch") to show a company's relative standing within the categories (e.g., A- or BBB+) and through the use of numbers by Moody's (e.g., A3 or Baa1). Ratings that fall within the high-grade and medium-grade categories are generally described as being "investment grade" ratings, whereas ratings below BBB- (or Baa3 for Moody's) are sometimes described as "junk bond" ratings.

In addition, each rating agency assigns an "outlook" to signal the potential direction of a rating over the intermediate term, which is typically six months to two years. A "positive" outlook indicates that the rating may be raised; a "negative" outlook indicates that the rating may be lowered; and a "stable" outlook indicates that the rating is not likely to change.

Q. YOUR DIRECT TESTIMONY NOTES THAT THE COMPANY'S CURRENT CREDIT RATING IS A3/A-. HAS THE COMPANY RECEIVED ANY GUIDANCE FROM THE RATINGS AGENCIES RELEVANT TO THE COMMISSION'S DECISION IN THIS CASE?

A. Yes. Attached to my testimony as Rebuttal Exhibit CR-1 is the recent rating of Southern Col Midco, LLC ("SCMC") by Fitch. By way of reminder, SUA's ownership structure is as shown below:



SCMC is the holding company for both SUA and Summit Utilities Oklahoma, Inc. ("SUO") and is owned by SCHC. As such, SCMC's credit is directly relevant to SUA and largely dependent on the amount of leverage at SCHC. Important aspects of Fitch's rating report that the Commission should consider when setting SUA's capital structure include Fitch's comments related to "FFO leverage" and the capital structure in this case that is "subject to regulatory approval" in Fitch's view.[8] The rating also demonstrates that Fitch

[8] Rebuttal Exhibit CR-1 at 2 (see paragraph 2 under "Rating Rationale").

is clearly looking at the results of this case—it is a "Key Rating Driver" in the rating report.[9] Simply put, the Commission's decision in this case related to capital structure will have a meaningful impact on Fitch's, and our debtholders', view of SCHC, SCMC and SUA's credit quality. It is not a decision with only a theoretical impact that will take place in a vacuum.

Q. HHEG WITNESS BLANK TAKES THE POSITION THAT SCHC SHOULD BE A PROXY ONLY FOR DETERMINING CAPITAL STRUCTURE. WHAT IS YOUR RESPONSE?

A. I disagree. In order to attract capital, debt holders and investors need to be compensated based on the amount of risk they are taking. Because capital structure is a key determinant of financial risk, and the cost of debt and cost of equity is the mechanism for compensating investors, it is incongruent to assess the two independently. SCHC is the means by which SUA will actually be financed and the means by which debt secured for SUA will be rated and priced. It makes no sense to view SCHC as a simple "proxy."

Q. IS THE CAPITAL STRUCTURE THAT WAS IMPUTED TO CENTERPOINT ENERGY RESOURCES CORP. IN ITS 2015 ARKANSAS RATE CASE RELEVANT TO THIS PROCEEDING?

A. Yes and no. On one hand, CenterPoint Energy Resource Corp's ("CERC") imputed capital structure of 51.50% debt (including 7.71% short-term debt) and 48.50% equity from Docket No. 15-098-U is a meaningful data point that represents a significant deviation from Mr. Daves' and Dr. Griffing's suggestion that a highly leveraged capital structure is appropriate. On the other hand, CERC is a completely different company with a materially

[9] Id. (see paragraph 2 under "Key Rating Drivers").

different risk profile and risk tolerance due to it being a large public company with ready access to public and private debt and equity markets. In addition, the capital structure imputed in Docket No. 15-098-U is nearly nine years old and market conditions are substantially different now. It would be a stretch to conclude that CERC's capital structure in 2015 would be relevant or appropriate for SUA today. SCHC's actual planned financing is relevant to this proceeding.

Q. DO YOU AGREE WITH MS. LACONTE THAT SUA'S REMOVAL OF ACCUMULATED DEFERRED INCOME TAX ("ADIT") FROM THE CAPITAL STRUCTURE IS UNREASONABLE AND INCREASES THE COMPANY'S RATE OF RETURN?

A. No. Ms. LaConte's concern was addressed in the Joint Settlement Agreement. According to the Joint Settlement Agreement in Docket No. 21-060-U, "SUA agrees to provide $29.9 million of ratepayer credit in order to hold customers harmless from the impact of the elimination of ADIT on the cost of capital."[10]

III. OTHER COST OF CAPITAL ISSUES

A. Long and Short-Term Debt

Q. DO YOU AGREE WITH DR. GRIFFING AND MR. DAVES THAT THE COMPANY DID NOT INCLUDE ANY SHORT-TERM DEBT IN ITS PROPOSED CAPITAL STRUCTURE?

A. No. SUA's proposed capital structure used total debt instead of breaking out long-term debt and short-term debt separately. This was done because the $200 million revolving credit facility is a long-term facility with a maturity date in January 2027.

[10] Docket No. 21-060-U, Doc. 126, Joint Settlement Agreement at Para. B.1.viii.1. (October 14, 2021).

Q. IS DR. GRIFFING'S PROPOSAL TO USE BLACK HILLS' SHORT-TERM COST OF DEBT OF 5.55% APPROPRIATE?

A. No. Black Hills' cost of debt is not relevant to this proceeding.

Q. IS STAFF'S CALCULATION OF SHORT-TERM DEBT COSTS OF 6.6074% REASONABLE?

A. Yes. This is our actual cost of debt under the revolving credit facility.

Q. IS MR. DAVES' PROPOSAL TO USE 3.3916% AS SUA'S LONG-TERM COST OF DEBT APPROPRIATE?

A. No. Mr. Daves' is excluding the Company's planned issuance of $115 million in term debt to arrive at this cost of debt, while simultaneously proposing that the Company's total debt be increased to 56%. He also fails to remove the Company's planned equity injection in 2024 of $158 million in his analysis, further skewing his recommendation. Simply put, Mr. Daves' methodology for arriving at his proposed cost of debt and cost of equity and his recommended capital structure are inconsistent and not congruent with each other.

Q. WHAT IS THE COMPANY'S PRO FORMA COST OF DEBT AND CAPITAL STRUCTURE IF YOU BREAK OUT LONG-TERM DEBT AND SHORT-TERM DEBT?

A. SUA's long-term and short-term cost of debt would be 3.7079% and 6.6074%, respectively. The rate proposed for cost of debt in my Direct Testimony was a weighted average cost of long-term debt and short-term debt combined. The actual pricing for the Company's term debt and revolving credit facility is the exact same; however, customers are gaining the benefit of interest rate swaps that the Company put into place on the term debt, which is why the all-in cost of long-term debt is different than short-term debt if the types of debt are broken out.

Q. PLEASE ADDRESS THE PROPOSED DEBT PERCENTAGES OF 54% AND 56% AS PROPOSED BY DR. GRIFFING AND MR. DAVES, RESPECTIVELY.

A. The Company's proposed cost of debt is the Company's current *actual* cost of debt, including the benefit from interest rate swaps. The Company's proposed capital structure is at the planned *actual* capital structure of SCHC as of December 31, 2024. As noted above, if the target capital structure was changed to increase debt from 45% to 56%, the Company's credit ratings would deteriorate. This would cause the Company's cost of debt, cost of equity, and, as a result, the Company Weighted Average Cost of Capital ("WACC") to increase. Mr. Daves' and Dr. Griffing's proposals to increase the total amount of debt to 56% or 54%, inclusive of short-term debt, respectively, is incongruent with their recommended cost of equity because it fails to account for the additional risk assumed by, and therefore additional return required by, investors. Their recommendation to increase debt to 56% and 54%, respectively, is also short-sighted. While higher levels of debt may seem cheaper when markets are favorable, since, as Ms. LaConte put it, "debt is cheaper than equity," higher financial leverage substantially reduces the Company's financial flexibility and results in substantial increases in the cost of debt when market conditions are unfavorable. It is for this reason, many utilities have adopted higher equity ratios in their capital structure since Winter Storm Uri in February 2021, as stated in Mr. Daves' Exhibit 16.[11]

[11] Direct Exhibits of Dan Daves, DD-16 at 6.

Q. DOES THE COMPANY'S ACTUAL UNADJUSTED CAPITAL STRUCTURE AS OF DECEMBER 31, 2023, SUPPORT THE PROPOSED DEBT PERCENTAGES OF 54% AND 56% AS PROPOSED BY DR. GRIFFING AND MR. DAVES, RESPECTIVELY?

A. No, SCHC's actual unadjusted capital structure as of December 31, 2023, does not support Dr. Griffing or Mr. Daves' proposed capital structure. In fact, as of December 31, 2023, SCHC had total debt of $1.163 million and total equity of $1.065 million, which equates to a capital structure consisting of 52.19% debt and 47.81% equity. Even though this capital structure includes the debt associated with Winter Storm Uri and goodwill from the acquisition of CERC's assets, it is still much less financially leveraged than Dr. Griffing and Dr. Daves' proposed capital structure.

B. Uri Debt

Q. DO YOU AGREE WITH MR. DAVES' ASSERTION THAT DEBT RELATED TO WINTER STORM URI SHOULD BE INCLUDED IN THE CAPITAL STRUCTURE?

A. No. In Order No. 9 in Docket No. 07-044-U, the Commission stated:

> Securitization has been thoroughly examined in this Docket, and the Commission has determined that it is not in the public interest in this instance because the costs of securitization in this time of unstable interest rates outweigh the possible marginal benefits that recovery by securitization offers. [12]

Including Winter Storm Uri debt in the target capital structure has the effect of implicitly penalizing SUA for internally financing Winter Storm Uri debt. Winter Storm Uri debt is undisputedly temporary in nature. It is being recovered through the use of a regulatory asset over a five-year period. It was not, and is not, a permanent source of funds to support

[12] Docket No. 07-044-U, Order No. 9 at 7 (June 6, 2022).

the Company's investment in rate base. Further, the fact that the carrying cost associated with the Winter Storm Uri debt is at the Company's WACC is not relevant because it is not a permanent portion of the Company's capital structure. While I agree that debt is generally fungible, the amount of Winter Storm Uri debt that should be excluded from the capital structure can be isolated in this case because it was specifically incurred by the Company to finance the acquisition of the regulatory asset from CERC in January 2022 and the Commission specifically authorized its recovery in a separate proceeding. The Company should not be adversely prejudiced through its cost of capital because it chose to act in the best interest of customers and recover Winter Storm Uri costs through a 5-year rider instead of using securitization.

Q. DID WINTER STORM URI IMPACT THE COMPANY'S TARGET CAPITAL STRUCTURE?

A. No. The target capital structure for the Company did not change based on Winter Storm Uri, but the actual amount of debt has increased temporarily due to the impact of Winter Storm Uri. SUO was able to securitize the Winter Storm Uri debt, while SUA is recovering the regulatory asset through a rider over the 5-year recovery period ending in 2027. The remaining debt financing of the SUA regulatory asset is expected to be extinguished as it is collected or used to partially finance the Company's ongoing capital expenditures as equity capital is injected into the business, in line with the Company's target capital structure.

Q. HHEG WITNESS BLANK STATES THAT THE COMPANY'S ADJUSTMENT FOR DEBT ASSOCIATED WITH THE WINTER STORM URI REGULATORY

ASSET "INCREASES THE COST OF CAPITAL BEYOND WHAT THE COMMISSION HAS APPROVED" FOR URI. IS THAT ACCURATE?

A. I disagree with this assertion. Any increase in the Company's cost of capital would have this effect, not just the exclusion of Winter Storm Uri debt. I do not believe that it was the Commission's intent in Order No. 9 of Docket No. 07-044-U to preclude the Company from having a higher cost of capital. Rather, the Company's pre-approved WACC was used as a proxy for the Company's all-in cost of financing the ongoing business in determining the appropriate carrying cost for Winter Storm Uri Gas Costs. By eliminating the Winter Storm Uri debt from the capital structure in the Company's proposed capital structure, the Company is maintaining a consistent view of the Company's cost of capital with respect to its ongoing business in such a way that it does not prejudice customers or the Company.

Q. DID WINTER STORM URI AFFECT THE OVERALL DEBT LEVELS OF THE PROXY GROUP?

A. Three companies in the proxy group experienced higher debt levels as a result of Winter Storm Uri. Atmos Energy Corporation ("ATO"), ONE Gas, Inc. ("ONG"), and Spire Inc. ("Spire") all experienced higher debt levels to Winter Storm Uri. ATO and ONG both sold the regulatory assets created by unrecovered gas costs from Winter Storm Uri through securitization and did not have Winter Storm debt on their balance sheet as of December 31, 2022. Spire received approval from the Missouri Public Service Commission to collect $195.8 million in Winter Storm Uri over a three-year period ending in May 2025. If Spire's debt balance was reduced by $195.8 million, Spire's debt and equity ratios would be reduced from 58.29% debt and 41.71% equity to 57.15% debt and 42.85% equity.

Q. HHEG WITNESS BLANK DISPUTES THE NEED TO ELIMINATE THE INCLUSION OF GOODWILL IN THE CAPITAL STRUCTURE. DO YOU AGREE?

A. No. In the Joint Settlement Agreement approved by the Commission in Docket No. 21-060-U, SUA agreed that any debt or equity associated with financing goodwill would be excluded from SUA's capital structure for rate making purposes. Eliminating the adjustment, as proposed by Mr. Blank, would violate the settlement agreement.

C. FRP

Q. AGC WITNESS LACONTE DISCUSSES THE COMMON EQUITY RATIO APPROVED BY THE COMMISSION FOR SUA'S FORMULA RATE PLAN. HAS SUA EVER HAD A FORMULA RATE PLAN IN ARKANSAS?

A. No. SUA's predecessor, CenterPoint, had a Formula Rate Plan ("FRP"), but it is an entity separate and distinct from SUA, which has never had an FRP.

IV. CONCLUSION

Q. WHAT IS YOUR RECOMMENDATION TO THE COMMISSION?

A. I recommend that the Commission approve SUA's proposed capital structure of 45.12% total debt and 54.88% equity, based on SCHC's planned capital structure as of December 31, 2024. I also recommend that the Commission approve SUA's proposed WACC of 6.9790%, based on a weighted average cost of debt of 4.1798% and a return on equity of 11.00%.

Q. DOES THIS CONCLUDE YOUR REBUTTAL TESTIMONY?

A. Yes.

CERTIFICATE OF SERVICE

I, Brooke South Parsons, do hereby certify that a true and correct copy of the foregoing has been delivered to all Parties of Record by electronic mail via the Electronic Filing System this 7th day of August 2024.

Brooke South Parsons

Brooke South Parsons

BEFORE THE

ARKANSAS PUBLIC SERVICE COMMISSION

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

REDACTED REBUTTAL EXHIBIT

OF

CRAIG ROOT

VICE PRESIDENT AND CORPORATE TREASURER

ON BEHALF OF

SUMMIT UTILITIES ARKANSAS, INC.

Date Filed: August 7, 2024

REDACTED REBUTTAL EXHIBIT CR-1

SOUTHERN COL MIDCO, LLC FITCH RATING

This Exhibit is redacted in its entirety, pursuant to Docket No. 23-079-U, Order No. 1

CERTIFICATE OF SERVICE

I, Brooke South Parsons, do hereby certify that a true and correct copy of the foregoing has been delivered to all Parties of Record by electronic mail via the Electronic Filing System this 7th day of August 2024.

Brooke South Parsons

Brooke South Parsons

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

REBUTTAL TESTIMONY

OF

SAM SPRINGER

DIRECTOR OF HUMAN RESOURCES

ON BEHALF OF

SUMMIT UTILITIES ARKANSAS, INC.

Date Filed: August 7, 2024

TABLE OF CONTENTS

I. INTRODUCTION

Q. PLEASE STATE YOUR NAME, POSITION AND BUSINESS ADDRESS.

A. My name is Sam Springer. I am the Director of Human Resources for Summit Utilities, Inc. ("SUI"), which is the ultimate parent company of Summit Utilities Arkansas, Inc. ("SUA" or "Company"). My business address is 10825 E. Geddes Avenue, Suite 410, Centennial, Colorado 80112.

Q. ARE YOU THE SAME SAM SPRINGER WHO FILED DIRECT TESTIMONY ON JANUARY 25, 2024, IN THIS PROCEEDING?

A. Yes.

Q. WHAT IS THE PURPOSE OF YOUR REBUTTAL TESTIMONY?

A. The purpose of my Rebuttal Testimony is to respond to proposed adjustments and recommendations in the Direct Testimonies of Arkansas Gas Consumers, Inc. witness Ms. Billie S. LaConte, Arkansas Public Service Commission ("Commission") General Staff ("Staff") witness Mr. Middleton Ray, and Attorney General ("AG") witness Mr. Dante Mugrace, all of whom address certain aspects of the Company's requested compensation and benefits costs. In general, I will address why employees are offered the compensation and benefit programs intervenor and Staff witnesses are challenging, which supports the reasonableness and necessity of the compensation and benefits costs SUA seeks to recover. Company witness Mr. Gillam will address the accounting and/or ratemaking aspects of their positions.

II. SHORT-TERM INCENTIVE COMPENSATION COSTS

Q. WHAT POSITIONS DO MS. LACONTE, MR. RAY, AND MR. MUGRACE TAKE REGARDING THE COMPANY'S REQUEST TO RECOVER SHORT-TERM INCENTIVE COMPENSATION COSTS?

A. The witnesses oppose recovery of short-term incentive ("STI") costs related to financial metrics based on their reasoning that customers do not benefit from the achievement of financial goals. Specifically:

- Ms. LaConte states that 40% of SUA's STI compensation is tied to achieving financial goals and recommends the Commission disallow \$0.5 million in capitalized STI and \$1.4 million in STI expenses.
- Mr. Ray acknowledges the Company did not include long-term incentive costs in the rate filing and proposes an adjustment to remove 50% of *pro forma* STI (both expense and capital) as financially based compensation, the benefits of which are shared by shareholders and customers consistent with the Commission's prior recognition of the shared benefit of financial incentives for disallowances of \$1.3 million in expense and \$1.75 million for capitalized amounts.
- Mr. Mugrace opposes approximately \$2.5 million in STI costs for the Company and SUI for the Corporate Excellence goals of Environmental, Social and Governance ("ESG"), Audited Financial Statements Issued, and Monthly Financial Reports Issued. Mr. Mugrace believes ESG costs are related to a focus on perceived corporate social responsibilities that should not be recovered from customers and the other two goals are related to financial performance and benefit the Company and shareholders.

Q. WHAT IS YOUR RESPONSE TO MS. LACONTE'S, MR. RAY'S, AND MR. MUGRACE'S POSITIONS THAT CERTAIN INCENTIVE COMPENSATION GOALS DO NOT BENEFIT CUSTOMERS?

A. Incentive compensation programs, as they are appropriately named, incentivize 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. Furthermore, 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 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. Being competitive for top talent while simultaneously maintaining low employee turnover ensures that employees with critical knowledge and skills are not leaving the Company for more competitive offers, requiring extensive Company resources to continuously hire, train, and develop new employees. Having long-tenured employees benefits customers and the State of Arkansas in its goal for its citizens to maintain reliable employment.

Q. HOW DO CUSTOMERS, SHAREHOLDERS, AND THE COMPANY BENEFIT FROM A COMBINATION OF DIFFERENT GOALS IN AN INCENTIVE COMPENSATION PLAN?

A. The goals exist as a means to align employees on obtaining results that will further the Company's mission to safely provide affordable and reliable energy solutions to its customers and to ensure the Company maintains its competitiveness as a reputable employer offering a competitive employment package in the locations where it operates. Individual performance measured against a variety of different goals is paramount in trying to align a workforce, regardless of its size, on achieving outcomes that impact the services being provided to a company's customers. This concept has proven successful in companies in all industries all over the world. Following achievement of these goals, rewarding employees for their contributions that impact customers through compensation programs that are tied to the market while also coming at a reasonable cost is key to the employer's goal of maintaining a competitive employment package that succeeds at attracting and retaining employees.

Q. HOW CAN THE COMPANY'S FINANCIAL GOALS BENEFIT CUSTOMERS?

A. The Company must be financially stable and healthy to maintain operations, continue investing in its system, and have the workforce necessary to meet 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. A financially strong utility is able to attract investors who provide access to the capital the Company needs to operate. In addition, no single employee or subset of employees can ensure the financial health of the Company. All employees play a role in making sure the Company's financial resources are used efficiently and effectively.

Q. WHY DOES SUA RELY ON A COMBINATION OF STI GOALS, INCLUDING FINANCIAL GOALS?

A. 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 it remains healthy and competitive for our customers, offering them the service levels they expect from us. For example, as mentioned above, a financially strong utility allows the Company to better serve customers. Safety goals help to ensure that the attention of the Company's employees is focused on doing everything possible to provide safe service and meeting safe operating obligations to customers. Corporate Excellence is a large category focused on making sure the Company is operating responsibly and efficiently with a focus on continuously improving the services we provide. The

Company's chosen goal categories consider all areas of the business and identify areas that are beneficial to customers and the Company by giving all employees something to aim to achieve that will move it in a direction that ensures we remain a strong, stable and safe entity within the state of Arkansas for many years.

Q. REGARDING THE COSTS OF FINANCIAL GOALS CERTAIN WITNESSES OPPOSE, HOW DO THE GOALS OF "AUDITED FINANCIAL STATEMENTS ISSUED" AND "MONTHLY FINANCIAL REPORTS ISSUED" HELP EMPLOYEES FOCUS ON ACTIVITIES THAT SUPPORT AND FURTHER CUSTOMER INTERESTS?

A. The Company's Scorecard goals of "Audited Financial Statements Issued" and "Monthly Financial Reports Issued" encourage employees to focus on ensuring that the financial outcomes of specific projects and other expenses across SUA are being managed responsibly and achieving the intended results. 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 Company is able to fulfill its regulatory reporting obligations in a timely and accurate manner, which is critical for a regulated utility.

Q. WHAT IS YOUR RESPONSE TO MS. LACONTE'S AND MR. MUGRACE'S RECOMMENDATIONS TO NOT ALLOW RECOVERY OF STI COSTS FOR MEETING FINANCIAL TARGETS?

A. Ms. LaConte addresses the targeted Earnings Before Income Taxes, Depreciation, and Amortization (EBITDA) and Dividend Yield goals, and Mr. Mugrace refers to SUI Financial goals. They each take a position to oppose STI recovery for these goals because they claim shareholders benefit from these goals and customers do not. Their positions are narrow and short-sighted. Customers care about how the Company manages its finances to complete projects and improve its operations because those issues affect our rates and the service customers receive. The Company encourages all employees to focus on sound fiscal management practices because it ensures the Company can efficiently use the financial resources it has across more projects that contribute to ensure affordable and reliable energy solutions are provided to customers. Customers share the same high expectations as the Company in being fiscally responsible. Therefore, having a corporate goal that focuses all 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.

Q. REGARDING STAFF'S POSITION OF OPPOSING FINANCIALLY BASED STI, HAS STAFF ALWAYS TAKEN THAT POSITION?

A. No. In the most recent rate case of SUA's predecessor, CenterPoint Energy Arkansas Gas, then Staff witness Kim Davis filed testimony in support of the utility's STI and long-term incentive cost recovery and in opposition to intervenor arguments proposing disallowance of 50% of incentive pay tied to financial goals.[1] At a high-level, Mr. Davis noted the following in his Surrebuttal Testimony:

- The intervenor witness opposing full recovery of STI had not shown the level of pay to employees including STI and LTI is not at a reasonable level in total when compared to external benchmarks.

[1] Docket No. 15-098-U, Direct Testimony of Kim O. Davis at 12-37 (April 14, 2016); Docket No. 15-098-U, Surrebuttal Testimony of Kim O. Davis at 10-20 (June 7, 2016).

- He addressed in his testimony clear customer benefits from a financially sound, well-run utility.

- STI was necessary for the provision of utility service in Arkansas because incentive compensation was part of the overall payroll expense of employees engaged in providing service in Arkansas, so it is necessary and appropriate to allow cost recovery to fully compensate employees.

- Reasonable payroll expense, including reasonable incentive compensation amounts, is a necessary cost of providing utility service.

- Explaining why the Commission should reexamine its past rulings regarding all forms of incentive compensation, Mr. Davis noted that when the Commission first took an approach of disallowing half of financially based incentive amounts, compensation plans that based a portion of compensation on performance measures (both operational and financial performance metrics) were not as common as those compensation plans were at the time he filed his testimony (2016). Mr. Davis noted that compensation plans with a portion of employees' compensation tied to operational performance metrics and financial performance metrics are common for most employees in the utility industry and in many other industries.

- Based on evidence the utility provided showing its total direct compensation including STI and LTI were at the median of the market, it appears the utility's compensation package including incentive pay was reasonable and not excessive.

- Incentive compensation associated with measures that focus on operational efficiency, safety, customer service, and customer satisfaction provide benefits to customers and stockholders. Including expense management, operating income or profitability measures and total shareholder returns further promote behavior by employees that is beneficial to ratepayers.

- If the Commission did not approve Staff's incentive cost recovery position (based on a three-year average), Mr. Davis recommended the Commission include at least 75% of the amounts adjusted by Staff rather than 50% as it had done in the past.

Q. WHAT IS YOUR REACTION TO MR. DAVIS' PRIOR TESTIMONY ON BEHALF OF STAFF?

A. Many of the issues Mr. Davis addressed align with information I have provided in my Direct and Rebuttal Testimony in this case. Since Mr. Davis filed that testimony in 2016, performance-based incentive compensation has continued to be an essential component of overall compensation for utility employees that align the interests of customers with those of the Company.

Q. WHAT IS YOUR RESPONSE TO MR. MUGRACE'S POSITION THAT COSTS FOR THE ESG METRIC SHOULD NOT BE RECOVERED BECAUSE THIS GOAL SHOULD BE THE RESPONSIBILITY OF THE COMPANY?

A. Mr. Mugrace states this goal is focused on "perceived corporate social responsibilities" and related costs should not be recovered from ratepayers. ESG evaluates a company's internal business practices and its 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 levels of customer safety. Following established ESG practices builds trust and a positive reputation with customers. ESG-focused companies focus on managing risks effectively. Supporting companies that follow ESG practices ensures long-term sustainability and resilience, offering financial benefits and increased safety for customers, while benefiting communities and the environment of the areas in which they operate. 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. So, in some ways, Mr. Mugrace is right about the focus of the ESG goal, which is precisely why it is reasonable to recover incentive costs for meeting this goal through customer rates.

Q. WHAT CONSEQUENCES COULD RESULT IF SUI DID NOT OFFER STI AND INSTEAD MOVED THAT FORM OF COMPENSATION TO EMPLOYEE BASE PAY?

A. 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. 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, yet ensures that there is an incentive for employees to go above-and-beyond because employees who do are reasonably compensated for doing so.

III. VOLUNTEER TIME OFF

Q. WHAT RECOMMENDATIONS DO MR. RAY AND MS. LACONTE MAKE RELATED TO THE COMPANY'S VOLUNTEER TIME OFF EXPENSES?

A. Both witnesses oppose cost recovery because they claim that volunteer time does not benefit customers, so shareholders should absorb this cost. Mr. Ray's adjustment affects payroll, payroll tax, and benefits amounts.

Q. WHY DOES SUI INCLUDE VOLUNTEER TIME OFF AS AN ACTIVITY FOR WHICH EMPLOYEES ARE PAID?

A. The Company encourages its employees to be active in the communities where it operates with the aim of supporting community involvement. This program supports employees' involvement in communities across a wide range of non-profit interests and furthers the mission and objectives of those entities where SUA employees live and work.

Q. DO THE HOURS AND ACTIVITIES COMPANY EMPLOYEES COMPLETE FOR VOLUNTEER TIME OFF BENEFIT CUSTOMERS?

A. To the extent that entities where employees volunteer to work these hours are supporting communities where SUA operates, yes, customers within the community benefit. When a non-profit organization is lifted up by companies and community members supporting its mission, that community is better off than it was prior to that support. The beneficiaries of this type of volunteerism are customers when it is happening in communities where SUA operates.

Q. SHOULD THE COMMISSION APPROVE THE COMPANY'S COST RECOVERY FOR VOLUNTEER TIME OFF?

A. Yes, community service provided through the Volunteer Time Off program is a reasonable and necessary cost and should be recovered.

IV. RETENTION AND SIGN-ON BONUSES

Q. WHAT DOES MR. MUGRACE RECOMMEND FOR THE COMPANY'S REQUESTED AMOUNTS FOR RETENTION AND SIGN-ON BONUSES?

A. Mr. Mugrace opposes cost recovery for retention bonuses and sign-on bonuses because he says retention bonus amounts are not necessary, the Company has not shown employees quit or were hired away by other employers, and there is no evidence the bonuses benefit customers. He takes a similar position for sign-on bonuses, focusing on lack of necessity and customer benefit and also stating there is no evidence addressing the rate treatment that results if an employee quits or is lured away by another employer.

Q. WHY DOES SUI OFFER RETENTION AND SIGN-ON BONUSES TO EMPLOYEES?

A. The reason these compensation components are used 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. Retention payments have been made to 1.8% of employees who are in the most critical roles within the company. Sign-on bonuses serve a number of purposes to enable the Company to bring talent into the Company. A sign-on bonus is most commonly provided in two situations: 1) due to timing of the candidate's current company's compensation cycle, they may be walking away from compensation that would prevent the candidate from leaving when SUI's vacant position is open, and 2) SUI's compensation philosophy is to pay at the market median, and in situations where a candidate is requesting a base salary that is above that median, to keep base salary aligned with market but also be able to bring the candidate into the Company, a sign-on bonus will sometimes enable the candidate to accept the position.

Q. ARE EMPLOYEES WHO RECEIVE RETENTION OR SIGN-ON BONUSES REQUIRED TO REPAY THE COMPANY IF THEY LEAVE THE COMPANY'S EMPLOYMENT WITHIN A CERTAIN TIME PERIOD?

A. Yes. Both types of compensation are accompanied by repayment agreements.

Q. IN YOUR EXPERIENCE, DO RETENTION AND SIGN-ON BONUSES ALLOW SUI AND SUA TO ATTRACT AND RETAIN EMPLOYEES?

A. Yes. To date, SUA has not had a single retention or sign-on bonus repaid, which clearly shows these programs achieve their intended purpose of attracting and retaining employees.

Q. DO CUSTOMERS BENEFIT FROM SUI AND SUA PROVIDING THESE TYPES OF BONUSES TO EMPLOYEES?

A. SUI, like any company, is only as good as the employees who work for it. Customers benefit when the Company is able to hire top talent in the market and likewise, when it is able to retain employees in its most critical roles. Customers benefit from these decisions and the rare occasions in which these employment tools are used to recruit and retain top talent within its workforce.

Q. SHOULD THE COMMISSION APPROVE THE COMPANY'S COST RECOVERY FOR RETENTION AND SIGN-ON BONUSES?

A. Yes. The market for talent is extremely competitive and using these employment tools on rare occasions has a material impact on the Company being competitive in that market to ensure that the Company is able to bring in top talent and retain employees in critical roles.

Q. PLEASE SUMMARIZE YOUR REBUTTAL TESTIMONY AND RECOMMENDATIONS.

A. The STI and other amounts Intervenors and Staff challenge are reasonable and necessary expenses to safely provide reliable and cost-effective service to SUA's customers. In particular, my Direct and Rebuttal Testimonies show that regardless of the specific goals in the STI plan, the total level of employee compensation costs included in this case are reasonable and illustrate that SUI targets the median of the market when structuring employee compensation. Third-party market data shows that SUI's employees are compensated slightly below the 50^{th} percentile of the market, which supports the reasonableness of the amounts SUA is requesting to recover. This also means disallowing any STI costs would prevent the Company from recovering reasonable and necessary amounts required to fairly compensate employees at the median of the market.

The volunteer time off amounts and sign-on and retention bonuses are also reasonable and necessary costs. These items are part of the overall compensation and benefits offered to certain employees. The volunteer time off motivates employees to invest their time and energy in the communities SUA services. In addition, the bonus amounts help the Company attract and retain employees, which helps the Company maintain a stable workforce by avoiding turnover and to retain knowledgeable, experienced utility employees.

Q. DOES THIS CONCLUDE YOUR REBUTTAL TESTIMONY?

A. Yes.

CERTIFICATE OF SERVICE

I, Brooke South Parsons, do hereby certify that a true and correct copy of the foregoing has been delivered to all Parties of Record by electronic mail via the Electronic Filing System this 7th day of August 2024.

Brooke South Parsons

Brooke South Parsons

BEFORE THE

ARKANSAS PUBLIC SERVICE COMMISSION

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

REBUTTAL TESTIMONY

OF

DYLAN W. D'ASCENDIS

SCOTTMADDEN, INC.

ON BEHALF OF

SUMMIT UTILITIES ARKANSAS, INC.

Date Filed: August 7, 2024

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LIST OF EXHIBITS

I. INTRODUCTION AND PURPOSE

Q. PLEASE STATE YOUR NAME, AFFILIATION, AND BUSINESS ADDRESS.

A. My name is Dylan W. D'Ascendis. I am employed by ScottMadden, Inc. as Partner. My business address is 3000 Atrium Way, Suite 200, Mount Laurel, NJ 08054.

Q. ON WHOSE BEHALF ARE YOU SUBMITTING THIS TESTIMONY?

A. I am submitting this rebuttal testimony (referred to throughout as my "Rebuttal Testimony") before the Arkansas Public Service Commission ("APSC" or the "Commission") on behalf of Summit Utilities Arkansas, Inc. ("SUA" or the "Company").

Q. ARE YOU THE SAME DYLAN W. D'ASCENDIS WHO FILED DIRECT TESTIMONY ON JANUARY 25, 2024, IN THIS PROCEEDING?

A. Yes.

Q. WHAT IS THE PURPOSE OF YOUR REBUTTAL TESTIMONY?

A. The purpose of my Rebuttal Testimony is two-fold. First, I update the analyses in my Direct Testimony to reflect current data. Second, I respond to the Direct Testimonies of Mr. Dan Daves, who testifies on behalf of the General Staff ("Staff") of the Commission, Dr. Marlon F. Griffing, Ph.D., who testifies on behalf of The Office of the Arkansas Attorney General Tim Griffin ("AG"), and Ms. Billie S. LaConte, who testifies on behalf of Arkansas Gas Consumers, Inc. ("AGC") (collectively, "the Opposing Witnesses"), as they relate to the Company's return on common equity ("ROE") on its Arkansas jurisdictional rate base and appropriate capital structure.

II. SUMMARY AND OVERVIEW

Q. PLEASE SUMMARIZE YOUR CONCLUSIONS.

A. I have updated my ROE analyses as of June 28, 2024. Based on these updated analyses, my range of reasonable ROEs attributable to SUA is between 10.03% and 12.48%

(unadjusted) and 10.08% to 12.53% (adjusted), from which I have maintained my specific ROE recommendation of 11.00%. In view of current markets and the updated results of my ROE models, recommended ROEs of 9.75% (Staff), 9.80% (AG), and 9.70% (AGC), are insufficient at this time.

My Rebuttal Testimony responds to substantive recommendations offered by the Opposing Witnesses in their direct testimonies. For example, I generally disagree with Dr. Griffing's and Ms. LaConte's use of a multi-stage Discounted Cash Flow ("DCF") model. In addition, the Opposing Witnesses' low Capital Asset Pricing Model ("CAPM") results are based on inappropriate inputs, including the estimate of the market risk premium ("MRP"). The Opposing Witnesses have also failed to recognize the greater risk faced by SUA relative to their proxy groups. Those factors serve to bias the Opposing Witnesses' ROE recommendations downward. My Rebuttal Testimony discusses those factors in detail, as well as other issues specific to each Opposing Witness, and also addresses their unfounded critiques of my Direct Testimony.

Q. HAVE YOU PREPARED EXHIBITS IN SUPPORT OF YOUR RECOMMENDATION?

A. Yes. I have prepared Schedules DWD-1R through DWD-20R, which were prepared by me or under my direction and can be found on Rebuttal Exhibit DWD-1.

Q. HOW IS THE REMAINDER OF YOUR REBUTTAL TESTIMONY ORGANIZED?

A. The remainder of my Rebuttal Testimony is organized as follows:

- <u>Section III</u> – Summarizes my updated analytical models;
- <u>Section IV</u> – Discusses the relevance of historical authorized ROEs;

- Section V – Discusses the Company's capital structure;
- Section VI – Provides my response to Staff Witness Daves;
- Section VII – Provides my response to AG Witness Griffing;
- Section VIII – Provides my response to AGC Witness LaConte; and
- Section IX – Presents my conclusions.

III. UPDATED ANALYSIS

Q. HAVE YOU UPDATED YOUR COST OF COMMON EQUITY ANALYSES FOR YOUR REBUTTAL TESTIMONY?

A. Yes, I have. Due to the passage of time since my Direct Testimony analysis (data as of November 30, 2023), I have updated my analysis using data as of June 28, 2024.

Q. HAVE YOU APPLIED YOUR ROE MODELS IN THE SAME MANNER IN YOUR UPDATED ANALYSES?

A. Yes, I have.

Q. WHAT ARE THE RESULTS OF YOUR UPDATED ANALYSES?

A. Using data available as of June 28, 2024, my updated results are presented in page 1 of Schedule DWD-1R and in Table 1, below:

Table 1: Summary of Common Equity Cost Rates

Discounted Cash Flow Model	10.03%
Risk Premium Model	10.98%
Capital Asset Pricing Model	11.91%
Cost of Equity Models Applied to Comparable Risk, Non-Price Regulated Companies	12.48%
Indicated Range	10.03% - 12.48%
Size Adjustment	0.05%
Recommended Range	10.08% - 12.53%
Recommended Cost of Common Equity	11.00%

In view of the unadjusted and adjusted ranges of ROEs, I maintain my original ROE recommendation of 11.00%.

Q. AS A PRELIMINARY MANNER, HOW HAVE CAPITAL COSTS CHANGED SINCE THE COMPANY'S LAST RATE CASE?

A. As shown in Table 2, below, several measures of risk are materially elevated compared to the last general rate case in Docket No. 15-098-U, filed by CenterPoint Energy Resources Corp. ("CEA"),[1] where they were authorized an ROE of 9.50%.

Table 2: Comparison of Government bond yields, utility bond yields, the Federal Funds Effective Rate, and inflation

Proceeding	30-Year U.S. Treasury Bond	Moody's A-Rated Utility Bond	Moody's Baa-Rated Utility Bond	Federal Funds Effective Rate	Average Consumer Price Index ("CPI") 12-month change
Current Proceeding (23—079-U)[2]	4.49%	5.65%	5.88%	5.25 – 5.50	3.2%
Prior Proceeding (15-098-U)[3]	2.61%	3.99%	4.88%	0.00 – 0.50	0.99%
Increase	71.76%	41.55%	20.50%	N/A	226.50%

As such, an ROE materially higher than 9.50% is appropriate in this proceeding.

IV. RELEVANCE OF HISTORICAL AUTHORIZED RETURNS

Q. YOUR RECOMMENDED ROE OF 11.00% IS ABOVE THE AVERAGE ROE APPROVED FOR NATURAL GAS UTILITIES OVER THE PAST SEVERAL YEARS. ARE HISTORICAL ROES A GOOD MEASURE OF PROSPECTIVE ROES?

A. No, they are not.

[1] The CEA's last proceeding covers the time period between November 10, 2015 through September 2, 2016.

[2] Spanning a date range of 1/25/2024 through 6/30/2024.

[3] Spanning a date range of 11/10/2015 through 9/2/2016.

Q. PLEASE SUMMARIZE THE OPPOSING WITNESSES' REVIEW OF AUTHORIZED ROES.

A. Mr. Daves reviews a recent report from Regulatory Research Associates ("RRA"), noting average authorized ROEs for gas utilities of 9.60% in 2023 and 9.78% in the first quarter of 2024. Further, he also calculates an average ROE of 9.57% for gas utilities in jurisdictions surrounding Arkansas from 2022 through 2024.[4] Mr. Daves concludes that my recommended ROE is higher than, and not comparable to, the authorized ROEs of utilities with corresponding risks in jurisdictions surrounding Arkansas.[5]

Dr. Griffing observes historical authorized ROEs between 2021-2023 to evaluate the reasonableness of his recommended ROE.[6] He also comments that my CAPM and Risk Premium Model ("RPM") results are unreasonable as they also fall outside of the range of authorized ROEs.[7] Despite this, Dr. Griffing also notes that the comparable earnings test is "a nullity."[8]

Ms. LaConte also reviews the RRA average gas utility authorized ROEs of 9.53% and 9.60% for 2022 and 2023, respectively, and notes that my recommended ROE is higher than the 2023 average.[9] She also notes that the "national authorized average ROE is an important consideration when determining the ROE for SUA."[10]

[4] Daves Direct Testimony, at 55.
[5] Daves Direct Testimony, at 56.
[6] Griffing Direct Testimony, at 42.
[7] Griffing Direct Testimony, at 52, 53.
[8] Griffing Direct Testimony, at 12.
[9] LaConte Direct Testimony, at 9-10.
[10] LaConte Direct Testimony, at 10.

Q. PLEASE DISCUSS THE APPLICABILITY OF HISTORICALLY AUTHORIZED ROES FOR COST OF CAPITAL PURPOSES.

A. While authorized ROEs may be reasonable benchmarks of acceptable ROEs, care must be exercised when evaluating their applicability in any given case, because they necessarily do not reflect the current cost of common equity. The reason why historical authorized returns do not reflect the investor-required return is because authorized ROEs are a lagging indicator of investor-required returns, i.e., authorized ROEs are based on market data presented in an evidentiary record, which spans a period before the decision, sometimes lasting over a year in some cases. Simply put, historical authorized returns do not completely reflect as to the investor-required return because the economic conditions in the past are not representative of economic conditions now.[11] On page 42 of his testimony, Dr. Griffing appears to agree with this when stating that authorized ROEs should "not be a substitute for forward-looking analysis based on current conditions." Because of this, the Opposing Witnesses' simple comparisons of my recommended ROE to previously authorized ROEs are of little value.

A more useful way to use historical authorized ROEs for cost of capital purposes would be to determine whether a relationship between authorized ROEs (or equity risk premiums) and interest rates exists so one can determine an expectational ROE or equity risk premium ("ERP") given an interest rate. As discussed in my Direct Testimony, it is clear that an inverse relationship exists between ERPs and interest rates (i.e., as interest rates move, ERPs move in the opposite direction, but not to the extent of the interest rate

[11] Dr. Griffing also acknowledges this on page 13 of his Direct Testimony.

move), which is confirmed in the work of Harris and Marston (2001) and Brigham, Dilip, Shome, and Vinson (1985).[12]

As shown on page 23 of Schedule DWD-1R, using historical authorized ROEs and interest data in regression analyses produces statistically significant inverse relationships between interest rates and ERPs, which can be used to determine expectational investor-required returns. Given an expectational A2-rated Public Utility bond yield of 5.58%, an indicated ERP of 4.82% is calculated using natural gas historical ROE data. Adding the expectational A2-rated public utility bond yield to that ERP results in an indicated ROEs of 10.40%.

Q. PLEASE SUMMARIZE THIS SECTION.

A. The Opposing Witnesses' simple comparisons of my recommended ROE and historically authorized ROEs are of little value because historical ROEs do not reflect current and expected capital market conditions. The only useful data that can be discerned by historically allowed ROEs would be the relationship between those ROEs and prevailing interest rates at the time of the decision. For all of these reasons, the Commission should not rely on historically authorized ROEs in setting the ROE for SUA in this proceeding and instead focus on the market analyses put forth by each expert in their respective testimonies.

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[12] D'Ascendis Direct Testimony, at 31-32.

V. CAPITAL STRUCTURE

Q. PLEASE BRIEFLY SUMMARIZE THE OPPOSING WITNESSES' TESTIMONY REGARDING SUA'S CAPITAL STRUCTURE.

A. Mr. Daves agrees that a hypothetical capital structure is appropriate for SUA but rejects the Company's proposed capital structure. Instead, Mr. Daves recommends imputing a capital structure consisting of 56.00% total debt (including 6.23% short-term debt) and 44.00% common equity based on his calculated eight-quarter average of his proxy group.[13] Mr. Daves believes that basing SUA's capital structure on the proxy group average ensures congruence between capital structure and the ROE he estimates, and that the Company's proposed capital structure is out of sync with the proxy group.[14]

Dr. Griffing recommends a hypothetical capital structure consisting of 54.00% total debt (including 8.00% short-term debt) and 46.00% common equity based on the eight-quarter average capital structure of his proxy group.[15]

Ms. LaConte notes that SUA's requested equity ratio is higher than the one previously approved for its predecessor, CenterPoint, and recommends a hypothetical common equity ratio "no higher than 50.00%".[16]

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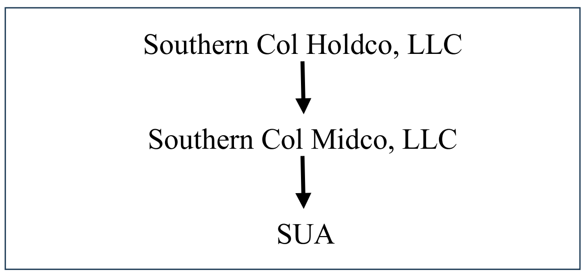
13 Daves Direct Testimony, at 29.
14 Daves Direct Testimony, at 29.
15 Griffing Direct Testimony, at 46-48.
16 LaConte Direct Testimony, at 32-34.

Q. DO YOU MAINTAIN THAT SUA'S PROPOSED CAPITAL STRUCTURE, WHICH CONSISTS OF 45.12% TOTAL DEBT AND 54.88% COMMON EQUITY, IS REASONABLE?[17]

A. Yes, I do. As discussed in my Direct Testimony,[18] SUA's proposed capital structure is based on Southern Col Holdco, LLC, which is an indirect owner of SUA, as shown in Figure 1, below:

<u>Figure 1: Organizational Structure of SUA Parent Companies</u>



As Southern Col Holdco primarily holds regulated gas utility companies and its capital structure is consistent with the range of utilities used to determine its ROE, it is appropriate to use for SUA for ratemaking purposes.

Q. HOW DOES THE REQUESTED COMMON EQUITY RATIO OF 54.88% COMPARE TO THE COMMON EQUITY RATIOS MAINTAINED BY THE UTILITY PROXY GROUP?

A. The Company's requested common equity ratio of 54.88% falls within the common equity ratios maintained by the Utility Proxy Group, which range from 34.75% to 61.53% for the fiscal year 2023. As shown on page 1 of Schedule DWD-2R, I also examined the past eight quarter average capital structures for the Utility Proxy Group, which range from 31.02% to 61.06% (including short-term debt), or 33.69% to 61.21% (excluding short-term

[17] Note SUA has updated its proposed capital structure from 44.41% debt and 55.59% equity to 45.12% debt and 54.88% equity as further explained in the Direct Testimony of Craig Root.
[18] D'Ascendis Direct Testimony, at 14-16.

debt). Additionally, page 2 of Schedule DWD-2R show the eight quarter average capital structures maintained by the operating subsidiaries of the Utility Proxy Group companies, which range from 31.02% to 61.01% (including short-term debt), or 33.69% to 61.21% (excluding short-term debt).

I also considered *Value Line's* projected capital structures for the Utility Proxy Group for 2024-2029, as shown on page 3 of Schedule DWD-2R. That analysis shows a range of projected common equity ratios between 37.50% and 60.00%.

Finally, I surveyed the authorized equity ratios of natural gas utility companies from 2020 through the present, which ranged from 39.23% to 60.61% as shown on page 4 of Schedule DWD-2R

In view of the above, it is clear that SUA's requested capital structure is consistent with the range of capital structures maintained by the Utility Proxy Group and their operating subsidiaries, and as such, should be used for SUA's ratemaking capital structure.

Q. IS IT APPROPRIATE TO COMPARE SUA'S CAPITAL STRUCTURE TO THE PROXY GROUP PARENT COMPANIES' OPERATING SUBIDIARIES' CAPITAL STRUCTURES?

A. Yes, it is. First, comparing the capital structure of SUA to the proxy group operating subsidiaries reflects an apples-to-apples comparison as opposed to using the proxy group capital structures at the parent level, which could be impacted by non-utility operations. The Opposing Witnesses and I both reflect that consideration given we both take into account the extent to which regulated natural gas operations are in place at the individual companies, as that is a necessary consideration in selecting a proxy group that appropriately reflects the risks that SUA faces.

Q. IS THE AVERAGE EQUITY RATIO OF THE PROXY COMPANIES AN APPROPRIATE BENCHMARK FOR ASSESSING SUA'S CAPITAL STRUCTURE?

A. No, it is not. While I agree that it is reasonable to review the capital structures of the proxy companies, the range of common equity ratios for the Utility Proxy Group depict the range of typical or proper equity ratios maintained by comparable risk companies. Because SUA's requested equity ratio falls within this range, there is no reason to look to the average common equity ratio of the Utility Proxy Group.

Q. PLEASE COMMENT ON MR. DAVES' EMPHASIS ON CONGRUENCE.

A. Mr. Daves puts forth the concept of congruence between the approved capital structure and the approved ROE several times in his capital structure discussion, as both are calculated based on the same group of proxy companies. I note that all companies in Mr. Daves' and my proxy group are similar, but all have different capital structures and required returns. The key issue is comparable earnings, not congruent earnings, and SUA's requested capital structure is comparable to its peers, as demonstrated above.

Q. PLEASE SUMMARIZE YOUR POSITION ON THE COMPANY'S REQUESTED CAPITAL STRUCTURE.

A. The Company's requested equity ratio of 54.88% falls within the ranges of equity ratios of the Utility Proxy Group and the equity ratios maintained by the operating subsidiaries of those companies. This demonstrates both the reasonableness of using it to set rates, and the Company's relative financial health. Setting the weighted average cost of capital as requested by the Company will continue to support the long-term financial health of the Company for the benefit of all of its stakeholders, including Arkansas customers.

VI. RESPONSE TO STAFF WITNESS DAVES

Q. PLEASE SUMMARIZE STAFF'S ROE RECOMMENDATIONS AS THEY RELATE TO THE COMPANY'S COST OF CAPITAL.

A. Mr. Daves recommends an ROE of 9.75%.[19] Although Mr. Daves notes his recommendation is based primarily on the results of his Constant Growth DCF analyses, he notes he also considered the results of my DCF model, his CAPM and RPM results, a financial ratio assessment on his analysis, the results of my other models, and an evaluation of qualitative factors.[20]

Table 3: Summary of Mr. Daves' Model Results

DCF Analysis	g1	10.1%
	g2	8.4%
	g3	9.2%
	g4	9.3%
CAPM Analysis		10.61%
		10.74%
RPM Analysis		9.86%
		9.82%
		9.91%

Q. DO YOU HAVE ANY PRELIMINARY REACTIONS TO MR. DAVES' MODEL RESULTS?

A. Yes, I do. In reviewing Mr. Daves' model results, I discovered that his 8.40% indicated DCF result was a statistical outlier (i.e., more than two standard deviations away from the average results). Removing the outlier from his analysis results in a range of ROEs from 9.20% to 10.74% (midpoint: 9.97%), and average and median results of 9.94% and 9.91%, respectively. As will be discussed below, while I do not agree with some of Mr. Daves' analyses, a simple statistical analysis of his indicated results, and the measures of central

19 Daves Direct Testimony, at 34.
20 Daves Direct Testimony, at 34, 56.

tendency of the remaining results, shows that his 9.75% ROE recommendation is understated.

Q. DO YOU HAVE ANY CONCERNS WITH MR. DAVES' DIRECT TESTIMONY AND HIS RECOMMENDATIONS?

A. Yes, I do. I do not agree with the following: (1) his recommended hypothetical capital structure for the Company; (2) his contention that the DCF model is superior to other models and his use of the CAPM as a "check;" (3) the timing of his DCF analysis; (4) his application of the DCF model; (5) his application of the CAPM; (6) his application of the RPM; (7) his failure to reflect the unique risks of the Company relative to his proxy group in his recommended ROE; and (8) his evaluation of Authorized ROEs. I have already addressed items (1) and (8) above and will not repeat those discussions here. I will respond to items (2) through (7) in turn below.

A. Inadequacy of the DCF Model

Q. DO YOU HAVE A GENERAL COMMENT ON MR. DAVES' INDICATED ROE BEFORE ADJUSTMENT?

A. Yes, I do. Mr. Daves' indicated ROE of 9.75% for SUA understates the Company's ROE because he places primary weight on his DCF model results.

Q. DOES MR. DAVES STATE REASONS WHY HE PRIMARILY RELIES ON HIS DCF MODEL RESULTS?

A. Yes, he does. Mr. Daves states that the DCF model is the most commonly used model for estimating the cost of equity for utilities, and that the Commission has consistently embraced its use.[21] He also suggests that it is the most company-specific model and most forward looking of the models he and I apply.[22]

Q. HOW DO YOU RESPOND TO MR. DAVES' COMMENTS RELATED TO THE COMMISSION'S HISTORICAL USE OF THE DCF MODEL FOR UTILITIES?

A. I recognize that the Commission has historically given the DCF model weight in their determination of the ROE in several litigated proceedings. As my testimony below demonstrates, however, every model has limitations, including the DCF. As such, the Commission should be aware of the DCF model's limitations whenever it is applied and take those limitations into account when evaluating the reasonableness of DCF model results.

Q. MR. DAVES' DCF RESULTS APPEAR SIGNIFICANTLY LOWER COMPARED TO THE REST OF HIS MODEL RESULTS. ARE THERE ANY SPECIFIC WEAKNESSES OF THE DCF MODEL WHERE IT WOULD MIS-SPECIFY INVESTOR RETURN ON COMMON EQUITY NECESSITATING THE USE OF MULTIPLE COMMON EQUITY COST RATE MODELS?

A. Yes. The DCF model presumes that market-to-book ("M/B") ratios are at unity or 1.00. However, that is rarely the case. Morin states:

> The third and perhaps most important reason for caution and skepticism is that application of the DCF model produces estimates of common equity cost that are consistent with investors' expected return only when stock price and book value are reasonably similar, that is, when the M/B is close to unity. As shown below, application of the standard DCF model to utility stocks understates the investor's expected return when the M/B ratio of a given stock exceeds unity. This was particularly relevant in the capital market environment of the early 2020s when utility stocks are trading at M/B ratios well above unity and have been for nearly two decades. The converse is also true, that is, the DCF model overstates the investor's return when the stock's M/B ratio is less than unity. The reason for the distortion

21 Daves Direct Testimony, at 35.
22 Daves Direct Testimony, at 45.

> is that the DCF market return is applied to a book value rate base by the regulator, that is, a utility's earnings are limited to earnings on a book value rate base.[23]

Since the "simplified" DCF model traditionally used in rate regulation assumes a M/B ratio of 1.00, it understates/overstates investors' required return rate when market value exceeds or is less than book value. It does so because utility investors evaluate and receive their returns on the <u>market</u> value of a utility's equity, whereas regulators authorize returns on <u>book</u> common equity. This means the market-based DCF model will produce the total annual dollar return expected by investors <u>only</u> when market and book values are equal, which is, again, a rare and unlikely situation.

Market values can diverge from book values for a myriad of reasons including, but not limited to, earnings per share ("EPS") and dividends per share ("DPS")expectations, merger/acquisition expectations, the rising interest rate environment, etc. As noted by Phillips:

> Many question the assumption that market price should equal book value, believing that "the earnings of utilities should be sufficiently high to achieve market-to-book ratios which are consistent with those prevailing for stocks of unregulated companies."[24]

In addition, Bonbright states:

> In the first place, commissions cannot forecast, except within wide limits, the effect their rate orders will have on the market prices of the stocks of the companies they regulate. In the second place, *whatever the initial market prices may be, they are sure to change not only with the changing prospects for earnings, but with the changing outlook of an inherently volatile stock market.* In short, market prices are beyond the control, though not beyond the influence of rate regulation. Moreover, even if a commission did possess the power of control, any attempt to exercise it ...

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23 Roger A. Morin, <u>Modern Regulatory Finance,</u> Public Utility Reports, Inc., 2021, at 481-482. ("Morin").

24 Charles F. Phillips, <u>The Regulation of Public Utilities</u>, Public Utilities Reports, Inc., 1993, at 395 ("Phillips").

would result in harmful, uneconomic shifts in public utility rate levels. [25]

Q. CAN THE UNDER- OR OVERSTATEMENT OF INVESTORS' REQUIRED RATE OF RETURN BY THE DCF MODEL BE DEMONSTRATED MATHEMATICALLY?

A. Yes. The under- or overstatement of the investor required rate of return on the market by the DCF model is demonstrated mathematically in a hypothetical example on page 2 of Schedule DWD-3R. Column [1] represents an M/B ratio of 100% (market and book value of equity is $30.00 per share). The DCF cost rate of 10.00% is comprised of a 3.00% dividend yield and 7.00% growth rate. The total return expected by investors is $3.00 ($0.90 dividends, $2.10 capital appreciation). When M/B ratios are not equal to 100%, the DCF model mis-specifies the investor expected return. As shown in Column [2], Line No. 7, using the same market value as Column [1] ($30.00) and a book value per share of $15.00 (a M/B ratio of 200%), the investor would only receive a return on book value of $1.50 ($15.00 * 10.00% investor-expected return). The $1.50 is broken down into $0.90 in dividends ($30.00 market price * 3.00% dividend yield) and $0.60 in capital appreciation. Since investor's expectations are based on market values, the capital appreciation return is 2.00% ($0.60 / $30.00), which is 5.00% less than the investor-expected return of 7.00% (the growth term in the DCF model). Conversely, as shown in Column [3], using the same market value of $30.00 and a book value per share of $37.50 (a M/B ratio of 80%), the investor would receive a return on book value of $3.75 ($37.50 * 10.00% investor-expected return) The $3.75 is broken down into $0.90 in dividends ($30.00 market price * 3.00% dividend yield) and $2.85 in capital appreciation. Since

[25] James C. Bonbright, Albert L. Danielsen and David R. Kamerschen, Principles of Public Utility Rates, Public Utilities Reports, Inc., 1988, at 334 ("Bonbright") (emphasis added).

investor's expectations are based on market values, the capital appreciation return is 9.50% (\$2.85 / \$30.00), which is 2.50% more than the investor-expected return of 7.00% (the growth term in the DCF model).

Stated simply, the DCF model either understates or overstates investors' required cost of common equity capital when market values exceed or are less than their underlying book values. In this instance, Mr. Daves' DCF model results for his proxy group are an outlier compared to his other cost of common equity model results, as discussed above. Because of this, multiple cost of common equity models must be used to derive a more reliable estimate of the cost of common equity for a company.

Q. IT IS MR. DAVES' OPINION THAT THE DCF MODEL HAS A DISTINCTLY SUPERIOR QUALITY FOR RATEMAKING.[26] DO YOU AGREE WITH HIS OPINION?

A. I respectfully disagree with Mr. Daves' opinion in this matter. As all models have limitations, it is my opinion that considering multiple models provided the greatest insight into the investor required return and that no one model is superior to all other models. This is a common opinion among the academic community. For example, Morin states:

> Each methodology requires the exercise of considerable judgment on the reasonableness of the assumptions underlying the methodology and on the reasonableness of the proxies used to validate a theory. The inability of the DCF model to account for changes in relative market valuation, discussed below, is a vivid example of the potential shortcomings of the DCF model when applied to a given company. Similarly, the inability of the CAPM to account for variables that affect security returns other than beta tarnishes its use.
>
> **No one individual method provides the necessary level of precision for determining a fair return, but each method provides useful evidence to facilitate the exercise of an informed judgment.** Reliance on any single method or preset formula is inappropriate when dealing with investor

[26] Daves Direct Testimony, at 45.

expectations because of possible measurement difficulties and vagaries in individual companies' market data. (emphasis added)

* * *

There is ample academic support in the financial literature for the need to rely upon several financial models in arriving at a recommended common equity cost rate. Professor Eugene Brigham, a widely respected scholar and finance academician, asserts(footnote omitted):

> *Three methods typically are used: (1) the Capital Asset Pricing Model (CAPM), (2) the discounted cash flow (DCF) method, and (3) the bond-yield-plus-risk-premium approach.* ***These methods are not mutually exclusive – no method dominates the others****, and all are subject to error when used in practice. Therefore, when faced with the task of estimating a company's cost of equity, we generally use all three methods and then choose among them on the basis of our confidence in the data used for each in the specific case at hand. (italics in original) (emphasis added)*

Another prominent finance scholar, Professor Stewart Myers, in an early pioneering article on regulatory finance, stated(footnote omitted):

> *Use more than one model when you can. Because estimating the opportunity cost of capital is difficult,* ***only a fool throws away useful information****. That means you should not use any one model or measure mechanically and exclusively. Beta is helpful as one tool in a kit, to be used in parallel with DCF models or other techniques for interpreting capital market data. (italics in original) (emphasis added)*

* * *

Reliance on multiple tests recognizes that no single methodology produces a precise definitive estimate of the cost of equity. As stated in Bonbright, Danielsen, and Kamerschen (1988), *'no single or group test or technique is conclusive.'* (italics in original)

* * *

While it is certainly appropriate to use the DCF methodology to estimate the cost of equity, there is no proof that the DCF produces a more accurate estimate of the cost of equity than other methodologies. Sole reliance on the DCF model ignores the capital market evidence and financial theory formalized in the CAPM and other risk premium methods. **The DCF model is one of many tools to be employed in conjunction with other methods to estimate the cost of equity**. It is not a superior

> methodology that supplants other financial theory and market evidence. The broad usage of the DCF methodology in regulatory proceedings in contrast to its virtual disappearance in academic textbooks does not make it superior to other methods. The same is true of the Risk Premium and CAPM methodologies. (emphasis added)[27]

Further, Brigham and Gapenski note:

> In practical work, *it is often best to use all three methods* – CAPM, bond yield plus risk premium, and DCF – and then apply judgment when the methods produce different results. People experienced in estimating equity capital costs recognize that both careful analysis and some very fine judgments are required. It would be nice to pretend that these judgments are unnecessary and to specify an easy, precise way of determining the exact cost of equity capital. Unfortunately, this is not possible. Finance is in large part a matter of judgment, and we simply must face this fact. (italics in original)[28]

Lastly, Brigham and Daves state regarding the use of the DCF and the CAPM:

> Recent surveys found that the CAPM approach is by far the most widely used method. Although most firms use more than one method, almost 74 percent of respondents in one survey, and 85 percent in the other, used the CAPM.[footnote omitted] This is in sharp contrast to a 1982 survey which found that only 30 percent of respondents used the CAPM.[footnote omitted] Approximately 16 percent now use the CF, down from 31 percent in 1982. The bond yield plus risk premium is used primarily by companies that aren't publicly traded.
>
> People experienced in estimating the cost of equity recognize that both careful analysis and sound judgment are required. It would be nice to pretend that judgment is unnecessary and to specify an easy, precise way of determining the exact cost of equity capital. Unfortunately, this is not possible – finance is in large part a matter of judgment, and we simply must face that fact.[29]

This final excerpt establishes four points: (1) most firms use multiple models; (2) the use of the CAPM is prevalent by firms in internal decision-making; (3) the importance of the DCF model in the decision-making process for firms has waned over time; and (4)

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27 Morin, at 476-479.

28 Eugene F. Brigham and Louis C. Gapenski, Financial Management – Theory and Practice, 4th Ed. (The Dryden Press, 1985) at 256 ("Brigham and Gapenski").

29 Eugene F. Brigham, Phillip R. Daves, Intermediate Financial Management, Ninth Edition, Thomson Southwestern, 2007, at 332-333 ("Brigham and Daves").

regardless of which models one uses, judgment is the key ingredient in determining the cost of equity capital.

Q. MR. DAVES STATES THAT THE CAPM IS NOT AS FORWARD-LOOKING AS THE DCF MODEL BECAUSE BETAS ARE NOT FORWARD-LOOKING.[30] PLEASE RESPOND.

A. I respectfully disagree with Mr. Daves on this issue. Both *Value Line* and Bloomberg betas are "Blume-adjusted." Blume studied the stability of betas over time and found that "[n]o economic variable including the beta coefficient is constant over time."[31] Consistent with that finding, Blume observed a tendency of raw betas to change gradually over time. Blume further stated:

> …there is obviously some tendency for the estimated values of the risk parameter [beta] to change gradually over time. This tendency is most pronounced in the lowest risk portfolios, for which the estimated risk in the second period is invariably higher than that estimated in the first period. There is some tendency for the high risk portfolios to have lower estimated risk coefficients in the second period than in those estimated in the first. Therefore, the estimated values of the risk coefficients in one period are biased assessments of the <u>future values</u>, and furthermore the values of the risk coefficients as measured by the estimates of β_1 tend to regress towards the means with this tendency stronger for the lower risk portfolios than the higher risk portfolios. (emphasis added)

Blume proposed a correction for this tendency, also known as "regression bias," which is inherent in the calculation of all betas. He stated:

> In so far as the rate of regression towards the mean is stationary over time, one can in principle correct for this tendency in forming one's assessments.
>
> * * *
>
> For individual securities as well as portfolios of two or more securities, the assessments adjusted for the historical rate of regression are more accurate than the unadjusted or naïve assessments. Thus, an improvement in the accuracy of one's assessments of risk can be obtained by adjusting for the

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30 Daves' Direct Testimony, at 45.

31 Marshal E. Blume, *On the Assessment of Risk*, <u>The Journal of Finance</u>, Vol. XXVI, No. 1, March 1971 ("Blume").

> historical rate of regression even though the rate of regression over time is not strictly stationary.[32]

Based on Blume's results, the typical adjustment is calculated based upon an approximate of the following formula:

$$\beta_{adjusted} = 0.35 + .67x\beta_{raw\ (unadjusted)} \quad \text{Equation [8]}$$

As noted by Morin:

> Several authors have investigated the regression tendency of beta and generally reached similar conclusions [as Blume]. High-beta portfolios have tended to decline over time toward unity, while low-beta portfolios have tended to increase over time toward unity…He demonstrated that the Value Line adjustment procedure anticipated differences between past and future betas.
>
> ***
>
> A comprehensive study of beta measurement methodology by Kryzanowski and Jalilvand (1983) concludes that raw unadjusted beta (OLS beta) is one of the poorest beta predictors, and is outperformed by the Merrill Lynch-style Bayesian beta approach. Gombola and Kahl (1990) examine the time-series properties of utility betas and find strong support for the application of adjustment procedures such as the Value Line and Merrill Lynch procedures.
>
> Because of this observed regressive tendency, a company's raw unadjusted beta is not the appropriate measure of market risk to use. Current stock prices reflect expected risk, that is, expected beta, rather than historical risk or historical beta. Historical betas, whether raw or adjusted, are only surrogates for expected beta. The best of the two surrogates is adjusted beta.[33]

In view of the above, Mr. Daves' contention that betas used in CAPM analyses are not forward-looking should be rejected by the Commission. Furthermore, Mr. Daves should view his CAPM results as more than just a "check," and the Commission should consider the results of all cost of equity models in determining its return for SUA.

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[32] Marshal E. Blume, *On the Assessment of Risk*, The Journal of Finance, Vol. XXVI, No. 1, March 1971.

[33] Morin, at 81-82.

B. Application of the DCF Model

Q. PLEASE SUMMARIZE MR. DAVES' APPLICATION OF THE DCF MODEL.

A. Mr. Daves uses 13-week historical prices after the date of each proxy company's *Value Line* sheet, annualized dividends from those same *Value Line* sheets, and projected and historical growth rates in EPS and DPS to produce indicated DCF costs rates from 8.40% to 10.10%.[34]

Q. DO YOU HAVE ANY CONCERNS WITH MR. DAVES' APPLICATION OF THE DCF MODEL?

A. Yes, I do. I disagree with the following: (1) the inconsistency of the timing of his data; (2) his use of historical growth rates; and (3) his use of DPS growth rates.

Q. IS THE TIMING OF MR. DAVES' DATA CONSISTENT BETWEEN THE INPUTS TO HIS DCF ANALYSIS?

A. No, it is not. Mr. Daves uses a 13-week average price period following the publication of the *Value Line* sheets for his proxy group (February 23, 2024), which ends May 22, 2024. Mr. Daves notes that "the time frame selected for the stock price determination must be after the pronouncement of the growth expectations" but does not provide any further support for why this must be the case.[35] Mr. Daves goes so far as to criticize my use of an average price period that precedes the date of my growth rates.[36]

Upon reviewing Mr. Daves's workpapers, it is apparent that two of the four growth rates[37] he uses are provided at the end of his average price period, not the beginning. This is important to note because cost of capital models, such as the DCF, are intended to

34 Daves Direct Testimony, at 40-43, Direct Exhibit DD-11.
35 Daves Direct Testimony, at 40.
36 Daves Direct Testimony, at 44.
37 Mr. Daves' Zacks and Yahoo! Finance growth rates appear to be provided as of May 22, 2024, which is the end of his average price period.

estimate the investor-required returns in a forward-looking manner, and therefore, Mr. Daves should have only relied on the most recently available data in his DCF to fully capture the most up-to-date market sentiment.

Seeing as Mr. Daves intended to use May 22, 2024, as his analysis date, he should have used the more up-to-date *Value Line* reports[38] that would have been available to him to properly align with his May 22, 2024, growth rates from Zacks and Yahoo! Finance. The more recent *Value Line* reports would have provided him with a more accurate annualized dividend and growth rate estimates.

Q. DO YOU AGREE WITH THE GROWTH RATES APPLIED BY MR. DAVES?

A. While I agree with his use of analyst projected EPS growth rates, I do not agree with Mr. Daves' use of historical growth rates or DPS growth rates. Over the long run, there can be no growth in DPS without growth in EPS. Earnings expectations have a more significant, but not sole, influence on market prices than dividend expectations. Thus, the use of earnings growth rates in a DCF analysis provides a better match between investors' market appreciation expectations implicit in market prices and the growth rate component of the DCF. Consequently, earnings expectations have a significant influence on market prices which affect market price appreciation, and hence, the "growth" experienced by investors. This should be evident just by listening to financial news reports on radio, TV, or reading newspapers. In fact, Morin states:

> Because of the dominance of institutional investors and their influence on individual investors, analysts' forecasts of long-run growth rates provide a sound basis for estimating required returns. Financial analysts exert a strong influence on the expectations of many investors who do not possess the resources to make their own forecasts, that is, they are a cause of g. The accuracy of these forecasts in the sense of whether they turn out to be correct is not at issue here, as long as they reflect widely held expectations. As long

[38] Note: The more recent *Value Line* reports are dated May 24, 2024, but would have been available for Mr. Daves on May 20, 2024.

> as the forecasts are typical and/or influential in that they are consistent with current stock price levels, they are relevant. The use of analysts' forecasts in the DCF model is sometimes denounced on the grounds that it is difficult to forecast earnings and dividends for only one year, let alone for longer time periods. This objection is unfounded, however, because it is present investor expectations that are being priced; it is the consensus forecast that is embedded in price and therefore in required return, and not the future as it will turn out to be.
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> * * *
>
> Published studies in the academic literature demonstrate that growth forecasts made by security analysts represent an appropriate source of DCF growth rates, are reasonable indicators of investor expectations and are more accurate than forecasts based on historical growth. These studies show that investors rely on analysts' forecasts to a greater extent than on historic data.[39]

In addition, studies performed by Cragg and Malkiel demonstrate that analysts' forecasts are superior to historical growth rate extrapolations. They state:

> Efficient market hypotheses suggest that valuation should reflect the information available to investors. Insofar as analysts' forecasts are more precise than other types we should therefore expect their differences from other measures to be reflected in the market. It is therefore noteworthy that our regression results do support the hypothesis that analysts' forecasts are needed even when calculated growth rates are available. As we noted when we described the data, security analysts do not use simple mechanical methods to obtain their evaluations of companies. The growth-rate figures we obtained were distilled from careful examination of all aspects of the companies' records, evaluation of contingencies to which they might be subject, and whatever information about their prospects the analysts could glean from the companies themselves of from other sources. It is therefore notable that the results of their efforts are found to be so much more relevant to the valuation than the various simpler and more "objective" alternatives that we tried.[40]

In addition, Vander Weide and Carleton conclude:

> . . . our studies affirm the superiority of analysts' forecasts over simple historical growth extrapolations in the stock price formation process. Indirectly, this finding lends support to the use of valuation models whose

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[39] Morin, at 371-373.

[40] John G. Cragg and Burton G. Malkiel, Expectations and the Structure of Share Prices (University of Chicago Press, 1982) Chapter 4 ("Cragg and Malkiel").

input includes expected growth rates.[41]

Burton G. Malkiel, the Chemical Bank Chairman's Professor of Economics at Princeton University and author of the widely read national bestseller book on investing entitled, A Random Walk Down Wall Street (2011), also expressed support for projected EPS growth rates in testimony before the Public Service Commission of South Carolina in November 2002. Malkiel affirmed his belief in the superiority of analysts' earnings forecasts when he testified:

> With all the publicity given to tainted analysts' forecasts and investigations instituted by the New York Attorney General, the National Association of Securities Dealers, and the Securities & Exchange Commission, I believe the upward bias that existed in the late 1990s has indeed diminished. In summary, I believe that current analysts' forecasts are more reliable than they were during the late 1990s. *Therefore, analysts' forecasts remain the proper tool to use in performing a Gordon Model DCF analysis.*[42]

Q. IN REVIEWING THE FINANCIAL LITERATURE, DID YOU DISCOVER ANY PUBLICATIONS THAT SUPPORTED THE USE OF PROJECTED DPS GROWTH RATES FOR USE IN A DCF MODEL?

A. No, I did not.

Q. HAVE YOU PERFORMED ANY ANALYSES TO DETERMINE WHICH MEASURES OF GROWTH ARE STATISTICALLY RELATED TO THE PROXY COMPANIES' STOCK VALUATION LEVELS?

A. Yes, I have. My analysis is based on the methodological approach used by Carleton and Vander Weide, who compared the predictive capability of historical growth estimates and

41 James H. Vander Weide and Willard T. Carleton, *Investor Growth Expectations: Analysts vs. History* (The Journal of Portfolio Management, Spring 1988) 78-82 ("Vander Weide and Carelton").

42 Rebuttal testimony, South Carolina Electric and Gas Co., pp. 16-17, Docket No. 2002-223-E (emphasis added).

analysts' forecasts on the valuation levels of 65 utility companies.[43] I structured the analysis to understand whether historical, or projected, earnings or dividend growth rates best explain utility stock valuations. In particular, my analysis examined the statistical relationship between the price-to-earnings ("P/E") ratios of the natural gas and electric utilities as classified by *Value Line*, and the historical and projected EPS and DPS growth rates as reported by *Value Line*. To determine which, if any, of those growth rates are statistically related to utility stock valuations, I performed a series of regression analyses in which the projected growth rates were explanatory variables and the P/E ratio was the dependent variable. The results of those analyses are presented in Schedule DWD-4XR.

In that analysis, I performed four separate regressions with the P/E as the dependent variable, and the historical and projected EPS and DPS as the independent variable. I then reviewed the T- and F-Statistics to determine whether the variables and equations were statistically significant.[44]

Q. WHAT DID THOSE ANALYSES REVEAL?

A. As shown in Schedule DWD-4R, the only growth rate that was statistically significant and positively related to the P/E ratio was projected EPS. Because EPS growth is the only growth rate that is both statistically and positively related to utility valuation, projected earnings is the proper measure of growth in the constant growth DCF model. As a result, I urge the Commission to only give weight to Mr. Daves' DCF results based on projected EPS growth rates (labeled as his "g1"), which result in a 10.10% ROE estimate.[45]

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43 James H. Vander Weide and Willard T. Carleton, *Investor Growth Expectations: Analysts vs History*, The Journal of Portfolio Management (Spring 1988).

44 In general, a T-Statistic of 2.00 or greater indicates that the variable is likely to be different than zero, or "statistically significant." The F-Statistic is used to determine whether the model as a whole has statistically significant predictive capability.

45 Direct Exhibit DD-11.

C. Application of the CAPM

Q. PLEASE BRIEFLY SUMMARIZE MR. DAVES' CAPM ANALYSIS AND RESULTS.

A. For the risk-free rate, Mr. Daves applies rates of 4.39% and 4.53% based on 10-year U.S. Treasury yields.[46] Mr. Daves calculates a MRP estimate using data from Kroll's <u>Stocks, Bonds, Bills, and Inflation ("SBBI") Yearbook 2023</u> ("<u>SBBI – 2023</u>"). He derives his MRP by subtracting the long-term average income returns of government bonds (4.90%) from the long-term average total return of large company stocks (12.00%), resulting in an MRP of 7.10%.[47] For the Beta coefficient ("beta"), Mr. Daves relies on the average value reported by *Value Line* for his proxy group (0.88).[48] Using these, Mr. Daves calculates ROEs of from 10.61% and 10.74%.

Q. DO YOU AGREE WITH MR. DAVES' CAPM ANALYSIS AND RESULTS?

A. No, I do not. I generally disagree with three aspects of Mr. Daves' analysis: (1) he does not consider a prospective risk-free rate; (2) he uses a 10-year Treasury bond as his risk-free rate; and (3) he does not perform an Empirical CAPM ("ECAPM") analysis. However, given that the current 10-year Treasury bond-based risk-free rate Mr. Daves uses in his CAPM is reasonably consistent with the projected 30-year Treasury bond-based risk-free rate used in my updated CAPM, to reduce the scope of this Rebuttal Testimony, I will not address Mr. Daves' use of a current risk-free rate.

Q. DOES MR. DAVES PERFORM AN EMPIRICAL CAPM IN HIS ANALYSIS?

A. No, he does not. Mr. Daves did not consider the ECAPM, despite the fact that numerous tests of the CAPM have confirmed the ECAPM's validity by showing that the empirical

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46 Daves Direct Testimony at 47, Direct Exhibit DD-12.
47 Daves Direct Testimony, at 47, Direct Exhibit DD-12, and Mr. Daves' Direct Workpapers.
48 Daves Direct Testimony at 47, Direct Exhibit DD-12.

Security Market Line ("SML") described by the traditional CAPM is not as steeply sloped as the predicted SML. While the results of these tests support the notion that betas are related to security returns, the empirical SML described by the CAPM formula is not as steeply sloped as the predicted SML, as discussed on pages 33 through 35 of my Direct Testimony.

Q. HAVE YOU UPDATED MR. DAVES' CAPM RESULTS BASED ON THE ADJUSTMENTS DISCUSSED ABOVE?

A. Yes, I have. As shown on Schedule DWD-5R, incorporating the ECAPM results in an average indicated CAPM/ECAPM cost rates of 10.72% and 10.85%. In view of these results, Mr. Daves' CAPM results of 10.61% and 10.74% understate the Company's ROE.

D. Application of the RPM

Q. PLEASE DESCRIBE MR. DAVES' RPM ANALYSIS.

A. Mr. Daves' RPM analysis reviews the authorized returns for natural gas utilities nationwide and for surrounding jurisdictions going back to 2022, to which he applies the monthly yield on public utility debt for the month in which the return was authorized in order to determine the corresponding ERP.[49] Mr. Daves then takes the average ERP and adds the three-, six, nine- and 12-month average historical A-rated and Baa-rated utility bond yields. Mr. Daves' RPM analysis produces ROE estimates ranging from 9.82% to 9.92%.[50]

Q. DO YOU AGREE WITH MR. DAVES' RPM ANALYSIS?

A. No, I do not. I have at least three concerns with Mr. Daves' analysis: (1) his use of a short time period to calculate his ERP; (2) his use of an average ERP; and (3) his use of current interest rates.

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49 Daves Direct Testimony, at 51; Direct Exhibit DD-14, DD-21; Daves Direct Workpapers.
50 Daves Direct Testimony, at 51.

Q. WHEN CALCULATING AN ERP, WHY IS USING A LONG TIME PERIOD APPROPRIATE?

A. Using a long historical period to calculate the ERP is appropriate because it considers several business cycles which gives insight to potential future outcomes. SBBI – 2023 states:

> Some analysts estimate the expected equity risk premium using a shorter, more recent period on the basis that recent events are more likely to be repeated in the near future; furthermore, they believe that the 1920s, 1930s, and 1940s contain too many unusual events. This view is suspect because all periods contain unusual events. Some of the most unusual events of the last 100 years took place quite recently, including the inflation of the late 1970s and early 1980s, the October 1987 stock market crash, the collapse of the high-yield bond market, the major contraction and consolidation of the thrift industry, the collapse of the Soviet Union, the development of the European Economic Community, the attacks of Sept. 11, 2001, and the more recent global financial crisis of 2008-2009, and most recently, the market crash in the first quarter of 2020 that was precipitated by the spread of the COVID-19 virus.
>
> It is even difficult for economists to predict the economic environment of the future. For example, if one were analyzing the stock market in 1987 before the crash, it would be statistically improbable to predict the impending short-term volatility without considering the stock market crash and market volatility of the 1929-1931 period.
>
> Without an appreciation of the 1920s and 1930s, no one would believe that such events could happen. The 97-year period starting with 1926 represents what can happen: It includes high and low returns, volatile and quiet markets, war and peace, inflation and deflation, and prosperity and depression. Restricting attention to a shorter historical period underestimates the amount of change that could occur in a long future period. Finally, because historical event-types (not specific events) tend to repeat themselves, long-run capital market return studies can reveal a great deal about the future. Investors probably expect unusual events to occur from time to time, and their return expectations reflect this.[51]

In addition to the above, the use of a long time period in the calculation of the ERP is consistent with Mr. Daves' use of the long-term historical average MRP in his CAPM

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51 SBBI-2023, at 194.

analysis. A major weakness in using historical average ERPs is that it does not reflect the relationship between ERPs and interest rates.

Q. WHAT IS THE RELATIONSHIP BETWEEN ERPS AND INTEREST RATES?

A. As discussed in my Direct Testimony,[52] and as observable in Mr. Daves' analysis, there is a readily discernible inverse relationship between interest rates and ERPs. This relationship is also consistent with financial literature on the subject. Specifically, in Brigham, Shome, and Vinson's article, *The Risk Premium Approach to Measuring a Utility's Cost of Equity*, the authors explain that "with 'proper' regulation, utility stocks would provide a better hedge against unanticipated inflation than would bonds."[53] In that case, if concerns regarding future inflation increase, the perceived risk of bonds would increase more than the perceived risk of equity. That is, the return required on equity would increase less than the return required on bonds, thereby decreasing the ERP.

The relationship between interest rates, inflation, and expected returns also was explained in a 1985 <u>Financial Analysts Journal</u> article:

> For securities such as bonds, whose cash flows (coupon payments) are fixed, an unanticipated increase in inflation results in a decline in price. The decline in price, combined with a fixed coupon, raises the expected return and compensates for the higher rate of inflation.
>
> ***
>
> For securities such as common stocks, whose cash flows (dividends) are flexible, the price of the security does not necessarily change in response to unanticipated inflation. Stock dividends may rise to offset an increase in the rate of inflation, precluding any need for price adjustment.[54]

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52 D'Ascendis Direct Testimony, at 31-32.

53 Eugene F. Brigham, Dilip K. Shome, and Steve R. Vinson, *The Risk Premium Approach to Measuring a Utility's Cost of Equity*, <u>Financial Management</u> (Spring 1985), at 43.

54 James L. Farrell Jr., *The Dividend Discount Model: A Primer*, <u>Financial Analysts Journal</u>, November-December 1985, at 23.

Other published research has shown the ERP is not constant but varies inversely with interest rates. Harris and Marston found the ERP to change inversely to changes in interest rates, concluding that "…the notion of a constant risk premium over time is not an adequate explanation of pricing in equity versus debt markets."[55] Similarly, a study by Maddox, Pippert, and Sullivan, found their results "indicate a statistically significant inverse relationship between interest rates and utility equity risk premiums."[56] In view of mine and Mr. Daves' rate case data, and the academic literature cited above, the ERP is not static and as such, Mr. Daves' use of an average ERP in his RPM is inappropriate and should be dismissed by the Commission.

Q. HOW DOES MR. DAVES' DATA SHOW THE INVERSE RELATIONSHIP BETWEEN ERPS AND INTEREST RATES?

A. As shown on Charts 1 and 2 below, empirical analyses of the data presented in Mr. Daves' workpapers, ERPs have moved inversely with changes in A and Baa-rated utility bond yields.

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55 Robert S. Harris and Felicia C. Marston, *The Market Risk Premium: Expectational Estimates Using Analysts' Forecasts*, Journal of Applied Finance, Vol. 11, No. 1, 2001, at 11-12, 14. The authors also found credit spreads are positively related to the ERP.

56 Farris M. Maddox, Donna T. Pippert, and Rodney N. Sullivan, *An Empirical Study of Ex Ante Risk Premiums for the Electric Utility Industry*, Financial Management, Vol. 24, No. 3, Autumn 1995 at 95.

Chart 1: Empirical Analysis of ERPs and A-Rated Public Utility Bonds[57]

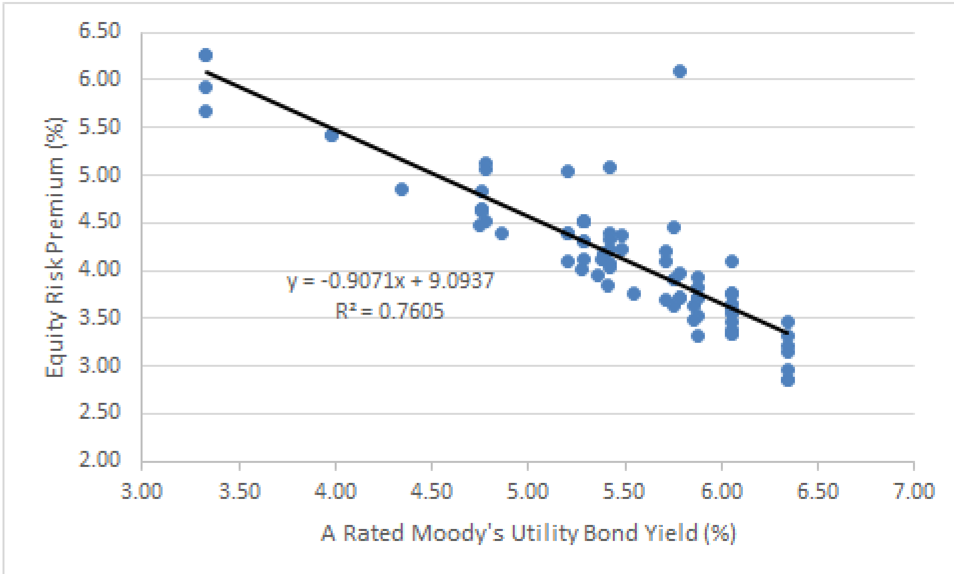
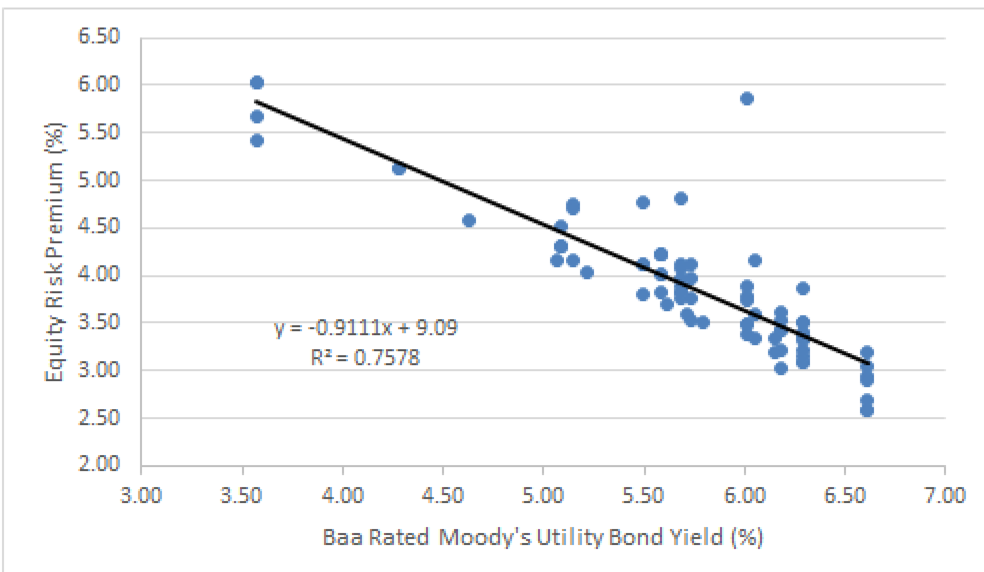


Chart 2: Empirical Analysis of ERPs and Baa-Rated Public Utility Bonds [58]



Q. PLEASE RESPOND TO MR. DAVES' USE OF A CURRENT UTILITY BOND YIELD IN HIS RPM.

A. Mr. Daves uses three-, six-, nine- and 12-month average historical A-rated and Baa-rated utility bond yields to arrive at his RPM ROE estimate, noting that the prospective yields

[57] Source: Daves Direct Workpapers.
[58] Source: Daves Direct Workpapers.

used in my RPM analysis insinuate "a great deal of uncertainty" in my analysis.[59] While I generally disagree with exclusive use of current bond yields, the A-rated utility bond yields Mr. Daves applies range from 5.63% - 5.74% and are reasonably consistent with the 5.58% prospective A2 rated utility bond yield used in my updated RPM analysis, so to reduce the scope of this Rebuttal Testimony, I will not address Mr. Daves' use of current utility bond yields in his RPM analysis.

Q. WHAT WOULD MR. DAVES' RPM RESULT BE IF CORRECTED FOR THE ERRORS NOTED ABOVE?

A. Based on the data provided in Mr. Daves' workpapers, I replicated the two sets of authorized returns relied on by Mr. Daves, but extending the dataset to 1980, which is the furthest back in time that data is available from Regulatory Research Associates. For each set, I performed a linear regression in which the ERP was the dependent variable and interest rates were the independent variable. Applying the corrected ERPs to Mr. Daves' A2-rated and Baa2-rated utility bond yields, the updated results applicable to Mr. Daves' RPM are shown in Schedule DWD-6R and in Table 4, below:

Table 4: Mr. Daves' Corrected RPM Results

	A-Rated Utility Yield	Baa-Rated Utility Yield
Nationwide	10.42%	10.35%
Surrounding Jurisdictions	10.42%	10.35%

As shown in Table 4, the corrected RPM results for Mr. Daves range from 10.35% to 10.42%. In view of these results, Mr. Daves' indicated RPM results from 9.82% to 9.92% are understated.

[59] Daves Direct Testimony, at 50.

E. Application of a Size Adjustment

Q. DOES MR. DAVES CONSIDER A SIZE ADJUSTMENT IN HIS RECOMMENDED ROE?

A. No, he does not. It is Mr. Daves' opinion that a size adjustment is inappropriate because: (1) SUA should not be considered as a stand-alone company; (2) the size adjustment is only applicable to my CAPM results; (3) the Commission has previously found that size adjustments are not applicable; and (4) any risks related to size are already reflected in the proxy groups.[60]

Q. WHY IS THE SIZE OF SUA'S DIRECT OR INDIRECT PARENT NOT MORE APPROPRIATE TO USE WHEN DETERMINING THE SIZE ADJUSTMENT?

A. As discussed in my Direct Testimony, the return derived in the proceeding will not apply to SUA's parents (Southern Col Midco, LLC or Southern Col Holdco, LLC) operations as a whole, but only to SUA's Arkansas operations.[61] As such, SUA's Arkansas operations should be considered a stand-alone company. On pages 44-45 of my Direct Testimony, I provided evidence supporting why SUA should be considered as a stand-alone company, which Mr. Daves has not responded to.

Q. PLEASE RESPOND TO MR. DAVES' CLAIM THAT THE INFORMATION PROVIDED IN YOUR DIRECT TESTIMONY SUGGESTS THAT A SIZE PREMIUM IS ONLY APPLICABLE TO YOUR CAPM RESULTS.

A. Mr. Daves appears to focus only on evidence I present from Fama and French on page 43 of my Direct Testimony, who came to their conclusion that size is a risk factor that must be reflected when they were specifically studying the CAPM model. Mr. Daves therefore

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60 Daves Direct Testimony, at 52-53.
61 D'Ascendis Direct Testimony, at 44.

ignores the non-CAPM specific evidence I presented from Kroll and Eugene Brigham that supports the need for a size adjustment, regardless of which ROE model it is applied to.

Q. PLEASE COMMENT ON MR. DAVES' OBSERVATION THAT THE COMMISSION HAS NOT PREVIOUSLY INCORPORATED A SIZE PREMIUM IN SETTING RETURNS.

A. While I respect the Commission's previous decisions, I note that Mr. Daves' reliance on those decisions fails to account for the observable and empirical evidence on the matter, as discussed above.

Q. MR. DAVES NOTES THAT BECAUSE A HIGHER PERCENTAGE OF SUA'S REVENUES ARE DERIVED FROM REGULATED OPERATIONS, IT SHOULD BE CONSIDERED LESS RISKY THAN OUR SHARED PROXY GROUP.[62] DO YOU AGREE?

A. No, I do not. I disagree with Mr. Daves' use of revenues, rather than net operating income ("NOI") or assets attributable to regulated electric operations. Measures of income are far more likely to be considered by the financial community in making credit assessments and investment decisions than are measures of revenue. From the perspective of credit markets, measures of financial strength and liquidity are focused on cash from operations, which is a direct derivative of earnings, as opposed to revenue. As part of its rating methodology, for example, Moody's assigns a 40.00% weight to measures of financial strength and liquidity, of which 22.50% specifically relates to the ability to cover debt obligations with cash from operations.[63]

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[62] Daves Direct Testimony, at 53.

[63] *See*, Moody's Investors Service, Rating Methodology, Regulated Electric and Gas Utilities, June 23, 2017, at 4.

Just as rating agencies focus on measures of cash from operations, equity analysts rely on measures of income in assessing equity valuation levels; common measures of relative value include the price-to-earnings ratio, and the ratio of EBITDA.[64] Revenue, however, may be several steps removed from the earnings and cash flows that form the basis of equity valuations. Focusing on revenue may mislead the analyst into assuming a given operating unit is the primary driver of expected growth when the majority of earnings and cash flows are derived from other business segments. Here, we are considering whether the underlying utility is the principal source of long-term growth, and as such, focusing on revenue may obscure important elements of the analysis.

Additionally, the use of assets attributable to natural gas distribution operations are more representative of operating risk because of the ratemaking paradigm (rate base * weighted average cost of capital = operating income).

Q. DO THE COMPANIES IN YOUR UTILITY PROXY GROUP HAVE SIGNIFICANT LEVELS OF BOTH NOI AND ASSETS ATTRIBUTABLE TO REGULATED NATURAL GAS DISTRIBUTION OPERATIONS?

A. Yes, they do. The average company in my Utility Proxy Group has approximately 88.18% of its NOI and assets attributable to regulated natural gas distribution operations. Mr. Daves' concern should be dismissed. The rationale he provides does not address the additional risk associated with smaller companies. As discussed in my Direct Testimony,[65] company size is a significant element of business risk for which investors expect to be compensated through greater returns.

64 Earnings Before Interest, Taxes, Depreciation, and Amortization.
65 D'Ascendis Direct Testimony, at 42-47.

F. <u>Staff's Adequacy of Overall Recommendation</u>

Q. PLEASE SUMMARIZE MR. DAVES' EVALUATION OF THE ADEQUACY OF HIS RECOMMENDATION.

A. Mr. Daves calculates three *pro forma* ratios: EBITDA/interest, times interest earned, and total debt to EBITDA ratios for SUA based on his recommended ROE of 9.75% and a capital structure based on a 38.53% equity ratio, which he compares to those of his proxy group. Based on his analysis, he concludes his recommendation is reasonable.[66] An important consideration is that Mr. Daves' analysis fundamentally assumes the Company will earn the entirety of its authorized ROE on a going-forward basis. The ROE set in this proceeding is not a guaranteed return, but an opportunity to earn that return.

Q. DO YOU AGREE WITH THE PREMISE OF MR. DAVES' ADEQUACY ANALYSIS?

A. No, I do not. As a preliminary matter, I reviewed S&P's ratings methodology and times interest earned (one of the ratios used by Mr. Daves) is not one of the cash flow/leverage analysis ratios used by S&P.[67] Also, Mr. Daves compares the resulting metrics in comparison with his proxy group, not with the Company. In setting the ROE for the Company, as discussed in my Direct Testimony, it is important that the allowed return: (1) be adequate to attract capital at reasonable terms; (2) allow the utility to maintain its financial integrity; and (3) be commensurate with returns on investments in enterprises having corresponding risks.[68] Because Mr. Daves does not use Company-specific data, his analysis provides no insight into whether his allowed return meets these standards.

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66 Daves Direct Testimony, at 57.
67 Standard & Poor's Ratings Services, *Corporate Methodology*, November 19, 2013 at 33.
68 D'Ascendis Direct Testimony, at 5.

Q. IGNORING THE ABOVE, ARE CREDIT RATINGS DETERMINED PRINCIPALLY BY THE TYPES OF *PRO FORMA* METRICS MR. DAVES USES IN HIS ANALYSIS?

A. No. S&P's ratings process considers a range of both quantitative and qualitative data. Cash Flow / Leverage considerations are one element of a broad set of criteria.[69] Unlike Mr. Daves' *pro forma* analysis, S&P's assessment does not look to a single period of time or assume static relationships among variables. Rather, S&P reviews credit ratios "on a time series basis with a clear forward-looking bias."[70] S&P explains that the time series length depends on a number of qualitative factors, but generally includes two years of historical data, and three years of projections. Further, the ratios depend on "base case" projections considering "current and near-term" economic conditions, industry assumptions, and financial policies. Consequently, even if we assume credit determinations are driven by three *pro forma* metrics, the actual assessment of those metrics is far more complex than Mr. Daves' analysis suggests.

Q. DO YOU HAVE OTHER CONCERNS WITH MR. DAVES' ADEQUACY ANALYSIS?

A. Yes, I do. Looking to S&Ps Cash Flow/Leverage Analysis Ratio—Medial Volatility, Mr. Daves EBITDA/interest and Debt/EBITDA ratios of 7.8x and 3.9x fall within the risk profiles of "Intermediate" and "Significant." Those profiles subsequently range from 5x – 9x and 3.5x – 4.5x.

Relying on *pro forma* credit metrics to assess the credit implications of any specific ROE or equity ratio is a partial analysis that may lead to incorrect conclusions. That

69 Standard & Poor's Ratings Services, *Corporate Methodology*, November 19, 2013 at 5.
70 Standard & Poor's Ratings Services, *Corporate Methodology*, November 19, 2013 at 33.

concern arises not only because the credit rating process is complex, but also because a wide range of assumed ROEs and equity ratios produce *pro forma* metrics within the benchmark ranges for a given credit rating. As shown in Schedule DWD-7R and Table 5 below, for example, Mr. Daves' *pro forma* analysis suggests an ROE in the range of 6.48% to 12.49% would maintain a *pro forma* Debt to EBITDA[71] ratio in the "Significant" financial risk range identified in his analysis. As the ROEs required for a "Significant" financial risk range include the recommendations of all of the parties in this case, focusing on *pro forma* ratios are not the sole determinant of credit ratings.

That is, even if we assume an unreasonably low ROE of 6.48% in Mr. Daves' analysis, the *pro forma* Debt to EBITDA ratios remain in the "Significant" financial risk range. Clearly, a return as low as 6.48% is an unrealistic estimate of the Company's ROE.

Table 5: Mr. Daves' Adequacy Test Using Alternate Assumptions[72]

	Debt / EBITDA	**EBITDA / Interest**	
S&P Benchmark Ranges			
"Significant"	3.5x – 4.5x	2.75x – 5.0x	
"Intermediate"	2.5x – 3.5x	5.0x – 9.0x	
Scenario	**Debt / EBITDA**	**EBITDA / Interest**	**Implied Financial Risk Rating**
9.75% ROE (Daves Recommendation)	3.9x	7.8x	Significant / Intermediate
11.00% ROE (D'Ascendis Recommendation)	3.7x	8.2x	Significant / Intermediate
6.48% ROE	4.5x	6.9x	Significant / Intermediate
12.49% ROE	3.5x	8.6x	Significant / Intermediate

71 Given the differing profiles based on Mr. Daves' metrics, I have focused on the Debt to EBITDA multiple as that is identified by S&P as a "core" ratio.

72 Standard & Poor's, Criteria – Corporates – General: Corporate Methodology, November 19, 2013.

G. Response to Mr. Daves' Critiques of Company Analysis

Q. PLEASE SUMMARIZE MR. DAVES' CRITICISMS OF YOUR DIRECT TESTIMONY.

A. Mr. Daves does not agree with: (1) the timing of my DCF analysis; (2) the MRPs used in my CAPM; (3) the use of prospective bond yields in my RPM; (4) the use of rate cases going back to 1980 in my regression-based ERP; (5) my application of a size adjustment to the ROE attributable to the Utility Proxy Group; and (6) my use of a non-regulated proxy group.

I have already addressed critiques 1, 3 and 5 previously and will not address them again here. I will discuss Mr. Daves' remaining arguments (2, 4, and 6) in turn.

Q. MR. DAVES SUGGESTS THAT YOUR CALCULATED MARKET RETURNS AND MRPS ARE TOO HIGH. PLEASE RESPOND.

A. I disagree with Mr. Daves' suggestion. Recalling that Mr. Daves' MRP is based on historical data from Kroll, I therefore produced a histogram of annual MRPs and market returns reported by Kroll. While Mr. Daves may question the reasonableness of my calculated market returns and MRPs, they are consistent with actual realized returns and MRPs, as shown on Table 6, below, and Schedule DWD-8R.

Table 6: Percentile Ranks of Calculated Market Returns and Market Risk Premiums[73]

	D'Ascendis Testimony	%	Percentile Rank
Average Market Return	Direct	14.27%	49th
Average Market Return	Rebuttal	13.41%	48th
Average Market Risk Premium	Direct	9.83%	53rd
Average Market Risk Premium	Rebuttal	9.16%	50th

[73] Schedule DWD-8R.

Chart 3: Frequency Distribution of Observed Market Returns, 1926 - 2023[74]

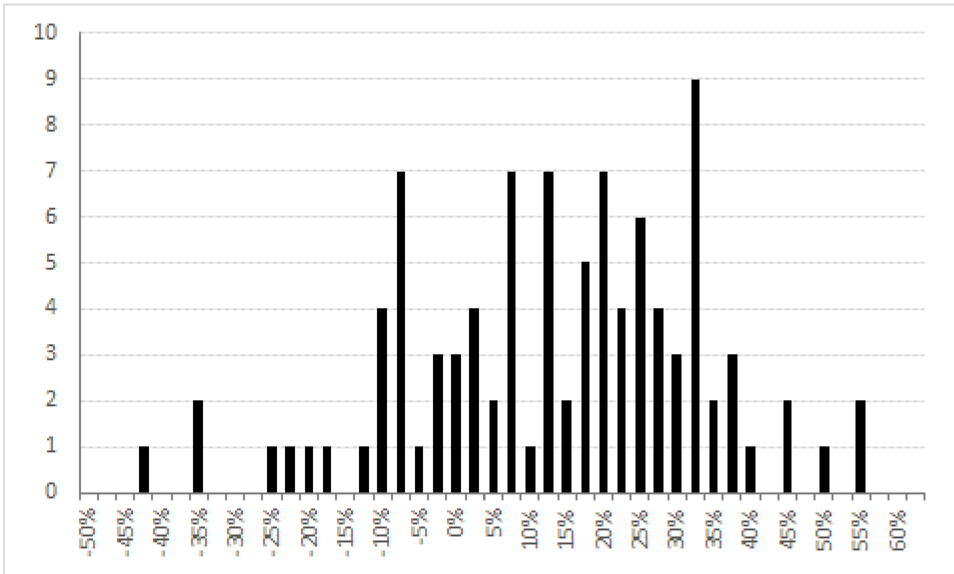
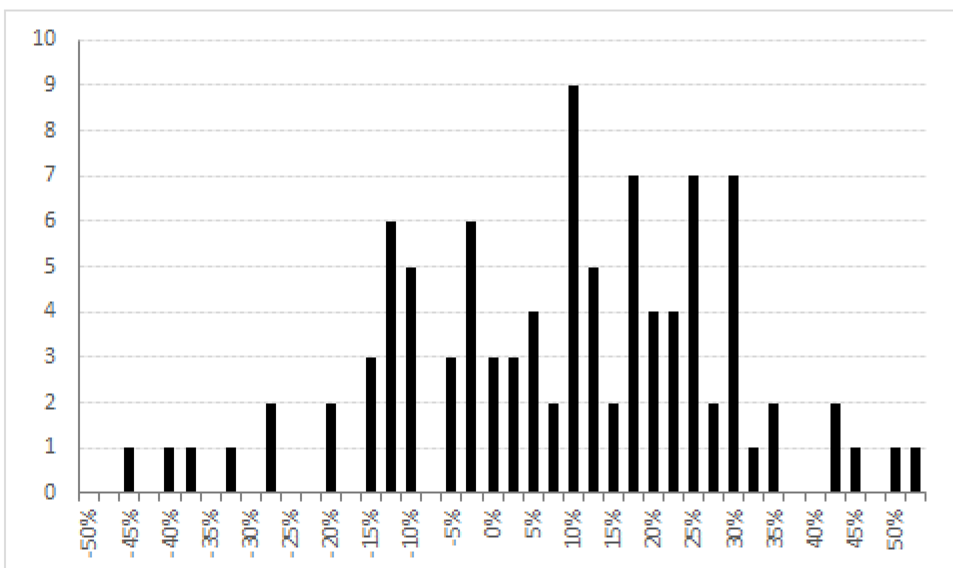


Chart 4: Frequency Distribution of Observed Market Risk Premiums, 1926 - 2023[75]



My implied market returns and MRPs are statistically indistinguishable from the <u>SBBI-2023</u> historical average considering the standard deviation of market returns of

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[74] Schedule DWD-8R.
[75] Schedule DWD-8R.

approximately 19%. Given all of the above, my calculation of the market returns and MRPs are consistent with observed values. Thus, Mr. Daves' concern should be dismissed.

Q. MR. DAVES STATES THAT YOUR CAPM PRODUCES AN "ANOMALOUSLY" HIGH RESULT DUE IN PART TO THE USE OF AN S&P 500 MARKET DCF.[76] IS THE USE OF A MARKET-DCF DERIVED PROSPECTIVE MRP AN ACCEPTED METHODOLOGY?

A. Yes, support for the market DCF-derived prospective market return is widespread. The CFA Institute notes the following:

> Approaches to estimating the ERP fall into three broad categories:
>
> 1. Methods based on a dividend discount model (DDM), earnings discount model, or cash-flow-to-the-investor discount model: forward-looking methods with their roots in discounted cash flow (DCF) analysis, wherein the value of an asset is regarded as the present value of the cash flows the asset is expected to generate… The earliest estimates of the ERP were derived by estimating the expected return on an equity portfolio using the DDM and then subtracting the expected return or yield on the riskless asset. This "DDM approach" which made a comeback at the end of the 20th century, is the method most widely used today.[77]

Morin states:

> A second approach is to estimate the MRP is prospective in nature and consists of applying the DCF model to a representative market index, such as the Standard & Poor's 500 Index, *Value Line* Composite, or the New York Stock Exchange index… If risk premiums are volatile, this method of directly measuring R_m is preferred. Subtracting the current risk-free rate from that estimate produces a valid estimate of the market risk premium.[78]

Finally, Brigham and Daves state:

> An alternative to the historical risk premium is to estimate a forward-looking, or *ex-ante* risk premium. The most common approach is to use the Discounted Cash Flow (DCF) model to estimate the expected market rate

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76 Daves Direct Testimony, at 48-49.

77 CFA Institute Research Foundation, Literature Review, *The Equity Risk Premium: A Contextual Literature Review*, at 2.

78 Morin, at 183.

of return, $\hat{r} = r_m$, and then calculate RP_m as $r_m - r_{rf}$.[79]

Given the above, Mr. Daves' concerns regarding my prospective market-DCF based MRPs should be dismissed.

Q. PLEASE RESPOND TO MR. DAVES' SUGGESTION THAT SOME OF THE GROWTH RATES USED IN YOUR MARKET DCFS ARE TOO HIGH.[80]

A. The Federal Energy Regulatory Commission ("FERC") has found that the DCF-based growth rates used to calculate the MRP in the CAPM need not meet a sustainability threshold because, although an individual company may not be expected to sustain high short-term growth rates in perpetuity, the same cannot be said for a stock index like the S&P 500 that is regularly updated to contain only companies with high market capitalization. The FERC noted that the S&P 500 is regularly updated to reflect high market capitalization companies and to be representative of the overall market. Second, the companies included in the S&P 500 represent companies in various growth stages. As such, the analyst growth estimates of companies in mature industries are likely to be lower than growth rates for companies in younger industries, which negates the need for the use of a long-term Gross Domestic Product ("GDP") growth rate.[81] The FERC ultimately concluded in Opinion No. 569:

> In summary, while it may be unreasonable to expect an individual company to sustain high short-term growth rates in perpetuity, the same cannot be said for a broad representative market index that is regularly updated to include new companies. Put differently, a portfolio of companies behaves differently than an individual company. Accordingly, the rationale for incorporating a long-term growth rate estimate in conducting a two-step DCF analysis of a specific utility or group of utilities for purposes of directly estimating cost of equity does not apply to the DCF analysis of a broad

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79 Eugene F. Brigham and Phillip R. Daves, Intermediate Financial Management, 9th Edition, Thomson / Southwestern, 2007, at 325.

80 Daves Direct Testimony, at 49.

81 Docket No. EL14-12-003 and EL15-45-000, *Opinion No. 569 Order on Briefs, Rehearing*, *and Initial Decision*, 169 FERC ¶ 61,129 (November 21, 2019), at Para. 264-265.

> representative market index with a wide variety of companies that is regularly updated to include new companies for purposes of determining the required return to the overall market.[82]

Furthermore, market returns and growth in GDP are not correlated. For the period 1929-2023, the correlation between market returns and GDP growth is 0.14. For these reasons, the Commission should again dismiss Mr. Daves' concern.

Q. PLEASE SUMMARIZE MR. DAVES' ISSUES WITH YOUR NON-PRICE REGULATED PROXY GROUP.

A. Mr. Daves does not see the relevance of including a Non-Price Regulated Proxy Group and believes that the companies contained in my Non-Price Regulated Proxy Group do not have anything in common with the utility Proxy Group.[83]

Q. PLEASE RESPOND TO MR. DAVES' SUGGESTION THAT YOUR NON-PRICE REGULATED PROXY GROUP IS NOT COMPARABLE TO YOUR UTILITY PROXY GROUP.

A. As discussed in my Direct Testimony, the selection criteria for my Non-Regulated Proxy Group were based on a range of unadjusted betas (a measure of systematic risk) and a range of standard errors of the regression (a measure of unsystematic risk), which gave rise to those betas, and together measure total risk, a concept echoed by Mr. Daves on pages 46 and 47 of his direct testimony.[84]

Business and financial risks may vary between companies and proxy groups, but if the collective average betas and standard errors of the regression of the group are similar, then the total, or aggregate, non-diversifiable market risks and diversifiable risks are

[82] Docket No. EL14-12-003 and EL15-45-000, *Opinion No. 569 Order on Briefs, Rehearing, and Initial Decision*, 169 FERC ¶ 61,129 (November 21, 2019), at Para. 266.
[83] Daves Direct Testimony, at 54.
[84] D'Ascendis Direct Testimony, at 39.

similar, as noted in "Comparable Earnings: New Life for an Old Precept" provided in Schedule DWD-9R. Thus, because the non-price regulated companies are selected based on analyses of market data, they are comparable in total risk (even though individual risks may vary) to the Utility Proxy Group. This is demonstrated clearly on page 273 of Jack C. Francis' Investments: Analysis and Management (page 3 of Schedule DWD-10R), which shows that total risk can be "partitioned into its systematic and unsystematic components." Essentially, companies that have similar betas and standard errors of regression have similar total investment risk.

Q. IS THERE A SPECIFIC ADVANTAGE TO USING YOUR SELECTION CRITERIA, WHICH USES MEASURES OF SYSTEMATIC AND UNSYSTEMATIC RISK, INSTEAD OF USING THE COMBINATION OF BUSINESS AND FINANCIAL RISK?

A. Yes. *Value Line* unadjusted betas and the standard error of the regressions giving rise to those betas are measurable objective values, whereas total business risk[85] and financial risk measures are more subjective. In view of all of the above, Mr. Daves' concerns regarding my Non-Price Regulated Proxy Group should be dismissed by the Commission.

Q. HAVE YOU CONDUCTED ANALYSES TO DETERMINE WHETHER YOUR UTILITY PROXY GROUP AND NON-PRICE REGULATED PROXY GROUP ARE OF COMPARABLE RISK?

A. Yes, I have. I compared the average and median *Value Line* Safety Ranking,[86] the

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85 Business risk in excess of size risk, which is measurable, as discussed previously.

86 *Value Line* also ranks stocks for Safety by analyzing the total risk of a stock compared to the approximately 1,700 stocks in the *Value Line* universe. Each of the stocks tracked in the *Value Line Investment Survey* is ranked in relationship to each other, from 1 (the highest rank) to 5 (the lowest rank). Safety is a quality rank, not a performance rank, and stocks ranked 1 and 2 are most suitable for conservative investors; those ranked 4 and 5 will be more volatile. Volatility means prices can move dramatically and often unpredictably, either down or up. The major influences on a stock's Safety rank are the company's

annualized volatility[87] of stock returns, and the Coefficient of Variation ("CoV")[88] of net profit for the Utility Proxy Group and Non-Price Regulated Proxy Group, as shown on Table 7, below:

Table 7: Comparison of Safety Rankings of Mr. D'Ascendis' Utility Proxy Group and Non-Price Regulated Proxy Group

Group	Average Safety Ranking	Median Safety Ranking	Average CoV Net Profit	Median CoV Net Profit	Average Annualized Volatility	Median Annualized Volatility
Utility Proxy Group	1.83	2.00	0.37	0.35	26.51%	27.05%
Non-Price Regulated Proxy Group	1.77	2.00	0.36	0.33	26.73%	26.65%

As noted above, the Safety Rankings, annualized volatility of their stock returns, and CoV of net profit of the Utility Proxy Group and the Non-Price Regulated Proxy Group are comparable, indicating comparable total risk. This, in addition to all of the above, should lead the Commission to consider the results of my Non-Price Regulated Proxy Group in its determination of SUA's ROE in this proceeding.

VII. RESPONSE TO AG WITNESS GRIFFING

Q. PLEASE SUMMARIZE DR. GRIFFING'S ROE RECOMMENDATION.

A. Dr. Griffing applies single stage and multi-stage DCF models and a CAPM to a proxy group of seven natural gas distribution utilities. The results of these models are summarized in Table 8, below.

financial strength, as measured by balance sheet and financial ratios, and the stability of its price over the past five years.

87 Annualized volatility equals the standard deviation of returns over the period multiplied by the square root of 252, or the approximate number of trading days in a year.

88 The CoV, which is a measure of relative volatility, equals the standard deviation divided by the average.

Table 8: Summary of Dr. Griffing's ROE Results[89]

	Constant Growth DCF	Multistage DCF	CAPM Kroll MRP	CAPM S&P 500 MRP
Mean	10.09%	9.45%	9.35%	10.34%
Median	10.09%	9.30%	9.28%	10.24%

Dr. Griffing derives his 9.80% recommended ROE by averaging the mean results of his four models. He also performs a reasonableness check based on recently authorized natural gas ROEs across the country.

Q. PLEASE SUMMARIZE THE KEY AREAS IN WHICH YOU DISAGREE WITH DR. GRIFFING'S ANALYSES AND RECOMMENDATIONS.

A. The key areas in which Dr. Griffing and I disagree are: (1) his recommendation of a hypothetical capital structure for the Company, based on proxy group data; (2) the applicability of the multi-stage DCF model in his analysis; (3) his application of the CAPM; (4) his failure to reflect the unique risks of the Company–application of a size adjustment—relative to his proxy group in his recommended ROE; and (5) his contention that the expansion of the Company's System Safety Enhancement Rider ("SSER") mechanism lowers risk. I have already addressed Dr. Griffing's proposed hypothetical capital structure (item 1) previously and will not repeat that discussion here. I will respond to the remaining items (2 through 5) in turn below.

A. Application of the Multi-Stage DCF Model

Q. PLEASE SUMMARIZE DR. GRIFFING'S MULTI-STAGE DCF MODEL.

A. Dr. Griffing's multi-stage DCF model relies on four-week average stock prices and the most recently available dividends from *Value Line* or Zacks to calculate the dividend yield. For his growth rate, Dr. Griffing assumes a growth rate equal to a weighted average of

89 Direct Exhibit MFG-17, Schedule 1.

analyst growth rates from Zacks, Yahoo! Finance, and *Value Line*, which he gives two-thirds weight, and an estimate of GDP growth from Social Security Administration ("SSA") and the Energy Information Administration ("EIA"), which he gives one-third weight.[90] Dr. Griffing's weighted average growth rate implies a transition between the analyst growth rates to the expected growth rate in GDP at some point in the future.

Q. IS DR. GRIFFING'S MULTI-STAGE DCF MODEL AN APPROPRIATE APPROACH TO ESTIMATING THE COMPANY'S ROE?

A. No. The multi-stage DCF model and its growth rates reflect the company/industry life cycle, which is typically described in three stages: (1) the growth stage, which is characterized by rapidly expanding sales, profits, and earnings. In the growth stage, dividend payout ratios are low in order to grow the firm; (2) the transition stage, which is characterized by slower growth in sales, profits, and earnings.[91] In the transition stage, dividend payout ratios increase, as their need for exponential growth diminishes; and (3) the maturity (steady-state) stage, which is characterized by limited, slightly attractive investment opportunities, and steady earnings growth, dividend payout ratios, and returns on equity. The economics of the public utility business indicate that the industry is in the steady-state, or constant-growth stage of a multi-stage DCF model.

Q. ARE THERE EXAMPLES IN BASIC FINANCE TEXTS THAT SUPPORT YOUR POSITION?

A. Yes. For example, in *Investments*, life cycles and multi-stage growth models are discussed:

> As useful as the constant-growth DDM (dividend discount model) formula is, you need to remember that it is based on a simplifying assumption, namely, that the dividend growth rate will be constant forever. In fact, firms typically pass through life cycles with very different dividend profiles in

[90] Griffing Direct Testimony, at 32-33.
[91] Dr. Griffing's weighted growth rate approach does not assume a transition stage.

> different phases. In early years, there are ample opportunities for profitable reinvestment in the company. Payout ratios are low, and growth is correspondingly rapid. In later years, the firm matures, production capacity is sufficient to meet market demand, competitors enter the market, and attractive opportunities for reinvestment may become harder to find. In this mature phase, the firm may choose to increase the dividend payout ratio, rather than retain earnings. The dividend level increases, but thereafter it grows at a slower pace because the company has fewer growth opportunities.
>
> Table 18.2 illustrates this pattern. It gives Value Line's forecasts of return on assets, dividend payout ratio, and 3-year growth in earnings per share for a sample of the firms in the computer software industry versus those of east coast electric utilities…
>
> By in large, the software firms have attractive investment opportunities. The median return on assets of these firms is forecast to be 19.5%, and the firms have responded with high plowback ratios. Most of these firms pay no dividends at all. The high return on assets and high plowback result in rapid growth. The median growth rate of earnings per share in this group is projected at 17.6%.
>
> In contrast, the electric utilities are *more representative of mature firms*. Their median return on assets is lower, 6.5%; dividend payout is higher, 68%; and median growth is lower, 4.6%.
>
> ***
>
> To value companies with temporarily high growth, analysts use a multistage version of the dividend discount model. Dividends in the early high-growth period are forecast and their combined present value is calculated. Then, once the firm is projected to settle down to *a steady-growth phase, the constant-growth DDM is applied to value the remaining stream of dividends*.[92]

In view of the above, Dr. Griffing should not apply a multi-stage DCF model, as it is not applicable to utilities, and instead exclusively rely on the three- to five-year projected growth rates for each company. He also should not apply the GDP growth rate to his company-specific growth rates, because it is not a company-specific growth rate, nor is it an upper bound for growth.

[92] Z. Bodie, A. Kane, and A. J. Marcus, Investments, 7th Edition, McGraw-Hill Irwin, 2008, at 616-617 (clarification and emphasis added).

Q. WHY IS LONG-TERM GROWTH IN GDP NOT AN UPPER BOUND FOR GROWTH, AS DR. GRIFFING CONTENDS?[93]

A. First, GDP is not a market measure – rather it is a measure of the value of the total output of goods and services, excluding inflation, in an economy. While I understand that EPS growth is also not a market measure, it is well established in the financial literature that projected growth in EPS is the superior measure of dividend growth in a DCF model.[94] Furthermore, GDP is simply the sum of all private industry and government output in the United States, and its growth rate is simply an average of the value of those industries. To illustrate, Schedule DWD-11R presents the compound growth rate of the industries that comprise GDP from 1947 to 2023. Of the fifteen industries represented, seven industries, including utilities, grew faster than the overall GDP, and eight industries grew slower than the overall GDP.[95]

Q. HOW DOES THE UTILITY PROXY GROUP'S GROWTH RATE COMPARE TO THE HISTORICAL GROWTH RATE OF THE UTILITY INDUSTRY FOR THE PERIOD 1947 TO 2023?

A. The average growth rate used in my updated DCF analysis is 5.78%, which is lower than the long-term growth rate of the utility industry of 6.55%. The comparability of these growth rates reinforces the maturity of the industry and that the multi-stage DCF model is not needed.

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93 Griffing Direct Testimony, at 32.

94 Christofi, Christofi, Lori and Moliver, "Evaluating Common Stocks Using Value Line's Projected Cash Flows and Implied Growth Rate", Journal of Investing, Spring 1999; Harris and Marston, "Estimating Shareholder Risk Premia Using Analysts' Growth Forecasts", Financial Management, Summer 1992; and Vander Weide and Carleton, "Investor Growth Expectations: Analysts vs. History", The Journal of Portfolio Management, Spring 1988; Harris, "Using Analysts' Growth Forecasts to Estimate Shareholder Required Rate of Return", Financial Management, Spring 1986.

95 Source of Information: Bureau of Economic Analysis.

Q. DID YOU CONDUCT ANOTHER ANALYSIS THAT CALCULATES THE AMOUNT OF TIME IT WOULD TAKE AN INDUSTRY TO OVERTAKE THE ENTIRE ECONOMY?

A. Yes. I examined the value added by industry from 1947 to 2023 in Schedule DWD-11R and used the compound annual growth rates for the highest growth rate industry (Educational Services, Healthcare, and Social Assistance, 8.55% / year) to see when that industry would comprise the entire economy. In the year 2291, or 344 years from the 1947 starting point, the industry would comprise over 50% of GDP; and in the year 8776, or 6,829 years after the 1947 starting point, the industry would comprise 100% of GDP.[96] Not only have individual companies or industries consistently grown at rates beyond GDP growth, but they have done so without overtaking the entire economy. While Dr. Griffing's argument is technically correct, it is unrealistic at best.

Q. DR. GRIFFING AND MS. LACONTE PERFORM A "TWO-STEP" DCF ANALYSIS, A TYPE OF MULTI-STAGE DCF APPROACH. IN WHAT REGULATORY JURISDICTION IS THE TWO-STEP DCF MODEL ACCEPTED?

A. In my experience, the only regulatory jurisdiction where the two-step DCF model is accepted is the FERC.

[96] To put the amount of time that will take these two milestones to happen in perspective, approximately 305 years ago, in the year 1719, France and Spain were at war in New France (now Louisiana), and approximately 6,023 years ago, around the year 4000 BC, was the earliest suggested date for humans to have domesticated the horse and chicken. *See also* Zager and Evans, *In the Year 2525*, *on* 2525 (Exordium & Terminus) (RCA 1968).

Q. DO FERC METHODOLOGIES NECESSARILY APPLY IN A STATE REGULATORY PROCEEDING?

A. No. The FERC has made it abundantly clear that "state-authorized and Commission-authorized ROEs are conceptually distinct and do not necessarily need to be aligned."[97]

Q. HAS THE TWO-STEP DCF FALLEN OUT OF FAVOR AT THE FERC?

A. Yes, it has. FERC Opinion No. 531, which speaks to the use of various methods to determine the ROE for electric transmission facilities raises concerns about the "two-step" model:

> We acknowledge that under the DCF analysis, the Commission typically sets the base ROE with regard to multiple entities at the midpoint of the zone of reasonableness. However, for the reasons set forth below, we conclude that a mechanical application of the DCF methodology with the use of the midpoint here would result in an ROE that does not satisfy the requirements of *Hope* and *Bluefield*. Therefore, based on the record in this case, including the unusual capital market conditions present, we conclude that the just and reasonable base ROE for the NETOs should be set halfway between the midpoint of the zone of reasonableness and the top of the zone of reasonableness.
>
> ***
>
> We are concerned that capital market conditions in the record are anomalous, thereby making it more difficult to determine the return necessary for public utilities to attract capital. In these circumstances, we have less confidence that the midpoint of the zone of reasonableness established in this proceeding accurately reflects the equity returns necessary to meet the *Hope* and *Bluefield* attraction standards.[footnote omitted] We find it is necessary and reasonable to consider additional record evidence, including evidence of alternative benchmark methodologies and state commission-approved ROEs, to gain insight into the potential impacts of these unusual capital market conditions on the appropriateness of using the resulting midpoint. [footnote omitted][98]

Opinion No. 531 indicates that under current market conditions, the "two-step" DCF method may understate the investor-required return, and that analysts should look to

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[97] Docket Nos. EL14-12-004 and EL15-45-013, *Opinion 569-A*, 171 FERC ¶ 61,154 (May 21, 2020), at Para. 167.

[98] Opinion No. 531, Order on Paper Hearing, 147 FERC ¶ 61,234 (2014).

other benchmarks to determine the cost of common equity. The FERC even more recently addressed its longstanding focus on the DCF method. In its November 15, 2018 *Order Directing Briefs*, FERC found that "in light of current investor behavior and capital market conditions, relying on the DCF methodology alone will not produce a just and reasonable ROE."[99] In its October 16, 2018 *Order Directing Briefs*, the FERC found that although it "previously relied solely on the DCF model to produce the evidentiary zone of reasonableness…" it is "…concerned that relying on that methodology alone will not produce just and reasonable results."[100] As the FERC explained, it is important to understand "how investors analyze and compare their investment opportunities."[101] The FERC also explained that, although certain investors may give some weight to the DCF approach, other investors "place greater weight on one or more of the other methods…"[102] Those methods include the CAPM and the RPM, which I have applied in this proceeding.

Q. DOES THE FERC WEIGHT EPS AND GDP GROWTH RATES DIFFERENTLY FOR DIFFERENT COMPANIES?

A. Yes, it does. In Docket Nos. EL 14-12-004 and EL 15-45-013 the FERC states that it weights EPS and GDP growth rates for electric companies and gas companies 80%/20% and 66%/33%, respectively.

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99 Docket Nos. EL14-12-003 and EL15-45-000, *Order Directing Briefs*, 165 FERC ¶ 61,118 (November 15, 2018) at para. 34.

100 Docket No. EL11-66-001, *et al*., *Order Directing Briefs* 165 FERC ¶ 61,030 (October 16, 2018) at para. 30.

101 *Ibid*., at para. 33.

102 *Ibid*., at para. 35.

Q. DOES THE FERC JUSTIFY ITS WEIGHTINGS OF PROJECTED EPS GROWTH AND GDP GROWTH WITH ANY ACADEMIC LITERATURE OR EMPIRICAL STUDIES?

A. No. It only cites the relative proximity of the electric projected EPS growth rates for their weighting adjustment and so do not point to any study regarding the applicability of blending EPS projections and GDP growth rates.

Q. AS A PRACTICAL MATTER, DOES DR. GRIFFING OR MS. LACONTE EXPLAIN THE TIMING OF THE LONG-TERM GROWTH ESTIMATE IN THEIR MULTI-STAGE DCF ANALYSES?

A. No, they do not. As Dr. Griffing and Ms. LaConte explain, their multi-stage DCF method is applied in a manner similar to the constant growth DCF model. The only difference is that the growth rate is a weighted average of analysts' earnings growth projections, and nominal GDP growth rate projections. Neither Dr. Griffing nor Ms. LaConte calculated the implied transition year between those two estimates. That is, neither Dr. Griffing nor Ms. LaConte have considered in what year their multi-stage DCF model transitions between the initial and final growth stages, or how it corresponds to the forecast horizon of his analysis. As such, it is difficult to determine the appropriateness of the model's growth assumptions.

B. Application of the CAPM

Q. PLEASE SUMMARIZE DR. GRIFFING'S CAPM.

A. Dr. Griffing develops his CAPM estimates *Value Line* betas and the 4.60% 4-week average 30-year Treasury Bond as the risk-free rate.[103] For the MRP, he relies on the Kroll

[103] Griffing Direct Testimony, at 34-35.

recommended MRP of 5.50% as well as a calculated S&P500 market DCF of 6.64% based on data from *Value Line.*[104] Dr. Griffing's mean and median CAPM results using the Kroll MRP were 9.35% and 9.28%, respectively, and his mean and median CAPM results using the market DCF MRP were 10.34% and 10.24%, respectively.[105]

Q. DO YOU AGREE WITH DR. GRIFFING'S APPLICATION OF THE CAPM?

A. No, I do not. Dr. Griffing's CAPM analysis is flawed in at least three respects: (1) While Dr. Griffing agrees that the cost of capital is a prospective measure, he does not use projected interest rates in his CAPM analysis; (2) his choice of an MRP from Kroll is flawed; (3) Dr. Griffing incorrectly excludes companies in his market DCF MRP; and (4) Dr. Griffing does not apply an ECAPM analysis. Again, given that the current risk-free rate Dr. Griffing uses in his CAPM is reasonably consistent with the projected risk-free rate used in my updated CAPM, at this time, I will not address Dr. Griffing's use of a current risk-free rate.

Q. WHAT IS YOUR POSITION ON THE KROLL MRP USED BY DR. GRIFFING?

A. The determination of the MRP as calculated by Kroll is not transparent, especially in view of the historical MRP presented in the <u>Stocks, Bonds, Bills, and Inflation ("SBBI") Yearbook 2023 ("SBBI–2023")</u>, which is already well known by investors. The historical MRP (using the long-term arithmetic mean return on large company stocks less the long-term arithmetic income returns on long-term Government bonds) is a superior MRP measure compared to Kroll's simplistic and opaque MRP forecast because of the transparency of the historical data.

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104 Griffing Direct Testimony, at 36-38.
105 Griffing Direct Testimony, at 40.

Q. WHY IS THE KROLL MRP MORE OPAQUE THAN OTHER MEASURES OF THE MRP?

A. The MRP is calculated by subtracting a risk-free rate from the investor-required return on the market. Typically, the return on the market uses observable market measures (e.g., historical average returns), but the Kroll MRP does not define how it calculates its expected return on the market. Similarly, the risk-free rate is typically also based on market measures (e.g., historical interest rates, forecasted interest rates), but Kroll does not explain how it derives its 3.5% normalized risk-free rate. Because Kroll does not reveal how it derives its estimates, we do not know if they are indeed based on market measures.

Q. DID YOU CONDUCT A STUDY TO DETERMINE THE FORECAST ACCURACY OF THE KROLL RECOMMENDED MARKET RETURN, AND EXPECTATIONAL MARKET RETURNS BASED ON SBBI-2023 HISTORICAL DATA?

A. Yes, I did. I have calculated the forecast bias[106] of (1) the long-term arithmetic mean return on large company stocks; (2) projected market returns resulting from a regression analysis applied to Kroll historical data; and (3) the implied market returns from Kroll from 2008-2023.[107] The estimated market returns for the historical Kroll returns are calculated every year. For example, the long-term average market return from 1926-2008 was used to determine the forecasted return for 2009. The result of this analysis is shown in Schedule DWD-12R and Table 9, below:

[106] Forecast bias can be described as a tendency to either over-forecast or under-forecast a given variable.
[107] 2008 was selected as the starting year as it is the first year Kroll published its recommended MRP and risk-free rate.

Table 9: Comparison of Forecast Bias for Various Measures 2009-2023

Year	Observed Market Return	Long-Term Average Return	Kroll Forecasted Market Return	Regression-Based Market Return
2009	26.46%	11.67%	10.50%	12.35%
2010	15.06%	11.85%	10.08%	11.92%
2011	2.11%	11.88%	9.63%	12.07%
2012	16.00%	11.77%	10.00%	12.09%
2013	32.39%	11.82%	9.50%	12.07%
2014	13.69%	12.05%	9.00%	12.25%
2015	1.38%	12.07%	9.00%	12.41%
2016	11.96%	11.95%	9.00%	12.32%
2017	21.83%	11.95%	9.00%	12.16%
2018	-4.38%	12.06%	8.50%	12.31%
2019	31.49%	11.88%	9.00%	12.33%
2020	18.40%	12.09%	8.00%	12.29%
2021	28.71%	12.16%	8.00%	12.27%
2022	-18.11%	12.33%	8.00%	12.83%
2023	26.61%	12.02%	9.00%	12.43%
Sum	223.60%	179.55%	136.21%	184.10%
Forecast Bias[108]		80.30%	60.92%	82.33%

As shown in Table 9, while all of these measures understate the actual return (both forecast bias values are under 100%), the Kroll forecasted market return significantly and consistently understates the actual return. The Kroll projected market return is a less accurate predictor of the actual return than the historical average return or the projected return using regression analyses. This result is consistent with Campbell, who states that when returns are serially uncorrelated, the arithmetic average represents the best forecast of future returns in any randomly selected future year.[109] As a result, I urge the Commission to afford zero weight to the results of Dr. Griffing's CAPM based on the Kroll MRP.

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108 Calculated by dividing the sum of the forecast returns by the sum of the actual returns.

109 John Y. Campbell, "Forecasting US Equity Returns in the 21st Century," Social Security Administration, July 2001.

Q. DO YOU HAVE ANY CONCERNS WITH DR. GRIFFING'S MARKET DCF BASED MRP?

A. Yes, I do. Although the methodology Dr. Griffing relies on to develop his market return estimate based on the Constant Growth DCF model is similar to one of the approaches in my Direct Testimony, I do not agree with Dr. Griffing's exclusion of companies with growth rates below 0% and above 20%. Nor do I agree with Dr. Griffing's removal of non-dividend paying companies.

First, the expected market return is meant to reflect just that – all companies in the market. At any given time, there are companies that have both high and low growth rates. Excluding companies with growth rates outside a certain band causes the estimate of the market return to no longer reflect the overall market, but rather an arbitrary subset of companies within the market.

In addition, investors recognize the market includes both dividend and non-dividend paying companies. Some of the largest companies, based on market capitalization, are excluded from Dr. Griffing's calculation because they do not pay dividends. For example, based on Dr. Griffing's Exhibit MPG-15, Schedule 6, he excluded 150 companies from the market return calculation, which comprise 32.44% of the entire S&P 500 market capitalization. As shown on Schedule DWD-13R, of the 150 companies that were excluded, 101 do not pay dividends and comprise 22.53% of the S&P 500 market capitalization. Excluding those companies has a significant effect on the calculated expected market return and subsequently the MRP. That is, because the companies Dr. Griffing removes tend to have higher growth rates, his methodology biases the estimate of the market return downward. More important, the resulting estimate does not represent an estimate of the market as a whole.

Q. IS THERE ANOTHER EFFECT ON CAPM INPUTS BY REMOVING COMPANIES FROM THE MARKET DCF CALCULATION?

A. Yes. My methodological concern is with internal consistency in the model's application. A fundamental assumption of the CAPM is that the required return is proportional to the risk of the investment. Under the CAPM, beta is the measure of risk, and is calculated by comparing the subject security's returns to the overall market returns. Because beta is calculated relative to the overall market, which includes both dividend paying and non-dividend paying companies, it is important that the expected market return also reflect the overall market. As noted above, Dr. Griffing's estimate of the market return includes less than 68% of the overall S&P 500 on both an absolute and market capitalization basis. As such, I do not believe it is appropriate to combine betas calculated relative to the entire market with a MRP calculated using only a subset of the market (i.e., dividend paying companies with growth rates within a range of 0% to 20%).

If Dr. Griffing chooses to remove non-dividend paying companies, and companies with growth rates below 0% and above 20% from the expected market return, he likewise should remove them from the index used to calculate beta. Because betas are a positive function of the correlation of returns between the subject company and the index, removing those companies may increase the correlation, thereby increasing beta.

In addition, dividend paying companies may have lower volatility than non-dividend paying companies. Because beta also reflects relative volatility (i.e., subject company relative to the index), if the volatility of the index falls, the relative volatility will increase, again increasing beta. Dr. Griffing's position inherently assumes the proxy companies' correlation coefficients and relative volatility would remain constant, and their betas would remain unchanged if non-dividend paying companies are removed from the market index. But he has not shown that to be the case.

Q. DOES DR. GRIFFING PERFORM AN ECAPM IN HIS ANALYSIS?

A. No. Dr. Griffing failed to consider the ECAPM despite the fact that numerous tests of the CAPM have confirmed the ECAPM's validity, as discussed above in response to Mr. Daves.

Q. HAVE YOU CORRECTED DR. GRIFFING'S CAPM ANALYSES?

A. Yes, I have. I corrected Dr. Griffing's CAPM analyses by including all S&P 500 companies in the calculation of market DCF based MRP and including an ECAPM. I also replaced the Kroll recommended MRP with the Kroll historical average MRP. As shown in Schedule DWD-14R, this results in an average and median CAPM result of 11.78% and 11.68%, respectively.

C. <u>Application of a Size Adjustment</u>

Q. DID DR. GRIFFING CONSIDER A SIZE ADJUSTMENT?

A. No, he did not.

Q. IS DR. GRIFFING'S LACK OF A SIZE ADJUSTMENT CONSISTENT WITH FERC METHODOLOGY?

A. No, it is not. Considering that Dr. Griffing relies on FERC's guidance for his multi-stage (two-step) DCF, his high and low outlier test, and his S&P 500 market DCF MRP, it is inconsistent that he does not rely on the FERC's guidance as it applies to a size adjustment.

As concluded by FERC in Opinion 569-A, and also noted in a Policy Statement on determining the ROE:[110]

> We continue to find that the size adjustment is necessary to correct for the CAPM's inability to fully account for the impact of firm size when determining the cost of equity… We continue to find that size adjustments are appropriate for the utility industry and improve the overall accuracy of the CAPM results.[111]

Q. WHAT ARE DR. GRIFFING'S CONCERNS WITH THE SIZE ADJUSTMENT?

A. Dr. Griffing cites to studies from Aswath Damodaran and Clifford Ang and suggests that the size effect may only be transitory and, as such, an adjustment is not appropriate.[112]

Q. WHAT IS YOUR RESPONSE TO DR. GRIFFING AS IT RELATES TO THE SIZE ADJUSTMENT?

A. As I discussed in my Direct Testimony, smaller companies face increased business risk as they are less equipped to cope with significant events that affect sales, revenues, and earnings, as the loss of a few larger customers will have a greater effect on a small company than a larger company.[113]

While Damodaran's observation that the size premium may come and go over time may be correct, again, risk is not measured by the level of returns but the variance of those returns. A study by Clifford Ang detailed the returns and volatility of returns of companies by size, showing while larger companies out-performed smaller companies, smaller companies exhibited more risk.[114] Reviewing data from the same source as the Ang study,

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110 *See* Docket No. PL19-4-000, Inquiry Regarding the Commission's Policy for Determining Return on Equity (May 21, 2020), at Para. 44.

111 Docket No. EL14-12-004 and EL15-45-013, *Opinion No. 569-A Order on Rehearing*, 171 FERC ¶ 61,154 (May 21, 2020), at Para. 75.

112 Griffing Direct Testimony, at 39.

113 D'Ascendis Direct Testimony, at 42.

114 Clifford S. Ang, "The Absence of a Size Effect Relevant to the cost of Equity", Business Valuation Review, Volume 37, No. 3, 2018.

I replicated the study through May 2024. Table 10 presents the largest monthly gain and loss for each value-weighted decile for the period 1981 through May 2024. As shown in Table 10, small capitalization stocks exhibit more volatility (i.e., risk) in their returns than larger capitalization stocks.

Table 10: Size and Volatility of Returns[115]

Decile:	1	2	3	4	5	6	7	8	9	10
Largest Gain:	29.5%	25.7%	21.3%	18.3%	19.8%	17.0%	17.2%	14.6%	14.3%	13.4%
Largest Loss:	-28.9%	-30.6%	-29.0%	-29.6%	-28.1%	-26.2%	-26.3%	-24.5%	-22.2%	-19.7%

Further, SBBI-2023 shows that the total return of large-cap stocks over the 1926-2022 period has a standard deviation of 19.8%, compared to 31.2% for small-cap stocks, echoing the findings of Table 10.[116] The higher level of risk indicates a higher level of required

Additionally, an article by Michael A. Paschall, ASA, CFA, and George B. Hawkins ASA, CFA, *Do Smaller Companies Warrant a Higher Discount Rate for Risk*? supports the applicability of a size premium. As the article makes clear, all else equal, size is a risk factor which must be taken into account when setting the cost of capital or capitalization (discount) rate. Paschall and Hawkins state in their conclusion as follows:

> The current challenge to traditional thinking about a small stock premium is a very real and potentially troublesome issue. The challenge comes from bright and articulate people and has already been incorporated into some court cases, providing further ammunition for the IRS. Failing to consider the additional risk associated with most smaller companies, however, is to fail to acknowledge reality. Measured properly, small company stocks have proven to be more risky over a long period of time than have larger company stocks. This makes sense due to the various advantages that larger companies have over smaller companies. Investors looking to purchase a riskier company will require a greater return on investment to compensate for that risk. There are numerous other risks affecting a particular company,

115 Deciles in ascending order with one (1) representing the smallest stocks by market capitalization. Source: http://mba.tuck.dartmouth.edu/pages/faculty/ken.french/data_library.html#BookEquity.

116 SBBI-2023, at 137. Note: Utility companies are included in this data set.

> yet the use of a size premium is one way to quantify the risk associated with smaller companies.[117]

Hence, Paschall and Hawkins corroborate the need for a small size adjustment, all else equal.

D. Impact of SSER

Q. WHAT IS THE SYSTEM SAFETY ENHANCEMENT RIDER ("SSER")?

A. The SSER is an infrastructure cost recovery rider the Company is requesting to be expanded in this proceeding.

Q. WOULD THE EXPANSION OF SUA'S SSER REDUCE THE COMPANY'S RISK PROFILE, AS SUGGESTED BY DR. GRIFFING?[118]

A. No, it would not. It is important to remember that the cost of capital is a comparative exercise, so if a mechanism is common throughout the companies on which one bases their analyses, the comparative risk is zero, because any impact of the perceived reduced risk (if any) of the mechanism(s) by investors would be reflected in the market data of the proxy group. However, as shown on Schedule DWD-15R, every single one of the proxy companies apart from Northwest Natural has an infrastructure investment recovery mechanism in at least one of their jurisdictions. As such, both the current use, and potential expansion, of SUA's SSER mechanism is not indicative of a lower level of risk for investors as compared to the Utility Proxy Group.

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117 Michael A. Paschall, ASA, CFA and George B. Hawkins ASA, CFA, Do Smaller Companies Warrant a Higher Discount Rate for Risk?, CCH Business Valuation Alert, Vol. 1, Issue No. 2, December 1999 ("Paschall and Hawkins").

118 Griffing Direct Testimony, at 43.

Q. DR. GRIFFING STATES THAT THE EXPANSION OF THE SSER WOULD RESULT IN AN IMPROVEMENT TO THE COMPANY'S CREDIT RATING. DO YOU AGREE?

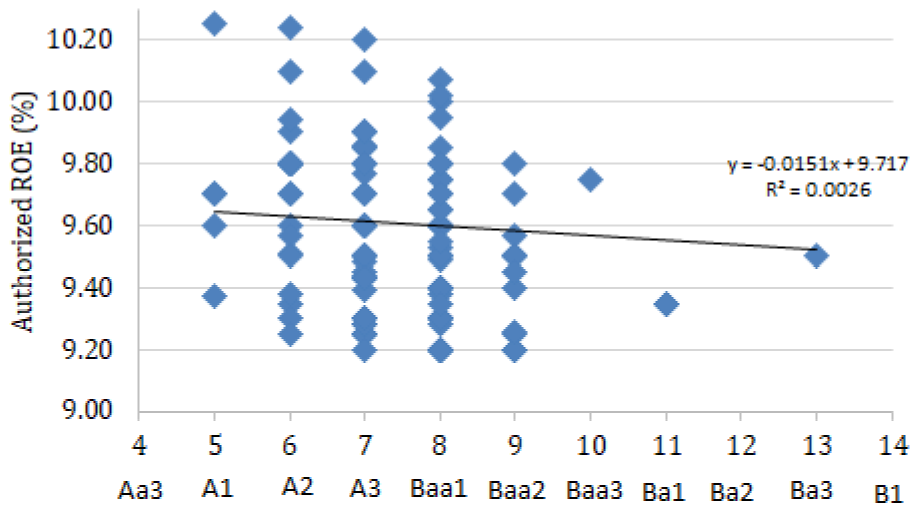
A. No, I do not. Dr. Griffing has not produced any evidence to show that the approval or expansion of an infrastructure investment recovery mechanism has ever resulted in a credit rating upgrade. As a result, I do not agree that a credit rating improvement is a plausible outcome of the Company's proposal.

Q. DR. GRIFFING CLAIMS THAT AUTHORIZED ROES AND CREDIT RATINGS ARE INVERSELY RELATED (I.E., UTILITIES THAT HAVE HIGH CREDIT RATINGS HAVE LOW RELATIVE ROES).[119] DO YOU AGREE?

A. No, I do not. I conducted an analysis to confirm Dr. Griffing's claim. As shown on Chart 5, the relationship between ROEs authorized in the past 10 years and credit ratings is not inverse, but a weak (low R-Squared), statistically insignificant, positive relationship.

119 Griffing Direct Testimony, at 44.

Chart 5: Relationship Between Authorized ROE and Credit Ratings[120] for Electric and Gas Utility Companies



In view of Chart 5, above, the data does not show a statistically significant relationship between authorized ROEs and credit ratings. Dr. Griffing's contention should be dismissed.

E. Response to Dr. Griffing's Critique of Company Analyses

Q. WHAT ARE DR. GRIFFING'S CONCERNS WITH YOUR ANALYSES?

A. Dr. Griffing does not agree with: (1) my authorized return regression-derived RPM; (2) the results of my RPM analysis; (3) the results of my CAPM analysis; and (4) my Non-Price Regulated Proxy Group. I have already addressed concerns (1) and (4) previously and will not address them again here. I will address Dr. Griffing's other concerns (2 and 3) in turn, below.

[120] Source: Regulatory Research Associates

Q. PLEASE RESPOND TO DR. GRIFFING'S CLAIM THAT YOUR RPM RESULT IS NOT A "REASONABLE" VALUE.[121]

A. Dr. Griffing claims that my RPM result is not reasonable in comparison to recently approved natural gas ROEs. I have previously discussed the issue with using historical authorized returns as benchmarks. Further, it is unclear why Dr. Griffing believes it is appropriate to compare my RPM result to past authorized ROEs when he believes that the comparable earnings test is a "nullity."[122]

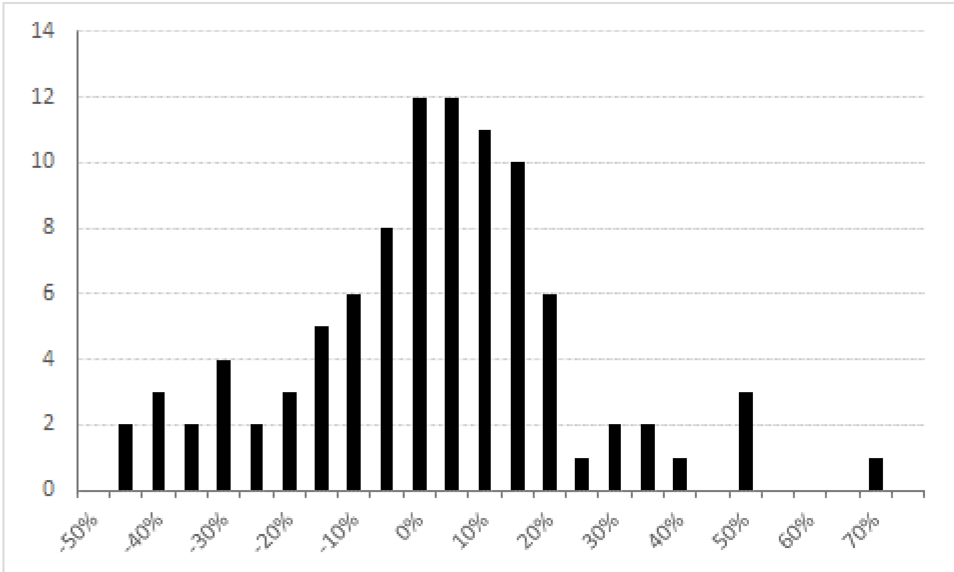
Additionally, Dr. Griffing only discussed the authorized-return based ERP used in my RPM analysis and fails to address the other two ERPs used in my RPM analysis. Had Dr. Griffing considered my overall average ERPs of 5.44% (direct) and 5.40% (rebuttal), he would have observed that they are both consistent with actual observed ERPs, as shown in Table 11 and Chart 6, below.

Table 11: Percentile Ranks of Calculated ERPs[123]

	D'Ascendis Testimony	**%**	**Percentile Rank**
Average Equity Risk Premium	Direct	5.44%	50th
Average Equity Risk Premium	Rebuttal	5.40%	50th

[121] Griffing Direct Testimony, at 52.
[122] Griffing Direct Testimony, at 12.
[123] Schedule DWD-16R

Chart 6: Frequency Distribution of Observed Equity Risk Premiums, 1926 - 2023[124]



This is consistent with my market returns and MRPs being comparable to historical observations. In view of the above, my ERPs are appropriate and should be used in the RPM analysis.

Q. PLEASE RESPOND TO ADDITIONAL ASPECTS OF DR. GRIFFING'S CLAIM THAT YOUR CAPM RESULT IS ALSO NOT A "REASONABLE" VALUE.[125]

A. It is unclear exactly which aspects of my CAPM Dr. Griffing takes issue with. The average beta and risk-free rates used in his analysis are comparable to the ones I apply in my updated analysis, with both of my values being slightly less than his. As discussed previously in response to Mr. Daves, the market returns and MRPs I use are consistent with actual realized market returns and MRPs. As a result, Dr. Griffing's concerns should be dismissed.

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124 Schedule DWD-16R

125 Griffing Direct Testimony, at 53.

VIII. RESPONSE TO AGC WITNESS LACONTE

Q. PLEASE SUMMARIZE MS. LACONTE'S DIRECT TESTIMONY.

A. Ms. LaConte recommends an ROE of 9.70% for SUA based on her application of the DCF model, the CAPM, and the RPM. In reviewing authorized ROEs for natural gas distribution utilities in her assessment of the ROE for SUA,[126] she notes that if the Commission approves the Company's Billing Determinant Adjustment ("BDA") Rider and its requested expansion of its SSER, it would be reasonable to recommend a lower ROE. Regarding the Company's capital structure, Ms. LaConte argues the Company's equity ratio should be no higher than 50.00%.[127]

Q. WHAT ARE YOUR CONCERNS WITH MS. LACONTE'S DIRECT TESTIMONY?

A. I have several concerns with Ms. LaConte's direct testimony, including: (1) her opinion that authorized ROEs should be considered in setting an ROE for SUA; (2) her interpretation of current market conditions; (3) her contention that SUA's risk is lower because of the potential implementation of the SSER and BDA; (4) the composition of her proxy group; (5) the applicability and application of her multi-stage DCF model; (6) her application of the CAPM; (7) her application of the of the RPM; and (8) her failure to account for the Company's size relative to her proxy group. Because I have already addressed my concerns with the use of a multi-stage DCF model (item 5) in response to Dr. Griffing, as well as her assessment of recently authorized ROEs (item 1) in Section IV, I will not repeat those discussions here. I will address the rest of my concerns (2 through 4, 6 through 8) in turn below.

126 LaConte Direct Testimony, at 2-3.
127 LaConte Direct Testimony, at 34.

A. Interpretation of Current Market Conditions

Q. WHAT IS MS. LACONTE'S POSITION ON THE RELATIONSHIP BETWEEN INTEREST RATES AND THE COST OF CAPITAL?

A. Ms. LaConte says that a declining risk-free rate should translate into a correspondingly lower ROE, but any increase to the risk-free rate would only result in a minimal increase in the ROE.[128]

Q. DO YOU AGREE WITH HER POSITION?

A. No, I do not. As I discussed in addressing Mr. Daves' testimony, there is a consistent inverse relationship between interest rates and ERPs. This relationship holds regardless of the directional movement of interest rates. For example, if interest rates declined 100 basis points, the ERP would increase 50 basis points; and if interest rates increased 100 basis points, the ERP would decline by 50 basis points. The relationship between ROEs and interest rates is a positive one, that is, they both move in the same direction, as put forth on Schedule DWD-17R. Schedule DWD-17R presents the relationship between authorized ROEs and 30-year Treasury Bond yields since 1980, the same data Ms. LaConte relied on in her RPM. That relationship is upward sloping, and statistically significant, meaning that changes in the risk-free rate cause a change in the cost of capital, albeit not on a one-for-one basis. Schedule DWD-17R also presents Ms. LaConte's projected risk-free rate in this proceeding, as well as the projected risk-free rate as of September 2016, following the same approach Ms. LaConte applied in this case. Applying those risk-free rates to the regression coefficients results in an indicated ROE of 10.34%, an increase of 72 basis points since the Company's most recently authorized ROE.

128 LaConte Direct Testimony, at 7.

B. Ratemaking Mechanisms and Risk

Q. PLEASE SUMMARIZE MS. LACONTE'S POSITION AS IT RELATES TO THE PRESENCE OF RATEMAKING MECHANISMS AND RISK.

A. Ms. LaConte's position is that SUA's ratemaking mechanisms, including the potential implementation of SSER and BDA Rider will reduce the risk to SUA, and therefore support an ROE below the Company's currently effective ROE of 9.50%.[129]

Q. HAVE YOU COMPARED THE RATEMAKING MECHANISMS PRESENT IN MS. LACONTE'S PROXY GROUP?

A. Yes. As noted in response to Dr. Griffing, the cost of capital is a comparative exercise, therefore we need to assess the presence of ratemaking mechanisms within Ms. LaConte's proxy group to determine if SUA is comparatively less risky. As observed in Schedule DWD-15R, the companies in Ms. LaConte's proxy group all either utilize similar infrastructure riders or decoupling adjustments in at least one of their jurisdictions, indicating that any comparative risk is zero.

Q. ARE YOU AWARE OF ANY STUDIES THAT HAVE ADDRESSED THE RELATIONSHIP BETWEEN RATE STABILIZATION MECHANISMS GENERALLY AND ROE?

A. Yes. I, along with Richard A. Michelfelder of Rutgers University, and my colleague at ScottMadden, Pauline M. Ahern, examined the relationship between rate stabilization mechanisms and ROE among electric, gas, and water utilities. Using the generalized consumption asset pricing model, also known as the Predictive Risk Premium Model

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129 LaConte Direct Testimony, at 9.

("PRPM"), we found rate stabilization mechanisms to have no statistically significant effect on investor perceived risk, and hence, ROE.[130]

Also, in March 2014, The Brattle Group (Brattle) published a study addressing the effect of revenue decoupling structures on the cost of capital for electric utilities.[131] In its report, which extended a prior analysis focused on natural gas distribution utilities, Brattle pointed out that although decoupling structures may affect revenues, net income still can vary. Brattle further noted that the distinction between diversifiable and non-diversifiable risk is important to equity investors, and the relationship between decoupling and ROE should be examined in that context. Further to that point, Brattle noted that although reductions in total risk may be important to bondholders, only reductions in non-diversifiable business risk would justify a reduction to the ROE. In November 2016, the Brattle study was updated based on data through the fourth quarter of 2015.[132]

Brattle's empirical analysis examined the relationship between decoupling and the After-Tax WACC for a group of electric utilities that had implemented decoupling structures in various jurisdictions throughout the United States. As with Brattle's 2014 study, the updated study found no statistically significant link between the cost of capital and revenue decoupling structures.[133]

[130] Richard A. Michelfelder, Pauline M. Ahern, Dylan W. D'Ascendis, *Decoupling Impact and Public Utility Conservation Investment*, Energy Policy Journal, April 2019, at 311-319.

[131] The Brattle Group, *The Impact of Revenue Decoupling on the Cost of Capital for Electric Utilities: An Empirical Investigation*, Prepared for the Energy Foundation, March 20, 2014.

[132] Michael J. Vilbert, Joseph B. Wharton, Shirley Zhang and James Hall, *Effect on the Cost of Capital of Innovative Ratemaking that Relaxes the Linkage between Revenue and kWh Sales – An Updated Empirical Investigation*, November 2016.

[133] *Ibid.*

C. Proxy Group

Q. DO YOU DISAGREE WITH THE COMPOSITION OF MS. LACONTE'S PROXY GROUP?

A. Yes, I disagree with Ms. LaConte's inclusion of Black Hills Corporation ("BKH") and WEC Energy Group ("WEC") in her proxy group. In selecting her proxy group Ms. LaConte relies in part on the screening criteria that a company have at least 50% or greater of revenues derived from natural gas utility operations. Ms. LaConte notes that her expanded proxy group improves her ROE estimate because the results are enhanced by additional data.[134]

Q. WHAT ARE YOUR CONCERNS WITH MS. LACONTE'S USE OF REVENUE, RATHER THAN NOI, AS A SCREENING CRITERION?

A. As I discussed previously in response to Mr. Daves, measures of income are far more likely to be considered by the financial community in making credit assessments and investment decisions than are measures of revenue. The use of NOI or assets results in a more appropriate comparable group of companies.

Q. HAVE YOU REVIEWED THE OPERATING DATA FOR BKH AND WEC?

A. Yes, I have. As shown on Table 12, below, the percentages of NOI and assets attributable to regulated natural gas utility service for BKH and WEC is below 50%. Given that we are attempting to determine the ROE for SUA, which derives 100% of its NOI and 100% of its assets attributable to regulated natural gas distribution service, their market data is not comparable.

134 LaConte Direct Testimony, at 13-14.

<u>Table 12: Percent of 2023 NOI and Assets Attributable to Regulated Natural Gas Utility Operations for BKH and WEC</u>[135]

	Net Oper. Income	Total Assets
Black Hills Corporation	48.40%	49.13%[136]
WEC Energy Group	14.65%	37.58%

Q. MS LACONTE STATES THAT HER EXPANDED PROXY GROUP ENHANCES HER ROE CALCULATION AS COMPARED TO YOURS.[137] DO YOU AGREE?

A. No. My objective in selecting a Utility Proxy Group is to develop a proxy group that is highly representative of the risks and prospects faced by the subject company. Therefore, I developed and used selection criteria to accomplish that objective. Ms. LaConte's inclusion of additional companies solely for the purpose of increasing the size of the Utility Proxy Group is not reasonable because it would produce results that may be less representative of the risks and prospects faced by SUA.

Q. WHAT WOULD MS. LACONTE'S MODEL RESULTS BE IF SHE EXCLUDED BKH AND WEC IN HER ANALYSIS?

A. Eliminating BKH and WEC would increase her average ROE result from 9.69% to 9.77% and the midpoint of her range of results from 9.75% to 9.95%.

D. <u>Applicability of and Application of the Multi-Stage DCF Model</u>

Q. PLEASE DESCRIBE MS. LACONTE'S DCF ANALYSES AND CONCLUSIONS.

A. Ms. LaConte performs a constant growth DCF and a multi-stage ("two-step") using 30-day average prices and annualized dividends. For her growth rate in her constant growth DCF,

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135 SEC form 10-K. Note that bolded companies are included in my Utility Proxy Group. EXC failed my proxy group screening criteria due to not having betas from *Value Line* and Bloomberg, FE failed due to speculation on its stock price following a bribery scandal in Ohio, and PPL failed due to not having a positive dividend per share growth rate from *Value Line*.

136 Gross PP&E.

137 LaConte Direct Testimony, at 14.

she relied on projected EPS growth rates; for her "two-step" DCF, she placed two-thirds weight on the projected EPS growth rates and one-third weight on her projected GDP growth rate. Applying her constant growth DCF, she calculates low, mean, and high indicated ROEs of 8.43%, 9.71%, and 11.07%, respectively. Ms. LaConte's "two-step" DCF results in an indicated cost rate of 9.56%.[138]

Q. DO YOU HAVE ANY CONCERNS WITH MS. LACONTE'S APPLICATION OF THE CONSTANT GROWTH DCF MODEL?

A. I do not. The only disagreement would be the composition of her proxy group, as discussed above. The elimination of BKH and WEC would result in low, mean, and high cost rates of 8.60%, 9.90%, and 11.31%, respectively.

Q. DO YOU HAVE ANY CONCERNS WITH MS. LACONTE'S USE OF THE "TWO-STEP" DCF?

A. Yes. As discussed previously, the FERC "two-step" DCF is inappropriate and should not be considered by the Commission in this proceeding.

E. <u>Application of the CAPM</u>

Q. PLEASE SUMMARIZE MS. LACONTE'S APPLICATION OF THE CAPM.

A. Ms. LaConte presents two applications of the CAPM. The first is based on the historical MRP (7.03%) that I provided in my Direct Testimony, *Value Line* Betas, and a projected risk-free rate (4.20%). Her second application is the same as her first except she uses a projected MRP of 6.11%, which is based on the *ex-ante* Market DCF's I provided in my Direct Testimony, except she excludes companies with negative growth rates and growth

138 LaConte Direct Testimony, at 16.

rates above 20%. Her indicated CAPM results are 10.57% based on the historical MRP, and 9.73% based on the projected MRP.[139]

Q. WHAT ARE YOUR CONCERNS WITH MS. LACONTE'S APPLICATION OF THE CAPM?

A. My concerns with Ms. LaConte's application of the CAPM include: (1) her projected risk-free rate based solely on forecasted interest rates for the first three quarters of 2025; (2) her projected MRP for the S&P 500; and (3) her failure to include the ECAPM.

Q. DO YOU AGREE WITH MS. LACONTE'S PROJECTED RISK-FREE RATE?

A. Only to a degree. While I appreciate that Ms. LaConte relied on a projected risk-free rate, she only relies on *Blue Chip's* projections for the first three quarters of 2025 and does not consider *Blue Chip's* projections for the second through fourth quarters of 2024, nor does she consider *Blue Chip's* long-term projections. Not including these projections is inconsistent with the Efficient Market Hypothesis ("EMH"). According to Eugene F. Fama,[140] a market in which prices always "fully reflect" available information is called "efficient." There are three forms of the EMH, namely:

- The "weak" form asserts that all past market prices and data are fully reflected in securities prices. In other words, technical analysis cannot enable an investor to "outperform the market."
- The "semi-strong" form asserts that all publicly available information is fully reflected in securities prices. In other words, fundamental analysis cannot enable an investor to "outperform the market."

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139 LaConte Direct Testimony, at 18-19.

140 Eugene F. Fama, *Efficient Capital Markets: A Review of Theory and Empirical Work*, The Journal of Finance, Vol. 25, No. 2. (May 1970), at 383-417.

- The "strong" form asserts that all information, both public and private, is fully reflected in securities prices. In other words, even insider information cannot enable an investor to "outperform the market."

The "semi-strong" form is generally considered the most realistic because the illegal use of insider information can enable an investor to "beat the market" and earn excessive returns, thereby disproving the "strong" form. The semi-strong form of the EMH assumes that all information (including long-term forecasts of interest rates) is available to the investor, which means the entirety of the forecasted interest rate would be considered by investors when making investment decisions and, therefore, should be included in Ms. LaConte's CAPM analysis. Further, not including long-term forecasts is inconsistent with her application of the DCF model in which there is an assumption that the projected "g" is constant into perpetuity, creating a mismatch between the application of his models.

Q. DO YOU AGREE WITH MS. LACONTE'S PROJECTED MRP?

A. No, I disagree with Ms. LaConte's decision to exclude companies with negative growth rates and growth rates above 20%. Because I have discussed my concerns with this approach in response to Dr. Griffing, I will not repeat that discussion here.

Q. DOES MS. LACONTE DESCRIBE THE USE OF A PROJECTED MRP MEASURE BASED ON *VALUE LINE'S* SUMMARY AND INDEX?

A. Yes. Although Ms. LaConte removed the *Value Line* Summary and Index based MRP in her correction of my CAPM,[141] in Appendix D to her direct testimony she describes that same approach as a means of estimating the projected MRP. Ms. LaConte has relied on

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141 LaConte Direct Testimony, at 24.

the use of *Value Line's* Summary and Index in determining the projected MRP is previous cases.[142]

Q. WHAT WOULD MS. LACONTE'S INDICATED MRP BE BASED ON *VALUE LINE'S* SUMMARY AND INDEX?

A. Using Ms. LaConte approach based on *Value Line's* Summary and Index results in a projected MRP of 7.84%.

Q. DOES MS. LACONTE APPLY THE ECAPM?

A. No, she does not. Ms. LaConte states that the ECAM is not necessary as *Value Line* betas are already adjusted to account for the under-estimation (or over-estimation) of the ROE, and the ECAPM simply captures what has already been accounted for.[143] This is incorrect. Using adjusted betas in a CAPM analysis is not equivalent to using the ECAPM nor is it a duplicative adjustment.

Betas are adjusted because of their general regression tendency to converge toward 1.0 over time, i.e., over successive calculations of beta. As also noted above, numerous studies have determined that the SML described by the CAPM formula at any given moment in time is not as steeply sloped as the predicted SML. Morin states:

> …some critics of the ECAPM argue that the use of *Value Line* adjusted betas in the traditional CAPM amounts to using an ECAPM. This is incorrect. The use of adjusted betas in a CAPM analysis is not equivalent to the ECAPM. Betas are adjusted because of the regression tendency of betas to converge toward 1.0 over time.
>
> * * *
>
> The use of an adjusted beta by *Value Line* is correcting for a different problem than the ECAPM. The adjusted beta captures the fact that betas regress toward one over time. The ECAPM corrects for the fact that the

142 *See*, Minnesota Public Utilities Commission, Docket No. E002/GR-21-630, Direct Testimony of Billie S. LaConte, at 23 (October 3, 2022).

143 LaConte Direct Testimony, at 26.

> CAPM under-predicts observed returns when beta is less than one and over-predicts observed returns when beta is greater than one.
>
> * * *
>
> Another way of looking at it is that the Empirical CAPM and the use of adjusted betas comprise two separate features of asset pricing. Assuming arguendo a company's beta is estimated accurately, the CAPM will still understate the return for low-beta stocks. Furthermore, if a company's beta is understated, the Empirical CAPM will also understate the return for low-beta stocks. Both adjustments are necessary.[144]

Moreover, the slope of the SML should not be confused with beta. As Brigham and Gapenski state:

> The slope of the SML reflects the degree of risk aversion in the economy – the greater the average investor's aversion to risk, then (1) the steeper is the slope of the line, (2) the greater is the risk premium for any risky asset, and (3) the higher is the required rate of return on risky assets.
>
> Students sometimes confuse beta with the slope of the SML. This is a mistake. As we saw earlier in connection with Figure 6-8, and as is developed further in Appendix 6A, beta does represent the slope of a line, but not the Security Market Line. This confusion arises partly because the SML equation is generally written, in this book and throughout the finance literature, as ki = RF + bi(kM – RF), and in this form bi looks like the slope coefficient and (kM – RF) the variable. It would perhaps be less confusing if the second term were written (kM – RF)bi, but this is not generally done.[145]

As noted in Appendix 6A of Brigham and Gapenski's textbook, beta, which accounts for regression bias, is not a return adjustment but rather is based on the slope of a different line.

A 1980 study by Litzenberger, et al., found the CAPM underestimates the ROE for companies, such as public utilities, with betas less than 1.00. In that study, the authors applied adjusted betas and still found the CAPM to underestimate the ROE for low-beta

[144] Morin, at 223-224.

[145] Eugene F. Brigham and Louis C. Gapenski, Financial Management - Theory and Practice, 4th Ed. (The Dryden Press, 1985) at 201-204.

companies. Similarly, Brattle's Risk and Return for Regulated Industries supports the use of adjusted betas in the ECAPM:

> Note that the ECAPM and the Blume adjustment are attempting to correct for different empirical phenomena and therefore both may be applicable. It is not inconsistent to use both, as illustrated by the fact that the Litzenberger et.al (1980) study relied on Blume adjusted betas and estimated an alpha of 2% points in a short-term version of the ECAPM. This issue sometimes arises in regulatory proceedings.[146]

Hence, using adjusted betas does not address the previously discussed empirical issues with the CAPM. In view of the foregoing, the use of adjusted betas in both the traditional and empirical applications of the CAPM is neither incorrect or inconsistent with the financial literature, nor is it a duplicative adjustment. As a result, Ms. LaConte should have performed an ECAPM analysis.

Q. WHAT ARE THE RESULTS OF MS. LACONTE'S CAPM ANALYSIS AFTER MAKING THE CORRECTIONS NOTED ABOVE?

A. As shown in Schedule DWD-18R, updating Ms. LaConte's CAPM to include a fully-forecasted risk-free rate, the ECAPM, and an MRP based on *Value Line's* Summary and Index, an unadjusted ex-ante Market DCF, and the historical average results in an average indicated result of 12.08%.[147]

F. <u>Application of the RPM</u>

Q. PLEASE SUMMARIZE MS. LACONTE'S RISK PREMIUM APPROACH.

A. Ms. LaConte calculates an indicated ROE of 8.79% based on her RPM. Using the data I provided, Ms. LaConte's calculates a historical average risk premium of 2.85% based on the average authorized ROE since 1980 (12.52%) less the average of the corresponding

146 Bente Villadsen, et. al, <u>Risk and Return for Regulated Industries</u> (2017) at 95, endnote 147 of Chapter 4.
147 Excluding BKH's and WEC's indicated ROEs as explained previously.

utility bond yields at the time of the respective orders (9.67%).[148] She then adds a projected Moody's A2 utility bond yield of 5.94% to arrive at her indicated ROE of 8.79%.[149]

Q. DO YOU AGREE WITH MS. LACONTE'S APPROACH?

A. No. I disagree with Ms. LaConte's use of a long-term historical average to calculate the ERP, which does not reflect the well-established inverse relationship between interest rates and the ERP. As discussed previously in response to Mr. Daves, several academic studies support the findings of such an inverse relationship.

As shown in page 11 of Schedule DWD-4 (the data in which Ms. LaConte based her RPM) the correct application of this approach would indicate an ROE of 10.60%. As shown on page 23 of Schedule DWD-1R, using more recent data, the indicated ROE would be 10.40%.

Q. HAS MS. LACONTE RELIED ON AN ALTERNATIVE RISK PREMIUM APPROACH IN PREVIOUS PROCEEDINGS?

A. Yes. Before the Minnesota Public Utilities Commission, Ms. LaConte determined her risk premium-based ROE by taking the simple average of the average annual authorized ROEs less the average annual 30-year Treasury Bond yields since 1990, to which she applied a projected Treasury yield. I have replicated that approach in Schedule DWD-19R, as shown, that approach results in an indicated ROE of 9.95%. I also assessed whether there is a statistically significant inverse relationship between the annual Treasury yields and ERPs. As shown in Schedule DWD-19R, the relationship between annual Treasury yields and ERPs is inverse and statistically significant. Applying the projected 30-year Treasury yield to that relationship results in an indicated ROE of 10.25%.

[148] Table 4 of Ms. LaConte Direct Testimony states she relies on 30-year Treasury yields, however, in reviewing Exhibit BSL-6, I determined that she used A2 utility bond yields.

[149] Exhibit BSL-6.

Q. PLEASE SUMMARIZE YOUR RESPONSE TO MS. LACONTE'S RPM.

A. Ms. LaConte's RPM-indicated ROE of 8.79% is not reflective of the investor required ROE for SUA. It is generally accepted that there is an inverse relationship between interest rates and ERPs, which result in indicated ROEs of 10.40% (based on the analysis presented in page 23 of Schedule DWD-1R) and 10.25%. Even if Ms. LaConte insists on using the simple average, replicating the approach she has used previously results in an ROE of 9.95%. Her analysis in this proceeding is inconsistent with prior analyses and her 8.79% indicated ROE is a clear outlier and should not be considered by the Commission.

G. Application of a Size Adjustment

Q. DOES MS. LACONTE ACCOUNT FOR SUA SIZE RELATIVE TO THE PROXY GROUP?

A. No. Ms. LaConte does not consider a size adjustment because she believes that comparing SUA's size to that of the Utility Proxy Group is not an apples-to-apples comparison.[150] I do not agree. While SUA is an operating utility and the Utility Proxy Group is comprised of mainly holding companies, we have established those companies as similar in risk to SUA and use that market data to determine the ROE for SUA. To the extent that SUA is riskier than the Utility Proxy Group (larger size), it should be reflected in an adjustment to the Utility Proxy Group's ROE.

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150 LaConte Direct Testimony, at 29.

H. Response to Ms. LaConte's Critique of Company Analyses

Q. WHAT ARE MS. LACONTE'S CRITIQUES OF YOUR DIRECT TESTIONY?

A. Ms. LaConte's critiques of my Direct Testimony include: (1) my use of a Non-Price Regulated Group;[151] (2) my use of an MRP based on *Value Line's* Summary and Index; (3) the calculation of the market DCF; (4) my use of an MRP based on a regression of historical interest rates and MRPs; (5) the use of the PRPM; (6) the employment of the ECAPM; (7) my inputs to the regression analysis I use to calculate one of my RPM results; and (8) my use of a size adjustment. I have addressed (1), (2), (3), (6) and (8) previously and will not repeat the discussions here. I respond to the remaining items (4, 5, and 7) in turn below.

Q. PLEASE RESPOND TO MS. LACONTE'S CONCERN WITH YOUR MRP BASED ON A REGRESSION OF HISTORICAL INTEREST RATES AND MRPS AND THE PRPM.[152]

A. Ms. LaConte states that MRPs based on a regression of historical interest rates and MRPs and based on the PRPM are unnecessary and not widely used. As noted above, there is well established academic and financial literature supporting the inverse relationship between interest rates and ERPs. Regarding the PRPM, As discussed in my Direct Testimony,[153] the PRPM is based on the research of Dr. Robert F. Engle, dating back to the early 1980s. Dr. Engle discovered that the volatility of market prices, returns, and risk premiums clusters over time, making prices, returns, and risk premiums highly predictable. In 2003, he shared the Nobel Prize in Economics for this work, characterized as "methods

151 LaConte Direct Testimony, at 23.
152 LaConte Direct Testimony, at 25.
153 D'Ascendis Direct Testimony, at 31-32.

of analyzing economic time series with time-varying volatility (ARCH)."[154] Dr. Engle[155] noted that relative to volatility, "the standard tools have become the ARCH/GARCH[156] models."

The GARCH methodology has been well tested by academia since Engle's, et al. research was originally published in 1982, 40 years ago. I use this well-established methodology to estimate the PRPM model using a standard commercial and relatively inexpensive statistical package, Eviews,©[157] to develop a means by which to estimate a predicted ERP which, when added to a relevant bond yield, results in an indicated cost of common equity.

Also, the PRPM is in the public domain, having been published six times in academically peer-reviewed journals: Journal of Economics and Business (June 2011 and April 2015),[158] The Journal of Regulatory Economics (December 2011),[159] The Electricity

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154 https://www.nobelprize.org/prizes/economic-sciences/2003/engle/facts/.

155 Robert Engle, GARCH 101: The Use of ARCH/GARCH Models in Applied Econometrics, Journal of Economic Perspectives, Volume 15, No. 4, Fall 2001, at 157-168.

156 Autoregressive Conditional Heteroskedasticity/Generalized Autoregressive Conditional Heteroskedasticity.

157 In addition to Eviews,® the GARCH methodology can be applied and the PRPM derived using other standard statistical software packages such as SAS, RATS, S-Plus and JMulti, which are not cost-prohibitive. The software that I used in this proceeding, Eviews,® currently costs $600 - $700 for a single user commercial license. In addition, JMulti is a free downloadable software with GARCH estimation applications.

158 *See*, Eugene A. Pilotte, and Richard A. Michelfelder, Treasury Bond Risk and Return, the Implications for the Hedging of Consumption and Lessons for Asset Pricing, Journal of Economics and Business, June 2011, 582-604. See also, Richard A. Michelfelder, Empirical Analysis of the Generalized Consumption Asset Pricing Model: Estimating the Cost of Capital, Journal of Economics and Business, April 2015, 37-50.

159 *See*, Pauline M. Ahern, Frank J. Hanley, and Richard A. Michelfelder, New Approach to Estimating the Equity Risk Premium for Public Utilities, The Journal of Regulatory Economics, December 2011, at 40:261-278.

Journal (May 2013 and March 2020),[160] and Energy Policy Journal (April 2019).[161] Notably, none of these articles have been rebutted in the academic literature.

Finally, the PRPM has also been presented to a number of utility industry/regulatory/academic groups including the following: The Edison Electric Institute Cost of Capital Working Group; The NARUC Staff Subcommittee on Accounting and Finance; The National Association of Electric Companies Finance/Accounting/Taxation and Rates and Regulations Committees; the NARUC Electric Committee; The Wall Street Utility Group; the Indiana Utility Regulatory Commission Cost of Capital Task Force; the Financial Research Institute of the University of Missouri Hot Topic Hotline Webinar; and the Center for Research and Regulated Industries Annual Eastern Conference on two occasions.

Q. IS THE PRPM CITED IN ACADEMIC LITERATURE BESIDES THE ARTICLES CITED ABOVE?

A. Yes, it is. The PRPM is cited in the following textbooks on cost of capital by authors unaffiliated the authors of the academic articles cited above:

- Shannon Pratt and Roger Grabowski, Cost of Capital: Applications and Examples, (Fifth Edition), Wiley & Sons, 2015;
- Shannon Pratt and Roger Grabowski, The Lawyer's Guide to Cost of Capital: Understanding Risk and Return for Valuing Businesses and Other Investments, ABA Publishing, 2015; and

160 *See*, Richard A. Michelfelder, Pauline M. Ahern, Dylan W. D'Ascendis, and Frank J. Hanley, Comparative Evaluation of the Predictive Risk Premium Model, the Discounted Cash Flow Model and the Capital Asset Pricing Model for Estimating the Cost of Common Equity, The Electricity Journal, April 2013, at 84-89; see also, Richard A. Michelfelder, Pauline M. Ahern, and Dylan W. D'Ascendis, Decoupling, Risk Impacts and the Cost of Capital, The Electricity Journal, January 2020.

161 *See*, Richard A. Michelfelder, Pauline M. Ahern, and Dylan W. D'Ascendis, Decoupling Impact and Public Utility Conservation Investment, Energy Policy Journal, April 2019, 311-319.

- Roger A. Morin, Modern Regulatory Finance, PUR Books, 2021.

On the subject of the PRPM, Pratt and Grabowski state:

> Empirical testing of this new model has yielded data allowing a comparison of results with other techniques including the DCF and CAPM. The results- combined with the stability of PRPM estimates- suggests that the model is robust when applied to electric, natural gas, combination electric and gas, and water utility companies.[162]

In addition, Morin states:

> PRPM cost of capital estimates then began to proliferate based on extensive work published in the Journal of Regulatory Economics, The Electricity Journal, and Energy Policy Journal. It is only a matter of time before the technique becomes more mainstream in regulatory proceedings.
>
> ***
>
> It is well known that security markets exhibit periods of relative calm and periodic high volatility for a variety of reasons. The GARCH technique does not explain the volatility but *models* its clustering. Investment analysts and financial institutions typically use models such as GARCH to estimate the volatility of returns for stocks, bonds, and market indices. They use the resulting information to help determine pricing decisions and judge which assets will potentially provide higher returns, as well as to forecast the returns. At its core, GARCH is a statistical modelling technique used in analyzing time-series data where the variance error is believed to be serially uncorrelated, and is used to help predict the volatility of returns on financial assets.[163]

Q. HAS THE PRPM BEEN IMPLICITLY ACCEPTED BY OTHER REGULATORY COMMISSIONS?

A. Yes. In Docket No. 2017-292-WS, the Public Service Commission of South Carolina approved Carolina Water Service's requested ROE, which included the PRPM. The relevant portion states:

> The Commission finds Mr. D'Ascendis' arguments persuasive. He provided more indicia of market returns, by using more analytical methods and proxy group calculations. Mr. D'Ascendis' use of analysts' estimates for his DCF

162 Shannon Pratt, Roger Grabowski, The Lawyer's Guide to The Cost of Capital: Understanding Risk and Return for Valuing Businesses and Other Investments, American Bar Association, 2015, at 421.
163 Morin, at 139-140, 141.

> analysis is supported by consensus, as is his use of the arithmetic mean. The Commission also finds that Mr. D'Ascendis' non-price regulated proxy group more accurately reflects the total risk faced [by] price regulated utilities and CWS. Furthermore, there is no dispute that CWS is significantly smaller than its proxy group counterparts, and, therefore, it may present a higher risk. An appropriate ROE for CWS is 10.45% to 10.95%. The Company used an ROE of 10.5% in computing its Application, a return on the low end of Mr. D'Ascendis' range, and the Commission finds that ROE is supported by the evidence.[164]

It should also be noted that in the above passage the Public Service Commission of South Carolina also found my Non-Price Regulated Proxy Group and size adjustment to be appropriate.

In addition, in Docket No. W-354, Subs 363, 364 and 365, the State of North Carolina Utilities Commission approved my RPM and CAPM analyses, which used PRPM analyses as presented in this proceeding. The relevant portion of the order states:

> In doing so the Commission finds that the DCF (8.81%), Risk Premium (10.00%) and CAPM (9.29%) model results provided by witness D'Ascendis, as updated to use current rates in D'Ascendis Late-Filed Exhibit No. 1, as well as the risk premium (9.57%) analysis of witness Hinton, are credible, probative, and are entitled to substantial weight as set forth below.[165]

Q. WHAT ARE MS. LACONTE'S CONCERNS WITH YOUR REGRESSION-BASED ERP?

A. Ms. LaConte states that the regression analysis fails to consider other factors beyond the relationship between the authorized ROE based ERP and bond yields.

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164 Docket No. 2017-292-WS - Order No. 2018-345, at 14. (May 17, 2018).

165 Docket No. W-354, Sub 363, 364, 365, Order Granting Partial Rate Increase and Requiring Customer Notice, at PDF 72. (March 31, 2020).

Q. HAVE YOU CONDUCTED ADDITIONAL ANALYSIS TO MODEL ANY OF THE ADDITIONAL FACTORS THAT IMPACT THE ERP?

A. Yes, I have. I included two additional independent variables in my regression analysis: credit spreads and the Cboe Volatility Index (VIX). Credit spreads are defined as the difference between the 30-year Treasury yield and the Moody's A rated Utility Bonds. As shown in Schedule DWD-20R, the results of the regression show that the relationship between the yield on A-rated public utility bonds and ERPs remains significant and inverse, and the resulting ERP estimates are generally consistent with those provided with my Direct Testimony. The result is consistent with Harris and Marston's research where the introduction of additional variables (such as credit spreads, consumer confidence, dispersion of analysts' forecasts of earnings growth, and volatility) did not change the conclusion that there is a negative relationship between interest rates and the ERP.[166]

IX. <u>CONCLUSION</u>

Q. PLEASE SUMMARIZE YOUR REBUTTAL TESTIMONY.

A. In this Rebuttal Testimony, I updated my ROE models with market data as of June 28, 2024. The results of the ROE models produced indicated ranges of ROEs from 10.03% to 12.48% (unadjusted) and from 10.08% to 12.53% (adjusted). I have maintained my initial ROE recommendation of 11.00%, which continues to remain reasonable, if not conservative. I also continue to recommend a capital structure consisting of 45.12% Total Debt and 54.88% Common Equity.

Q. SHOULD ANY OR ALL OF THE ARGUMENTS MADE BY THE OPPOSING WITNESSES PERSUADE THE COMMISSION TO LOWER THE RETURN ON

166 Robert S. Harris and Felicia C. Marston, The Market Risk Premium: Expectational Estimates Using Analysts' Forecasts, Journal of Applied Finance, Vol. 11, No. 1, 2001, at 11-12, 14.

COMMON EQUITY IT APPROVES FOR SUA BELOW YOUR RECOMMENDATION?

A. No, they should not. My recommended cost of common equity of 11.00% will provide SUA with sufficient earnings to enable it to attract necessary new capital efficiently and at a reasonable cost, to the benefit of both customers and investors.

Q. DOES THIS CONCLUDE YOUR REBUTTAL TESTIMONY?

A. Yes, it does.

CERTIFICATE OF SERVICE

I, Brooke South Parsons, do hereby certify that a true and correct copy of the foregoing has been delivered to all Parties of Record by electronic mail via the Electronic Filing System this 7th day of August 2024.

Brooke South Parsons

Brooke South Parsons

BEFORE THE

ARKANSAS PUBLIC SERVICE COMMISSION

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

REBUTTAL EXHIBIT

OF

DYLAN W. D'ASCENDIS

SCOTTMADDEN, INC.

ON BEHALF OF

SUMMIT UTILITIES ARKANSAS, INC.

Date Filed: August 7, 2024

REBUTTAL EXHIBIT DWD-1

SCHEDULES DWD-1R THROUGH DWD-20R

Summit Natural Gas of Arkansas
Table of Contents of Exhibits
Rebuttal Testimony of Dylan W. D'Ascendis

Summit Natural Gas of Arkansas
Recommended Capital Structure and Cost Rates
for Ratemaking Purposes

Type Of Capital	Ratios (1)	Cost Rate	
Total Debt	45.12%	4.18%	(1)
Common Equity	54.88%	11.00%	(2)
Total	100.00%		

Notes:
(1) Company-Provided.
(2) From page 2 of this Schedule.

Summit Natural Gas of Arkansas
Brief Summary of Common Equity Cost Rate

Line No.	Principal Methods	Proxy Group of Six Natural Gas Companies
1.	Discounted Cash Flow Model (DCF) (1)	10.03%
2.	Risk Premium Model (RPM) (2)	10.98%
3.	Capital Asset Pricing Model (CAPM) (3)	11.91%
4.	Market Models Applied to Comparable Risk, Non-Price Regulated Companies (4)	12.48%
5.	Indicated Range of Common Equity Cost Rates before Adjustment for Company-specific Risk	10.03% - 12.48%
6.	Size Adjustment (5)	0.05%
7.	Recommended Range of Common Equity Cost Rates after Adjustment for Company-specec Risk	10.08% - 12.53%
8.	Recommended Common Equity Cost Rate	11.00%

Notes:
(1) From page 6 of this Schedule.
(2) From page 13 of this Schedule.
(3) From page 24 of this Schedule.
(4) From page 29 of this Schedule.
(5) Adjustment to reflect the Company's greater business risk due to its smaller size relative to the Utility Proxy Group as detailed in Mr. D'Ascendis' Direct Testimony.

Proxy Group of Six Natural Gas Distribution Companies
CAPITALIZATION AND FINANCIAL STATISTICS (1)
2019 - 2023, Inclusive

	2023	2022	2021	2020	2019	5 YEAR AVERAGE
			(MILLIONS OF DOLLARS)			
Capitalization Statistics						
Amount of Capital Employed						
Total Permanent Capital	$9,387.228	$8,327.368	$7,455.217	$6,855.835	$6,012.401	
Short-Term Debt	$764.667	$703.086	$415.467	$333.183	$612.061	
Total Capital Employed	$10,151.895	$9,030.454	$7,870.684	$7,189.018	$6,624.462	
Indicated Average Capital Cost Rates (2)						
Total Debt	3.92 %	3.05 %	2.95 %	3.29 %	3.63 %	
Preferred Stock	5.22 %	4.84 %	5.33	6.19	4.60	
Capital Structure Ratios						
Based on Total Permanent Capital:						
Long-Term Debt	51.20 %	49.83 %	50.18 %	50.03 %	46.42 %	49.53 %
Preferred Stock	1.01	2.15	2.31	1.78	1.92	1.83
Common Equity	47.79	48.03	47.51	48.18	51.66	48.64
Total	100.00 %	100.00 %	100.00 %	100.00 %	100.00 %	100.00 %
Based on Total Capital:						
Total Debt, Including Short-Term Debt	53.81 %	54.18 %	54.26 %	53.51 %	51.06 %	53.37 %
Preferred Stock	0.88	1.92	2.18	1.66	1.68	1.66
Common Equity	45.31	43.91	43.56	44.83	47.26	44.97
Total	100.00 %	100.00 %	100.00 %	100.00 %	100.00 %	100.00 %
Financial Statistics						
Financial Ratios - Market Based						
Earnings / Price Ratio	5.74 %	5.55 %	5.25 %	3.45 %	3.84 %	4.76 %
Market / Average Book Ratio	160.87	183.48	176.32	191.60	224.79	187.41
Dividend Yield	3.74	3.31	3.42	3.09	2.60	3.23
Dividend Payout Ratio	63.32	58.56	60.27	83.22	69.25	66.92
Rate of Return on Average Book Common Equity	9.26 %	10.51 %	9.85 %	6.75 %	8.68 %	9.01 %
Total Debt / EBITDA (3)	5.10 x	5.18 x	5.10 x	6.03 x	4.96 x	5.27 x
Funds from Operations / Total Debt (4)	30.70 %	12.97 %	11.66 %	12.42 %	14.94 %	16.54 %
Total Debt / Total Capital	53.81 %	54.18 %	54.26 %	53.51 %	51.06 %	53.37 %

Notes:
(1) All capitalization and financial statistics for the group are the arithmetic average of the achieved results for each individual company in the group, and are based upon financial statements as originally reported in each year.
(2) Computed by relating actual total debt interest or preferred stock dividends booked to average of beginning and ending total debt or preferred stock reported to be outstanding.
(3) Total debt relative to EBITDA (Earnings before Interest, Income Taxes, Depreciation and Amortization).
(4) Funds from operations (sum of net income, depreciation, amortization, net deferred income tax and investment tax credits, less total AFUDC) plus interest charges as a percentage of total debt.

Source of Information: Company Annual Forms 10-K

Capital Structure Based upon Total Permanent Capital for the
Proxy Group of Six Natural Gas Distribution Companies
2019 - 2023, Inclusive

	2023		2022		2021		2020		2019		5 YEAR AVERAGE	
Atmos Energy												
Total Debt, Including Short-Term	38.47	%	38.70	%	39.35	%	40.02	%	40.99	%	39.51	%
Preferred Stock	-		-		-		-		-		-	
Common Equity	61.53		61.30		60.65		59.98		59.01		60.49	
Total Capital	100.00	%	100.00	%	100.00	%	100.00	%	100.00	%	100.00	%
New Jersey Resources												
Total Debt, Including Short-Term	61.17	%	62.15	%	61.56	%	56.66	%	50.52	%	58.41	%
Preferred Stock	-		-		-		-		-		-	
Common Equity	38.83		37.85		38.44		43.34		49.48		41.59	
Total Capital	100.00	%	100.00	%	100.00	%	100.00	%	100.00	%	100.00	%
NiSource Inc.												
Total Debt, Including Short-Term	63.08	%	59.90	%	58.52	%	62.88	%	61.70	%	61.22	%
Preferred Stock	2.17		8.19		9.23		5.68		5.63		6.18	
Common Equity	34.75		31.91		32.25		31.44		32.67		32.60	
Total Capital	100.00	%	100.00	%	100.00	%	100.00	%	100.00	%	100.00	%
Northwest Natural												
Total Debt, Including Short-Term	56.48	%	57.57	%	60.08	%	58.64	%	54.33	%	57.42	%
Preferred Stock	-		-		-		-		-		-	
Common Equity	43.52		42.43		39.92		41.36		45.67		42.58	
Total Capital	100.00	%	100.00	%	100.00	%	100.00	%	100.00	%	100.00	%
ONE Gas, Inc.												
Total Debt, Including Short-Term	44.05	%	48.47	%	48.10	%	47.49	%	45.84	%	46.79	%
Preferred Stock	-		-		-		-		-		-	
Common Equity	55.95		51.53		51.90		52.51		54.16		53.21	
Total Capital	100.00	%	100.00	%	100.00	%	100.00	%	100.00	%	100.00	%
Spire Inc.												
Total Debt, Including Short-Term	59.63	%	58.29	%	57.97	%	55.39	%	52.98	%	56.84	%
Preferred Stock	3.09		3.30		3.83		4.28		4.47		3.79	
Common Equity	37.28		38.41		38.20		40.33		42.54		39.36	
Total Capital	100.00	%	100.00	%	100.00	%	100.00	%	99.99	%	99.99	%
Proxy Group of Six Natural Gas Distribution Companies												
Total Debt, Including Short-Term	53.81	%	54.18	%	54.26	%	53.51	%	51.06	%	53.37	%
Preferred Stock	0.88		1.92		2.18		1.66		1.68		1.66	
Common Equity	45.31		43.91		43.56		44.83		47.26		44.97	
Total Capital	100.00	%	100.00	%	100.00	%	100.00	%	100.00	%	100.00	%

Source of Information
Annual Forms 10-K

Summit Natural Gas of Arkansas
Operating Subsidiary Company Capital Structures of the
Proxy Group of Six Natural Gas Companies

Company Name	Parent Company Ticker	2023 Common Equity	2023 Total Debt	2023 Total Capital
Atmos Energy Corporation	ATO	60.41%	39.59%	100.00%
New Jersey Natural Gas Company	NJR	37.70%	62.30%	100.00%
Northern Indiana Public Service Company	NI	59.26%	40.74%	100.00%
Northwest Natural Gas Company	NWN	45.77%	54.23%	100.00%
ONE Gas, Inc.	OGS	47.40%	52.60%	100.00%
Spire Alabama Inc.	SR	50.89%	49.11%	100.00%
Spire Missouri Inc.	SR	44.21%	55.79%	100.00%
	Average	49.38%	50.62%	
	Maximum	60.41%	62.30%	
	Minimum	37.70%	39.59%	

Source: S&P Global Market Intelligence.
Company Financial Statements.
Northern Indiana Public Service Company is from FERC financial Report Form Form No. 1.

Summit Natural Gas of Arkansas
Indicated Common Equity Cost Rate Using the Discounted Cash Flow Model for the
Gas Utility Proxy Group

	[1]	[2]	[3]	[4]	[5]	[6]	[7]
Proxy Group of Six Natural Gas Companies	Average Dividend Yield (1)	Value Line Projected Five Year Growth in EPS (2)	Zack's Five Year Projected Growth Rate in EPS	Yahoo! Finance Projected Five Year Growth in EPS	Average Projected Five Year Growth in EPS (3)	Adjusted Dividend Yield (4)	Indicated Common Equity Cost Rate (5)
Atmos Energy Corporation	2.76 %	7.00 %	7.00 %	7.40 %	7.13 %	2.86 %	9.99 %
New Jersey Resources Corporation	3.89	5.00	NA	6.00	5.50	4.00	9.50
NiSource Inc.	3.75	9.50	6.00	7.40	7.63	3.89	11.52
Northwest Natural Holding Company	5.27	6.50	NA	2.80	4.65	5.39	10.04
ONE Gas, Inc.	4.21	3.50	5.00	5.00	4.50	4.30	8.80
Spire Inc.	5.00	4.50	5.00	6.36	5.29	5.13	10.42
						Average	10.05 %
						Median	10.02 %
						Average of Mean and Median	10.03 %

NA=Not available

Notes:
(1) Indicated dividend at 06/28/2024 divided by the average closing price of the last 60 trading days ending 06/28/2024 for each company.
(2) From pages 7 through 12 of this Schedule.
(3) Average of columns 2 through 4 excluding negative growth rates.
(4) This reflects a growth rate component equal to one-half the conclusion of growth rate (from column 5) x column 1 to reflect the periodic payment of dividends (Gordon Model) as opposed to the continuous payment. Thus, for Atmos Energy Corporation, 2.76% x (1+(1/2 x 7.13%)) = 2.86%.
(5) Column 5 + Column 6.

Source of Information: Value Line Investment Survey.
www.zacks.com, Downloaded on 06/28/2024.
www.yahoo.com, Downloaded on 06/28/2024.

ATMOS ENERGY CORP. NYSE-ATO

RECENT PRICE 116.33 | P/E RATIO 16.8 (Trailing: 17.4 Median: 20.0) | RELATIVE P/E RATIO 0.92 | DIV'D YLD 2.9% | VALUE LINE

TIMELINESS 4 Lowered 2/16/24
SAFETY 1 Raised 6/6/14
TECHNICAL 3 Lowered 3/22/24
BETA .85 (1.00 = Market)

18-Month Target Price Range

Low-High	Midpoint (% to Mid)
$102-$148	$125 (5%)

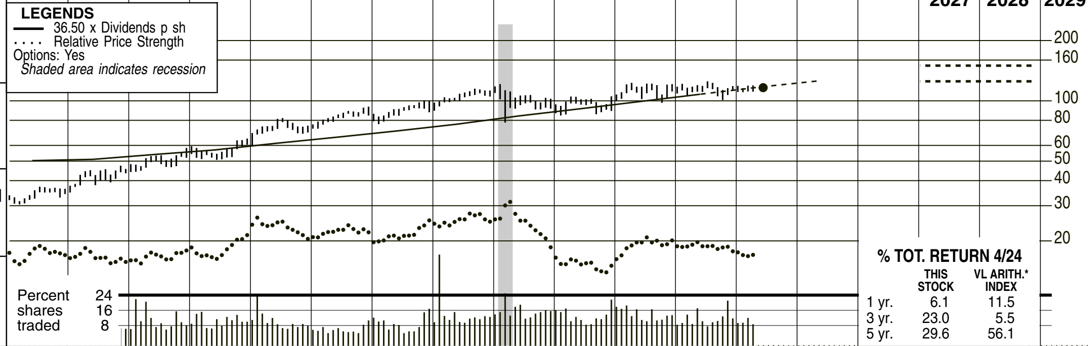
2027-29 PROJECTIONS

	Price	Gain	Ann'l Total Return
High	150	(+30%)	*10%*
Low	125	(+5%)	*5%*

Institutional Decisions

	2Q2023	3Q2023	4Q2023
to Buy	314	322	358
to Sell	281	280	295
Hld's(000)	136508	137279	137294

	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024
High:	47.4	58.2	64.8	82.0	93.6	100.8	115.2	121.1	105.3	123.0	125.3	121.5
Low:	34.9	44.2	50.8	60.0	72.5	76.5	89.2	77.9	84.6	97.7	101.0	110.5



Target Price Range 2027 | 2028 | 2029

% TOT. RETURN 4/24

	THIS STOCK	VL ARITH.* INDEX
1 yr.	6.1	11.5
3 yr.	23.0	5.5
5 yr.	29.6	56.1

2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	© VALUE LINE PUB. LLC	27-29
79.52	53.69	53.12	48.15	38.10	42.88	49.22	40.82	32.23	26.01	28.00	24.32	22.41	25.73	29.82	28.79	*27.10*	*28.50*	Revenues per sh A	*37.15*
4.19	4.29	4.64	4.72	4.76	5.14	5.42	5.81	6.19	6.62	7.24	7.57	8.03	8.64	9.30	10.04	*10.95*	*11.75*	"Cash Flow" per sh	*13.65*
2.00	1.97	2.16	2.26	2.10	2.50	2.96	3.09	3.38	3.60	4.00	4.35	4.72	5.12	5.60	6.10	*6.75*	*7.20*	Earnings per sh AB	*8.35*
1.30	1.32	1.34	1.36	1.38	1.40	1.48	1.56	1.68	1.80	1.94	2.10	2.30	2.50	2.72	2.96	*3.22*	*3.46*	Div'ds Decl'd per sh C■	*4.25*
5.20	5.51	6.02	6.90	8.12	9.32	8.32	9.61	10.46	10.72	13.19	14.19	15.38	14.87	17.35	18.90	*20.00*	*20.25*	Cap'l Spending per sh	*20.00*
22.60	23.52	24.16	24.98	26.14	28.47	30.74	31.48	33.32	36.74	42.87	48.18	53.95	59.71	66.85	73.20	*75.30*	*78.60*	Book Value per sh	*83.50*
90.81	92.55	90.16	90.30	90.24	90.64	100.39	101.48	103.93	106.10	111.27	119.34	125.88	132.42	140.90	148.49	*155.00*	*158.00*	Common Shs Outst'g D	*175.00*
13.6	12.5	13.2	14.4	15.9	15.9	16.1	17.5	20.8	22.0	21.7	23.2	22.3	18.8	19.3	18.7	*Bold figures are*		Avg Ann'l P/E Ratio	*16.5*
.82	.83	.84	.90	1.01	.89	.85	.88	1.09	1.11	1.17	1.24	1.15	1.02	1.12	1.08	*Value Line*		Relative P/E Ratio	*.90*
4.8%	5.3%	4.7%	4.2%	4.1%	3.5%	3.1%	2.9%	2.4%	2.3%	2.2%	2.1%	2.2%	2.6%	2.5%	2.6%	*estimates*		Avg Ann'l Div'd Yield	*3.1%*

CAPITAL STRUCTURE as of 3/31/24
Total Debt $7535.7 mill. **Due in 5 Yrs** $915.0 mill.
LT Debt $7526.1 mill. **LT Interest** $135.0 mill.
(LT interest earned: 8.3x; total interest coverage: 8.3x)
Leases, Uncapitalized Annual rentals $41.3 mill.

Pfd Stock None

Pension Assets-9/23 $502.4 mill.
Oblig. $431.6 mill.
Common Stock 150,877,056 shs.
as of 5/3/24

MARKET CAP: $17.6 billion (Large Cap)

2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025		27-29
4940.9	4142.1	3349.9	2759.7	3115.5	2901.8	2821.1	3407.5	4201.7	4275.4	*4200*	*4500*	Revenues ($mill) A	*6500*
289.8	315.1	350.1	382.7	444.3	511.4	580.5	665.6	774.4	885.9	*1025*	*1115*	Net Profit ($mill)	*1475*
39.2%	38.3%	36.4%	36.6%	27.0%	21.4%	19.5%	18.8%	9.1%	11.4%	*15.5%*	*16.0%*	Income Tax Rate	*25.0%*
5.9%	7.6%	10.5%	13.9%	14.3%	17.6%	20.6%	19.5%	18.4%	20.7%	*24.4%*	*24.8%*	Net Profit Margin	*22.7%*
44.3%	43.5%	38.7%	44.0%	34.3%	38.0%	40.0%	38.4%	37.9%	37.9%	*40.0%*	*40.0%*	Long-Term Debt Ratio	*40.0%*
55.7%	56.5%	61.3%	56.0%	65.7%	62.0%	60.0%	61.6%	62.1%	62.1%	*60.0%*	*60.0%*	Common Equity Ratio	*60.0%*
5542.2	5650.2	5651.8	6965.7	7263.6	9279.7	11323	12837	15180	17509	*19450*	*20700*	Total Capital ($mill)	*24350*
6725.9	7430.6	8280.5	9259.2	10371	11788	13355	15064	17240	19607	*21900*	*23000*	Net Plant ($mill)	*27000*
6.4%	6.6%	7.2%	6.4%	6.9%	6.1%	5.5%	5.5%	5.4%	5.5%	*6.5%*	*6.5%*	Return on Total Cap'l	*7.5%*
9.4%	9.9%	10.1%	9.8%	9.3%	8.9%	8.5%	8.4%	8.2%	8.1%	*9.0%*	*9.0%*	Return on Shr. Equity	*10.0%*
9.4%	9.9%	10.1%	9.8%	9.3%	8.9%	8.5%	8.4%	8.2%	8.1%	*9.0%*	*9.0%*	Return on Com Equity	*10.0%*
4.7%	4.9%	5.1%	4.9%	4.8%	4.6%	4.4%	4.3%	4.2%	4.2%	*4.5%*	*4.5%*	Retained to Com Eq	*5.0%*
50%	51%	50%	50%	48%	48%	49%	49%	49%	49%	*49%*	*49%*	All Div'ds to Net Prof	*50%*

CURRENT POSITION ($MILL.)	2022	2023	3/31/24
Cash Assets	51.6	15.4	262.5
Other	2996.1	870.4	1169.9
Current Assets	3047.7	885.8	1432.4
Accts Payable	496.0	336.1	367.9
Debt Due	2386.4	253.4	9.6
Other	720.2	763.1	677.7
Current Liab.	3602.6	1352.6	1055.2
Fix. Chg. Cov.	1238%	1059%	1070%

ANNUAL RATES of change (per sh)	Past 10 Yrs.	Past 5 Yrs.	Est'd '21-'23 to '27-'29
Revenues	-4.0%	-.5%	*5.0%*
"Cash Flow"	6.5%	7.0%	*6.5%*
Earnings	9.5%	9.0%	*7.0%*
Dividends	7.0%	8.5%	*7.5%*
Book Value	9.5%	12.0%	*4.0%*

Fiscal Year Ends	QUARTERLY REVENUES ($ mill.) A Dec.31	Mar.31	Jun.30	Sep.30	Full Fiscal Year
2021	914.5	1319.1	605.6	568.3	3407.5
2022	1012.8	1649.8	816.4	722.7	4201.7
2023	1484.0	1541.0	662.7	587.7	4275.4
2024	1158.5	1647.2	*786.5*	*607.8*	*4200*
2025	*1250*	*1725*	*865*	*660*	*4500*

Fiscal Year Ends	EARNINGS PER SHARE A B E Dec.31	Mar.31	Jun.30	Sep.30	Full Fiscal Year
2021	1.71	2.30	.78	.37	5.12
2022	1.86	2.37	.92	.51	5.60
2023	1.91	2.48	.94	.80	6.10
2024	2.08	2.85	*1.00*	*.82*	*6.75*
2025	*2.26*	*2.94*	*1.10*	*.90*	*7.20*

Cal-endar	QUARTERLY DIVIDENDS PAID C■ Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2020	.575	.575	.575	.625	2.35
2021	.625	.625	.625	.68	2.56
2022	.68	.68	.68	.74	2.78
2023	.74	.74	.74	.805	3.03
2024	.805	.805			

BUSINESS: Atmos Energy Corporation is engaged primarily in the distribution and sale of natural gas to over three million customers through six regulated natural gas utility operations: Louisiana Division, West Texas Division, Mid-Tex Division, Mississippi Division, Colorado-Kansas Division, and Kentucky/Mid-States Division. Gas sales breakdown for fiscal 2023: 66.5%, residential; 28.0%, commercial; 3.8%, industrial; and 1.7% other. The company sold Atmos Energy Marketing, 1/17. Officers and directors own approximately .5% of common stock (12/23 Proxy). President and Chief Executive Officer: Kevin Akers. Incorporated: Texas. Address: Three Lincoln Centre, Suite 1800, 5430 LBJ Freeway, Dallas, Texas 75240. Telephone: 972-934-9227. Internet: www.atmosenergy.com.

Atmos Energy has performed nicely, from an earnings standpoint, thus far in fiscal 2024 (ends September 30th). Through the first half, per-share profits of $4.93 were 12.3% higher than the $4.39 amount registered for the same period last year. This was brought about partially by positive rate-case outcomes. Lower bad-debt expense also helped. Furthermore, results were favorably impacted by legislation to reduce property-tax expenses in Texas. But a rise in both depreciation expense and interest charges provided somewhat of an offset. Nevertheless, for the entire year, it appears that the bottom line will increase around 10%, to $6.75 per share, relative to fiscal 2023's $6.10 tally. Concerning fiscal 2025, share net may grow another 7% or so, to $7.20, as operating margins expand further.

There has been action on the rate-filing front. During the first six months, Atmos managed to complete some regulatory proceedings leading to a $138.4 million boost in annual operating income. What's more, there were ratemaking initiatives in progress at the conclusion of March seeking $96.4 million of annual operating income. Of course, there are no guarantees that the company will receive everything it desires.

The capital spending target for fiscal 2024 was raised from $2.9 billion to $3.1 billion. The revised estimate marks a 10.5% increase from fiscal 2023's $2.8 billion figure. Like last year, a substantial amount of the resources is being used to enhance the safety and reliability of Atmos' natural gas distribution and transmission systems. Leadership adds that it projects total capital expenditures from fiscal 2024 through fiscal 2028 to be roughly $17 billion. A meaningful portion of the investments will continue to be deployed to where they are currently. Assuming that finances remain healthy, the company ought to have minimal difficulty accomplishing these objectives.

These top-quality shares have strengthened some in price over the past six months. That's due partly, we think, to the energy firm's solid earnings of late. However, long-term total return potential looks unspectacular. The equity is untimely, as well.

Frederick L. Harris, III *May 24, 2024*

(A) Fiscal year ends Sept. 30th. **(B)** Diluted shrs. Excl. nonrec. gains (loss): '10, 5¢; '11, (1¢); '18, $1.43; '20, 17¢. Excludes discontinued operations: '11, 10¢; '12, 27¢; '13, 14¢; '17, 13¢. Next earnings report due early Aug.
(C) Dividends historically paid in early March, June, Sept., and Dec. ■ Div. reinvestment plan. Direct stock purchase plan avail.
(D) In millions.
(E) Qtrs may not add due to change in shrs outstanding.

Company's Financial Strength	A
Stock's Price Stability	95
Price Growth Persistence	60
Earnings Predictability	100

NEW JERSEY RES. NYSE-NJR

RECENT PRICE 44.12 | P/E RATIO 14.9 (Trailing: 17.3 / Median: 17.0) | RELATIVE P/E RATIO 0.82 | DIV'D YLD 3.9% | VALUE LINE

TIMELINESS 4 Raised 3/29/24
SAFETY 2 Lowered 4/17/20
TECHNICAL 5 Lowered 5/3/24
BETA 1.00 (1.00 = Market)

18-Month Target Price Range

Low-High	Midpoint (% to Mid)
$37-$60	$49 (10%)

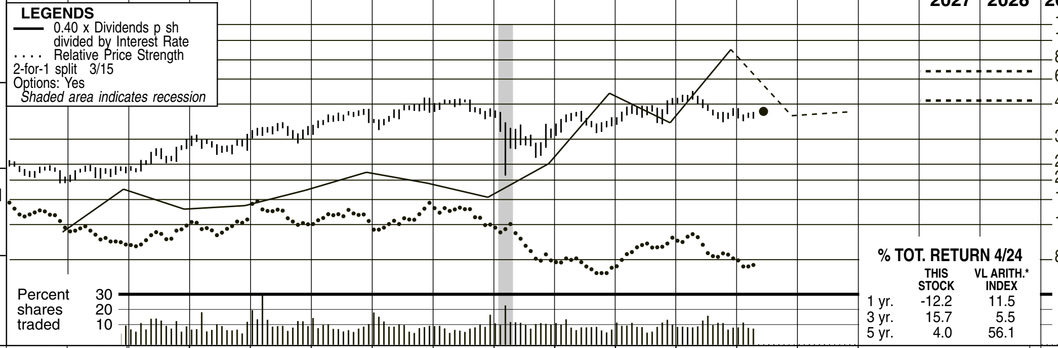
2027-29 PROJECTIONS

	Price	Gain	Ann'l Total Return
High	70	(+60%)	15%
Low	50	(+15%)	7%

Institutional Decisions

	2Q2023	3Q2023	4Q2023
to Buy	157	153	161
to Sell	156	163	143
Hld's(000)	71570	69494	70304

	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024
High:	23.8	32.1	34.1	38.9	45.4	51.8	51.2	44.7	44.4	51.4	55.8	45.8
Low:	19.5	21.9	26.8	30.5	33.7	35.6	40.3	21.1	33.3	37.8	38.9	39.4



Target Price Range
2027 | 2028 | 2029

% TOT. RETURN 4/24

	THIS STOCK	VL ARITH.* INDEX
1 yr.	-12.2	11.5
3 yr.	15.7	5.5
5 yr.	4.0	56.1

2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	© VALUE LINE PUB. LLC	27-29
45.37	31.17	32.05	36.30	27.08	38.38	44.40	32.09	21.90	26.28	33.24	29.01	20.39	22.71	30.38	20.12	**21.50**	**22.00**	Revenues per sh A	**25.00**
1.81	1.58	1.63	1.70	1.86	1.93	2.73	2.52	2.46	2.68	3.72	2.99	3.30	3.36	3.86	4.22	**4.55**	**4.60**	"Cash Flow" per sh	**5.25**
1.35	1.20	1.23	1.29	1.36	1.37	2.08	1.78	1.61	1.73	2.72	1.96	2.07	2.16	2.50	2.70	**2.95**	**3.00**	Earnings per sh B	**3.50**
.56	.62	.68	.72	.77	.81	.86	.93	.98	1.04	1.11	1.19	1.27	1.36	1.45	1.56	**1.68**	**1.76**	Div'ds Decl'd per sh C■	**1.95**
.86	.90	1.05	1.13	1.26	1.33	1.52	3.76	4.15	3.80	4.39	5.83	4.65	5.42	6.50	5.13	**4.40**	**5.50**	Cap'l Spending per sh	**6.25**
8.64	8.29	8.81	9.36	9.80	10.65	11.48	12.99	13.58	14.33	16.18	17.37	19.26	17.18	19.00	20.40	**22.30**	**23.65**	Book Value per sh D	**27.00**
84.12	83.17	82.35	82.89	83.05	83.32	84.20	85.19	85.88	86.32	87.69	89.34	95.80	94.95	95.64	97.57	**100.00**	**100.00**	Common Shs Outst'g E	**100.00**
12.3	14.9	15.0	16.8	16.8	16.0	11.7	16.6	21.3	22.4	15.6	24.3	17.7	17.5	17.0	17.7	*Bold figures are*		Avg Ann'l P/E Ratio	**17.0**
.74	.99	.95	1.05	1.07	.90	.62	.84	1.12	1.13	.84	1.29	.91	.94	.98	1.02	*Value Line*		Relative P/E Ratio	**.95**
3.3%	3.5%	3.7%	3.3%	3.4%	3.7%	3.5%	3.1%	2.9%	2.7%	2.6%	2.5%	3.5%	3.6%	3.4%	3.3%	*estimates*		Avg Ann'l Div'd Yield	**4.0%**

CAPITAL STRUCTURE as of 3/31/24
Total Debt $3070.8 mill. **Due in 5 Yrs** $580 mill.
LT Debt $2726.2 mill. **LT Interest** $125 mill.
Incl. $9.3 mill. capitalized leases.
(Interest coverage: 4.85x)
Pension Assets-9/23 $405.0 mill. **Oblig.** $493.7 mill.

Pfd Stock None

Common Stock 98,822,278 shs. as of 5/3/24

MARKET CAP: $4.4 billion (Mid Cap)

2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025		27-29
3738.1	2734.0	1880.9	2268.6	2915.1	2592.0	1953.7	2156.6	2906.0	1963.0	**2150**	**2200**	Revenues ($mill) A	**2500**
176.9	153.7	138.1	149.4	240.5	175.0	196.2	207.7	240.3	261.8	**295**	**300**	Net Profit ($mill)	**350**
30.2%	26.3%	15.5%	17.2%	- -	- -	NMF	10.3%	21.4%	15.8%	**21.5%**	**22.0%**	Income Tax Rate	**22.0%**
4.7%	5.6%	7.3%	6.6%	8.2%	6.7%	10.0%	9.6%	8.3%	13.3%	**13.7%**	**13.6%**	Net Profit Margin	**14.0%**
38.2%	43.2%	47.7%	44.6%	45.4%	49.8%	55.1%	57.0%	57.8%	58.2%	**57.5%**	**57.0%**	Long-Term Debt Ratio	**55.0%**
61.8%	56.8%	52.3%	55.4%	54.6%	50.2%	44.9%	43.0%	42.2%	41.8%	**42.5%**	**43.0%**	Common Equity Ratio	**45.0%**
1564.4	1950.6	2230.1	2233.7	2599.6	3088.9	4104.2	3793.0	4302.6	4758.8	**5250**	**5500**	Total Capital ($mill)	**6000**
1884.1	2128.3	2407.7	2609.7	2651.0	3041.2	3983.0	4213.5	4649.9	5022.1	**5150**	**5250**	Net Plant ($mill)	**5550**
12.1%	8.6%	6.9%	7.7%	10.1%	6.4%	5.6%	6.5%	5.6%	5.5%	**5.5%**	**5.5%**	Return on Total Cap'l	**6.0%**
18.3%	13.9%	11.8%	12.1%	16.9%	11.3%	10.6%	12.7%	13.2%	13.2%	**13.0%**	**12.5%**	Return on Shr. Equity	**13.0%**
18.3%	13.9%	11.8%	12.1%	16.9%	11.3%	10.6%	12.7%	13.2%	13.2%	**13.0%**	**12.5%**	Return on Com Equity	**13.0%**
11.0%	7.0%	4.8%	5.0%	10.2%	4.6%	4.3%	5.6%	6.2%	5.6%	**5.5%**	**5.0%**	Retained to Com Eq	**5.5%**
40%	50%	60%	59%	40%	59%	60%	56%	53%	58%	**57%**	**59%**	All Div'ds to Net Prof	**56%**

CURRENT POSITION ($MILL.)	2022	2023	3/31/24
Cash Assets	1.1	1.0	5.0
Other	755.0	531.1	548.7
Current Assets	756.1	532.1	553.7
Accts Payable	156.6	151.8	127.2
Debt Due	499.1	368.3	344.6
Other	448.5	286.5	317.3
Current Liab.	1104.2	806.6	789.1
Fix. Chg. Cov.	545%	520%	480%

ANNUAL RATES of change (per sh)	Past 10 Yrs.	Past 5 Yrs.	Est'd '21-'23 to '27-'29
Revenues	-3.0%	-6.0%	*2.5%*
"Cash Flow"	7.0%	4.5%	*5.0%*
Earnings	5.0%	2.5%	*5.0%*
Dividends	6.5%	6.5%	*5.0%*
Book Value	7.5%	7.0%	*4.5%*

Fiscal Year Ends	QUARTERLY REVENUES ($ mill.) A Dec.31	Mar.31	Jun.30	Sep.30	Full Fiscal Year
2021	454.3	802.2	367.6	532.5	2156.6
2022	675.8	912.3	552.3	765.5	2906.0
2023	723.6	644.0	264.1	331.3	1963.0
2024	467.2	657.9	**450**	**574.9**	**2150**
2025	**680**	**575**	**460**	**485**	**2200**

Fiscal Year Ends	EARNINGS PER SHARE A B Dec.31	Mar.31	Jun.30	Sep.30	Full Fiscal Year
2021	.46	1.77	d.15	.07	2.16
2022	.69	1.36	d.04	.50	2.50
2023	1.14	1.16	.10	.30	2.70
2024	.74	1.41	**.05**	**.75**	**2.95**
2025	**.75**	**1.45**	**.05**	**.75**	**3.00**

Cal-endar	QUARTERLY DIVIDENDS PAID C■ Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2020	.3125	.3125	.3125	.3325	1.27
2021	.3325	.3325	.3325	.3625	1.36
2022	.3625	.3625	.3625	.3625	1.45
2023	.39	.39	.39	.39	1.56
2024	.42	.42			

BUSINESS: New Jersey Resources Corp. is a holding company providing retail/wholesale energy svcs. to customers in NJ, and in states from the Gulf Coast to New England, and Canada. New Jersey Natural Gas had 576,000 cust. at 9/30/23. Fiscal 2023 volume: 128 bill. cu. ft. (23% interruptible, 50% residential, commercial & firm transportation, 27% other). N.J. Natural Energy subsidiary provides unregulated retail/wholesale natural gas and related energy svcs. 2023 dep. rate: 2.8%. Has 1,350 empls. Off./dir. own less than 1% of common; BlackRock, 15.9%; Vanguard, 11.4% (12/23 Proxy). CEO, President & Director: Steven D. Westhoven. Incorporated: New Jersey. Address: 1415 Wyckoff Road, Wall, NJ 07719. Telephone: 732-938-1480. Web: www.njresources.com.

New Jersey Resources delivered a strong fiscal 2024 second-quarter performance. (Fiscal year ends September 30th.) Despite a lower-than-expected revenue figure due to falling natural gas prices, the company's cost structure allowed earnings to remain unfettered. Indeed, net financial earnings exceeded our projections, landing at $1.41 per share, well above the prior year's tally. This brings the total for the first six months of fiscal 2024 to $2.15, just shy of the $2.30 in the year before, which was boosted by a unique winter storm. The performance was bolstered by significant capital investments of more than $850 million since the last rate case in 2021. Too, the company's SAVEGREEN program, a large energy efficiency filing, helped in catering to New Jersey's increasingly sustainability-focused regulatory climate. Despite some broader headwinds, the company continues to manage its operating costs well.

We have raised our earnings outlook for the next two years. The energy services segment is poised to contribute to our increased expectations due to the earlier mentioned SAVEGREEN program within the context of a particularly strong residential construction market and efficiency incentives in its operating region. On a similar note, Clean Energy Ventures is experiencing rapid deployment with 34 megawatts under construction and a solar pipeline of over 870 megawatts of investment opportunities. Most importantly for sustainable earnings performances henceforth is a new rate case progressing through regulatory channels that should amplify earnings performance substantially in fiscal 2026, if passed.

New Jersey's regional strength provides a solid base for sustainable growth. With a favorable regulatory backdrop characterized by a commitment to the transition to sustainable energy systems, infrastructure investment opportunities are wide, which will help to grow the company's earnings base for the foreseeable future.

The stock remains favorable for low risk and steady income characteristics. The issue has returned about 6% over the past three months but still offers decent value from its income component.

Earl B. Humes *May 24, 2024*

(A) Fiscal year ends Sept. 30th.
(B) Diluted earnings. Qtly. revenues and egs. may not sum to total due to rounding and change in shares outstanding. Next earnings report due early August.
(C) Dividends historically paid in early Jan., April, July, and October. ■ Dividend reinvestment plan available.
(D) Includes regulatory assets in 2023: $585 million, $6.00/share.
(E) In millions, adjusted for 3/15 split.

Company's Financial Strength	A
Stock's Price Stability	85
Price Growth Persistence	40
Earnings Predictability	60

NISOURCE INC. NYSE-NI

RECENT PRICE **28.80** | P/E RATIO **16.9** (Trailing: 17.1 / Median: 21.0) | RELATIVE P/E RATIO **0.93** | DIV'D YLD **3.8%** | **VALUE LINE**

TIMELINESS 3 Raised 3/22/24
SAFETY 2 Raised 2/23/24
TECHNICAL 4 Raised 5/24/24
BETA .95 (1.00 = Market)

18-Month Target Price Range

Low-High	Midpoint (% to Mid)
$25-$40	$33 (15%)

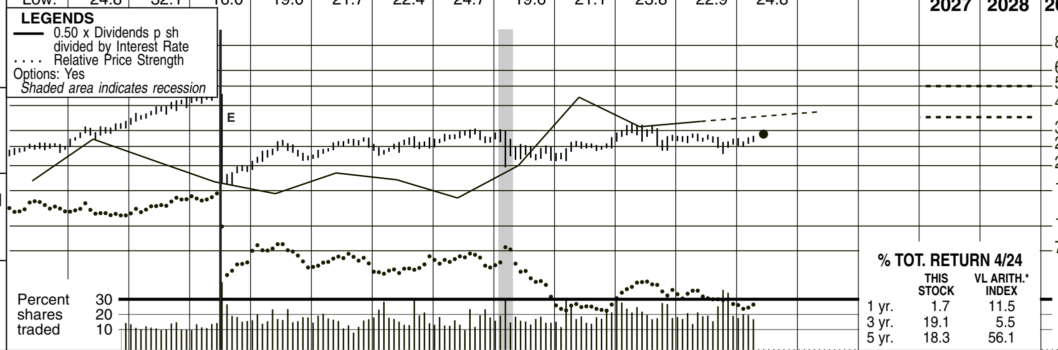
2027-29 PROJECTIONS

	Price	Gain	Ann'l Total Return
High	50	(+75%)	17%
Low	35	(+20%)	8%

Institutional Decisions

	2Q2023	3Q2023	4Q2023
to Buy	249	278	313
to Sell	256	234	253
Hld's(000)	393166	394475	413866

	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024
High:	33.5	44.9	49.2	26.9	27.8	28.1	30.7	30.5	27.8	32.6	29.0	29.2
Low:	24.8	32.1	16.0	19.0	21.7	22.4	24.7	19.6	21.1	23.8	22.9	24.8



Target Price Range

2027	2028	2029

% TOT. RETURN 4/24

	THIS STOCK	VL ARITH.* INDEX
1 yr.	1.7	11.5
3 yr.	19.1	5.5
5 yr.	18.3	56.1

2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	© VALUE LINE PUB. LLC	27-29
32.36	24.02	22.99	21.33	16.31	18.04	20.47	14.58	13.90	14.46	13.74	13.63	11.95	12.09	14.23	12.33	*13.80*	*14.55*	Revenues per sh	*16.10*
3.32	2.96	3.19	2.98	3.13	3.41	3.60	2.27	2.71	2.07	2.86	3.17	3.15	3.26	3.47	3.64	*3.80*	*4.80*	"Cash Flow" per sh	*4.40*
1.34	.84	1.06	1.05	1.37	1.57	1.67	.63	1.00	.39	1.30	1.31	1.32	1.37	1.47	1.60	*1.70*	*1.85*	Earnings per sh A	*2.20*
.92	.92	.92	.92	.94	.98	1.02	.83	.64	.70	.78	.80	.84	.88	.94	1.00	*1.06*	*1.12*	Div'ds Decl'd per sh B ■	*1.20*
3.54	2.81	2.88	3.99	4.83	5.99	6.42	4.26	4.57	5.03	4.88	4.72	4.49	4.53	6.32	5.93	*7.00*	*6.50*	Cap'l Spending per sh	*6.75*
17.24	17.54	17.63	17.71	17.90	18.77	19.54	12.04	12.60	12.82	13.08	13.36	12.44	13.33	13.14	22.71	*23.20*	*22.15*	Book Value per sh C	*20.40*
274.26	276.79	279.30	282.18	310.28	313.68	316.04	319.11	323.16	337.02	372.36	382.14	391.76	404.30	411.10	446.38	*450.00*	*450.00*	Common Shs Outst'g D	*450.00*
12.1	14.3	15.3	19.4	17.9	18.9	22.7	37.3	23.2	NMF	19.3	21.3	18.7	18.0	19.6	16.8	*Bold figures are*		Avg Ann'l P/E Ratio	*19.0*
.73	.95	.97	1.22	1.14	1.06	1.19	1.88	1.22	NMF	1.04	1.13	.96	.99	11.8	.97	*Value Line*		Relative P/E Ratio	*1.05*
5.7%	7.6%	5.7%	4.5%	3.8%	3.3%	2.7%	3.5%	2.8%	2.8%	3.1%	2.9%	3.4%	3.6%	3.3%	3.7%	*estimates*		Avg Ann'l Div'd Yield	*3.0%*

2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025		27-29
6470.6	4651.8	4492.5	4874.6	5114.5	5208.9	4681.7	4899.6	5850.6	5505.4	*6200*	*6550*	Revenues ($mill)	*7250*
530.7	198.6	328.1	128.6	478.3	549.8	562.6	626.3	648.2	716.3	*765*	*835*	Net Profit ($mill)	*990*
36.9%	41.6%	35.7%	71.0%	19.7%	17.0%	18.3%	15.7%	17.2%	17.8%	*19.0%*	*19.0%*	Income Tax Rate	*19.0%*
- -	- -	- -	- -	- -	- -	- -	2.0%	2.3%	3.5%	*3.0%*	*2.5%*	AFUDC % to Net Profit	*2.5%*
56.9%	60.7%	59.8%	63.5%	55.3%	56.8%	61.6%	56.9%	55.7%	52.2%	*52.5%*	*52.5%*	Long-Term Debt Ratio	*55.0%*
43.1%	39.3%	40.2%	36.5%	37.9%	36.9%	32.5%	33.5%	31.6%	45.5%	*40.0%*	*40.0%*	Common Equity Ratio	*37.5%*
14331	9792.0	10129	11832	12856	13843	14972	16131	17099	21192	*22000*	*21000*	Total Capital ($mill)	*24450*
16017	12112	13068	14360	15543	16912	16620	17882	19843	22275	*24500*	*25750*	Net Plant ($mill)	*28000*
5.3%	4.0%	5.0%	2.6%	5.1%	5.3%	5.0%	4.9%	3.8%	3.4%	*3.5%*	*4.0%*	Return on Total Cap'l	*4.0%*
8.6%	5.2%	8.1%	3.0%	8.3%	9.2%	9.8%	9.0%	9.3%	7.1%	*7.5%*	*8.5%*	Return on Shr. Equity	*9.0%*
8.6%	5.2%	8.1%	3.0%	9.6%	9.7%	10.4%	10.6%	12.0%	7.4%	*8.5%*	*10.0%*	Return on Com Equity	*11.0%*
3.4%	NMF	3.0%	NMF	4.0%	3.8%	3.8%	4.2%	4.0%	2.8%	*3.5%*	*4.0%*	Retained to Com Eq	*5.0%*
61%	NMF	63%	NMF	60%	64%	67%	64%	64%	63%	*62%*	*61%*	All Div'ds to Net Prof	*55%*

CAPITAL STRUCTURE as of 3/31/24
Total Debt $12970.9 mill. **Due in 5 Yrs** $4175 mill.
LT Debt $11724.6 mill. **LT Interest** $450 mill.
(Interest cov. earned: 4.5x) (54% of Cap'l)

Leases, Uncapitalized Annual rentals $9.6 mill.
Pension Assets-12/22 $1.4 bill. **Oblig.** $1.4 bill.

Pfd Stock $486 mill. **Pfd Div'd** $42.8 mill.

Common Stock 448,305,338 shs.
as of 4/30/24
MARKET CAP: $12.9 billion (Large Cap)

CURRENT POSITION ($MILL.)	2022	2023	3/31/24
Cash Assets	40.8	2245.4	102.2
Other	2543.5	2254.0	1958.0
Current Assets	2584.3	4499.4	2060.2
Accts Payable	899.5	749.4	612.5
Debt Due	1791.9	3072.4	1246.3
Other	1969.1	1443.3	1266.2
Current Liab.	4660.5	5265.1	3125.0
Fix. Chg. Cov.	255%	225%	425%

ANNUAL RATES of change (per sh)	Past 10 Yrs.	Past 5 Yrs.	Est'd '21-'23 to '27-'29
Revenues	-5.0%	-3.5%	*5.5%*
"Cash Flow"	.5%	6.5%	*5.5%*
Earnings	1.5%	15.0%	*9.5%*
Dividends	-.5%	3.5%	*4.5%*
Book Value	-3.0%	.5%	*5.0%*

Cal-endar	QUARTERLY REVENUES ($ mill.) Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2021	1545.6	986.0	959.4	1408.6	4899.6
2022	1873.3	1183.2	1089.5	1704.6	5850.6
2023	1966.0	1090.0	1027.4	1422.0	5505.4
2024	1706.3	*1400*	*1200*	*1893.7*	*6200*
2025	*1805*	*1480*	*1270*	*1995*	*6550*

Cal-endar	EARNINGS PER SHARE A Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2021	.77	.13	.11	.39	1.37
2022	.75	.12	.10	.50	1.47
2023	.77	.11	.19	.53	1.60
2024	.85	*.15*	*.13*	*.57*	*1.70*
2025	*.90*	*.20*	*.15*	*.60*	*1.85*

Cal-endar	QUARTERLY DIVIDENDS PAID B ■ Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2020	.21	.21	.21	.21	.84
2021	.22	.22	.22	.22	.88
2022	.235	.235	.235	.235	.94
2023	.25	.25	.25	.25	1.00
2024	.265	.265			

BUSINESS: NiSource Inc. is a holding company for Northern Indiana Public Service Company (NIPSCO), which supplies electricity and gas to the northern third of Indiana. Customers: 488,833 electric in Indiana, 3,200,000 gas in Indiana, Ohio, Pennsylvania, Kentucky, Virginia, Maryland, through its Columbia subsidiaries. Revenue breakdown, 2024: electrical, 32%; gas, 67%; other, less than 1%. Generating capacity, coal, 69.4%; purchased & other, 30.6%. 2022 reported depreciation rates: 3.5% electric, 2.4% gas. Has 7,364 employees. Chairman: Richard L. Thompson. President & Chief Executive Officer: Lloyd Yates. Incorporated: Indiana. Address: 801 East 86th Avenue, Merrillville, Indiana 46410. Telephone: 877-647-5990. Internet: www.nisource.com.

NiSource had a strong earnings performance in the first quarter of 2024. The company continued its streak of consecutive quarterly growth by posting earnings of $0.85 per share, a 10% increase from the previous year. While this matched our target, the metric shows an outperformance considering the significant expansion of the number of diluted shares outstanding in the quarter, which we did not anticipate. The shares were likely issued in response to a large portion of debt that came due in the quarter, reflecting the utility's challenge of financing in the current high interest-rate environment. Still, investment is critical for the company's growth. Fortunately, the utility enjoys a strong regulatory environment across its geographies in Indiana, Ohio, Pennsylvania and Virginia, which together contributed to a rate-base of $18.8 billion at the end of 2023.

Our near-term earnings targets remain unchanged at the current juncture. Year-end earnings per share of $1.70 is likely, due to our anticipation of rate-base growth of roughly 8%-10%. The company has plans for significant capital expansion, including $16.4 billion aimed at enhancing system reliability and the transition to more sustainable energy sources. NiSource's track record for efficient capital allocation has led to consistent regulatory execution and affordable energy for its customers, supporting a low operating-risk profile. Too, tailwinds from sustainable investments, such as solar projects and infrastructure hardening, are likely to synergize with trends within the mid-west, such as the reshoring of manufacturing and the increasing development of data centers within its operating footprint. Economic conditions permitting, we anticipate steady earnings growth through to late decade.

Our stock projections reflect NiSource's strong prospects. Despite a strong return of more than 12% over the past three months, these good quality shares still reflect appealing value to the risk-sensitive accounts. The stock's high marks for Price Stability (95) pair well with it's above-average dividend yield of 3.8% to create a strong offering to income-style conservative investors.

Earl B. Humes *May 24, 2024*

(A) Dil. EPS. Excl. gains (losses) on disc. ops.: '08, ($1.14); '15, (30¢); '18, ($1.48). Next egs. report due early August. Qtl'y egs. may not sum to total due to rounding.
(B) Div'ds historically paid in mid-Feb., May, Aug., Nov. ■ Div'd reinv. avail.
(C) Incl. intang in '23: $1485.9 million, $3.33/sh.
(D) In mill.
(E) Spun off Columbia Pipeline Group (7/15)

Company's Financial Strength	B++
Stock's Price Stability	95
Price Growth Persistence	20
Earnings Predictability	60

N.W. NATURAL NYSE-NWN

RECENT PRICE 38.48 | P/E RATIO 15.4 (Trailing: 16.9 Median: 24.0) | RELATIVE P/E RATIO 0.85 | DIV'D YLD 5.1% | VALUE LINE

TIMELINESS 3 Raised 3/22/24
SAFETY 2 Raised 2/23/24
TECHNICAL 4 Raised 5/17/24
BETA .85 (1.00 = Market)

	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024
High:	46.6	52.6	52.3	66.2	69.5	71.8	74.1	77.3	56.8	57.6	52.4	40.3
Low:	40.0	40.1	42.0	48.9	56.5	51.5	57.2	42.3	41.7	42.4	35.7	34.9

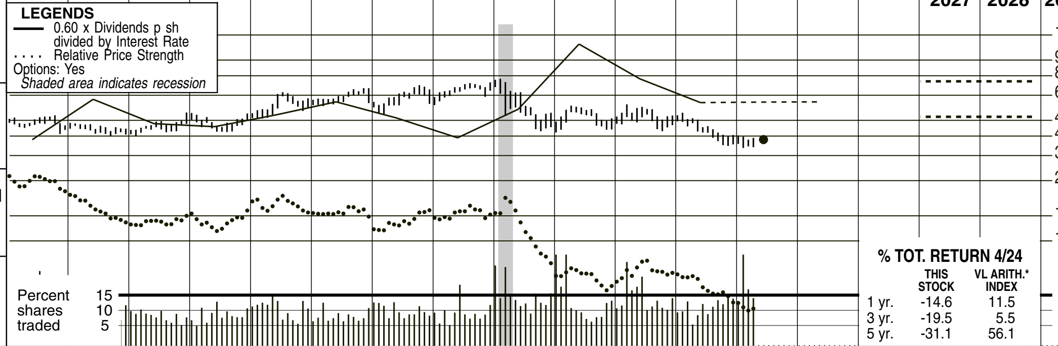
18-Month Target Price Range
Low-High $33-$54 | Midpoint (% to Mid) $44 (15%)

2027-29 PROJECTIONS

	Price	Gain	Ann'l Total Return
High	75	(+95%)	22%
Low	50	(+30%)	11%

Institutional Decisions

	2Q2023	3Q2023	4Q2023
to Buy	122	115	123
to Sell	123	110	90
Hld's(000)	26926	27474	28414



Target Price Range 2027 | 2028 | 2029

% TOT. RETURN 4/24

	THIS STOCK	VL ARITH.* INDEX
1 yr.	-14.6	11.5
3 yr.	-19.5	5.5
5 yr.	-31.1	56.1

2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	© VALUE LINE PUB. LLC	27-29
39.16	38.17	30.56	31.72	27.14	28.02	27.64	26.39	23.61	26.52	24.45	24.49	25.29	27.64	29.20	31.82	*29.50*	*29.25*	Revenues per sh	*31.25*
5.31	5.20	5.18	5.00	4.94	5.04	5.05	4.91	4.93	1.04	5.28	5.15	5.69	6.17	5.71	5.83	*5.85*	*6.65*	"Cash Flow" per sh	*7.20*
2.57	2.83	2.73	2.39	2.22	2.24	2.16	1.96	2.12	d1.94	2.33	2.19	2.30	2.56	2.54	2.59	*2.50*	*3.00*	Earnings per sh A	*3.20*
1.52	1.60	1.68	1.75	1.79	1.83	1.85	1.86	1.87	1.88	1.89	1.90	1.91	1.92	1.93	1.94	*1.95*	*1.96*	Div'ds Decl'd per sh B■	*1.98*
3.92	5.09	9.35	3.76	4.91	5.13	4.40	4.37	4.87	7.43	7.43	7.95	9.18	9.49	9.53	8.70	*9.25*	*9.50*	Cap'l Spending per sh	*10.00*
23.71	24.88	26.08	26.70	27.23	27.77	28.12	28.47	29.71	25.85	26.41	28.42	29.05	30.04	33.08	34.12	*36.55*	*36.60*	Book Value per sh D	*36.10*
26.50	26.53	26.58	26.76	26.92	27.08	27.28	27.43	28.63	28.74	28.88	30.47	30.59	31.13	35.53	37.63	*39.00*	*41.00*	Common Shs Outst'g C	*45.00*
18.1	15.2	17.0	19.0	21.1	19.4	20.7	23.7	26.9	- -	26.6	30.9	25.0	19.5	19.6	16.6	Bold figures are		Avg Ann'l P/E Ratio	*20.0*
1.09	1.01	1.08	1.19	1.34	1.09	1.09	1.19	1.41	- -	1.44	1.65	1.28	1.06	1.13	.96	Value Line		Relative P/E Ratio	*1.10*
3.3%	3.7%	3.6%	3.9%	3.8%	4.2%	4.1%	4.0%	3.3%	3.0%	3.0%	2.8%	3.3%	3.8%	3.9%	4.5%	estimates		Avg Ann'l Div'd Yield	*3.3%*

CAPITAL STRUCTURE as of 3/31/24
Total Debt $1670.3 mill. **Due in 5 Yrs** $1415 mill.
LT Debt $1574.7 mill. **LT Interest** $80 mill.

(Total interest coverage: 5.0x)

Pension Assets-12/23 $283.0 mill.
Oblig. $425.5 mill.

Pfd Stock None

Common Stock 38,028,137 shares as of 4/26/24

MARKET CAP $1.5 billion (Small Cap)

2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025		27-29
754.0	723.8	676.0	762.2	706.1	746.4	773.7	860.4	1037.4	1197.5	*1150*	*1200*	Revenues ($mill)	*1400*
58.7	53.7	58.9	d55.6	67.3	65.3	70.3	78.7	86.3	93.9	*97.5*	*125*	Net Profit ($mill)	*145*
41.5%	40.0%	40.9%	- -	26.4%	16.2%	23.1%	25.8%	25.2%	25.7%	*25.0%*	*25.0%*	Income Tax Rate	*25.0%*
7.8%	7.4%	8.7%	NMF	9.5%	8.8%	9.1%	9.1%	8.3%	7.8%	*8.5%*	*10.3%*	Net Profit Margin	*10.2%*
44.8%	42.5%	44.4%	47.9%	48.1%	48.2%	49.2%	52.8%	51.5%	52.6%	*50.0%*	*50.0%*	Long-Term Debt Ratio	*50.0%*
55.2%	57.5%	55.6%	52.1%	51.9%	51.8%	50.8%	47.2%	48.5%	47.4%	*50.0%*	*50.0%*	Common Equity Ratio	*50.0%*
1389.0	1357.7	1529.8	1426.0	1468.9	1672.0	1748.8	1979.7	2421.6	2709.2	*2850*	*3000*	Total Capital ($mill)	*3250*
2121.6	2182.7	2260.9	2255.0	2421.4	2438.9	2654.8	2871.4	3114.4	3358.0	*3500*	*3675*	Net Plant ($mill)	*3900*
5.8%	5.5%	5.1%	NMF	5.8%	5.2%	5.2%	5.1%	3.6%	3.5%	*3.5%*	*4.0%*	Return on Total Cap'l	*4.5%*
7.6%	6.9%	6.9%	NMF	8.8%	7.5%	7.9%	8.4%	7.3%	7.3%	*7.0%*	*8.0%*	Return on Shr. Equity	*9.0%*
7.6%	6.9%	6.9%	NMF	8.8%	7.5%	7.9%	8.4%	7.3%	7.3%	*7.0%*	*8.0%*	Return on Com Equity	*9.0%*
1.1%	.6%	.9%	NMF	2.1%	1.4%	1.7%	2.4%	2.1%	1.7%	*1.5%*	*3.0%*	Retained to Com Eq	*3.5%*
85%	92%	87%	NMF	76%	82%	79%	71%	79%	75%	*78%*	*65%*	All Div'ds to Net Prof	*62%*

CURRENT POSITION ($MILL.)	2022	2023	3/31/24
Cash Assets	29.3	32.9	72.4
Other	714.9	568.5	465.3
Current Assets	744.2	601.4	537.7
Accts Payable	180.7	145.4	107.9
Debt Due	348.9	240.7	95.6
Other	369.1	310.8	264.8
Current Liab.	898.7	696.9	468.3
Fix. Chg. Cov.	320%	240%	535%

ANNUAL RATES of change (per sh)	Past 10 Yrs.	Past 5 Yrs.	Est'd '21-'23 to '27-'29
Revenues	-2.5%	- -	*4.5%*
"Cash Flow"	1.0%	2.5%	*5.0%*
Earnings	-1.0%	2.5%	*6.5%*
Dividends	1.5%	.5%	*.5%*
Book Value	1.0%	.5%	*4.0%*

Cal-endar	QUARTERLY REVENUES ($ mill.) Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2021	315.9	148.9	101.5	294.1	860.4
2022	350.3	195.0	116.8	375.3	1037.4
2023	462.4	237.9	141.5	355.7	1197.5
2024	433.5	*220*	*130*	*366.5*	*1150*
2025	*450*	*230*	*135*	*385*	*1200*

Cal-endar	EARNINGS PER SHARE A Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2021	1.94	d.02	d.67	1.31	2.56
2022	1.80	.05	d.56	1.36	2.54
2023	2.01	.03	d.65	1.21	2.59
2024	1.69	*.05*	*d.65*	*1.41*	*2.50*
2025	*2.10*	*.05*	*d.60*	*1.45*	*3.00*

Cal-endar	QUARTERLY DIVIDENDS PAID B ■ Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2020	.4775	.4775	.4775	.48	1.91
2021	.48	.48	.48	.483	1.92
2022	.483	.483	.483	.485	1.93
2023	.485	.485	.485	.488	1.94
2024	.488	.488			

BUSINESS: Northwest Natural Holding Co. distributes natural gas to 1,000 communities, 795,000 customers, in Oregon (88% of customers) and in southwest Washington state. Principal cities served: Portland and Eugene, OR; Vancouver, WA. Service area population: 3.7 mill. (77% in OR). Company buys gas supply from Canadian and U.S. producers; has transportation rights on Northwest Pipeline system. Owns local underground storage. Rev. breakdown: residential, 38%; commercial, 23%; industrial, gas transportation, 39%. Employs 1,380. BlackRock Inc. owns 17.6% of shares; Vanguard, 12.4%; Off./Dir., .84% (4/24 proxy). CEO: David H. Anderson. Inc.: Oregon. Address: 220 NW 2nd Ave., Portland, OR 97209. Tel.: 503-226-4211. Internet: www.nwnatural.com.

Northwest Natural Holdings continues to face challenging earnings comparisons. The northwestern natural gas utility saw its earnings decrease year-over-year for the fourth consecutive quarter in the March period to start 2024. Earnings per share in the company's cyclical-peak season amounted to $1.69, well below our target for a flat performance versus the year-prior's $2.01 result. The downturn in performance was primarily due to regulatory lag effects on its capital investments and rising cost pressures resulting in higher pension, depreciation, and interest expenses. Despite this, strengths such as a 1.7% growth in its customer base, low regional unemployment, and a peak-day delivery record of 8 million thermal units, paint an backdrop of strong demand. However, we expect that cost-of-living concerns across its operating footprint have led regulators to scrutinize the company's filings and tighten up on the rate-base regulatory approval process, hampering results of late.

We've cut our near-term earnings target to reflect the likelihood of continued regulatory challenges. While underlying operations should continue to grow steadily based on demographic trends, profitability leading into the cyclical-low season is likely to underwhelm. Instead, the company is refocusing its efforts on infrastructure hardening, including a planned $82 million investment that is slated for the current year as part of its rate case filings. We expect a relief in the final stanza of the year with rate adjustments likely to be resolved by November.

The long-term outlook here is more nuanced. Northwest is positioned in a strong geographic market that is undergoing a heavy investment cycle into clean-energy and energy-efficiency initiatives that ought to provide ample tailwinds to late decade. However, we also note some potential risks as both wildfires and seismic events have the potential to cause impairment to the company's infrastructure.

These good quality shares offer solid return potential and an above average dividend. The stock is a strong pick for conservative accounts, due to its Price Stability (85) and Financial Strength (A).

Earl B. Humes *May 24, 2024*

(A) Diluted earnings per share. Excludes nonrecurring items: '08, ($0.03); '09, $0.06; May not sum due to rounding. Next earnings report due in early August.
(B) Dividends historically paid in mid-February, May, August, and November.
■ Dividend reinvestment plan available.
(C) In millions.
(D) Includes intangibles. In 2023: $163 million, $4.33/share.

Company's Financial Strength	A
Stock's Price Stability	85
Price Growth Persistence	25
Earnings Predictability	15

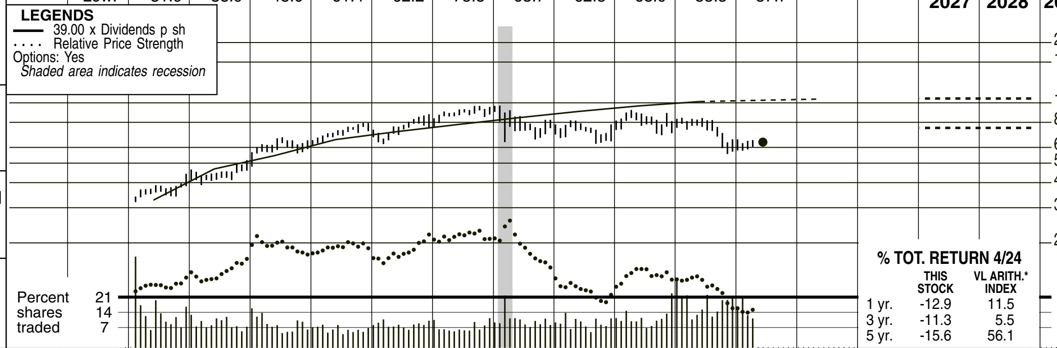
ONE GAS, INC. NYSE-OGS

RECENT PRICE 63.81 | P/E RATIO 16.0 (Trailing: 15.8 Median: 21.0) | RELATIVE P/E RATIO 0.88 | DIV'D YLD 4.2% | VALUE LINE

TIMELINESS 3 Raised 12/8/23
SAFETY 2 New 6/2/17
TECHNICAL 3 Raised 5/24/24
BETA .85 (1.00 = Market)

	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024
High:	44.3	51.8	67.4	79.5	87.8	96.7	97.0	81.9	92.3	84.3	66.5
Low:	31.9	38.9	48.0	61.4	62.2	75.8	63.7	62.5	68.9	55.5	57.7

Target Price Range
2027 | 2028 | 2029



18-Month Target Price Range

Low-High	Midpoint (% to Mid)
$42-$77	$60 (-5%)

2027-29 PROJECTIONS

	Price	Gain	Ann'l Total Return
High	105	(+65%)	16%
Low	75	(+20%)	8%

Institutional Decisions

	2Q2023	3Q2023	4Q2023
to Buy	158	148	159
to Sell	133	153	160
Hld's(000)	53044	51074	52932

% TOT. RETURN 4/24

	THIS STOCK	VL ARITH.* INDEX
1 yr.	-12.9	11.5
3 yr.	-11.3	5.5
5 yr.	-15.6	56.1

The shares of ONE Gas, Inc. began trading "regular-way" on the New York Stock Exchange on February 3, 2014. That happened as a result of the separation of ONEOK's natural gas distribution operation. Regarding the details of the spinoff, on January 31, 2014, ONEOK distributed one share of OGS common stock for every four shares of ONEOK common stock held by ONEOK shareholders of record as of the close of business on January 21. It should be mentioned that ONEOK did not retain any ownership interest in the new company.

2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	© VALUE LINE PUB. LLC	27-29
34.92	29.62	27.30	29.43	31.08	31.32	28.78	33.72	46.58	41.95	*39.30*	*42.50*	Revenues per sh	*70.15*
4.52	4.82	5.43	5.96	6.32	6.96	7.36	7.71	8.13	9.04	*9.65*	*10.70*	"Cash Flow" per sh	*13.95*
2.07	2.24	2.65	3.02	3.25	3.51	3.68	3.85	4.08	4.14	*4.00*	*4.20*	Earnings per sh A	*5.00*
.84	1.20	1.40	1.68	1.84	2.00	2.16	2.32	2.48	2.60	*2.64*	*2.68*	Div'ds Decl'd per sh B■	*2.85*
5.70	5.63	5.91	6.81	7.50	7.91	8.87	9.23	11.01	11.79	*11.95*	*12.15*	Cap'l Spending per sh	*12.60*
34.45	35.24	36.12	37.47	38.86	40.35	42.01	43.81	46.69	48.91	*50.15*	*53.55*	Book Value per sh	*60.20*
52.08	52.26	52.28	52.31	52.57	52.77	53.17	53.63	55.35	56.55	*56.50*	*56.50*	Common Shs Outst'g C	*57.00*
17.8	19.8	22.7	23.5	23.1	25.3	21.7	18.9	19.9	18.0	*Bold figures are*		Avg Ann'l P/E Ratio	*18.0*
.94	1.00	1.19	1.18	1.25	1.35	1.11	1.02	1.16	1.01	*Value Line*		Relative P/E Ratio	*1.00*
2.3%	2.7%	2.3%	2.4%	2.5%	2.3%	2.7%	3.2%	3.1%	3.5%	*estimates*		Avg Ann'l Div'd Yield	*3.2%*
1818.9	1547.7	1427.2	1539.6	1633.7	1652.7	1530.3	1808.6	2578.0	2372.0	*2220*	*2400*	Revenues ($mill)	*4000*
109.8	119.0	140.1	159.9	172.2	186.7	196.4	206.4	221.7	231.2	*225*	*235*	Net Profit ($mill)	*285*
38.4%	38.0%	37.8%	36.4%	23.7%	18.7%	17.5%	16.3%	17.3%	14.9%	*15.5%*	*16.0%*	Income Tax Rate	*20.0%*
6.0%	7.7%	9.8%	10.4%	10.5%	11.3%	12.8%	11.4%	8.6%	9.7%	*10.1%*	*9.8%*	Net Profit Margin	*7.1%*
40.1%	39.5%	38.7%	37.8%	38.6%	37.7%	41.5%	61.1%	50.7%	43.8%	*45.0%*	*45.0%*	Long-Term Debt Ratio	*51.0%*
59.9%	60.5%	61.3%	62.2%	61.4%	62.3%	58.5%	38.9%	49.3%	56.2%	*55.0%*	*55.0%*	Common Equity Ratio	*49.0%*
2995.3	3042.9	3080.7	3153.5	3328.1	3415.5	3815.7	6032.9	5246.2	4926.3	*5150*	*5500*	Total Capital ($mill)	*7000*
3293.7	3511.9	3731.6	4007.6	4283.7	4565.2	4867.1	5190.8	5628.8	6135.2	*6425*	*6800*	Net Plant ($mill)	*8000*
4.4%	4.7%	5.2%	5.8%	5.9%	6.4%	6.0%	3.9%	5.0%	5.9%	*5.5%*	*5.5%*	Return on Total Cap'l	*5.5%*
6.1%	6.5%	7.4%	8.2%	8.4%	8.8%	8.8%	8.8%	8.6%	8.4%	*8.0%*	*8.0%*	Return on Shr. Equity	*8.5%*
6.1%	6.5%	7.4%	8.2%	8.4%	8.8%	8.8%	8.8%	8.6%	8.4%	*8.0%*	*8.0%*	Return on Com Equity	*8.5%*
3.7%	3.1%	3.5%	3.7%	3.7%	3.8%	3.7%	3.5%	3.4%	3.2%	*3.0%*	*3.0%*	Retained to Com Eq	*3.5%*
40%	53%	52%	55%	56%	56%	58%	60%	60%	62%	*66%*	*64%*	All Div'ds to Net Prof	*57%*

CAPITAL STRUCTURE as of 3/31/24
Total Debt $3128.0 mill. **Due in 5 Yrs** $890.0 mill.
LT Debt $2146.4 mill. **LT Interest** $120.0 mill.
(LT interest earned: 3.4x; total interest coverage: 3.4x)
Leases, Uncapitalized Annual rentals $6.7 mill.
Pfd Stock None
Pension Assets-12/23 $977.0 mill.
Oblig. $962.1 mill.
Common Stock 56,569,396 shs.
as of 4/29/24
MARKET CAP: $3.6 billion (Mid Cap)

CURRENT POSITION ($MILL.)	2022	2023	3/31/24
Cash Assets	9.7	18.8	11.5
Other	1207.9	746.4	652.2
Current Assets	1217.6	765.2	663.7
Accts Payable	360.5	278.1	196.6
Debt Due	572.7	888.9	981.6
Other	256.2	310.2	225.3
Current Liab.	1189.4	1477.2	1403.5
Fix. Chg. Cov.	540%	390%	420%

ANNUAL RATES of change (per sh)	Past 10 Yrs.	Past 5 Yrs.	Est'd '21-'23 to '27-'29
Revenues	- -	7.0%	*9.5%*
"Cash Flow"	- -	7.0%	*9.0%*
Earnings	- -	6.0%	*3.5%*
Dividends	- -	8.5%	*2.5%*
Book Value	- -	4.5%	*4.5%*

Cal-endar	QUARTERLY REVENUES ($ mill.) Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2021	625.3	315.6	273.9	593.8	1808.6
2022	971.5	428.9	359.4	818.2	2578.0
2023	1032.1	398.1	335.8	606.0	2372.0
2024	758.3	*410*	*350*	*701.7*	*2220*
2025	*800*	*430*	*410*	*760*	*2400*

Cal-endar	EARNINGS PER SHARE A Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2021	1.79	.56	.38	1.12	3.85
2022	1.83	.59	.44	1.23	4.08
2023	1.84	.58	.45	1.27	4.14
2024	1.75	*.56*	*.43*	*1.26*	*4.00*
2025	*1.85*	*.60*	*.48*	*1.27*	*4.20*

Cal-endar	QUARTERLY DIVIDENDS PAID B■ Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2020	.54	.54	.54	.54	2.16
2021	.58	.58	.58	.58	2.32
2022	.62	.62	.62	.62	2.48
2023	.65	.65	.65	.65	2.60
2024	.66	.66			

BUSINESS: ONE Gas, Inc. provides natural gas distribution services to more than two million customers. There are three divisions: Oklahoma Natural Gas, Kansas Gas Service, and Texas Gas Service. The company purchased 160 Bcf of natural gas supply in 2023, compared to 165 Bcf in 2022. Total volumes delivered by customer (fiscal 2023): transportation, 59.3%; residential, 29.7%; commercial & industrial, 10.6%; other, .4%. ONE Gas has around 3,900 employees. BlackRock owns 14.5% of common stock; The Vanguard Group, 11.6%; American Century Investment, 7.5%; officers and directors, 1.5% (4/24 Proxy). CEO: Robert S. McAnnally. Incorporated: Oklahoma. Address: 15 East Fifth Street, Tulsa, Oklahoma 74103. Tel.: 918-947-7000. Internet: www.onegas.com.

ONE Gas, Inc. began 2024 in low gear. First-quarter earnings per share slipped about 5%, to $1.75, relative to last year's $1.84 figure. That was traced partly to higher employee-related costs, given planned investments in the company's workforce and ongoing in-sourcing efforts. Also, sales volumes decreased and interest expense rose. But new rates did provide somewhat of an offset. Still, right now, it appears that the bottom line will recede around 3% for the whole year, to $4.00 per share, versus the $4.14 tally generated in 2023. But turning to 2025, a 5% recovery, to $4.20 a share, seems plausible. That's based, to a certain degree, on our assumption that the business environment is generally favorable.

Prospects out to the end of the decade appear promising. ONE Gas remains the top natural gas distributor, as measured by number of customers, in both Oklahoma and Kansas, and holds the number-three position in Texas. (Services are provided to more than two million residential, commercial, and transportation clients at present.) Furthermore, we believe those markets have decent growth potential and are located in one of the most active drilling areas in the United States. Also, supported by the solid balance sheet, the company ought to continue to meet its working capital requirements, capital expenditures, and other obligations with little difficulty.

There are risk factors to bear in mind, however. ONE Gas' lack of geographic diversification leaves it somewhat more susceptible to regional economic downturns and regulations. Moreover, there's competition from other energy suppliers, including propane dealers and electric companies. Finally, pipeline ruptures, leaks, and other unfortunate occurrences can take a major toll on corporate profits if not adequately covered by insurance.

The stock has some investment appeal. Its dividend yield is respectable in comparison with other equities within *Value Line's* Natural Gas Utility Industry. Also, capital appreciation possibilities over the 2027-2029 horizon look worthwhile. Consider, too, the 2 (Above Average) rank for Safety and high Price Stability score of 90 out of 100.

Frederick L. Harris, III *May 24, 2024*

(A) Diluted EPS. Excludes nonrecurring gain: 2017, $0.06. Next earnings report due early Aug. Quarterly EPS figures for 2022 don't equal total due to rounding.
(B) Dividends historically paid in early March, June, Sept., and Dec. ■ Dividend reinvestment plan. Direct stock purchase plan.
(C) In millions.

Company's Financial Strength	B++
Stock's Price Stability	90
Price Growth Persistence	50
Earnings Predictability	100

SPIRE INC. NYSE-SR

RECENT PRICE 62.20 | P/E RATIO 14.5 (Trailing: 15.7 Median: 19.0) | RELATIVE P/E RATIO 0.80 | DIV'D YLD 5.0% | VALUE LINE

TIMELINESS 3 Raised 2/16/24
SAFETY 2 Raised 6/20/03
TECHNICAL 4 Raised 5/17/24
BETA .85 (1.00 = Market)

18-Month Target Price Range
Low-High Midpoint (% to Mid)
$44-$72 $58 (-5%)

2027-29 PROJECTIONS

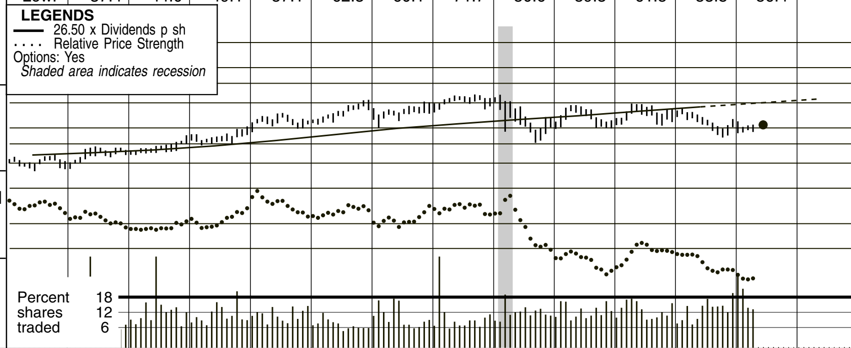
	Price	Gain	Ann'l Total Return
High	100	(+60%)	16%
Low	75	(+20%)	10%

Institutional Decisions

	2Q2023	3Q2023	4Q2023
to Buy	142	131	140
to Sell	138	144	123
Hld's(000)	46098	48374	48459

High:	48.5	55.2	61.0	71.2	82.9	81.1	88.0	88.0	77.9	79.2	75.8	64.6
Low:	37.4	44.0	49.1	57.1	62.3	60.1	71.7	50.6	59.3	61.5	53.8	56.4

LEGENDS
—— 26.50 x Dividends p sh
.... Relative Price Strength
Options: Yes
Shaded area indicates recession



Percent shares traded 18 12 6

Target Price Range
2027 | 2028 | 2029
160 120 100 80 60 50 40 30 20 15

% TOT. RETURN 4/24

	THIS STOCK	VL ARITH.* INDEX
1 yr.	-4.4	11.5
3 yr.	-6.9	5.5
5 yr.	-10.8	56.1

2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	© VALUE LINE PUB. LLC	27-29
100.44	85.49	77.83	71.48	49.90	31.10	37.68	45.59	33.68	36.07	38.78	38.30	35.96	43.24	41.88	50.12	45.20	45.65	Revenues per sh A	57.25
4.22	4.56	4.11	4.62	4.58	3.12	3.87	6.15	6.16	6.54	7.55	7.12	5.25	9.09	8.44	8.60	8.80	9.25	"Cash Flow" per sh	11.00
2.64	2.92	2.43	2.86	2.79	2.02	2.35	3.16	3.24	3.43	4.33	3.52	1.44	4.96	3.95	3.85	4.30	4.55	Earnings per sh A B	5.50
1.49	1.53	1.57	1.61	1.66	1.70	1.76	1.84	1.96	2.10	2.25	2.37	2.49	2.60	2.74	2.88	3.02	3.16	Div'ds Decl'd per sh C■	3.60
2.57	2.36	2.56	3.02	4.83	4.00	3.96	6.68	6.42	9.08	9.86	16.15	12.37	12.09	10.52	12.45	13.70	13.90	Cap'l Spending per sh	14.50
22.12	23.32	24.02	25.56	26.67	32.00	34.93	36.30	38.73	41.26	44.51	45.14	44.19	46.74	49.08	50.29	52.65	55.75	Book Value per sh D	66.05
21.99	22.17	22.29	22.43	22.55	32.70	43.18	43.36	45.65	48.26	50.67	50.97	51.60	51.70	52.50	53.20	58.50	60.00	Common Shs Outst'g E	62.00
14.3	13.4	13.7	13.0	14.5	21.3	19.8	16.5	19.6	19.8	16.7	22.8	51.1	13.6	17.5	17.3	Bold figures are		Avg Ann'l P/E Ratio	16.0
.86	.89	.87	.82	.92	1.20	1.04	.83	1.03	1.00	.90	1.21	2.62	.73	1.01	1.00	Value Line		Relative P/E Ratio	.90
3.9%	3.9%	4.7%	4.3%	4.1%	4.0%	3.8%	3.5%	3.1%	3.1%	3.1%	3.0%	3.4%	3.8%	4.0%	4.3%	estimates		Avg Ann'l Div'd Yield	4.1%

CAPITAL STRUCTURE as of 3/31/24
Total Debt $4514.4 mill. **Due in 5 Yrs**$2310.0 mill.
LT Debt $3421.4 mill. **LT Interest** $140.0 mill.
(Total interest coverage: 2.4x)

Leases, Uncapitalized Annual rentals $9.8 mill.
Pension Assets-9/23 $630.3 mill.
Oblig. $832.5 mill.
Pfd Stock $242.0 mill. **Pfd Div'd** $14.8 mill.
Common Stock 57,747,978 shs.
as of 4/28/24

MARKET CAP: $3.6 billion (Mid Cap)

2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025		27-29
1627.2	1976.4	1537.3	1740.7	1965.0	1952.4	1855.4	2235.5	2198.5	2666.3	2645	2740	Revenues ($mill) A	3550
84.6	136.9	144.2	161.6	214.2	184.6	88.6	271.7	220.8	217.5	240	260	Net Profit ($mill)	340
27.6%	31.2%	32.5%	32.4%	- -	15.7%	12.3%	20.1%	21.1%	15.1%	19.5%	19.5%	Income Tax Rate	24.0%
5.2%	6.9%	9.4%	9.3%	10.9%	9.5%	4.8%	12.2%	10.0%	8.2%	9.1%	9.5%	Net Profit Margin	9.6%
55.1%	53.0%	50.9%	50.0%	45.7%	45.0%	49.0%	52.5%	51.2%	54.9%	52.0%	52.0%	Long-Term Debt Ratio	51.0%
44.9%	47.0%	49.1%	50.0%	54.3%	49.7%	46.1%	43.2%	44.6%	41.3%	44.0%	44.0%	Common Equity Ratio	45.0%
3359.4	3345.1	3601.9	3986.3	4155.5	4625.6	4946.0	5597.3	5777.0	6471.3	7000	7600	Total Capital ($mill)	9100
2759.7	2941.2	3300.9	3665.2	3970.5	4352.0	4680.1	5055.7	5370.4	5778.9	6150	6530	Net Plant ($mill)	7675
3.1%	5.1%	4.9%	5.0%	6.3%	5.1%	2.9%	5.8%	4.9%	4.8%	5.0%	5.0%	Return on Total Cap'l	5.5%
5.6%	8.7%	8.2%	8.1%	9.5%	7.3%	3.5%	10.2%	7.8%	7.5%	8.0%	8.0%	Return on Shr. Equity	8.5%
5.6%	8.7%	8.2%	8.1%	9.5%	7.9%	3.2%	10.6%	8.0%	7.6%	8.0%	8.0%	Return on Com Equity	8.5%
1.5%	3.7%	3.3%	3.3%	4.7%	2.7%	NMF	5.1%	2.5%	1.9%	2.0%	1.5%	Retained to Com Eq	2.5%
73%	58%	59%	60%	51%	66%	NMF	54%	71%	76%	77%	79%	All Div'ds to Net Prof	70%

CURRENT POSITION ($MILL.)	2022	2023	3/31/24
Cash Assets	6.5	5.6	25.6
Other	1585.5	1071.3	980.1
Current Assets	1592.0	1076.9	1005.7
Accts Payable	617.4	253.1	193.4
Debt Due	1318.7	1112.1	1093.0
Other	417.5	390.2	363.9
Current Liab.	2353.6	1755.4	1650.3
Fix. Chg. Cov.	393%	294%	315%

ANNUAL RATES of change (per sh)	Past 10 Yrs.	Past 5 Yrs.	Est'd '21-'23 to '27-'29
Revenues	-1.0%	4.5%	4.0%
"Cash Flow"	8.0%	5.0%	4.0%
Earnings	5.0%	3.0%	4.5%
Dividends	5.0%	5.5%	4.5%
Book Value	5.5%	3.5%	5.5%

Fiscal Year Ends	QUARTERLY REVENUES ($ mill.)A Dec.31	Mar.31	Jun.30	Sep.30	Full Fiscal Year
2021	512.6	1104.9	327.8	290.2	2235.5
2022	555.4	880.9	448.0	314.2	2198.5
2023	814.0	1123.4	418.5	310.4	2666.3
2024	756.6	1128.5	434.9	325	2645
2025	790	1135	465	350	2740

Fiscal Year Ends	EARNINGS PER SHARE A B F Dec.31	Mar.31	Jun.30	Sep.30	Full Fiscal Year
2021	1.65	3.55	.03	d.26	4.96
2022	1.01	3.27	d.10	d.20	3.95
2023	1.66	3.33	d.48	d.66	3.85
2024	1.52	3.58	d.34	d.46	4.30
2025	1.50	3.45	d.16	d.24	4.55

Cal-endar	QUARTERLY DIVIDENDS PAID C■ Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2020	.6225	.6225	.6225	.6225	2.49
2021	.65	.65	.65	.65	2.60
2022	.685	.685	.685	.685	2.74
2023	.72	.72	.72	.72	2.88
2024	.755	.755			

BUSINESS: Spire Inc., formerly known as the Laclede Group, Inc., is a holding company for natural gas utilities, which distributes natural gas across Missouri, including the cities of St. Louis and Kansas City, Alabama, and Mississippi. Has roughly 1.7 million customers. Acquired Missouri Gas 9/13, Alabama Gas Co 9/14. Utility therms sold and transported in fiscal 2023: 3.2 bill. Revenue mix for regulated operations: residential, 67%; commercial and industrial, 25%; transportation, 5%; other, 3%. Officers and directors own 2.9% of common shares; American Century Companies, 15.4% (12/23 proxy). Chairman: Edward Glotzbach; CEO: Steve Lindsey. Inc.: Missouri. Address: 700 Market Street, St. Louis, Missouri 63101. Tel.: 314-342-0500. Internet: www.spireenergy.com.

Spire managed to post decent bottom-line results in the second quarter of fiscal 2024 (which concluded on March 31st). Indeed, earnings per share of $3.58 were 7.5% above the previous year's $3.33 tally. That was brought about, to a certain extent, by the Gas Utility division, which benefited partly from improved results at Spire Alabama. The Gas Marketing segment had a better showing for that period, too.

Higher profits appear to be in store for the year as a whole, as well. The company did get off to a slow start, with first-quarter share net receding 8.4%, to $1.52, relative to last year's $1.66 figure. That was attributed partly to the fact that, for both the Gas Marketing and Midstream divisions, fiscal 2023's very favorable market conditions did not reoccur. But, as mentioned, Spire's second-quarter performance was decent. Furthermore, bottom-line comparisons during the second half ought to be easier. (Losses are typical over that time frame because of the seasonality of the business.) All told, we expect full-year share net to rebound about 12%, to $4.30, versus fiscal 2023's $3.85 result. Concerning next year, profits might increase another 6% or so, to $4.55 a share, assuming additional widening of operating margins.

The Financial Strength rating sits at B++. When the second quarter ended, cash and equivalents were $25.6 million. Furthermore, there was $1.3 billion available through a revolving credit facility expiring in July, 2027. Also, long-term debt resided at a manageable 50% of total capital, and short-term obligations of almost $1.1 billion did not seem to be a major obstacle. So, the company should continue to satisfy its commitments, which include working capital requirements and capital expenditures, with minimal difficulty.

The equity ought to draw the attention of some investors. Its dividend yield stacks up well compared to those of other stocks in *Value Line's* Natural Gas Utility Industry. What's more, capital appreciation potential over the 2027-2029 horizon looks worthwhile. Meanwhile, SR shares are pegged to mimic the market over the next six to 12 months (Timeliness rank 3: Average).

Frederick L. Harris, III *May 24, 2024*

(A) Fiscal year ends Sept. 30th. **(B)** Based on diluted shares outstanding. Excludes gain from discontinued operations: '08, 94¢. Next earnings report due late July. **(C)** Dividends paid in early January, April, July, and October. ■ Dividend reinvestment plan available. **(D)** Incl. deferred charges. In '23: $1,171.6 mill., $22.02/sh. **(E)** In millions. **(F)** Qtly. egs. may not sum due to rounding or change in shares outstanding.

Company's Financial Strength	B++
Stock's Price Stability	90
Price Growth Persistence	35
Earnings Predictability	45

Summit Natural Gas of Arkansas
Indicated Common Equity Cost Rate
Through Use of a Risk Premium Model
Using an Adjusted Total Market Approach

Line No.		Proxy Group of Six Natural Gas Companies
1.	Prospective Yield on Aaa Rated Corporate Bonds (1)	5.09 %
2.	Adjustment to Reflect Yield Spread Between Aaa Rated Corporate Bonds and A2 Rated Public Utility Bonds (2)	0.49
3.	Adjusted Prospective Yield on A2 Rated Public Utility Bonds	5.58 %
4.	Equity Risk Premium (3)	5.40
5.	Risk Premium Derived Common Equity Cost Rate	10.98 %

Notes: (1) Consensus forecast of Moody's Aaa Rated Corporate bonds from Blue Chip Financial Forecasts (see pages 20 and 21 of this Schedule).

(2) The average yield spread of A2 rated public utility bonds over Aaa rated corporate bonds of 0.49% from page 14 of this Schedule.

(3) From page 17 of this Schedule.

Summit Natural Gas of Arkansas
Interest Rates and Bond Spreads for
Moody's Corporate and Public Utility Bonds

Selected Bond Yields

	[1] Aaa Rated Corporate Bond	[2] A2 Rated Public Utility Bond	[3] Baa2 Rated Public Utility Bond
Jun-2024	5.13 %	5.61 %	5.84 %
May-2024	5.25	5.74	5.97
Apr-2024	5.28	5.79	6.01
Average	5.22 %	5.71 %	5.94 %

Selected Bond Spreads

A2 Rated Public Utility Bonds Over Aaa Rated Corporate Bonds: 0.49 % (1)

Baa2 Rated Public Utility Bonds Over A2 Rated Public Utility Bonds: 0.23 % (2)

Notes:
(1) Column [2] - Column [1].
(2) Column [3] - Column [2].

Source of Information:
Bloomberg Professional Services

Summit Natural Gas of Arkansas
Comparison of Long-Term Issuer Ratings for the
Gas Utility Proxy Group

Proxy Group of Six Natural Gas Companies	Moody's Long-Term Issuer Rating June 2024: Long-Term Issuer Rating (1)	Moody's Long-Term Issuer Rating June 2024: Numerical Weighting (2)	Standard & Poor's Long-Term Issuer Rating June 2024: Long-Term Issuer Rating (1)	Standard & Poor's Long-Term Issuer Rating June 2024: Numerical Weighting (2)
Atmos Energy Corporation	A1	5.0	A-	7.0
New Jersey Resources Corporation	A1	5.0	NR	- -
NiSource Inc.	Baa1	8.0	BBB+	8.0
Northwest Natural Holding Company	Baa1	8.0	A+	5.0
ONE Gas, Inc.	A3	7.0	A-	7.0
Spire Inc.	A1/A2	5.5	BBB+	8.0
Average	A2	6.4	A-	7.0

Notes:
(1) Ratings are that of the average of each company's utility operating subsidiaries.
(2) From page 16 of this Schedule.

Source Information: Moody's Investors Services
Standard & Poor's Global Utilities Rating Services

Numerical Assignment for
Moody's and Standard & Poor's Bond Ratings

Moody's Bond Rating	Numerical Bond Weighting	Standard & Poor's Bond Rating
Aaa	1	AAA
Aa1	2	AA+
Aa2	3	AA
Aa3	4	AA-
A1	5	A+
A2	6	A
A3	7	A-
Baa1	8	BBB+
Baa2	9	BBB
Baa3	10	BBB-
Ba1	11	BB+
Ba2	12	BB
Ba3	13	BB-
B1	14	B+
B2	15	B
B3	16	B-

Summit Natural Gas of Arkansas
Judgment of Equity Risk Premium for the
Gas Utility Proxy Group

Line No.		Proxy Group of Six Natural Gas Companies
1.	Calculated equity risk premium based on the total market using the beta approach (1)	6.69 %
2.	Mean equity risk premium based on a study using the holding period returns of public utilities with A rated bonds (2)	4.69
3.	Predicted Equity Risk Premium Based on Regression Analysis of 835 Fully-Litigated Natural Gas Cases (3)	4.82
4.	Average equity risk premium	5.40 %

Notes: (1) From page 18 of this Schedule.
(2) From page 22 of this Schedule.
(3) From page 23 of this Schedule.

Summit Natural Gas of Arkansas
Derivation of Equity Risk Premium Based on the Total Market Approach
Using the Beta for the
Gas Utility Proxy Group

Line No.	Equity Risk Premium Measure	Proxy Group of Six Natural Gas Companies
1.	Kroll Equity Risk Premium (1)	5.96 %
2.	Regression on Kroll Risk Premium Data (2)	6.98
3.	Kroll Equity Risk Premium based on PRPM (3)	8.28
4.	Equity Risk Premium Based on Value Line Summary and Index (4)	7.14
5.	Equity Risk Premium Based on Value Line S&P 500 Companies (5)	9.55
6.	Equity Risk Premium Based on Bloomberg S&P 500 Companies (6)	11.67
7.	Conclusion of Equity Risk Premium	8.26 %
8.	Adjusted Beta (7)	0.81
9.	Forecasted Equity Risk Premium	6.69 %

Notes provided on page 19 of this Schedule.

Summit Natural Gas of Arkansas
Derivation of Equity Risk Premium Based on the Total Market Approach
Using the Beta for the
Gas Utility Proxy Group

Notes:

(1) Based on the arithmetic mean historical monthly returns on large company common stocks from Kroll 2023 SBBI® Yearbook minus the arithmetic mean monthly yield of Moody's average Aaa and Aa corporate bonds from 1928-2023.

(2) This equity risk premium is based on a regression of the monthly equity risk premiums of large company common stocks relative to Moody's average Aaa and Aa rated corporate bond yields from 1928-2023 referenced in note 1 above.

(3) The Predictive Risk Premium Model (PRPM) is discussed in the accompanying direct testimony. The SBBI equity risk premium based on the PRPM is derived by applying the PRPM to the monthly risk premiums between SBBI large company common stock monthly returns and average Aaa and Aa corporate monthly bond yields, from January 1928 through June 2024.

(4) The equity risk premium based on the Value Line Summary and Index is derived by subtracting the average consensus forecast of Aaa corporate bonds of 5.09% (from page 13 of this Schedule) from the projected 3-5 year total annual market return of 12.23% (described fully in note 1 on page 25 of this Schedule).

(5) Using data from Value Line for the S&P 500, an expected total return of 14.64% was derived based upon expected dividend yields and long-term earnings growth estimates as a proxy for capital appreciation. Subtracting the average consensus forecast of Aaa corporate bonds of 5.09% results in an expected equity risk premium of 9.55%.

(6) Using data from Bloomberg Professional Services for the S&P 500, an expected total return of 16.76% was derived based upon expected dividend yields and long-term earnings growth estimates as a proxy for capital appreciation. Subtracting the average consensus forecast of Aaa corporate bonds of 5.09% results in an expected equity risk premium of 11.67%.

(7) Average of mean and median beta from page 24 of this Schedule.

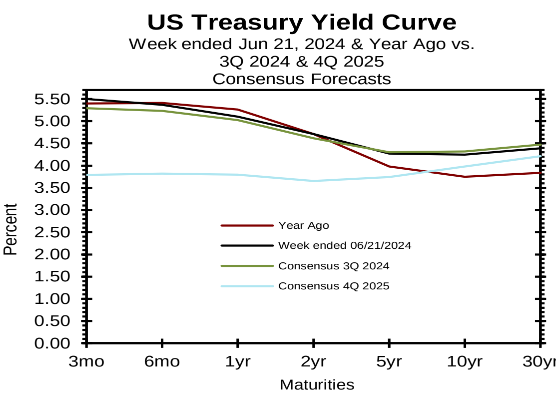
Sources of Information:

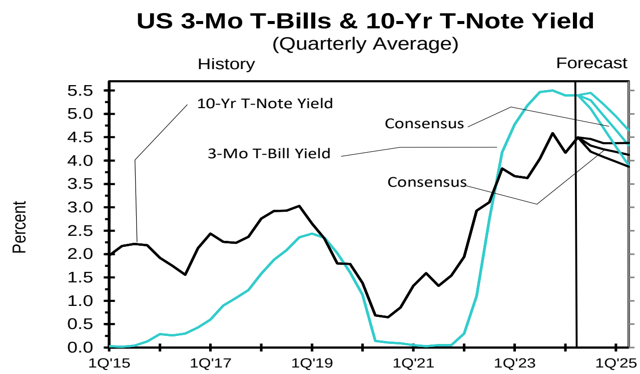
Kroll 2023 SBBI® Yearbook
Value Line Summary and Index
Blue Chip Financial Forecasts July 1, 2024 and May 31, 2024
Bloomberg Professional Services

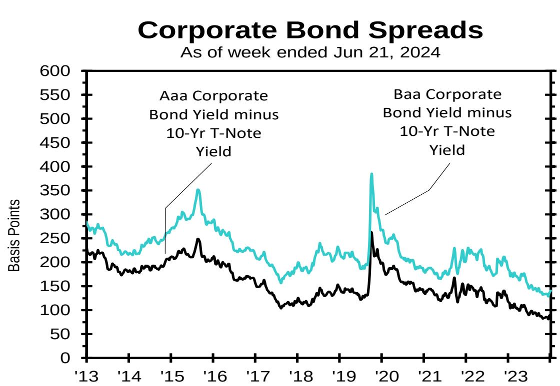
Consensus Forecasts of U.S. Interest Rates and Key Assumptions

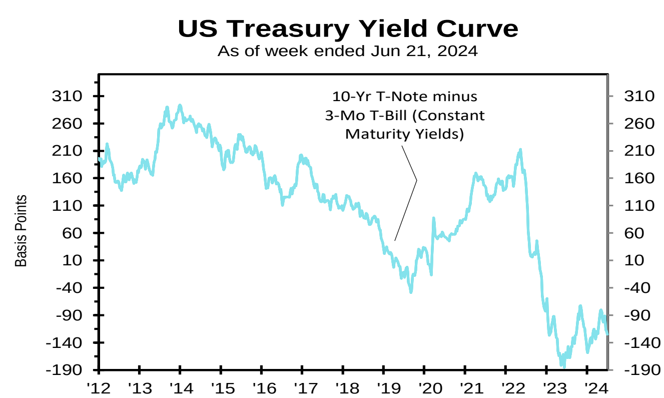
	History								Consensus Forecasts-Quarterly Avg.					
	Average For Week Ending				Average For Month			Latest Qtr	3Q	4Q	1Q	2Q	3Q	4Q
Interest Rates	Jun 21	Jun 14	Jun 7	May 31	May	Apr	Mar	2Q 2024*	2024	2024	2025	2025	2025	2025
Federal Funds Rate	5.33	5.33	5.33	5.33	5.33	5.33	5.33	5.33	**5.3**	**5.0**	**4.7**	**4.4**	**4.1**	**3.9**
Prime Rate	8.50	8.50	8.50	8.50	8.50	8.50	8.50	8.50	**8.4**	**8.2**	**7.9**	**7.6**	**7.3**	**7.0**
SOFR	5.32	5.31	5.33	5.33	5.31	5.32	5.31	5.32	**5.3**	**5.0**	**4.7**	**4.4**	**4.1**	**3.9**
Commercial Paper, 1-mo.	5.32	5.31	5.30	5.31	5.32	5.31	5.32	5.31	**5.3**	**5.0**	**4.7**	**4.4**	**4.0**	**3.8**
Treasury bill, 3-mo.	5.50	5.51	5.52	5.46	5.46	5.44	5.47	5.47	**5.3**	**5.0**	**4.7**	**4.3**	**4.0**	**3.8**
Treasury bill, 6-mo.	5.37	5.38	5.38	5.43	5.42	5.38	5.36	5.39	**5.2**	**4.9**	**4.6**	**4.3**	**4.0**	**3.8**
Treasury bill, 1 yr.	5.10	5.12	5.12	5.20	5.16	5.14	4.99	5.14	**5.0**	**4.8**	**4.5**	**4.2**	**4.0**	**3.8**
Treasury note, 2 yr.	4.71	4.76	4.78	4.93	4.86	4.87	4.59	4.83	**4.6**	**4.4**	**4.2**	**4.0**	**3.8**	**3.7**
Treasury note, 5 yr.	4.27	4.33	4.37	4.57	4.50	4.56	4.20	4.47	**4.3**	**4.2**	**4.1**	**3.9**	**3.8**	**3.7**
Treasury note, 10 yr.	4.25	4.32	4.35	4.55	4.48	4.54	4.21	4.45	**4.3**	**4.2**	**4.2**	**4.1**	**4.0**	**4.0**
Treasury note, 30 yr.	4.39	4.47	4.49	4.69	4.62	4.66	4.36	4.58	**4.5**	**4.4**	**4.4**	**4.3**	**4.3**	**4.2**
Corporate Aaa bond	5.17	5.22	5.23	5.36	5.33	5.38	5.11	5.31	**5.2**	**5.1**	**5.1**	**5.0**	**5.0**	**4.9**
Corporate Baa bond	5.66	5.70	5.71	5.84	5.81	5.88	5.62	5.80	**6.0**	**6.0**	**5.9**	**5.9**	**5.8**	**5.8**
State & Local bonds	4.19	4.24	4.31	4.37	4.28	4.28	4.12	4.27	**4.3**	**4.2**	**4.2**	**4.2**	**4.2**	**4.1**
Home mortgage rate	6.87	6.95	6.99	7.03	7.06	6.99	6.82	7.01	**6.8**	**6.6**	**6.5**	**6.3**	**6.2**	**6.1**
	History								Consensus Forecasts-Quarterly					
	3Q	4Q	1Q	2Q	3Q	4Q	1Q	2Q	3Q	4Q	1Q	2Q	3Q	4Q
Key Assumptions	2022	2022	2023	2023	2023	2023	2024	2024**	2024	2024	2025	2025	2025	2025
Fed's AFE $ Index	118.8	119.8	115.5	114.6	115.0	116.6	115.5	117.3	**117.3**	**117.0**	**116.5**	**116.0**	**115.9**	**115.7**
Real GDP	2.7	2.6	2.2	2.1	4.9	3.4	1.4	2.2	**1.8**	**1.7**	**1.9**	**1.9**	**2.0**	**2.1**
GDP Price Index	4.4	3.9	3.9	1.7	3.3	1.6	3.1	2.8	**2.3**	**2.3**	**2.4**	**2.2**	**2.2**	**2.1**
Consumer Price Index	5.3	4.0	3.8	3.0	3.4	2.7	3.8	3.5	**2.5**	**2.5**	**2.4**	**2.3**	**2.3**	**2.4**
PCE Price Index	4.7	4.1	4.2	2.5	2.6	1.8	3.4	2.9	**2.2**	**2.2**	**2.3**	**2.1**	**2.1**	**2.1**

Forecasts for interest rates and the Federal Reserve's Advanced Foreign Economies Index represent averages for the quarter. Forecasts for Real GDP, GDP Price Index, CPI and PCE Price Index are seasonally adjusted annual rates of change (saar). Individual panel members' forecasts are on pages 4 through 9. Historical data: Treasury rates from the Federal Reserve Board's H.15; AAA-AA and A-BBB corporate bond yields from Bank of America-Merrill Lynch and are 15+ years, yield to maturity; State and local bond yields from Bank of America-Merrill Lynch, A-rated, yield to maturity; Mortgage rates from Freddie Mac, 30-year, fixed; SOFR from the New York Fed.*Interest rate data for 2Q 2024 based on historical data through the week ended June 21. **Data for 2Q 2024 for the Fed's AFE $ Index based on data through the week ended June 21. Figures for 2Q 2024 Real GDP, GDP Chained Price Index, Consumer Price Index, and PCE Price Index are consensus forecasts from the June 2024 survey.









Long-Range Survey:

The table below contains the results of our twice-annual long-range CONSENSUS survey. There are also Top 10 and Bottom 10 averages for each variable. Shown are consensus estimates for the years 2025 through 2030 and averages for the five-year periods 2026-2030 and 2031-2035. Apply these projections cautiously. Few if any economic, demographic and political forces can be evaluated accurately over such long time spans.

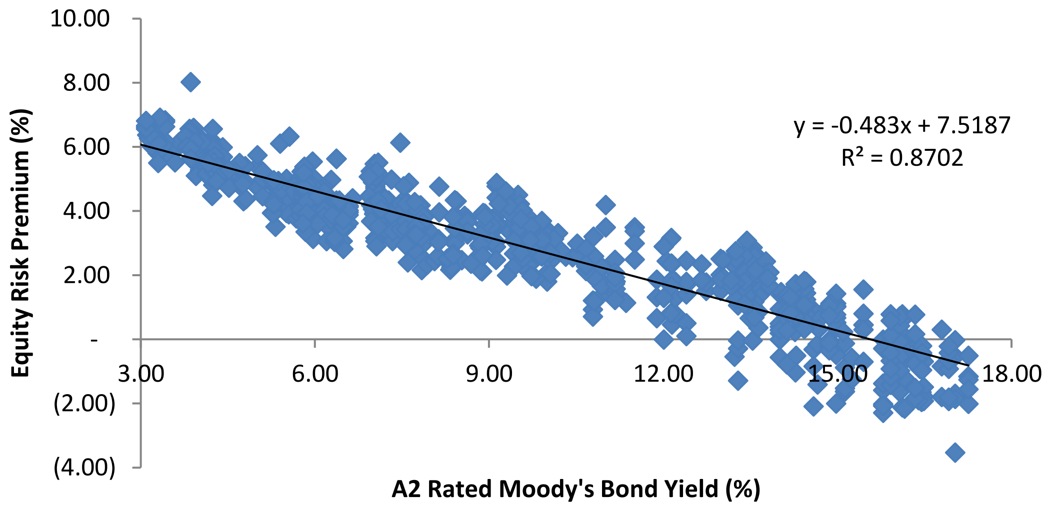
		------------------------ Average For The Year ------------------------						Five-Year Averages	
		2025	2026	2027	2028	2029	2030	2026-2030	2031-2035
1. Federal Funds Rate	CONSENSUS	**4.1**	**3.4**	**3.2**	**3.2**	**3.3**	**3.3**	**3.3**	**3.2**
	Top 10 Average	4.5	3.8	3.8	3.8	3.8	3.8	3.8	3.8
	Bottom 10 Average	3.6	3.0	2.7	2.7	2.7	2.7	2.8	2.7
2. Prime Rate	CONSENSUS	**7.1**	**6.5**	**6.4**	**6.4**	**6.4**	**6.3**	**6.4**	**6.3**
	Top 10 Average	7.5	6.9	6.9	6.9	6.9	6.9	6.9	6.8
	Bottom 10 Average	6.8	6.1	5.9	5.8	5.8	5.7	5.9	5.7
3. SOFR	CONSENSUS	**4.0**	**3.4**	**3.3**	**3.3**	**3.2**	**3.2**	**3.3**	**3.2**
	Top 10 Average	4.3	3.7	3.7	3.6	3.6	3.6	3.6	3.6
	Bottom 10 Average	3.8	3.1	2.9	2.8	2.8	2.7	2.8	2.7
4. Commercial Paper, 1-Mo	CONSENSUS	**4.0**	**3.4**	**3.4**	**3.3**	**3.3**	**3.3**	**3.4**	**3.3**
	Top 10 Average	4.2	3.6	3.6	3.6	3.5	3.5	3.6	3.6
	Bottom 10 Average	3.8	3.2	3.0	3.0	3.0	2.9	3.0	2.9
5. Treasury Bill Yield, 3-Mo	CONSENSUS	**4.0**	**3.4**	**3.3**	**3.2**	**3.2**	**3.2**	**3.2**	**3.2**
	Top 10 Average	4.4	3.7	3.7	3.7	3.7	3.7	3.7	3.7
	Bottom 10 Average	3.6	3.0	2.8	2.7	2.7	2.7	2.8	2.6
6. Treasury Bill Yield, 6-Mo	CONSENSUS	**4.0**	**3.5**	**3.4**	**3.4**	**3.4**	**3.3**	**3.4**	**3.3**
	Top 10 Average	4.3	3.8	3.8	3.7	3.7	3.7	3.8	3.7
	Bottom 10 Average	3.7	3.2	3.0	2.9	2.9	2.8	3.0	2.8
7. Treasury Bill Yield, 1-Yr	CONSENSUS	**4.0**	**3.6**	**3.5**	**3.5**	**3.5**	**3.5**	**3.5**	**3.4**
	Top 10 Average	4.3	3.9	3.9	3.9	3.9	3.9	3.9	3.8
	Bottom 10 Average	3.8	3.4	3.2	3.1	3.0	3.0	3.1	3.0
8. Treasury Note Yield, 2-Yr	CONSENSUS	**3.8**	**3.7**	**3.6**	**3.6**	**3.6**	**3.6**	**3.6**	**3.6**
	Top 10 Average	4.1	4.0	4.1	4.1	4.1	4.1	4.1	4.1
	Bottom 10 Average	3.5	3.3	3.2	3.1	3.1	3.1	3.2	3.0
9. Treasury Note Yield, 5-Yr	CONSENSUS	**3.9**	**3.8**	**3.8**	**3.9**	**3.9**	**3.9**	**3.9**	**3.9**
	Top 10 Average	4.2	4.2	4.3	4.3	4.5	4.4	4.3	4.5
	Bottom 10 Average	3.6	3.5	3.4	3.3	3.4	3.4	3.4	3.3
10. Treasury Note Yield, 10-Yr	CONSENSUS	**4.0**	**4.0**	**4.0**	**4.0**	**4.2**	**4.2**	**4.1**	**4.2**
	Top 10 Average	4.4	4.5	4.5	4.6	4.7	4.7	4.6	4.8
	Bottom 10 Average	3.7	3.6	3.5	3.5	3.6	3.6	3.5	3.6
11. Treasury Bond Yield, 30-Yr	CONSENSUS	**4.2**	**4.2**	**4.2**	**4.3**	**4.4**	**4.4**	**4.3**	**4.4**
	Top 10 Average	4.5	4.6	4.7	4.8	4.9	4.9	4.7	4.9
	Bottom 10 Average	3.9	3.9	3.8	3.8	3.8	3.9	3.8	3.8
12. Corporate Aaa Bond Yield	CONSENSUS	**5.1**	**5.1**	**5.1**	**5.2**	**5.3**	**5.3**	**5.2**	**5.2**
	Top 10 Average	5.4	5.4	5.6	5.7	5.8	5.8	5.7	5.8
	Bottom 10 Average	4.8	4.7	4.7	4.7	4.7	4.7	4.7	4.7
13. Corporate Baa Bond Yield	CONSENSUS	**6.0**	**6.0**	**6.1**	**6.1**	**6.2**	**6.2**	**6.1**	**6.2**
	Top 10 Average	6.3	6.3	6.5	6.6	6.7	6.7	6.5	6.7
	Bottom 10 Average	5.7	5.7	5.6	5.6	5.6	5.7	5.6	5.7
14. State & Local Bonds Yield	CONSENSUS	**4.1**	**4.1**	**4.2**	**4.2**	**4.3**	**4.4**	**4.2**	**4.3**
	Top 10 Average	4.4	4.5	4.5	4.6	4.7	4.7	4.6	4.8
	Bottom 10 Average	3.8	3.8	3.8	3.8	3.8	3.8	3.8	3.7
15. Home Mortgage Rate	CONSENSUS	**6.3**	**6.1**	**6.1**	**6.1**	**6.1**	**6.2**	**6.1**	**6.1**
	Top 10 Average	6.7	6.5	6.5	6.5	6.6	6.6	6.6	6.6
	Bottom 10 Average	6.0	5.7	5.7	5.6	5.6	5.6	5.6	5.5
A. Fed's AFE Nominal $ Index	CONSENSUS	**115.6**	**114.6**	**114.3**	**113.9**	**113.4**	**112.8**	**113.8**	**112.3**
	Top 10 Average	116.9	116.3	115.8	115.7	115.3	115.1	115.6	114.8
	Bottom 10 Average	114.2	113.0	112.7	112.1	111.5	110.9	112.0	110.1
		--------------------- Year-Over-Year, % Change ---------------------						Five-Year Averages	
		2025	2026	2027	2028	2029	2030	2026-2030	2031-2035
B. Real GDP	CONSENSUS	**1.9**	**2.0**	**2.1**	**2.1**	**2.0**	**2.0**	**2.1**	**2.0**
	Top 10 Average	2.3	2.3	2.3	2.3	2.3	2.3	2.3	2.2
	Bottom 10 Average	1.6	1.8	1.9	1.8	1.8	1.8	1.8	1.8
C. GDP Chained Price Index	CONSENSUS	**2.3**	**2.2**	**2.2**	**2.1**	**2.2**	**2.1**	**2.2**	**2.1**
	Top 10 Average	2.6	2.4	2.4	2.3	2.3	2.3	2.4	2.3
	Bottom 10 Average	2.1	2.0	2.0	2.0	2.0	2.0	2.0	2.0
D. Consumer Price Index	CONSENSUS	**2.4**	**2.2**	**2.2**	**2.2**	**2.2**	**2.2**	**2.2**	**2.2**
	Top 10 Average	2.7	2.4	2.4	2.4	2.4	2.4	2.4	2.4
	Bottom 10 Average	2.1	2.1	2.0	2.0	2.0	2.0	2.0	2.0
E. PCE Price Index	CONSENSUS	**2.2**	**2.1**	**2.1**	**2.1**	**2.1**	**2.1**	**2.1**	**2.1**
	Top 10 Average	2.4	2.3	2.3	2.3	2.3	2.3	2.3	2.2
	Bottom 10 Average	2.0	1.9	1.9	1.9	2.0	2.0	1.9	2.0

Summit Natural Gas of Arkansas
Derivation of Mean Equity Risk Premium Based Studies
Using Holding Period Returns and
Projected Market Appreciation of the S&P Utility Index

Line No.	Equity Risk Premium based on S&P Utility Index Holding Period Returns (1):	Implied Equity Risk Premium
1.	Historical Equity Risk Premium	4.02 %
2.	Regression of Historical Equity Risk Premium (2)	4.86
3.	Forecasted Equity Risk Premium Based on PRPM (3)	4.74
4.	Forecasted Equity Risk Premium based on Projected Total Return on the S&P Utilities Index (Value Line Data) (4)	4.16
5.	Forecasted Equity Risk Premium based on Projected Total Return on the S&P Utilities Index (Bloomberg Data) (5)	5.69
6.	Average Equity Risk Premium (6)	4.69 %

Notes:
(1) Based on S&P Public Utility Index monthly total returns and Moody's Public Utility Bond average monthly yields from 1928-2023 Holding period returns are calculated based upon income received (dividends and interest) plus the relative change in the market value of a security over a one-year holding period.
(2) This equity risk premium is based on a regression of the monthly equity risk premiums of the S&P Utility Index relative to Moody's A2 rated public utility bond yields from 1928 - 2023 referenced in note 1 above.
(3) The Predictive Risk Premium Model (PRPM) is applied to the risk premium of the monthly total returns of the S&P Utility Index and the monthly yields on Moody's A2 rated public utility bonds from January 1928 - June 2024.
(4) Using data from Value Line for the S&P Utilities Index, an expected return of 9.74% was derived based on expected dividend yields and long-term growth estimates as a proxy for market appreciation. Subtracting the expected A2 rated public utility bond yield of 5.58%, calculated on line 3 of page 13 of this Schedule results in an equity risk premium of 4.16%. (9.74% - 5.58% = 4.16%)
(5) Using data from Bloomberg Professional Services for the S&P Utilities Index, an expected return of 11.27% was derived based on expected dividend yields as a proxy for income returns and long-term growth estimates as a proxy for market appreciation. Subtracting the expected A2 rated public utility bond yield of 5.58%, calculated on line 3 of page 13 of this Schedule results in an equity risk premium of 5.69%. (11.27% - 5.58% = 5.69%)
(6) Average of lines 1 through 5.

Summit Natural Gas of Arkansas
Prediction of Equity Risk Premiums Relative to
Moody's A2 Rated Utility Bond Yields - Gas Utilities



Constant	Slope	Prospective A2 Rated Utility Bond (1)	Prospective Equity Risk Premium
7.5187 %	-0.483	5.58 %	4.82 %

Notes:

(1) From line 3 of page 13 of this Schedule.

Source of Information: Regulatory Research Associates.

Summit Natural Gas of Arkansas
Indicated Common Equity Cost Rate Through Use
of the Traditional Capital Asset Pricing Model (CAPM) and Empirical Capital Asset Pricing Model (ECAPM)

Proxy Group of Six Natural Gas Companies	[1] Value Line Adjusted Beta	[2] Bloomberg Adjusted Beta	[3] Average Beta	[4] Market Risk Premium (1)	[5] Risk-Free Rate (2)	[6] Traditional CAPM Cost Rate	[7] ECAPM Cost Rate	[8] Indicated Common Equity Cost
Atmos Energy Corporation	0.85	0.73	0.79	9.16 %	4.35 %	11.59 %	12.07 %	11.83 %
New Jersey Resources Corporation	1.00	0.70	0.85	9.16	4.35	12.14	12.48	12.31
NiSource Inc.	0.95	0.68	0.82	9.16	4.35	11.86	12.28	12.07
Northwest Natural Holding Company	0.85	0.64	0.75	9.16	4.35	11.22	11.79	11.51
ONE Gas, Inc.	0.85	0.63	0.74	9.16	4.35	11.13	11.73	11.43
Spire Inc.	0.85	0.79	0.82	9.16	4.35	11.86	12.28	12.07
Mean			0.80			11.63 %	12.10 %	11.87 %
Median			0.81			11.73 %	12.17 %	11.95 %
Average of Mean and Median			0.81			11.68 %	12.14 %	11.91 %

Notes on page 25 of this Schedule.

Summit Natural Gas of Arkansas
Notes to Accompany the Application of the CAPM and ECAPM

Notes:

(1) The market risk premium (MRP) is derived by using six different measures from three sources: Kroll, Value Line, and Bloomberg as illustrated below:

Historical Data MRP Estimates:

Measure 1: Kroll Arithmetic Mean MRP (1926-2023)

Arithmetic Mean Monthly Returns for Large Stocks 1926-2023:	12.16	%
Arithmetic Mean Income Returns on Long-Term Government Bonds:	4.99	
MRP based on Kroll Historical Data:	7.17	%

Measure 2: Application of a Regression Analysis to Kroll Historical Data (1926-2023)	8.00	%
Measure 3: Application of the PRPM to Kroll Historical Data: (January 1926 - June 2024)	9.23	%

Value Line MRP Estimates:

Measure 4: Value Line Projected MRP (Thirteen weeks ending June 28, 2024)

Total projected return on the market 3-5 years hence*:	12.23	%
Projected Risk-Free Rate (see note 2):	4.35	
MRP based on Value Line Summary & Index:	7.88	%

*Forcasted 3-5 year capital appreciation plus expected dividend yield

Measure 5: Value Line Projected Return on the Market based on the S&P 500

Total return on the Market based on the S&P 500:	14.64	%
Projected Risk-Free Rate (see note 2):	4.35	
MRP based on Value Line data	10.29	%

Measure 6: Bloomberg Projected MRP

Total return on the Market based on the S&P 500:	16.76	%
Projected Risk-Free Rate (see note 2):	4.35	
MRP based on Bloomberg data	12.41	%
Average of Value Line, Kroll, and Bloomberg MRP:	9.16	%

(2) For reasons explained in the direct testimony, the appropriate risk-free rate for cost of capital purposes is the average forecast of 30 year Treasury Bonds per the consensus of nearly 50 economists reported in Blue Chip Financial Forecasts. (See pages 20 and 21 of this Schedule) The projection of the risk-free rate is illustrated below:

Third Quarter 2024	4.50	%
Fourth Quarter 2024	4.40	
First Quarter 2025	4.40	
Second Quarter 2025	4.30	
Third Quarter 2025	4.30	
Fourth Quarter 2025	4.20	
2026-2030	4.30	
2031-2035	4.40	
	4.35	%

(3) Average of Column 6 and Column 7.

Sources of Information:

Value Line Summary and Index
Blue Chip Financial Forecasts July 1, 2024 and May 31, 2024
Kroll 2023 SBBI® Yearbook
Bloomberg Professional Services

Summit Natural Gas of Arkansas
Basis of Selection of the Group of Non-Price Regulated Companies
Comparable in Total Risk to the Utility Proxy Group

The criteria for selection of the proxy group of non-price regulated companies comparable in total risk to the Utility Proxy Group was that the non-price regulated companies be domestic and reported in Value Line Investment Survey (Standard Edition).

The proxy group of non-price regulated companies was selected based on the unadjusted beta range of 0.65 - 0.93 and residual standard error of the regression range of 2.8139 - 3.3559 of the proxy group of six natural gas companies.

These ranges are based upon plus or minus two standard deviations of the unadjusted beta and standard error of the regression. Plus or minus three standard deviations captures 95.50% of the distribution of unadjusted betas and residual standard errors of the regression.

The standard deviation of the Utility Proxy Group's residual standard error of the regression is 0.1355. The standard deviation of the standard error of the regression is calculated as follows:

$$\text{Standard Deviation of the Std. Err. of the Regr.} = \frac{\text{Standard Error of the Regression}}{\sqrt{2N}}$$

where: N = number of observations. Since Value Line betas are derived from weekly price change observations over a period of five years, N = 259

$$\text{Thus,} \quad 0.1355 = \frac{3.0849}{\sqrt{518}} = \frac{3.0849}{22.7596}$$

Source of Information: Value Line Proprietary Database, June 2024.

Summit Natural Gas of Arkansas
Basis of Selection of Comparable Risk
Domestic Non-Price Regulated Companies

Proxy Group of Six Natural Gas Companies	[1] Value Line Adjusted Beta	[2] Unadjusted Beta	[3] Residual Standard Error of the Regression	[4] Standard Deviation of Beta
Atmos Energy Corporation	0.85	0.76	2.9065	0.0650
New Jersey Resources Corporation	1.00	0.93	3.0807	0.0689
NiSource Inc.	0.95	0.85	2.6368	0.0590
Northwest Natural Holding Company	0.85	0.73	3.4283	0.0767
ONE Gas, Inc.	0.85	0.73	3.3343	0.0746
Spire Inc.	0.85	0.76	3.1226	0.0698
Average	0.89	0.79	3.0849	0.0690
Beta Range (+/- 2 std. Devs. of Beta)	0.65	0.93		
2 std. Devs. of Beta	0.14			
Residual Std. Err. Range (+/- 2 std. Devs. of the Residual Std. Err.)	2.8139	3.3559		
Std. dev. of the Res. Std. Err.	0.1355			
2 std. devs. of the Res. Std. Err.	0.2710			

Source of Information: Value Line Proprietary Database, June 2024.

Summit Natural Gas of Arkansas
Proxy Group of Non-Price Regulated Companies
Comparable in Total Risk to the
Gas Utility Proxy Group

	[1]	[2]	[3]	[4]
Proxy Group of Fifty-Three Non-Price Regulated Companies	Value Line Adjusted Beta	Unadjusted Beta	Residual Standard Error of the Regression	Standard Deviation of Beta
Abbott Labs.	0.90	0.78	2.9772	0.0666
Agilent Technologies	0.95	0.87	2.9277	0.0655
Air Products & Chem.	0.90	0.84	3.2408	0.0725
Allstate Corp.	1.00	0.93	2.8557	0.0639
Alphabet Inc.	0.90	0.80	3.1933	0.0714
Altria Group	0.85	0.76	2.8345	0.0634
Analog Devices	1.00	0.93	2.9113	0.0651
Apple Inc.	0.95	0.87	3.1798	0.0711
Archer Daniels Midl'	0.95	0.90	3.3342	0.0746
Assurant Inc.	0.90	0.80	3.0102	0.0673
AutoZone Inc.	0.95	0.88	3.3134	0.0741
Booz Allen Hamilton	0.85	0.75	3.3171	0.0742
Brady Corp.	0.95	0.89	3.0413	0.0680
Brown-Forman 'B'	0.90	0.79	2.8192	0.0630
CACI Int'l	0.90	0.80	3.0193	0.0675
Casella Waste Sys.	0.85	0.74	3.3204	0.0742
Casey's Gen'l Stores	0.90	0.78	3.1783	0.0711
Corteva, Inc.	0.95	0.89	3.3083	0.0740
CSW Industrials	0.85	0.77	3.2789	0.0733
Danaher Corp.	0.90	0.81	3.0031	0.0672
Dolby Labs.	0.95	0.88	2.9736	0.0665
Fastenal Co.	0.90	0.78	2.9421	0.0658
GATX Corp.	0.95	0.90	3.0102	0.0673
Henry (Jack) & Assoc	0.85	0.73	3.1916	0.0714
Hunt (J.B.)	0.95	0.90	3.2833	0.0734
Innospec Inc.	1.00	0.93	2.9548	0.0661
Juniper Networks	0.95	0.91	3.0796	0.0689
L3Harris Technologie	0.90	0.83	3.0313	0.0678
Lockheed Martin	0.85	0.74	2.8607	0.0640
McKesson Corp.	0.85	0.70	3.0267	0.0677
Microsoft Corp.	0.90	0.77	2.8505	0.0637
MSA Safety	1.00	0.92	3.0981	0.0693
MSC Industrial Direc	0.90	0.83	2.9811	0.0667
Oracle Corp.	0.80	0.69	3.2292	0.0722
O'Reilly Automotive	0.90	0.83	3.0602	0.0684
OSI Systems	0.90	0.83	2.9498	0.0660
Packaging Corp.	0.95	0.85	2.8727	0.0642
Pfizer, Inc.	0.80	0.68	3.2942	0.0737
Philip Morris Int'l	0.95	0.86	2.8650	0.0641
Prestige Consumer	0.85	0.76	3.3107	0.0740
Selective Ins. Group	0.85	0.74	3.0074	0.0672
Sensient Techn.	0.95	0.85	2.8317	0.0633
Service Corp. Int'l	0.95	0.85	3.2188	0.0720
Sherwin-Williams	0.95	0.89	2.9082	0.0650
Smith (A.O.)	0.90	0.78	3.0334	0.0678
Texas Instruments	0.85	0.76	2.8501	0.0637
Thermo Fisher Sci.	0.85	0.76	2.8431	0.0636
UniFirst Corp.	0.90	0.80	2.9200	0.0653
UnitedHealth Group	0.95	0.90	3.0706	0.0687
VeriSign Inc.	0.90	0.78	2.9246	0.0654
Verisk Analytics	0.90	0.78	2.8196	0.0630
Waters Corp.	0.95	0.88	3.1969	0.0715
Watsco, Inc.	0.90	0.78	3.2257	0.0721
Average	0.91	0.82	3.0524	0.0683
Proxy Group of Six Natural Gas Companies	0.89	0.79	3.0849	0.0690

Source of Information: Value Line Proprietary Database, June 2024.

Summit Natural Gas of Arkansas
Summary of Cost of Equity Models Applied to
Proxy Group of Non-Price Regulated Companies
Comparable in Total Risk to the
Gas Utility Proxy Group

Principal Methods	Proxy Group of Fifty-Three Non-Price Regulated Companies	
Discounted Cash Flow Model (DCF) (1)	11.16	%
Risk Premium Model (RPM) (2)	13.09	
Capital Asset Pricing Model (CAPM) (3)	12.66	
Mean	12.30	%
Median	12.66	%
Average of Mean and Median	12.48	%

Notes:
(1) From page 30 of this Schedule.
(2) From page 31 of this Schedule.
(3) From page 34 of this Schedule.

Summit Natural Gas of Arkansas
DCF Results for the Proxy Group of Non-Price-Regulated Companies Comparable in Total Risk to the
Gas Utility Proxy Group

	[1]	[2]	[3]	[4]	[5]	[6]	[7]	
Proxy Group of Fifty-Three Non-Price Regulated Companies	Average Dividend Yield	Value Line Projected Five Year Growth in EPS	Zack's Five Year Projected Growth Rate in EPS	Yahoo! Finance Projected Five Year Growth in EPS	Average Projected Five Year Growth Rate in EPS (1)	Adjusted Dividend Yield	Indicated Common Equity Cost Rate (2)	
Abbott Labs.	2.08 %	4.00 %	9.00 %	8.10 %	7.03 %	2.15 %	9.18 %	
Agilent Technologies	0.68	8.00	5.60	4.95	6.18	0.70	6.88	
Air Products & Chem.	2.78	10.50	7.50	6.58	8.19	2.89	11.08	
Allstate Corp.	2.21	30.00	7.00	NMF	18.50	2.41	20.91	(3)
Alphabet Inc.	0.47	12.00	17.50	19.70	16.40	0.51	16.91	
Altria Group	8.82	6.00	3.20	3.73	4.31	9.01	13.32	
Analog Devices	1.72	7.50	9.50	-1.41	8.50	1.79	10.29	
Apple Inc.	0.53	8.00	12.50	10.50	10.33	0.56	10.89	
Archer Daniels Midl'	3.27	3.00	NA	-4.20	3.00	3.32	6.32	
Assurant Inc.	1.67	9.50	6.20	6.20	7.30	1.73	9.03	
AutoZone Inc.	-	12.50	13.20	11.65	12.45	-	NA	
Booz Allen Hamilton	1.36	8.50	14.00	13.70	12.07	1.44	13.51	
Brady Corp.	1.50	13.00	7.70	7.70	9.47	1.57	11.04	
Brown-Forman 'B'	1.86	15.00	NA	-1.20	15.00	2.00	17.00	
CACI Int'l	-	7.00	10.40	6.70	8.03	-	NA	
Casella Waste Sys.	-	4.50	20.10	14.90	13.17	-	NA	
Casey's Gen'l Stores	0.60	11.00	9.80	11.02	10.61	0.63	11.24	
Corteva, Inc.	1.16	9.00	13.40	13.50	11.97	1.23	13.20	
CSW Industrials	0.34	10.00	15.00	12.00	12.33	0.36	12.69	
Danaher Corp.	0.43	6.50	8.60	7.52	7.54	0.45	7.99	
Dolby Labs.	1.49	9.50	NA	16.00	12.75	1.58	14.33	
Fastenal Co.	2.33	9.00	9.00	6.33	8.11	2.42	10.53	
GATX Corp.	1.76	11.50	NA	12.00	11.75	1.86	13.61	
Henry (Jack) & Assoc	1.33	6.50	7.50	7.50	7.17	1.38	8.55	
Hunt (J.B.)	1.03	7.50	13.60	7.60	9.57	1.08	10.65	
Innospec Inc.	2.43	13.00	NA	7.50	10.25	2.55	12.80	
Juniper Networks	2.48	7.50	3.60	11.00	7.37	2.57	9.94	
L3Harris Technologie	2.14	9.50	9.20	9.22	9.31	2.24	11.55	
Lockheed Martin	2.72	9.50	4.10	3.76	5.79	2.80	8.59	
McKesson Corp.	0.44	8.00	13.60	11.76	11.12	0.46	11.58	
Microsoft Corp.	0.71	14.00	16.10	16.24	15.45	0.76	16.21	
MSA Safety	1.10	8.50	NA	18.00	13.25	1.17	14.42	
MSC Industrial Direc	3.75	5.00	NA	9.12	7.06	3.88	10.94	
Oracle Corp.	1.29	10.00	11.00	10.61	10.54	1.36	11.90	
O'Reilly Automotive	-	10.50	13.00	11.40	11.63	-	NA	
OSI Systems	-	10.50	11.00	8.00	9.83	-	NA	
Packaging Corp.	2.75	9.00	4.40	-14.29	6.70	2.84	9.54	
Pfizer, Inc.	6.10	2.50	10.70	14.03	9.08	6.38	15.46	
Philip Morris Int'l	5.30	5.00	7.70	9.56	7.42	5.50	12.92	
Prestige Consumer	-	7.00	8.00	8.00	7.67	-	NA	
Selective Ins. Group	1.44	16.50	16.20	17.15	16.62	1.56	18.18	(3)
Sensient Techn.	2.23	2.50	NA	3.80	3.15	2.27	5.42	
Service Corp. Int'l	1.69	5.50	10.10	12.00	9.20	1.77	10.97	
Sherwin-Williams	0.93	11.00	10.90	11.37	11.09	0.98	12.07	
Smith (A.O.)	1.52	9.00	9.00	10.00	9.33	1.59	10.92	
Texas Instruments	2.80	3.00	9.00	-6.20	6.00	2.88	8.88	
Thermo Fisher Sci.	0.27	6.00	9.90	6.82	7.57	0.28	7.85	
UniFirst Corp.	0.82	9.50	NA	7.80	8.65	0.86	9.51	
UnitedHealth Group	1.71	12.00	12.50	12.92	12.47	1.82	14.29	
VeriSign Inc.	-	12.50	NA	8.00	10.25	-	NA	
Verisk Analytics	0.64	8.50	12.30	12.58	11.13	0.68	11.81	
Waters Corp.	-	6.50	5.30	5.54	5.78	-	NA	
Watsco, Inc.	2.36	9.00	NA	4.42	6.71	2.44	9.15	
	NA= Not Available					Mean	11.28 %	
						Median	11.04 %	
						Average of Mean and Median	11.16 %	

Notes:
(1) Average of columns 2 through 4 excluding negative growth rates.
(2) The application of the DCF model to the domestic, non-price regulated comparable risk companies is identical to the application of the DCF to the Utility Proxy Group. The dividend yield is derived by using the 60 day average price and the spot indicated dividend as of June 28, 2024. The dividend yield is then adjusted by 1/2 the average projected growth rate in EPS, which is calculated by averaging the 5 year projected growth in EPS provided by Value Line, www.zacks.com, and www.yahoo.com (excluding any negative growth rates) and then adding that growth rate to the adjusted dividend yield.
(3) Results were excluded from the final average and median as they were more than two standard deviations from the proxy group's mean.

Source of Information: Value Line Investment Survey
www.zacks.com, Downloaded on 06/28/2024
www.yahoo.com, Downloaded on 06/28/2024

Summit Natural Gas of Arkansas
Indicated Common Equity Cost Rate
Through Use of a Risk Premium Model
Using an Adjusted Total Market Approach

Line No.		Proxy Group of Fifty-Three Non-Price Regulated Companies
1.	Prospective Yield on Baa2 Rated Corporate Bonds (1)	5.96 %
2	Adjustment to Reflect Bond rating Difference of Non-Price Regulated Companies (2)	(0.22)
3	Adjusted Prospective Bond Yield	5.74
4.	Equity Risk Premium (3)	7.35
5.	Risk Premium Derived Common Equity Cost Rate	13.09 %

Notes: (1) Average forecast of Baa corporate bonds based upon the consensus of nearly 50 economists reported in Blue Chip Financial Forecasts dated July 1, 2024 and May 31, 2024 (see pages 20 and 21 of this Schedule). The estimates are detailed below.

Third Quarter 2024	6.00 %
Fourth Quarter 2024	6.00
First Quarter 2025	5.90
Second Quarter 2025	5.90
Third Quarter 2025	5.80
Fourth Quarter 2025	5.80
2026-2030	6.10
2031-2035	6.20
Average	5.96 %

(2) The average yield spread of Baa rated corporate bonds over A corporate bonds for the three months ending June 2024. To reflect the A3 average rating of the Non-Utility proxy groups, the prosepctive yield on Baa corporate bonds must be adjusted by 2/3 of the spread between A and Baa corporate bond yields as shown below:

	A Corp. Bond Yield	Baa Corp. Bond Yield	Spread
Jun-24	5.50 %	5.82 %	0.32 %
May-24	5.62	5.95	0.33
Apr-24	5.67	6.00	0.33
		Average yield spread	0.33 %
		2/3 of spread	0.22 %

(3) From page 33 of this Schedule.

Summit Natural Gas of Arkansas
Comparison of Long-Term Issuer Ratings for the
Gas Utility Proxy Group

Proxy Group of Fifty-Three Non-Price Regulated Companies	Moody's Long-Term Issuer Rating June 2024 Long-Term Issuer Rating	Moody's Numerical Weighting (1)	Standard & Poor's Long-Term Issuer Rating June 2024 Long-Term Issuer Rating	Standard & Poor's Numerical Weighting (1)
Abbott Labs.	Aa3	4.0	AA-	4.0
Agilent Technologies	Baa1	8.0	BBB+	8.0
Air Products & Chem.	A2	6.0	A	6.0
Allstate Corp.	A3	7.0	BBB+	8.0
Alphabet Inc.	Aa2	3.0	AA+	2.0
Altria Group	A3	7.0	BBB	9.0
Analog Devices	A2	6.0	A-	7.0
Apple Inc.	Aaa	1.0	AA+	2.0
Archer Daniels Midl'	A2	6.0	A	6.0
Assurant Inc.	Baa2	9.0	BBB	9.0
AutoZone Inc.	Baa1	8.0	BBB	9.0
Booz Allen Hamilton	NA	--	NA	--
Brady Corp.	NA	--	NA	--
Brown-Forman 'B'	A1	5.0	A-	7.0
CACI Int'l	NA	--	BB+	11.0
Casella Waste Sys.	NA	--	BB	12.0
Casey's Gen'l Stores	NA	--	NA	--
Corteva, Inc.	NA	--	A-	7.0
CSW Industrials	NA	--	NA	--
Danaher Corp.	A3	7.0	A-	7.0
Dolby Labs.	NA	--	NA	--
Fastenal Co.	NA	--	NA	--
GATX Corp.	Baa2	9.0	BBB	9.0
Henry (Jack) & Assoc	NA	--	NA	--
Hunt (J.B.)	Baa1	8.0	BBB+	8.0
Innospec Inc.	NA	--	NR	--
Juniper Networks	Baa2	9.0	BBB	9.0
L3Harris Technologie	Baa2	9.0	BBB	9.0
Lockheed Martin	A2	6.0	A-	7.0
McKesson Corp.	A3	7.0	BBB+	8.0
Microsoft Corp.	Aaa	1.0	AAA	1.0
MSA Safety	NA	--	NA	--
MSC Industrial Direc	NA	--	NA	--
Oracle Corp.	Baa2	9.0	BBB	9.0
O'Reilly Automotive	Baa1	8.0	BBB	9.0
OSI Systems	NA	--	NA	--
Packaging Corp.	Baa2	9.0	BBB	9.0
Pfizer, Inc.	A2	6.0	A	6.0
Philip Morris Int'l	A2	6.0	A-	7.0
Prestige Consumer	NA	--	BB	12.0
Selective Ins. Group	Baa2	9.0	BBB	9.0
Sensient Techn.	WR	--	NR	--
Service Corp. Int'l	Ba3	13.0	BB+	11.0
Sherwin-Williams	Baa2	9.0	BBB	9.0
Smith (A.O.)	NA	--	NA	--
Texas Instruments	Aa3	4.0	A+	5.0
Thermo Fisher Sci.	A3	7.0	A-	7.0
UniFirst Corp.	NA	--	NA	--
UnitedHealth Group	A2	6.0	A+	5.0
VeriSign Inc.	Baa3	10.0	BBB	9.0
Verisk Analytics	Baa2	9.0	BBB	9.0
Waters Corp.	NA	--	NA	--
Watsco, Inc.	NA	--	NA	--
Average	A3	7.0	BBB+	7.6

Notes:
(1) From page 16 of this Schedule.

Source of Information:
Bloomberg Professional Services

Summit Natural Gas of Arkansas
Derivation of Equity Risk Premium Based on the Total Market Approach
Using the Beta for
Non-Price Regulated Companies of Comparable risk to the
Gas Utility Proxy Group

Line No.	Equity Risk Premium Measure	Proxy Group of Fifty-Three Non-Price Regulated Companies
1.	Kroll Equity Risk Premium (1)	5.96 %
2.	Regression on Kroll Risk Premium Data (2)	6.98
3.	Kroll Equity Risk Premium based on PRPM (3)	8.28
4.	Equity Risk Premium Based on Value Line Summary and Index (4)	7.14
5	Equity Risk Premium Based on Value Line S&P 500 Companies (5)	9.55
6.	Equity Risk Premium Based on Bloomberg S&P 500 Companies (6)	11.67
7.	Conclusion of Equity Risk Premium	8.26 %
8.	Adjusted Beta (7)	0.89
9.	Forecasted Equity Risk Premium	7.35 %

Notes:
(1) From note 1 of page 19 of this Schedule.
(2) From note 2 of page 19 of this Schedule.
(3) From note 3 of page 19 of this Schedule.
(4) From note 4 of page 19 of this Schedule.
(5) From note 5 of page 19 of this Schedule.
(6) From note 6 of page 19 of this Schedule.
(7) Average of mean and median beta from page 34 of this Schedule.

Sources of Information:
Kroll 2023 SBBI® Yearbook
Value Line Summary and Index
Blue Chip Financial Forecasts July 1, 2024 and May 31, 2024
Bloomberg Professional Services

Summit Natural Gas of Arkansas
Traditional CAPM and ECAPM Results for the Proxy Group of Non-Price-Regulated Companies Comparable in Total Risk to the
Gas Utility Proxy Group

	[1]	[2]	[3]	[4]	[5]	[6]	[7]	[8]
Proxy Group of Fifty-Three Non-Price Regulated Companies	Value Line Adjusted Beta	Bloomberg Beta	Average Beta	Market Risk Premium (1)	Risk-Free Rate (2)	Traditional CAPM Cost Rate	ECAPM Cost Rate	Indicated Common Equity Cost Rate (3)
Abbott Labs.	0.90	0.78	0.84	9.16 %	4.35 %	12.05 %	12.41 %	12.23 %
Agilent Technologies	0.95	1.16	1.05	9.16	4.35	13.97	13.86	13.91
Air Products & Chem.	0.90	0.82	0.86	9.16	4.35	12.23	12.55	12.39
Allstate Corp.	1.00	0.53	0.76	9.16	4.35	11.31	11.86	11.59
Alphabet Inc.	0.90	1.18	1.04	9.16	4.35	13.88	13.79	13.83
Altria Group	0.85	0.57	0.71	9.16	4.35	10.86	11.52	11.19
Analog Devices	1.00	1.15	1.07	9.16	4.35	14.15	13.99	14.07
Apple Inc.	0.95	1.12	1.04	9.16	4.35	13.88	13.79	13.83
Archer Daniels Midl'	0.95	0.73	0.84	9.16	4.35	12.05	12.41	12.23
Assurant Inc.	0.90	0.81	0.85	9.16	4.35	12.14	12.48	12.31
AutoZone Inc.	0.95	0.68	0.81	9.16	4.35	11.77	12.21	11.99
Booz Allen Hamilton	0.85	0.81	0.83	9.16	4.35	11.95	12.34	12.15
Brady Corp.	0.95	0.72	0.84	9.16	4.35	12.05	12.41	12.23
Brown-Forman 'B'	0.90	0.88	0.89	9.16	4.35	12.50	12.76	12.63
CACI Int'l	0.90	0.81	0.86	9.16	4.35	12.23	12.55	12.39
Casella Waste Sys.	0.85	0.75	0.80	9.16	4.35	11.68	12.14	11.91
Casey's Gen'l Stores	0.85	0.66	0.76	9.16	4.35	11.31	11.86	11.59
Corteva, Inc.	0.95	0.83	0.89	9.16	4.35	12.50	12.76	12.63
CSW Industrials	0.85	0.87	0.86	9.16	4.35	12.23	12.55	12.39
Danaher Corp.	0.90	1.06	0.98	9.16	4.35	13.33	13.38	13.35
Dolby Labs.	0.95	0.88	0.92	9.16	4.35	12.78	12.96	12.87
Fastenal Co.	0.90	0.96	0.93	9.16	4.35	12.87	13.03	12.95
GATX Corp.	0.95	0.92	0.93	9.16	4.35	12.87	13.03	12.95
Henry (Jack) & Assoc	0.85	0.87	0.86	9.16	4.35	12.23	12.55	12.39
Hunt (J.B.)	0.95	1.03	0.99	9.16	4.35	13.42	13.44	13.43
Innospec Inc.	1.00	0.91	0.95	9.16	4.35	13.05	13.17	13.11
Juniper Networks	0.95	0.77	0.86	9.16	4.35	12.23	12.55	12.39
L3Harris Technologie	0.90	0.93	0.91	9.16	4.35	12.69	12.89	12.79
Lockheed Martin	0.85	0.59	0.72	9.16	4.35	10.95	11.59	11.27
McKesson Corp.	0.80	0.48	0.64	9.16	4.35	10.21	11.04	10.63 (4)
Microsoft Corp.	0.90	1.10	1.00	9.16	4.35	13.51	13.51	13.51
MSA Safety	0.95	0.92	0.94	9.16	4.35	12.96	13.10	13.03
MSC Industrial Direc	0.90	0.87	0.89	9.16	4.35	12.50	12.76	12.63
Oracle Corp.	0.85	1.14	0.99	9.16	4.35	13.42	13.44	13.43
O'Reilly Automotive	0.90	0.64	0.77	9.16	4.35	11.41	11.93	11.67
OSI Systems	0.90	1.02	0.96	9.16	4.35	13.15	13.24	13.19
Packaging Corp.	0.95	0.88	0.91	9.16	4.35	12.69	12.89	12.79
Pfizer, Inc.	0.80	0.61	0.71	9.16	4.35	10.86	11.52	11.19
Philip Morris Int'l	0.95	0.75	0.85	9.16	4.35	12.14	12.48	12.31
Prestige Consumer	0.85	0.65	0.75	9.16	4.35	11.22	11.79	11.51
Selective Ins. Group	0.85	0.55	0.70	9.16	4.35	10.76	11.45	11.11
Sensient Techn.	0.90	0.93	0.92	9.16	4.35	12.78	12.96	12.87
Service Corp. Int'l	0.95	0.81	0.88	9.16	4.35	12.41	12.69	12.55
Sherwin-Williams	0.95	1.11	1.03	9.16	4.35	13.79	13.72	13.75
Smith (A.O.)	0.90	1.05	0.98	9.16	4.35	13.33	13.38	13.35
Texas Instruments	0.85	1.13	0.99	9.16	4.35	13.42	13.44	13.43
Thermo Fisher Sci.	0.85	1.02	0.94	9.16	4.35	12.96	13.10	13.03
UniFirst Corp.	0.90	0.87	0.88	9.16	4.35	12.41	12.69	12.55
UnitedHealth Group	0.95	0.39	0.67	9.16	4.35	10.49	11.24	10.87 (4)
VeriSign Inc.	0.90	0.99	0.94	9.16	4.35	12.96	13.10	13.03
Verisk Analytics	0.90	0.94	0.92	9.16	4.35	12.78	12.96	12.87
Waters Corp.	0.95	1.17	1.06	9.16	4.35	14.06	13.92	13.99
Watsco, Inc.	0.90	1.26	1.08	9.16	4.35	14.25	14.06	14.15
		Mean	0.89			12.48 %	12.74 %	12.68 %
		Median	0.89			12.50 %	12.76 %	12.63 %
		Average of Mean and Median	0.89			12.49 %	12.75 %	12.66 %

Notes:
(1) From note 1 of page 24 of this Schedule.
(2) From note 2 of page 24 of this Schedule.
(3) Average of CAPM and ECAPM cost rates.
(4) Results were excluded from the final average and median as they were more than two standard deviations from the proxy group's mean.

Summit Natural Gas of Arkansas
Derivation of Investment Risk Adjustment Based upon
Kroll Associates' Size Premia for the Decile Portfolios of the NYSE/AMEX/NASDAQ

		[1]		[2]	[3]	[4]
Line No.		Market Capitalization on June 28, 2024 (1)		Applicable Decile of the NYSE/AMEX/ NASDAQ (2)	Applicable Size Premium (3)	Spread from Applicable Size Premium (4)
		(millions)	(times larger)			
1	Summit Natural Gas of Arkansas - based on the Gas Utility Proxy Group	$ 973.414		8	1.14%	
2	Proxy Group of Six Natural Gas Companies	$ 3,890.609	4.0 x	5	0.95%	0.19%

	[A]	[B]	[C]	[D]
	Decile	Market Capitalization of Smallest Company (millions)	Market Capitalization of Largest Company (millions)	Size Premium (Return in Excess of CAPM)*
Largest	1	$ 36,942.976	$ 2,662,326.048	-0.06%
	2	14,910.719	36,391.113	0.46%
	3	7,493.607	14,820.048	0.61%
	4	4,622.261	7,461.284	0.64%
	5	3,011.224	4,621.785	0.95%
	6	1,864.293	3,010.806	1.21%
	7	1,050.083	1,862.491	1.39%
	8	555.880	1,046.037	1.14%
	9	213.039	554.523	1.99%
Smallest	10	1.576	212.644	4.70%

*From 2024 Kroll Cost of Capital Navigator

Notes:

(1) From page 36 of this Schedule.
(2) Gleaned from Columns [B] and [C] on the bottom of this page. The appropriate decile (Column [A]) corresponds to the market capitalization of the proxy group, which is found in Column [1].
(3) Corresponding risk premium to the decile is provided in Column [D] on the bottom of this page.
(4) Line No. 1 Column [3] – Line No. 2 Column [3]. For example, the 0.19% in Column [4], Line No. 2 is derived as follows 0.19% = 1.14% - 0.95%.

Summit Natural Gas of Arkansas
Market Capitalization of Summit Natural Gas of Arkansas and the
Gas Utility Proxy Group

Company	Exchange	[1] Common Stock Shares Outstanding at Fiscal Year End 2023 (millions)	[2] Book Value per Share at Fiscal Year End 2023(1)	[3] Total Common Equity at Fiscal Year End 2023 (millions)	[4] Closing Stock Market Price on June 28, 2024	[5] Market-to-Book Ratio on June 28, 2024 (2)	[6] Market Capitalization on June 28, 2024 (3) (millions)
Summit Natural Gas of Arkansas		NA	NA	671.320 (4)	NA		
Based upon Proxy Group of Six Natural Gas Companies						145.0 (5)	$ 973.414 (6)
Proxy Group of Six Natural Gas Companies							
Atmos Energy Corporation	NYSE	148.493	$ 73.20	$ 10,870.06	$ 116.65	159.4 %	$ 17,321.683
New Jersey Resources Corporation	NYSE	97.584	20.400	1,990.735	42.740	209.5	4,170.760
NiSource Inc.	NYSE	447.382	17.398	7,783.500	28.810	165.6	12,889.066
Northwest Natural Holding Company	NYSE	37.631	34.116	1,283.838	36.110	105.8	1,358.855
ONE Gas, Inc.	NYSE	56.546	48.914	2,765.877	63.850	130.5	3,610.457
Spire Inc.	NYSE	53.170	54.867	2,917.300	60.730	110.7	3,229.028
Median		77.065	$ 41.515	$ 2,841.589	$ 51.735	145.0 %	$ 3,890.609

NA= Not Available

Notes: (1) Column 3 / Column 1.
(2) Column 4 / Column 2.
(3) Column 1 * Column 4.
(4) Requested rate base multiplied by the requested common equity ratio.
(5) The market-to-book ratio of Summit Natural Gas of Arkansas on June 28, 2024 is assumed to be equal to the market-to-book ratio of Proxy Group of Six Natural Gas Companies on June 28, 2024 as appropriate.
(6) Column [3] multiplied by Column [5].

Source of Information: 2023 Annual Forms 10K.
yahoo.finance.com.
Bloomberg Professional Services.

Summit Natural Gas of Arkansas
Range of Capital Structures for the Past Eight Fiscal Quarters for the
Proxy Group of Six Natural Gas Distribution Companies

Common Equity Ratio (including Short-Term Debt)

Company	2024 Q1	2023 Q4	2023 Q3	2023 Q2	2023 Q1	2022 Q4	2022 Q3	2022 Q2	8Q average ending Q1 2024
Atmos Energy Corporation	60.22%	61.30%	61.79%	60.89%	60.05%	61.11%	61.71%	60.97%	61.01%
New Jersey Resources Corporation	38.70%	38.49%	39.42%	39.95%	36.98%	37.59%	37.55%	40.09%	38.60%
NiSource Inc.	37.50%	28.67%	29.19%	30.30%	31.46%	30.25%	29.62%	31.17%	31.02%
Northwest Natural Holding Company	44.58%	43.52%	41.97%	44.04%	43.71%	42.84%	43.57%	47.84%	44.01%
ONE Gas, Inc.	49.52%	49.73%	49.12%	50.34%	49.70%	55.37%	55.46%	51.25%	51.31%
Spire Inc.	35.75%	35.05%	35.94%	36.39%	34.73%	36.07%	38.12%	38.66%	36.34%
								Minimum	31.02%
								Maximum	61.01%

Total Debt Ratio (including Short-Term Debt)

Company	2024 Q1	2023 Q4	2023 Q3	2023 Q2	2023 Q1	2022 Q4	2022 Q3	2022 Q2	8Q average ending Q1 2024
Atmos Energy Corporation	39.78%	38.70%	38.21%	39.11%	39.95%	38.89%	38.29%	39.03%	38.99%
New Jersey Resources Corporation	61.30%	61.51%	60.58%	60.05%	63.02%	62.41%	62.45%	59.91%	61.40%
NiSource Inc.	62.50%	63.56%	65.25%	63.96%	60.60%	60.58%	60.76%	58.77%	62.00%
Northwest Natural Holding Company	55.42%	56.48%	58.03%	55.96%	56.29%	57.16%	56.43%	52.16%	55.99%
ONE Gas, Inc.	50.48%	50.27%	50.88%	49.66%	50.30%	44.63%	44.54%	48.75%	48.69%
Spire Inc.	61.17%	61.78%	60.82%	60.40%	62.06%	60.54%	58.33%	57.74%	60.36%
								Minimum	38.99%
								Maximum	62.00%

Common Equity Ratio (excluding Short-Term Debt)

Company	2024 Q1	2023 Q4	2023 Q3	2023 Q2	2023 Q1	2022 Q4	2022 Q3	2022 Q2	8Q average ending Q1 2024
Atmos Energy Corporation	60.22%	62.15%	61.79%	60.89%	60.05%	61.85%	61.71%	60.97%	61.21%
New Jersey Resources Corporation	40.75%	40.46%	40.58%	41.50%	40.61%	41.20%	40.75%	43.01%	41.11%
NiSource Inc.	39.81%	33.12%	32.69%	32.91%	33.68%	33.30%	31.84%	32.19%	33.69%
Northwest Natural Holding Company	46.02%	44.89%	43.02%	44.69%	44.84%	47.30%	46.10%	52.78%	46.20%
ONE Gas, Inc.	59.44%	50.53%	52.29%	52.50%	52.46%	62.79%	61.35%	57.09%	56.06%
Spire Inc.	41.25%	40.07%	38.84%	39.32%	41.47%	42.20%	42.54%	42.50%	41.02%
								Minimum	33.69%
								Maximum	61.21%

Long-Term Debt Ratio (excluding Short-Term Debt)

Company	2024 Q1	2023 Q4	2023 Q3	2023 Q2	2023 Q1	2022 Q4	2022 Q3	2022 Q2	8Q average ending Q1 2024
Atmos Energy Corporation	39.78%	37.85%	38.21%	39.11%	39.95%	38.15%	38.29%	39.03%	38.79%
New Jersey Resources Corporation	59.25%	59.54%	59.42%	58.50%	59.39%	58.80%	59.25%	56.99%	58.89%
NiSource Inc.	60.19%	57.90%	61.09%	60.85%	57.82%	56.60%	57.83%	57.42%	58.71%
Northwest Natural Holding Company	53.98%	55.11%	56.98%	55.31%	55.16%	52.70%	53.90%	47.22%	53.80%
ONE Gas, Inc.	40.56%	49.47%	47.71%	47.50%	47.54%	37.21%	38.65%	42.91%	43.94%
Spire Inc.	55.20%	56.30%	57.67%	57.22%	54.70%	53.83%	53.51%	53.54%	55.25%
								Minimum	38.79%
								Maximum	58.89%

Summit Natural Gas of Arkansas
Range of Capital Structures for the Past Eight Fiscal Quarters for the
Proxy Group of Six Natural Gas Distribution Companies at the Operating Company Level

Common Equity Ratio (including Short-Term Debt)

Company	2024 Q1	2023 Q4	2023 Q3	2023 Q2	2023 Q1	2022 Q4	2022 Q3	2022 Q2	8Q average ending Q1 2024
Atmos Energy Corporation	60.22%	61.30%	61.79%	60.89%	60.05%	61.11%	61.71%	60.97%	61.01%
New Jersey Natural Gas Company	52.41%	53.63%	54.70%	54.56%	51.00%	53.10%	54.09%	55.98%	53.68%
NiSource Inc.	37.50%	28.67%	29.19%	30.30%	31.46%	30.25%	29.62%	31.17%	31.02%
Northwest Natural Gas Company	47.87%	47.15%	46.12%	47.75%	48.56%	48.41%	50.01%	53.05%	48.61%
ONE Gas, Inc.	49.52%	49.73%	49.12%	50.34%	49.70%	55.37%	55.46%	51.25%	51.31%
Spire Alabama Inc.	50.57%	50.84%	51.50%	51.18%	49.45%	51.26%	54.00%	55.39%	51.78%
Spire Missouri Inc.	43.81%	44.05%	44.88%	44.90%	43.79%	45.43%	47.76%	47.59%	45.28%
								Minimum	31.02%
								Maximum	61.01%

Total Debt Ratio (including Short-Term Debt)

Company	2024 Q1	2023 Q4	2023 Q3	2023 Q2	2023 Q1	2022 Q4	2022 Q3	2022 Q2 0	8Q average ending Q1 2024
Atmos Energy Corporation	39.78%	38.70%	38.21%	39.11%	39.95%	38.89%	38.29%	39.03%	38.99%
New Jersey Natural Gas Company	47.59%	46.37%	45.30%	45.44%	49.00%	46.90%	45.91%	44.02%	46.32%
NiSource Inc.	62.50%	63.56%	65.25%	63.96%	60.60%	60.58%	60.76%	58.77%	62.00%
Northwest Natural Gas Company	52.13%	52.85%	53.88%	52.25%	51.44%	51.59%	49.99%	46.95%	51.39%
ONE Gas, Inc.	50.48%	50.27%	50.88%	49.66%	50.30%	44.63%	44.54%	48.75%	48.69%
Spire Alabama Inc.	49.43%	49.16%	48.50%	48.82%	50.55%	48.74%	46.00%	44.61%	48.22%
Spire Missouri Inc.	56.19%	55.95%	55.12%	55.10%	56.21%	54.57%	52.24%	52.41%	54.72%
								Minimum	38.99%
								Maximum	62.00%

Common Equity Ratio (excluding Short-Term Debt)

Company	2024 Q1	2023 Q4	2023 Q3	2023 Q2	2023 Q1	2022 Q4	2022 Q3	2022 Q2	8Q average ending Q1 2024
Atmos Energy Corporation	60.22%	62.15%	61.79%	60.89%	60.05%	61.85%	61.71%	60.97%	61.21%
New Jersey Natural Gas Company	53.98%	54.19%	54.88%	54.56%	52.81%	54.43%	54.09%	55.98%	54.36%
NiSource Inc.	39.81%	33.12%	32.69%	32.91%	33.68%	33.30%	31.84%	32.19%	33.69%
Northwest Natural Gas Company	48.44%	47.46%	46.12%	47.75%	48.56%	52.01%	51.18%	55.01%	49.57%
ONE Gas, Inc.	59.44%	50.53%	52.29%	52.50%	52.46%	62.79%	61.35%	57.09%	56.06%
Spire Alabama Inc.	54.39%	54.55%	54.77%	54.82%	53.75%	60.14%	60.94%	61.06%	56.80%
Spire Missouri Inc.	51.29%	50.58%	47.52%	47.89%	52.08%	51.39%	51.76%	51.48%	50.50%
								Minimum	33.69%
								Maximum	61.21%

Total Debt Ratio (excluding Short-Term Debt)

Company	2024 Q1	2023 Q4	2023 Q3	2023 Q2	2023 Q1	2022 Q4	2022 Q3	2022 Q2	8Q average ending Q1 2024
Atmos Energy Corporation	39.78%	37.85%	38.21%	39.11%	39.95%	38.15%	38.29%	39.03%	38.79%
New Jersey Natural Gas Company	46.02%	45.81%	45.12%	45.44%	47.19%	45.57%	45.91%	44.02%	45.64%
NiSource Inc.	60.19%	57.90%	61.09%	60.85%	57.82%	56.60%	57.83%	57.42%	58.71%
Northwest Natural Gas Company	51.56%	52.54%	53.88%	52.25%	51.44%	47.99%	48.82%	44.99%	50.43%
ONE Gas, Inc.	40.56%	49.47%	47.71%	47.50%	47.54%	37.21%	38.65%	42.91%	43.94%
Spire Alabama Inc.	45.61%	45.45%	45.23%	45.18%	46.25%	39.86%	39.06%	38.94%	43.20%
Spire Missouri Inc.	48.71%	49.42%	52.48%	52.11%	47.92%	48.61%	48.24%	48.52%	49.50%
								Minimum	38.79%
								Maximum	58.71%

Source: S&P Global Market Intelligence; S&P Capital IQ; Company Filings

Summit Natural Gas of Arkansas
Range of Projected Common Equity Ratios from Value Line for the
Proxy Group of Six Natural Gas Distribution Companies

Ticker	Company	2024	2025	2027-2029
ATO	Atmos Energy Corporation	60.0%	60.0%	60.0%
NJR	New Jersey Resources Corporation	42.5%	43.0%	45.0%
NI	NiSource Inc.	40.0%	40.0%	37.5%
NWN	Northwest Natural Holding Company	50.0%	50.0%	50.0%
OGS	ONE Gas, Inc.	55.0%	55.0%	49.0%
SR	Spire Inc.	44.0%	44.0%	45.0%

Source: Value Line reports, May 24, 2024

Summit Natural Gas of Arkansas
Range of Authorized Common Equity Ratios - 2020 to Present

State	Company	Parent Company Ticker	Docket	Rate Case Service Type	Authorized Common Equity to Total Capital (%)	Decision Date	Decision Type
Wyoming	MDU Resources Group	MDU	D-30013-351-GR-19	Natural Gas	51.25	1/15/2020	Settled
New York	Consolidated Edison Company of	ED	C-19-G-0066	Natural Gas	48.00	1/16/2020	Settled
Virginia	Roanoke Gas Co.	RGCO	C-PUR-2018-00013	Natural Gas	59.64	1/24/2020	Fully Litigated
Washington	Cascade Natural Gas Corp.	MDU	D-UG-190210	Natural Gas	49.10	2/3/2020	Settled
Kansas	Atmos Energy Corp.	ATO	D-19-ATMG-525-RTS	Natural Gas	56.32	2/24/2020	Fully Litigated
Utah	Questar Gas Co.		D-19-057-02	Natural Gas	55.00	2/25/2020	Fully Litigated
Massachusetts	Fitchburg Gas & Electric Light	UTL	DPU 19-131	Natural Gas	52.45	2/28/2020	Settled
Washington	Avista Corp.	AVA	D-UG-190335	Natural Gas	48.50	3/25/2020	Settled
Maine	Northern Utilities Inc.	UTL	D-2019-00092	Natural Gas	50.00	3/26/2020	Fully Litigated
Texas	Atmos Energy Corp.	ATO	D-GUD-10900	Natural Gas	60.12	4/21/2020	Settled
Colorado	Black Hills Colorado Gas Inc.	BKH	D-19AL-0075G	Natural Gas	50.15	5/19/2020	Fully Litigated
Texas	CenterPoint Energy Resources	CNP	D-GUD-10920	Natural Gas	56.95	6/16/2020	Settled
Washington	Puget Sound Energy Inc.		D-UG-190530	Natural Gas	48.50	7/8/2020	Fully Litigated
Texas	Texas Gas Service Co.	OGS	D-GUD-10928	Natural Gas	59.00	8/4/2020	Settled
Wyoming	Questar Gas Co.		D-30010-187-GR-19	Natural Gas	55.00	8/21/2020	Settled
New Jersey	South Jersey Gas Co.	JPM	D-GR20030243	Natural Gas	54.00	9/23/2020	Settled
Nevada	Southwest Gas Corp.	SWX	D-20-02023 (Southern)	Natural Gas	49.26	9/25/2020	Fully Litigated
Nevada	Southwest Gas Corp.	SWX	D-20-02023 (Northern)	Natural Gas	49.26	9/25/2020	Fully Litigated
South Carolina	Piedmont Natural Gas Co.	DUK	D-2020-7-G	Natural Gas	52.31	10/4/2020	Settled
Massachusetts	Eversource Gas Co MA	ES	DPU 20-59	Natural Gas	53.25	10/7/2020	Settled
Colorado	Public Service Co. of CO	XEL	D-20AL-0049G	Natural Gas	55.62	10/12/2020	Settled
Oregon	Northwest Natural Gas Co.	NWN	D-UG-388	Natural Gas	50.00	10/16/2020	Settled
Massachusetts	NSTAR Gas Co.	ES	DPU 19-120	Natural Gas	54.77	10/30/2020	Fully Litigated
Maryland	Columbia Gas of Maryland Inc	NI	C-9644	Natural Gas	52.63	11/7/2020	Settled
New York	NY State Electric & Gas Corp.	IBE	C-19-G-0379	Natural Gas	48.00	11/19/2020	Settled
New York	Rochester Gas & Electric Corp.	IBE	C-19-G-0381	Natural Gas	48.00	11/19/2020	Settled
Florida	Peoples Gas System	EMA	D-20200051-GU	Natural Gas	54.70	11/19/2020	Settled
Wisconsin	Madison Gas and Electric Co.	MGEE	D-3270-UR-123 (Gas)	Natural Gas	55.00	11/24/2020	Settled
Arizona	Southwest Gas Corp.	SWX	D-G-01551A-19-0055	Natural Gas	51.10	12/9/2020	Fully Litigated
Oregon	Avista Corp.	AVA	D-UG 389	Natural Gas	50.00	12/10/2020	Settled
New Mexico	New Mexico Gas Co.	EMA	C-19-00317-UT	Natural Gas	52.00	12/16/2020	Settled
Maryland	Baltimore Gas and Electric Co.	EXC	C-9645 (Gas)	Natural Gas	52.00	12/16/2020	Fully Litigated
Wisconsin	Wisconsin Power and Light Co	LNT	D-6680-UR-122 (Gas)	Natural Gas	52.53	12/23/2020	Fully Litigated
Oregon	Cascade Natural Gas Corp.	MDU	D-UG 390	Natural Gas	50.00	1/6/2021	Settled
Delaware	Delmarva Power & Light Co.	EXC	D-20-0150	Natural Gas	50.37	1/6/2021	Settled
Illinois	Ameren Illinois	AEE	D-20-0308	Natural Gas	52.00	1/13/2021	Fully Litigated
Nebraska	Black Hills Nebraska Gas LLC	BKH	D-NG-109	Natural Gas	50.00	1/26/2021	Settled
Tennessee	Piedmont Natural Gas Co.	DUK	D-20-00086	Natural Gas	50.50	2/16/2021	Settled
Pennsylvania	Columbia Gas of Pennsylvania	NI	D-R-2020-3018835	Natural Gas	54.19	2/19/2021	Fully Litigated
District of Columbia	Washington Gas Light Co.	ALA	FC-1162	Natural Gas	52.10	2/24/2021	Settled
California	Southwest Gas Corp.	SWX	A-19-08-015 (SoCal)	Natural Gas	52.00	3/25/2021	Settled
California	Southwest Gas Corp.	SWX	A-19-08-015 (NoCal)	Natural Gas	52.00	3/25/2021	Settled
California	Southwest Gas Corp.	SWX	A-19-08-015 (LkTah)	Natural Gas	52.00	3/25/2021	Settled
Maryland	Washington Gas Light Co.	ALA	C-9651	Natural Gas	52.03	4/9/2021	Fully Litigated
North Dakota	MDU Resources Group	MDU	C-PU-20-379	Natural Gas	50.31	5/5/2021	Settled
Washington	Cascade Natural Gas Corp.	MDU	D-UG-200568	Natural Gas	49.10	5/18/2021	Fully Litigated
New York	Corning Natural Gas Corp.		C-20-G-0101	Natural Gas	48.00	5/19/2021	Fully Litigated
Pennsylvania	PECO Energy Co	EXC	D-R-2020-3018929	Natural Gas	53.38	6/17/2021	Fully Litigated
West Virginia	Hope Gas Inc.		C-20-0746-G-42T	Natural Gas	47.45	7/27/2021	Fully Litigated
New Hampshire	Liberty Utilities EnergyNorth	AQN	D-DG-20-105	Natural Gas	52.00	7/30/2021	Settled
New York	KeySpan Gas East Corp.	NG.	C-19-G-0310	Natural Gas	48.00	8/12/2021	Settled
New York	The Brooklyn Union Gas Co.	NG.	C-19-G-0309	Natural Gas	48.00	8/12/2021	Settled
Idaho	Avista Corp.	AVA	C-AVU-G-21-01	Natural Gas	50.00	9/1/2021	Settled
Illinois	North Shore Gas Co.	WEC	D-20-0810	Natural Gas	51.58	9/8/2021	Fully Litigated
Virginia	Virginia Natural Gas Inc.	SO	C-PUR-2020-00095	Natural Gas	51.89	9/14/2021	Settled
Washington	Avista Corp.	AVA	D-UG-200901	Natural Gas	48.50	9/27/2021	Settled
South Carolina	Piedmont Natural Gas Co.	DUK	D-2021-7-G	Natural Gas	52.20	9/29/2021	Settled
Massachusetts	Boston Gas Co.	NG.	DPU 20-120	Natural Gas	53.44	9/30/2021	Fully Litigated
Indiana	Sthrn IN Gas & Electric Co.	CNP	Ca-45447	Natural Gas	45.74	10/6/2021	Settled
Missouri	Spire Missouri Inc.	SR	C-GR-2021-0108	Natural Gas	49.86	10/27/2021	Fully Litigated
New Jersey	New Jersey Natural Gas Co.	NJR	D-GR21030679	Natural Gas	54.00	11/17/2021	Settled
Indiana	Indiana Gas Co.	CNP	Ca-45468	Natural Gas	46.21	11/17/2021	Settled
New York	Central Hudson Gas & Electric	FTS	C-20-G-0429	Natural Gas	50.00	11/18/2021	Settled
Illinois	Northern Illinois Gas Co.	SO	D-21-0098	Natural Gas	54.46	11/18/2021	Fully Litigated
Wisconsin	Northern States Power Co.	XEL	D- 4220-UR-125 (Gas)	Natural Gas	52.50	11/18/2021	Settled
Wisconsin	Wisconsin Power and Light Co	LNT	D-6680-UR-123 (Gas)	Natural Gas	52.50	11/18/2021	Settled
Wisconsin	Madison Gas and Electric Co.	MGEE	D-3270-UR-124 (Gas)	Natural Gas	55.00	11/23/2021	Settled
Oklahoma	Oklahoma Natural Gas Co	OGS	Ca-PUD202100063	Natural Gas	58.55	11/30/2021	Settled
Maryland	Columbia Gas of Maryland Inc	NI	C-9664	Natural Gas	52.95	12/3/2021	Fully Litigated
Michigan	DTE Gas Co.	DTE	C-U-20940	Natural Gas	39.23	12/9/2021	Fully Litigated
Colorado	Black Hills Colorado Gas Inc.	BKH	D-21AL-0236G	Natural Gas	50.26	12/13/2021	Settled
Kentucky	Columbia Gas of Kentucky Inc	NI	C-2021-00183	Natural Gas	52.64	12/28/2021	Settled
Kentucky	Duke Energy Kentucky Inc.	DUK	C-2021-00190	Natural Gas	51.34	12/28/2021	Settled
Iowa	Black Hills Iowa Gas Utility	BKH	D-RPU-2021-0002	Natural Gas	50.01	12/28/2021	Settled
North Carolina	Piedmont Natural Gas Co.	DUK	D-G-9, Sub 781	Natural Gas	51.60	1/6/2022	Settled
New York	Niagara Mohawk Power Corp.	NG.	C-20-G-0381	Natural Gas	48.00	1/20/2022	Settled
North Carolina	Public Service Co. of NC	D	D-G-5 Sub 632	Natural Gas	51.60	1/21/2022	Settled
Nevada	Southwest Gas Corp.	SWX	D-21-09001 (Southern)	Natural Gas	50.00	3/22/2022	Settled
Nevada	Southwest Gas Corp.	SWX	D-21-09001 (Northern)	Natural Gas	50.00	3/22/2022	Settled
New York	Orange & Rockland Utlts Inc.	ED	C-21-G-0073	Natural Gas	48.00	4/14/2022	Settled
Kentucky	Atmos Energy Corp.	ATO	C-2021-00214	Natural Gas	54.50	5/19/2022	Fully Litigated

Summit Natural Gas of Arkansas
Range of Authorized Common Equity Ratios - 2020 to Present

State	Company	Parent Company Ticker	Docket	Rate Case Service Type	Authorized Common Equity to Total Capital (%)	Decision Date	Decision Type
New York	Corning Natural Gas Corp.		C-21-G-0394	Natural Gas	48.00	6/16/2022	Settled
New Hampshire	Northern Utilities Inc.	UTL	D-DG-21-104	Natural Gas	52.00	7/20/2022	Settled
Indiana	Northern IN Public Svc Co. LLC	NI	Ca-45621	Natural Gas	49.47	7/27/2022	Settled
Oregon	Avista Corp.	AVA	D-UG 433	Natural Gas	50.00	8/2/2022	Settled
New Jersey	Elizabethtown Gas Co.	JPM	D-GR21121254	Natural Gas	52.00	8/17/2022	Settled
Minnesota	CenterPoint Energy Resources	CNP	D-G-008/GR-21-435	Natural Gas	51.00	8/18/2022	Settled
Washington	Cascade Natural Gas Corp.	MDU	D-UG-210755	Natural Gas	47.00	8/23/2022	Settled
South Carolina	Piedmont Natural Gas Co.	DUK	D-2022-89-G	Natural Gas	52.20	9/15/2022	Settled
Arkansas	Black Hills Energy Arkansas	BKH	D-21-097-U	Natural Gas	45.00	10/10/2022	Fully Litigated
Delaware	Delmarva Power & Light Co.	EXC	D-22-0002	Natural Gas	49.94	10/12/2022	Settled
Oregon	Northwest Natural Gas Co.	NWN	D-UG-435	Natural Gas	50.00	10/24/2022	Settled
Colorado	Public Service Co. of CO	XEL	D-22AL-0046G	Natural Gas	53.78	10/25/2022	Fully Litigated
Massachusetts	The Berkshire Gas Co.	IBE	DPU 22-20	Natural Gas	54.00	10/27/2022	Settled
North Dakota	Northern States Power Co.	XEL	C-PU-21-381	Natural Gas	52.54	10/27/2022	Settled
California	San Diego Gas & Electric Co.	SRE	A-21-08-014 (Gas)	Natural Gas	52.00	11/3/2022	Fully Litigated
Maryland	Columbia Gas of Maryland Inc	NI	C-9680	Natural Gas	52.97	11/17/2022	Settled
New Mexico	New Mexico Gas Co.	EMA	C-21-00267-UT	Natural Gas	52.00	11/30/2022	Settled
California	Southern California Gas Co.	SRE	A-22-04-011	Natural Gas	52.00	12/15/2022	Fully Litigated
New Jersey	South Jersey Gas Co.	JPM	D-GR22040253	Natural Gas	54.00	12/21/2022	Settled
Washington	Puget Sound Energy Inc.		D-UG-220067	Natural Gas	49.00	12/22/2022	Settled
Wisconsin	Wisconsin Public Service Corp.	WEC	D-6690-UR-127 (Gas)	Natural Gas	53.40	12/22/2022	Fully Litigated
Utah	Questar Gas Co.		D-22-057-03	Natural Gas	51.00	12/23/2022	Fully Litigated
Wisconsin	Wisconsin Electric Power Co.	WEC	D-5-UR-110 (WEP-Gas)	Natural Gas	58.22	12/29/2022	Fully Litigated
Wisconsin	Wisconsin Gas LLC	WEC	D-5-UR-110	Natural Gas	52.70	12/29/2022	Fully Litigated
Texas	Texas Gas Service Co.	OGS	D-OSS-22-00009896	Natural Gas	59.74	1/19/2023	Fully Litigated
Arizona	Southwest Gas Corp.	SWX	D-G-01551A-21-0368	Natural Gas	50.00	1/23/2023	Settled
Florida	Florida Public Utilities Co.	CPK	D-20220067-GU	Natural Gas	45.16	1/24/2023	Fully Litigated
Ohio	Columbia Gas Ohio Inc.	NI	C-21-0637-GA-AIR	Natural Gas	50.60	1/26/2023	Settled
Minnesota	Northern States Power Co.	XEL	D-G-002/GR-21-678	Natural Gas	52.50	3/23/2023	Settled
Florida	Pivotal Utility Holdings Inc.	CPK	20220069-GU	Natural Gas	59.60	3/28/2023	Fully Litigated
Colorado	Atmos Energy Corp.	ATO	D-22AL-0348G	Natural Gas	58.00	5/4/2023	Settled
Idaho	Intermountain Gas Co.	MDU	C-INT-G-22-07	Natural Gas	50.00	6/30/2023	Settled
New York	Consolidated Edison Company of	ED	C-22-G-0065	Natural Gas	48.00	7/20/2023	Settled
Idaho	Avista Corp.	AVA	C-AVU-G-23-01	Natural Gas	50.00	8/31/2023	Settled
Maine	Northern Utilities Inc.	UTL	D-2023-00051	Natural Gas	52.01	9/20/2023	Settled
South Carolina	Dominion Energy South Carolina	D	D-2023-70-G	Natural Gas	54.78	9/20/2023	Settled
South Carolina	Piedmont Natural Gas Co.	DUK	D-2023-7-G	Natural Gas	53.13	10/5/2023	Settled
Tennessee	Chattanooga Gas Co.	SO	D-23-00029	Natural Gas	49.23	10/6/2023	Settled
New York	NY State Electric & Gas Corp.	IBE	C-22-G-0318	Natural Gas	48.00	10/12/2023	Settled
New York	Rochester Gas & Electric Corp.	IBE	C-22-G-0320	Natural Gas	48.00	10/12/2023	Settled
Montana	NorthWestern Energy Group	NWE	D-2022-7-78 (gas)	Natural Gas	48.02	10/25/2023	Settled
Oregon	Avista Corp.	AVA	D-UG-461	Natural Gas	50.00	10/26/2023	Settled
Minnesota	Minnesota Energy Resources	WEC	D-G-011/GR-22-504	Natural Gas	53.00	10/26/2023	Settled
Ohio	Duke Energy Ohio Inc.	DUK	C-22-0507-GA-AIR	Natural Gas	52.32	11/1/2023	Settled
Wisconsin	Madison Gas and Electric Co.	MGEE	D-3270-UR-125 (Gas)	Natural Gas	56.06	11/3/2023	Fully Litigated
Wyoming	Questar Gas Co.		D-30010-215-GR-23	Natural Gas	51.56	11/7/2023	Settled
Wisconsin	Northern States Power Co.	XEL	D-4220-UR-126 (Gas)	Natural Gas	52.50	11/9/2023	Fully Litigated
Wisconsin	Wisconsin Power and Light Co	LNT	D-6680-UR-124 (Gas)	Natural Gas	53.70	11/9/2023	Fully Litigated
Illinois	North Shore Gas Co.	WEC	D-23-0068	Natural Gas	52.58	11/16/2023	Fully Litigated
Illinois	The Peoples Gas Light & Coke C	WEC	D-23-0069	Natural Gas	50.79	11/16/2023	Fully Litigated
Illinois	Ameren Illinois	AEE	D-23-0067	Natural Gas	50.00	11/16/2023	Fully Litigated
Illinois	Northern Illinois Gas Co.	SO	D-23-0066	Natural Gas	50.00	11/16/2023	Fully Litigated
Tennessee	Piedmont Natural Gas Co.	DUK	D-23-00035	Natural Gas	50.09	12/4/2023	Settled
Maryland	Baltimore Gas and Electric Co.	EXC	C-9692 (GAS)	Natural Gas	52.00	12/14/2023	Fully Litigated
Maryland	Washington Gas Light Co.	ALA	C-9704	Natural Gas	52.60	12/14/2023	Fully Litigated
District of Columbia	Washington Gas Light Co.	ALA	FC-1169	Natural Gas	52.00	12/15/2023	Fully Litigated
California	Southern California Gas Co.	SRE	Advice Letter No. 6207-G	Natural Gas	52.00	12/22/2023	Fully Litigated
Wyoming	Black Hills Wyoming Gas LLC		D-30026-78-GR-23	Natural Gas	51.00	1/17/2024	Settled
Texas	Texas Gas Service Co.	OGS	D-OSS-23-00014399	Natural Gas	59.07	1/31/2024	Settled
Colorado	Black Hills Colorado Gas Inc.	BKH	D-23AL-0231G	Natural Gas	50.87	3/24/2024	Settled
Nevada	Southwest Gas Corp.	SWX	D-23-09012 (Northern)	Natural Gas	50.00	4/8/2024	Settled
Nevada	Southwest Gas Corp.	SWX	D-23-09012 (Southern)	Natural Gas	50.00	4/8/2024	Settled
Alaska	ENSTAR Natural Gas Co.		D-U-22-081	Natural Gas	54.11	4/8/2024	Fully Litigated
Ohio	Northeast Ohio NaturalGas Corp		C-23-0154-GA-AIR	Natural Gas	51.42	4/17/2024	Settled
Texas	CenterPoint Energy Resources	CNP	D-OSS-23-00015513	Natural Gas	60.61	6/26/2024	Settled
Massachusetts	Fitchburg Gas & Electric Light	UTL	DPU 23-81	Natural Gas	52.26	6/28/2024	Fully Litigated

Minimum Authorized Equity Ratio: 39.23
Maximum Authorized Equity Ratio: 60.61

Source of Information: Regulatory Research Associates

Summit Natural Gas of Arkansas
Hypothetical Example of the Inadequacy of
A DCF Return Rate Related to Book Value
When Market Value is Greater / Less than Book Value

		[1]	[2]	[3]
Line No.		Market Value	Book Value with Market to Book Ratio of 200%	Book Value with Market to Book Ratio of 80%
1.	Per Share	$ 30.00	$ 15.00	$ 37.50
2.	DCF Cost Rate (1)	10.00%	10.00%	10.00%
3.	Return in Dollars	$ 3.000	$ 1.500	$ 3.750
4.	Dividends (2)	$ 0.900	$ 0.900	$ 0.900
5.	Growth in Dollars	$ 2.100	$ 0.600	$ 2.850
6.	Return on Market Value	10.00%	5.00% (3)	12.50% (4)
7.	Rate of Growth on Market Value	7.00% (5)	2.00% (6)	9.50% (7)

Notes:
(1) Comprised of 3.0% dividend yield and 6.0% growth.
(2) $30.00 * 3.0% yield = $0.900.
(3) $1.50 / $30.00 market value = 5.00%.
(4) $3.75 / $30.00 market value = 12.50%.
(5) Expected rate of growth per market based DCF model.
(6) Actual rate of growth when DCF cost rate is applied to book value ($1.500 possible earnings - $0.900 dividends = $0.600 for growth / $30.00 market value = 2.00%).
(7) Actual rate of growth when DCF cost rate is applied to book value ($3.750 possible earnings - $0.900 dividends = $2.850 for growth / $30.00 market value = 9.50%).

Summit Natural Gas of Arkansas
Growth Rate Regression Analysis

Company	Ticker	P/E Ratio	Proj. Earnings Growth Rate	Proj. Dividend Growth Rate	Historical 10-year EPS Growth Rate	Historical 10-year DPS Growth Rate
ALLETE, Inc.	ALE	16.8	6.00%	3.50%	3.00%	3.50%
Alliant Energy Corporation	LNT	16.4	6.00%	6.00%	6.00%	6.50%
Ameren Corporation	AEE	15.5	6.50%	6.50%	4.00%	3.50%
American Electric Power Company, Inc.	AEP	15.9	6.50%	5.50%	5.00%	5.00%
Avangrid, Inc.	AGR	16.3	3.50%	0.00%	NA	NA
Avista Corporation	AVA	14.6	6.00%	4.50%	3.00%	4.50%
Black Hills Corporation	BKH	14.2	3.50%	4.00%	7.50%	5.00%
CenterPoint Energy, Inc.	CNP	20.4	6.50%	6.00%	NA	-1.00%
CMS Energy Corporation	CMS	18.6	5.00%	4.00%	6.00%	7.00%
Consolidated Edison, Inc.	ED	17.7	6.00%	3.50%	2.00%	2.50%
Dominion Energy Inc.	D	18.3	3.00%	0.50%	1.50%	2.00%
DTE Energy Company	DTE	16.9	4.50%	3.00%	4.00%	5.50%
Duke Energy Corporation	DUK	16.5	5.00%	2.00%	3.00%	3.00%
Edison International	EIX	14.3	6.00%	5.50%	2.00%	8.00%
Entergy Corporation	ETR	20.6	0.50%	3.50%	2.50%	2.00%
Exelon Corporation	EXC	15.4	NMF	NMF	-0.50%	-3.00%
FirstEnergy Corp.	FE	14.4	5.50%	5.50%	1.00%	-2.50%
Evergy, Inc.	EVRG	14.8	7.50%	7.00%	NA	NA
Hawaiian Electric Industries, Inc.	HE	6.0	-11.50%	NMF	3.00%	0.50%
IDACORP, Inc.	IDA	18.1	5.00%	5.50%	4.00%	8.00%
MGE Energy, Inc.	MGEE	21.1	7.00%	3.50%	5.00%	4.50%
NextEra Energy, Inc.	NEE	19.8	8.00%	9.00%	9.50%	11.00%
Eversource Energy	ES	13.1	6.00%	6.00%	6.50%	7.00%
NorthWestern Corporation	NWE	13.7	4.00%	2.00%	3.50%	5.50%
OGE Energy Corp.	OGE	17.0	6.50%	3.00%	3.00%	7.50%
Otter Tail Corporation	OTTR	14.3	4.50%	7.00%	18.00%	2.50%
PG&E Corporation	PCG	12.3	9.00%	NMF	-6.50%	NA
Pinnacle West Capital Corporation	PNW	15.8	4.50%	1.50%	3.50%	4.00%
PNM Resources, Inc.	PNM	14.2	5.00%	5.00%	7.50%	9.00%
Portland General Electric Company	POR	14.3	6.00%	5.50%	3.50%	5.00%
PPL Corporation	PPL	16.2	7.50%	-0.50%	-9.00%	-1.00%
Public Service Enterprise Group Incorporated	PEG	18.8	5.00%	5.00%	3.00%	4.50%
Sempra Energy	SRE	15.0	7.00%	5.00%	7.50%	7.00%
Southern Company	SO	18.6	6.50%	3.50%	3.00%	3.50%
Unitil Corp.	UTL	NA	NA	NA	NA	NA
WEC Energy Group, Inc.	WEC	16.5	6.00%	7.00%	6.50%	10.00%
Xcel Energy Inc.	XEL	15.3	7.00%	5.50%	5.50%	6.00%
Atmos Energy Corporation	ATO	16.8	7.00%	7.50%	9.50%	7.00%
Chesapeake Utilities	CPK	21.6	6.50%	8.00%	9.00%	8.00%
NiSource Inc.	NI	16.9	9.50%	4.50%	1.50%	-0.50%
New Jersey Resources	NJR	14.9	5.00%	5.00%	5.00%	6.50%
Northwest Natural Gas Holding	NWN	15.4	6.50%	0.50%	-1.00%	1.50%
One Gas, Inc.	OGS	16.0	3.50%	2.50%	NA	NA
RGC Resources	RGCO	NA	NA	NA	NA	NA
Spire Inc.	SR	14.5	4.50%	4.50%	5.00%	5.00%
Southwest Gas Holdings	SWX	23.0	10.00%	5.50%	5.50%	8.50%
UGI Corporation	UGI	8.4	6.50%	3.50%	8.00%	6.50%

Notes:
Source: Value Line Reports as of June 30, 2024.

Summit Natural Gas of Arkansas
Growth Rate Regression Analysis

SUMMARY OUTPUT

Regression Statistics	
Multiple R	0.44818
R Square	0.20086
Adjusted R Square	0.18183
Standard Error	2.79671
Observations	44

ANOVA

	df	*SS*	*MS*	*F*	*Significance F*
Regression	1	82.56943	82.56943	10.55663	0.00228
Residual	42	328.50603	7.82157		
Total	43	411.07545			

	Coefficients	*Standard Error*	*t Stat*	*P-value*	*Lower 95%*	*Upper 95%*
Intercept	13.72298	0.85289	16.09000	0.00000	12.00178	15.44418
Proj. Earnings Growth Rate	44.25428	13.62049	3.24910	0.00228	16.76702	71.74153

SUMMARY OUTPUT

Regression Statistics	
Multiple R	0.10524
R Square	0.01108
Adjusted R Square	-0.01365
Standard Error	2.67345
Observations	42

ANOVA

	df	*SS*	*MS*	*F*	*Significance F*
Regression	1	3.20215	3.20215	0.44802	0.50712
Residual	40	285.89428	7.14736		
Total	41	289.09643			

	Coefficients	*Standard Error*	*t Stat*	*P-value*	*Lower 95%*	*Upper 95%*
Intercept	15.89458	0.94584	16.80478	0.00000	13.98298	17.80619
Proj. Dividend Growth Rate	12.89890	19.27101	0.66934	0.50712	-26.04926	51.84705

SUMMARY OUTPUT

Regression Statistics	
Multiple R	0.06053
R Square	0.00366
Adjusted R Square	-0.02188
Standard Error	3.16149
Observations	41

ANOVA

	df	*SS*	*MS*	*F*	*Significance F*
Regression	1	1.43353	1.43353	0.14342	0.70695
Residual	39	389.80598	9.99503		
Total	40	391.23951			

	Coefficients	*Standard Error*	*t Stat*	*P-value*	*Lower 95%*	*Upper 95%*
Intercept	15.85782	0.69204	22.91474	0.00000	14.45805	17.25760
Historical 10-year EPS Growth Rate	4.44204	11.72926	0.37871	0.70695	-19.28262	28.16670

SUMMARY OUTPUT

Regression Statistics	
Multiple R	0.13094
R Square	0.01714
Adjusted R Square	-0.00806
Standard Error	3.15364
Observations	41

ANOVA

	df	*SS*	*MS*	*F*	*Significance F*
Regression	1	6.76574	6.76574	0.68029	0.41450
Residual	39	387.87182	9.94543		
Total	40	394.63756			

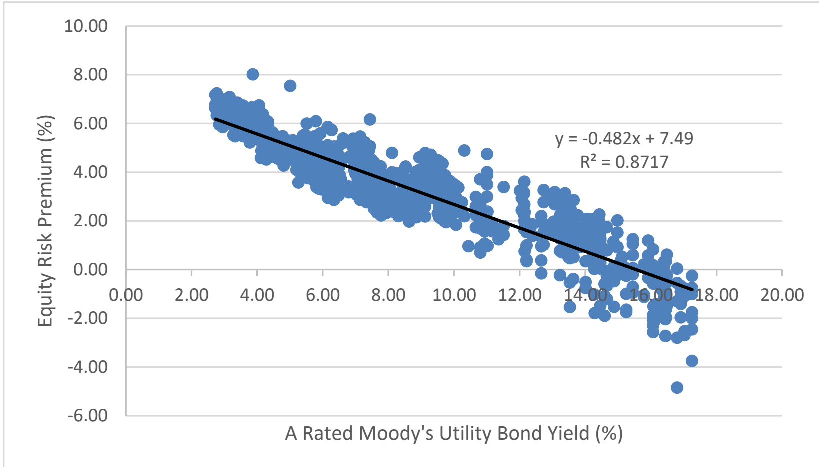
	Coefficients	*Standard Error*	*t Stat*	*P-value*	*Lower 95%*	*Upper 95%*
Intercept	15.66769	0.84995	18.43371	0.00000	13.94850	17.38687
Historical 10-year DPS Growth Rate	12.42700	15.06678	0.82479	0.41450	-18.04843	42.90243

Summit Natural Gas of Arkansas
Updated CAPM for Mr. Daves

	Risk-Free Rate (1)	Beta (2)	Market Risk Premium (3)	CAPM	ECAPM	Average CAPM/ECAPM
Value Line dates	4.39%	0.88	7.10%	10.61%	10.83%	**10.72%**
Prior 30-day avg.	4.53%	0.88	7.10%	10.74%	10.96%	**10.85%**
					Mean	**10.79%**

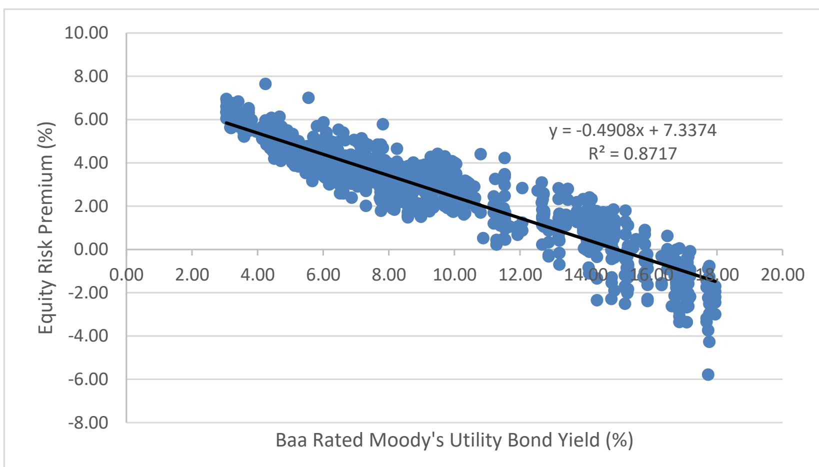
Sources
(1) - Direct Exhibit DD-12 - Treasury.gov
(2) - Direct Exhibit DD-12 - Value Line Investment Survey Issue #3 February 2024
(3) - Direct Exhibit DD-12 - Kroll 2023 SBBI Yearbook

Summit Natural Gas of Arkansas
Mr. Daves' Corrected Risk Premium Model - A Utility Bond
Natural Gas Cases Nationwide Since 1980



	Constant	Slope	A Utility Yield (%) (1)	Risk Premium (%)	ROE (%)
12-Month	7.49	-0.48	5.65	4.77	10.42
9-Month	7.49	-0.48	5.74	4.72	10.46
6-Month	7.49	-0.48	5.63	4.78	10.40
3-Month	7.49	-0.48	5.63	4.77	10.41
Average					**10.42**

Mr. Daves' Corrected Risk Premium Model - Baa Utility Bond
Natural Gas Cases Nationwide Since 1980

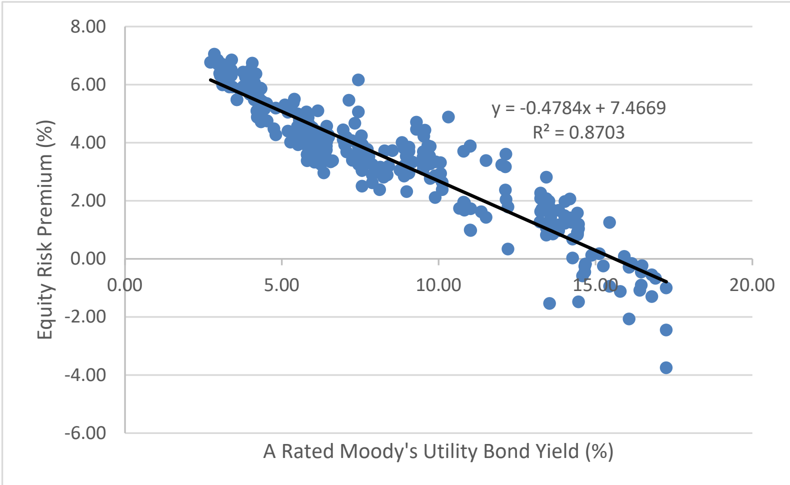


	Constant	Slope	Baa Utility Yield (%) (1)	Risk Premium (%)	ROE (%)
12-Month	7.32	-0.49	5.93	4.42	10.36
9-Month	7.32	-0.49	6.00	4.39	10.39
6-Month	7.32	-0.49	5.87	4.45	10.32
3-Month	7.32	-0.49	5.86	4.46	10.32
Average					**10.35**

Sources:
Regulatory Research Associates, Bloomberg Professional Services, and Direct Exhibit DD-14

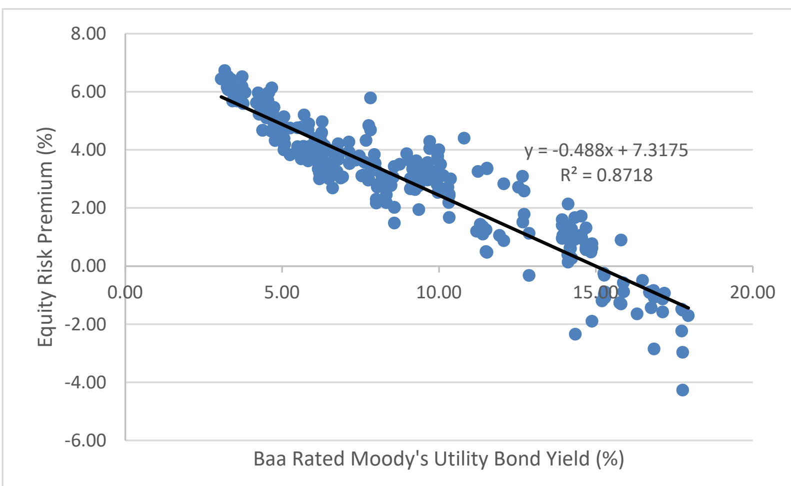
Notes:
(1) From Daves' electronic workpapers.

Summit Natural Gas of Arkansas
Mr. Daves' Corrected Risk Premium Model - A Utility Bond
Natural Gas Cases for Surrounding Jurisdictions Since 1980



	Constant	Slope	A Utility Yield (%) (1)	Risk Premium (%)	ROE (%)
12-Month	7.47	-0.48	5.65	4.76	10.41
9-Month	7.47	-0.48	5.74	4.72	10.46
6-Month	7.47	-0.48	5.63	4.77	10.40
3-Month	7.47	-0.48	5.63	4.77	10.40
Average					**10.42**

Mr. Daves' Corrected Risk Premium Model - Baa Utility Bond
Natural Gas Cases for Surrounding Jurisdictions Since 1980



	Constant	Slope	Baa Utility Yield (%) (1)	Risk Premium (%)	ROE (%)
12-Month	7.32	-0.49	5.93	4.42	10.36
9-Month	7.32	-0.49	6.00	4.39	10.39
6-Month	7.32	-0.49	5.87	4.45	10.32
3-Month	7.32	-0.49	5.86	4.46	10.32
Average					**10.35**

Sources:
Regulatory Research Associates, Bloomberg Professional Services, and Direct Exhibit DD-14

Notes:
(1) From Daves' electronic workpapers.

Summit Natural Gas of Arkansas
Evaluation of Staff's Credit Metric Adequacy Test - Debt/EBITDA

Staff's Recommended ROE - 9.75%

Line			Source
1	Total Debt %	48.35%	Long-term debt, short-term debt
2	Pre-tax ROR	6.80%	Mr. Daves' Proposed Capital Structure and 9.75% ROE
3	Arkansas Rate Base	1,225,235,434	Daves Workpapers
4	EBIT	83,359,035	Line 2 x Line 3
5	Depreciation & Amortization	68,739,800	Daves Workpapers
6	EBITDA	152,098,835	Sum of lines 4-5
7	Total Debt	592,402,680	Line 1 x Line 3
8	Debt/EBITDA (x)	3.9	Line 7 / Line 6

Company's Proposed ROE - 11.00%

Line			Source
1	Total Debt %	48.35%	Long-term debt, short-term debt
2	Pre-tax ROR	7.44%	Mr. Daves' Proposed Capital Structure and 11.00% ROE
3	Arkansas Rate Base	1,225,235,434	Daves Workpapers
4	EBIT	91,180,626	Line 2 x Line 3
5	Depreciation & Amortization	68,739,800	Daves Workpapers
6	EBITDA	159,920,426	Sum of lines 4-5
7	Total Debt	592,402,680	Line 1 x Line 3
8	Debt/EBITDA (x)	3.7	Line 7 / Line 6

Minimum ROE for a "Significant" Financial Risk Rating - 6.48%

Line			Source
1	Total Debt %	48.35%	Long-term debt, short-term debt
2	Pre-tax ROR	5.13%	Mr. Daves' Proposed Capital Structure and 6.48% ROE
3	Arkansas Rate Base	1,225,235,434	Daves Workpapers
4	EBIT	62,897,753	Line 2 x Line 3
5	Depreciation & Amortization	68,739,800	Daves Workpapers
6	EBITDA	131,637,553	Sum of lines 4-5
7	Total Debt	592,402,680	Line 1 x Line 3
8	Debt/EBITDA (x)	4.5	Line 7 / Line 6

Maximum ROE for a "Significant" Financial Risk Rating - 12.49%

Line			Source
1	Total Debt %	48.35%	Long-term debt, short-term debt
2	Pre-tax ROR	8.20%	Mr. Daves' Proposed Capital Structure and 12.49% ROE
3	Arkansas Rate Base	1,225,235,434	Daves Workpapers
4	EBIT	100,503,962	Line 2 x Line 3
5	Depreciation & Amortization	68,739,800	Daves Workpapers
6	EBITDA	169,243,762	Sum of lines 4-5
7	Total Debt	592,402,680	Line 1 x Line 3
8	Debt/EBITDA (x)	3.5	Line 7 / Line 6

Source: Daves Direct Workpapers

Summit Natural Gas of Arkansas
Evaluation of Staff's Credit Metric Adequacy Test - EBITDA/Interest

Staff's Recommended ROE - 9.75%

Line			Source
1	Weighted Cost of Debt	1.82%	Long-term debt, short-term debt, and customer deposits
2	Pre-tax ROR	6.80%	Mr. Daves' Proposed Capital Structure and 9.75% ROE
3	Arkansas Rate Base	1,225,235,434	Daves Workpapers
4	EBIT	83,359,035	Line 2 x Line 3
5	Depreciation & Amortization	68,739,800	Daves Workpapers
6	EBITDA	152,098,835	Sum of lines 4-5
7	Total Interest	22,350,626	Line 1 x Line 3
8	EBITDA Interest Coverage (x)	7.8	(Line 6 + Line 7) / Line 7

Company's Proposed ROE - 11.00%

Line			Source
1	Weighted Cost of Debt	1.82%	Long-term debt, short-term debt, and customer deposits
2	Pre-tax ROR	7.44%	Mr. Daves' Proposed Capital Structure and 11.00% ROE
3	Arkansas Rate Base	1,225,235,434	Daves Workpapers
4	EBIT	91,180,626	Line 2 x Line 3
5	Depreciation & Amortization	68,739,800	Daves Workpapers
6	EBITDA	159,920,426	Sum of lines 4-5
7	Total Interest	22,350,626	Line 1 x Line 3
8	EBITDA Interest Coverage (x)	8.2	(Line 6 + Line 7) / Line 7

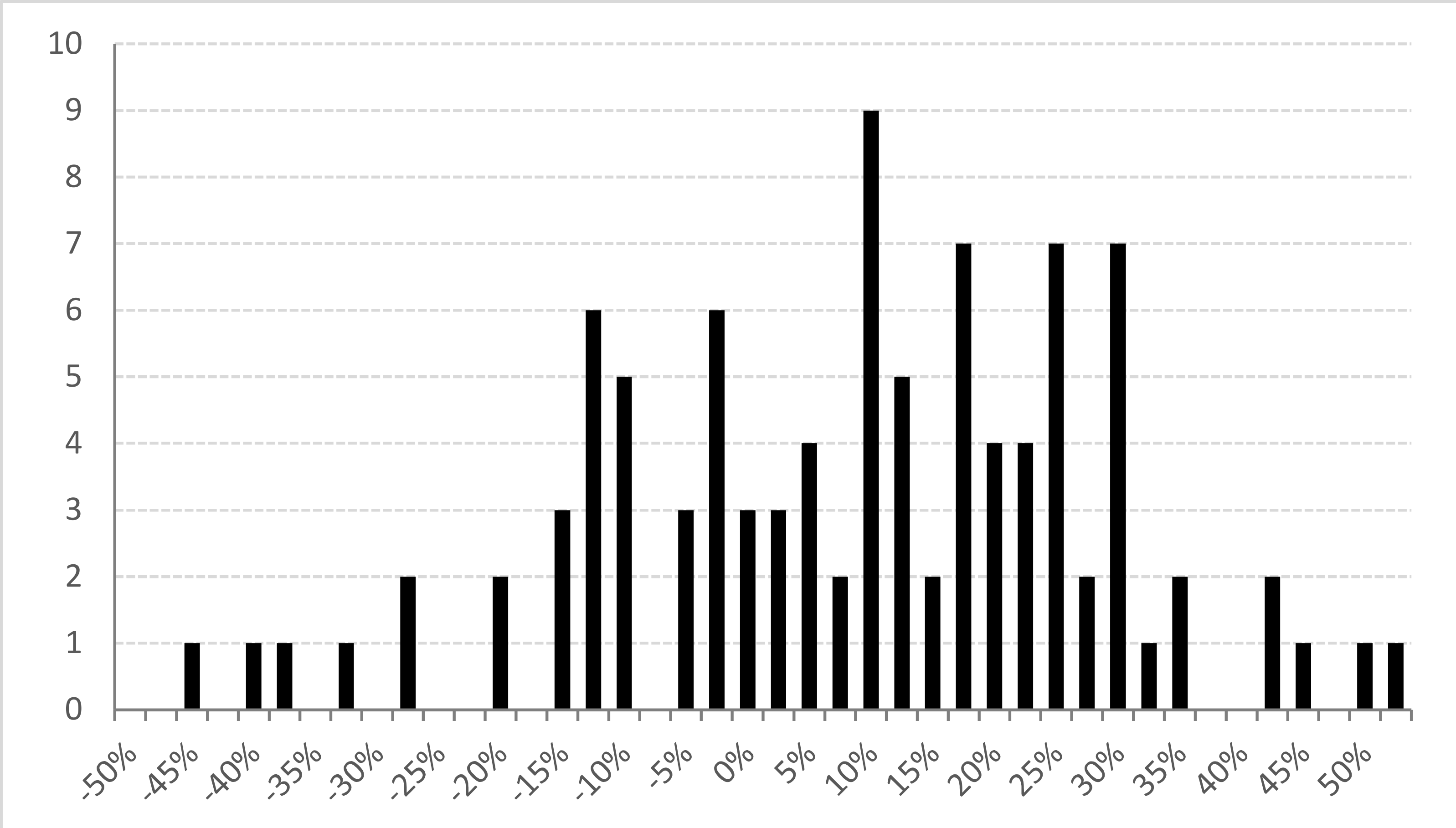
Minimum ROE for a "Significant" Financial Risk Rating - 6.48%

Line			Source
1	Weighted Cost of Debt	1.82%	Long-term debt, short-term debt, and customer deposits
2	Pre-tax ROR	5.13%	Mr. Daves' Proposed Capital Structure and 6.48% ROE
3	Arkansas Rate Base	1,225,235,434	Daves Workpapers
4	EBIT	62,897,753	Line 2 x Line 3
5	Depreciation & Amortization	68,739,800	Daves Workpapers
6	EBITDA	131,637,553	Sum of lines 4-5
7	Total Interest	22,350,626	Line 1 x Line 3
8	EBITDA Interest Coverage (x)	6.9	(Line 6 + Line 7) / Line 7

Maximum ROE for a "Significant" Financial Risk Rating - 12.49%

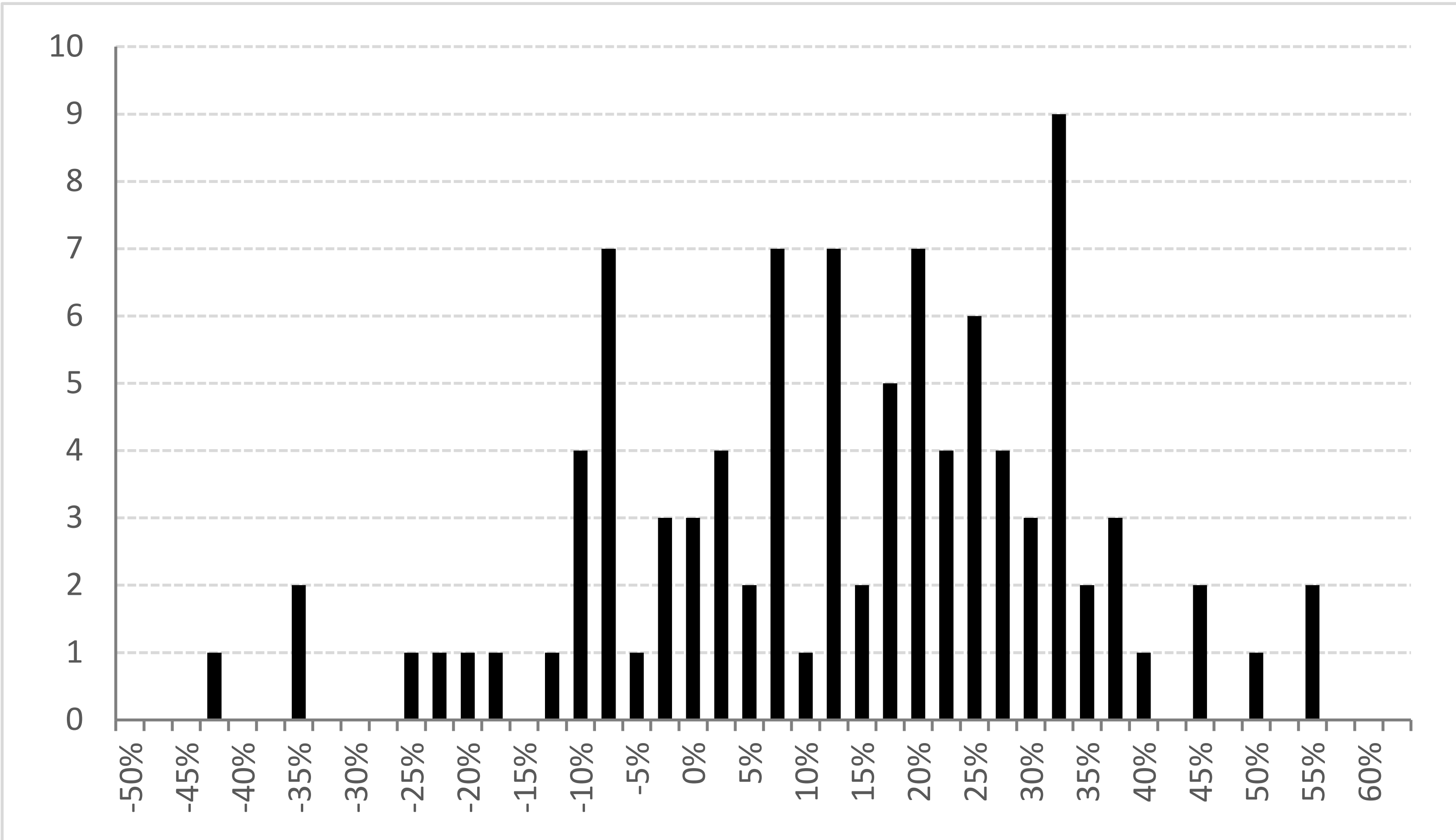
Line			Source
1	Weighted Cost of Debt	1.82%	Long-term debt, short-term debt, and customer deposits
2	Pre-tax ROR	8.20%	Mr. Daves' Proposed Capital Structure and 12.49% ROE
3	Arkansas Rate Base	1,225,235,434	Daves Workpapers
4	EBIT	100,503,962	Line 2 x Line 3
5	Depreciation & Amortization	68,739,800	Daves Workpapers
6	EBITDA	169,243,762	Sum of lines 4-5
7	Total Interest	22,350,626	Line 1 x Line 3
8	EBITDA Interest Coverage (x)	8.6	(Line 6 + Line 7) / Line 7

Summit Natural Gas of Arkansas
Frequency Distribution of Market Risk Premium, 1926 - 2023



Source: Kroll Cost of Capital Analyzer

Summit Natural Gas of Arkansas
Frequency Distribution of Observed Market Returns, 1926 - 2023



Source: Kroll Cost of Capital Analyzer

FINANCIAL QUARTERLY
R·E·V·I·E·W

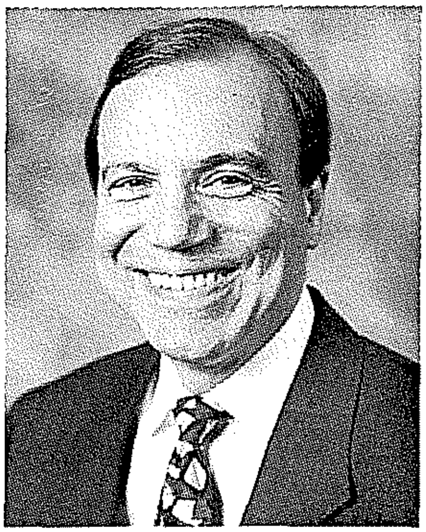
Comparable Earnings: New Life for an Old Precept

by
Frank J. Hanley
Pauline M. Ahern

Reprinted from the American Gas Association's *Financial Quarterly Review*
Summer 1994 edition, Arlington, Va.

Comparable Earnings: New Life for an Old Precept

Accelerating deregulation has greatly increased the investment risk of natural gas utilities. As a result, the authors believe it more appropriate than ever to employ the comparable earnings model. We believe our application of the model overcomes the greatest traditional objection to it — lack of comparability of the selected non-utility proxy firms. Our illustration focuses on a target gas pipeline company with a beta of 0.96 — almost equal to the market's beta of 1.00.



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Introduction

The comparable earnings model used to determine a common equity cost rate is deeply rooted in the standard of "corresponding risk" enunciated in the landmark *Bluefield* and *Hope* decisions of the U.S. Supreme Court.[1] With such solid grounding in the foundations of rate of return regulation, comparable earnings should be accepted as a principal model, along with the currently popular market-based models, provided that its most common criticism, non-comparability of the proxy companies, is overcome.

Our comparable earnings model overcomes the non-comparability issue of the non-utility firms selected as a proxy for the target utility, in this example, a gas pipeline company. We should note that in the absence of common stock prices for the target utility (as with a wholly-owned subsidiary), it is appropriate to use the average of a proxy group of similar risk gas pipeline companies whose common stocks are actively traded. As we will demonstrate, our selection process results in a group of domestic, non-utility firms that is comparable in total risk, the sum of business and financial risk, which reflects both non-diversifiable systematic, or market, risk as well as diversifiable unsystematic, or firm-specific, risk.

Embedded in the Landmark Decisions

As stated in *Bluefield* in 1922: "A public utility is entitled to such rates as will permit it to earn a return ... on investments in other business undertakings which are attended by corresponding risks and uncertainties ..."

In addition, the court stated in *Hope* in 1944: "By that standard the return to the equity owner should be commensurate with returns on investments in other enterprises having corresponding risks."

Thus, the "corresponding risk" precept of *Bluefield* and *Hope* predates the use of such market-based cost-of-equity models as the Discounted Cash Flow (DCF) and Capital Asset Pricing (CAPM), which were developed later and are currently popular in rate-base/rate-of-return regulation. Consequently, the comparable earnings model has a longer regulatory and judicial history. However, it has far greater relevance now than ever before in its history because significant deregulation has substantially increased natural gas utilities' investment risk to a level similar to that of non-utility firms. As a result, it is

Comparable Earnings *from page 4*

more important than ever to look to similar-risk non-utility firms for insight into common equity cost rate, especially in view of the deficiencies inherent in the currently popular market-based cost of common equity models, particularly the DCF model.

Despite the fact that the landmark decisions are still regarded as having set the standards for determining a fair rate of return, the comparable earnings model has experienced decreased usage by expert witnesses, as well as less regulatory acceptance over the years. We believe the decline in the popularity of the comparable earnings model, in large measure, is attributable to the difficulty of selecting non-utility proxy firms that regulators will accept as comparable to the target utility. Regulatory acceptance is difficult to gain when the selection process is arbitrary. Our application of the model is objective and consistent with fundamental financial tenets.

Principles of Comparable Earnings

Regulation is a substitute for the competition of the marketplace. Moreover, regulated public utilities compete in the capital markets with all firms, including unregulated non-utilities. The comparable earnings model is based upon the opportunity cost principle; i.e., that the true cost of an investment is the return that could have been earned on the next best available alternative investment of similar risk. Consequently, the comparable earnings model is consistent with regulatory and financial principles, as it is a surrogate for the competition of the marketplace, and investors seek the greatest available rate of return for bearing similar risk.

The selection of comparable firms is the most difficult step in applying the comparable earnings model, as noted by Phillips[2] as well as by Bonbright, Danielsen and Kamerschen.[3] The selection of non-utility proxy firms should result in a sufficiently broad-based group in order to minimize the effect of company-specific aberrations. However, if the selection process is arbitrary, it likely would result in a proxy group that is too broad-based, such as the Standard & Poor's 500 Composite Index or the Value Line Industrial Composite. The use of such groups would require subjective adjustments to the comparable earnings results to reflect risk differences between the group(s) and the target utility, a gas pipeline company in this example.

Authors' Selection Criteria

We base the selection of comparable non-utility firms on market-based, objective, quantitative measures of risk resulting from market prices that subsume investors' assessments of all elements of risk. Thus, our approach is based upon the principle of risk and return; namely, that firms of comparable risk should be expected to earn comparable returns. It is also consistent with the "corresponding risk" standard established in *Bluefield* and *Hope*. We measure total investment risk as the sum of non-diversifiable systematic and diversifiable unsystematic risk. We use the unadjusted beta as a measure of systematic risk and the standard error of the estimate (residual standard error) as a measure of unsystematic risk. Both the unadjusted beta and the residual standard error are derived from a regression of the target utility's security returns relative to the market's returns, which takes the general form:

$$r_{it} = a_i + b_i\, r_{mt} + e_{it}$$

where:

- r_{it} = tth observation of the ith utility's rate of return
- r_{mt} = tth observation of the market's rate of return
- e_{it} = tth random error term
- a_i = constant least-squares regression coefficient
- b_i = least-squares regression slope coefficient, the unadjusted beta.

As shown by Francis,[4] the total variation or risk of a firm's return, Var (r_i), comes from two sources:

Var (r_i) = total risk of ith asset

= var$(a_i + b_i r_m + e)$ substituting $(a_i + b_i r_m + e)$ for r_i

= var$(b_i r_m)$ + var (e) since var$(a_i) = 0$

= b_i^2 var(r_m) + var (e) since var$(b_i r_m) = b_i^2$ var(r_m)

= systematic + unsystematic risk

Francis[5] also notes: "The term $\sigma^2(r_i|r_m)$ is called the *residual variance around the regression line* in statistical terms or *unsystematic risk* in capital market theory language. $\sigma^2\,(r_i|r_m)$ = ... = var (e). The residual variance is the squared standard error in regression language, a measure of unsystematic risk." Application of these criteria results in a group of non-utility firms whose average total investment risk is indeed comparable to that of the target gas pipeline.

As a measure of systematic risk, we use the Value Line unadjusted beta. Beta measures the extent to which market-wide or macro-economic events affect a firm's stock price. We use the unadjusted beta of the target utility as a starting point because it results from the regression of the target utility's security returns relative to the market's returns. Thus, the resulting standard deviation of beta relates to the unadjusted beta. We use the standard deviation of the unadjusted beta to determine the range around it as the selection criterion based on systematic risk.

We use the residual standard error of the regression as a measure of unsystematic risk. The residual standard error reflects the extent to which events specific to the firm's operations affect a firm's stock price. Thus, it is a measure of diversifiable, unsystematic, firm-specific risk.

An Illustration of Authors' Approach

Step One: We begin our approach by establishing the selection criteria as a range of both unadjusted beta and residual standard error of the target gas

continued on page 6

Comparable Earnings *from page 5*

pipeline company.

As shown in table 1, our target gas pipeline company has a Value Line unadjusted beta of 0.90, whose standard deviation is 0.1250. The selection criterion range of unadjusted beta is the unadjusted beta plus (+) and minus (-) three of its standard deviations. By using three standard deviations, 99.73 percent of the comparable unadjusted betas is captured.

Three standard deviations of the target utility's unadjusted beta equals 0.38 (0.1250 x 3 = 0.3750, rounded to 0.38). Consequently, the range of unadjusted betas to be used as a selection criteria is 0.52 - 1.28 (0.52 = 0.90 - 0.38) and (1.28 = 0.90 + 0.38).

Likewise, the selection criterion range of residual standard error equals the residual standard error plus (+) and minus (-) three of its standard deviations. The standard deviation of the residual standard error is defined as: $\sigma/\sqrt{2N}$.

As also shown in table 1, the target gas pipeline company has a residual standard error of 3.7867. According to the above formula, the standard deviation of the residual standard error would be 0.1664 ($0.1664 = 3.7867/\sqrt{2(259)} = 3.7867/22.7596$, where 259 = N, the number of weekly price change observations over a period of five years). Three standard deviations of the target utility's residual standard error would be 0.4992 (0.1664 x 3 = .4992). Consequently, the range of residual standard errors to be used as a selection criterion is 3.2875 - 4.2859 (3.2875 = 3.7867 - 0.4992) and (4.2859 = 3.7867 + 0.4992).

Step Two: The step one criteria are applied to Value Line's data base of nearly 4,000 firms for which Value Line derives unadjusted betas and residual standard errors on a weekly basis. All firms with unadjusted betas and residual standard errors within the criteria ranges are then selected.

Step Three: In the regulatory ratemaking environment, authorized common equity return rates are applied to a book-value rate base. Thus, the earnings rates on book common equity, or net worth, of competitive, non-utility firms are highly relevant provided those firms are indeed comparable in total risk to the target gas pipeline. The use of the return rates of other utilities has no relevance because their allowed, and hence subsequently achieved, earnings rates are dependent upon the regulatory

table 1

Summary of the Comparable Earnings Analysis for the Proxy Group of 248 Non-Utility Companies Comparable in Total Risk to the Target Gas Pipeline Company[1]

	1	2	3	4	5	6	7	8
			residual	rate of return on net worth				
	adj. beta	unadj. beta	standard error	3-year average[2]	4-year average[2]	5-year average[2]	5-year projected[3]	
average for the proxy group of 248 non-utility companies comparable in total risk to the target gas pipeline company	0.97	0.92	3.7705					
target gas pipeline company	0.96	0.90[4]	3.7867					
median				11.7%	12.0%	12.6%	15.5%	
average of the median historical returns					12.1%			
conclusion[5]								13.8%

[1] The criteria for selection of the non-utility group was that the non-utility companies be domestic and included in *Value Line Investment Survey*. The non-utility group was selected based on an unadjusted beta range of 0.52 to 1.28 and a residual standard error range of 3.2875 to 4.2859.
[2] Ending 1992.
[3] 1996-1998/1997-1999.
[4] The average standard deviation of the target gas pipeline company's unadjusted beta is 0.1250.
[5] Equal weight given to both the average of the 3-, 4- and 5-year historical medians (12.1%) and 5-year projected median rate of return on net worth (15.5%). Thus, 13.8% = (12.1% + 15.5% / 2).
Source: Value Line Inc., March 15, 1994
Value Line Investment Survey

Comparable Earnings *from page 6*

process. Consequently, we believe all utilities must be eliminated to avoid circularity. Moreover, we believe non-domestic firms must be eliminated because their reporting methods differ significantly from U.S. firms.

Step Four: We then eliminated those firms for which Value Line does not publish a "Ratings & Report" in *Value Line Investment Survey* so that the historical and projected returns on net worth[6] are from a consistent source. We use historical returns on net worth for the most recent five years, as well as those projected three to five years into the future. We believe it is logical to evaluate both historical and projected return rates because it is reasonable to assume that investors avail themselves of both when they are available from widely disseminated information services, such as Value Line Inc. The use of Value Line's return rates on net worth understates the common equity return rates for two reasons. First, preferred stock is included in net worth. Second, the net worth return rates are as of the end of each period. Thus, the use of average common equity return rates would yield higher results.

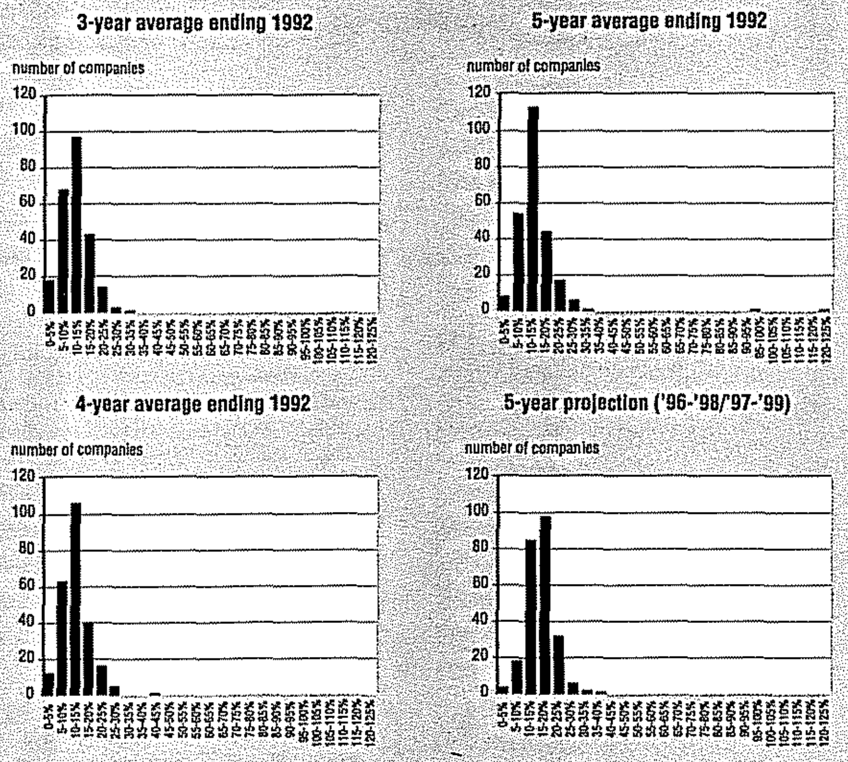
Step Five: Median returns based on the historical average three, four and five years ending 1992 and projected 1996-1998 or 1997-1999 rates of return on net worth are then determined as shown in columns 4 through 7 of table 1. The median is used due to the wide variations and skewness in rates of return on net worth for the non-utility firms as evidenced by the frequency distributions of those returns as shown in illustration 1.

However, we show the average unadjusted beta, 0.92, and residual standard error, 3.7705, for the proxy group in columns 2 and 3 of table 1 because their frequency distributions are not significantly skewed, as shown in illustration 2.

Step Six: Our conclusion of a com-

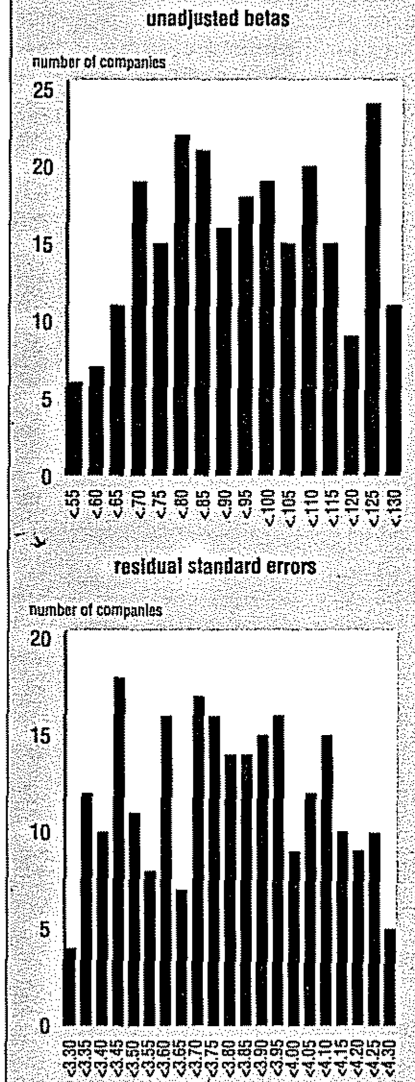
continued on page 8

Illustration 1
Rates of Return on Net Worth for the Proxy Group of 248 Non-Utility Companies[1]



[1]Comparable to target gas pipeline

Illustration 2
Unadjusted Betas and Residual Standard Errors for the Proxy Group of 248 Non-Utility Companies[1]



[1]Comparable to target gas pipeline

Comparable Earnings *from page 7*

parable earnings cost rate is based upon the mid-point of the average of the median three-, four- and five-year historical rates of return on net worth of 12.1 percent as shown in column 5 and the median projected 1996-1998/1997-1999 rate of return on net worth of 15.5 percent as shown in column 7 of table 1. As shown in column 8, it is 13.8 percent.

Summary

Our comparable earnings approach demonstrates that it is possible to select a proxy group of non-utility firms that is comparable in total risk to a target utility. In our example, the 13.8 percent comparable earnings cost rate is very conservative as it is an expected achieved rate on book common equity (a regulatory allowed rate should be greater) and because it is based on end-of-period net worth. A similar rate on average net worth would be about 20 to 40 basis points higher (i.e., 14.0 to 14.2 percent) and still understate the appropriate regulatory allowed rate of return on book common equity.

Our selection criteria are based upon measures of systematic and unsystematic risk, specifically unadjusted beta and residual standard error. They provide the basis for the objective selection of comparable non-utility firms. Our selection criteria rely on changes in market prices over approximately five years. We compare the aggregate total risk, or the sum of systematic and unsystematic risk, which reflects investors' aggregate assessment of both business and financial risk. Thus, no adjustments are necessary to the proxy group results to compensate for the differences in business risk and financial risk, such as accounting practices and debt/equity ratios. Moreover, it is inappropriate to attempt a comparison of the target utility with any individual firm, or subset of firms, in the proxy group because only the average firm of the group is relevant.

Because the comparable earnings model is firmly anchored in the "corresponding risk" precept established in the landmark court decisions, it is worthy of consideration as a principal model for use in estimating the cost rate of common equity capital of a regulated utility. Our approach to the comparable earnings model produces a proxy group that is indeed comparable in total risk because the selection process is objective and quantitative. It therefore overcomes criticism linked to arbitrary selection processes.

All cost-of-common-equity models, including the DCF and CAPM, are fraught with deficiencies, usually stemming from the many necessary but unrealistic assumptions that underlie them. The effects of the deficiencies of individual models can be mitigated by using more than one model when estimating a utility's common equity cost rate. Therefore, when the non-comparability issue is overcome, the comparable earnings model deserves to receive the same consideration as a primary model, as do the currently popular market-based models. ■

Report Lists Pipeline, Storage Projects

More than $9 billion worth of projects to expand the nation's natural gas pipeline network are in various stages of development, according to an A.G.A. report. These projects involve nearly 8,000 miles of new pipelines and capacity additions to existing lines and represent 15.3 billion cubic feet (Bcf) per day of new pipeline capacity.

During 1993 and early 1994, construction on 3,100 miles of pipeline was completed or under way, at a cost of nearly $4 billion, says A.G.A. These projects are adding 5.4 Bcf in daily delivery capacity nationwide.

Among the projects completed in 1993 were Pacific Gas Transmission Co.'s 805 miles of looping that allows increased deliveries of Canadian gas to the West Coast; Northwest Pipeline Corp.'s addition of 433 million cubic feet of daily capacity for customers in the Pacific Northwest and Rocky Mountain areas; and the 156-mile Empire State Pipeline in New York.

In addition, major construction projects were started on the systems of Texas Eastern Transmission Corp. and Algonquin Gas Transmission Co. — both subsidiaries of Panhandle Eastern Corp. — and along Florida Gas Transmission Co.'s pipeline.

The report goes on to discuss another $5 billion in proposed projects, which, if completed, will add nearly 5,000 miles of pipeline and 9.8 Bcf per day in capacity, much of it serving Florida and West Coast markets.

A.G.A. also identifies 47 storage projects and says that if all of them are built, existing storage capacity will increase by more than 500 Bcf, or 15 percent.

For a copy of *New Pipeline Construction: Status Report 1993-94* (#F00103), call A.G.A. at (703) 841-8490. Price per copy is $6 for employees of member companies and associates and $12 for other customers.

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[1]*Bluefield Water Works Improvement Co. v. Public Service Commission*. 262 U.S. 679 (1922) and *Federal Power Commission v. Hope Natural Gas Co.*, 320 U.S. 519 (1944).
[2]Charles F. Phillips Jr., The Regulation of Public Utilities: Theory and Practice, Public Utilities Reports Inc., 1988, p. 379
[3]James C. Bonbright, Albert L. Danielsen and David R. Kamerschen, Principles of Public Utilities Rates, 2nd edition, Public Utilities Reports Inc. 1988, p. 329
[4]Jack Clark Francis, Investments: Analysis and Management, 3rd edition, McGraw-Hill Book Co., 1980, p. 363
[5]Id., p. 548
[6]Returns on net worth must be used when relying on Value Line data because returns on book common equity for non-utility firms are not available from Value Line

Investments: Analysis and Management

Fifth Edition

Jack Clark Francis

Bernard M. Baruch College
City University of New York

McGraw-Hill, Inc.

New York St. Louis San Francisco Auckland Bogotá Caracas Hamburg Lisbon London Madrid Mexico Milan Montreal New Delhi Paris San Juan São Paulo Singapore Sydney Tokyo Toronto

Investments: Analysis and Management

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Beta Measurements The beta coefficient is an *index of systematic risk.* Beta coefficients may be used for ranking the systematic risk of different assets. If the beta is larger than 1, $b > 1.0$, then the asset is more volatile than the market and is called an **aggressive asset.** If the beta is less than 1, $b < 1.0$, the asset is a **defensive asset;** its price fluctuations are less volatile than the market's. Figure 10-1 illustrates the characteristic lines for three different assets that have low, medium, and high levels of beta (or undiversifiable risk).

Figure 10-2 shows that IBM is a stock with an average amount of systematic risk. IBM's beta of 1.02 indicates that its return tends to increase 2 percent more than the return on the market average when the market is rising. When the market falls, IBM's return tends to fall 2 percent more than the market's. The characteristic line for IBM has an above average correlation coefficient of $\rho = .7495$, indicating that the returns on this security follow its particular characteristic line slightly more closely than those of the average stock.

Partitioning Risk

Total risk can be measured by the variance of returns, denoted Var(r). This measure of *total risk is partitioned into its systematic and unsystematic components in Equation (10-8).*[7]

$$\begin{aligned}
\text{Var}(r_i) &= \text{total risk of } i\text{th asset} \\
&= \text{Var}(a_i + b_i r_{m,t} + e_{i,t}) \\
&\quad \text{by substituting } (a_i + b_i r_{m,t} + e_{i,t}) \text{ for } r_{i,t} \\
&= 0 + \text{Var}(b_i r_{m,t}) + \text{Var}(e_{i,t}) \\
&\quad \text{since Var}(a_i) = 0 \qquad (10\text{-}8)
\end{aligned}$$

$$\begin{aligned}
\text{Var}(r_i) &= b_i^2\,\text{Var}(r_m) + \text{Var}(e) \qquad \text{since Var}(b_i r_m) = b_i^2\,\text{Var}(r_m) \\
&= \text{systematic} + \text{unsystematic risk} \qquad (10\text{-}8a) \\
.01389 &= .00780 + .00609 \qquad \text{for IBM}
\end{aligned}$$

The unsystematic risk measure Var(e) is called in regression language the *residual variance* or, synonymously, the *standard error squared.*

Undiversifiable Proportion The percentage of total risk that is systematic can be measured by the coefficient of determination ρ^2 (that is, the characteristic line's squared correlation coefficient).

[7]In this context, **partition** is a technical statistical term that means to divide the total variance into *mutually exclusive* and *exhaustive* pieces. This partition is only possible if the returns from the market are statistically independent from the residual error terms that occur simultaneously, $\text{Cov}(r_{m,t}, e_{i,t}) = 0$. The mathematics of regression analysis will orthogonalize the residuals and thus ensure that the needed statistical independence exists.

$$\frac{\text{Systematic risk}}{\text{Total risk}} = \frac{b_i^2 \text{ Var}(r_m)}{\text{Var}(r_m)} = \rho^2 \tag{10-9}$$

$$\frac{.007802}{.01389} = \frac{(1.021)^2 (.00749)}{.00749} = .5617 \times 100 = 56.17\% \qquad \text{for IBM}$$

Diversifiable Proportion The percentage of unsystematic risk equals $(1.0 - \rho^2)$.

$$\frac{\text{Unsystematic risk}}{\text{Total risk}} = \frac{\text{Var}(e)}{\text{Var}(r_i)} = (1.0 - \rho^2)$$

$$\frac{.00609}{.01389} = (1.0 - .5617) = .438 \times 100 \tag{10-10}$$

$$= 43.8\% \text{ unsystematic} \qquad \text{for IBM}$$

Studies of the characteristic lines of hundreds of stocks listed on the NYSE indicate that the average correlation coefficient is approximately $\rho = .5$.[8] This means that about $\rho^2 = 25$ percent of the total variability of return in most NYSE securities is explained by movements in the market.

	NYSE average	IBM
Systematic risk: ρ^2	.25	.5617
Unsystematic risk: $(1.0 - \rho^2)$	.75	.4383
Total risk: 100%	1.00	1.0000

As explained above, systematic changes are common to all stocks and are therefore undiversifiable.

A primary use of the characteristic line (or *market model,* or the *single-index model,* as it is also called) is to assess the risk characteristics of one asset.[9] The statistics in Table 10-2, for instance, indicate that IBM's common stock is slightly more risky than the average common stock in terms of total risk and

[8]The average ρ was found to be about .5, as reported in Marshall Blume, "On the Assessment of Risk," *Journal of Finance,* March 1971, p. 4. For similar estimates, see J. C. Francis, "Statistical Analysis of Risk Surrogates for NYSE Stocks," *Journal of Financial and Quantitative Analysis,* Dec. 1979.

[9]Professor Jensen reformulated the characteristic line in a risk-premium form. See M. C. Jensen, "The Performance of Mutual Funds in the Period 1945 through 1964," *Journal of Finance,* May 1968, pp. 389–416. See also M. C. Jensen, "Risk, the Pricing of Capital Assets, and the Evaluation of Investment Portfolios," *Journal of Business,* vol. XLII, 1969. Jensen interprets the alpha intercept term of the characteristic line, as he formulates it, as an investment performance measure. It has been suggested that Jensen's performance measure is biased. See Keith V. Smith and Dennis A. Tito, "Risk-Return Measures of Ex-Post Portfolio Performance," *Journal of Financial and Quantitative Analysis,* Dec. 1969, vol. IV, no. 4, p. 466.

systematic risk.[10] New risk measurements must be made periodically, however, because the risk and return of an asset may change with the passage of time.[11]

10-3 CAPITAL ASSET PRICING MODEL (CAPM)

An old axiom states "there is no such thing as a free lunch." This means that you cannot expect to get something for nothing—a rule that certainly applies to investment returns. Investors who want to earn high average rates of return must take high risks and endure the associated loss of sleep, the possibility of ulcers, and the chance of bankruptcy. The question to which we now turn is: Should investors worry about total risk, undiversifiable risk, diversifiable risk, or all three?

In Chapter 1 it was suggested that *investors should seek investments that have the maximum expected return in their risk class.* Their happiness from investing is presumed to be derived as indicated in the expected utility $E(U)$ function below.

$$E(U) = f[E(r), \sigma]$$

The investment preferences of wealth-seeking risk-averse investors represented by the function above cause them to maximize their expected utility (or, equivalently, happiness) by (1) maximizing their expected return in any given risk class, $\partial E(U)/\partial E(r) > 0$, or, conversely, (2) minimizing their total risk at any given rate of expected return, $\partial E(U)/\partial \sigma < 0$. However, in selecting individual assets, investors will not be particularly concerned with the asset's total risk σ. Figure 9-1 showed that the unsystematic portion of total risk can be easily diversified by holding a portfolio of different securities. But, systematic risk affects all stocks in the market because it is undiversifiable. Portfolio theory therefore suggests that only the undiversifiable (or systematic) risk is worth avoiding.[12]

[10]Statements about the relative degree of total risk are made in the context of a long-run horizon—that is, over at least one *complete business cycle*. Obviously, an accurate short-run forecast which says that some particular company will go bankrupt next quarter makes it more risky than IBM, although IBM may have had more historical variability of return.

[11]Empirical studies documenting the intertemporal instability of betas have been published. Marshall Blume, "Betas and Their Regression Tendencies," *Journal of Finance,* June 1975, pp. 785–795. See also J. C. Francis, "Statistical Analysis of Risk Coefficients for NYSE Stocks," *Journal of Financial and Quantitative Analysis,* Dec. 1979, vol. XIV, no. 5, pp. 981–997. An appendix at the end of this chapter reviews some evidence about shifting betas, standard deviations, and correlations.

[12]Both the systematic and unsystematic portions of total risk must be considered by **undiversified investors.** Entrepreneurs who have their entire net worth invested in one business, for example, can be bankrupted by a piece of bad luck that could be easily averaged away to zero in a diversified portfolio. Poorly diversified investors should not treat diversifiable risk lightly. Only well-diversified investors can afford to ignore diversifiable risk.

Summit Natural Gas of Arkansas
Gross Domestic Product by Industry
from 1947 - 2023

Industry	1947	2023	CAGR
Agriculture, forestry, fishing, and hunting	19.9	251.7	3.40%
Mining	5.8	380.9	5.66%
Utilities	3.5	434.3	**6.55%**
Construction	8.9	1,203.8	**6.67%**
Manufacturing	63.4	2,804.7	5.11%
Wholesale trade	15.6	1,613.7	6.29%
Retail trade	23.2	1,738.5	5.84%
Transportation and warehousing	14.1	970.5	5.73%
Information	7.7	1,475.1	**7.16%**
Finance, insurance, real estate, rental, and leasing	25.8	5,656.5	**7.35%**
Professional and business services	8.2	3,543.9	**8.31%**
Educational services, health care, and social assistance	4.6	2,351.6	**8.55%**
Arts, entertainment, recreation, accommodation, and food services	8.0	1,231.3	**6.85%**
Other services, except government	7.5	597.0	5.93%
Government	33.5	3,107.4	6.14%
Total Gross domestic product	249.7	27,360.9	6.37%

Source: Bureau of Economic Analysis

Industry	Gross Domestic Product	1947-2023 CAGR	Beginning Year	Ending Year	Gross Domestic Product In Ending Year	% of Total
Agriculture, forestry, fishing, and hunting	251.7	3.40%	1	267	2.E+06	
Mining	380.9	5.66%	1	267	9.E+08	
Utilities	434.3	6.55%	1	267	1.E+10	
Construction	1,203.8	6.67%	1	267	4.E+10	
Manufacturing	2,804.7	5.11%	1	267	2.E+09	
Wholesale trade	1,613.7	6.29%	1	267	2.E+10	
Retail trade	1,738.5	5.84%	1	267	7.E+09	
Transportation and warehousing	970.5	5.73%	1	267	3.E+09	
Information	1,475.1	7.16%	1	267	2.E+11	
Finance, insurance, real estate, rental, and leasing	5,656.5	7.35%	1	267	9.E+11	
Professional and business services	3,543.9	8.31%	1	267	6.E+12	
Educational services, health care, and social assistance	2,351.6	8.55%	1	267	8.E+12	50.01%
Arts, entertainment, recreation, accommodation, and food services	1,231.3	6.85%	1	267	6.E+10	
Other services, except government	597.0	5.93%	1	267	3.E+09	
Government	3,107.4	6.14%	1	267	3.E+10	
Total Gross domestic product	27,360.9				2.E+13	

Industry	Gross Domestic Product	1947-2023 CAGR	Beginning Year	Ending Year	Gross Domestic Product In Ending Year	% of Total
Agriculture, forestry, fishing, and hunting	251.7	3.40%	1	6,752	2.E+100	
Mining	380.9	5.66%	1	6,752	1.E+164	
Utilities	434.3	6.55%	1	6,752	4.E+188	
Construction	1,203.8	6.67%	1	6,752	3.E+192	
Manufacturing	2,804.7	5.11%	1	6,752	5.E+149	
Wholesale trade	1,613.7	6.29%	1	6,752	2.E+182	
Retail trade	1,738.5	5.84%	1	6,752	6.E+169	
Transportation and warehousing	970.5	5.73%	1	6,752	2.E+166	
Information	1,475.1	7.16%	1	6,752	9.E+205	
Finance, insurance, real estate, rental, and leasing	5,656.5	7.35%	1	6,752	5.E+211	
Professional and business services	3,543.9	8.31%	1	6,752	5.E+237	
Educational services, health care, and social assistance	2,351.6	8.55%	1	6,752	1.E+244	100.00%
Arts, entertainment, recreation, accommodation, and food services	1,231.3	6.85%	1	6,752	3.E+197	
Other services, except government	597.0	5.93%	1	6,752	5.E+171	
Government	3,107.4	6.14%	1	6,752	2.E+178	
Total Gross domestic product	27,360.9				1.E+244	

Summit Natural Gas of Arkansas
Comparison of Market Return Measures

	[1]	[2]	[3]	[4]
	Actual Market Return (1)	LT average Market Return (2)	Kroll (3)	Regression-Based MRP (4)
2009	26.46%	11.67%	10.50%	12.35%
2010	15.06%	11.85%	10.08%	11.92%
2011	2.11%	11.88%	9.63%	12.07%
2012	16.00%	11.77%	10.00%	12.09%
2013	32.39%	11.82%	9.50%	12.07%
2014	13.69%	12.05%	9.00%	12.25%
2015	1.38%	12.07%	9.00%	12.41%
2016	11.96%	11.95%	9.00%	12.32%
2017	21.83%	11.95%	9.00%	12.16%
2018	-4.38%	12.06%	8.50%	12.31%
2019	31.49%	11.88%	9.00%	12.33%
2020	18.40%	12.09%	8.00%	12.29%
2021	28.71%	12.16%	8.00%	12.27%
2022	-18.11%	12.33%	8.00%	12.83%
2023	26.61%	12.02%	9.00%	12.43%
Sum	223.60%	179.55%	136.21%	184.10%
Forecast Bias (5)		**80.30%**	**60.92%**	**82.33%**

Notes:
(1) Source: Kroll, 2023 SBBI, Appendix A-1, A-7; Cost of Capital Navigator
(2) Rolling historic long-term average of data in Column 1 since 1926
(3) Source: Kroll Recommended ERP + Corresponding Risk-Free Rate
(4) Source: Based on a regression of market risk premiums and RF annualized yields from 1926 - 2023.
(5) Sum of forecasts divided by sum of actual observations

Summit Natural Gas of Arkansas

Analysis of Excluding Non-Dividend Paying Companies from the CAPM Analysis

S&P 500 - Value Line	Number of Companies Excluded	Percentage of Total Market Cap Excluded
Companies not paying dividends	101	22.53%
Companies with EPS ≤ 0%	35	1.65%
Companies with EPS > 20%	15	8.26%
Total Excluded	150	32.44%

Summit Natural Gas of Arkansas
Updated CAPM for Dr. Griffing

	A	B	C	D	E	F	G	H
	Rf	MRP	Beta	RP	CAPM ROE	ECAPM ROE	Average CAPM/ ECAPM	Filtered Results
Atmos Energy Corporation	4.60%	8.15%	0.85	6.93%	11.53%	11.83%	11.68%	11.68%
Chesapeake Utilities	4.60%	8.15%	0.80	6.52%	11.12%	11.53%	11.32%	11.32%
NiSource	4.60%	8.15%	0.95	7.74%	12.34%	12.45%	12.39%	12.39%
Northwest Natural Holding Co.	4.60%	8.15%	0.90	7.34%	11.94%	12.14%	12.04%	12.04%
Southwest Gas Holdings	4.60%	8.15%	0.85	6.93%	11.53%	11.83%	11.68%	11.68%
ONE Gas, Inc.	4.60%	8.15%	0.85	6.93%	11.53%	11.83%	11.68%	11.68%
Spire, Inc.	4.60%	8.15%	0.85	6.93%	11.53%	11.83%	11.68%	11.68%
				Mean	11.65%	11.92%	11.78%	11.78%
				Median	11.53%	11.83%	11.68%	11.68%

A: A: MFG-15, Sch 1
B: As discussed in Mr. D'Ascendis' Rebuttal Testimony, the corrected MRP is calculated as follows:

Measure 1: Kroll Arithmetic Mean MRP (1926-2023)		
Arithmetic Mean Monthly Returns for Large Stocks 1926-2023:	12.16	%
Arithmetic Mean Income Returns on Long-Term Government Bonds:	4.99	
MRP based on Kroll Historical Data:	7.17	%
Measure 2: Dr. Griffing's Value Line Market DCF using all S&P 500 Companies		
Full S&P 500 Market DCF Return	13.74	%
Dr. Griffing's Rf	4.60	
MRP based on Value Line Market DCF:	9.14	%
Average Kroll and Value Line MRP:	8.15	%

C: MFG-15, Sch 2
D = C*B
E = A+D
F = A+(0.75*D)+(0.25*B)
G = (E+F)/2
H: Low end test < Colum H < High-end test

Low-End Test	Moody's 10-Year Baa Corporate Bond Index, MFG-18, Schedule 3	5.94%
	CAPM Risk Premium, Column C	8.15%
	20 percent of CAPM risk premium	1.63%
	Moody's 10-Year Baa Corporate Bond Index + 20 percent of CAPM Risk	7.57%

High-End Test	Proxy Group median, Column H	11.68%
	200 percent of Proxy Group median	23.36%

Summit Natural Gas of Arkansas
Summary of Adjustment Clauses & Alternative Regulation/Incentive Plans
Proxy Group of Six Natural Gas Distribution Companies

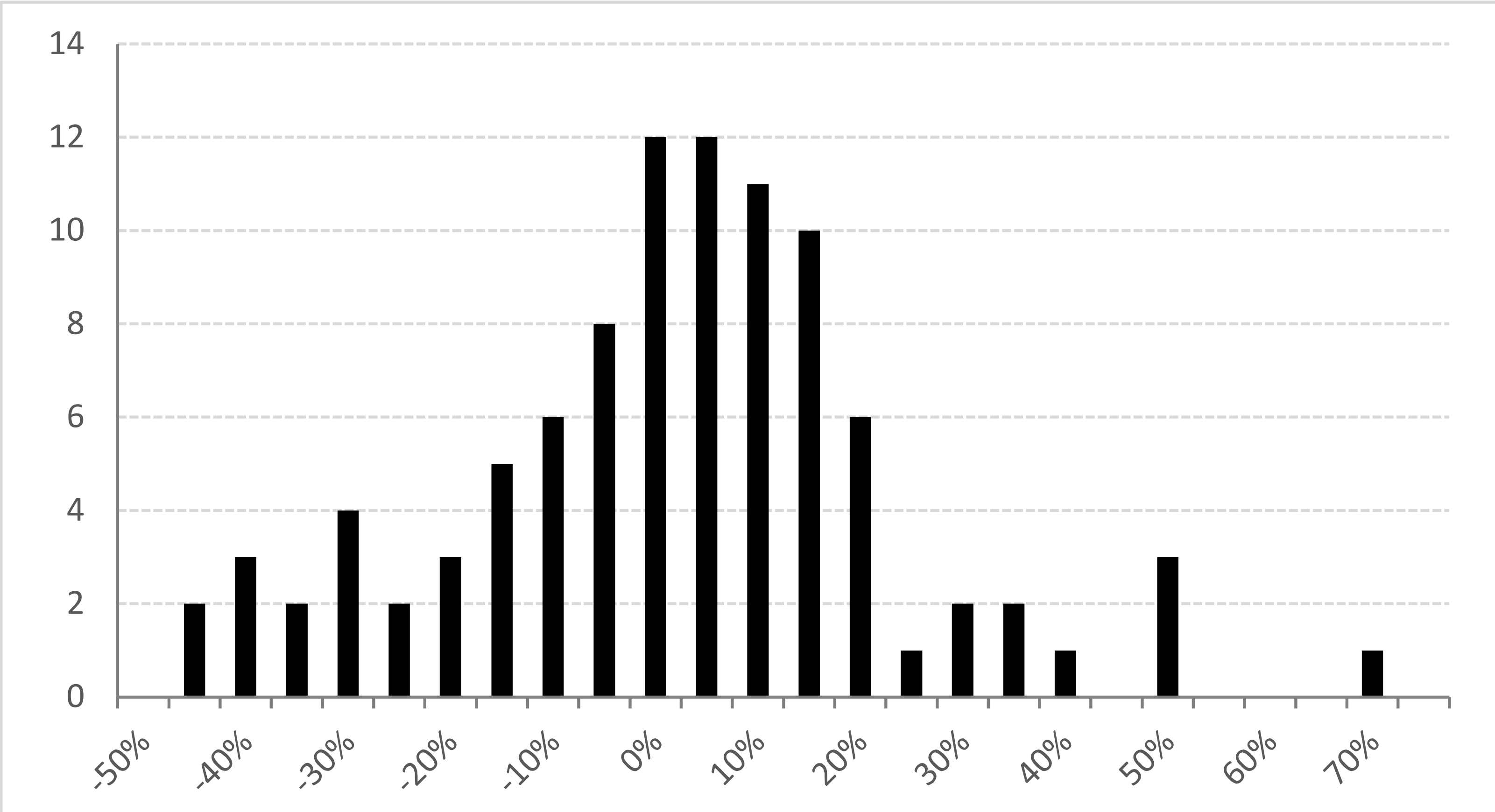
			Adjustment Clauses					Alternative Regulation / Incentive Plans		
Company	Parent	State	Gas Commodity	Decoupling (F/P) [1]	Capital Investment [2]	Energy Efficiency [3]	Other [4]	Formula-Based Rates	Earnings Sharing/PBR	Forward Test Year Allowed in Jurisdiction [5]
Atmos Energy	ATO	Colorado			✓					
Atmos Energy	ATO	Kansas	✓	P	✓		✓		✓	
Atmos Energy	ATO	Kentucky	✓	P	✓		✓		✓	✓
Atmos Energy	ATO	Louisiana	✓	P	✓			✓		✓
Atmos Energy	ATO	Mississippi	✓	P	✓			✓		K
Atmos Energy	ATO	Tennessee	✓	P	✓		✓	✓	✓	✓
Atmos Energy	ATO	Texas	✓	P	✓		✓	✓		
Atmos Energy	ATO	Virginia	✓	P	✓		✓			✓
Chesapeake Utilities Corporation	CPK	Delaware	✓	P	✓	✓	✓			K
Chesapeake Utilities Corporation	CPK	Maryland	✓			✓				✓
Florida Public Utilities	CPK	Florida	✓		✓	✓	✓			✓
New Jersey Natural Gas	NJR	New Jersey		P	✓	✓				K
Northern Indiana Public Service Company, LLC	NI	Indiana	✓		✓	✓			✓	K
Columbia Gas of Kentucky, Inc.	NI	Ohio	✓	P	✓	✓	✓			✓
Columbia Gas of Ohio, Inc.	NI	Ohio		P	✓	✓			✓	✓
Columbia Gas of Pennsylvania, Inc.	NI	Pennsylvania	✓	P	✓					✓
Columbia Gas of Maryland, Inc.	NI	Pennsylvania	✓	P	✓	✓				✓
Columbia Gas of Virginia, Inc.	NI	Virginia	✓	P	✓	✓				✓
Northwest Natural Gas	NWN	Oregon	✓	P		✓			✓	✓
Northwest Natural Gas	NWN	Washington	✓			✓				K
Kansas Gas Service	OGS	Kansas	✓	P	✓			✓		
Oklahoma Natural Gas	OGS	Oklahoma	✓	P		✓		✓	✓	K
Texas Gas Service	OGS	Texas	✓	P	✓	✓	✓	✓		
Southwest Gas Corporation	SWX	Arizona	✓	F			✓			K
Southwest Gas Corporation	SWX	California	✓	F	✓		✓	✓		✓
Southwest Gas Corporation	SWX	Nevada	✓	F	✓		✓			K
Spire Alabama Inc.	SR	Alabama	✓	P				✓	✓	K
Spire Mississippi Inc.	SR	Mississippi	✓	P				✓		K
Spire Missouri Inc.	SR	Missouri	✓	P	✓		✓			K

Notes:
Note: A mechanism may cover one or more cost categories; therefore, designations may not indicate separate mechanisms for each category.
[1] Full or partial decoupling (such as Fixed Variable rate design, weather normalization clauses, and recovery of lost revenues as a result of Energy Efficiency programs). All full or partial decoupling mechanisms include weather normalization adjustments.

[2] Includes recovery of costs related to infrastructure replacement, system integrity/hardening, and other capital expenditures.
[3] Utility-sponsored conservation, energy efficiency, or other demand side management programs.
[4] Pension expenses, bad debt costs, storm costs, transmission/transportation costs, environmental, regulatory fee, government & franchise fees and taxes, economic development, and low income programs.
[5] K = Known and Measurable or similar language, partially forecasted test years are included.
Sources: Company SEC Form 10-Ks; Operating company tariffs; Regulatory Research Associates.

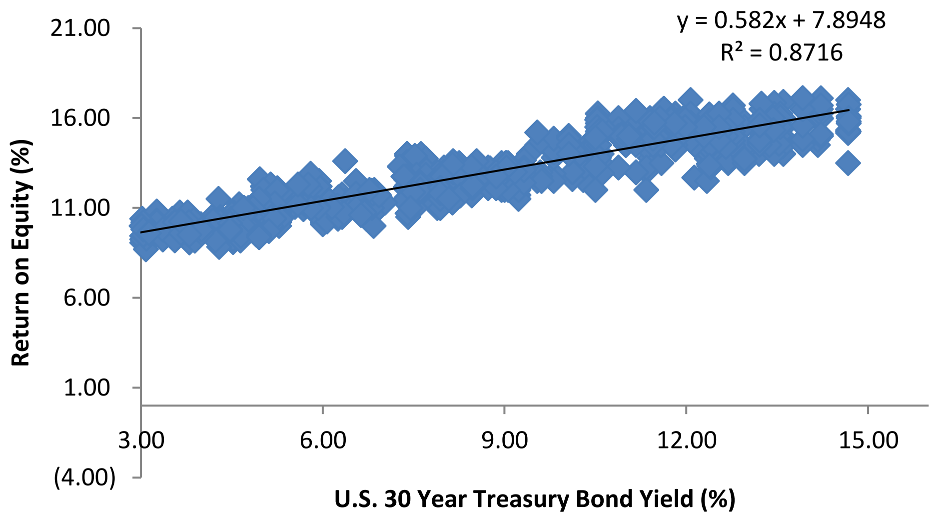
Summit Natural Gas of Arkansas

Frequency Distribution of Equity Risk Premiums, 1928 - 2023



Source of Information: Bloomberg Professional Services; Mergent Bond Record

Summit Natural Gas of Arkansas
Relationship between Authorized ROEs and Interest Rates



Constant	Slope	Prospective U.S. Treasury Bond		Return on Equity
7.8948 %	0.582	4.20	% (1)	10.34 %
7.8948 %	0.582	2.97	% (2)	9.62 %

Notes:

(1) From Exhibit BSL-5

(2) Average Forecast from Blue Chip Financial Forecasts, August 1, 2016, at 2 for the Second Quarter 2017 through the Fourth

Sources of Information:

Regulatory Research Associates.
Blue Chip Financial Forecasts

Summit Natural Gas of Arkansas
Ms. LaConte's Corrected CAPM Analysis

Company	Ticker	Current Beta (B)	Projected Risk-Free Rate (R_f)	Historical Risk Premium (R_p)	Historical CAPM ROE	Historical ECAPM ROE	Projected Risk Premium (R_p)	Projected Risk Premium CAPM ROE	Projected Risk Premium ECAPM ROE	Average Risk Premium	Average CAPM ROE	Average ECAPM ROE
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)
Atmos Energy Corporation	ATO	0.85	4.31%	7.03%	10.29%	10.55%	9.87%	12.70%	13.07%	8.45%	11.49%	11.81%
New Jersey Resources	NJR	1.00	4.31%	7.03%	11.34%	11.34%	9.87%	14.18%	14.18%	8.45%	12.76%	12.76%
NiSource Inc.	NI	0.95	4.31%	7.03%	10.99%	11.08%	9.87%	13.69%	13.81%	8.45%	12.34%	12.44%
Northwest Natural Holding Company	NWN	0.85	4.31%	7.03%	10.29%	10.55%	9.87%	12.70%	13.07%	8.45%	11.49%	11.81%
ONE Gas, Inc.	OGS	0.85	4.31%	7.03%	10.29%	10.55%	9.87%	12.70%	13.07%	8.45%	11.49%	11.81%
Spire Inc.	SR	0.85	4.31%	7.03%	10.29%	10.55%	9.87%	12.70%	13.07%	8.45%	11.49%	11.81%
Southwest Gas	SWX	0.90	4.31%	7.03%	10.64%	10.81%	9.87%	13.19%	13.44%	8.45%	11.91%	12.13%
Average		0.89			10.59%	10.78%		13.12%	13.39%		11.85%	12.08%
Minimum		0.85			10.29%	10.55%		12.70%	13.07%		11.49%	11.81%
Maximum		1.00			11.34%	11.34%		14.18%	14.18%		12.76%	12.76%

SOURCES:
Column 2: Value Line Investment Survey (Exhibit BSL-5)
Column 3: Blue Chip Financial Forecast, calculated as:

Second Quarter 2024	4.60	%
Third Quarter 2024	4.50	
Fourth Quarter 2024	4.40	
First Quarter 2025	4.30	
Second Quarter 2025	4.20	
Third Quarter 2025	4.20	
2025-2029	4.10	
2030-2034	4.20	
	4.31	%

Column 4: Exhibit No. TAW-1 (A-14), Schedule D-5 at 7.
Column 7: Average of projected S&P return (including all companies) from D'Ascendis Schedule DWD-5 and Value Line Summary and Index projected market return (page 2 of this Schedule), less risk-free rate.

Bloomberg Profesional S&P 500 Market Return:	18.21	%
Value Line S&P 500 Market Return:	14.21	
Average Market DCF Return:	16.21	
Value Line Summary & Index Return:	12.15	
Overall Average Market Return:	14.18	%

Summit Natural Gas of Arkansas
Ms. LaConte's recreated Value Line MRP

Value Line Investment Survey Issue	Total Market Return 3-5 Years	Estimated Annual Growth	Estimated Median Dividend Yield	Estimated Annual Return
14-Jun-2024	45%	9.73%	2.10%	11.83%
7-Jun-2024	45%	9.73%	2.10%	11.83%
31-May-2024	45%	9.73%	2.10%	11.83%
24-May-2024	45%	9.73%	2.10%	11.83%
17-May-2024	45%	9.73%	2.10%	11.83%
10-May-2024	50%	10.67%	2.10%	12.77%
3-May-2024	50%	10.67%	2.20%	12.87%
26-Apr-2024	50%	10.67%	2.20%	12.87%
19-Apr-2024	45%	9.73%	2.10%	11.83%
12-Apr-2024	45%	9.73%	2.10%	11.83%
5-Apr-2024	45%	9.73%	2.10%	11.83%
29-Mar-2024	45%	9.73%	2.10%	11.83%
22-Mar-2024	45%	9.73%	2.10%	11.83%
15-Mar-2024	45%	9.73%	2.20%	11.93%
8-Mar-2024	45%	9.73%	2.20%	11.93%
1-Mar-2024	50%	10.67%	2.20%	12.87%
23-Feb-2024	45%	9.73%	2.20%	11.93%
16-Feb-2024	50%	10.67%	2.20%	12.87%
9-Feb-2024	50%	10.67%	2.20%	12.87%
26-Jan-2024	45%	9.73%	2.20%	11.93%
19-Jan-2024	45%	9.73%	2.20%	11.93%
Average	46.43%	10.00%	2.15%	12.15%

Source: Value Line Investment Survey

Summit Natural Gas of Arkansas
Ms. LaConte's Recreated Risk Premium Analysis

Line	Year	Average Authorized ROE	Annual 30-Year Bond Yield	Risk Premium
1	1990	12.68%	8.6%	4.1%
2	1991	12.45%	8.1%	4.3%
3	1992	12.02%	7.7%	4.4%
4	1993	11.37%	6.6%	4.8%
5	1994	11.24%	7.4%	3.9%
6	1995	11.44%	6.9%	4.6%
7	1996	11.12%	6.7%	4.4%
8	1997	11.30%	6.6%	4.7%
9	1998	11.51%	5.6%	5.9%
10	1999	10.74%	5.9%	4.9%
11	2000	11.34%	5.9%	5.4%
12	2001	10.96%	5.5%	5.5%
13	2002	11.17%	5.4%	5.7%
14	2003	10.99%	5.1%	5.9%
15	2004	10.63%	5.1%	5.5%
16	2005	10.41%	4.6%	5.9%
17	2006	10.40%	4.9%	5.5%
18	2007	10.22%	4.8%	5.4%
19	2008	10.39%	4.3%	6.1%
20	2009	10.22%	4.1%	6.1%
21	2010	10.15%	4.3%	5.9%
22	2011	9.92%	3.9%	6.0%
23	2012	9.94%	2.9%	7.0%
24	2013	9.68%	3.4%	6.2%
25	2014	9.78%	3.3%	6.4%
26	2015	9.60%	2.8%	6.8%
27	2016	9.54%	2.6%	6.9%
28	2017	9.72%	2.9%	6.8%
29	2018	9.59%	3.1%	6.5%
30	2019	9.72%	2.6%	7.1%
31	2020	9.47%	1.6%	7.9%
32	2021	9.56%	2.1%	7.5%
33	2022	9.53%	3.1%	6.4%
34	2023	9.64%	4.1%	5.5%
35	2024	9.78%	4.5%	5.3%
36	Average	10.52%	4.77%	5.75%
37	Projected 30-Year Yield			4.20%
38	Return on Equity			**9.95%**

SUMMARY OUTPUT

Regression Statistics	
Multiple R	0.9576
R Square	0.9171
Adjusted R Square	0.9146
Standard Error	0.0029
Observations	35

ANOVA

	df	*SS*	*MS*	*F*	*Significance F*
Regression	1	0.00313	0.00313	365.02296	0.00000
Residual	33	0.00028	0.00001		
Total	34	0.00342			

	Coefficients	*Standard Error*	*t Stat*	*P-value*	*Lower 95%*	*Upper 95%*
Intercept	0.08294	0.00142	58.38784	0.00000	0.08005	0.08583
X Variable 1	-0.53330	0.02791	-19.10557	0.00000	-0.59009	-0.47651

Constant	Slope	Projected 30-Year Yield	Risk Premium	ROE
0.0829	-0.5333	4.20%	6.05%	**10.25%**

SOURCES:
Regulatory Research Associates Regulatory Focus Major Energy Rate Case Decisions as of March 31, 2024
Exhibit BSL-5
St. Louis Federal Reserve Economic Data https://fred.stlouisfed.org/series/DGS30.

Summit Natural Gas of Arkansas
Prediction of Equity Risk Premiums Relative to
Moody's A2 Rated Utility Bond Yields, Credit Spreads, and VIX

SUMMARY OUTPUT

Regression Statistics	
Multiple R	0.8587
R Square	0.7374
Adjusted R Square	0.7356
Standard Error	0.6133
Observations	449

ANOVA

	df	*SS*	*MS*	*F*	*Significance F*
Regression	3	470.025699	156.675233	416.562701	8.885E-129
Residual	445	167.370911	0.37611441		
Total	448	637.39661			

	Coefficients	*Standard Error*	*t Stat*	*P-value*	*Lower 95%*	*Upper 95%*
Intercept	7.9254	0.1312	60.3935	0.0000	7.6675	8.1833
A Rated Utility Bond (%)	-0.5228	0.0153	-34.1591	0.0000	-0.5529	-0.4927
Credit Spread (%)	-0.3380	0.0907	-3.7285	0.0002	-0.5162	-0.1599
VIX (%)	0.0100	0.0053	1.8844	0.0602	-0.0004	0.0205

Constant		A Rated Utility Bond Coefficient	Credit Spread Coefficient	VIX Coefficient	Prospective A2 Rated Utility Bond (1)	Prospective 30-year Treasury Bond (2)	Prospective Credit Spread	VIX (long-term average)	Prospective Equity Risk Premium	Indicated ROE
7.93	%	-0.52	-0.34	0.01	5.58	4.35	1.23	19.57	4.79	10.37

Notes:
(1) From line 3 of page 13 of Schedule DWD-1R
(2) From Note 2 of page 24 of Schedule DWD-1R
Source of Information: Regulatory Research Associates, Bloomberg Professional Services

BEFORE THE

ARKANSAS PUBLIC SERVICE COMMISSION

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

REBUTTAL TESTIMONY

OF

TIMOTHY S. LYONS

SCOTTMADDEN, INC.

ON BEHALF OF

SUMMIT UTILITIES ARKANSAS, INC.

Date Filed: August 7, 2024

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I. INTRODUCTION

Q. PLEASE STATE YOUR NAME AND BUSINESS ADDRESS.

A. My name is Timothy S. Lyons. My business address is 3 Speen Street, Suite 150, Framingham, Massachusetts 01701.

Q. ARE YOU THE SAME TIMOTHY S. LYONS WHO FILED DIRECT TESTIMONY ON JANUARY 25, 2024, IN THIS PROCEEDING?

A. Yes.

Q. WHAT IS THE PURPOSE OF YOUR REBUTTAL TESTIMONY?

A. The purpose of my rebuttal testimony ("Rebuttal Testimony") is to address on behalf of Summit Utilities Arkansas, Inc. ("SUA" or the "Company") concerns and recommendations regarding the class cost of service study ("COSS") and rate design made by Mark Burdette on behalf of the General Staff of the Arkansas Public Service Commission ("Staff"), by Robert Swaim on behalf of Staff, by Larry Blank of TAHOEconomics on behalf of Hospitals and Higher Education Group ("HHEG"), by Richard Porter of Rod Walker & Associates Consultancy on behalf of the Office of Arkansas Attorney General, and by Jonathan Ly of J. Pollock, Incorporated on behalf of Arkansas Gas Consumers, Inc. ("AGC").

II. RESPONSE TO STAFF WITNESS BURDETTE

Q. WHAT ARE STAFF WITNESS BURDETTE'S CONCERNS REGARDING THE COMPANY'S COSS?

A. 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.

Q. WHAT ARE MR. BURDETTE'S CONCERNS RELATED TO DERIVATION OF CURRENT REVENUES?

A. Mr. Burdette states rolled-in rider revenues are not currently recovered in base rates and therefore should not be included in the COSS. Mr. Burdette recommends current revenues in the COSS be based only on the Company's base rate revenues.

Q. DO YOU AGREE WITH MR. BURDETTE'S CONCERNS REGARDING DERIVATION OF CURRENT REVENUES?

A. In part. 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. In other words, if SSER revenues are not included in current revenues then the increase in base revenues would seem overstated because a portion of the revenue requirement increase is already recovered through the SSER revenues.

Finally, the Company's tariff in Section 2.4.2 of the System Safety Enhancement Rider (SSER) requires SSER revenues be rolled into base rates following a general rate case application.

Q. WHAT ARE MR. BURDETTE'S CONCERNS REGARDING THE COMPANY'S APPROACH TO CLASSIFY AND ALLOCATE COSTS?

A. Mr. Burdette states the Company reversed the order of operation for classification and allocation of costs such that the Company first allocated costs to each rate class and then classified those costs into demand, commodity, customer or revenue related cost types. Mr. Burdette terms the Company's approach 'alternative' and 'non-traditional' and further states that the Company's approach yields results that are considerably different than Staff's COSS results that were developed using the traditional approach.

Q. DO YOU AGREE THE COMPANY'S APPROACH TO CLASSIFY AND ALLOCATE COSTS WAS IN REVERSE ORDER?

A. No. The Company's COSS follows the traditional three-step COSS method. First, the Company's COSS functionalized or assigned costs into functional categories. Second, functionalized costs were classified into cost drivers such as customer, demand, energy, and revenue. And finally, the classified costs were allocated to each rate class based on methods that best reflect how costs are incurred. The approach is illustrated in Figure 1 (below).

The Figure shows, as an example, that Plant Account 376 (Mains) was first functionalized as distribution plant in accordance with the Federal Energy Regulatory Commission's ("FERC") Uniform System of Accounts ("USOA"). The Figure further shows that a portion of Plant Account 376 (Mains) was classified as demand and a portion was classified as customer. Finally, the Figure shows that plant classified as demand were allocated based on the demand allocator and plant classified as customer were allocated based on the customer allocator.

Figure 1[1]

(1) Line No.	(2) Rate Base Detail	(3) Allocation Factor Label (b)	(4) Arkansas Jurisdiction	(5) Residential	(6) SCS-1
	GAS PLANT IN-SERVICE				
1	Intangible Plant				
2	301 - Organization	DISTPLT	$ -	$ -	$ -
3	302 - Franchise and Consents	DISTPLT	137,343	99,613	25,945
4	303 - Miscellaneous Intangible Plant	DISTPLT	27,495,757	19,942,423	5,194,149
5	309 - Structures and Improvements (Intangible)	DISTPLT	2,481,392	1,799,731	468,753
6	Total Intangible Plant		$ 30,114,492	$ 21,841,767	$ 5,688,848
7	Distribution Plant				
8	374 - Land and Land Rights	MAINS	$ 9,650,343	$ 6,800,775	$ 1,946,277
9	375 - Structures and Improvements	MAINS	16,754,547	11,807,238	3,379,050
10	376 - Mains		1,009,636,796	711,509,647	203,623,105
11	Demand	DEMAND	464,035,689	227,014,622	143,655,960
12	Customer	CUSTOMERS	545,601,108	484,495,025	59,967,145
13	378 - Measuring and regulating station equip.—General	DEMAND	16,751,378	8,195,076	5,185,884
14	379 - Measuring and reg. station equip.—City gate check stations	DEMAND	2,308,619	1,129,418	714,701
15	380 - Services	Services	458,831,187	400,140,146	55,972,307
16	381 - Meters	Meters	81,329,872	58,896,131	21,193,542
17	382 - Meter Installations	Meter Inst.	31,353,660	22,705,178	8,170,370
18	383 - House Regulators	Regulators	32,624,199	25,606,478	6,424,103
19	385 - Industrial measuring and regulating station equipment	LCS-1	23,495,269	-	-
20	387 - Other Equipment	MAINS	-	-	-
21	Total Distribution Plant		$ 1,682,735,871	$ 1,246,790,087	$ 306,609,338

Q. DO YOU AGREE THE COMPANY'S APPROACH TO CLASSIFY AND ALLOCATE COSTS YIELDS DIFFERENT RESULTS THAN STAFF'S APPROACH?

A. No. The Company's approach to classify and allocate costs yields identical results as Staff's approach. In both approaches, costs are first classified and then classified costs are allocated to each rate class, that is, the order of COSS operation is 'traditional' and consistent in both studies.

[1] Schedule G-2

Q. WHY DOES STAFF'S COMPARISON OF THE TWO COSS STUDIES, AS ILLUSTRATED IN STAFF EXHIBIT MB-1, SHOW DIFFERENT RESULTS?

A. Staff Exhibit MB-1 presents Staff's comparison of class cost allocation results between Staff and the Company's COSS studies. Per Staff's testimony, the comparison is presented as Staff utilizing similar cost classification and allocation methodologies as the Company's COSS that differs only in the order in which the classification and allocation steps were applied.[2] The exhibit provides an example of Plant Account 376 (Mains) and expense Account 887 (Maintenance of Mains) and shows that Staff's approach results in a 6.42 percent higher allocation of costs to the residential class than the Company's study.

However, Staff's COSS is based on classification factors that are different than those used in the Company's COSS. Specifically, the Company classifies as customer 54.04 percent of Plant Account 376 (Mains) while Staff classifies as customer 66.17 percent. When Staff's COSS is adjusted to reflect Company's classification factors, then the results of the COSS studies are the same, as shown in Figure 2 below.

Figure 2: Classification and Allocation Methodology Differences
[Updated with Customer-related Cost of 54.04 percent]

Plant Account 376.00		Mains		Classification:		Other	Allocation Factor:		Min_Study	
	Total	Residential	SCS-1	SCS-2	SCS-3	LCS-1	DEM	COM	CUST	REV
L1 Staff's COS Model	1,009,636,796	711,509,647	203,623,105	1,669,933	45,817	92,788,294	464,035,689	-	545,601,108	-
L2 SUA's COS Model	1,009,636,796	711,509,647	203,623,105	1,669,933	45,817	92,788,294	464,035,689	-	545,601,108	-
L3 Difference (L1-L2)	-	-	-	-	-	-	-	-	-	-
L4 % Diff (L1-L2)/L1	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%

O&M Exp. Account 887.00		Mains		Classification:		Other	Allocation Factor:		Min_Study	
	Total	Residential	SCS-1	SCS-2	SCS-3	LCS-1	DEM	COM	CUST	REV
L5 Staff's COS Model	9,943,239	7,007,184	2,005,348	16,446	451	913,810	4,569,978	-	5,373,261	-
L6 SUA's COS Model	9,943,239	7,007,184	2,005,348	16,446	451	913,810	4,569,978	-	5,373,261	-
L7 Difference (L5-L6)	-	-	-	-	-	-	-	-	-	-
L8 % Diff (L7/L5)	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%

[2] In describing Exhibit MB-1, Staff states: "In the examples reflected in the exhibit, I have presented a plant account and an expense account for which Staff and the Company used similar cost classifications and allocation factors but differed only in the order in which the steps were applied." Direct Testimony of Staff Witness Mark Burdette, p. 12.

Staff's COSS is also based on Mains and Services allocators ('Mains/Services') and Meters, Meter Install & Regulators allocators ('Meters/Regs') that are different than those used in the Company's COSS.

Thus, the differences between Staff and the Company's COSS are not related to the order of operation but on the classification and allocation factors used to classify and allocate costs.

Q. DO YOU AGREE WITH MR. BURDETTE'S RECOMMENDATION TO ALLOCATE OTHER WORKING CAPITAL ASSETS BASED ON NET PLANT?

A. No. Other Working Capital Assets largely consists of the Company's allowance for cash working capital, which represents the net funds required by the Company to finance goods and services used to provide service to customers from the time those goods and services are paid for by the Company to the time that payment is received from customers. The goods and services included in Other Working Capital Assets largely consists of operations and maintenance ("O&M") expenses, income taxes, and taxes other than income.

Consequently, the Company allocated Other Working Capital Assets based on a composite allocation of O&M expenses.

It is important to note the NARUC Manual – a generally-accepted authority on cost allocation methodologies for gas distribution companies – provides an illustrative class cost of service study that allocates the allowance for cash working capital based on total O&M expenses, which is consistent with the Company's approach.[3]

[3] NARUC Manual, pp. 42 and 47

Q. DO YOU AGREE WITH MR. BURDETTE'S RECOMMENDATION TO ALLOCATE EXPENSE ACCOUNT 874 (MAINS AND SERVICES) BASED ON AN INTERNAL ALLOCATOR DERIVED FROM PLANT ACCOUNTS 376 (MAINS) AND 380 (SERVICES)?

A. Yes.

Q. DO YOU AGREE WITH MR. BURDETTE'S RECOMMENDATION TO ALLOCATE EXPENSE ACCOUNTS 880 (OTHER DISTRIBUTION OPERATING EXPENSES) AND 881 (RENTS) BASED ON AN INTERNAL ALLOCATOR DERIVED FROM EXPENSE ACCOUNTS 871-879?

A. Yes.

Q. DO YOU AGREE WITH MR. BURDETTE'S RECOMMENDATION TO REVISE THE INTERNAL ALLOCATOR FOR EXPENSE ACCOUNTS 885 AND 894 TO INCLUDE EXPENSE ACCOUNT 886?

A. Yes.

Q. DO YOU AGREE WITH MR. BURDETTE'S RECOMMENDATION TO DISAGGREGATE TAXES OTHER THAN INCOME TAXES INTO INDIVIDUAL TAXES AND THEN ALLOCATE THE INDIVIDUAL TAXES BASED ON STAFF'S RECOMMENDED ALLOCATOR?

A. Yes.

Q. DO YOU AGREE WITH MR. BURDETTE'S CONCERNS REGARDING THE COMPANY'S CLASSIFICATION OF PLANT ACCOUNT 376 (MAINS)

BASED ON AN AVERAGE OF THE MINIMUM-SIZE AND ZERO-INTERCEPT STUDIES?

A. No. The Company's classification of Plant Account 376 (Mains) is based on two approaches: minimum system study and zero-intercept study. Both approaches are recognized by NARUC to classify Plant Account 376 (Mains). The approaches in this case lead to different results: the minimum system study yields a customer portion of 66.17 percent, while the zero-intercept study yields a customer portion of 41.91 percent.

The Company believes utilizing both approaches in its COSS is reasonable and appropriate and more accurately reflects the underlying cost of service. There are advantages and disadvantages to each study, such as the minimum size mains study reflects some demand capabilities while the zero-intercept study has no such demand capabilities.

Q. DO YOU AGREE WITH MR. BURDETTE'S RECOMMENDATION THAT EACH CUSTOMER CLASS PAYS ITS REVENUE REQUIREMENT?

A. In part. The Company agrees with the principle that each customer class should pay its revenue requirement – or its cost of service. However, the Company also believes in the principle that rate changes should be tempered by rate continuity considerations. Because these principles can conflict, the Company also believes a level of judgement is required in developing rates. That was the approach the Company used in developing its proposed rates.

III. RESPONSE TO STAFF WITNESS SWAIM

Q. WHAT ARE STAFF WITNESS SWAIM'S CONCERNS REGARDING THE COMPANY'S CLASS COST OF SERVICE STUDY?

A. Mr. Swaim's concerns are related to the following areas: (1) proforma billing determinants; (2) the reinstatement of Weather Normalization Adjustment ("WNA") and Billing Determinant Adjustment ("BDA") riders; and (3) rate design.

Q. WHAT ARE MR. SWAIM'S CONCERNS REGARDING THE COMPANY'S *PRO FORMA* BILLING DETERMINANTS?

A. Mr. Swaim states the Company's use of a multi-year regression analysis to estimate base use and Degree Day Factors ("DDFs") is a departure from its prior practice of using Staff's methodology, as in its predecessor's last general rate case, Docket No. 15-098-U. He further states the Company's weather adjustment methodology employs econometric techniques which are not readily understood by people without years of specialized training and that econometric models are also subject to unseen modifications that may alter their results.

Q. DOES THE COMPANY AGREE WITH MR. SWAIM'S CONCERNS REGARDING THE COMPANY'S UTILIZATION OF REGRESSION ANALYSIS TO DEVELOP BILLING DETERMINANTS?

A. No. The Company's utilization of regression analysis to weather normalize volumes in this proceeding appears to be the same approach filed by its predecessor in the last general rate case, Docket No. 15-098-U. Moreover, utilization of regression analysis to weather normalize volumes is a generally accepted practice in the industry.

The regression analysis used in this rate case proceeding measures the extent to which changes in a dependent variable (in this case, volumes) can be explained by changes in independent variables (in this case, weather or heating degree days). The regression analysis yielded an r-square that quantifies the extent to which changes in volumes can be explained by changes in heating degree days. For the residential class, the Company's regression analysis yielded an r-square of 0.9747 that indicates 97.47 percent of the changes in volumes can be explained by changes in heating degree days.

Q. WHAT OTHER CHANGES HAS MR. SWAIM MADE IN THE COMPANY'S BILLING DETERMINANTS?

A. Mr. Swaim updated the number of bills for each rate class with November and December 2023 actual number of bills.

Q. DOES THE COMPANY AGREE WITH THE UPDATE TO THE NUMBER OF BILLS?

A. Yes.

Q. DOES THE COMPANY AGREE WITH STAFF'S APPROACH TO CALCULATE DESIGN DAY DEMANDS?

A. No. There are two significant differences between the Company and Staff's calculation of design day demands. First, the Company's calculation includes a heating factor for the LCS-1 class because there is a strong statistical relationship between LCS-1 volumes and heating degrees during the analysis period. Staff's calculation excludes a heating factor for the LCS-1 class. As a result, the LCS-1 class under the Company's calculation has higher demands and allocation of demand-related costs than Staff's calculation.

Second, the Company's derivation of heat factors is based on regression analysis utilizing actual volumes, number of bills, and heating degree days during the one-year period November 1, 2022 through October 31, 2023. Staff's derivation of the heat factors is based on an average of actual volumes, number of bills, and heating degree days during the five-year period November 1, 2019 through April 30, 2024.

The Company believes that heat factors based on the one-year period November 1, 2022 through October 31, 2023 are more appropriate because they reflect recent usage trends.

Q. DOES THE COMPANY AGREE WITH STAFF'S PROFORMA BILLING DETERMINANTS?

A. In part. The Company agrees with Staff's forecasted number of bills for each customer class since they reflect the updated number of bills in November and December 2023.

However, as discussed earlier, the Company continues to support its proposed normalization methodology for forecasting customer volumes.

Q. DOES THE COMPANY AGREE WITH MR. SWAIM'S RECOMMENDATION THAT NO CUSTOMER CLASS HAVE A RATE DECREASE IN THE CONTEXT OF AN OVERALL INCREASE?

A. Yes. However, the Company believes such approach to adjust class revenues should reflect a uniform movement of class revenues toward cost-based rates.

IV. RESPONSE TO HHEG WITNESS BLANK

Q. WHAT ARE HHEG WITNESS BLANK'S CONCERNS REGARDING THE CLASS COST-OF-SERVICE STUDY?

A. Mr. Blank's concerns are related to the following areas: (1) cost allocation; (2) calculation of design day demands; and (3) rate design.

Q. WHAT ARE MR. BLANK'S CONCERNS REGARDING COST ALLOCATION?

A. Mr. Blank has the following concerns regarding cost allocation:

- He states the Company's decision to use the average of the minimum system and zero-inch methods for classification of distribution mains is a departure from the rate case filing in Docket No. 15-098-U, in which the minimum system method was used.
- He states the Company's choice of averaging classification methods is an attempt to create mitigated results relative to the precedent model design.
- He also states the Company further mitigates the results of its approach by "rate smoothing" adjustments between the SCS-1, SCS-2, SCS-3 and LCS-1 classes.

Q. DOES THE COMPANY AGREE WITH MR. BLANK'S CONCERNS REGARDING THE COMPANY'S APPROACH TO CLASSIFY DISTRIBUTION MAINS?

A. No. As stated earlier, the Company believes its approach to classify Plant Account 376 (Mains) based on an average of the minimum system and zero-inch method is reasonable and appropriate and more accurately reflects the underlying cost of service.

Q. WHAT ARE MR. BLANK'S CONCERNS REGARDING CALCULATION OF DESIGN DAY DEMANDS?

A. Mr. Blank has the following concerns regarding design day demand calculations:

- He states the methodology used to calculate design day demands for SCS-2, SCS-3, SCS-3 TSO, LCS-1, and LCS-1 TSO is flawed.
- He states that while the data set used for the design day demand calculation was found to be weather sensitive for LCS-1 and LCS-1 TSO, the same customer classes were found not to be weather sensitive when the company weather normalized the revenues for each customer class. He opines that it is nonsensical to identify the same set of customers as weather sensitive for the calculation of allocating cost and not weather sensitive in the revenue calculation.
- He is also concerned with the Company's use of heating degree days to calculate the design day demand of LCS-1 TSO. He states that LCS-1 TSO is the first to be curtailed during extreme events, and the referenced design day of February 16, 2021, was when the system was under curtailment.
- He is concerned with the Company's use of February 2023 average daily consumption to calculate SCS-2, SCS-3, and SCS-3 TSO contribution to the system's design day demand. He states that choosing the month with the total maximum volume to calculate non-weather sensitive customers' contribution to the design day demand makes is unsupported and choosing a month with lower heating degree days than December 2022 and January 2023 is contradictory from the purpose of the exercise.

Q. DOES THE COMPANY AGREE WITH MR. BLANK'S CONCERNS REGARDING THE COMPANY'S CALCULATION OF DESIGN DAY DEMANDS?

A. In part. First, the Company's approach to weather normalize volumes was based on regression analysis that showed over a 6-year period an r-squared for the LCS-1 class of only 55.48 percent. Consequently, there was insufficient support to weather normalize volumes for the LCS-1 class.

Second, the Company's approach to calculate design day demands was based on regression analysis that showed over the most recent 1-year period an r-squared for the LCS-1 and LCS-1 TSO rate classes of 87.70 percent and 80.30 percent, respectively. Consequently, there was sufficient support to utilize heat factors to calculate design day demands for the LCS-1 and LCS-1 TSO rate classes.

However, the Company 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. Consequently, the Company has revised its approach to utilize average daily consumption during the winter months.

Q. DOES THE COMPANY AGREE WITH MR. BLANK'S CONCERNS REGARDING THE COMPANY'S APPROACH TO CLASSIFY DISTRIBUTION MAINS?

A. No. As stated earlier, the Company believes its approach to classify Plant Account 376 (Mains) based on an average of the minimum system and zero-inch method is reasonable and appropriate and more accurately reflects the underlying cost of service.

Q. WHAT ARE MR. BLANK'S CONCERNS REGARDING RATE DESIGN?

A. Mr. Blank has the following concerns regarding rate design:

- He is concerned that the overall magnitude of the Company's proposed revenue requirement increase requires some level of mitigation. He recommends holding SCS-2 and SCS-3 at present rate levels and use the revenue above cost of service to offset the revenue increase for residential customers.
- He is concerned with the Company's proposed separation of transportation customers from sales customers when calculating rates for the SCS-1 and LCS-1 customer classes. He states that it does not stand to reason that a customer should pay higher demand or usage charges solely due to the change of supplier. He recommends that the transportation customers and sales customers billing determinants should be combined when calculating the rates for SCS-1 and LCS-1 rate classes. The customer demand and/or usage rates for SCS-1 and LCS-1 should be calculated as one SCS-1 and LCS-1 rate class with additional fees for telemetry and administrative cost for transportation customers.

Q. DO YOU AGREE WITH MR. BLANK'S RECOMMENDATION TO HOLD THE SCS-2 AND SCS-3 CLASSES AT THE PRESENT LEVEL?

A. Yes. As stated earlier, the Company agrees there should be no class revenue decrease in the context of an overall rate increase.

Q. DO YOU AGREE WITH MR. BLANK'S RECOMMENDATION TO COMBINE THE SALES AND TRANSPORTATION BILLING DETERMINANTS?

A. Yes.

V. RESPONSE TO ATTORNEY GENERAL WITNESS PORTER

Q. WHAT ARE ATTORNEY GENERAL WITNESS PORTER'S CONCERNS REGARDING THE RESIDENTIAL CLASS RATES AND REVENUES?

A. Mr. Porter states that the Company's current allocation method disproportionately allocates costs to the typical residential customer. He states the use of an allocation methodology based on customer and peak demands is generally prejudicial to relatively low-load factor customers such as the typical residential customer. He recommends an allocation methodology based on peak-period demands and annual customer requirements.

Q. DOES THE COMPANY AGREE WITH MR. PORTER'S RECOMMENDATION TO ALLOCATE THE CUSTOMER PORTION OF PLANT ACCOUNT 376 (MAINS) BASED ON ANNUAL USAGE?

A. No. The Company classification of Plant Account 376 (Mains) is consistent with cost-causation and reflects two drivers. The first cost driver is number of customers. Distribution mains were designed to provide customer access to the natural gas system. The second driver is customer demands. Distribution mains are designed to meet customer design day demands.

By comparison, Mr. Porter's recommendation to allocate Plant Account 376 (Mains) based on annual energy usage is inconsistent with cost-causation because distribution mains costs do not vary with changes in energy usage.

VI. RESPONSE TO AGC WITNESS LY

Q. WHAT ARE AGC WITNESS LY'S CONCERNS REGARDING THE CLASS COST OF SERVICE STUDY?

A. AGC witness Ly's concerns are in the following areas: (1) COSS study, and (2) class revenue allocation.

Q. WHAT ARE AGC WITNESS LY'S CONCERNS REGARDING FURTHER ADJUSTMENTS TO THE CLASS COST-OF-SERVICE STUDY?

A. Witness Ly provides the following concerns related to the COSS:

- He states that the Company inappropriately uses the average of the results of its studies using the minimum size main and zero-intercept methodologies to classify the costs of its distribution mains between customer- and demand-related portions. He states Arkansas Act 725 of 2015 (Act 725) explicitly states that the customer-related portion of distribution mains should be determined solely using the minimum size main methodology.
- He states the NARUC Gas Distribution Rate Design Manual referenced in Act 725 does not include a description of the zero-intercept study, but rather refers to a singular methodology based upon "the historic unit cost of the smallest main installed in the system".
- He states that it is unclear whether the Company's Heating Assistance Fund costs are included in SUA's COSS, and if so, how they are allocated.

Q. DOES THE COMPANY AGREE WITH MR. LY'S CONCERN THAT THE ARKANSAS ACT 725 OF 2015 PROHIBITS UTILIZATION OF A ZERO-INTERCEPT STUDY?

A. No. While I am not an attorney, the Arkansas Act 725 of 2015 ("Act 725") does not appear to prohibit utilization of a zero-intercept study. Act 725 states,

> To develop a cost allocation method under this section for natural gas utilities, the commission shall use the Gas Distribution Rate Design Manual, June 1989 edition, as prepared by the National Association of Regulatory Utility Commissioners, as it existed on January 1, 2015, or any subsequent version of the manual, to the extent it produces an equivalent result.

The zero-intercept study method is recognized in the referenced Gas Distribution Rate Design Manual. Specifically, the Gas Distribution Rate Design Manual states,

> The zero-inch main method would allocate the cost of a theoretical main of zero-inch diameter to the customer function, and allocate the remaining costs associated with mains to demand. (NARUC Manual at 22-23)

Q. DOES THE COMPANY AGREE WITH MR. LY'S RECOMMENDATION THAT THE COMMISSION SHOULD REJECT THE COMPANY'S CLASSIFICATION OF PLANT ACCOUNT 376 (MAINS) BASED ON THE MINIMUM SYSTEM AND ZERO-INTERCEPT STUDIES?

A. No. As stated earlier, the Company believes its classification of Plant Account 376 (Mains) is reasonable and appropriate and reflects cost-causation.

Q. ARE THE COMPANY'S HEATING ASSISTANCE FUND COSTS INCLUDED IN THE COMPANY'S COSS?

A. Yes. The Company's heating assistance fund costs are included in the Company's cost of service and are further addressed in the testimony of Company Rebuttal Witness Phillip B. Gillam.

Q. DOES THE COMPANY AGREE WITH MR. LY'S RECOMMENDATIONS TO SET REVENUES FOR SCS-2 AND SCS-3 AT THEIR PRESENT LEVELS?

A. Yes. The Company agrees no class should receive a rate decrease in the context of an overall rate increase.

Q. DOES THE COMPANY AGREE WITH MR. LY'S RECOMMENDATIONS TO REJECT THE COMPANY'S APPROACH TO SET CLASS REVENUE TARGETS?

A. No. The Company's approach strikes a reasonable balance of three rate design principles:

1. Rates should recover the overall cost of providing service
2. Rates should be fair in that each rate class should recover the costs caused by that customer class, minimizing inter- and intra-class inequities to the extent possible
3. Rate changes should be tempered by rate continuity concerns

VII. UPDATES TO SCHEDULES G AND H

Q. HAS THE COMPANY MADE ANY UPDATES TO SCHEDULES G AND H?

A. Yes. The Company has made the following updates to Schedules G-1 through G-4:

- Updated allocation of Account 874 Mains and Services Expense to be based on Mains and Services Plant.
- Updated allocation of Accounts 880 and 881 to be based on composite allocation of Accounts 871-879.
- Updated allocation of Accounts 885 and 894 to be based on composite allocation of Accounts 886-893.
- Updated allocation of taxes other than income by disaggregating into payroll and property taxes and then allocating these separately based on Staff's recommended allocators (i.e., composite allocation of O&M expenses and composite allocation of net plant respectively).
- Updated design day demand calculation for SCS-2 and SCS-3 to reflect average daily consumption during winter months for these classes.
- Updated allocation of Account 904 Uncollectibles to be based on 5-year historical write-offs by rate schedule.
- Updated calculation of income taxes for each class to account for interest expenses and other income deductions.

In addition, the Company has made the following updates to Schedules H-1 and H-2:

- Updated rider revenues for each rate schedule to include Energy Efficiency Cost Recovery ("EECR") – Lost Contributions to Fixed Costs ("LCFC") portion.
- Updated number of bills, resulting volumes, and resulting base revenues to reflect the changes discussed earlier in the testimony.
- Updated LCS-1 and LCS-1 TSO rate design to achieve the same rates.

VIII. CONCLUSION

Q. WHAT IS THE COMPANY'S RECOMMENDATION TO THE COMMISSION?

A. The Company's recommendations to the Commission are as follows:

- Approve the Company's approach to functionalize, classify, and allocate costs in its COSS study, as modified in this rebuttal testimony. The Company's approach allocates costs to each rate class in a manner that reflects the underlying cost of service.
- Approve the Company's approach to establish class revenue targets, as modified in this rebuttal testimony. The Company's approach balances three rate design objectives: (1) to establish rates that recover the Commission-approved revenue requirement; (2) to establish rates that reflect the underlying cost of serving each rate class; and (3) to establish rates that are tempered to address rate continuity considerations.

Q. DOES THIS COMPLETE YOUR TESTIMONY?

A. Yes.

CERTIFICATE OF SERVICE

I, Brooke South Parsons, do hereby certify that a true and correct copy of the foregoing has been delivered to all Parties of Record by electronic mail via the Electronic Filing System this 7th day of August 2024.

Brooke South Parsons

Brooke South Parsons

BEFORE THE

ARKANSAS PUBLIC SERVICE COMMISSION

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

REBUTTAL TESTIMONY

OF

DANE A. WATSON, PE CDP

MANAGING PARTNER,

ALLIANCE CONSULTING GROUP

ON BEHALF OF

SUMMIT UTILITIES ARKANSAS, INC.

Date Filed: August 7, 2024

TABLE OF CONTENTS

LIST OF EXHIBITS

I. EXECUTIVE SUMMARY

My rebuttal testimony in this proceeding addresses recommended changes in the service lives and net salvage costs for certain accounts as well as the resulting depreciation rates and expense being recommended by the Arkansas Public Service Commission ("Commission") Staff ("Staff") witness Claude Robertson and Office of the Arkansas Attorney General Tim Griffin ("AG") witness Michael Majoros, both having filed Direct Testimony on depreciation.

I think it is important to note that my recommendations and those of Staff are very close. In fact, Mr. Robertson proposes only two life changes, which I will discuss, and no changes to net salvage. Mr. Robertson and I agree on the 10-year amortization period for General Plant Amortization true-up, but he provides an alternative recommendation on where to record that true-up for the reserve amortization related to General Plant Amortized accounts. Summit Utilities Arkansas, Inc. ("SUA") witness Phillip B. Gillam will address this accounting aspect of Mr. Robertson's recommendation on this issue.

As it pertains to the AG witness Mr. Majoros, the majority of my testimony will be directed at the inaccuracies, departure from standard depreciation theory, and misinterpretation of long-standing guidance from the Federal Energy Regulatory Commission ("FERC"), Uniform System of Accounts ("USOA"), and authoritative depreciation texts in regard to the accounting for the retirement of assets and associated costs. He also has proposed different lives for two Accounts, 376 Mains and 380 Services, which I will address. Mr. Majoros' 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. Mr. Majoros' recommendations should be disregarded in their entirety.

II. INTRODUCTION

Q. PLEASE STATE YOUR NAME, POSITION AND BUSINESS ADDRESS.

A. My name is Dane A. Watson, and my business address is 101 E. Park Blvd., Suite 220, Plano, Texas 75074. I am a Partner of Alliance Consulting Group. Alliance Consulting Group provides consulting and expert services to the utility industry.

Q. ARE YOU THE SAME DANE A. WATSON WHO FILED DIRECT TESTIMONY ON JANUARY 25, 2024, IN THIS PROCEEDING?

A. Yes.

III. PURPOSE OF DIRECT TESTIMONY

Q. WHAT IS THE PURPOSE OF YOUR REBUTTAL TESTIMONY?

A. The purpose of my testimony on behalf of SUA is to rebut the Direct Testimony of Staff witness Claude Robertson and Arkansas Attorney General witness Michael Majoros regarding their proposed changes to the depreciation rates I proposed in the appendices to Direct Exhibit DAW-1 of my Direct Testimony.

Q. ARE YOU SPONSORING ANY EXHIBITS TO YOUR TESTIMONY?

A. Yes, I sponsor the exhibits listed in the Table of Contents.

Q. WAS YOUR REBUTTAL TESTIMONY PREPARED BY YOU OR UNDER YOUR DIRECT SUPERVISION?

A. Yes.

Q. WERE THE EXHIBITS PREPARED BY YOU OR UNDER YOUR DIRECTION?

A. Yes. I have prepared or supervised the preparation of the exhibits and workpapers listed in the Table of Contents.

Q. WHAT RECOMMENDATIONS ARE YOU MAKING IN YOUR REBUTTAL TESTIMONY?

A. I recommend that the Commission disregard Mr. Majoros' recommendations entirely and approve the annual depreciation rates I proposed in the appendices to Direct Exhibit DAW-1 of my Direct Testimony. Although Mr. Robertson's two life changes are not unreasonable, I believe that my lives are more reasonable based on the facts and circumstances.

Q. PLEASE PROVIDE A BRIEF SUMMARY OF YOUR TESTIMONY.

A. My testimony refutes the testimony of AG witness Mr. Majoros that depreciation rates should be set lower than the Company's requested depreciation rates. It outlines the global concerns I have with Mr. Majoros' methodology. His analyses do not use the standard depreciation methodology that Staff witness Mr. Robertson and I have utilized to compute depreciation rates. I then address the problems in Mr. Majoros' specific account analyses and address the calculations for depreciation rates. Importantly, in addressing Mr. Majoros' testimony, I address errors in his methodology and specific weaknesses in his individual account analysis. His recommendations regarding net salvage and cost of removal would shift removal cost to become a capital item which is added to new additions. In short, Mr. Majoros' unique interpretation of the Uniform System of Accounts would create a material shift in capitalization that is different from the mainstream application of removal cost accounting by other gas utilities across North America. I will address Mr. Majoros' recommendations in specific portions of this testimony.

Q. DO YOU ADDRESS STAFF'S DEPRECIATION RECOMMENDATIONS?

A. Yes. I will discuss those in the next sections of my testimony.

IV. DEPRECIATION STUDY PROCESS

Q. PLEASE DESCRIBE YOUR DEPRECIATION STUDY APPROACH.

A. The purpose of a depreciation study is to determine the life and net salvage characteristics associated with assets currently in service. In my decades of experience, I have found that the necessary activities can be categorized into four phases. The four phases, as stated in my Direct Testimony are: Data Collection, Analysis, Evaluation, and Calculation.[1] I began each of the studies by collecting the historical data to be used in the analysis. After the data had been assembled, I performed analyses to determine the life and net salvage percentage for the different property groups being studied. As part of this process, I conferred with field personnel, engineers, and managers responsible for the installation, operation, and removal of the assets to gain their input into the operation, maintenance, and salvage of the assets. The information obtained from field personnel, engineers, and managerial personnel, combined with the analytical results, is then evaluated to determine how the results of the historical asset activity analysis, in conjunction with SUA's operational experience, should be applied. In addition, I also brought to the results my nearly 40 years of experience as an engineer and depreciation analyst in selecting rational lives and net salvage for utility assets. Using all these resources, I determined the most appropriate lives and net salvage factors, and then calculated the depreciation rate for each function.

Q. PLEASE EXPLAIN THE IMPORTANCE OF REFLECTING THE INPUT FROM SUBJECT MATTER EXPERTS IN THE RESULTS AND OBSERVING ACTIVITIES IN THE FIELD.

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[1] Direct Testimony of Dane A. Watson at 16-17.

A. As stated above, as part of the depreciation study process, I conferred with field personnel, engineers, and managers responsible for the installation, operation, and removal of the assets to gain their input into the operation, maintenance, removal, and salvage of the assets. The information obtained from field personnel, engineers, and managerial personnel, combined with the study results, is then evaluated to determine how the results of the historical asset activity analysis, in conjunction with SUA's current and future expectations for the operation of the assets, should be applied. The determination of the life and net salvage parameters of assets is not simply done by a simplistic evaluation of history. Characteristics may change over time, recent history may not be fully reflected in the statistics, and the past may not always be the same as the future. The goal of determining the life and net salvage for an account is to project as accurately as possible the <u>future</u> life and net salvage (i.e. the life and net salvage characteristics the assets will exhibit over their remaining lives), not simply the historical activity. With that said, care must be given to ensure that the projection of recent and future changes does not cross the line into speculation. In my depreciation study, I only used known activities and facts to guide my recommendations, and I did not speculate on improbable future outcomes to set depreciation rates.

Understanding how the system is operated, and the characteristics of the specific assets is important for an analyst to get a better understanding of the assets that are being studied and an understanding of the actual drivers "behind" the accounting information being analyzed. Key information from Subject Matter Experts ("SMEs") or recent and future changes in operations can be pivotal for a depreciation analyst.

In its 1996 edition of the publication *Public Utility Depreciation Practices*, the National Association of Regulatory Utility Commissioners ("NARUC") advises against strict reliance on historical data and fitting, stating:

> Depreciation analysts should avoid becoming ensnared in the historical life study and relying solely on mathematical solutions. The reason for making an historic life analysis is to develop a sufficient understanding of history in order to evaluate whether it is a reasonable predictor of the future. The importance of being aware of circumstances having direct bearing on the reason for making an historical life analysis cannot be understated. The analyst should become familiar with the physical plant under study and its operating environment, including talking with the field people who use the equipment being studied.[2]

Q. DID ANY INTERVENOR WITNESS INCORPORATE INFORMATION FROM COMPANY SMEs IN FORMING THEIR LIFE RECOMMENDATIONS?

A. Commission witness Mr. Robertson incorporated this vital step in his depreciation study.[3] I could not find anything in the record that would suggest that AG witness Mr. Majoros incorporated this vital depreciation study input.

V. SPECIFIC REBUTTAL TO INTERVENOR LIFE RECOMMENDATIONS

A. RESPONSE TO AG WITNESS MAJOROS

Q. WHAT POINTS OF MR. MAJOROS DO YOU ADDRESS IN THIS SECTIONS?

A. In this portion of my testimony, I address the AG's contention that the Company's depreciation rates are excessive. Specifically, I address Mr. Majoros' recommendations 1 and 2: the contention that the Company's rates should be reduced and that the service lives for Account 376 Mains and Account 380 should be lengthened.

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[2] NARUC, *Public Utility Depreciation Practices*, at 126 (1996).
[3] Robertson Direct: 8:19-9:2.

Q. WHY DOES MR. MAJOROS STATE THAT THE COMPANY'S DEPRECIATION RATES ARE TOO HIGH?

A. Mr. Majoros states that "Company has a $191 million excess in its accumulated depreciation account resulting from its current and prior depreciation rates. [4]"

Q. HOW DOES SOMEONE DETERMINE IF THERE IS EXCESS DEPRECIATION IN THE RESERVE?

A. Depreciation analysts compute the theoretical depreciation reserve, which is a benchmark of where the reserve should be if the proposed or current depreciation parameters are being used. In Direct Exhibit MJM-12[5], Mr. Majoros does not make this theoretical reserve computation correctly. His theoretical reserve amounts do not use standard algorithms for remaining life, rendering his analysis inaccurate.

Q. MR MAJOROS STATES THAT YOU DID NOT SHOW THE THEORETICAL RESERVES USING YOUR PROPOSED DEPRECIATION RATES.[6] IS THAT ANALYSIS CORRECT?

A. No. The computation of theoretical reserves using Company proposed depreciation parameters is shown in my Rebuttal Exhibit DAW-1, which was included in my direct workpapers. There is a difference between the book reserve and theoretical reserve, where the theoretical reserve is slightly higher.[7] This indicates that the depreciation reserve is under accrued, not over accrued as Mr. Majoros suggests.

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[4] Majoros Direct, 9:1-3.
[5] Majoros Direct Exhibits, Exhibit MJM-12, Page 35.
[6] Id, p. 27:13-16.
[7] The difference is less than 6%, not the $191 million Mr. Majoros claims.

Q. DID STAFF WITNESS MR. ROBERSTON REVIEW THE THEORETICAL RESERVE FOR THE COMPANY?

A. Yes, Mr. Robertson examined the theoretical reserve computations and level. The only differences he addressed were in two small general plant accounts where he recommended a slightly different life for Account 391.2 and 394.[8] Mr. Robertson made no remarks about excess reserve. His proposed depreciation rates adopted the same net salvage parameters that I recommend, and in life analysis the proposed adjustments to accounts that comprise 0.96% of SUA's depreciable plant.[9] Mr. Majoros' excess reserve claim of $191 million is incorrect and does not rise to level of scrutiny by Staff's depreciation expert.

Q. WHAT ACCOUNTS DOES MR MAJOROS MAKE A DIFFERENT LIFE RECOMMENDATION THAN YOUR PROPOSED LIFE?

A. The accounts where Mr. Majoros makes a different life recommendation are shown in the table below. Staff witness Mr. Robertson supports my recommendations for these accounts.[10]

Life Parameter Comparison by Party

Account	Company Current	Company and Staff Proposed	AG Proposed
376 Mains	65 R2.5	65 R2.5	70
380 Services	38 R4	38 R4	50

Mr. Majoros does not specify an Iowa type curve, which is very unusual, given the Company's approved depreciation system of straight line, broad group, remaining life.

[8] Robertson Direct: 13:9-14:6.
[9] (Account 391.2 plant + Account 394 Plant)/Total Depreciable Plant = (2,984.690 + 11,328,223)/1,495,738 = 0.96% Plant amounts found in Direct Exhibit DAW-1, Appendix A and A-1.
[10] Robertson Direct, 6:9-14.

Q. HOW DID YOU FORM YOUR RECOMMENDATIONS?

A. I used a multi-step process as described in the Depreciation Study Process section of this testimony.

Q. DID ANOTHER PARTY IN THIS CASE PERFORM A SIMILAR PROCESS?

A. Yes. Staff witness Mr. Robertson performed the same steps to form his recommendations. As Mr. Robertson states, "I performed my own depreciation study, using Company data updated through December 31, 2022."[11] Mr. Robertson also conducted a site visit where he met with Company personnel. [12] I commend Mr. Robertson for performing these vital steps in his depreciation study.

Q. WHAT IS A STANDARD APPROACH TO ACTUARIAL ANALYSIS USED BY DEPRECIATION EXPERTS?

A. Depreciation analysts will determine if there is sufficient data to match Company historical data to analyze the information using aged data models, called actuarial analysis. SUA has aged data back to 1939 for these accounts, so there is a great deal of information available. I then analyzed different placement and experience bands across history to review an account's life characteristics over time. This involves visually matching Company historical data to various Iowa curve models. Mr. Majoros agrees that this approach is normal in the industry.[13] I will next describe best practices in actuarial analysis as described in two authoritative treatises.

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[11] Id. 8: 11-12.
[12]Id, 8:19-9:2.
[13] Majoros Direct, 13:19-20

Q. WHAT DOES THE PLACEMENT BAND ANALYZE?

A. The placement bands are a group of vintages that show the composite retirement history from the asset's installation to the present. The placement band illustrates changes in technology and materials that occur.

Q. WHAT DOES THE EXPERIENCE BAND ANALYZE?

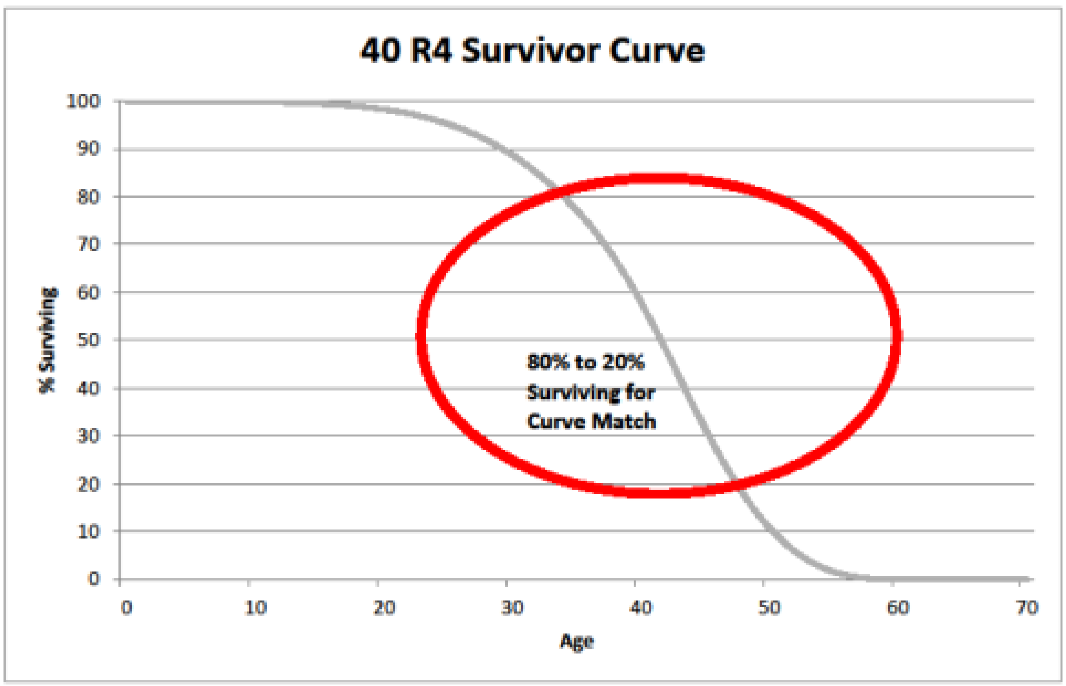
A. The experience band is a composite retirement history of all vintages during a select period of time. These can be helpful in isolating the effects on the group of assets over a specified period.

Q. HOW ARE THESE BANDS USED?

A. The depreciation analyst will evaluate the data in the placement and experience bands in numerous ways, generally using what is referred to as rolling bands and shrinking bands. This helps identify trends in the data. The selection of band width is also an important aspect of the analysis. Ultimately, various curve fits are made that assist the depreciation analyst in evaluating and recommending an average service life ("ASL") and associated dispersion pattern.

Q. ARE THERE ANY INDUSTRY STANDARD TEXTS THAT PROVIDE GUIDANCE ON WHAT IS CONSIDERED TO BE ADEQUATE OR SUFFICIENT HISTORY FOR PERFORMING AN ACTUARIAL ANALYSIS?

A. Yes. The NARUC publication *Public Utility Depreciation Practices* states that a band width needs to include enough data to provide some confidence in the reliability of the resulting curve fit and be narrow enough to see if there is an emerging trend. It also states that, for longer life plant (e.g., conduit), widths of ten or more years may be necessary.[14] As the noted treatise, *Depreciation Systems*, explains, "Often the middle section of the curve (that section ranging from approximately 80% to 20% surviving) is given more weight than the first and last sections. The middle section is relatively straight and is the portion of the curve that often best characterizes the survivor curve."[15] This is depicted in the illustrative graph, 40 R4 Survivor Curve, provided below.



Additionally, the NARUC depreciation manual discusses a stub curve, which is an observed survivor curve that does not reach 0% surviving, stating "it is desirable to have the stub curve drop below 50% surviving."[16] The below illustrative graph, 40 R2 Survivor Curve, indicates where the desired 50% and below area is on a survivor curve.

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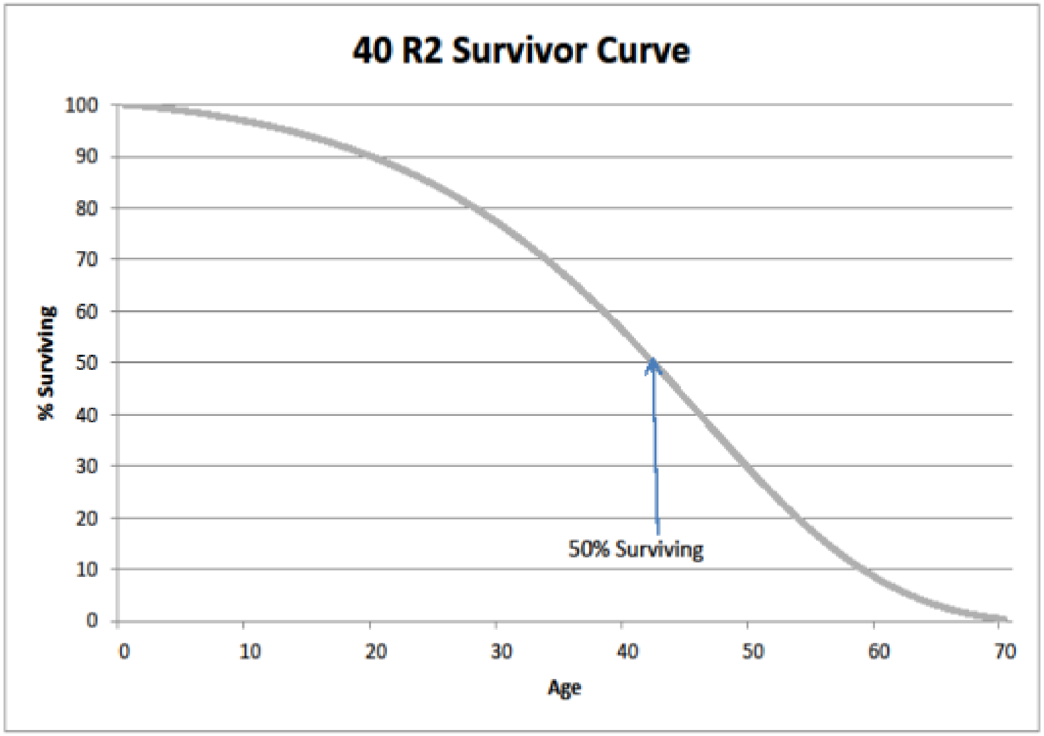
[14] NARUC, *Public Utility Depreciation Practices*, at 115.
[15] *Depreciation Systems* at 46-47.
[16] NARUC, *Public Utility Depreciation Practices*, at 120.



AG witness Mr. Majoros has inappropriately relied upon survivor curves that do not have any "middle section" and numerous stub curves that are not even below the 50% surviving discussed above in a perfect statistical sample as discussed in the doctoral dissertation of Harold Cowles (1957) and later noted in *Depreciation Systems*.[17] In addition to NARUC's 50% guidance, the treatise *Depreciation Systems* teaches that even in a perfect world where the data is statistically complete, the observed life table should at least drop below 70% to have any chance of differentiating between curves.[18] "Longer stub curves (i.e. those with 40% or less surviving) were fit with a high degree of accuracy."[19]

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[17] *Depreciation Systems* at 49.
[18] *Id.*
[19] *Id.*

Q. WHAT STEPS DID AG WITNESS MAJOROS UNDERTAKE TO SUPPORT HIS RECOMMENDATIONS?

A. First, Mr. Majoros reviewed the actuarial analysis for these accounts that was provided in my workpapers. Among the many bands I analyzed, Mr. Majoros cherry-picked examples to support a longer life that he displays in Direct Exhibit MJM-5[20] and Direct Exhibit MJM-6[21].

Q. PLEASE DESCRIBE THE BANDS AND INFORMATION YOU EXAMINED IN ACCOUNT 376 MAINS?

A. In Account 376 Mains, I ran 11 different bands and presented 17 graphs to analyze that account. Of that information, Mr. Majoros presented only two graphs to show: Placement band 1953-2022 and Experience band 1973-2002 and Placement Band and Experience Band 1993-2022.

Q. WHAT DOES A VISUAL COMPARISON SHOW?

A. Below are graphs over various placement and experience bands. The dark blue triangles represent the observed life table, the green rectangles represent the Company's proposal, and the slanted light blue triangles show Mr. Majoros' proposal. Below is a graph of both proposals with the full placement band (1931-2022) and the full observation band (1939-2022). Since Mr. Majoros did not specify a specific Iowa type curve, I am assuming the same Iowa type curve as is currently used and proposed by myself and Staff witness Mr. Robertson.

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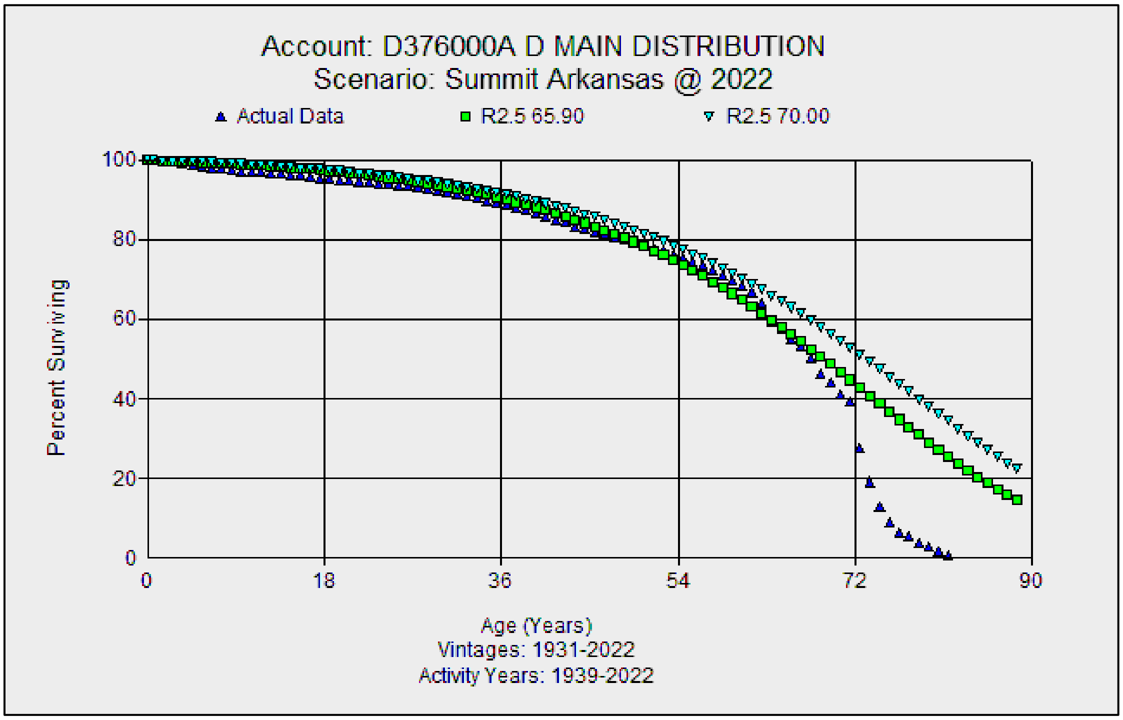
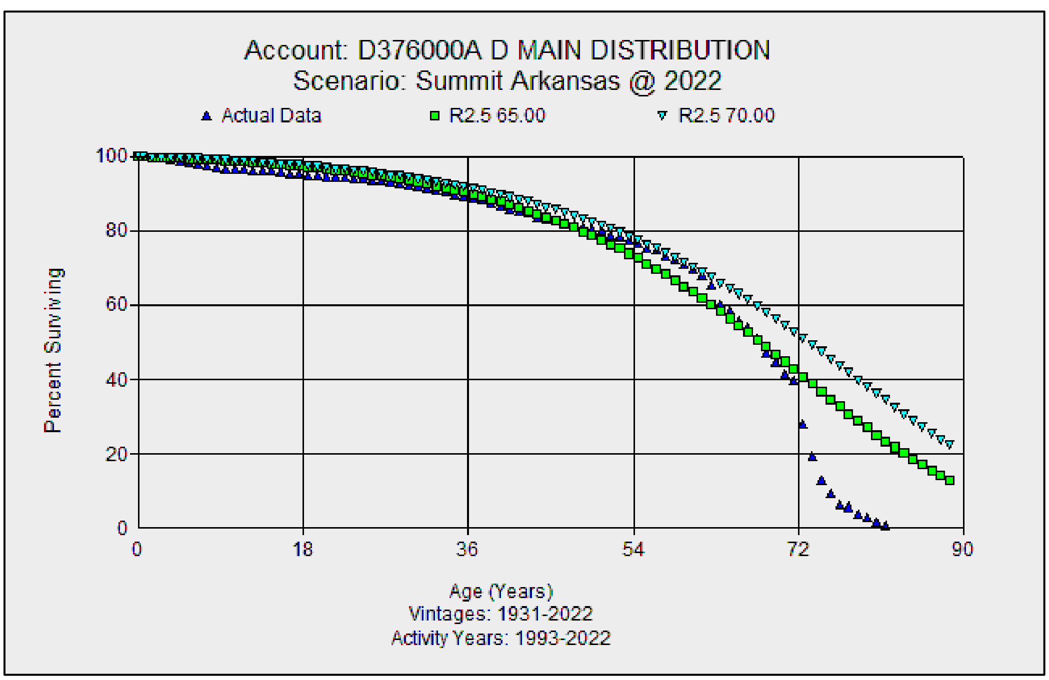
[20] Majoros Direct Exhibits, Exhibit MJM-5 pages 8 through 10.
[21] Majoros Direct Exhibits, Exhibit MJM-6 pages 11 through 24.



The Company's proposal matches the critical 80% to 20% better than Mr. Majoros. The same is true of placement band (1931-2022) and a later experience band (1993-2022) which is shown below.



The two graphs shown in Mr. Majoros Direct Exhibit MJM-5 pages 9 and 10 do not rise to the level of definitive analysis and proof. The graph on page 9 goes to 92.26% surviving, and the graph in Direct Exhibit MJM-5, page 10, ends at 54.74% surviving. Neither of Mr. Majoros' proposals reach the 40% surviving benchmark advocated by Depreciation Systems. Mr. Majoros offers no other support for his 70-year life, and his recommendation should be rejected.

Q. PLEASE DESCRIBE THE BANDS AND INFORMATION YOU EXAMINED IN ACCOUNT 380 SERVICES?

A. In Account 380 Services, I ran 13 different placement and experience bands, and I presented 29 graphs to analyze that account. Of that information, Mr. Majoros cherry-picked four graphs[22], all using the same placement band and experience band: Placement Band 1993-2002 and Experience Band 1993-2022.

Q. WHAT DOES A VISUAL COMPARISON SHOW?

A. Below are graphs over various placement and experience bands. The dark blue triangles represent the observed life table, the green rectangles represent the Company's proposal, and the slanted light blue triangles show Mr. Majoros' proposal. Below is a graph of both proposals with the full placement band (1920-2022) and the full observation band (1939-2022). In this comparison, I am assuming the same Iowa type curve as is currently used and proposed by myself and Staff witness Mr. Robertson.

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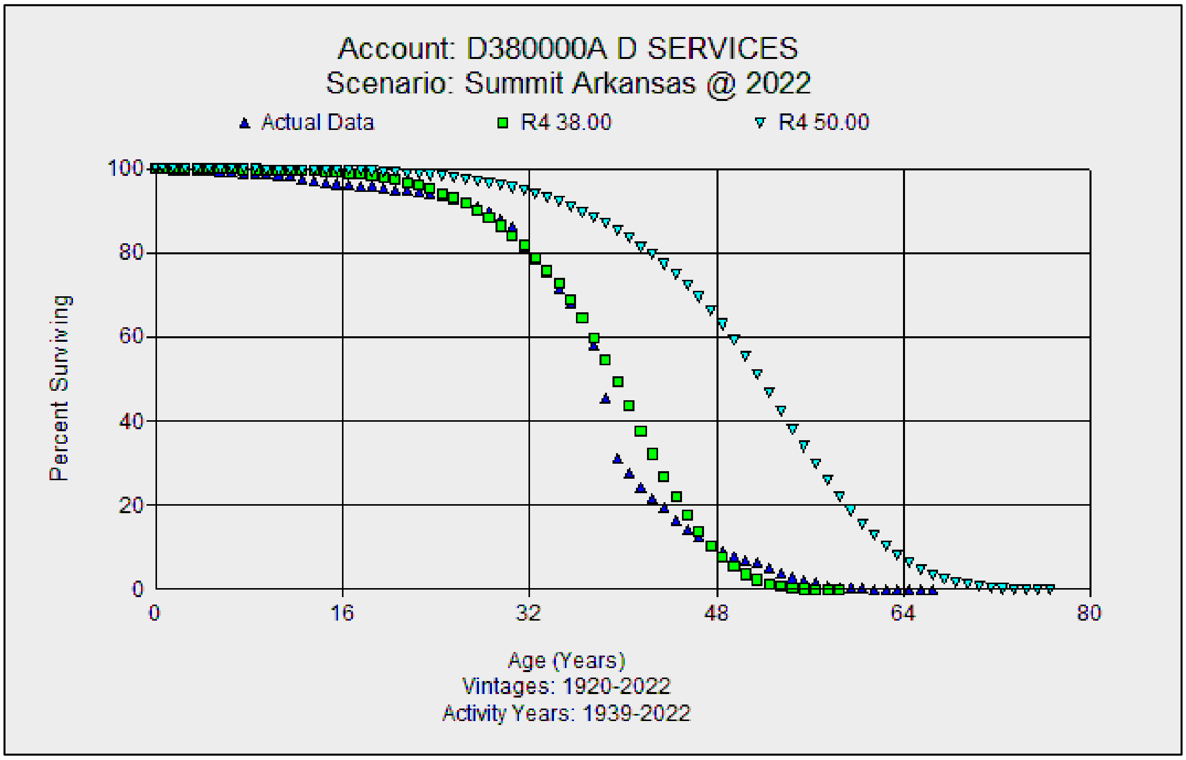
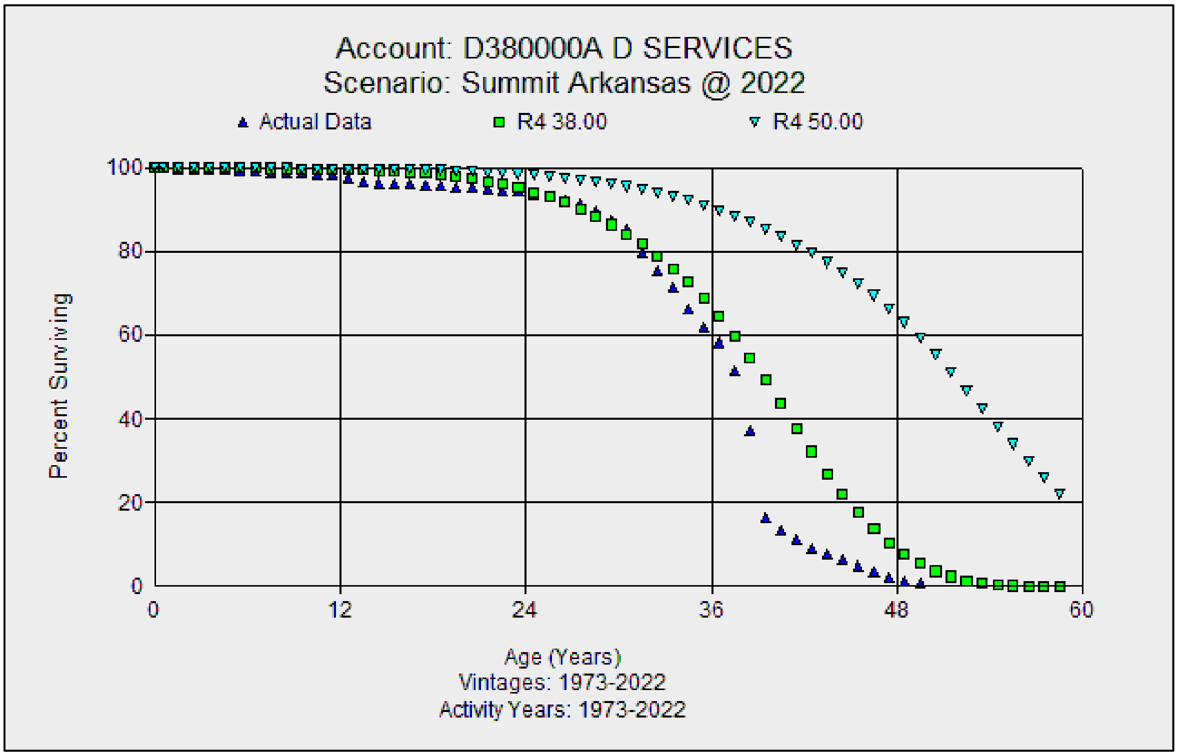
[22] Majoros Direct Exhibit MJM-6, page 12-13, 20-21.



It is clear that the Company's proposal matches the critical 80% to 20% better than Mr. Majoros' proposal. The same is true of placement band (1973-2022) and experience band (1973-2022), which is shown below.



The graphs shown in Direct Exhibit MJM-6[23] used the same experience band 1993-2022. In this account, that band ends at 89.67% surviving. Mr. Majoros emphasizes the curve fits in his Direct Exhibit MJM-6 pages 12 and 13.[24] The short stub curve in those graphs is not advocated by authoritative literature.

Q. MR. MAJOROS MENTIONS A SYSTEM SAFETY ENHANCEMENT RIDER ("SSER") THAT WILL INCREASE THE LIFE OF THIS ACCOUNT.[25] WHAT IS THE SSER?

A. In my Direct Testimony I discuss the SSER efforts. "Discussions with Company personnel revealed that the service life of these assets continues to be impacted by the expedited

[23] Majoros Direct Exhibit MJM-16, pages 12 and 13.
[24] Majoros Direct: 16:5-7
[25] Id, p. 15: 18: - 16:2

replacement of certain pipeline facilities through SUA's System Safety Enhancement Rider ("SSER"). While these factors had little effect on the service lives of mains, the change had a much greater impact on the life of certain services assets. However, the expectation is the life will increase once the program is complete, so the study retained the existing life instead of reducing the life based on the indications from the actuarial analysis. The validation by operations personnel with the analysis in both the current and prior study is important in assisting us in recommending the most appropriate service life going forward."[26]

Q. IS THE SSER PROJECT COMPLETE?

A, No. Mr. Majoros mistakenly assumes that the project has been completed. The SSER project is ongoing and continues to impact the life of the subject assets. Mr. Majoros mistakenly assumes that it has been completed and that a longer service life for Account 380 should occur immediately. He ignores the fact that Company SMEs state that the existing life is reasonable from an operations perspective.[27] This red herring should not rise to the level of evidence.

[26] Watson Direct: p. 11: 3-12.
[27] Watson Direct, Exhibit DAW-1, p. 28

Q. WHAT OTHER SUPPORT DOES AG WITNESS MAJOROS PRESENT TO SUPPORT HIS RECOMMENDATION FOR ACCOUNT 380?

A. Mr. Majoros uses a geometric mean turnover analysis ("GMT") as shown in Direct Exhibit MJM-7.[28]

Q. IS GEOMETRIC MEAN TURNOVER ANALYSIS WIDELY UTILIZED BY DEPRECIATION PROFESSIONALS?

A. No. In *Public Utility Depreciation Practices*, the pages Mr. Majoros quotes are in a chapter, "Turnover and Simulation Analysis", used to describe life analysis approaches for unaged property. Given the abundant aged data available, it is unusual to present an unaged life analysis approach as Mr. Majoros has done. The Geometric Mean Turnover Analysis (GMT) was developed in 1940 and has been replaced by other analytical tools.

Q. WHAT LIMITATIONS DOES GMT HAVE?

A. According to Public Utility Depreciation Practices:

> A major drawback to all of the turnover methods is that they do not provide an indication as to the retirement dispersion…All the methods assume uniformity for the growth ratio and the dispersion of retirements for each vintage. A more reliable estimate may be made if the property has experienced at least one life cycle (roughly twice average life) since, under the constancy assumptions above, the property will be at stability.
>
> Since utility property typically does not meet the above constancy assumptions, the methods may produce considerable variation in life indications. This is especially true for the Geometric Mean Method…
>
> The use of turnover methods has decreased considerably with the increased experience in applying and interpreting the results of improved life analysis methods.[29]

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[28] Majoros Direct Exhibit MJM-7, pages 25-29.
[29] *Public Utility Depreciation Practices*, p. 92.

In my nearly 40 years of performing depreciation studies, I have never used GMT since superior life analysis methods exist.

Q. DOES ANOTHER AUTHORITATIVE TREATISE MAKE OBSERVATIONS REGARDING GMT?

A. Yes. *Depreciation Systems*, by Drs. F.K. Wolf and W.C. Fitch, states "Before the 1950s, turnover methods were the predominate means of analysis used to provide indications of service life when only unaged data were available. These methods have been replaced by the SPR methods and are now of primarily historical interest."[30] They further state "The turnover methods have two weaknesses. First, they provide an indication of average life but not curve type. Second, they require either a constant balance or a balance that increases at a constant rate every year."[31]

Q. DOES ANOTHER AUTHORITATIVE TREASTISE MAKE OBSERVATIONS REGARDING GMT?

A. Yes. In *Methods of Estimating Utility Plant Life* published by Edison Electric Institute (1952), they state: "Estimates produced by the Geometric Mean Method (a) are difficult to gauge as to probable accuracy and (b) may be sometimes unpredictably erratic."[32] Given the abundance of actuarial data, Mr. Majoros' use of a rarely used or cited methodology for unaged data provides far less accuracy in determining the life of this account than does the actuarial analysis that I used.

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[30] *Depreciation Systems*, p. 218.
[31] *Id.*, at 221.
[32] *Methods of Estimating Utility Plant Life*, Edison Electric Institute (1952), p. 38.

B. RESPONSE TO STAFF WITNESS MR. ROBERTSON

Q. WHAT DEPRECIATION POSITIONS DOES STAFF WITNESS MR. ROBERTSON RECOMMEND?

A. Mr. Robertson adopts most of the depreciation rates, life and net salvage parameters I recommend. There are three differences in position between our recommendations, which are shown below:

- Recommended life for Account 391.2 Furniture and Equipment (Computer Equipment). This is an amortization account where assets are retired automatically when they reach the average service life in age. The current life for this account is 5 years. I recommend 4 years for this account, and Mr. Robertson recommends retention of the 5-year life.
- Recommended life for Account 394 Tools, Shop, and Garage Equipment. The current life for this account is 15 years. I recommend 10 years for this account, and Mr. Robertson recommends retention of the 15-year life.
- His last recommendation that differs from my position involves the difference between the theoretical reserve and book depreciation reserve for amortized accounts. He recommends that difference be moved to a regulatory asset and the Company would not earn a return on those costs.

Q. DO YOU AGREE WITH MR. ROBERTSON'S RECOMMENDATIONS?

A. No. I believe my life recommendation is the most appropriate for Account 391.2 Computer Equipment and 394 Tools, Shop and Garage Equipment.

Q. WHAT TYPE OF EQUIPMENT IS IN ACCOUNT 391.2 COMPUTER EQUIPMENT?

A. The types of assets in this account shown below:

Account 391.2- Equipment Type

Equipment Type	Plant at 12/31/21	% of Total
Computer-Desktop/Laptop	2,450,300.21	82.10%
Printer	80,973.98	2.71%
Servers and Hardware	309,736.03	10.38%
Unclassified	143,679.90	4.81%

The Company SMEs shared the following details which were gathered through the course of my interviews with SUA's subject matter experts:

Physically, PCs and laptops (standard business equipment) only last four years. iPads will only last three years. They try to get five years out of Toughbook devices. Cell phones would have a two-year replacement period. The current balance in the account would last on average four years. The equipment in the future will mostly be iPads with only a three-year life.

Given the Company's four-year refresh cycle for laptops, which is the majority of the investment in the account, I believe that my four-year life recommendation for this account is the most appropriate.

Q. WHAT ASSETS ARE IN ACCOUNT 394?

A. Account 394 contains various items or tools used in shops and garages such as air compressors, grinders, mixers, hoists, and cranes. Company SMEs state that items such as air compressors, provers, leak survey equipment, CP equipment, etc. will not last 15 years operationally. Welders and tapping equipment would last 15 years. Investment prior to vintage year 2022 does not specify the type of asset in service. Rebuttal Exhibit DAW-2 shows the type of equipment added in 2022 forward: electrofusion equipment, winch, line squeeze tools, chart recorders, and gas locators. I believe those items will fall into the 10 year category and not the 15 year grouping.

Q. WHAT IS ONE REASON MR. ROBERTSON GIVES TO SUPPORT THE 15-YEAR LIFE HE RECOMMENDS?

A. Mr. Robertson reviewed the vintage investment in the account and recommended a longer life since many of the vintage years of the assets were beyond the Computation of General Plant Reserve Amortization Amount Company Parameters Updated Vintages 10-year life I recommended. The problem with that approach is that the age distribution for Account 394 after SUA completed the transition to their books from CenterPoint Energy Resources Corp.'s ("CERC") accounting system was not accurate.

Q. WAS THERE A SIGNIFICANT DIFFERENCE BETWEEN THE TWO SOURCES?

A. Yes. At the time we were completing the study the CERC data was the source for some accounts since SUA was still in the conversion process. As the Company approached the filing date, we realized there was a data discrepancy. In Rebuttal Exhibit DAW-2 I have included the details from the rate computation spreadsheet previously included in my direct workpapers. I added a tab in the accrual to show the corrected plant amount and corrected theoretical reserve. Below is a summary of these vintage investments:

Account 394- Vintage Investment Summary

Vintage	Age	Original Age Distribution	Revised Age Distribution
2022	0.5	1,206,415.89	1,210,293.74
2021	1.5	1,731,088.25	1,326,880.92
2020	2.5	513,341.90	764,007.61
2019	3.5	1,410,454.85	1,410,454.85
2018	4.5	621,408.33	771,072.10

Vintage	Age	Original Age Distribution	Revised Age Distribution
2017	5.5	426,335.44	426,335.44
2016	6.5	293,764.07	293,764.07
2015	7.5	608,087.76	608,087.76
2014	8.5	827,198.91	4,517,326.42
2013	9.5	186,869.78	0
2012	10.5	382,181.08	0
2011	11.5	341,951.43	0
2010	12.5	197,350.33	0
2009	13.5	702,884.57	0
2008	14.5	302,063.59	0
2007	15.5	23,255.16	0
2006	16.5	327,325.41	0
2005	17.5	222,963.91	0
2004	18.5	248,186.77	0
2003	19.5	357,315.01	0
2002	20.5	187,241.00	0
2001	21.5	71,674.71	0
2000	22.5	138,864.76	0

Mr. Robertson may not have realized the data in Appendix A2 of my Direct Testimony came from a different source than what is shown in the worksheet tab that computes the theoretical reserve for the amortized accounts.

Q. WHAT IS THE IMPACT OF THE CHANGE IN THEORETICAL RESERVE AND AMORTIZATION DIFFERENCE?

A. My Direct Exhibit DAW-1, Appendix A2 shows the impact of using the Company's life recommendations. In Rebuttal Exhibit DAW-3, I show the impact of using Staff lives. Both computations use the corrected vintage investment. In Rebuttal Exhibit DAW-4, I show the amortization difference would be $169,356 annually, the same as shown in Direct Exhibit DAW-1, Appendix A2. In that case, the theoretical reserve is too low and additional amortization expense is needed to align the two.

In Rebuttal Exhibit DAW-5, the amortization difference would be $(59,176) annually, since the book depreciation reserve is higher than the theoretical.

Q. ARE MR. ROBERTSON'S COMPUTATIONS IN STAFF EXHIBIT CR-4 AND CR-5 CORRECT?

A. No. It is necessary to use the revised vintaged investment for Account 394 as I have done in Rebuttal Exhibit DAW-4 and Rebuttal Exhibit DAW-5. I disagree with Mr. Robertson's recommendation to transfer those costs to a regulatory asset and deny the Company the ability to earn a return on those costs. SUA Rebuttal Witness Gillam will address this recommendation.

Q. WHAT BASIS DOES MR. ROBERTSON USE TO SUPPORT HIS POSITION ON REGULATORY ASSET TREATMENT FOR THE RESERVE DIFFERENCE FOR THE AMORTIZED ACCOUNTS?

A. Mr. Robertson relies on two recent decisions in Docket No. 22-085-U and 21-097-U.[33] I was a party in Docket No. 22-085-U for The Empire District Electric Company. In that case the regulatory asset treatment involved two functions: unrecovered costs of retired meters after implementation of AMI meters and the unrecovered costs of Asbury coal plant which was retired earlier than projected.[34] There was a reserve difference in the accumulated depreciation between book and theoretical reserve in that case. Mr. Robertson did not advocate regulatory asset treatment in that proceeding for that situation. The situation in this proceeding involves only amortized accounts, and I find Mr. Robertson's

[33] Robertson Direct, 14: 14-17.
[34] Docket 22-085-U, Robertson Direct, p. 14:10-15.

regulatory asset treatment inconsistent with the Company's predecessor's prior depreciation study in Docket No. 15-098-U.

Q. WHAT WAS APPROVED FOR AMORTIZED ACCOUNTS IN DOCKET NO. 15-098-U?

A. In that case, the CERC recommended inclusion in rate base of the reserve amortization difference for general plant.[35] Staff witness Gerilynn Wolfe, CDP, adopted the Company's recommended rates,[36] which were incorporated in Order No. 8 in that case. In Docket No. 15-098-U, the total amount approved for amortization of the general plant reserve difference was $125,433 annually. Mr. Robertson's computation of this amount in this proceeding is $(59,176).[37] I see no reason why the treatment of the general plant reserve difference in this case should require regulatory asset treatment. I recommend that the Commission allow inclusion of the amortization difference in rate base to achieve a consistent treatment between proceedings.

VI. SPECIFIC REBUTTAL TO AG COST OF REMOVAL AND NET SALVAGE RECOMMENDATIONS

Q. WHAT ARE AG WITNESS MAJOROS' RECOMMENDATIONS REGARDING NET SALVAGE?

A. Mr. Majoros states in his recommendation "4. Mr. Watson proposes inflated cost-of-removal ratios to calculate depreciation rates for the Company's plant accounts. I recommend the Commission only approve the uninflated cost of removal ratios. Otherwise,

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[35] Docket 15-098-U, Watson Direct, Direct Exhibit DAW-1, p. 118, 119-120.
[36] Docket 15-098-U, Wolfe Direct.
[37] Exhibit DAW-R-2.

it will be condoning an unnecessary practice that charges current ratepayers for frontloaded, future inflation that may not occur."[38]

Q. DO YOU AGREE WITH MR. MAJOROS' RECOMMENDATION?

A. Absolutely not. To my knowledge, the Company and this Commission have always approved traditional net salvage, computed as Staff witness Mr. Robertson and I have done.

Q. WHAT DEPRECIATION SYSTEM HAS THE COMMISSION APPROVED IN PAST PROCEEDINGS?

A. As Staff witness Mr. Robertson states: "The requested rates are based on the straight-line method, average life group procedure and remaining life technique, which are typically used by Staff and have previously been approved by this Commission."[39]

Q. HOW ARE DEPREICIATION RATES COMPUTED USING THIS DEPRECIATION SYSTEM?

A. The depreciation rate is computed as follows[40]:

Annual Depreciation Expense =	$\dfrac{\text{Original Cost – Book Reserve-Future Net Salvage}}{\text{Composite Remaining Life}}$
Proposed Annual Depreciation Rate =	$\dfrac{\text{Proposed Annual Depreciation Expense}}{\text{Original Cost}}$

Note that the definition specifies *Future net salvage*. Mr. Majoros omits the important word future in his definition[41]

[38] Majoros Direct, 9:10-13.
[39] Robertson Direct, 8:15-17
[40] *Public Utility Depreciation Practices*, p. 64
[41] Majoros Direct, 8:2-14.

Q. HOW HAS THE COMMISSION TREATED REMOVAL COST?

A. The Commission has historically treated removal cost in the same manner as the Company is requesting in this case. Specifically, the Commission has repeatedly ruled in favor of using a company's historical net salvage experience to project the estimated future removal costs. These estimated future costs are then allocated to customers ratably on a straight-line basis, just as the Company has done in this case.

Q. PLEASE SUMMARIZE THE NET SALVAGE ARGUMENTS PRESENTED BY MR. MAJOROS IN HIS TESTIMONY.

A. Mr. Majoros suggests that the Commission reject its historical practice and rely on an inflation-adjusted pattern of removal cost recovery to calculate net salvage rates. This argument has been repeatedly rejected by regulatory authorities and is referred to as the "net present value" argument. Adoption of this change would shift the Commission's long-standing practice to net salvage.

Q. PLEASE EXPLAIN MR. MAJOROS' RECOMMENDATIONS RELATED TO HIS NET PRESENT VALUE APPROACH TO NET SALVAGE.

A. Mr. Majoros proposes to establish the estimated *future* removal cost of the Company's assets based on the *present* cost of removal for those assets. Mr. Majoros takes this position even though the vast majority of the Company's assets will not be retired until many years in the future. Under Mr. Majoros' theory, the net present value (or total accrual for removal cost to "target" collecting) will grow based on the time value of money and a new, higher, removal cost expense will be established for each subsequent generation of ratepayers in order to reflect the higher net present cost of removal that exists at the time new rates are established.

Q. PLEASE LIST THE REGULATORY, METHODOLOGICAL, AND INTERGENERATION INEQUITY FLAWS IN MR. MAJOROS' NET PRESENT VALUE ARGUMENT.

- Mr. Majoros' net present value method violates authoritative guidance;
- Mr. Majoros' net present value method creates a back end loading of costs for customers; and
- Mr. Majoros' method creates different recovery patterns for installation and material cost of assets and the removal cost of assets.

Q. HOW DOES MR. MAJOROS' PROPOSED USE OF NET PRESENT VALUE CONTRADICT THE COMMISSION'S LONG STANDING PRECENDENT REGARDING DEPRECIATION EXPENSE?

A. Staff depreciation witnesses articulate clearly what methodology the Commission uses to set depreciation rates – the recovery of assets costs on a straight-line basis ratably from all customers. Mr. Majoros' recommendation distorts the straight-line recovery of removal costs and fails to recognize that there will be future inflation that will increase the cost of removal. This in turn will require future customers to pay more than their fair share of asset costs, and thus violated the Commission's policy requiring straight-line recovery and the use of estimated future salvage and removal cost as part of the depreciation rate calculation.

Q. PLEASE PROVIDE AN ANALOGY FOR THE INTERGENERATIONAL INEQUITY PROBLEM CAUSED BY MR. MAJOROS' PROPOSAL TO REJECT HISTORICAL PRECEDENT AND WELL-ESTABLISHED METHODOLOGY IN FAVOR OF HIS "PAY AS YOU GO" APPROACH.

A. A good analogy for Mr. Majoros' removal cost proposals as compared to the well-established methodology (and the Company's proposal) is a balloon mortgage or a reverse mortgage as opposed to a fixed rate mortgage for a homeowner. Under the existing removal cost paradigm of the Commission and the Company, the recovery of removal costs could be viewed as a fixed rate mortgage. In a fixed rate mortgage, the total future cost of the mortgage is paid evenly over the life of the loan. The current paradigm is that the estimated amount of removal cost required to remove assets at the end of their lives (parallel to the total mortgage cost) is accrued evenly or on a straight-line basis over the expected life of the assets (parallel to the loan period). The effect of adopting Mr. Majoros' different paradigm on ratepayers is in effect to move from a fixed rate mortgage to a balloon mortgage. Under a balloon mortgage, a small payment sufficient to cover interest is paid each year until the balloon payment for the actual loaned amount is required. Paying this balloon payment will be a significant problem unless the holder of the mortgage has been saving during the life of the loan for the eventual balloon payment. Mr. Majoros' plan would have the Company accrue each year a small amount that would only cover a small portion of the necessary removal cost. Unfortunately, as with the balloon mortgage, this does not allow the Company to "save" for the dramatically higher cost to remove larger quantities of assets at future costs. Customers paying these "balloon payment removal costs" will be customers who are using the asset at the end of its useful life. The effect that this proposal has on the Company is clear. It will prevent the Company from accruing a reasonable level of removal cost on a consistent basis over the useful life of the plant asset. The effect of Mr. Majoros' proposal on future ratepayers is also clear. Customers' grandchildren will be forced to pay a disproportional share of the removal costs of assets that they are using.

Q. DOES THE COMPANY'S STRAIGHT-LINE METHOD CREATE INGENERATIONAL INEQUITIES?

A. No. In the same way as depreciation expense for assets is shared ratably by current and future customers, the straight-line approach used by the Company spreads net salvage costs or benefits to all customers evenly.

Q. PLEASE EXPLAIN HOW MR. MAJOROS' METHOD CONTRADICTS AUTHORITATIVE GUIDANCE.

A. All authoritative utility depreciation sources agree that projecting the cost to remove assets at the end of their lives is a necessary factor in establishing net salvage rates. NARUC's *Public Utility Depreciation Practices* supports the use of estimated future salvage and removal cost as part of the depreciation calculation. *Public Utility Depreciation Practices* (1996 Edition) published by the National Association of Regulatory Utility Commissioners ("NARUC") states:

> Under presently accepted concepts, the amount of depreciation to be accrued over the life of an asset is its original cost less net salvage. Net salvage is the difference between the gross salvage that will be realized when the asset is disposed of <u>and the cost of retiring it</u>. Positive net salvage occurs when gross salvage exceeds cost of retirement, and negative net salvage occurs when cost of retirement exceeds gross salvage. **Net salvage is expressed as a percentage of plant retired by dividing the dollars of net salvage by the dollars of original cost of plant retired**. The goal of accounting for net salvage is to allocate the net cost of an asset to accounting periods, making due allowance for the net salvage, positive or negative. This concept carries with it the premise that property ownership includes the responsibility for the property's ultimate abandonment or removal. Hence, if current users benefit from its use, **they should pay their pro rata share of the costs involved in the abandonment or removal of the property** and also receive their pro rata share of the benefits of the proceeds realized.

> **This treatment of net salvage is in harmony with generally accepted accounting principles** and tends to remove from the income statement any fluctuations caused by erratic, although necessary, abandonment and removal operations. It also has the advantage that **current customers pay or receive a fair share of cost associated with the property devoted to their service, even though the costs may be estimated.**[42] (Emphasis added.)

Also, two of the most widely regarded experts on depreciation, Frank Wolf and Chester Fitch, state in their 1994 treatise Depreciation Systems:

> Effect of Inflation on the Salvage Ratio: One inherent characteristic of the salvage ratios is that the numerator and denominator are measured in different units; **the numerator is measured in dollars at the time of retirement while the denominator is measured in dollars at the time of installation.**[43] (Emphasis added.)

Drs. Wolf and Fitch further explain the importance of recognizing the future cost to retire current assets as follows:

> Negative salvage is a common occurrence. With inflation, the cost of retiring long-lived property, such as a water main, may exceed the original installed cost. Decommissioning cost of nuclear power plants is an example of large negative salvage. The matching principle specifies that all costs incurred to produce a service should be matched against the revenue produced. Estimated future costs of retiring of an asset currently in service must be accrued and allocated as part of the current expenses. … The accounting treatment of these future costs is clear. They are part of the current cost of using the asset and must be matched against revenue. While the current consumers would say they should not pay for future costs, it would be unfair to the future users if these costs were postponed. Some say that although the current consumers should pay for the future cost, that the future value of the payments, calculated at some reasonable interest rate, should equal the retirement cost. Studies show that the salvage is often "more negative" than forecasters had predicted.[44]

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[42] NARUC *Public Utility Depreciation Practices*, Page 18.
[43] *See Depreciation Systems*, page 53:
[44] *See Depreciation Systems*, pages 7 and 8.

The Company has adhered to these teachings and well-established methodologies by including future estimated removal costs in its proposed depreciation rates – Mr. Majoros has not.

Q. IS THERE ANY CONFUSION AMONG REGULATORY AUTHORITIES REGARDING THE CORRECT TREATMENT OF REMOVAL COSTS?

A. No. Nearly every Commission in the country adopts the same approach as this Commission has always adopted, which is to include future estimated removal costs in net salvage rates. It is this precedent and sound policy on which Staff witness Mr. Robertson and I have relied to develop the proposed net salvage rates for the Company's assets in this case.

Q. PLEASE EXPLAIN HOW MR. MAJOROS' METHOD BACK-END LOADS COST FOR FUTURE CUSTOMERS.

A. Mr. Majoros inappropriately dismisses the rate base effects (and future maintenance costs) in his argument that inflation-adjusting removal cost expense is good for current and future customers. The reality is that under his alternative method, future customers will pay more for removal cost in depreciation expense than current customers. Future customers will also have a higher rate base (lower depreciation expense means higher net book value) which will require that they pay more for carrying the cost of the net book value of the assets. Future customers will also pay more in maintenance expenses for the assets as they age. Finally, future customers will pay more for subsequent new assets used to serve them that are capitalized at a higher cost. Adding all these higher costs together shows that future customers are not benefited by Mr. Majoros' method, but instead hurt by his suggestion by getting an unfairly large shift in costs. Perhaps in this is some of the wisdom that promulgated this Commission's (and that of most commissions around the country) current, long-standing rule and practice of using straight-line depreciation.

Mr. Majoros' methodology would create intergenerational inequity as current net salvage would be under-recovered in his proposed depreciation rates. His proposals are significantly different than the position recommended by Staff and me.

Q. HOW DID THE COMPANY CALCULATE REMOVAL COST FOR PURPOSES OF DEVELOPING ITS PROPOSED NET SALVAGE RATES?

A. Data from the general ledger was extracted by project from gross salvage and removal cost and summed by year. Removal cost was subtracted from salvage values by individual year to determine the net salvage for the transaction year (Gross salvage minus removal cost equals net salvage). The resulting net salvage was divided by retirements for the same year to calculate net salvage percentages. These calculations are found in the net salvage section of my Direct Exhibit DAW-1 with my Direct Testimony and enumerated in Appendix D.

Q. HOW DOES MR. MAJOROS DERIVE HIS RECOMMENDATIONS?

A. In Direct Exhibit MJM-11, Mr. Majoros demonstrates his unique and flawed computations. Instead of retirements as a basis. which is the industry standard, he begins with plant in service balances. Then he uses the average age of survivors to create what he terms as an average year of installation. He then uses the recommended net salvage for each account and deflates the plant values to what he calls "uninflated cost of removal ratios". Then for mains and services (376 and 380), he assumes that 33% of the activity is for retirement only projects, since he would propose to eliminate capitalization of retirement only project removal cost[45].

Q. IS THE 33% MR. MAJOROS RELIES UPON CORRECT?

A. No. It is derived from the response to AG-001-007 shown as Majoros Direct Exhibit MJM-3 and also referenced in the SUA's response to data request No. AG-001-008; included as Rebuttal Exhibit DAW-6. The information is based on 2023 capital expenditure. The problem with Mr. Majoros' interpretation of the data is that the capital expenditures include new projects, replacements, and retirements only projects that occur. By including new capital additions in the ratios, the proportions become invalid. In fact, his derived 33% is primarily describing the percentage of new assets as a percentage of all capital spend – not removal only projects, as he opines. This is evidenced by the title of the first line in the table he uses for his errant calculation which is "Growth/Customer Additions." Between the flawed concepts of accounting interpretations of the projects that generate removal cost and Mr. Majoros' select sample of one year of data, I cannot follow nor agree with the logic of Mr. Majoros' proposal.

Q. HOW DID MR. MAJOROS DETERMINE 33% OF THE ACTIVITY IS FOR RETIREMENT-ONLY PROJECTS?

A. In Mr. Majoros' Direct Testimony, it is important to clarify that his calculation of 33% for retirement only projects, based on the Company's 2023 capital expenditures less 67% for total asset replacements, is flawed. His method inaccurately assumes that since 67% of the expenditures were associated with projects that replaced existing plant, then it suggests that

[45] Majoros Direct, 23:17-18. Majoros Direct Exhibits, MJM-3, pages 5-6.

33% represents retirement-only projects. This approach overlooks that the remaining 33% includes both retirement-only (non-replacement) projects and new additions. Furthermore, the expenditure data is not broken down by specific plant sub-accounts, such as Mains (376) and Services (380), which may have different replacement and retirement-only percentages compared to the overall company average. Additionally, relying on 2023 data alone is insufficient for establishing a reliable trend, as it represents too limited a sample size for a comprehensive trend analysis.

Q. OVERALL, ARE MR. MARJOROS' RECOMMENDATIONS LOGICAL?

A. Not in my opinion. Mr. Majoros does not examine the per book removal cost and retirements as Staff and I have done. By ignoring actual Company net salvage history, he creates a bizarre methodology that creates widely varying results from the data Staff witness Mr. Robertson and I (and generally held depreciation principles) relied upon.

Q. HOW DO THE PROPOSED NET SALVAGE RECOMMENDATIONS COMPARE?

A. The various positions are shown in the table below.

Summary of Net Salvage Recommendations

Account	Company and Staff Proposed Net Salvage %	AG Proposed Net Salvage %
375 Structures and Improvements	-5%	-2.84%
376 Mains	-40%	-5.11%
378 Measuring and Regulating Stations	-65%	-29.08%
379 City Gates	-5%	-1.15%
380 Services	-130%	-25.22%
382 Meter Installations	-10%	-3.36%
385 Industrial Measuring and Reg Stations	-2%	-1.13%
3851 Other Distribution Plant	-25%	-6.46%

Q. DOES MR. MAJOROS MAKE OTHER ASSUMPTIONS THAT ARE INCORRECT?

A. Yes. For Account 376 Mains, he assumes the proportion of investment by material type is 1/3 respectively for cast iron, steel, and plastic. SUA no longer has any cast iron mains. The current split is steel 42.48% and plastic 57.52%. Mr. Majoros assumes that 1/3 of the projects are related to retirement only projects where no replacement occurred.[46]

Q. DOES MR. MAJOROS MAKE A SIMILAR ASSUMPTION FOR ACCOUNT 380 SERVICES?

A. Yes. For Account 380 Mains, he assumes the proportion of investment by material type is 1/2 respectively for Steel and Plastic. The property records do not show a split between material type. Usually there is a similarity between Account 376 and 380 since those frequently occur on the same job and the material proportions are similar. Then Mr. Majoros makes the same adjustment that he did in Account 376, assuming that 1/3 of the projects are related to retirement only projects where no replacement occurred.[47]

Q. HOW DO THE PROPOSED NET SALVAGE RECOMMENDATIONS COMPARE?

A. In contrast to Mr. Majoros' creative math, the actual historical net salvage indications are used in my recommendations. The graphs below illustrate SUA's net salvage experience for the past 10 years. The solid black line is my proposal which Staff endorses. The other various dark dotted lines show the recent 3, 5, and 10 year averages. Finally, the red dashed

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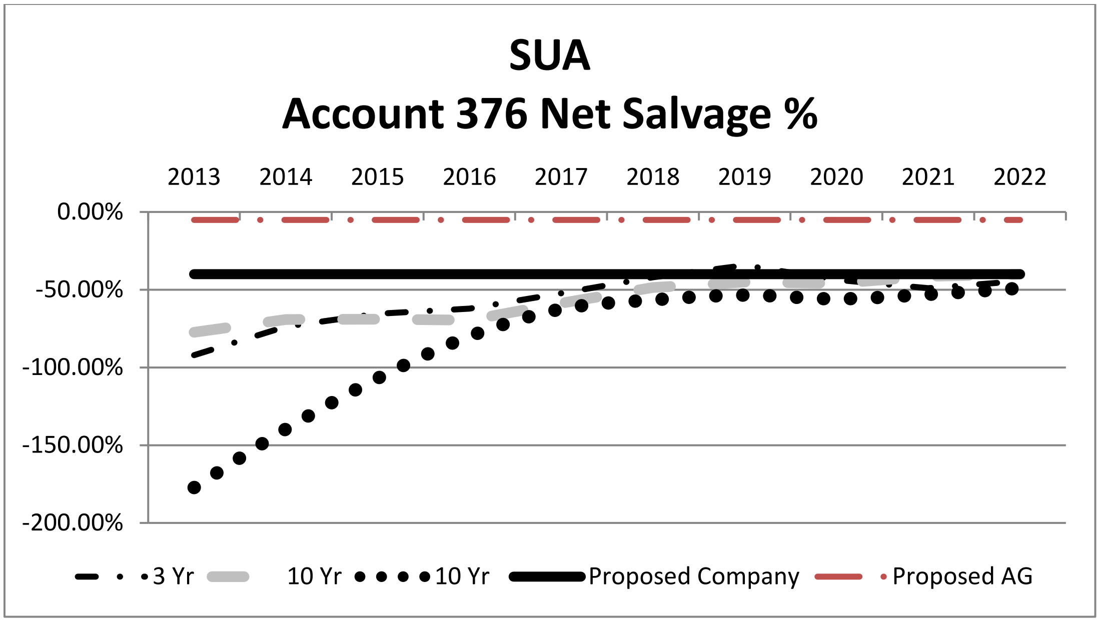
[46] Majoros Direct Exhibits, MJM-3, Response to Request AG-001-007. The 33% used by Mr. Majoros is based on 2023 activity. Experience over a longer time period could change the percentage with more robust data.

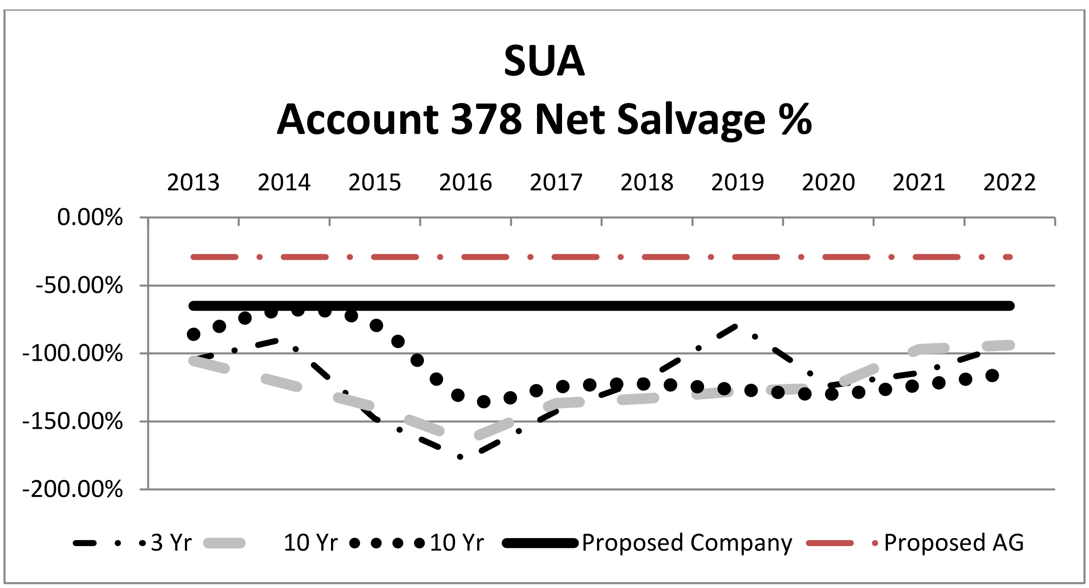
[47] Id.

line shows Mr. Majoros' recommendation. I will show Account 376, 378, and 380 to demonstrate the position differences.

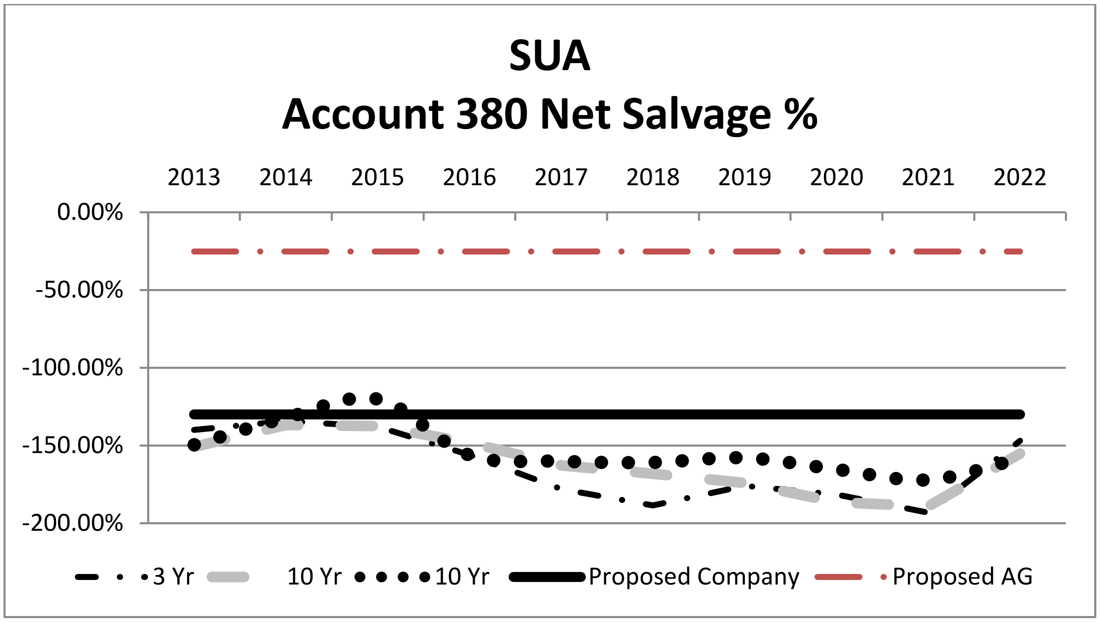
SUA Account 376 Mains Net Salvage Experience



SUA Account 378 Measuring and Regulating Station Net Salvage Experience



SUA Account 380 Services Net Salvage Experience



Q. WHAT DO YOU CONCLUDE FROM THESE REPRESENTATIONS?

A. Mr. Majoros' recommendations are vastly understated compared to the Company's experience. My proposals reflect current levels of net salvage and follow the matching principle in capital recovery. Mr. Majoros defers those costs to future customers.

Q. DOES MR. MAJOROS' PROPOSAL CREATE INTERGENERATIONAL INEQUITIES?

A. Yes. As can be seen from examining the Company's experience, Mr. Majoros' methodology would indeed create the balloon payment that I described earlier in this testimony.

VII. SPECIFIC REBUTTAL TO AG ACCOUNTING PRACTICE RECOMMENDATIONS

Q. WHAT ARE AG WITNESS MAJOROS' RECOMMENDATIONS REGARDING NET SALVAGE?

A. Mr. Majoros presented recommendations Nos. 3, 5 and 6 regarding net salvage in his Direct Testimony:

- Majoros Recommendation No. 3: "I reiterate and explain the significance of Mr. Watson's explanation that when SUA replaces a section of Main or a Service, it does not actually <u>remove</u> anything as contemplated in the FERC Uniform System of Accounts (USOA.)"
- Majoros Recommendation No. 5: "I recommend that the Commission instruct SUA to stop the practice of allocating or assigning to accumulated depreciation any portion of the project expenditures relating to plant replacements. This is particularly important with respect to pipes in the ground."
- Majoros Recommendation No. 6: "I recommend that the Commission require SUA file a new depreciation study within three years that includes net salvage studies with a separation of cost of removal between the amounts derived from replacement additions costs and those derived from final non-replaced retirements, along with a complete explanation of how cost of removal from replacements were calculated."[48]

Q. DO YOU AGREE WITH MR. MAJOROS' RECOMMENDATIONS?

A. Definitely not. Mr. Majoros seeks to interpret USOA[49] in a novel way for the purpose of reducing depreciation rates. The USOA is a federal directed series of accounting instructions on which US companies use to classify costs, both capital additions, retirements and net salvage. To my knowledge, I have not seen any regulated entity adopt

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[48] Majoros Direct, 9:7-9 and 14-21.
[49] Majoros Direct: 19:10-15, 24: 13-20.

Mr. Majoros' interpretation of USOA. This attempt to create a new paradigm for accounting should be rejected in its entirety.

Q. WHAT DOES THE USOA SAY IN ITS INSTRUCTIONS?

A. FERC Code of Federal Regulations 18, Part 201, Plant Instruction 10(B)(2) states that:

> When a retirement unit is retired from gas plant, with or without replacement, the book cost thereof shall be credited to the gas plant account in which it is included, determined in the manner set forth in paragraph B(1), above, if the retirement unit is of a depreciable class, the book cost of the unit retired and credited to gas plant shall be charged to the accumulated provision for depreciation applicable to such property. *The cost of removal and the salvage shall be charged or credited, as appropriate, to such deprecation account.* (Emphasis Added)

Mr. Majoros' proposal violates this FERC rule since it would not allow removal cost to be charged to the accumulated provision (Depreciation reserve) as is currently done by the Company. In addition, this approach no longer follows accrual accounting, which is endorsed by the Commission.

Q. DOES MR. MAJOROS' PROPOSAL REGARDING REMOVAL COST DESTROY ADHERENCE TO ACCRUAL ACCOUNT PRINCIPLES?

A. Accrual accounting allows the cost of removal to be recovered on a straight-line basis from customers prior to the actual retirement of the asset. In contrast, Mr. Majoros' proposals would not allow these costs to be expensed on an annual basis. The ramifications of Mr. Majoros' proposal are: (1) to prevent the Company from ever recovering those amounts expensed in prior periods and (2) to limit removal costs to a level that cannot and will not be representative of the future removal cost. This is particularly true for SUA since the Company's removal cost continues to increase and exhibits inflationary pressures on an ongoing basis. These factors combined with the increasing levels of retirements SUA will have in the future, serve only to amplify the need to accrue the proper amount of depreciation expense through the rates set in this case. This is necessary in order to avoid unfairly burdening future customers with these costs.

Q. HOW IS REMOVAL COST CHARGED TO ACCUMULATED DEPRECIATION?

A. Removal cost is booked to accumulated depreciation on a project level through the accounting system. There are two types of projects: retirement-only projects and replacement projects. Retirement-only projects charge all labor costs associated with the project to removal cost. In replacement projects, only a portion of the project is booked to removal cost while the rest are considered installation costs of the new (replacement) assets. Two methods are used in the utility industry: direct charge of labor costs or using an allocated percentage of labor cost. In a directly charged project, the project manager determines what portion of the total project cost is booked to removal cost. The percentage of labor cost method allocates a percentage of labor costs associated with a replacement project based on an allocation percentage of the total labor cost in the project. SUA allocates a fixed percentage of labor cost to removal when retiring an asset with replacement. This is a standard approach across the utility industry that I have seen during my career as a depreciation consultant and in practice during my prior employment as a property accounting manager.

Q. IS MR. MAJOROS' PROPOSAL TO ELIMINATE REMOVAL COST FROM RETIREMENT ONLY PROJECTS CONSISTENT WITH FERC ACCOUNTING REQUIREMENTS?

A. No. Mr. Majoros ignores the reality that a retirement only project for an account like 376 Mains or 380 Services would involve labor activities and charges for materials in the removal of an asset from service involving cutting, capping, and purging of gas. If those costs are not capitalized, then the only alternative is to charge operating expenses.

Q. MR. MAJOROS' PROPOSES TO REDUCE REMOVAL COST FOR REPLACEMENT ASSETS/ CURRENT EXPENSE. IS THAT RECOMMENDATION CONSISTENT WITH FERC ACCOUNTING REQUIREMENTS?

A. No. The reality of Mr. Majoros' methodology is demonstrated in the prior sections where I discuss net salvage recommendations. Adopting his accounting policy recommendations would put SUA in a situation that no other regulated company has been required to adopt.

Q. WHAT ABOUT MR. MAJOROS' RECOMMENDATION TO FILE ANOTHER DEPRECIATION STUDY IN THREE YEARS?

A. The Company will comply with whatever order the Commission renders regarding the filing of another depreciation study. But I reject Mr. Majoros' proposals regarding accounting methodology.

VIII. CONCLUSION

Q. PLEASE SUMMARIZE THE CONCLUSIONS YOU HAVE REACHED AS A RESULT OF YOUR ANALYSIS.

A. The depreciation study and analysis performed under my supervision fully supports setting depreciation rates at the levels I have indicated in my direct testimony. The depreciation study describes the extensive analysis performed and the resulting rates that are now appropriate for Company property. The Company's depreciation rates should be set at my recommended amounts to recover the Company's total investment in property over the estimated remaining life of the assets.

Q. DOES THIS CONCLUDE YOUR REBUTTAL TESTIMONY?

A. Yes, it does.

CERTIFICATE OF SERVICE

I, Brooke South Parsons, do hereby certify that a true and correct copy of the foregoing has been delivered to all Parties of Record by electronic mail via the Electronic Filing System on this 7th day of August 2024.

Brooke South Parsons

Brooke South Parsons

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

REBUTTAL EXHIBITS

OF

DANE A. WATSON, PE CDP

MANAGING PARTNER,

ALLIANCE CONSULTING GROUP

ON BEHALF OF

SUMMIT UTILITIES ARKANSAS, INC.

Date Filed: August 7, 2024

REBUTTAL EXHIBIT DAW-1

Computation of Theoretical Reserves Using Company Proposed Parameters

Summit Utilities - Arkansas Assets
Computation of Proposed Depreciation Accrual Rates
Using Average Life Group Depreciation
As of December 31, 2022

New Asset Group (a)	New Account (b)	Old Account (c)	Sub FCA (d)	Description (e)	Plant Balance (f)	Book Reserve (g)	Theoretical Reserve (h)
						-	
	Distribution Plant						
3742	D374200A	G37402	Multi	Land Rights	4,020,565.65	1,013,488.53	1,356,567.59
3751	D375100A	G37501	6900	City Gate Main Line M/F	224,807.59	143,969.21	120,920.02
3753	D375300A	G37502	6910	Meas & Dist Reg Sta Str	400,508.13	179,759.46	205,611.49
3754	D375400A	G37503	6920	Other Structures- Distri	10,189,841.76	4,866,930.30	2,678,143.04
3755	D375500A	G37503	6930	Other Structures- Distri	5,244,325.19	1,851,926.56	995,223.79
3760	D376000A	G37601	6940	Mains	858,698,342.45	260,324,249.11	241,620,554.46
3780	D378000A	G37801	6980	Mea/ Reg Sta Equipmer	14,120,321.49	2,518,068.38	5,102,680.65
3783	D378300A	G37801	7000	Other Equipment- Odor	1,111,690.19	814,031.95	426,274.28
3790	D379000A	G37901	7010	Mea Reg Sta Equipmen	2,422,516.99	1,447,967.07	1,350,391.00
3800	D380000A	G38001	7020	Services	395,610,297.61	235,262,527.64	304,308,394.40
3811	D381100A	G38101	7050	Meters- Domestic	30,121,837.85	19,337,459.49	14,647,484.03
3812	D381200A	G39703	7420	Meters - ERTS	29,222,228.15	20,078,076.53	13,836,022.83
3813	D381300A	G38101	7060	Meters - Industrial	14,561,884.43	9,134,489.65	7,289,644.58
3820	D382000A	G38201	7080	Meter Installation - Dor	21,184,765.09	7,071,081.02	6,571,458.66
3831	D383100A	G38301	7120	Regulators- Domestic	18,504,773.29	8,167,660.43	5,241,024.42
3832	D383200A	G38301	7130	Regulators- Industrial	12,758,397.10	6,320,197.46	7038764.68
3850	D385000A	G38501	7150	Industrial Meas and Re;	7,450,385.75	781,229.37	791,395.30
3851	D385100A	G38201	7090	M&R Station Equipmen	12,964,151.12	8,605,387.79	7,909,702.34

Summit Utilities - Arkansas Assets
Computation of Proposed Depreciation Accrual Rates
Using Average Life Group Depreciation
As of December 31, 2022

New Asset Group	New Account	Old Account	Sub FCA	Description	Plant Balance		Book Reserve		Theoretical Reserve
(a)	(b)	(c)	(d)	(e)	(f)		(g)		(h)
	General Plant - Depreciated								249,058.23
3901	D390100A	G39001	7200	General Plant Structure	8,316,933.37		167,576.30		8,061,050.71
3920	D392000A	G39201	7300	Transportation Equipm	25,034,296.44		8,102,533.25		1,509,624.49
3960	D396000A	G39601	7380	Power Operated Equipr	5,112,178.99		2,521,062.51		
3910	D391000A	391001	7230	Office Furniture and Eq	2,431,158.13	-	518,338.85	-	653,255.68
3912	D391200A	391002	7260	Computer Equipment	2,984,690.12	-	2,142,108.73	-	2,593,803.08
3940	D394000A	394001	7360	Tools, Shop, and Garag	11,328,222.91	-	4,976,498.91	-	6,012,414.78
3970	D397000A	397001	7390	Communication Equipr	513,602.80	-	332,435.78	-	417,631.79
3971	D397100A	397002	7410	Data Collection Equipn	742,282.08	-	12,371.36	-	37,114.10
3980	D398000A	398001	7450	Miscellaneous Equipm	463,219.83	-	292,942.49	-	254,041.25
							606,984,368.13		641,278,251.67

REBUTTAL EXHIBIT DAW-2
Account 394 Equipment 2022-Forward

Ledger	0L
	Leading Ledger
Company Code	1116
	Summit Utilities Arkansas

Asset Group		**Asset Number**	**Asset Description**	**Asset Additional Description**	**Vintage Year**	**Fiscal Year** 2022 Amount $	2023 Amount $	2024 Amount $	**Result Amount $**
3940	TOOLS, SHOP, GARAGE EQUIPMENT	111160000000	PURCHASE ELECTROFUSION EQUIPMENT	TOOLS, SHOP, GAR EQ LITTLE ROCK DL-38	2023		45,685.22		**45,685.22**
3940	TOOLS, SHOP, GARAGE EQUIPMENT	111160103956	GEN - TOOLS,SHOP,GAR EQ, G-A00001	GEN - TOOLS,SHOP,GAR EQ, G-A00001	2014	138,864.76			**138,864.76**
3940	TOOLS, SHOP, GARAGE EQUIPMENT	111160103957	GEN - TOOLS,SHOP,GAR EQ, G-A00001	GEN - TOOLS,SHOP,GAR EQ, G-A00001	2014	71,674.71			**71,674.71**
3940	TOOLS, SHOP, GARAGE EQUIPMENT	111160103958	GEN - TOOLS,SHOP,GAR EQ, G-A00001	GEN - TOOLS,SHOP,GAR EQ, G-A00001	2014	187,241.00			**187,241.00**
3940	TOOLS, SHOP, GARAGE EQUIPMENT	111160103959	GEN - TOOLS,SHOP,GAR EQ, G-A00001	GEN - TOOLS,SHOP,GAR EQ, G-A00001	2014	357,315.01			**357,315.01**
3940	TOOLS, SHOP, GARAGE EQUIPMENT	111160103960	GEN - TOOLS,SHOP,GAR EQ, G-A00001	GEN - TOOLS,SHOP,GAR EQ, G-A00001	2014	248,186.77			**248,186.77**
3940	TOOLS, SHOP, GARAGE EQUIPMENT	111160103961	GEN - TOOLS,SHOP,GAR EQ, G-A00001	GEN - TOOLS,SHOP,GAR EQ, G-A00001	2014	222,963.91			**222,963.91**
3940	TOOLS, SHOP, GARAGE EQUIPMENT	111160103962	GEN - TOOLS,SHOP,GAR EQ, G-A00001	GEN - TOOLS,SHOP,GAR EQ, G-A00001	2014	327,325.41			**327,325.41**
3940	TOOLS, SHOP, GARAGE EQUIPMENT	111160103963	GEN - TOOLS,SHOP,GAR EQ, G-A00001	GEN - TOOLS,SHOP,GAR EQ, G-A00001	2014	302,063.59			**302,063.59**
3940	TOOLS, SHOP, GARAGE EQUIPMENT	111160103964	GEN - TOOLS,SHOP,GAR EQ, G-A00001	GEN - TOOLS,SHOP,GAR EQ, G-A00001	2014	702,884.57			**702,884.57**
3940	TOOLS, SHOP, GARAGE EQUIPMENT	111160103965	GEN - TOOLS,SHOP,GAR EQ, G-A00001	GEN - TOOLS,SHOP,GAR EQ, G-A00001	2014	197,350.33			**197,350.33**
3940	TOOLS, SHOP, GARAGE EQUIPMENT	111160103966	GEN - TOOLS,SHOP,GAR EQ, G-A00001	GEN - TOOLS,SHOP,GAR EQ, G-A00001	2014	341,951.43			**341,951.43**
3940	TOOLS, SHOP, GARAGE EQUIPMENT	111160103967	GEN - TOOLS,SHOP,GAR EQ, G-A00001	GEN - TOOLS,SHOP,GAR EQ, G-A00001	2014	382,181.08			**382,181.08**
3940	TOOLS, SHOP, GARAGE EQUIPMENT	111160103968	GEN - TOOLS,SHOP,GAR EQ, G-A00001	GEN - TOOLS,SHOP,GAR EQ, G-A00001	2014	186,869.78			**186,869.78**
3940	TOOLS, SHOP, GARAGE EQUIPMENT	111160103969	GEN - TOOLS,SHOP,GAR EQ, G-A00001	GEN - TOOLS,SHOP,GAR EQ, G-A00001	2014	827,198.91			**827,198.91**
3940	TOOLS, SHOP, GARAGE EQUIPMENT	111160103970	GEN - TOOLS,SHOP,GAR EQ, G-A00001	GEN - TOOLS,SHOP,GAR EQ, G-A00001	2015	608,087.76			**608,087.76**
3940	TOOLS, SHOP, GARAGE EQUIPMENT	111160103971	GEN - TOOLS,SHOP,GAR EQ, G-A00001	GEN - TOOLS,SHOP,GAR EQ, G-A00001	2016	293,764.07			**293,764.07**
3940	TOOLS, SHOP, GARAGE EQUIPMENT	111160103972	GEN - TOOLS,SHOP,GAR EQ, G-A00001	TOOLS, SHOP, GAR EQ	2017	426,335.44			**426,335.44**
3940	TOOLS, SHOP, GARAGE EQUIPMENT	111160103973	GEN - TOOLS,SHOP,GAR EQ, G-A00001	GEN - TOOLS,SHOP,GAR EQ, G-A00001	2014	23,255.16			**23,255.16**
3940	TOOLS, SHOP, GARAGE EQUIPMENT	111160103974	GEN - TOOLS,SHOP,GAR EQ, G-A00001	GEN - TOOLS,SHOP,GAR EQ, G-A00001	2018	771,072.10			**771,072.10**
3940	TOOLS, SHOP, GARAGE EQUIPMENT	111160103975	GEN - TOOLS,SHOP,GAR EQ, G-A00001	GEN - TOOLS,SHOP,GAR EQ, G-A00001	2019	1,410,454.85			**1,410,454.85**
3940	TOOLS, SHOP, GARAGE EQUIPMENT	111160103976	GEN - TOOLS,SHOP,GAR EQ, G-A00001	GEN - TOOLS,SHOP,GAR EQ, G-A00001	2020	764,007.61			**764,007.61**
3940	TOOLS, SHOP, GARAGE EQUIPMENT	111160103977	GEN - TOOLS,SHOP,GAR EQ, G-A00001	GEN - TOOLS,SHOP,GAR EQ, G-A00001	2021	1,326,880.92			**1,326,880.92**
3940	TOOLS, SHOP, GARAGE EQUIPMENT	111160103978	GEN - TOOLS,SHOP,GAR EQ, G-A00001	GEN - TOOLS,SHOP,GAR EQ, G-A00001	2022	1,146,621.48			**1,146,621.48**
3940	TOOLS, SHOP, GARAGE EQUIPMENT	111160104450	Valve and other inventory	TOOLS PROCUREMENT FOR TRAINING	2022	54,283.58			**54,283.58**
3940	TOOLS, SHOP, GARAGE EQUIPMENT	111160104457	1" SCH40 VALVE and other inventory items	GENL PLANT TOOLS	2022	8,369.75			**8,369.75**
3940	TOOLS, SHOP, GARAGE EQUIPMENT	111160104462	Winch - Unit #8400 Kubota RTV X900	Winch - Unit #8400 Kubota RTV X900 - C15506785	2022	1,018.93			**1,018.93**
3940	TOOLS, SHOP, GARAGE EQUIPMENT	111160150929	PURCHASE SHOP TOOLS	TOOLS, SHOP, GAR EQ TEXARKANA, ARK	2023		30,451.57		**30,451.57**
3940	TOOLS, SHOP, GARAGE EQUIPMENT	111160150930	CAPITAL PURCHASE LINE SQUEEZE TOOLS	TOOLS, SHOP, GAR EQ GENERAL ARKANSAS	2023		8,282.18		**8,282.18**
3940	TOOLS, SHOP, GARAGE EQUIPMENT	111160150931	PURCHASE 10 GAS LOCATORS	TOOLS, SHOP, GAR EQ TEXARKANA, ARK	2023		172,567.38		**172,567.38**
3940	TOOLS, SHOP, GARAGE EQUIPMENT	111160150932	PURCHASE 100 LB VALVE CHANGER	TOOLS, SHOP, GAR EQ TEXARKANA, ARK	2023		7,967.00		**7,967.00**
3940	TOOLS, SHOP, GARAGE EQUIPMENT	111160150935	CAPITAL PURCHASE 40 CHART RECORDERS	TOOLS, SHOP, GAR EQ GENERAL ARKANSAS	2023		101,507.28		**101,507.28**
3940	TOOLS, SHOP, GARAGE EQUIPMENT	111160150970	GENL PLANT TOOLS, Old WO #100126575	LOCATOR PURCHASE, JONESBORO	2021		19,923.76		**19,923.76**
3940	TOOLS, SHOP, GARAGE EQUIPMENT	111160150972	GENL PLANT TOOLS, Old WO #101905650	WEST THIRD, PINE BLUFF	2022		47,692.37		**47,692.37**
3940	TOOLS, SHOP, GARAGE EQUIPMENT	111160150977	GENL PLANT TOOLS, Old WO #103346627	LONSDALE RD, HOT SPRINGS	2022		13,452.41		**13,452.41**
3940	TOOLS, SHOP, GARAGE EQUIPMENT	111160150980	GENL PLANT TOOLS, Old WO #103770025	E 28TH ST, TEXARKANA	2022		15,235.80		**15,235.80**
3940	TOOLS, SHOP, GARAGE EQUIPMENT	111160150981	GENL PLANT TOOLS, Old WO #103845608	E 28TH ST, TEXARKANA	2022		133,178.33		**133,178.33**
3940	TOOLS, SHOP, GARAGE EQUIPMENT	111160150982	GENL PLANT TOOLS, Old WO #104046410	E 28TH ST, TEXARKANA	2022		2,180.01		**2,180.01**
3940	TOOLS, SHOP, GARAGE EQUIPMENT	111160150983	GENL PLANT TOOLS, Old WO #104087819	OLE FEED HOUSE RD, JONESBORO	2022		40,876.28		**40,876.28**
3940	TOOLS, SHOP, GARAGE EQUIPMENT	111160150984	GENL PLANT TOOLS, Old WO #104169347	S OAK ST, JACKSONVILLE	2022		2,645.01		**2,645.01**
3940	TOOLS, SHOP, GARAGE EQUIPMENT	111160150986	GENL PLANT TOOLS, Old WO #104190969	E ROOSEVELT RD, LITTLE ROCK	2022		69,316.30		**69,316.30**
3940	TOOLS, SHOP, GARAGE EQUIPMENT	111160150987	GENL PLANT TOOLS, Old WO #104257437	W 3RD AVE, PINE BLUFF	2022		2,879.14		**2,879.14**
3940	TOOLS, SHOP, GARAGE EQUIPMENT	111160150989	GENL PLANT TOOLS, Old WO #104317265	BAKER ST, HOT SPRINGS	2022		16,939.99		**16,939.99**
3940	TOOLS, SHOP, GARAGE EQUIPMENT	111160150991	GENL PLANT TOOLS, Old WO #104348456	E 28TH ST, TEXARKANA	2022		13,505.62		**13,505.62**
3940	TOOLS, SHOP, GARAGE EQUIPMENT	111160150992	GENL PLANT TOOLS, Old WO #104349163	E 28TH ST, TEXARKANA	2022		8,642.27		**8,642.27**
3940	TOOLS, SHOP, GARAGE EQUIPMENT	111160150993	GENL PLANT TOOLS, Old WO #104441614	TURNER RD, FORREST CITY	2022		5,633.60		**5,633.60**
3940	TOOLS, SHOP, GARAGE EQUIPMENT	111160150994	GENL PLANT TOOLS, Old WO #104478397	E 17TH ST, RUSSELLVILLE	2022		4,086.83		**4,086.83**
3940	TOOLS, SHOP, GARAGE EQUIPMENT	111160150996	GENL PLANT TOOLS, Old WO #104522961	S OAK ST, JACKSONVILLE	2022		4,395.72		**4,395.72**
3940	TOOLS, SHOP, GARAGE EQUIPMENT	111160150998	GENL PLANT TOOLS, Old WO #104598013	E 28TH ST, TEXARKANA	2022		25,286.05		**25,286.05**
3940	TOOLS, SHOP, GARAGE EQUIPMENT	111160150999	GENL PLANT TOOLS, Old WO #104598467	N CREEK DR, CONWAY	2022		3,219.19		**3,219.19**
3940	TOOLS, SHOP, GARAGE EQUIPMENT	111160151002	GENL PLANT TOOLS, Old WO #104991083	S COLLEGE ST, STUTTGART	2022		5,950.00		**5,950.00**
3940	TOOLS, SHOP, GARAGE EQUIPMENT	111160151003	PURCHASE POLY FUSION EQUIPMENT	TOOLS, SHOP, GAR EQ TEXARKANA, ARK	2023		91,205.12		**91,205.12**
3940	TOOLS, SHOP, GARAGE EQUIPMENT	111160151007	PURCHASE DRILL DRIVER	TOOLS, SHOP, GAR EQ PINE BLUFF	2023		830.06		**830.06**
3940	TOOLS, SHOP, GARAGE EQUIPMENT	111160151008	ELECTROFUSION PROCESSORS FOR S ARKANSAS	TOOLS, SHOP, GAR EQ TEXARKANA, ARK	2023		73,345.93	-17,334.22	**56,011.71**

					Ledger	0L			
						Leading Ledger			
					Company Code	1116			
						Summit Utilities Arkansas			
					Fiscal Year	2022	2023	2024	**Result**
						Amount	Amount	Amount	**Amount**
Asset Group		**Asset Number**	**Asset Description**	**Asset Additional Description**	**Vintage Year**	$	$	$	**$**
3940	TOOLS, SHOP, GARAGE EQUIPMENT	111160151009	PURCHASE OF TDW TAPPING EQUIPMENT	TOOLS, SHOP, GAR EQ PINE BLUFF	2023		88,055.42		**88,055.42**
3940	TOOLS, SHOP, GARAGE EQUIPMENT	111160151010	PURCHASE 2 1000# GAUGES	TOOLS, SHOP, GAR EQ CAMDEN	2023		2,731.78		**2,731.78**
3940	TOOLS, SHOP, GARAGE EQUIPMENT	111160151012	PURCHASE RIGID INSPECTION CAMERA	TOOLS, SHOP, GAR EQ CAMDEN	2023		7,638.45		**7,638.45**
3940	TOOLS, SHOP, GARAGE EQUIPMENT	111160151017	CAPITAL PURCHASE- TOOLS	TOOLS, SHOP, GAR EQ GENERAL ARKANSAS	2023		5,406.59	-5,134.66	**271.93**
3940	TOOLS, SHOP, GARAGE EQUIPMENT	111160151018	PERSONAL GAS MONITORS	TOOLS, SHOP, GAR EQ JONESBORO	2023		13,861.73		**13,861.73**
3940	TOOLS, SHOP, GARAGE EQUIPMENT	111160151021	PURCHASE 20 GAS DETECTORS	TOOLS, SHOP, GAR EQ LITTLE ROCK DL-38	2023		88,597.86		**88,597.86**
3940	TOOLS, SHOP, GARAGE EQUIPMENT	111160151022	PURCHASE 20 GAS LOCATORS	TOOLS, SHOP, GAR EQ LITTLE ROCK DL-38	2023		362,756.75		**362,756.75**
3940	TOOLS, SHOP, GARAGE EQUIPMENT	111160151023	PURCHASE 20 GAS SERVICE TRACERS	TOOLS, SHOP, GAR EQ LITTLE ROCK DL-38	2023		33,543.98		**33,543.98**
3940	TOOLS, SHOP, GARAGE EQUIPMENT	111160151024	PURCHASE 6 BYPASS KIT SYSTEM AND ACCESSO	TOOLS, SHOP, GAR EQ LITTLE ROCK DL-38	2023		11,243.96		**11,243.96**
3940	TOOLS, SHOP, GARAGE EQUIPMENT	111160151025	PURCHASE CRYSTAL DIGITAL 2000# PRESSURE	TOOLS, SHOP, GAR EQ LITTLE ROCK DL-38	2023		2,555.94		**2,555.94**
3940	TOOLS, SHOP, GARAGE EQUIPMENT	111160151026	PURCHASE PORTACOOL EVAPORATIVE COOLER	TOOLS, SHOP, GAR EQ LITTLE ROCK DL-38	2023		5,020.51		**5,020.51**
3940	TOOLS, SHOP, GARAGE EQUIPMENT	111160151034	PURCHASE GAUGES	TOOLS, SHOP, GAR EQ HOT SPRINGS	2023		6,289.92		**6,289.92**
3940	TOOLS, SHOP, GARAGE EQUIPMENT	111160151036	BYPASS KIT SYSTEM	TOOLS, SHOP, GAR EQ JONESBORO	2023		19,103.24		**19,103.24**
3940	TOOLS, SHOP, GARAGE EQUIPMENT	111160151037	PURCHASE ELECTROFUSION MACHINE	TOOLS, SHOP, GAR EQ JONESBORO	2023		4,795.70		**4,795.70**
3940	TOOLS, SHOP, GARAGE EQUIPMENT	111160151038	PURCHASE CLAMPS FOR ELECTROFUSION	TOOLS, SHOP, GAR EQ LITTLE ROCK DL-38	2023		4,644.89		**4,644.89**
3940	TOOLS, SHOP, GARAGE EQUIPMENT	111160151040	PURCHASE LINE TRACER	TOOLS, SHOP, GAR EQ PINE BLUFF	2023		1,524.89		**1,524.89**
3940	TOOLS, SHOP, GARAGE EQUIPMENT	111160151041	PURCHASE WELD BENDER/PLASMA CUTTER	TOOLS, SHOP, GAR EQ JACKSONVILLE	2023		4,151.89		**4,151.89**
3940	TOOLS, SHOP, GARAGE EQUIPMENT	111160151042	PURCHASE STREET PLATES	TOOLS, SHOP, GAR EQ HOPE	2023		2,619.05		**2,619.05**
3940	TOOLS, SHOP, GARAGE EQUIPMENT	111160151043	PURCHASE HDPE TOOLS	TOOLS, SHOP, GAR EQ JONESBORO	2023		163,715.85		**163,715.85**
3940	TOOLS, SHOP, GARAGE EQUIPMENT	111160151044	PURCHASE QUICK CUT SAW W/ ACCESSORIES	TOOLS, SHOP, GAR EQ HOT SPRINGS	2023		2,426.06		**2,426.06**
3940	TOOLS, SHOP, GARAGE EQUIPMENT	111160151086	PURCHASE GAS DETECTOR	TOOLS, SHOP, GAR EQ PINE BLUFF	2023		4,986.02		**4,986.02**
3940	TOOLS, SHOP, GARAGE EQUIPMENT	111160151087	PURCHASE RTK PRO LOCATORS	TOOLS, SHOP, GAR EQ TEXARKANA, ARK	2023		39,291.54		**39,291.54**
3940	TOOLS, SHOP, GARAGE EQUIPMENT	111160151088	PURCHASE REMOTE SQUEEZE TOOLS	TOOLS, SHOP, GAR EQ PINE BLUFF RURAL	2023		18,039.16		**18,039.16**
3940	TOOLS, SHOP, GARAGE EQUIPMENT	111160151089	BANDSAW PURCHASE	TOOLS, SHOP, GAR EQ HOT SPRINGS	2023		2,167.77		**2,167.77**
3940	TOOLS, SHOP, GARAGE EQUIPMENT	111160151090	AIR COMPRESSOR PURCHASE	TOOLS, SHOP, GAR EQ CAMDEN	2023		2,104.49		**2,104.49**
3940	TOOLS, SHOP, GARAGE EQUIPMENT	111160151091	PURCHASE DIGITAL GAUGES	TOOLS, SHOP, GAR EQ PINE BLUFF	2023		20,498.62		**20,498.62**
3940	TOOLS, SHOP, GARAGE EQUIPMENT	111160151092	PERSONAL GAS MONITORS	TOOLS, SHOP, GAR EQ JACKSONVILLE	2023		1,660.02		**1,660.02**
3940	TOOLS, SHOP, GARAGE EQUIPMENT	111160151093	PURCHASE TOOLS FOR CONSTRUCTION CREW	TOOLS, SHOP, GAR EQ TEXARKANA, ARK	2023		2,071.05		**2,071.05**
3940	TOOLS, SHOP, GARAGE EQUIPMENT	111160151094	PURCHASE MILWAUKEE CHAINSAWS	TOOLS, SHOP, GAR EQ TEXARKANA, ARK	2023		1,361.60		**1,361.60**
3940	TOOLS, SHOP, GARAGE EQUIPMENT	111160151095	PURCHASE BLACK WIDOW GREASE GUN	TOOLS, SHOP, GAR EQ JONESBORO	2023		2,250.37		**2,250.37**
3940	TOOLS, SHOP, GARAGE EQUIPMENT	111160151096	PURCHASE ANGLE WRENCH	TOOLS, SHOP, GAR EQ LITTLE ROCK DL-38	2023		6,523.87		**6,523.87**
3940	TOOLS, SHOP, GARAGE EQUIPMENT	111160151097	PURCHASE SAFETY LADDER	TOOLS, SHOP, GAR EQ PINE BLUFF	2023		1,940.98		**1,940.98**
3940	TOOLS, SHOP, GARAGE EQUIPMENT	111160151119	PURCHASE 12 LINE LOCATORS	TOOLS, SHOP, GAR EQ JONESBORO	2023		455,652.97		**455,652.97**
3940	TOOLS, SHOP, GARAGE EQUIPMENT	111160151120	PURCHASE GAUGES	TOOLS, SHOP, GAR EQ ARKADELPHIA	2023		10,280.16		**10,280.16**
3940	TOOLS, SHOP, GARAGE EQUIPMENT	111160151121	LOCATOR PIPE AND CABLE SPLIT BOX TW-6	TOOLS, SHOP, GAR EQ JONESBORO	2023		8,534.49		**8,534.49**
3940	TOOLS, SHOP, GARAGE EQUIPMENT	111160151122	PURCHASE COMBUSTIBLE GAS INDICATORS	TOOLS, SHOP, GAR EQ JONESBORO	2023		35,788.96		**35,788.96**
3940	TOOLS, SHOP, GARAGE EQUIPMENT	111160151123	PURCHASE BINS AND SHELVING	TOOLS, SHOP, GAR EQ BLDG 2536 PINE BLUFF WHSE	2023		17,947.31		**17,947.31**
3940	TOOLS, SHOP, GARAGE EQUIPMENT	111160151124	BREATH AIR BOXES	TOOLS, SHOP, GAR EQ PINE BLUFF	2023		5,594.16		**5,594.16**
3940	TOOLS, SHOP, GARAGE EQUIPMENT	111160151137	SUI - Phoenix Tools/Equip(CapEx)	SUI - Phoenix Tools/Equip(CapEx) PP-02-1344	2023		90,338.15		**90,338.15**
3940	TOOLS, SHOP, GARAGE EQUIPMENT	111160151166	ELECTROFUION EQUIPMENT: SURPEEL MINI PE	TOOLS, SHOP, GAR EQ TEXARKANA, ARK	2023		17,301.80		**17,301.80**
3940	TOOLS, SHOP, GARAGE EQUIPMENT	111160151195	PURCHASE VALVE CHANGERS	TOOLS, SHOP, GAR EQ LITTLE ROCK DL-38	2023		27,726.62	6,704.63	**34,431.25**
3940	TOOLS, SHOP, GARAGE EQUIPMENT	111160151196	PURCHASE PEELER/SCRAPERS	TOOLS, SHOP, GAR EQ LITTLE ROCK DL-38	2023		86,172.86	19,477.19	**105,650.05**
3940	TOOLS, SHOP, GARAGE EQUIPMENT	111160151197	2023 EQUIPMENT/TOOLS - SUA	TOOLS, SHOP, GAR EQ GENERAL ARKANSAS	2023		1,017,986.91	512,628.24	**1,530,615.15**
3940	TOOLS, SHOP, GARAGE EQUIPMENT	111160205908	PURCHASE DUAL PIPE SIZE CLAMP	TOOLS, SHOP, GAR EQ JONESBORO	2023			2,940.20	**2,940.20**
3940	TOOLS, SHOP, GARAGE EQUIPMENT	111160205930	EQUIPMENT FOR METER SHOP MAUMELLE AR	TOOLS, SHOP, GAR EQ GENERAL ARKANSAS	2023			821,868.53	**821,868.53**
3940	TOOLS, SHOP, GARAGE EQUIPMENT	111160205950	OUNCE GAUGES	TOOLS, SHOP, GAR EQ TEXARKANA, ARK	2024			5,611.25	**5,611.25**
3940	TOOLS, SHOP, GARAGE EQUIPMENT	111160205969	SHORTSTOPP EQUIPMENT	TOOLS, SHOP, GAR EQ PINE BLUFF	2024			30,540.17	**30,540.17**
3940	TOOLS, SHOP, GARAGE EQUIPMENT	611160008023	2024 SUA TOOLS/EQUIPMENT	TOOLS, SHOP, GARAGE EQUIPMENT - Non Unitized GENER	#			412,509.07	**412,509.07**

REBUTTAL EXHIBIT DAW-3

Comparison of Approved vs. Proposed Depreciation Accrual Rates Using Staff Parameters

Summit Utilities - Arkansas
Comparison of Approved Depreciation Rates vs Proposed Depreciation Accrual Rates
Using Average Life Group Depreciation
As of December 31, 2022
Using Updated 394 Investment

New Asset Group	New Asset Class	Old Account	Old Sub	Description	Plant at 12/31/22	Approved Annual Rate	Approved Annual Expense	Proposed Annual Rate	Proposed Annual Expense	Expense Change
(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h) =(f) *(g)	(i)	(j) =(f) *(i)	(k) =(j) -(h)
				Intangible Plant						
3030	P303025A	303.001	6030	Pipeline Interconnect	$ 3,216,436.00	2.00%	$ 64,328.72	2.00%	$ 64,328.72	$ -
3032	P303033A	303.003	6050	Software Miscellaneous (Picarro)	6,092,623.30	14.29%	870,635.87	20.00%	1,218,524.66	347,888.79
3032	P303033A	303.003	6050	Software Miscellaneous (SAP/Other)	18,351,599.02	14.29%	2,622,443.50	10.00%	1,835,159.90	(787,283.60)
3032	P303032A	303.003	6060	Software EA	2,135,129.36	14.29%	305,109.99	10.00%	213,512.94	(91,597.05)
				Subtotal Intangibles	29,795,787.68	12.96%	3,862,518.08	11.18%	3,331,526.22	(530,991.86)
				Leasehold Improvements						
3902	D390200A	390.002	7225	Leasehold Improvements	2,481,392.04	10.00%	248,139.20	10.00%	248,139.20	-
				Subtotal Leasehold Improvements	2,481,392.04	10.00%	248,139.20	10.00%	248,139.20	-
				Distribution Plant						
3742	D374200A	G37402	Multi	Land Rights	4,020,565.65	1.33%	53,606.20	1.51%	60,710.54	7,104.34
3751	D375100A	G37501	6900	City Gate Main Line M/R Structures	224,807.59	1.10%	2,472.88	1.20%	2,697.69	224.81
3753	D375300A	G37502	6910	Meas & Dist Reg Sta Structures	400,508.13	2.91%	11,654.79	1.83%	7,329.30	(4,325.49)
3754	D375400A	G37503	6920	Other Structures- Distribution	10,189,841.76	0.86%	87,632.64	1.48%	150,809.66	63,177.02
3755	D375500A	G37503	6930	Other Structures- Distribution Imp	5,244,325.19	2.55%	133,730.29	2.24%	117,472.88	(16,257.41)
3760	D376000A	G37601	6940	Mains	858,698,342.45	1.94%	16,658,747.84	2.11%	18,118,535.03	1,459,787.18
3780	D378000A	G37801	6980	Mea/ Reg Sta Equipment- General	14,120,321.49	4.82%	680,599.50	4.71%	665,067.14	(15,532.35)
3783	D378300A	G37801	7000	Other Equipment- Odorizing Equip.	1,111,690.19	4.15%	46,135.14	3.34%	37,130.45	(9,004.69)
3790	D379000A	G37901	7010	Mea Reg Sta Equipment City Gate	2,422,516.99	1.42%	34,399.74	1.69%	40,940.54	6,540.80
3800	D380000A	G38001	7020	Services	395,610,297.61	6.89%	27,257,549.51	6.74%	26,664,134.06	(593,415.45)
3811	D381100A	G38101	7050	Meters- Domestic	30,121,837.85	1.45%	436,766.65	1.94%	584,363.65	147,597.01
3812	D381200A	G39703	7420	Meters - ERTS	29,222,228.15	10.00%	2,922,222.82	4.25%	1,241,944.70	(1,680,278.12)
3813	D381300A	G38101	7060	Meters - Industrial	14,561,884.43	1.93%	281,044.37	2.49%	362,590.92	81,546.55
3820	D382000A	G38201	7080	Meter Installation - Domestic	21,184,765.09	1.34%	283,875.85	2.68%	567,751.70	283,875.85
3831	D383100A	G38301	7120	Regulators- Domestic	18,504,773.29	3.46%	640,265.16	2.89%	534,787.95	(105,477.21)
3832	D383200A	G38301	7130	Regulators- Industrial	12,758,397.10	2.31%	294,718.97	2.76%	352,131.76	57,412.79
3850	D385000A	G38501	7150	Industrial Meas and Reg Stat Equip.	7,450,385.75	2.52%	187,749.72	2.55%	189,984.84	2,235.12
3851	D385100A	G38201	7090	M&R Station Equipment - Other	12,964,151.12	3.03%	392,813.78	2.39%	309,843.21	(82,970.57)
				Subtotal Distribution Plant	1,438,811,639.83	3.50%	50,405,985.85	3.48%	50,008,226.02	(397,759.82)
				General Plant Depreciated						
3901	D390100A	G39001	7200	General Plant Structures	8,316,933.37	0.47%	39,089.59	2.35%	195,447.93	156,358.35
3920	D392000A	G39201	7300	Transportation Equipment	25,034,296.44	5.77%	1,444,478.90	9.08%	2,273,114.12	828,635.21
3960	D396000A	G39601	7380	Power Operated Equipment	5,112,178.99	5.76%	294,461.51	3.24%	165,634.60	(128,826.91)
				Subtotal General Depreciated	38,463,408.80	4.62%	1778030.001	6.85%	2,634,196.65	856,166.65

Summit Utilities - Arkansas
Comparison of Approved Depreciation Rates vs Proposed Depreciation Accrual Rates
Using Average Life Group Depreciation
As of December 31, 2022
Using Updated 394 Investment

	Amortized After Retirement Assets > ASL									
3910	D391000A	G39101	7230	Office Furniture and Equipment	2,111,175.36	5.00%	105,558.77	5.00%	105,558.77	0.00
3912	D391200A	G39102	7260	Computer Equipment	812,861.61	20.00%	162,572.32	25.00%	203,215.40	40,643.08
3940	D394000A	G39401	7360	Tools, Shop, and Garage Equipment	11,328,222.91	6.67%	755,214.86	10.00%	1,132,822.29	377,607.43
3970	D397000A	G39701	7390	Communication Equipment	440,122.97	5.18%	22,798.37	10.00%	44,012.30	21,213.93
3971	D397100A	G39703	7410	Data Collection Equipment	742,282.08	10.00%	74,228.21	10.00%	74,228.21	0.00
3980	D398000A	G39801	7450	Miscellaneous Equipment	417,209.46	10.00%	41,720.95	10.00%	41,720.95	0.00
				Subtotal General Amortized	15,851,874.39	7.33%	1,162,093.47	10.10%	1,601,557.91	439,464.44
	Reserve Difference 10 Years Amortization General Plant Accoiunts						179,519.64		169,356.46	(10,163.18)
				Total Summit Depreciable and Amortized	$ 1,525,404,102.74	3.78%	$ 57,636,286.24	3.80%	$ 57,993,002.46	$ 356,716.23

Rates Authorized in Docket 15-098-U

GL	1,547,858,725.00
Difference	(22,454,622.26)
Franchise	137,342.70
Land	4,421,875.35
ARO	2,280,940.28
CCNC Account 378	829.44
Assets Retired > ASL	2,611,301.48
Difference	(13,002,333.01)
Exclude 375&390 Leases	12,971,393.00
Account 394 Asset Conversion Excluded to be Retired	30,941.00
Unreconciled Difference	$ 0.99

REBUTTAL EXHIBIT DAW-4

General Plant Amortized Accounts- Computation of Theoretical Reserve and Amortization Amounts Using Company Proposals

Summit Utilities Arkansas, Inc.
Docket No. 23-079-U
Theoretical Reserve
As of December 31, 2022

Theoretical Reserve Company Recommendation

		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	2,593,803	(451,694)	10	45,169
3940	TOOLS, SHOP, 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 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**	**9,968,261**	**(1,693,565)**	10	**169,356**

Amortized Theoretical Reserve Calculation

Account (a)	Vintage Year (b)	Age (c)	Plant Balance (d)	Average Service Life (e)	Remaining Life (f)	Net Salvage % (g)	Theoretical Reserve (h)	$ x RL (i)	Asset > ASL (j)	Avg. RL (k)
D391000A D FURN AND EQUIP	2022	0.5	148,048.61	20	19.5	0%	3,701.22	2,886,947.90		
D391000A D FURN AND EQUIP	2021	1.5	872,432.75	20	18.5	0%	65,432.46	16,140,005.88		
D391000A D FURN AND EQUIP	2020	2.5	803,173.54	20	17.5	0%	100,396.69	14,055,536.95		
D391000A D FURN AND EQUIP	2019	3.5	656.31	20	16.5	0%	114.85	10,829.12		
D391000A D FURN AND EQUIP	2018	4.5	543.13	20	15.5	0%	122.20	8,418.52		
D391000A D FURN AND EQUIP	2016	6.5	151,006.87	20	13.5	0%	49,077.23	2,038,592.75		
D391000A D FURN AND EQUIP	2015	7.5	4,983.39	20	12.5	0%	1,868.77	62,292.38		
D391000A D FURN AND EQUIP	2012	10.5	27,703.72	20	9.5	0%	14,544.45	263,185.34		
D391000A D FURN AND EQUIP	2010	12.5	4,606.91	20	7.5	0%	2,879.32	34,551.83		
D391000A D FURN AND EQUIP	2004	18.5	8,678.24	20	1.5	0%	8,027.37	13,017.36		
D391000A D FURN AND EQUIP	2003	19.5	89,341.89	20	0.5	0%	87,108.34	44,670.95		
D391000A D FURN AND EQUIP	2002	20.5	306,432.04	20	0	0%	306,432.04	-	306,432.04	
D391000A D FURN AND EQUIP	2001	21.5	13,550.73	20	0	0%	13,550.73	-	13,550.73	
D391000A Total			2,431,158.13				653,255.68	35,558,048.94	319,982.77	14.63
D391200A D COMPUTER EQUIPMENT	2022	0.5	130,704.61	4	3.5	0%	16,338.08	457,466.14		
D391200A D COMPUTER EQUIPMENT	2021	1.5	165,778.83	4	2.5	0%	62,167.06	414,447.08		
D391200A D COMPUTER EQUIPMENT	2020	2.5	433,445.86	4	1.5	0%	270,903.66	650,168.79		
D391200A D COMPUTER EQUIPMENT	2019	3.5	82,932.31	4	0.5	0%	72,565.77	41,466.16		
D391200A D COMPUTER EQUIPMENT	2018	4.5	1,967,921.61	4	0	0%	1,967,921.61	-	1,967,921.61	
D391200A D COMPUTER EQUIPMENT	2017	5.5	203,906.90	4	0	0%	203,906.90	-	203,906.90	
D391200A Total			2,984,690.12				2,593,803.08	1,563,548.16	2,171,828.51	0.52
D394000A D TOOLS SHOP GAR EQ	2022	0.5	1,210,293.74	10	9.5	0%	60,514.69	11,497,790.53		
D394000A D TOOLS SHOP GAR EQ	2021	1.5	1,326,880.92	10	8.5	0%	199,032.14	11,278,487.82		
D394000A D TOOLS SHOP GAR EQ	2020	2.5	764,007.61	10	7.5	0%	191,001.90	5,730,057.08		
D394000A D TOOLS SHOP GAR EQ	2019	3.5	1,410,454.85	10	6.5	0%	493,659.20	9,167,956.53		
D394000A D TOOLS SHOP GAR EQ	2018	4.5	771,072.10	10	5.5	0%	346,982.45	4,240,896.55		
D394000A D TOOLS SHOP GAR EQ	2017	5.5	426,335.44	10	4.5	0%	234,484.49	1,918,509.48		
D394000A D TOOLS SHOP GAR EQ	2016	6.5	293,764.07	10	3.5	0%	190,946.65	1,028,174.25		
D394000A D TOOLS SHOP GAR EQ	2015	7.5	608,087.76	10	2.5	0%	456,065.82	1,520,219.40		
D394000A D TOOLS SHOP GAR EQ	2014	8.5	4,517,326.42	10	1.5	0%	3,839,727.46	6,775,989.63		
D394000A D TOOLS SHOP GAR EQ	2013	9.5	-	10	0.5	0%	-	-		
D394000A D TOOLS SHOP GAR EQ	2012	10.5	-	10	0	0%	-	-	-	
D394000A D TOOLS SHOP GAR EQ	2011	11.5	-	10	0	0%	-	-	-	
D394000A D TOOLS SHOP GAR EQ	2010	12.5	-	10	0	0%	-	-	-	
D394000A D TOOLS SHOP GAR EQ	2009	13.5	-	10	0	0%	-	-	-	
D394000A D TOOLS SHOP GAR EQ	2008	14.5	-	10	0	0%	-	-	-	

Amortized Theoretical Reserve Calculation

Account (a)	Vintage Year (b)	Age (c)	Plant Balance (d)	Average Service Life (e)	Remaining Life (f)	Net Salvage % (g)	Theoretical Reserve (h)	$ x RL (i)	Asset > ASL (j)	Avg. RL (k)
D394000A D TOOLS SHOP GAR EQ	2007	15.5	-	10	0	0%	-	-	-	
D394000A D TOOLS SHOP GAR EQ	2006	16.5	-	10	0	0%	-	-	-	
D394000A D TOOLS SHOP GAR EQ	2005	17.5	-	10	0	0%	-	-	-	
D394000A D TOOLS SHOP GAR EQ	2004	18.5	-	10	0	0%	-	-	-	
D394000A D TOOLS SHOP GAR EQ	2003	19.5	-	10	0	0%	-	-	-	
D394000A D TOOLS SHOP GAR EQ	2002	20.5	-	10	0	0%	-	-	-	
D394000A D TOOLS SHOP GAR EQ	2001	21.5	-	10	0	0%	-	-	-	
D394000A D TOOLS SHOP GAR EQ	2000	22.5	-	10	0	0%	-	-	-	
D394000A Total			11,328,222.91				6,012,414.78	53,158,081.26	-	4.69
D397000A D COMMUNICATION EQ	2022	0.5	10,564.58	10	9.5	0%	528.23	100,363.51		
D397000A D COMMUNICATION EQ	2021	1.5	1,909.43	10	8.5	0%	286.41	16,230.16		
D397000A D COMMUNICATION EQ	2018	4.5	6,866.77	10	5.5	0%	3,090.05	37,767.24		
D397000A D COMMUNICATION EQ	2017	5.5	52,915.52	10	4.5	0%	29,103.54	238,119.84		
D397000A D COMMUNICATION EQ	2016	6.5	6,702.47	10	3.5	0%	4,356.61	23,458.65		
D397000A D COMMUNICATION EQ	2015	7.5	2,024.45	10	2.5	0%	1,518.34	5,061.13		
D397000A D COMMUNICATION EQ	2014	8.5	359,139.75	10	1.5	0%	305,268.79	538,709.63		
D397000A D COMMUNICATION EQ	2012	10.5	46,663.40	10	0	0%	46,663.40	-	46,663.40	
D397000A D COMMUNICATION EQ	2011	11.5	10,154.48	10	0	0%	10,154.48	-	10,154.48	
D397000A D COMMUNICATION EQ	2007	15.5	16,661.95	10	0	0%	16,661.95	-	16,661.95	
D397000A Total			513,602.80				417,631.79	959,710.14	73,479.83	1.87
D397100A D DATA COLLECTION EQ	2022	0.5	742,282.08	10	9.5	0%	37,114.10	7,051,679.76		
D397100A Total			742,282.08				37,114.10	7,051,679.76	-	9.50
D398000A D MISC EQUIPMENT	2022	0.5	130,416.36	10	9.5	0%	6,520.82	1,238,955.42		
D398000A D MISC EQUIPMENT	2021	1.5	10,934.27	10	8.5	0%	1,640.14	92,941.30		
D398000A D MISC EQUIPMENT	2020	2.5	5,982.43	10	7.5	0%	1,495.61	44,868.23		
D398000A D MISC EQUIPMENT	2019	3.5	26,284.40	10	6.5	0%	9,199.54	170,848.60		
D398000A D MISC EQUIPMENT	2018	4.5	8,007.58	10	5.5	0%	3,603.41	44,041.69		
D398000A D MISC EQUIPMENT	2017	5.5	8,298.63	10	4.5	0%	4,564.25	37,343.84		
D398000A D MISC EQUIPMENT	2016	6.5	49,381.36	10	3.5	0%	32,097.88	172,834.76		
D398000A D MISC EQUIPMENT	2015	7.5	58,527.03	10	2.5	0%	43,895.27	146,317.58		
D398000A D MISC EQUIPMENT	2014	8.5	83,945.75	10	1.5	0%	71,353.89	125,918.63		
D398000A D MISC EQUIPMENT	2013	9.5	35,431.65	10	0.5	0%	33,660.07	17,715.83		
D398000A D MISC EQUIPMENT	2012	10.5	11,998.64	10	0	0%	11,998.64	-	11,998.64	
D398000A D MISC EQUIPMENT	2009	13.5	6,317.10	10	0	0%	6,317.10	-	6,317.10	
D398000A D MISC EQUIPMENT	2008	14.5	3,415.50	10	0	0%	3,415.50	-	3,415.50	
D398000A D MISC EQUIPMENT	2007	15.5	7,864.40	10	0	0%	7,864.40	-	7,864.40	

Amortized Theoretical Reserve Calculation

Account (a)	Vintage Year (b)	Age (c)	Plant Balance (d)	Average Service Life (e)	Remaining Life (f)	Net Salvage % (g)	Theoretical Reserve (h)	$ x RL (i)	Asset > ASL (j)	Avg. RL (k)
D398000A D MISC EQUIPMENT	2006	16.5	10,353.76	10	0	0%	10,353.76	-	10,353.76	
D398000A D MISC EQUIPMENT	2005	17.5	6,060.97	10	0	0%	6,060.97	-	6,060.97	
D398000A Total			463,219.83				254,041.25	2,091,785.85	46,010.37	4.52
Grand Total			18,463,175.87				9,968,260.68	100,382,854.10	2,611,301.48	5.44

REBUTTAL EXHIBIT DAW-5

General Plant Amortized Accounts- Computation of Theoretical Reserve and Amortization Amounts Using Staff Proposals (Corrected for 394 investment)

Summit Utilities Arkansas, Inc.
Docket No. 23-079-U
Theoretical Reserve
As of December 31, 2022

Staff Recommended Lives

		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	4,008,277	968,222	10	(96,822)
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**	**7,682,935**	**591,761**	10	**(59,176)**

Amortized Theoretical Reserves

Account (a)	Vintage Year (b)	Age (c)	Plant Balance (d)	Average Service Life (e)	Remaining Life (f)	Net Salvage % (g)	Theoretical Reserve (h)	$ x RL (i)	Asset > ASL (j)	Avg. RL (k)
D391000A D FURN AND EQUIP	2022	0.5	148,048.61	20	19.5	0%	3,701.22	2,886,947.90		
D391000A D FURN AND EQUIP	2021	1.5	872,432.75	20	18.5	0%	65,432.46	16,140,005.88		
D391000A D FURN AND EQUIP	2020	2.5	803,173.54	20	17.5	0%	100,396.69	14,055,536.95		
D391000A D FURN AND EQUIP	2019	3.5	656.31	20	16.5	0%	114.85	10,829.12		
D391000A D FURN AND EQUIP	2018	4.5	543.13	20	15.5	0%	122.20	8,418.52		
D391000A D FURN AND EQUIP	2016	6.5	151,006.87	20	13.5	0%	49,077.23	2,038,592.75		
D391000A D FURN AND EQUIP	2015	7.5	4,983.39	20	12.5	0%	1,868.77	62,292.38		
D391000A D FURN AND EQUIP	2012	10.5	27,703.72	20	9.5	0%	14,544.45	263,185.34		
D391000A D FURN AND EQUIP	2010	12.5	4,606.91	20	7.5	0%	2,879.32	34,551.83		
D391000A D FURN AND EQUIP	2004	18.5	8,678.24	20	1.5	0%	8,027.37	13,017.36		
D391000A D FURN AND EQUIP	2003	19.5	89,341.89	20	0.5	0%	87,108.34	44,670.95		
D391000A D FURN AND EQUIP	2002	20.5	306,432.04	20	0	0%	306,432.04	-	306,432.04	
D391000A D FURN AND EQUIP	2001	21.5	13,550.73	20	0	0%	13,550.73	-	13,550.73	
D391000A Total			2,431,158.13				653,255.68	35,558,048.94	319,982.77	14.63
D391200A D COMPUTER EQUIPMENT	2022	0.5	130,704.61	5	4.5	0%	13,070.46	588,170.75		
D391200A D COMPUTER EQUIPMENT	2021	1.5	165,778.83	5	3.5	0%	49,733.65	580,225.91		
D391200A D COMPUTER EQUIPMENT	2020	2.5	433,445.86	5	2.5	0%	216,722.93	1,083,614.65		
D391200A D COMPUTER EQUIPMENT	2019	3.5	82,932.31	5	1.5	0%	58,052.62	124,398.47		
D391200A D COMPUTER EQUIPMENT	2018	4.5	1,967,921.61	5	0.5	0%	1,771,129.45	983,960.81		
D391200A D COMPUTER EQUIPMENT	2017	5.5	203,906.90	5	0	0%	203,906.90	-	203,906.90	
D391200A Total			2,984,690.12				2,312,616.01	3,360,370.57	203,906.90	1.13
D394000A D TOOLS SHOP GAR EQ	2022	0.5	1,210,293.74	15	14.5	0%	40,343.12	17,549,259.23		
D394000A D TOOLS SHOP GAR EQ	2021	1.5	1,326,880.92	15	13.5	0%	132,688.09	17,912,892.42		
D394000A D TOOLS SHOP GAR EQ	2020	2.5	764,007.61	15	12.5	0%	127,334.60	9,550,095.13		
D394000A D TOOLS SHOP GAR EQ	2019	3.5	1,410,454.85	15	11.5	0%	329,106.13	16,220,230.78		
D394000A D TOOLS SHOP GAR EQ	2018	4.5	771,072.10	15	10.5	0%	231,321.63	8,096,257.05		
D394000A D TOOLS SHOP GAR EQ	2017	5.5	426,335.44	15	9.5	0%	156,322.99	4,050,186.68		
D394000A D TOOLS SHOP GAR EQ	2016	6.5	293,764.07	15	8.5	0%	127,297.76	2,496,994.60		
D394000A D TOOLS SHOP GAR EQ	2015	7.5	608,087.76	15	7.5	0%	304,043.88	4,560,658.20		
D394000A D TOOLS SHOP GAR EQ	2014	8.5	4,517,326.42	15	6.5	0%	2,559,818.30	29,362,621.73		
D394000A D TOOLS SHOP GAR EQ	2013	9.5	-	15	5.5	0%	-	-		
D394000A D TOOLS SHOP GAR EQ	2012	10.5	-	15	4.5	0%	-	-		
D394000A D TOOLS SHOP GAR EQ	2011	11.5	-	15	3.5	0%	-	-		
D394000A D TOOLS SHOP GAR EQ	2010	12.5	-	15	2.5	0%	-	-		
D394000A D TOOLS SHOP GAR EQ	2009	13.5	-	15	1.5	0%	-	-		
D394000A D TOOLS SHOP GAR EQ	2008	14.5	-	15	0.5	0%	-	-		

Amortized Theoretical Reserves

Account (a)	Vintage Year (b)	Age (c)	Plant Balance (d)	Average Service Life (e)	Remaining Life (f)	Net Salvage % (g)	Theoretical Reserve (h)	$ x RL (i)	Asset > ASL (j)	Avg. RL (k)
D394000A D TOOLS SHOP GAR EQ	2007	15.5	-	15	0	0%	-	-	-	
D394000A D TOOLS SHOP GAR EQ	2006	16.5	-	15	0	0%	-	-	-	
D394000A D TOOLS SHOP GAR EQ	2005	17.5	-	15	0	0%	-	-	-	
D394000A D TOOLS SHOP GAR EQ	2004	18.5	-	15	0	0%	-	-	-	
D394000A D TOOLS SHOP GAR EQ	2003	19.5	-	15	0	0%	-	-	-	
D394000A D TOOLS SHOP GAR EQ	2002	20.5	-	15	0	0%	-	-	-	
D394000A D TOOLS SHOP GAR EQ	2001	21.5	-	15	0	0%	-	-	-	
D394000A D TOOLS SHOP GAR EQ	2000	22.5	-	15	0	0%	-	-	-	
D394000A Total			11,328,222.91				4,008,276.52	109,799,195.81	-	9.69
D397000A D COMMUNICATION EQ	2022	0.5	10,564.58	10	9.5	0%	528.23	100,363.51		
D397000A D COMMUNICATION EQ	2021	1.5	1,909.43	10	8.5	0%	286.41	16,230.16		
D397000A D COMMUNICATION EQ	2018	4.5	6,866.77	10	5.5	0%	3,090.05	37,767.24		
D397000A D COMMUNICATION EQ	2017	5.5	52,915.52	10	4.5	0%	29,103.54	238,119.84		
D397000A D COMMUNICATION EQ	2016	6.5	6,702.47	10	3.5	0%	4,356.61	23,458.65		
D397000A D COMMUNICATION EQ	2015	7.5	2,024.45	10	2.5	0%	1,518.34	5,061.13		
D397000A D COMMUNICATION EQ	2014	8.5	359,139.75	10	1.5	0%	305,268.79	538,709.63		
D397000A D COMMUNICATION EQ	2012	10.5	46,663.40	10	0	0%	46,663.40	-	46,663.40	
D397000A D COMMUNICATION EQ	2011	11.5	10,154.48	10	0	0%	10,154.48	-	10,154.48	
D397000A D COMMUNICATION EQ	2007	15.5	16,661.95	10	0	0%	16,661.95	-	16,661.95	
D397000A Total			513,602.80				417,631.79	959,710.14	73,479.83	1.87
D397100A D DATA COLLECTION EQ	2022	0.5	742,282.08	10	9.5	0%	37,114.10	7,051,679.76		
D397100A Total			742,282.08				37,114.10	7,051,679.76	-	9.50
D398000A D MISC EQUIPMENT	2022	0.5	130,416.36	10	9.5	0%	6,520.82	1,238,955.42		
D398000A D MISC EQUIPMENT	2021	1.5	10,934.27	10	8.5	0%	1,640.14	92,941.30		
D398000A D MISC EQUIPMENT	2020	2.5	5,982.43	10	7.5	0%	1,495.61	44,868.23		
D398000A D MISC EQUIPMENT	2019	3.5	26,284.40	10	6.5	0%	9,199.54	170,848.60		
D398000A D MISC EQUIPMENT	2018	4.5	8,007.58	10	5.5	0%	3,603.41	44,041.69		
D398000A D MISC EQUIPMENT	2017	5.5	8,298.63	10	4.5	0%	4,564.25	37,343.84		
D398000A D MISC EQUIPMENT	2016	6.5	49,381.36	10	3.5	0%	32,097.88	172,834.76		
D398000A D MISC EQUIPMENT	2015	7.5	58,527.03	10	2.5	0%	43,895.27	146,317.58		
D398000A D MISC EQUIPMENT	2014	8.5	83,945.75	10	1.5	0%	71,353.89	125,918.63		
D398000A D MISC EQUIPMENT	2013	9.5	35,431.65	10	0.5	0%	33,660.07	17,715.83		
D398000A D MISC EQUIPMENT	2012	10.5	11,998.64	10	0	0%	11,998.64	-	11,998.64	
D398000A D MISC EQUIPMENT	2009	13.5	6,317.10	10	0	0%	6,317.10	-	6,317.10	
D398000A D MISC EQUIPMENT	2008	14.5	3,415.50	10	0	0%	3,415.50	-	3,415.50	
D398000A D MISC EQUIPMENT	2007	15.5	7,864.40	10	0	0%	7,864.40	-	7,864.40	

Amortized Theoretical Reserves

Account (a)	Vintage Year (b)	Age (c)	Plant Balance (d)	Average Service Life (e)	Remaining Life (f)	Net Salvage % (g)	Theoretical Reserve (h)	$ x RL (i)	Asset > ASL (j)	Avg. RL (k)
D398000A D MISC EQUIPMENT	2006	16.5	10,353.76	10	0	0%	10,353.76	-	10,353.76	
D398000A D MISC EQUIPMENT	2005	17.5	6,060.97	10	0	0%	6,060.97	-	6,060.97	
D398000A Total			463,219.83				254,041.25	2,091,785.85	46,010.37	4.52
Grand Total			18,463,175.87				7,682,935.35	158,820,791.06	643,379.87	8.60

REBUTTAL EXHIBIT DAW-6

Data Request No. AG-001-008

ARKANSAS PUBLIC SERVICE COMMISSION
APSC 23-079-U

2023 SUA RATE CASE

REQUEST NO.: AG-001-008

COMPANY NAME: **SUMMIT UTILITIES ARKANSAS**

DATE RECEIVED: **3/4/2024**

DATE DUE: **3/19/2024**

EXTENSION DATE:

INFORMATION REQUESTED:
Refer to Table 1 on page 5 of Mr. McNully Direct Testimony. Provide the percentage of each "2023 Spend" numbers that involved replacements as Mr. McNully discusses in the remainder of his testimony.

REQUESTED BY: **ARKANSAS ATTORNEY GENERAL**

RESPONSE:
Please see the attached file "AG-001-008 2023 CapEx and Asset Replacements.xlsx". We have updated SUA's total capital expenditures for 2023 to capture more recent entries. The updated capital expenditure total for SUA is $162.8 million, and of that amount 67% were for replacements.

SPONSOR:
Vernon McNully, Tiffany Brazle, Margaret Sanchez

RESPONSIVE DOCUMENTS:
AG-001-008 2023 CapEx and Asset Replacements.xlsx

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

/s/ Brooke South Parsons
Signature of Company Representative

DATE PROVIDED: **MARCH 19, 2024**

AG-001-008 2023 CapEx and Asset Replacements.xlsx

($ in Millions)	Total CapEx Actuals	Total Asset Replacements	% of Total CapEx Actuals
Growth/Customer Additions	23.2	0.4	2%
Rehab/System Maintenance/Improvements	102.5	96.6	94%
Public Improvements	12.5	12.0	96%
Meters and Regulators	10.2	-	0%
Total Gas System Capital Expenditures	148.4	109.0	73%
	-	-	
IT	0.2	-	0%
Facilities	0.6	-	0%
Fleet	5.2	-	0%
Other	8.4	0.2	2%
Total Other Capital Expenditures	14.4	0.2	1%
	-	-	
Total Capital Expenditures	162.8	109.2	67%