COMMONWEALTH OF PENNSYLVANIA

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June 3, 2025

Via Electronic Filing
Matthew L. Homsher, Secretary
Pennsylvania Public Utility Commission
Commonwealth Keystone Building
400 North Street
Harrisburg, PA 17120

Re: Pennsylvania Public Utility Commission
v.
Pike County Light & Power Company - Gas
Docket No. R-2024-3052357

Dear Secretary Homsher:

Consistent with 52 Pa. Code Section 5.412a of the Commission's regulations, which requires the electronic submission of pre-served testimony, please note that the following pre-served testimony on behalf of the Office of Consumer Advocate ("OCA") was submitted via eFiling on June 3, 2025, in the above-referenced proceeding.

DIRECT TESTIMONY

OCA Statement 1:	Direct Testimony of Jennifer L. Rogers consisting of 19 pages of testimony, Appendix A, and Schedules JLR-1 through JLR-16 along with a signed verification of Jennifer L. Rogers.
OCA Statement 2:	Direct Testimony of Maureen L. Reno consisting of 55 pages of testimony, Appendix A, and Exhibits MLR-1 through MLR-6 along with a signed verification of Maureen L. Reno.
OCA Statement 3:	Direct Testimony of Karl R. Pavlovic consisting of 30 pages of testimony and Exhibits KRP-1 through KRP-4 along with a signed verification of Karl R. Pavlovic.

REBUTTAL TESTIMONY

OCA Statement 3R: Rebuttal Testimony of Karl R. Pavlovic consisting of 9 pages of testimony and Exhibit KRP-1R along with a signed verification of Karl R. Pavlovic.

SURREBUTTAL TESTIMONY

OCA Statement 3SR: Surrebuttal Testimony of Karl R. Pavlovic consisting of 14 pages of testimony along with a signed verification of Karl R. Pavlovic.

Copies of this letter are being served on parties of record per the attached Certificate of Service.

Respectfully submitted,

/s/ Jacob D. Guthrie
Jacob D. Guthrie, Esq.
Assistant Consumer Advocate
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Enclosures

cc: The Honorable Alphonso Arnold III (**email only:** alphonarno@pa.gov)
The Honorable Marta Guhl (**email only:** mguhl@pa.gov)
Certificate of Service

OCA Statement 1

BEFORE THE

PENNSYLVANIA PUBLIC UTILITY COMMISSION

Pennsylvania Public Utility Commission	)	
v.	)	**Docket No. R-2024-3052357**
Pike County Light & Power Company-Gas	)	

DIRECT TESTIMONY

OF

JENNIFER L. ROGERS

ON BEHALF OF THE

PENNSYLVANIA OFFICE OF CONSUMER ADVOCATE

April 3, 2025

EXETER ASSOCIATES, INC.
10480 Little Patuxent Parkway, Suite 300
Columbia, Maryland 21044

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I. INTRODUCTION

Q. PLEASE STATE YOUR NAME AND BUSINESS ADDRESS.

A. My name is Jennifer L. Rogers. My business address is 10480 Little Patuxent Parkway, Suite 300, Columbia, Maryland, 21044. I am a Principal and Vice President at Exeter Associates, Inc. ("Exeter"). Exeter is a consulting firm specializing in issues pertaining to public utilities.

Q. PLEASE DESCRIBE YOUR EDUCATIONAL BACKGROUND AND QUALIFICATIONS.

A. I received a Master of Arts degree in Economics from Northeastern University. I also have a Bachelor of Arts degree in Economics with a minor in Environmental Studies from St. Mary's College of Maryland.

I attended the 42nd Eastern National Association of Regulatory Utility Commissioners ("NARUC") Utility Rate School. I have also completed the Institute of Public Utilities Accounting and Ratemaking Course and the Advanced Course: Regulatory Accounting and Auditing, as well as EUCI's Electric Cost-of-Service Course.

Q. PLEASE DESCRIBE YOUR PROFESSIONAL EXPERIENCE.

A. I have been employed with Exeter since 2009, initially as a Research Assistant before being promoted to Economist, then Senior Economist, and then Lead Economist. I am now a Principal and Vice President for the firm. At Exeter, I review utility rate filings and provide analysis of revenue requirement issues. I also evaluate and forecast power supply requirements, costs, and renewable energy needs; provide bill and rate analysis; and review energy use, scheduling, and scheduling deviation data for clients. In addition, I conduct utility service assessments to identify areas for potential utility cost savings, providing detailed analysis of supply contracts, energy use, and a review of billing practices.

Q. HAVE YOU PREVIOUSLY TESTIFIED IN REGULATORY PROCEEDINGS ON UTILITY RATES?

A. Yes. I have previously presented testimony before the Pennsylvania Public Utility Commission; the Philadelphia Water, Sewer, and Storm Water Rate Board; the Maryland Public Service Commission; the Public Utility Commission of Texas; the Maine Public Utilities Commission; and the State Corporation Commission of the State of Kansas. My resume is attached as Appendix A.

Q. ON WHOSE BEHALF ARE YOU APPEARING?

A. I am presenting testimony on behalf of the Pennsylvania Office of Consumer Advocate ("OCA").

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

A. Exeter has been retained by the OCA to assist in the evaluation of the application of the Pike County Light & Power Company- Gas Division ("PCLP" or "Company") to increase base rates for gas service. My direct testimony presents my findings with respect to PCLP's revenue requirements and its proposed rate increases. I calculate PCLP's rate base, pro forma operating income under present rates, and overall revenue deficiency based upon my recommended adjustments. Additionally, Maureen Reno will present the OCA's recommendations regarding rate of return (OCA Statement 2). In her direct testimony, Ms. Reno recommends an overall rate of return on rate base of 7.80%.

Further, Karl R. Pavlovic will present the OCA's recommendations regarding cost of service, revenue allocation, and rate design. (OCA Statement 3). Based on my revenue requirement recommendation, Mr. Pavlovic presents an alternative revenue allocation and scale back proposal

II. SUMMARY AND RECOMMENDATIONS

Q. PLEASE SUMMARIZE THE RATE RELIEF REQUESTED BY PCLP IN ITS FILING.

A. On December 31, 2024, PCLP filed an application with the Pennsylvania Public Utility Commission ("Commission") to increase its base rates for gas service. PCLP is requesting an overall rate increase of $905,900. The Company's proposed rate increase is based upon the future test year ("FTY") ending September 30, 2025. The Company's requested rate increase reflects an overall rate of return ("ROR") of 8.59%.

Note that in the currently ongoing base rate case for the Company's electric division, the Company requested to roll in its current distribution system improvement charge balance into rates. The Company has not proposed this for the gas division, and I do not address this in my testimony.

Q. PLEASE SUMMARIZE YOUR FINDINGS AND RECOMMENDATIONS.

A. As shown on Schedule JLR-1, I have determined that PCLP's proposed revenue increase should be reduced to reflect an increase of no more than $762,400 for the FTY. My recommendation includes a correction to the Company's calculation of interest synchronization, discussed in the 'Interest Synchronization' section of my Direct Testimony, that results in an upward adjustment of over $100,000 to income taxes, which nets out the impact of most other adjustments. My recommendation is $143,500 less than the Company's requested increase of $905,900. My recommendation reflects an overall rate of return on rate base of 7.80%, which is per the recommendation detailed in the Direct Testimony of Maureen Reno.

Q. WHAT PERIOD HAVE YOU USED IN MAKING YOUR DETERMINATION OF PCLP'S REVENUE REQUIREMENT?

A. I have determined my revenue requirement recommendations based on the future test year ending September 30, 2025. This is the same period used by the Company to develop its revenue requirement.

Q. IN CONNECTION WITH THIS CASE, WHAT DOCUMENTS HAVE YOU EXAMINED AND REVIEWED IN MAKING YOUR RECOMMENDATIONS?

A. I have reviewed PCLP's rate filing, testimony, and exhibits. I also reviewed the Company's responses to data requests propounded by the OCA, the Office of Small Business Advocate ("OSBA"), and the Bureau of Investigation and Enforcement ("I&E").

Q. HAVE YOU PREPARED SCHEDULES TO ACCOMPANY YOUR TESTIMONY?

A. Yes. I have prepared Schedules JLR-1 through JLR-16. Schedule JLR-1 provides a summary of the calculation of the increase in revenues after reflecting the adjustments proposed by the OCA. Schedule JLR-2 provides my recommended rate base. Schedule JLR-3 presents the summary of the cost of service (revenues and operating expenses) adjustments. My adjustments to PCLP's claimed revenues and operating expenses are presented on Schedules JLR-4 through JLR-16.

Q. PLEASE EXPLAIN HOW THE REMAINING SECTIONS OF YOUR TESTIMONY ARE ORGANIZED.

A. The discussion of my findings and recommendations is presented in the following section, Section III. In that section, I address the revenue requirement issues (rate base and operating income) that I identified in this proceeding. Where I recommend an adjustment to a particular component of the rate base, revenues, or expenses, I document and explain the reason for the adjustment and note the related schedule in which the detailed calculations can be found. An outline of the topics within the section is set forth in the Table of Contents of my testimony.

III. ADJUSTMENTS

Summary of OCA Adjustments	
Rate Base	
Plant in Service	($1,201,900)
Accumulated Depreciation	$88,430
ADIT	($10,800)
Deferred Debit in Rate Base: Rate Case Expense	($34,700)
Cash Working Capital	($8,611)
Total of Adjustments to Rate Base:	**($1,167,581)**
Expenses and Interest Synchronization	
Depreciation Expense	($33,278)
M&T Credit Card Charges	($30,000)
Informational Advertising	($831)
Auditing	($8,451)
Intercompany A&O: Inflation Adjustment	($7,800)
Annual Dinner Expense	($240)
Interest Synchronization	$130,021
Total of Adjustments to Expenses:	**$49,422**

A. <u>Plant In Service</u>

Q. BRIEFLY DESCRIBE THE COMPANY'S PROPOSAL RELATED TO PLANT IN SERVICE.

A. The Company is proposing to include $11.5 million of utility plant in rate base, including gas plant in service, common plant in service which is allocated between electric and gas divisions, and intercompany plant allocated from Corning Gas.[1] While intercompany plant allocated from Corning Gas does not extend beyond the FTY, the Company has proposed extending the gas and common plant in service values through a post future test year period October 2025 through March 31, 2026.[2]

Q. DO YOU AGREE WITH THE COMPANY'S INCLUSION OF POST FUTURE TEST YEAR PLANT ADDITIONS AND RETIREMENTS THROUGH MARCH 31, 2026?

A. No, I do not. The Company is claiming a future test year ending September 30, 2025. Therefore, the inclusion of net plant additions through March 30, 2026 is inappropriate as those go beyond the future test year and these plants will not be used and useful by the end of the period the Company has selected to establish the rates. This also creates a mismatch between plant in service in the cost of service with the revenues and operating expenses, which were forecast consistent with the FTY. This is in violation of the accounting principal of matching, which dictates that financial statements should be presented on a consistent basis. Revenues, operating expenses, assets, liabilities and owners' equity should all be recognized in the period in which they are incurred and/or expenditures are made. Therefore, revenues should be recorded in the accounting

[1] Company Exhibit G-3, Summary page 1.
[2] Company Exhibit G-3, Schedule 1.

period in which they are earned, and expenses should be recorded during the period that benefits from the expense. Similarly, assets, liabilities and shareholder equity are to be recorded during the period in which the expenditures are made or funds are received. For a specific accounting period, the forementioned components should all be reported for the same period as a matter of consistency.

Q. PLEASE EXPLAIN YOUR ADJUSTMENT TO PLANT IN SERVICE.

A. For the reasons explained above, I recommend disallowing the inclusion of the post future test year plant additions and retirements. This adjustment removes $1,280,000 in post FTY plant additions and ($78,100) of post FTY plant retirements, for a net reduction in rate base totaling $1,201,900, as shown on Schedule JLR-5.

B. <u>Accumulated Depreciation</u>

Q. PLEASE EXPLAIN YOUR ADJUSTMENT TO ACCUMULATED DEPRECIATION.

A. As explained in the 'Plant In Service' section of my direct testimony, I am recommending the Commission disallow the inclusion of post FTY plant additions, which necessitates an additional adjustment to remove accumulated depreciation associated with the post FTY period from the cost of service. The Company has included in rate base $86,600 of accumulated depreciation for gas plant and $1,830 of accumulated depreciation for common plant associated with the post FTY period additions and retirements October 1, 2025 through March 31, 2026.[3] Consistent with my recommendation to disallow post FTY plant additions, I therefore have made an adjustment to remove the post FTY accumulated depreciation. This adjustment increases rate base by $88,430, as shown on Schedule JLR-6.

[3] Company Exhibit G-3, Schedule 2.

C. Accumulated Deferred Income Taxes

Q. PLEASE EXPLAIN YOUR ADJUSTMENT TO ACCUMULATED DEFERRED INCOME TAXES ("ADIT").

A. The Company has proposed an ADIT balance of $245,100. As explained in the 'Plant In Service' section of my direct testimony, I am recommending the Commission disallow the inclusion of post FTY plant additions. The Company has included ($10,800) of accumulated deferred income taxes associated with the post FTY period October 1, 2025 through March 31, 2026.[4] Consistent with my recommendation to disallow post FTY plant additions, I therefore have made an adjustment to remove the post FTY accumulated deferred income taxes. This adjustment decreases rate base by $10,800, as shown on Schedule JLR-7.

D. Deferred Debit: Rate Case Expense

Q. PLEASE DESCRIBE THE COMPANYS PROPOSAL RELATED TO THE DEFERRED DEBIT FOR RATE CASE EXPENSE.

A. The Company has included $34,700 in rate base deferred debit associated with Rate Case Acct 186171, rounded value after tax.[5]

Q. DO YOU AGREE WITH THE INCLUSION OF RATE CASE EXPENSES IN RATE BASE?

A. No, I do not. It is my understanding that no return is allowed to be earned on expenses, only on capital investments. Expenses are to be recovered without profit. Including these accumulated expenses in the rate base would allow the Company to inappropriately earn a return on these expenses, which is not permitted. When asked in

[4] Company Exhibit G-3, Schedule 9.
[5] Company Exhibit G-3, Schedule 6.

discovery for an explanation why the Company believes it is appropriate to use amortization rather than normalization to recover rate case expenses, the Company did not provide an explanation in their response.[6] The Commission's practice is to normalize rate case expense over a number of years.[7] I recommend normalizing rather than amortizing this expense, consistent with the Pennsylvania Public Utility Commission's practice, and disallowing inclusion of rate case expenses in rate base. This reduces rate base by $34,700, as shown in Schedule JLR-8.

E. <u>Allowance for Cash Working Capital</u>

Q. HOW DO YOU DEFINE CASH WORKING CAPITAL?

A. For ratemaking purposes, cash working capital is the investment that a utility needs to have on hand to fund its day-to-day operations. Positive cash working capital represents funds provided by investors that should be included in rate base so that the utility earns a return on it. Negative cash working capital represents funds supplied by ratepayers that should be recognized as a rate base offset to reflect funds advanced for operations by ratepayers.

Q. HOW DID THE COMPANY REFLECT CASH WORKING CAPITAL IN ITS FILING?

A. The Company's cash working capital allowance has been determined based upon the results of a lead/lag study. A lead/lag study is an in-depth analysis that measures the difference between the lapse of time when a company receives revenue for the provision of service and the lapse of time when a company pays for the costs of providing service. This difference is expressed as a number of days and is used to

[6] Company response to I&E-RE-5-D, part G.
[7] James H. Cawley and Norman J. Kennard, A Guide to Utility Ratemaking (2018 Edition), Pennsylvania Public Utility Commission, 1983, p. 112.

calculate the level of investor-supplied funds advanced for operations, or the funds advanced by customers for operations.

Q. WHAT CHANGES HAVE YOU MADE TO THE ALLOWANCE FOR CASH WORKING CAPITAL?

A. Since O&M expenses serve as the basis upon which the cash working capital is calculated, I have incorporated the adjustments to O&M expenses that I am recommending below. I have therefore made an adjustment to cash working capital to reduce rate base by $8,611 as shown on Schedule JLR-4.

F. <u>Depreciation Expense</u>

Q. PLEASE EXPLAIN YOUR ADJUSTMENT TO DEPRECIATION EXPENSES.

A. As explained in the 'Plant In Service' section of my direct testimony, I am recommending the Commission disallow the inclusion of post FTY plant additions, which necessitates an additional adjustment to the depreciation expenses. Consistent with my recommendation to disallow post FTY plant additions and retirements, I therefore have made an adjustment to remove the post FTY additions and retirements from the Company's calculation of depreciation expenses. This adjustment decreases depreciation expenses by $33,278, as shown on Schedule JLR-9.

G. <u>M&T Credit Card Charges</u>

Q. PLEASE EXPLAIN THE COMPANY'S PROPOSED M&T CREDIT CARD CHARGES INCLUDED IN THE INTERCOMPANY ADMINISTRATIVE & OPERATING CHARGES EXPENSE.

A. The Company has based its Intercompany Administrative & Operating ("A&O") Charges expense on the actual amount charged to O&M expenses for the twelve months ended September 30, 2024, which totals of $780,177. They then applied a one percent inflation factor, increasing the expense by $7,800.[8]

These Intercompany A&O Charges are comprised of numerous expense items, one of which is 'M&T Credit Card Charges,' which totaled $202,824 in the year ending September 30, 2024[9]. These are total values, of which 15% is allocated to the gas division.[10]

Q. DO YOU AGREE WITH THE COMPANY'S PROPOSED M&T CREDIT CARD CHARGES EXPENSE?

A. No, I do not. The Company is proposing to base the value on the actual amounts charged for the twelve months ended September 30, 2024, before applying a general one percent inflation factor. I address the one percent inflation factor in the 'Intercompany Administrative & Operating Charges: Inflation' section of my direct testimony. With respect to the twelve months ended September 30, 2024, the value increased from $3,006 in year ended September 30, 2023, to $202,824 in year ended September 30, 2024. In response to I&E-RE-28, the Company explained that "The M&T labeled item is an intercompany reclass between Pike and Corning Natural Gas, and is mislabeled as a bank fee. This was a one-time intercompany transfer for a balance that was booked in the wrong GL account, and is not expected to occur again." The Company went on to explain that this value represents a loan, which was recorded as a credit card expense in error.[11] This represents a one-time loan, not an expense, and therefore should not be included in the cost of service.

[8] Company response to OCA 9-1, "Intercompany allocations 2022-2024" Excel attachment, and Company Exhibit G-4, Schedule 6.
[9] Company response to OCA 9-1, "Intercompany allocations 2022-2024" Excel attachment.
[10] Company response to OCA 9-2.
[11] Company response to OCA 11-1.

Q. PLEASE EXPLAIN YOUR ADJUSTMENT TO PROPOSED M&T CREDIT CARD CHARGES INCLUDED IN THE INTERCOMPANY ADMINISTRATIVE & OPERATING CHARGES EXPENSE.

A. For the reasons explained above, I recommend disallowing the $200,000 value associated with the one-time intercompany reclass. To calculate the adjustment, I first applied a 15 percent allocation factor to the original values, reflecting the portion allocated to the gas division. I then remove the portion of the total M&T Credit Charges associated with the loan. This adjustment reduces O&M expenses by $30,000, as shown on Schedule JLR-10. I address the one percent inflation factor, which the Company proposes to apply to all Intercompany Administrative & Operating Charges expenses, in the 'Intercompany Administrative & Operating Charges: Inflation' section of my direct testimony.

H. Informational Advertising

Q. PLEASE EXPLAIN THE COMPANY'S PROPOSED INFORMATIONAL ADVERTISING COSTS INCLUDED IN THE INTERCOMPANY ADMINISTRATIVE & OPERATING CHARGES EXPENSE.

A. As previously discussed, the Company has based its Intercompany Administrative & Operating Charges expense on the actual amount charged for the year ended September 30, 2024, which totals of $780,177. They then applied a one percent inflation factor, increasing the expense by $7,800.[12]

[12] Company response to OCA 9-1, "Intercompany allocations 2022-2024" Excel attachment, and Company Exhibit G-4, Schedule 6.

These Intercompany Administrative & Operating Charges are comprised of numerous expense items, one of which is 'Informational Advertising' totaling $8,618 in the year ending September 30, 2024.[13] Note that these are total values, of which 15% is allocated to the gas division.[14]

Q. DO YOU AGREE WITH THE COMPANY'S PROPOSED INFORMATIONAL ADVERTISING EXPENSE?

A. No, I do not. The Company is proposing to base the value on the actual amounts charged for the twelve months ended September 30, 2024, before applying a general one percent inflation factor. I address the one percent inflation factor in the 'Intercompany Administrative & Operating Charges: Inflation' section of my direct testimony. With respect to the twelve months ended September 30, 2024, this 2024 basis for the Informational Advertising charges is abnormally high, as shown in the chart below.

	12 mos. Ending September 2022	12 mos. Ending September 2023	12 mos. Ending September 2024
Informational Advertising[15]	$449	$171	$8,618

Informational advertising expenses are a variable cost item, increasing and decreasing depending on the year. Basing rates on these abnormally high 2024 expenses could result in an overcollection from customers.

[13] Company response to OCA 9-1, "Intercompany allocations 2022-2024" Excel attachment.
[14] Company response to OCA 9-2.
[15] Company response to OCA 9-1, "Intercompany allocations 2022-2024" Excel attachment.

Q. PLEASE EXPLAIN YOUR ADJUSTMENT TO PROPOSED INFORMATIONAL ADVERTISING COSTS INCLUDED IN THE INTERCOMPANY ADMINISTRATIVE & OPERATING CHARGES EXPENSE.

A. I am recommending normalizing the annual expense level allocated to the gas division (15% of the total values) using the average of the most recent three years rather than the value for the year ended September 30, 2024. This adjustment is presented on Schedule JLR-11, and results in a decrease to O&M expenses of $831. I address the one percent inflation factor the Company proposes to apply to all Intercompany Administrative & Operating Charges expenses in the 'Intercompany Administrative & Operating Charges: Inflation' section of my direct testimony.

I. Auditing Expenses

Q. PLEASE EXPLAIN THE COMPANY'S PROPOSED AUDITING COSTS INCLUDED IN THE INTERCOMPANY ADMINISTRATIVE & OPERATING CHARGES EXPENSE.

A. As previously discussed, the Company has based its Intercompany Administrative & Operating Charges expense on the actual amount charged for the year ended September 30, 2024, which totals of $780,177. They then applied a one percent inflation factor, increasing the expense by $7,800.[16]

These Intercompany Administrative & Operating Charges are comprised of numerous expense items, one of which is 'Auditing' totaling $87,342 in the year ending

[16] Company response to OCA 9-1, "Intercompany allocations 2022-2024" Excel attachment, and Company Exhibit G-4, Schedule 6.

September 30, 2024.[17] Note that these are total values, of which 15% is allocated to the gas division.[18]

Q. DO YOU AGREE WITH THE COMPANY'S PROPOSED AUDITING EXPENSE?

A. No, I do not. The Company is proposing to base the value on the actual amounts charged for the twelve months ended September 30, 2024, before applying a general one percent inflation factor. I address the one percent inflation factor in the 'Intercompany Administrative & Operating Charges: Inflation' section of my direct testimony. With respect to the twelve months ended September 30, 2024, this 2024 basis for the Auditing charges is abnormally high, as shown in the chart below.

	12 mos. Ending September 2022	12 mos. Ending September 2023	12 mos. Ending September 2024
Auditing[19]	$4,365	$1,302	$87,342

PCLP transitioned Companies for the 2023 audit and were billed for costs of the audit transition, resulting in unusually high auditing expenses in the twelve months ending September 2024.[20] Not only were additional costs incurred for the transition, but it is also reasonable to assume that this cost will be higher in the first year of a switch to a new company than it will be in subsequent years due to the principle of economy of repetition, wherein processes for recurring tasks are developed and refined as they are repeated, which results in efficiency gains and lower costs. Using this year as the basis for future expenses could result in an overcollection from customers given this out of the ordinary activity.

[17] Company response to OCA 9-1, "Intercompany allocations 2022-2024" Excel attachment.
[18] Company response to OCA 9-2.
[19] Company response to OCA 9-1, "Intercompany allocations 2022-2024" Excel attachment.
[20] Company response to OCA 9-1.

Q. PLEASE EXPLAIN YOUR ADJUSTMENT TO PROPOSED AUDITING COSTS INCLUDED IN THE INTERCOMPANY ADMINISTRATIVE & OPERATING CHARGES EXPENSE.

A. I am recommending normalizing the annual expense level allocated to the gas division (15% of the total values) using the average of the most recent three years rather than the value for the year ended September 30, 2024. This adjustment is presented on Schedule JLR-12, and results in a decrease to O&M expenses of $8,451. I address the one percent inflation factor the Company proposes to apply to all Intercompany Administrative & Operating Charges expenses in the 'Intercompany Administrative & Operating Charges: Inflation' section of my direct testimony.

J. <u>Intercompany Administrative & Operating Charges: Inflation</u>

Q. PLEASE EXPLAIN THE COMPANY'S PROPOSED INTERCOMPANY ADMINISTRATIVE & OPERATING CHARGES EXPENSE.

A. The Company has based its Intercompany Administrative & Operating Charges expense on the actual amount charged for the year ended September 30, 2024, which totals of $780,177. They then applied a one percent inflation factor, increasing the expense by $7,800.[21]

Q. DO YOU AGREE WITH THE COMPANY'S USE OF AN INFLATION ADJUSTMENT TO THESE EXPENSES?

A. No, I do not. The Company's application of a one percent inflation escalation is problematic for several reasons. First, in response to discovery, the Company was not

[21] Company response to OCA 9-1, "Intercompany allocations 2022-2024" Excel attachment, and Company Exhibit G-4, Schedule 6.

able to provide any backup data or documentation to show the basis of how they projected a one percent inflation rate, merely stating this was an estimate.[22] Second, the Intercompany Administrative & Operating Charges reflect a wide variety of expense items, such as landscaping, credit card charges, petty cash, maintenance and repair, and more.[23] Some of the costs included are not subject to inflationary increases, and an inflationary adjustment is therefore inappropriate. Moreover, a blanket escalation adjustment does not reflect actual expectations for the expense items in the FTY. It is apparent in the historical data that many of these costs are variable, with some increasing and others decreasing year over year to varying degrees. This blanket escalator does not capture actual expected expenses. Finally, the $780,177 amount to which the Company has applied the one percent escalation is a total value, which is allocated between electric and gas customers, with 15% applicable to the gas cost of service. In applying the escalation to the total amount of Intercompany Administrative & Operating Charges, not solely the gas service portion, the Company has included an adjustment that includes increases allocated to the electric division. This is inappropriate to apply to gas customers and double counts increases applied in the electric division's rate case.

Q. PLEASE EXPLAIN YOUR ADJUSTMENT TO THE INTERCOMPANY ADMINISTRATIVE & OPERATING CHARGES EXPENSE.

A. For the reasons detailed above, I am recommending the Commission disallow the inflation escalation adjustment the Company has applied to the Intercompany

[22] Company response to OCA 6-25.
[23] Company response to OCA 9-1, "Intercompany allocations 2022-2024" Excel attachment.

Administrative & Operating Charges. This adjustment reduces O&M expenses by $7,800, as shown on Schedule JLR-13.

K. Annual Dinner Expense

Q. PLEASE EXPLAIN YOUR ADJUSTMENT RELATED TO THE GREATER PIKE COMMUNITY FOUNDATION ANNUAL DINNER.

A. The Company has included $1,600 related to the Greater Pike Community Foundation for their annual dinner in the cost of service, of which 15% is allocated to the gas division. In response to discovery, the Company explained that the benefit associated with this expense is related to supporting the community.[24] This is related to image building and public relations for the Company, which benefits shareholders, rather than provide service to ratepayers. Ratepayers should therefore not be responsible for this expense, and I recommend disallowing expenses related to the Greater Pike Community Foundation for their annual dinner from inclusion in the cost of service. This adjustment reduces O&M expenses by $240, as shown in Schedule JLR-14.

L. Interest Synchronization

Q. DO YOU AGREE WITH THE COMPANY'S CALCULATION OF INTEREST SYNCHRONIZATION?

A. No, I do not. To determine the tax-deductible interest for ratemaking, the recommended rate base is multiplied by the weighted cost of debt included in the capital structure. This procedure synchronizes the interest deduction for tax purposes with the interest component of the return on rate base to be recovered from ratepayers.

In the Company's proposed cost of service, they have applied the unweighted cost of debt from a prior DSIC filing to rate base for interest synchronization, which is

[24] Company response to OCA 9-6.

incorrect. The weighted cost of debt is the portion of debt that supports rate base, and therefore it is this value which must be used in the calculation to correctly determine the interest expense. The Company has multiplied the unweighted long-term cost of debt from their Pike Gas DSIC filing for Q3 2024, 7.21%, by their proposed rate base in calculating their interest synchronization.[25] In the proposed capital structure for this case, however, the Company has proposed a weighted cost of debt of 3.43%.[26] Applying the 3.43% weighted cost of debt included in the capital structure is the correct method to determine the interest component of the return on rate base to be recovered from ratepayers. The Company therefore undercalculated income taxes by $110,250 in the Company's proposed model.

Q. PLEASE EXPLAIN YOUR INTEREST SYNCHRONIZATION ADJUSTMENT.

A. To determine the tax-deductible interest for ratemaking, I multiplied the OCA's recommended rate base by the weighted cost of debt included in the capital structure recommended per the direct testimony of OCA Witness Reno. As previously discussed, this procedure synchronizes the interest deduction for tax purposes with the interest component of the return on rate base to be recovered from ratepayers. This adjustment increases state income taxes by $38,037 and federal income taxes by $91,984, as shown on Schedule JLR-15.

Q. DOES THIS COMPLETE YOUR DIRECT TESTIMONY?

A. Yes, it does.

[25] Company Exhibit G-4, Schedule 10 and Data Input Tab.
[26] Company Exhibit G-2, Schedule 3.

BEFORE THE

PENNSYLVANIA PUBLIC UTILITY COMMISSION

Pennsylvania Public Utility Commission	)	
v.	)	**Docket No. R-2024-3052357**
Pike County Light & Power Company-Gas	)	

SCHEDULES ACCOMPANYING THE

DIRECT TESTIMONY

OF

JENNIFER L. ROGERS

ON BEHALF OF THE

PENNSYLVANIA OFFICE OF CONSUMER ADVOCATE

April 3, 2025

EXETER
ASSOCIATES, INC.
10480 Little Patuxent Parkway, Suite 300
Columbia, Maryland 21044

APPENDIX A – Resume of Jennifer L. Rogers

JENNIFER L. ROGERS

Ms. Rogers is a Principal and Vice President at Exeter Associates, Inc., with over fifteen years of experience in the energy industry. At Exeter, Ms. Rogers reviews and analyzes utility rate filings, and presents testimony focusing primarily on revenue requirements determination. She also evaluates and forecasts power supply requirements, costs, and renewable energy needs; provides bill and rate analysis; and reviews energy use, scheduling, and scheduling deviation data for clients. In addition, Ms. Rogers conducts utility service assessments to identify areas for potential utility cost savings, providing detailed analysis of supply contracts, energy use, and a review of billing practices.

Education

B.A. (Economics) – Saint Mary's College of Maryland, 2007

M.A. (Economics) – Northeastern University, Boston, MA, 2009

Previous Employment

2009-Current Exeter Associates, Inc.
Columbia, MD

- Principal and Vice President 2025-Current
- Lead Economist 2023-2024
- Senior Economist 2018-2022
- Economist 2011-2017
- Research Assistant 2009-2010

2007-2008 Economics Research and Teaching Assistant
Northeastern University
Boston, MA

Professional Experience

Ms. Rogers' work at Exeter is primarily related to analysis of revenue requirement issues in utility rate filings, analysis power supply acquisition, bill and rate analysis and forecasting, and utility service assessment. Ms. Rogers provides support to the U.S. Department of Energy's Northern California national laboratories, generating cost simulations and power procurement models to forecast future power supply requirements and costs. In addition, Ms. Rogers reviews and tracks the Laboratories' billing, energy use, scheduling, and scheduling deviation data. Ms. Rogers works with the U.S. Air Force Civil Engineer Center to complete utility service assessments to identify areas for potential utility cost savings, providing detailed analysis of energy usage, supply contracts, and a review of billing practices. Ms. Rogers also assists clients in reviewing utility rate filings, providing analysis on revenue requirement issues. Ms. Rogers' work at Exeter has also included assisting in studies of variable generation forecasting, feed-in tariffs for renewable energy generation, and transmission cost allocation methodologies.

As a Research Assistant at Northeastern University, Ms. Rogers worked in the fields of industrial organization and labor economics, while her studies focused on economic modeling and policy analysis. Ms. Rogers developed surveys to be used in a longitudinal labor economics study, tutored undergraduate economics students, and provided research on a variety of economics-related topics.

Expert Testimony

Before the Pennsylvania Public Utility Commission, Docket No. R-2024-3050208, Newtown Artesian Water Company, 2024, on behalf of the Pennsylvania Office of Consumer Advocate. Testimony addressed revenue requirement issues.

Before the Maryland Public Utility Commission, Case No. 9744, Hagerstown Light Department, 2024, on behalf of the Maryland Office of People's Counsel. Testimony addressed revenue requirement issues.

Before the Maryland Public Utility Commission, Case No. 9719, Easton Utilities Commission, 2024, on behalf of the Maryland Office of People's Counsel. Testimony addressed revenue requirement issues.

Before the Pennsylvania Public Utility Commission, Docket Nos. R-2023-3042804 and R-2023-3042805, Community Utilities of Pennsylvania Inc., 2024, on behalf of the Pennsylvania Office of Consumer Advocate. Testimony addressed revenue requirement issues.

Before the State Corporation Commission of the State of Kansas; Docket No. 23-EKCE-775-RTS; Evergy Kansas Central, Inc., Evergy Kansas South, Inc. and Evergy Metro, Inc.; 2023; on behalf of the United States Department of Defense and all other Federal Executive Agencies. Testimony addressed revenue requirement issues.

Before the Pennsylvania Public Utility Commission, Docket No. R-2023-3040258, Columbia Water Company, 2023, on behalf of the Pennsylvania Office of Consumer Advocate. Testimony addressed revenue requirement issues.

Before the Maine Public Utilities Commission, Docket No. 2023-00065, Maine Water Company – Biddeford & Saco Division, 2023, on behalf of the Maine Office of the Public Advocate. Testimony addressed revenue requirement issues.

Before the Philadelphia Water, Sewer, and Storm Water Rate Board, Fiscal Years 2024-2025 Rate Proceeding, Philadelphia Water Department, 2023, on behalf of the Public Advocate. Testimony addressed revenue requirement issues.

Before the Pennsylvania Public Utility Commission, Docket No. R-2022-3032764, Leatherstocking Gas Company, LLC., 2022, on behalf of the Pennsylvania Office of Consumer Advocate. Testimony addressed revenue requirement issues.

Before the Public Utility Commission of Texas, Docket No. 53601, Oncor Electric Delivery Company LLC, 2022, on behalf of the United States Department of Defense and the Federal Executive Agencies. Testimony addressed revenue requirement issues.

Before the Maryland Public Service Commission, Case No. 9680, Columbia Gas of Maryland, Inc., 2022, on behalf of the Maryland Office of People's Counsel. Testimony addressed revenue requirement issues.

Before the Pennsylvania Public Utility Commission, Docket No. R-2015-2462723, United Water Pennsylvania, Inc., 2015, on behalf of the Pennsylvania Office of Consumer Advocate. Testimony addressed revenue requirement issues.

Publications and Consulting Reports

A Survey of Variable Generation Integration Charges, National Renewable Energy Laboratory, NREL Report No. NREL/TP-5500-57583, March 2013 (with Kevin Porter, Sari Fink, and Michael Buckley of Exeter Associates, and with B.-M. Hodge of NREL)

Survey of Variable Generation Forecasting in the West, National Renewable Energy Laboratory, NREL Report No. NREL/SR-5500-54457, April 2012 (with Kevin Porter).

Summary of Time Period-Based and Other Approximation Methods for Determining the Capacity Value of Wind and Solar in the United States, National Renewable Energy Laboratory, NREL Report No. NREL/SR-5500-54338, March 2012 (with Kevin Porter).

Long-Term Electricity Report for Maryland, prepared for the Maryland Department of Natural Resources Power Plant Research Program Pursuant to Executive Order 01.01.2010.16, December 2011, (with Steven Estomin, Kevin Porter, Christina Mudd, Emma Nicholson, Sari Fink, Michael Buckley, and Krista Ozarowski).

Alternative Energy Resource Market Assessment, National Association of Regulatory Utility Commissioners, A report for the Public Utility Commission of Ohio, September 2011 (with Kevin Porter of Exeter Associates, Inc., Ed Holt & Associates, Inc., and Sustainable Energy Advantage LLC)

Central Wind Power Forecasting Programs in North America by Regional Transmission Organizations and Electric Utilities: Revised Edition, National Renewable Energy Laboratory, NREL Report No. NREL/SR-5500-51263, March 2011 (with Kevin Porter).

A Survey of Transmission Cost Allocation Methodologies for Regional Transmission Organizations, National Renewable Energy Laboratory, NREL Report No. SR-5500-49880, February 2011 (with Kevin Porter, Sari Fink, and Christina Mudd).

The Relationship between Wind Generation and Balancing-Energy Market Prices in ERCOT: 2007–2009, National Renewable Energy Laboratory, NREL Report No. NREL/SR-5500-49415, November 2010 (with Kevin Porter and Emma Nicholson).

The Relevance of Generation Interconnection Procedures to Feed-in Tariffs in the United States, National Renewable Energy Laboratory, NREL Report No. NREL/SR-6A20-48987, October 2010 (with Kevin Porter and Sari Fink).

Transmission Cost Allocation Methodologies for Regional Transmission Organizations, National Renewable Energy Laboratory, NREL Report No. NREL/SR-550-48738, July 2010 (with Kevin Porter and Sari Fink).

Examples of Wind Energy Curtailment Practices, National Renewable Energy Laboratory, NREL Report No. NREL/SR-550-48737, July 2010 (with Kevin Porter and Sari Fink).

Status of Centralized Wind Power Forecasting in North America, National Renewable Energy Laboratory, NREL/SR-550-47853, April 2010 (with Kevin Porter).

"Bi-Monthly Transmission Updates," of the National Wind Coordinating Collaborative, Prepared for National Renewable Energy Lab, August 2009 - June 2010 (with Kevin Porter).

"Maryland Power Plants and the Environment: A Review of the Impacts of Power Plants and Transmission Lines on Maryland's Natural Resources, Maryland Power Plant Research Program, PPRP-CEIR-15," January 2010 (with Steven Estomin, Christina Mudd, and Sari Fink of Exeter Associates, Inc. and contributing authors from Versar, Inc. and Environmental Resources Management).

"Wind Power and Electricity Markets," Compiled for the Utility Wind Interest Group, August 2009 (with Kevin Porter and Sari Fink).

Pike County Light And Power Company
Gas Division
Cost of Service
For the Future Test Year Ended September 30, 2025

Line No.	Description	Company Amounts at Present Rates	OCA Adjustments	Amounts After OCA Adjustments	Pro Forma Change in Revenues	Amounts After Change in Revenues
1	Total Operating Revenues	2,259,200	-	2,259,200	762,400	3,021,600
2						
3	Operating Expenses					
4	Purchased Gas Expense	1,135,000	-	1,135,000		1,135,000
5	Other O&M Expenses	694,100	(47,322)	646,778	2,100	648,878
6	Depreciation & Amortization Expense	333,100	(33,278)	299,822		299,822
7	Taxes other than Income	27,700	-	27,700	-	27,700
8	Total Operating Expenses	$ 2,189,900	$ (80,599)	$ 2,109,301	$ 2,100	$ 2,111,401
9						
10	Operating Income Before Income Taxes	69,300	80,599	149,899	760,300	910,199
11	State Income Tax	(56,000)	44,476	(11,524)	60,748	49,224
12	Federal Income Tax	(135,400)	107,558	(27,842)	146,906	119,064
13						
14	Operating Income after Taxes	$ 260,700	$ (71,435)	$ 189,265	$ 552,646	$ 741,911
15						
16	Rate Base	$ 10,679,042		$ 9,511,461		$ 9,511,461
17						
18	Rate of Return	2.44%		1.99%		7.80%

Pike County Light And Power Company
Gas Division
Summary of Revenue Increase at OCA Rate of Return
For the Twelve Months Ended September 30, 2025

Line No.	Description		Amount	Source
1	Adjusted Rate Base		$ 9,511,461	Schedule JLR-2, Page 1
2	Required Rate of Return		7.80%	Schedule JLR-16
3				
4	Net Operating Income Required		$ 741,894	
5	Net Operating Income at Present Rates		189,265	Schedule JLR-1, Page 1
6				
7	Income Deficiency/(Surplus)		$ 552,629	
8	Revenue Multiplier		1.3796	
9				
10	Required Change in Company Revenue		$ 762,400	
11				
12	Proposed Revenue Change		$ 762,400	
13	Less: Revenue Taxes - N/A	0.00%	$ -	
14	Net of Revenue Taxes		$ 762,400	
15	Less: Uncollectibles	0.28%	$ 2,100	
16	Net of Uncollectibles		$ 760,300	
17	Less: State Income Tax @ 7.99%	7.99%	$ 60,748	
18				
19	Income Before Federal Taxes		$ 699,552	
20	Federal Income Tax @ 21.0%	21.00%	146,906	
21				
22	Net Income (Surplus)/Deficiency		552,646	

Note:
1/ Company Exhibit G-4, Summary, Page 2

Revenue Muliplier		Revenue Mulitplier
Additional Revenue		100.0000
Less: Revenue Taxes - N/A		0.0000
Less: Uncollectibles	0.28%	0.280
		99.7200
Less: State Income Tax	7.99%	7.9676
		91.7524
Less: Federal Income Tax @ 0%	21%	19.2680
Retention Factor		72.484
		1.0000
		0.7248
		1.3796

Pike County Light And Power Company
Gas Division
Summary of Rate Base
For the Twelve Months Ended September 30, 2025

Line No.	Description	Amount per Company Filing 1/	OCA Adjustments	Amount After OCA Adjustments
1	Utility Plant			
2	Gas Plant in Service	11,214,142	(1,189,200)	10,024,942
3	Common Plant in Service (Allocated)	241,000	(12,700)	228,300
4	Interco plant allocated from Corning Gas (Net)	41,600		41,600
5	CWIP not taking interest	-		-
6	Total Utility Plant	$ 11,496,742	$ (1,201,900)	$ 10,294,842
7				
8	Utility Plant Reserves			
9	Accumulated Provision For Depreciation			
10	of Gas Plant in Service	755,100	(86,600)	668,500
11	of Common Plant in Service (Allocated)	198,400	(1,830)	196,570
12	Total Utility Plant Reserves	$ 953,500	$ (88,430)	$ 865,070
13				-
14	Net Plant	10,543,242	(1,113,470)	9,429,772
15				
16	Additions to Net Plant			
17	Working Capital Requirements:			
18	Cash Working Capital	118,800	$ (8,611)	110,189
19	Materials and Supplies	276,800		276,800
20	Prepayments	5,500		5,500
21	Deferred Debits (Net of Tax)	34,700	(34,700)	-
22	Total Additions	$ 435,800	$ (43,311)	$ 392,489
23				
24	Deductions to Net Plant			
25	Deferred Credits (Net of Tax)	(4,400)		(4,400)
26	Customer Deposits	59,300		59,300
27	Accumulated Deferred Income Taxes	245,100	10,800	255,900
28	Total Deductions	$ 300,000	$ 10,800	$ 310,800
29				
30	Gas Rate Base	$ 10,679,042	$ (1,167,581)	$ 9,511,461

Note:
1/ Company Exhibit G-3, Summary Page 1

Pike County Light And Power Company
Gas Division
Summary of Rate Base Adjustments
For the Twelve Months Ended September 30, 2025

Line No.	Description	Source	Amount
1	Rate Base per Company Filing	Schedule JLR-2, Page 1	$ 10,679,042
2			
3	OCA Adjustments:		
4	Adjustment to Remove Post FTY Plant Additions	Schedule JLR- 5	(1,201,900)
5	Adjustment to Accumulated Depreciation	Schedule JLR- 6	88,430
6	Adjustment to Accumulated Deferred Income Taxes	Schedule JLR- 7	(10,800)
7	Adjustment to Deferred Debits: Rate Case Expense	Schedule JLR- 8	(34,700)
8	Adjustment to Cash Working Capital	Schedule JLR- 4	(8,611)
9			
10	Total Ratemaking Adjustments		$ (1,167,581)
11			
12	Adjusted Rate Base per OCA		$ 9,511,461

Pike County Light And Power Company
Gas Division
Summary of Adjustments to Operating Income
For the Twelve Months Ended September 30, 2025

Line No.	Description	Operating Revenues	Purchased Gas Expense	Other O&M Expenses	Depreciation & Amortization	Taxes Other Than Income	State Income Taxes	Federal Income Taxes	Operating Income
1	Amount per Company	$ 2,259,200	$ 1,135,000	$ 694,100	$ 333,100	$ 27,700	$ (56,000)	$ (135,400)	$ 260,700
2									
3	OCA Adjustments:								
4	Adjustment to Depreciation Expense				(33,278)		2,659	6,430	$ 24,189
5	Adjustment to M&T Credit Card Charges			(30,000)			2,397	5,797	$ 21,806
6	Adjustement to Informational Advertising			(831)			66	161	$ 604
7	Adjustment to Auditing Expenses			(8,451)			675	1,633	$ 6,143
8	Adjustment to Intercompany A&O: Inflation Adjustment			(7,800)			623	1,507	$ 5,670
9	Adjustment to Annual Dinner Expense			(240)			19	46	$ 175
10	Interest Synchronization						38,037	91,984	$ (130,021)
11									
12	Total OCA Adjustments	$ -	$ -	$ (47,322)	$ (33,278)	$ -	$ 44,476	$ 107,558	$ (71,435)
13									
14	Total Adjusted Income Before Income Taxes	$ 2,259,200	$ 1,135,000	$ 646,778	$ 299,822	$ 27,700	$ (11,524)	$ (27,842)	$ 189,265

Pike County Light And Power Company
Gas Division
Adjustment to Cash Working Capital
For the Twelve Months Ended September 30, 2025

Line No.	Description	Rate Year Amount Per Company 1/	OCA Adjustments	Pro Forma Expense After OCA Adjustments	Company Daily Requirement	OCA Adjusted Daily Requirement	(Lead)/Lag Days	Company Dollar Days	OCA Adjusted Dollar Days
1	Revenue Recovery	3,373,900		3,373,900	9,244	9,244	21	196,703	196,703
2									
3	Gas Supply Expenses:	1,135,000		$ 1,135,000	$ 3,110	$ 3,110	10	31,065	$ 31,065
4	Pike Salaries & Wages	291,667		$ 291,667	$ 799	$ 799	8	6,393	$ 6,393
5	401K Pension Match	6,499		$ 6,499	$ 18	$ 18	8	142	$ 142
6	Employee Welfare Expenses	82,889		$ 82,889	$ 227	$ 227	23	5,223	$ 5,223
7	Intercompany Charges	787,977	(47,082)	$ 740,896	$ 2,159	$ 2,030	30	64,765	$ 60,896
8	Uncollectible Accounts Accrual	6,175		$ 6,175	$ 17	$ 17	8	135	$ 135
9	Other O&M	(505,785)	(240)	$ (506,025)	$ (1,386)	$ (1,386)	23	(31,871)	$ (31,887)
10	Amortizations:			$ -	$ -	$ -		-	$ -
11	Rate Case Costs	9,400		$ 9,400	$ 26	$ 26	-	-	$ -
12	PUC Assessment	4,978		$ 4,978	$ 14	$ 14	-	-	$ -
13	Insurance	13,500		$ 13,500	$ 37	$ 37	-	-	$ -
14	Depreciation & Amortization	333,100	(33,278)	$ 299,822	$ 913	$ 821	-	-	$ -
15	Taxes Other - Payroll	27,700		$ 27,700	$ 76	$ 76	11	835	$ 835
16	- Property Tax	-		$ -	$ -	$ -	-	-	$ -
17	Income Taxes:			$ -	$ -	$ -		-	$ -
18	Federal Income Tax	10,440	107,558	$ 117,998	$ 29	$ 323	30	858	$ 9,698
19	Deferred Federal Income Tax	(10,440)		$ (10,440)	$ (29)	$ (29)	-	-	$ -
20	Corporate Business Tax (State)	3,972	44,476	$ 48,448	$ 11	$ 133	30	326	$ 3,982
21	Deferred Corporate Business Tax	(3,972)		$ (3,972)	$ (11)	$ (11)	-	-	$ -
22	Return on Invested Capital	1,077,000		$ 1,077,000	$ 2,951	$ 2,951	-	$ -	$ -
23	Total Requirement	3,270,100		$ 3,341,535			9	77,872	86,483
24									
25	Net Lag Days Per Company	13 1/							
26									
27	Per Company: Net Requirement	$ 118,831 1/							
28									
29	OCA Net Requirement	$ 110,220							
30									
31	OCA Adjustment to CWC	$ (8,611)							

Note:
1/ Company Exhibit G-3, Schedule 3, page 2.

Pike County Light And Power Company
Gas Division
Adjustment to Remove Post FTY Plant Additions
For the Twelve Months Ended September 30, 2025

Line No.	Plant In Service	Amount	
1	*Gas Plant In Service Post FTY Additions*		
2	Additions - October 1, 2025 through March 31, 2026	$ 1,250,000	1/
3	Retirements - October 1, 2025 through March 31, 2026	$ (60,800)	1/
4	Net Additions	$ 1,189,200	
5			
6	*Common Plant In Service Post FTY Additions - Gas Allocation 15%*		
7	Additions - October 1, 2025 through March 31, 2026	$ 30,000	1/
8	Retirements - October 1, 2025 through March 31, 2026	$ (17,300)	1/
9	Net Additions	$ 12,700	
10			
11	Total Adjustment to Plant In Service	$ (1,201,900)	

Notes
1/ Exhibit G-3 Schedule 1.

Pike County Light And Power Company
Gas Division
Adjustment to Accumulated Depreciation
For the Twelve Months Ended September 30, 2025

Line No.	Plant In Service	Amount	
1	*Accumulated Provision for Depreciation of Gas Plant*		
2	Additions - October 1, 2025 thru March 31, 2026	$ 147,400	1/
3	Retirements - October 1, 2025 thru March 31, 2026	$ (60,800)	1/
4		$ 86,600	
5	*Accumulated Provision for Depreciation of Common Plant - Gas Allocation 15%*		
6	Additions - October 1, 2025 thru March 31, 2026	$ 127,500	1/
7	Retirements - October 1, 2025 thru March 31, 2026	$ (115,300)	1/
8		$ 12,200	
9	Gas Allocation of Common Plant	15%	
10		$ 1,830	
11			
12	Adjustment to Accumulated Depreciation	$ 88,430	

Notes
1/ Exhibit G-3 Schedule 2.

Pike County Light And Power Company
Gas Division
Adjustment to Accumulated Deferred Income Taxes
For the Twelve Months Ended September 30, 2025

Line No.	Description	Amount
1	Net Additions October 1, 2025 through March 31, 2026	$ (10,800) [1/]
2		
3	Adjustment to Rate Base	$ 10,800

Note:
[1/] Company Exhibit G-3, Schedule 9

Pike County Light And Power Company
Gas Division
Adjustment to Deferred Debits: Rate Case Expense
For the Twelve Months Ended September 30, 2025

Line No.	Description		Amount	
1	Rate Case Acct 186172 & 186185			
2	Deferred Debit Balance as of September 30, 2025	$	47,975	[1/]
3	Net of SIT & FIT Multiplier (1/1-28.8921%)		72.2929%	[1/]
4	Company Proposed Amount Included in Rate Base	$	34,700	
5				
6	Adjustment to Rate Base	$	(34,700)	

Note:
[1/] Company Exhibit G-3, Schedule 6

Pike County Light And Power Company
Gas Division
Adjustment to Depreciation Expense
For the Twelve Months Ended September 30, 2025

Line No.	Description	Gas Dist. Plant	Common Gen'l Plant Allocated	Total Gas
1	Depreciation Expense per OCA Recommendation			
2	Gas Plant in Service			
3	At September 30, 2024	7,193,512 [1/]	219,580 [1/]	7,413,092 [1/]
4	Less Acquisition Adjustment	0 [1/]	0 [1/]	0 [1/]
5	September 30, 2024 Plant In Service Balance	7,193,512 [1/]	219,580 [1/]	7,413,092 [1/]
6	Less: Non-Depreciable Plant	0 [1/]	(46,650) [1/]	(46,650) [1/]
7	Depreciable Plant at September 30, 2024	7,193,512 [1/]	172,930 [1/]	7,366,442 [1/]
8	Additions - October 1, 2024 thru September 30, 2025			
9	Distribution - Completed CWIP at 9/30/2025	453,042 [1/]	0 [1/]	453,042 [1/]
10	Distribution / General Additions Plant	2,500,000 [1/]	90,000 [1/]	2,590,000 [1/]
11	**OCA Recommendation**			
12	**Additions - October 1, 2025 thru March 31, 2026**			
13	**Distribution / General Additions**	0	0	0
14	*Total Additions*	2,953,042	90,000	3,043,042
15	Retirements - October 1, 2024 thru September 30, 2025			
16	Distribution / General Plant	(121,600) [1/]	(34,600) [1/]	(156,200) [1/]
17	**OCA Recommendation**			
18	**Retirements - October 1, 2025 thru March 31, 2026**			
19	**Distribution / General Plant**	0	0	0
20	*Total Retirements*	(121,600)	(34,600)	(156,200)
21	Gas Depreciable Plant at September 30, 2025	10,024,954	228,330	10,253,285
22	x Existing Composite Book Depreciation Rate	2.629% [1/]	15.866% [1/]	2.924%
23	Calculated Accruals to Depreciation Expense			
24	For The Twelve Months Ended September 30, 2025	263,556	36,227	299,783
25	Less: 12 Months Ending September 30, 2024	153,739 [1/]	54,422 [1/]	208,161 [1/]
26				
27	*Increase In Depreciation Expense Per OCA Recommendation*	109,817	(18,195)	91,622
28				
29				
30	*Increase In Depreciation Expense Per Company*			124,900 [1/]
31				
32	Adjustment to O&M expenses			$ (33,278)

Note:
[1/] Company Exhibit G-4, Schedule 8 page 1.

Pike County Light And Power Company
Gas Division
Adjustment to Intercompany Admin & Operating Charges: M&T Credit Card Charges
For the Twelve Months Ended September 30, 2025

Line No.	Description	Total		15% - Gas Division
1	2024 Intercompany Admin & Operating Charges: M&T Credit Card Charges	202,824	[1/]	$ 30,424
2	One-time intercompany reclass between Pike and Corning Natural Gas	200,000	[2/]	30,000
3	Subtotal less one-time reclass			424
4				
5	Adjustment to O&M Expenses			$ (30,000)

Note:
[1/] Company response to OCA 9-1, "Intercompany allocations 2022-2024" Excel attachment
[2/] Company response to OCA 9-1

Pike County Light And Power Company
Gas Division
Adjustment to Intercompany Admin & Operating Charges: Informtional Advertising
For the Twelve Months Ended September 30, 2025

Line No.	Description	Total		15% - Gas Division
1	2024 Intercompany Admin & Operating Charges: Informational Advertisin	8,618	[1/]	$ 1,293
2				
3	2022 Intercompany Admin & Operating Charges: Informational Advertisin	449	[1/]	
4	2023 Intercompany Admin & Operating Charges: Informational Advertisin	171	[1/]	
5	2024 Intercompany Admin & Operating Charges: Informational Advertisin	8,618	[1/]	
6				
7	Average 2022 through 2024	3,079		462
8				
9	Adjustment to O&M Expenses			$ (831)

Note:
[1/] Company response to OCA 9-1, “Intercompany allocations 2022-2024” Excel attachment

Pike County Light And Power Company
Gas Division
Adjustment to Intercompany Admin & Operating Charges: Auditing
For the Twelve Months Ended September 30, 2025

Line No.	Description	Total	15% - Gas Division
1	2024 Intercompany Admin & Operating Charges: Auditing	87,342 [1/]	$ 13,101 [1/]
2			
3	2022 Intercompany Admin & Operating Charges: Auditing	4,365 [1/]	
4	2023 Intercompany Admin & Operating Charges: Auditing	1,302 [1/]	
5	2024 Intercompany Admin & Operating Charges: Auditing	87,342 [1/]	
6			
7	Average 2022 through 2024	31,003	4,650
8			
9	Adjustment to O&M Expenses		$ (8,451)

Note:
[1/] Company response to OCA 9-1, “Intercompany allocations 2022-2024” Excel attachment

Pike County Light And Power Company
Gas Division
Adjustment to Intercompany Admin & Operating Charges: Inflation Adjustment
For the Twelve Months Ended September 30, 2025

Line No.	Description	Amount
1	Per Company: Intercompany allocations (excl. Payroll, Benefits, & Workers' Comp.) charged	
2	to O&M Expense for the Twelve Months Ended September 30, 2024	780,177 [1/]
3	Company Proposed Inflation Factor	1.00% [1/]
4	Company Proposed Adjustment	7,800
5		
6	Adjustment to O&M Expenses	$ (7,800)

Note:
[1/] Company Exhibit G-4, Schedule 6

Pike County Light And Power Company
Gas Division
Adjustment to Greater Pike Community Foundation Annual Dinner Expense
For the Twelve Months Ended September 30, 2025

Line No.	Description	Amount
1	Company Proposed Expense for Greater Pike Community Foundation Annual Dinner	$ 1,600
2	Gas Division Allocation Percentage	15% [1/]
3	Gas Division Allocation of Expense	240 [1/]
4		
5	Adjustment to O&M expenses	$ (240)

Note:
[1/] Company response to OCA 9-6

Pike County Light And Power Company
Gas Division
Interest Synchronization Adjustment
For the Twelve Months Ended September 30, 2025

Line No.	Description		Amount	
1	Company Rate Base	$	9,511,461	1/
2	Weighted Cost of Debt		3.090%	2/
3	Adjusted Interest Deduction	$	293,904	
4	Interest Deduction Per Company		769,959	2/
5	Adjustment to Synchronize Interest Expense	$	(476,055)	
6	Effective State Income Tax Rate		7.99%	
7	Adjustment to State Income Taxes	$	38,037	
8	Federal Income Tax Base	$	(438,018)	
9	Federal Income Tax Rate		21.00%	
10	Adjustment to Federal Income Taxes	$	91,984	

Notes:
1/ Schedule JLR-2, Page 1.
2/ Schedule JLR-16
2/ Company Exhibit G-4, Schedule 10, Page 3.

Pike County Light And Power Company
Gas Division
Calculation of Rate of Return
For the Twelve Months Ended September 30, 2025

Line No.	Description	Capitalization Ratio	Cost Rate	Weighted Cost
1	Long-Term Debt	40.72%	6.00%	2.44%
2	Short-Term Debt	8.64%	7.50%	0.65%
3	Total Debt	49.37%		3.09%
4				
5	Common Stock Equity	50.63%	9.30%	4.71%
6				
7	Total	100.00%		7.80%

Source:
Per Direct Testimony of OCA Witness Reno

BEFORE THE
PENNSYLVANIA PUBLIC UTILITY COMMISSION

Pennsylvania Public Utility Commission	:	
	:	Docket No. R-2024-3052357
v.	:	
	:	
Pike County Light & Power Company (Gas)	:	
	:	
	:	
	:	
	:	

VERIFICATION

I, Jennifer L. Rogers, hereby state that the facts above set forth in my Direct Testimony, OCA Statement 1, are true and correct to the best of my knowledge, information, and belief and that I expect to be able to prove the same at a hearing held in this matter. I understand that the statements herein are made subject to the penalties of 18 Pa.C.S. § 4904 (relating to unsworn falsification to authorities).

DATED: April 3, 2025

Signature: Jennifer L. Rogers

Jennifer L. Rogers

Address: 10480 Little Patuxent Parkway,
Suite 300,
Columbia, Maryland, 21044

OCA Statement No. 2

BEFORE THE

PENNSYLVANIA PUBLIC UTILITY COMMISSION

Pennsylvania Public Utility Commission	)	
v.	)	**DOCKET NO. R-2024-3052357**
Pike County Light & Power Company (Gas)	)	

DIRECT TESTIMONY OF

MAUREEN L. RENO

ON BEHALF OF THE

COMMONWEALTH OF PENNSYLVANIA

OFFICE OF CONSUMER ADVOCATE

Dated: April 3, 2025

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- Exhibit MLR-5 (Pike Response to OCA Interrogatory 8-3).
- Exhibit MLR-6 (Pike Response to OCA Interrogatory 5-6).

I. <u>INTRODUCTION AND QUALIFICATIONS</u>

Q. PLEASE STATE YOUR FULL NAME, OCCUPATION, AND BUSINESS ADDRESS.

A. My name is Maureen L. Reno. I am an economist with a specialization in public utility economics and finance. I am the founder and principal consultant of Reno Energy Consulting Services, L.L.C. My business address is 19 Hope Hill Road, Derry, New Hampshire 03038.

Q. PLEASE SUMMARIZE YOUR EDUCATION.

A. I received a Bachelor of Arts degree in Economics from the University of Maine at Orono, Maine in 1996. In 1998, I earned a Master of Arts degree in Economics from the University of New Hampshire in Durham, New Hampshire, where I also completed all course work and examination requirements for a Ph.D. degree in Economics, except for my dissertation. My areas of academic concentration included industrial organization and environmental economics.

Q. WHAT IS YOUR PROFESSIONAL BACKGROUND?

A. I have 24 years of professional experience in the regulated utilities and energy sectors. From 2001 to 2011, I served as a utility analyst and program manager with the New Hampshire Public Utilities Commission, advising the Commissioners on regulated utilities' cost of capital and return on equity ("ROE"), among other regulatory matters. From 2011 to 2012, I served as a Senior Energy Economist with the Union of Concerned Scientists, advising on the intricacies of the regulated utility industry and helping to develop alternative financing programs for renewable energy investments. Since 2012, I have served as an independent consultant to multiple firms, including Exeter Associates, Inc. and TAHOEconomics, LLC on utility cost of capital, ROE, and capital structure; Stephenson Strategic Communications, LLC on federal climate and energy policy; and TrueLight Energy, LLC on regulated utility rate impacts and energy markets.

Q. HAVE YOU PREVIOUSLY TESTIFIED AS AN EXPERT WITNESS BEFORE A PUBLIC SERVICE COMMISSION?

A. Yes. My testimony was presented and accepted in 38 regulated utility proceedings in several states, including Alaska, Arizona, California, Delaware, Georgia, Kansas, Missouri, New Hampshire, New Mexico, North Carolina, Oklahoma, South Carolina and Texas, on a wide range of issues concerning regulated utilities, retail and wholesale energy markets, and renewable energy. (See Appendix A for my curriculum vitae and qualifications.)

Q. ON WHOSE BEHALF ARE YOU APPEARING IN THIS PROCEEDING?

A. I am serving as an expert witness on cost of capital, ROE, and capital structure on behalf of the Pennsylvania Office of Consumer Advocate ("OCA").

Q. HOW IS YOUR TESTIMONY ORGANIZED?

A. My testimony is organized into eight sections including this one. In Section II, I discuss the purpose of my testimony, which is to compare the rate of return ("ROR") proposed by Pike County Light and Power ("Pike" or "the Company") with the ROR that I am recommending. In Section III, I review current and near-term economic and financial conditions in the United States and Pennsylvania. In Section IV, I evaluate Pike's proposed capital structure and discuss my recommended capital structure. In Section V, I summarize Pike's proposed cost of debt. In Section VI, I discuss different types of risks for regulated gas utilities and evaluate whether Pike is facing greater or lesser risks than its peers in the proxy group that I use in my ROE analysis. In Section VII, I present my ROE analysis which includes the methodologies that I applied to develop my ROE recommendation. I also evaluate Pike's proposed ROE. Finally, in Section VIII, I summarize my recommendations concerning a fair and reasonable ROR, which includes my recommended capital structure and ROE.

II. PURPOSE AND SUMMARY OF RECOMMENDATIONS

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

A. The purpose of my testimony is to recommend an ROR for ratemaking purposes.[1] I recommend a different ROR—to include a different ROE—rather than that proposed by Pike. My ROE recommendation was determined in accordance with the standards identified in *Bluefield Water Works v. Public Service Commission*, 262 U.S. 679, 692-93 (1923) ("*Bluefield*") and *Federal Power Commission v. Hope Natural Gas Co.*, 320 U.S. 591, 605 (1944) ("*Hope*"). In *Bluefield* and *Hope*, the U.S. Supreme Court established the principle that a public utility may be allowed to earn a return comparable to a return on investments in other enterprises having similar risks that allow the utility, under efficient management, to maintain financial integrity so that it can attract capital on reasonable terms and maintain its credit.

Q. WHAT IS THE RATE OF RETURN THAT PIKE IS PROPOSING?

A. For the future test period ending September 30, 2025 ("FTY"), Pike proposed an ROR of 8.59%, which is composed of (1) a capital structure of 50.63% common equity, 40.72% long-term debt, and 8.64% short-term debt; (2) a cost of long-term debt of 6.80%; (3) a cost of short-term debt of 7.58%; and (4) an ROE of 10.20%.[2] See Table

[1] For the purpose of my testimony, I will utilize the term "rate of return," or ROR, which I consider to be synonymous with the terms "return on rate base" or "weighted average cost of capital."

[2] Lenns and Lenns Direct, at 21-24 and Exhibit G-2, Schedule 3, for the future test period ending September 30, 2025. The historical test period is October 1, 2023 through September 30, 2024.

1 at the end of this section of my testimony for a comparison of the proposed and recommended RORs.

Q. SHOULD THE COMMISSION ACCEPT PIKE'S PROPOSED RATE OF RETURN?

A. No. The Commission should reject Pike's proposed ROR because of two main reasons. First, it is based on an overstated ROE that does not accurately reflect investors' current expected returns on utility stocks. Second, Pike's proposed natural gas system ROR of 8.59% is excessively high and inconsistent with the RORs typically allowed for distribution natural gas utilities.

Q. SHOULD THE COMMISSION ACCEPT PIKE'S PROPOSED CAPITAL STRUCTURE?

A. Yes, subject to my concern about Pike's claimed ROR and my further recommendation discussed below. Pike's proposed equity ratio of 50.63%, based on the FTY ending September 30, 2025, is reasonable for determining its capital structure in the current proceeding. Pennsylvania precedent allows utilities to base their equity ratios on an FTY. Pike's proposed equity ratio of 50.63% is consistent with regulated utility sector trends and recently observed values for the Company. However, I have significant concerns regarding the reasonableness of Pike's ROR, and a higher equity ratio further amplifies these concerns.

Q. WHAT IS YOUR FURTHER RECOMMENDATION?

A. I further recommend that Pike's proposed FTY equity ratio of 50.63% be established as a maximum for the Company and that the Commission require Pike to actively manage its capital structure to prevent further increases in the equity ratio in future years.

Q. SHOULD THE COMMISSION ACCEPT PIKE'S PROPOSED COST OF LONG-TERM DEBT?

A. No. While Pike's long-term debt costs appear to be based on the Company's embedded cost of long-term debt. I am concerned that the proposed 6.80% cost of long-term debt is excessive and not consistent with market rates during the time of each debt issuance. Pike's management has a responsibility to effectively manage long-term debt costs, and ratepayers should not bear the burden of any failure to do so.

Q. SHOULD THE COMMISSION ACCEPT PIKE'S PROPOSED COST OF SHORT-TERM DEBT?

A. No. Pike's management has a responsibility to effectively manage short-term debt costs but has failed to do so. While Pike's short-term debt costs appear to be based on the Company's embedded cost of short-term debt, the individual short-term debt costs are inconsistent with market rates during the time of each debt issuance.

Q. SHOULD THE COMMISSION ACCEPT PIKE'S PROPOSED ROE?

A. No. The 10.20% ROE proposed by Pike witnesses Chuck Lenns and Matthew Lenns does not comport with current market trends and the return on equity investors expect for a stock from a similar-risk gas utility.

Q. WHAT EVIDENCE DOES PIKE PRESENT TO SUPPORT ITS RECOMMENDED ROE OF 10.20%?

A. Witnesses Lenns and Lenns did not conduct their own analysis using industry-standard ROE models, such as the Discounted Cash Flow ("DCF") Model and the Capital Asset Pricing Model ("CAPM"). Instead, in their testimony, they stated that they simply rounded the ROE of 10.15% from the Gas Distribution System Improvement Charge ("DSIC") Eligible Utilities Return on Equity Summary, as published for September 18, 2024.[3] In response to OCA Discovery Set 5, Question 4, Mr. Matthew Lenns referenced page 15 of 30 of the *Report of the Quarterly Earnings of Jurisdictional Utilities for the Year Ended June 30, 2024* ("QE Report Ended June 30, 2024") issued by the Commission's Bureau of Technical Utility Services ("TUS") and provided a copy of the same.[4]

Q. HAS THE BUREAU OF TECHNICAL UTILITY SERVICES ISSUED A NEW QUARTERLY EARNINGS REPORT SINCE PIKE SUBMITTED ITS FILING?

A. Yes. On February 6, 2025, TUS issued the latest edition of the *Report on the Quarterly Earnings of Jurisdictional Utilities for the Year Ended September 30, 2024* ("QE Report Ended September 30, 2024").[5]

Q. DID THE BUREAU OF TECHNICAL UTILITY SERVICES ADJUST ITS COMMISSION-APPROVED ROE FOR DSIC-ELIGIBLE UTILITIES FOR PIKE?

A. No. The QE Report Ended September 30, 2024 shows a DISC ROE for Pike of 10.15%.[6]

Q. DO YOU AGREE WITH PIKE'S PROPOSED ROE?

A. No. Neither Pike's proposed ROE of 10.20%, which is based on the QE Report Ended June 30, 2024, nor the ROE of 10.15% set forth in the QE Report Ended September 30, 2024 is reflective of investors' expected ROE for a distribution-only gas utility in a low-risk regulatory environment.

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[3] Lenns and Lenns Direct, at 23.

[4] Exhibit MLR-2 (Pike Response to OCA Interrogatory 5-4); and See QE Report Ended June 30, 2024, , at 15, *available at* https://www.puc.pa.gov/pcdocs/1852340.pdf (last visited March 29, 2025).

[5] See QE Report Ended September 30, 2024, at 15, *available at* https://www.puc.pa.gov/pcdocs/1865077.pdf (last visited March 29, 2025).

[6] Id., at 15.

Q. WHAT DO YOU RECOMMEND AS THE APPROPRIATE ROR FOR PIKE?

A. For Pike (gas), I recommend an overall ROR of 7.80%, which is composed of (1) a capital structure of 50.63% equity, 40.% long-term debt, and 8.64% short-term debt (no difference from the Company's claim); (2) a cost of long-term debt of 6.00% and a cost of short-term debt of 7.50% (different from the Company's claim);[7] and (3) an ROE of 9.30% (again, different from the Company's claim). See Table 1 below for a comparison of the proposed and recommended RORs.

Q. WHY SHOULD THE COMMISSION ACCEPT YOUR RECOMMENDED 9.30% ROE?

A. My ROE recommendation of 9.30% is based on the rounded midpoint of my DCF results (9.27%) and falls within my ROE range of 8.71% to 9.84%. I recommend an ROE based on the midpoint of my DCF range because it represents a fair and reasonable ROE for Pike (gas) in consideration of its risks and investors' current valuation of public utilities and equity assets in general. I discuss my modeling in greater detail further below in my testimony.

Q. DID YOU EMPLOY ANY OTHER MODELS WHEN ESTIMATING YOUR ROE RESULTS?

A. Yes. I also use the CAPM as a check on the reasonableness of my DCF results; however, my recommended ROE is not based on my CAPM results. I use the CAPM to estimate a range of ROE results of 8.06% to 11.24%, with a midpoint of 9.65%. This midpoint of CAPM results is 38 basis points greater than my DCF midpoint. As noted, these CAPM results serve as a check on my DCF results to show that my

[7] Most jurisdictions do not permit the inclusion of short-term debt in determining an allowed ROR. However, Pennsylvania does allow its inclusion, and therefore, I find it reasonable for Pike to include short-term debt for the purposes of this proceeding.

recommendation based on the DCF model is reasonable and should be accepted by the Commission.

Q. HAVE YOU PREPARED A TABLE THAT COMPARES PIKE'S REQUESTED ROR TO THE ROR THAT YOU RECOMMEND?

A. Yes. See Table 1 below.

TABLE 1. COMPARISON OF PROPOSED & RECOMMENDED RATES OF RETURN

	PIKE WITNESSES LENNS & LENNS			OCA WITNESS RENO		
	Weight	**Cost of Capital**	**Weighted Cost**	**Weight**	**Cost of Capital**	**Weighted Cost**
Long-Term Debt	40.72%	6.80%	2.77%	40.72%	6.00%	2.44%
Short-Term Debt	8.64%	7.58%	0.66%	8.64%	7.50%	0.65%
Common Equity	50.63%	10.20%	5.16%	50.63%	9.30%	4.71%
Total Capital Structure	100.00%		8.59%	100.00%		7.80%

Amounts may not add up due to rounding.
Source: Exhibit G-2, Schedule

III. MACROECONOMIC AND FINANCIAL MARKET CONDITIONS

Q. WHY IS IT IMPORTANT TO CONSIDER MACROECONOMIC CONDITIONS IN DEVELOPING A RECOMMENDED ROE, COST OF DEBT, AND ROR?

A. I present current and expected macroeconomic conditions in this section to set the context for my ROE, cost of debt, and resulting ROR recommendations to the Commission. With respect to the expected ROE, investors evaluate both economic and monetary conditions when assessing the opportunity costs of their investments. Global, national, and regional economic conditions affect investor expectations regarding investment returns, as measured by stock prices, interest rates, and sustainable dividend growth, each of which serve as inputs I use in my DCF and CAPM analyses. Additionally, investors closely monitor market interest rates and the return on fixed income securities, in particular U.S. Treasury bonds as they weigh alternative investment options when making capital allocation decisions. The cost of new debt issuances is also determined according to the expectations set by bond holders.

Q. HOW ARE INTEREST RATE ON FIXED-INCOME SECURITIES DETERMINED?

A. Interest-rates or bond yields on long-term bonds are determined by investors expectation on economic growth and inflation over the duration of the term of a particular bond. Interest rates on short-term bonds are also determined by these expectations but are largely driven by actions by the U.S. Federal Reserve Bank ("Federal Reserve"), specifically the Federal Open Markets Committee ("FOMC"), by adjusting the Federal Funds Rate (the overnight interest rate it charges commercial banks) and buying or selling U.S. Treasury securities to meet certain policy objectives.

Q. PLEASE ELABORATE ON THE FEDERAL RESERVE'S POLICY OBJECTIVES.?

A. The Federal Reserve has two policy objectives: the first is to maintain full employment or the total amount of employment that the economy can experience without any overt inflationary pressures; and the second, is to maintain a target rate of inflation of 2.0% over the long run.[8] Thus, the Federal Reserve monitors key economic indicators to gauge whether it is necessary to adjust the Federal Fund Rate to influence borrowing

[8] https://www.federalreserve.gov/faqs/economy_14400.htm

behaviors and/or adjust its balance of securities to change the level of money supply in the economy.

Q. WHAT ECONOMIC INDICATORS DO BOTH THE FEDERAL RESERVE AND INVESTORS MONITOR?

A. The Federal Reserve and investors monitor economic indicators including measures of economic growth, such as real Gross Domestic Product ("GDP'), the unemployment rate, and measures of inflation, such as the Consumer Price Index ("CPI"), among others.

Q. HOW WOULD YOU DESCRIBE THE CURRENT STATE OF THE U.S. ECONOMY?

A. In general, economic signals show a slight slowdown in light of stubborn inflation, although inflation remains far lower than in 2022. Recent economic growth, as measured by real GDP, shows that the U.S. economy is slowing down after experiencing a post-COVID-19 pandemic rebound. Although inflation has fallen since it peaked in 2022, inflation is not falling at the rate the Federal Reserve had hoped. Therefore, there remains uncertainty regarding when the Federal Reserve will continue to decrease interest rates after reversing course of its aggressive increases in interest rates in July 2023.

Q. HOW HAS ECONOMIC GROWTH CHANGED SINCE THE COVID-19 PANDEMIC?

A. In 2021, real GDP growth reached an annual high of 6.1%, only to fall to 2.5% in 2022, rebound slightly to 2.9% in 2023 and 2.8% in 2024.[9]

[9] Council of Economic Advisers, "Economic Indicators" (January 2025), at 3.

Q. HOW HAS UNEMPLOYMENT CHANGED SINCE THE COVID-19 PANDEMIC?

A. Unemployment decreased from 5.3% in 2021 to 3.6% in 2022 and 2023. Unemployment has increased slightly to 4.0% in 2024.[10]

Q. HOW HAS INFLATION CHANGED SINCE THE COVID-19 PANDEMIC?

A. Inflation, as measured by the CPI, remains the primary concern in the economy, though it has decreased from its peak of 8.0% in 2022 to 2.9% in 2024.[11]

Q. HOW HAS THE FEDERAL RESERVE RESPONDED TO THESE ECONOMIC TRENDS?

A. Since July 2023, the FOMC has paused its campaign of aggressively increasing the federal funds to dampen stubborn inflationary pressures to reduce the amount of money circulating through the economy and drive down aggregate demand. Since then, the FOMC decreased the federal funds rate on three consecutive times in 2024. In its most recent press release issued on January 29, 2025, the FOMC states that "[r]ecent indicators suggest that economic activity has continued to expand at a solid pace. The unemployment rate has stabilized at a low level in recent months, and labor market conditions remain solid. Inflation remains somewhat elevated."[12] The FOMC continued by stating that although the risks to achieving its goal of maximum employment and 2% inflation are in balance, the economic outlook is uncertain. Thus, the FOMC decided to maintain the current target range for the federal funds rate at 4.25% to 4.50%.[13] The FOMC further stated, "[i]n considering the extent and timing

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[10] Id., at 11.
[11] Id., at 24.
[12] Federal Open Market Committee, Federal Reserve Bank, "Press Release" (January 29, 2025), at 1.
[13] Id.

of additional adjustments to the target range for the federal funds rate, the Committee will carefully assess incoming data, the evolving outlook, and the balance of risks."[14] The FOMC also stated its intention to continue its reduction of holdings of U.S. Treasury securities, agency debt, and agency mortgage-backed securities.[15]

Q. HOW HAVE INVESTORS RESPONDED TO THESE ECONOMIC TRENDS?

A. According to *Value Line Investment Survey* ("*Value Line*"), this continued inflation is weighing on the consumer sector, which has powered the nation's economy the last few years and is now showing signs of fatigue with consumer spending, which fell 0.2% in January.[16] *Value Line* also notes that stock market volatility has picked up in light of continued uncertainty around the Trump Administration's tariff policies that threaten to increase prices in both the consumer and producer sectors and have resulted in stock market sell offs with each announcement.[17]

Q. HOW DO INVESTOR'S EXPECTATIONS INFLUENCE YOUR ROE RESULTS?

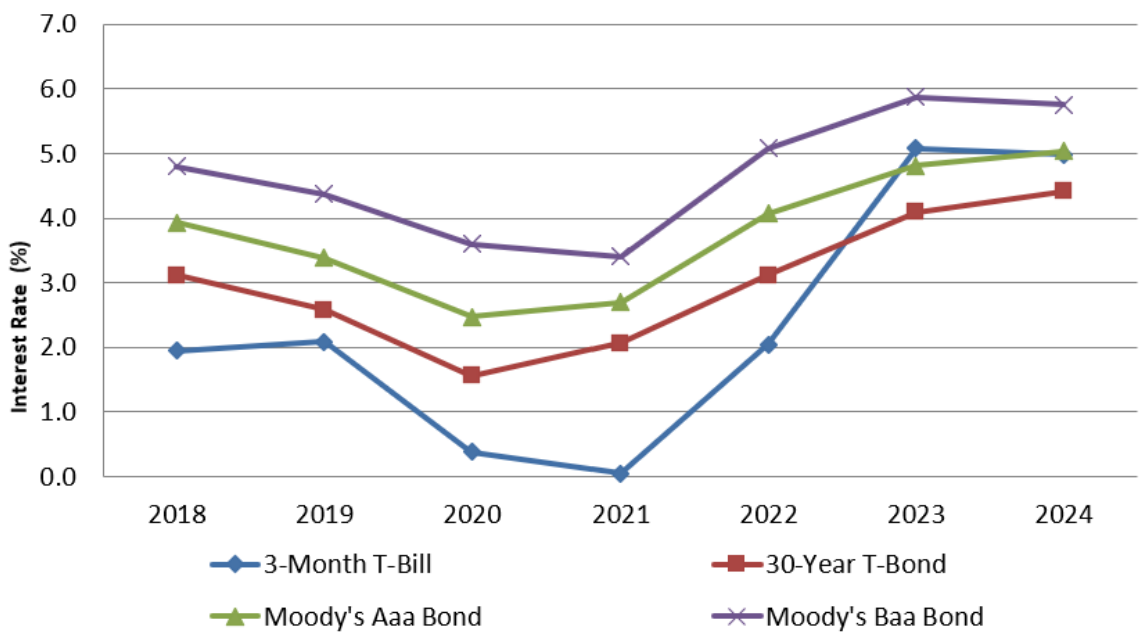
A. Investors consider action of the Federal Reserve and the economic conditions discussed above when estimating the opportunity cost of investing in a share of utility stock, or their expected return on equity in the long run. Thus, in addition to assessing economic growth, unemployment, and inflation, they will consider the yields or the return on fixed-income securities (e.g., interest rates on bonds), in particular interest rates on U.S. Treasury bonds.

[14] Id.
[15] Id.
[16] The Value Line Investment Survey, "Selection & Opinion", Issue 6, (March 14, 2025), at 2429.
[17] Id.

Q. HOW HAVE INTEREST RATES AND INVESTOR EXPECTATIONS CHANGED IN RECENT YEARS?

A. Figure 1 below shows how the interest rates have changed from 2018 to 2024. Yields on short-term Treasury bonds have currently peaked at elevated levels in response to the FOMC's recent actions. Yields on long-term Treasury bonds and corporate bonds also appear to have peaked.

FIGURE 1. INTEREST RATES AND BOND YIELDS (2018-2024)



Schedule MLR-2a (Interest Rates and Bond Yields (2018-2024)).

Yields on long-term bonds (reference the 30-Year Treasury Bond or "T-Bond," shown in red in Figure 1 above) rose from 2.06% in 2021 to 4.41% in 2024.[18] The cost of debt for Moody's Investors Service ("Moody's") Baa-rated corporations peaked in

[18] Council of Economic Advisers, "Economic Indicators" (January 2025), at 30.

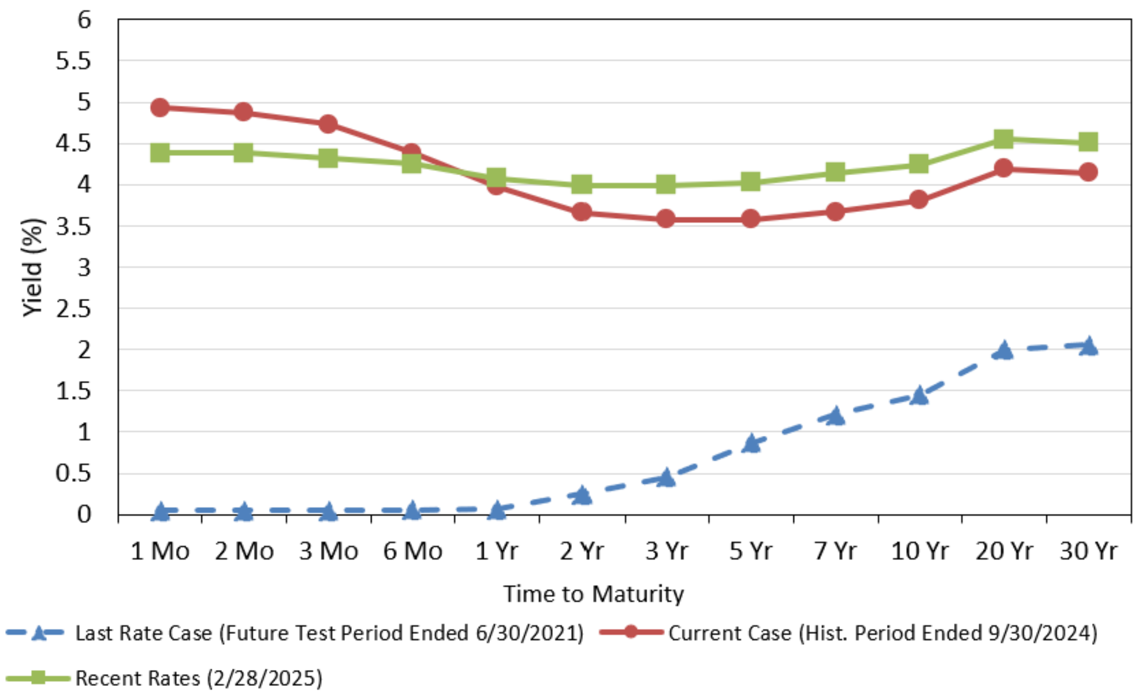
2023 at 5.87% and fell slightly to 5.76% in 2024.[19] Moreover, short-term interest rates (reference the 3-Month U.S. Treasury Bill or "T-Bill," shown in blue in Figure 1 above) rebounded from 0.04% in 2021 to 4.98% in 2024.[20]

Short-term interest rates are primarily determined by the FOMC's policy actions. Recent decreases in short-term interest rates follow the FOMC's decrease in the Federal Funds rate and reduce its holdings of Treasury and agency mortgage-backed securities to increase money supply.[21] Long-term interest rates are primarily determined by market forces, including investor expectations of future levels of inflation and economic growth.

Figure 2 below shows the yields on the different types of T-Bills and T-Bonds, with values along the horizontal axis representing the maturity of each T-Bill or T-Bond and the vertical axis showing the corresponding yield or interest rate. Each line represents the yields associated with each type of asset on a particular date and is referred to by financial analysts as the "yield curve." The yield curve reflects the bond market's consensus opinion of future financial market conditions as investors decide which bill or bond to purchase in response to expected levels of inflation and interest rates.

[19] Id.
[20] Id.
[21] Monetary Policy Report, February 2025

FIGURE 2. TREASURY SECURITY YIELD CURVE



Source: www.treasury.gov

Q. HOW HAS THE YIELD CURVE CHANGED IN RECENT YEARS?

A. It is important to recall the evolution of the yield curve in recent years. During Pike's last rate case which incorporated a future test period ended June 30, 2021, the yield curve was upward-sloping with yields ranging from 0.05% for 1-month T-Bills to 2.06% for 30-year T-Bonds. The yields on short-term T-Bills were near 0% in response to FOMC actions, while the yields on some long-term T-Bonds were increasing slightly.

The shape of the yield curve has since flipped in 2024 and most recently flattened. As shown in Figure 2 below, yields on long-term T-Bonds are lower than the yields on short-term T-Bills as of September 30, 2024. This shows that investors were expecting a sustained economic slowdown and for the FOMC to shift its monetary policy to start decreasing interest rates to avoid an economic slowdown. However, the flattening yield curve for February 28, 2025 shows that yields on longer-term bonds are increasing while yields on short-term T-Bills are falling slightly, which suggests that investors may not be expecting an economic slowdown.

Q. WHAT OTHER MEASURES OF INVESTORS' EXPECTATIONS DO YOU CONSIDER?

A. Another metric by which to gauge investor expectations regarding long-term inflation is the Treasury Inflation-Protected Securities ("TIPS") spread, or the difference between yields on long-term nominal Treasury securities and long-term TIPS. The yield on a long-term conventional Treasury bond pays its holder a fixed nominal coupon and principal to compensate the investor for future inflation, and it includes the real rate of interest and inflation compensation. For TIPS, the coupons and principal both rise and fall with inflation, as measured by the CPI. The published yield includes only the real rate of interest. Therefore, the difference, roughly speaking, between the prevailing yields on these two types of Treasury securities reflects the inflation compensation over that maturity horizon that is expected by bond investors.

The 30-day average difference in the yield on the 30-year T-Bond and 30-year TIPS for the period ended February 28, 2025 equals 2.34% and represents the market's most recent expectations of long-term inflation. In other words, this data confirms that investors are anticipating that the rate of inflation over the long term is expected to stabilize at a higher rate than the FOMC's goal of 2.0%, which may further feed fears that the FOMC may delay interest rate cuts.

Q. WHAT ARE THE EXPECTATIONS FOR THE U.S. ECONOMY IN THE NEAR FUTURE?

A. As the FOMC continues to pause reducing short-term interest rates in response to persistent inflation, forecasters have noted the projections in near-term economic growth are higher than previously forecasted figures. However, the economy is still expected to slow down in the near term and then hover around 2.0% in the longer term. Specifically, according to the Q1 2025 edition of *Survey of Professional Forecasters* published by the Federal Reserve Bank of Philadelphia, economic growth, as measured by real GDP, is expected to decrease from 2.4% during 2025 to 2.2% during 2026 and 1.8% during 2027. Long-run economic growth beyond 2027 is expected to hover near 2.0% in 2028.[22]

Over the next year, inflation is expected to decrease but remain near moderate levels, with the CPI remaining near 2.8% in 2025 and then falling to 2.6% in 2026 and 2.3% in 2027. Another inflation metric closely watched by the FOMC is the Personal Consumption Expenditures ("PCE") index because it represents a broader measure of inflation. The PCE is expected to decrease from 2.4% in 2025 to 2.3% in 2026 and 2.0% in 2027, matching the FOMC's monetary policy goal of inflation. The data also show that analysts expect the national unemployment rate to increase slightly from 4.2% in 2025 and 2026 to 4.3% in 2027 and 2028.[23]

[22] Federal Reserve Bank of Philadelphia, "Survey of Professional Forecasters: First Quarter 2025" (February 14, 2025), at 9 & 11.
[23] Id.

Q. HOW DOES THE PENNSYLVANIA ECONOMY COMPARE TO THE U.S. ECONOMY?

A. Pennsylvania's economy is stronger than the national economy. Pennsylvania's real GDP for the most recent quarter for which data is available (Q3 2024) is 3.9% compared to the national average of 3.2%.[24] Personal income also grew at a faster rate than the national average over the same period, with an increase of 3.9% compared to the U.S. average of 3.2%.[25] Pennsylvania's unemployment rate of 3.6% in 2024 was lower than the national unemployment rate of 4.0%, though the Pennsylvania county of Pike County had a higher unemployment rate at 4.3%.[26]

According to the Federal Reserve Bank of Philadelphia, the regional economy declined slightly in 2025 after edging up in the prior period. Employment continued to grow somewhat, although firms were more reluctant to hire workers amid economic uncertainty. Reported nonauto sales showed little or no change in consumer spending on balance but noted that sales to low-income consumers are trading down as they continue to be burdened by high prices, while auto sales increased slightly.[27]

Q. ARE INVESTORS AWARE OF PENNSYLVANIA'S ECONOMIC CONDITION?

A. Yes. Investors consider local, regional, and national economic conditions when making their investment decisions. For example, investors often compare Pike to its affiliates in other states that have similar or lower credit ratings.

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[24] Bureau of Economic Analysis, "Gross Domestic Product by State and Personal Income by State, 3rd Quarter 2024" (December 20, 2024), available at https://www.bea.gov/news/2024/gross-domestic-product-state-and-personal-income-state-3rd-quarter-2024

[25] Id.

[26] www.bls.gov/news.release/pdf/srgune.pdf and https://fred.stlouisfed.org/series/PAPIKE3URN

[27] Federal Reserve System, "The Beige Book: Summary of Commentary on Current Economic Conditions by Federal Reserve District" (February 2025), at 13-16.

Q. HOW DO INVESTORS VIEW UTILITY STOCKS?

A. In general, investors view utility stocks as a safe investment, especially during times of uncertainty, because of the industry's defensive fundamentals and high dividend yields. Utility stocks are considered defensive by investors because gas service is essential, and utilities are regulated monopolies. *Value Line* reports that the big draw of utility equities is their dividends, which tend to be adequately covered by corporate earnings. As of February 21, 2025, *Value Line* reports that the average yield for the Natural Gas group was approximately 3.6%, compared to the Value Line median of 2.1%. According to *Value Line*, long-term prospects are optimistic due to the abundance of natural gas and steady population growth considering about half of all domestic households use natural gas.[28] Total returns on utility stocks are dependent on investors' expectations of where interest rates will go next and prospects for the economy in general since investors choose these stocks (with low betas) over economically sensitive higher-risk stocks during an economic downturn.

Q. HOW DO INVESTORS' EXPECTATIONS OF AN ECONOMIC SOFT LANDING RELATE TO PIKE'S ROE?

A. As discussed previously in this testimony, despite a slight reprieve in inflation earlier last year, inflation has increased again, causing the Federal Reserve to delay any changes in its monetary policy. Persistent high interest rates are contributing to lower economic growth. Although the stock market performed well throughout 2024, investors seem to be anxious about when the FOMC will resume decreasing interest rates. Furthermore, investors are growing weary of the uncertainties regarding the Trump Administration's tariffs on imports across many goods from multiple

[28] Value Line Investment Survey, "Natural Gas Utility" (February 21, 2025), at 535.

countries—inducing fears of yet higher inflation and plummeting consumer confidence. Given this uncertainty, investors may choose more defensive stocks, such as utility stocks, that typically have a lower expected return compared to higher-risk stocks. This trend is demonstrated by my cost of equity study estimates.

IV. CAPITAL STRUCTURE

Q. WHAT IS MEANT BY THE TERM "CAPITAL STRUCTURE"?

A. Capital structure refers to the relative percentage of equity, preferred stock, and debt that a company uses to finance its investments.

Equity (or common equity) represents ownership in a company and its investments. It includes common stock, retained earnings, and additional paid-in capital. Equity financing is more expensive than debt financing for two reasons. Because companies have a legal obligation to pay debt before equity, stockholders expect a higher return to compensate for this risk. In addition, returns on equity (or dividends) are not tax deductible as a business expense like a company's interest payments on debt.

Preferred stock is a type of stock that offers greater benefits than common equity. Preferred stockholders receive a fixed dividend and have priority for payment over common stockholders.

Debt represents liabilities on a company's books that must be repaid prior to any common or preferred stockholders receiving a return on their investment. Corporate debt generally includes two time horizons: (1) long-term debt that matures over a period of more than one year; and (2) short-term debt that matures within one year.

Q. HOW IS A UTILITY'S TOTAL RATE OF RETURN CALCULATED?

A. The total rate of return is composed of the weighted costs of long-term debt and equity capital. Long-term debt costs are typically computed using the utility's actual debt costs as of a certain date, such as the last day of the test year. In some jurisdictions, such as Pennsylvania, short-term debt is typically included in the capital structure for ratemaking purposes. Unlike the debt components of the capital structure, equity cost rates must be estimated.

The utility's total ROR is developed by multiplying the percentage of each type of financing (common equity, long-term debt, and short-term debt) by their specific cost rates and then totaling the results for a total after-tax ROR. This rate is then converted to pre-tax returns by grossing up the common equity and the preferred stock dividends for taxes. The final pre-tax return is then multiplied by the utility's rate base to determine the amount of money that customers must pay to the utility for the return on investment and associated tax payments.

Q. HOW DOES THE CAPITAL STRUCTURE IMPACT THE TOTAL RATE OF RETURN?

A. The cost of equity is generally higher than the cost of debt, so ratepayers bear higher costs when the utility finances more of its rate base investment using common equity and preferred stock. As explained above, stockholders expect a higher return because companies are contractually obligated to repay their debt where no such obligation exists for equity. Additionally, equity is also more expensive than debt because debt financing is tax deductible while stock dividend payments are not. Thus, if a utility is allowed to use a capital structure for ratemaking purposes that has more equity than debt, ratepayers also pay a higher tax burden.

Q. HOW DO INVESTORS VIEW THE CAPITAL STRUCTURE?

A. On the one hand, investors may view a high reliance on debt as risky (referred to as financial or leverage risk) because debt has priority of payment over equity. Given that creditors must be paid before investors, a company's relatively high debt burden can lead to a higher required ROE relative to similar investment opportunities to accommodate the higher risk. On the other hand, excessive equity, while reducing financial risk for an enterprise's creditors and investors, increases the overall cost of capital (and therefore return on rate base), which must be recovered through rate for customers (giving rise to investor concern over affordability of utility rates in the context of macroeconomic inflation conditions).

Q. WHAT CAPITAL STRUCTURE IS PIKE REQUESTING FOR USE IN THIS CASE?

A. For the FTY ending September 30, 2025, Pike is proposing a capital structure of 50.63% common equity, 40.72% long-term debt, and 8.64% short-term debt.[29] This capital structure includes new financed long-term debt that Pike issued on September 12, 2024, with its parent entity, Corning Energy Corporation ("CEC"), in the amount of $17.584 million at a coupon rate of 6.31%. This capital structure also includes the daily short-term debt balance for the 12 months ended September 30, 2024 of $2,006,792 as a proxy for the short-term debt balance for the FTY.

Q. WHAT IS PIKE'S CURRENT CAPITAL STRUCTURE?

A. Pike's actual capitalization for the historical period ended September 30, 2024 is 44.69% long-term debt, 5.10% short-term debt, and 50.21% equity.[30]

[29] Lenns and Lenns Direct, at 21-24 and Exhibit G-2, Schedule 3. The test period is October 1, 2023 through September 30, 2024.

[30] Exhibit MLR-3 (Pike Response to OCA Interrogatory 5-3 Supplemental Attachment Corning Energy Corporation Capitalization Structure).

Q. HOW HAS PIKE'S CAPITAL STRUCTURE CHANGED SINCE THE LAST RATE CASE?

A. Pike's equity ratio has gradually increased since the last rate case from 47.17% for year ended September 30, 2022 to 47.97% for the year ended September 30, 2023 and 50.21% for the year ended September 30, 2024.[31]

Q. WHY IS THIS INCREASE IN THE EQUITY RATIO OVER THE LAST THREE YEARS A CONCERN?

A. As noted above, as Pike's equity ratio increases, the financial burden on ratepayers increases because the cost of common equity is higher than the cost of long-term debt. In addition, dividend payments associated with equity must be made with after-tax funds, which are more expensive than pre-tax funds.

Q. SHOULD THE COMMISSION ACCEPT PIKE'S PROPOSED CAPITAL STRUCTURE?

A. Yes, subject to my concern about Pike's claimed ROR and my further recommendation discussed below. Pike's proposed equity ratio of 50.63%, based on the FTY, is reasonable for determining its capital structure in the current proceeding. Pennsylvania precedent allows utilities to base their equity ratios on a FTY. However, I have significant concerns regarding the reasonableness of Pike's proposed ROR, and a higher equity ratio further amplifies these concerns.

I further recommend that Pike's proposed FTY equity ratio of 50.22% be established as a maximum. The Commission should require Pike to actively manage its capital structure to prevent further increases in the equity ratio in future years.

[31] Id.

Q. WHY SHOULD THE COMMISSION ACCEPT PIKE'S PROPOSED CAPITAL STRUCTURE.

A. Pike's proposed equity ratio of 50.63% falls below the range of annual average equity ratios approved by regulatory commissions for regulated gas utilities since 2020, which are in the range of 50.94% to 52.45% (as shown in Figure 3 below).[32] For example, the average equity ratio approved by regulatory commissions for regulated gas utilities was 52.45% in 2023 and 52.13% in 2024.[33]

However, Pike's proposed equity ratio of 50.63% exceeds the proxy group average of 45.50% and median of 45.50% that is expected for 2025.[34]

[32] S&P Global Market Intelligence, "RRA Regulatory Focus - Major Energy Rate Case Decisions in the US January – December 2024" (February 4, 2025), at 6-7.

[33] Id.

[34] Schedule MLR-4 (Sample Characteristics).

FIGURE 3. AVERAGE AUTHORIZED EQUITY RATIO

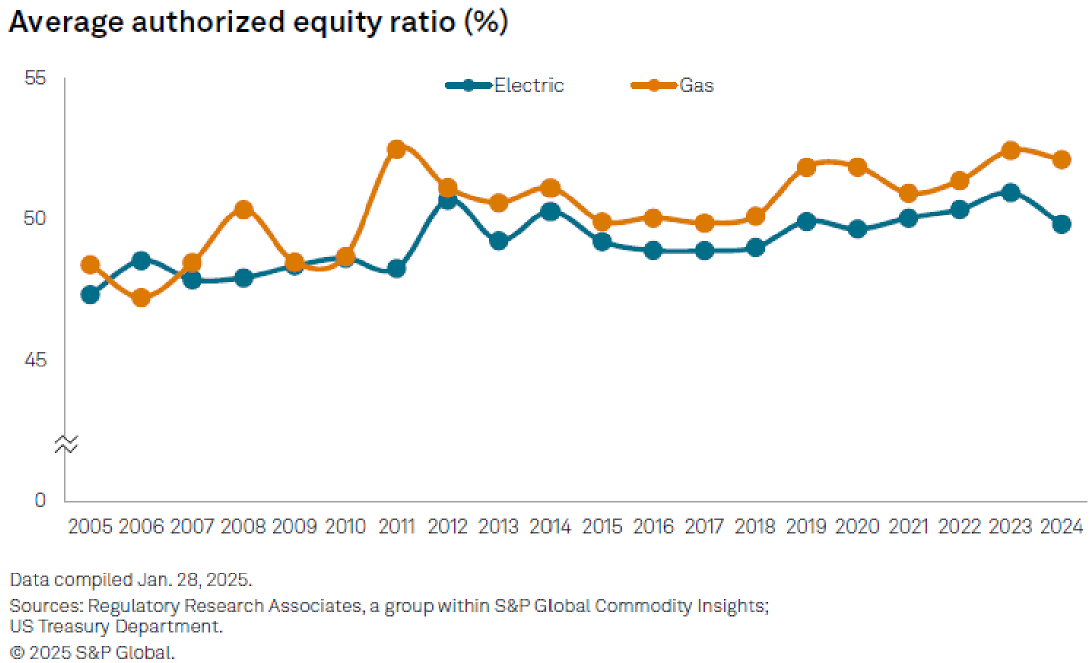

Exhibit No.___(MLR-??) (S&P Global Market Intelligence ("S&P MI"), "RRA Regulatory Focus - Major Energy Rate Case Decisions in the US – January – December 2024" (February 4, 2025)) at 7.

Additionally, Pike's proposed equity ratio of 50.63% far exceeds the 25.73% equity ratio of its parent company, CEC.[35] The Commission needs to be aware that CEC would benefit from double leveraging, in which a parent company issues debt and then infuses that debt into the regulated subsidiary as common equity.

Q. PLEASE EXPLAIN THE CONCEPT OF DOUBLE LEVERAGE.

A. Double leverage occurs when a utility parent company issues debt and then infuses that debt into the regulated subsidiary as common equity. CED as the holding company wholly owns the regulated utility subsidiary, Pike, and itself does not offer utility services. The purpose of the parent company issuing debt and infusing it into the utility subsidiary is to reduce costs to the parent company at the expense of the subsidiary's

[35] Exhibit MLR-3 (Pike Response to OCA Interrogatory 5-3 Supplemental Attachment Corning Energy Corporation Capitalization Structure).

ratepayers because equity is more expensive than debt. Also, equity is grossed up for taxes, such that the costs that CEC can collect from Pike, as the subsidiary, are far greater than the cost of issuing the debt.

V. COST OF DEBT

Q. WHAT DOES PIKE PROPOSE AS THE COST OF LONG-TERM DEBT?

A. Pike's proposed cost of long-term debt of 6.80% is the Company's embedded cost of debt for the FTY ended September 30, 2025, which is comprised solely of the $17.584 million intercompany loan from CEC to Pike, as refinanced on September 12, 2024, at a two-tranche blended rate of 6.31%.[36]

Q. DO YOU CONSIDER THE COMPANY'S REQUESTED OVERALL COST OF LONG-TERM DEBT REASONABLE?

A. No. Pike's management had multiple opportunities to refinance its long-term debt in prior years when interest rates for BB- credits were significantly lower than 6.80%.

As shown earlier in Figure 1, interest rates followed a downward trajectory from 2018 through 2021 before experiencing a sharp increase. Pike's management had the option to refinance its long-term debt during this period but chose not to do so. This was a management decision, and it would be unreasonable for ratepayers to bear an undue cost burden due to Pike's delayed refinancing.

Pike only recently refinanced its long-term debt in 2024. Although interest rates have declined from their 2023 peak, they remain relatively high compared to historical values, as previously illustrated in Figure 1. For instance, current market rates for

[36] Lenns and Lenns Direct, Exhibit G-2; Schedule 2.

Moody's Baa-rated corporate bonds are around 6.00%, which is still lower than the 6.80% rate Pike is proposing as a reasonable cost of long-term debt in this proceeding.[37]

Q. DO YOU RECOMMEND THAT THE COMMISSION ACCEPT PIKE'S REQUESTED COST OF LONG-TERM DEBT?

A. No. The Company's proposed cost of debt of 6.80% is unreasonably high, primarily due to Pike's management decisions regarding the handling of long-term debt refinancing. Given the current financial circumstances, this rate is not justified.

Q. WHAT IS YOUR PROPOSED COST OF LONG-TERM DEBT LEVEL FOR PIKE IN THIS PROCEEDING?

A. I propose a 6.00% cost of long-term debt as a reasonable rate for Pike in this proceeding, as this reflects the current (2025) average interest rate for Moody's Baa-rated corporate bonds.[38]

Historical data shows that the cost of long-term debt for Moody's Baa-rated corporations was 4.80% in 2018, 4.37% in 2019, 3.60% in 2020, 3.40% in 2021, and 5.08% in 2022, peaking at 5.87% in 2023, before slightly declining to 5.76% in 2024 and at about 6.00% currently.[39]

Pike's management had the opportunity to refinance its long-term debt between 2018 and 2022 at lower interest rates but chose not to do so. Given this, the current cost of long-term debt for Moody's Baa-rated credits serves as an appropriate proxy for Pike's cost of debt and should be adopted by the Commission.

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[37] Exhibit MLR-1, Schedule MLR-3 (Survey of Professional Forecasters).
[38] Id.
[39] Exhibit MLR-1, Schedule MLR-2a (Interest Rates & Bond Yields (2018 to 2024)).

Q. WHAT DOES PIKE PROPOSE AS THE COST OF SHORT-TERM DEBT?

A. Pike's proposed cost of short-term debt of 7.58% is the Company's cost on its short-term line of credit currently in effect.

Q. DO YOU RECOMMEND THAT THE COMMISSION ACCEPT PIKE'S REQUESTED COST OF SHORT-TERM DEBT?

A. No. The Company's proposed cost of short-term debt of 7.58% is unreasonably high; given the current financial circumstances, this rate is not justified. For instance, the current Prime interest rate is 7.50%.[40] This rate is used by commercial banks to determine interest on consumer loans, credit cards, and mortgages. Since a regulated utility has a less risky credit profile than a typical homebuyer, I use the Prime interest rate as a cap on the interest rate for short-term debt.

VI. RETURN ON EQUITY

Q. HOW DO YOU DETERMINE THE ROE FOR A REGULATED UTILITY?

A. For ratemaking purposes, the cost of equity must be estimated because it cannot be directly observed, and it varies with changing expectations of financial market conditions. The cost of equity is the long-term annualized market return that investors (in general) expect when they purchase equity shares of a particular company. It reflects the risk factors of that investment as compared to alternative investment opportunities and investors' current opportunity cost of investing in the securities of that company (i.e., the investors' risk-adjusted alternatives).

Because Pike is a wholly-owned subsidiary of Corning Energy Corporation, which is 100% owned by ACP Crotona Corporation, and is not a publicly traded

[40] Prime Rate | Federal Funds Rates Discount Rate Fed Fund Reserve Lending COFI

company, it is not possible to directly apply cost of equity models to the Company. As an alternative, I calculate an estimate of Pike's cost of equity by deriving average expected market returns for a proxy group of regulated gas utility companies with comparable risk.

Q. DID YOU CHOOSE THE COMPANIES INCLUDED IN YOUR PROXY GROUP?

A. Yes. However, I decided to use the gas utility proxy group listed in the TUS QE Report Ended June 30, 2024 for consistency given that Pike relies on that report for its proposed ROE.

Q. HOW DID YOU CHOOSE THE COMPANIES FOR YOUR UTILITY PROXY GROUP?

A. For my gas utility proxy group, I began with a group of 11 gas utilities that are publicly traded and included in *Value Line*. I then apply a series of criteria for my utility proxy group, which includes companies that have not publicly announced involvement in any major merger or acquisition activity; companies that have not cut or omitted their common dividends during the last six months; companies that are consistently covered by at least two utility industry equity analysts; and companies that have investment grade senior unsecured bond and/or corporate credit ratings (an S&P rating of BBB- or higher). After applying these criteria, I compiled a utility proxy group comparable to the proxy group used in the TUS QE Report Ended June 30, 2024.

Q. PLEASE DESCRIBE PIKE AND ITS OPERATIONS.

A. Pike is an electric and gas utility that provides electric service to approximately 4,900 customers and natural gas to 1,300 customers in eastern Pike County, Pennsylvania.

Pike was acquired by CEC in 2016 from Orange & Rockland Utilities, Inc., a local utility company owned by Consolidated Edison.[41]

Q. PLEASE DISCUSS THE DIFFERENT TYPES OF RISK THAT A REGULATED MONOPOLY, SUCH AS A GAS UTILITY, MAY FACE.

A. An investor's expected return on an investment is composed of the risk-free rate and different types of risk, to include inflation risk, interest rate risk, business risk, financial risk, and regulatory risk.

The risk-free rate is the level of return investors can achieve without assuming any risk. In general, most investors agree that a Treasury bond is an asset perceived by the market as having relatively less risk than other market instruments because the federal government's access to tax proceeds to fulfill its debt obligations and strong credit rating make Treasury securities practically default-free. However, Treasury bonds are not absolutely risk-free because they incorporate a risk premium associated with interest rate risk. This is the premium investors require to compensate them for the foregone opportunity cost of an alternative, higher interest rate later.

From an investor's perspective, inflation risk, also called purchasing power risk, is the chance that the cash flows from an investment will not be worth as much in the future because of changes in purchasing power due to inflation.

Interest rate risk is the risk that arises for investors from the variability in returns caused by fluctuating interest rates, which depends on how sensitive an asset's price is to interest rate changes in the market. For bonds, for example, their price sensitivity to interest rates depends on the bond's time to maturity and the coupon rate of the bond.

[41] CEC was acquired by Argo Infrastructure Partners, LP in July 2022. Argo Infrastructure Partners, LP is an independent infrastructure investment manager that invests in industries such as regulated utilities, energy, renewables, and transportation. Corning Energy Corporation: Unpublished Rating Report, KBRA Corporates, issued by Kroll Bond Rating Agency, LLC (September 12, 2024), at 4.

Business risk, as perceived by investors, includes all the operating factors that increase the probability that expected future cash flows accruing to investors may not be realized. Business risk would include such factors as sales volatility and operating leverage. A utility's business risk is a function of factors such as customer base diversity, necessary capital expenditures, the regional and national economy, and the regulatory environment in which the utility operates.

Financial risk relates to the capital structure of a company, including its fixed contractual obligations and ability to pay interest on its debt and refinance that debt when it is due. Credit-rating agencies assess the financial health of a company through the use of key financial ratios that measure the extent to which a company can pay its debt, including principal and interest. Corporate rating designations that are commonly used are shown later in Table 2 of my testimony, which identifies rating categories used by S&P, Fitch, and Moody's for investment-grade issuances.

One of the key financial ratios used by credit-rating agencies is the debt ratio. The higher the portion of the capital structure that is comprised of debt or leverage, the higher the risk of default on those debt obligations.

Regulatory risk is based on the investor's perceived understanding of the current regulatory environment along with possible changes to that regulatory environment. How regulators treat regulatory lag is one example of regulatory risk. To the extent that companies face a time lag between incurring expenses and cost recovery, such risk is best measured by choosing a proxy group of companies that face similar regulatory oversight and earn the majority of their revenues from regulated operations.

A. INFLATION RISK

Q. IN YOUR VIEW, DOES PIKE FACE GREATER INFLATION RISK THAN OTHER REGULATED UTILITIES IN THE PROXY GROUP?

A. No. The risks associated with current inflation trends, which have decreased from a CPI of 8.0% in 2022 to 2.9% in 2024,[42] are shared by all regulated utilities and, as a result, are reflected in the utility proxy group's calculated costs of equity.

B. INTEREST RATE RISK

Q. IN YOUR VIEW, DOES PIKE FACE GREATER INTEREST RATE RISK THAN OTHER REGULATED UTILITIES IN THE PROXY GROUP?

A. Yes. Since changes in interest rates affect borrowing costs, the effect of such risk depends on the company's credit rating and portion of debt to total financial capital compared to the proxy group. As I discuss in greater detail in the financial risk section below, since Pike is not credit-rated and receives debt and equity funding through its parent company, CEC, the relevant comparison is CEC's credit rating. CEC has a lower credit rating than the average of the proxy group. Thus, Pike faces higher debt cost when issuing new debt compared with the debt costs incurred by one of the proxy group companies, on average.

[42] Exhibit MLR-1, Schedule MLR-1.

C. BUSINESS RISK

Q. HOW DO CREDIT-RATING AGENCIES VIEW UTILITIES IN TERMS OF BUSINESS RISK?

A. Kroll Bond Rating Agency ("KBRA") characterizes CEC and its subsidiaries, including Pike's, business risk as "average" with the subcategory of industry risk considered "strong." KBRA reports that "The essential nature of the services provided and the nature of the regulatory protection in which the utility companies are granted natural monopolies with little competition in their service territories. In addition, the regulatory environment is typically supportive, allowing utility companies the opportunity to recover and earn a rate of return based on the costs to provide services."[43] KBRA also notes that CEC and Pike's competitive risk is considered "average" because "the company's monopolistic position through the ownership of regulated utilities operations, offset by its limited corporate scale and market share and concentrated customer base."[44]

Q. HOW DOES KBRA VIEW PIKE'S JOINT OPERATIONS IN THE GAS AND ELECTRIC UTILITY SECTORS?

A. KBRA looks favorably on Pike's diversified operations in both the distribution-only electric services and natural gas sectors, with both segments benefiting from long-term contracts for supply and a constructive regulatory environment, which I will discuss in greater detail later in this section. KBRA addresses Pike's long-term natural gas contracts and close proximity to the Marcellus gas fields as factors reducing Pike and

[43] Exhibit MLR-4 (Pike Response to OCA Interrogatory OCA 5-17 Supplemental Attachment Corning Energy Corporation: Unpublished Rating Report, KBRA Corporates, issued by Kroll Bond Rating Agency, LLC (September 12, 2024)), at 6.
[44] Id.

its affiliates' exposure to industry risk.[45] KBRA also notes that CEC and Pike's natural gas operations continue to grow as customers continue to switch to natural gas and the Commission remains supportive of natural gas use, while Pike affiliates in New York face challenges since the New York Public Service Commission has shifted its focus to the transition toward renewable energy sources.[46]

Q. IN YOUR VIEW, DOES PIKE FACE GREATER BUSINESS RISK THAN OTHER REGULATED UTILITIES IN THE PROXY GROUP?

A. No. The fundamental comparison here is to the proxy group. Every utility is different, but I do not believe that Pike has greater business risk than its peers in the proxy group.

D. <u>FINANCIAL RISK</u>

Q. IN YOUR VIEW, DOES PIKE FACE GREATER FINANCIAL RISK THAN OTHER REGULATED UTILITIES IN THE PROXY GROUP?

A. No. Pike faces similar financial risk compared to the proxy group. Although Pike acquires financing through its parent company, CEC, which has a lower credit rating than the proxy group, Pike's lower debt ratio relative to the proxy group reduces its financial risk. According to KBRA, CEC has an issuer credit rating of BB/Stable; a Series A Senior Secured Notes rated at BBB-/Stable; and a Series B Senior Secured Notes rating of BBB-/Stable.[47] In Pike Response to OCA Interrogatory Set 9, No. 4, the Company confirmed that the KBRA credit-rating scale is comparable to the credit-rating scale assigned by S&P.[48] Although CEC's ratings are lower than the median for the proxy group, which is an S&P rating of A-/BBB+ and a Moody's rating of A3/Baa1,

[45] Id., at 8.
[46] Id., at 10.
[47] Id., at 3.
[48] Exhibit No. MLR-3 (Pike Response to OCA Interrogatory 8-3).

KBRA classifies CEC liquidity and financial risk as average because CEC's liquidity and cash flow profile is sufficient to meet its ongoing obligations. "The company [CEC]'s liquidity position is expected to benefit from the reimbursement of prudently managed costs and capital expenditures."[49] See Table 2 below for a comparison of CEC's credit ratings compared to the proxy group. Note that the proxy group median ratings are highlighted.

Table 2. Rating Categories
(Investment Grade)

S&P and Fitch	Moody's
AAA	Aaa
AA+	Aa1
AA	Aa2
AA-	Aa3
A+	A1
A	A2
A-	A3
BBB+	Baa1
BBB	Baa2
BBB-	Baa3

[49] Exhibit MLR-4 (Pike Response to OCA Interrogatory 2-11: Supplemental Attachment Corning Energy Corporation: Unpublished Rating Report, KBRA Corporates, issued by Kroll Bond Rating Agency, LLC (September 12, 2024)), at 6.

Q. DOES THE CAPITAL STRUCTURE OF PIKE INDICATE THAT IT IS EXPOSED TO LESS FINANCIAL RISK THAN OTHER MEMBERS OF THE PROXY GROUP?

A. Yes. Pike's current capital structure of 44.69% long-term debt and 5.10% short-term debt (totaling 49.79%) is lower than the utility proxy group's average debt-to-total-capital ratio average of 50.69% and median of 53.50%, meaning that Pike faces lower financial or leverage risk than the proxy group.[50]

E. REGULATORY RISK

Q. IN YOUR VIEW, DOES PIKE FACE GREATER REGULATORY RISK THAN OTHER REGULATED UTILITIES IN THE PROXY GROUP?

A. No. Pike does not face greater regulatory risk than the proxy group. Pennsylvania has a regulatory ranking of "Above Average/2", according to S&P Market Intelligence, which is the second highest rating of "Above Average/1" and outranked by only Alabama.[51] In a more recent publication by Regulatory Research Associates ("RRA"), (a division of S&P Market Intelligence), RRA states that, "RRA views the regulatory climate for energy utilities in Pennsylvania to be relatively constructive from an investor standpoint…"[52] RRA continues by stating that the Commission allows utilities to employ a series of ratemaking practices meant to reduce regulatory lag, such as recovering costs using a forward-looking test year and year-end base valuations. The Commission also permits utilities to employ a series of rate mechanisms meant to recover costs in between general rate cases. Moreover, RRA notes that almost all the

[50] Exhibit MLR-1, Schedule MLR-4 (Sample Characteristics); and Exhibit MLR-3 (Pike Response to OCA Interrogatory 5-3 Supplemental Attachment Corning Energy Corporation Capitalization Structure).

[51] S&P MI, "RRA State Regulatory Evaluations – Energy" (January 2025), at 3.

[52] S&P MI, "Regulatory Research Associates: Focus Notes" (February 18, 2025) at 9-11

cases decided since the 1990s have been resolved by black box settlements that do not disclose the settled ROE or rate of return.

Q. PLEASE ELABORATE ON HOW A FUTURE TEST YEAR REDUCES REGULATORY LAG AND, ULTIMATELY, RISK.

A. A future test year allows a utility to forecast costs forward into the first full year when the proposed new rates will be in effect so that rates can be matched to costs. It significantly reduces regulatory lag, which is the time between when a utility incurs increases in costs and when it recovers costs through increases in rates.

Q. HOW DOES REDUCING REGULATORY LAG REDUCE REGULATORY RISK?

A. Reducing the time or "lag" in between rate cases or when costs increase helps mitigate regulatory risk in several ways: It allows utilities to better align their revenues with current operating expenses, which in turn improves cash flow and enhances financial stability. By enabling more timely cost recovery, reducing lag also lowers uncertainty for investors, increasing the likelihood that a utility will achieve its authorized ROE without delay. Additionally, when rates more accurately reflect contemporaneous operating conditions, a utility can more effectively manage its expenses and maintain a sound financial position, ultimately reducing financial risk.

Q. HOW DO INVESTORS PERCEIVE THE USE OF FUTURE TEST YEARS?

A. Investors consider this type of test year to reduce regulatory risk, particularly in periods where there is a robust level of capital spending, high inflation, and rising interest rates.[53] S&P MI reports that less than a quarter of states allow a future test year.[54]

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[53] S&P MI, "RRA State Regulatory Evaluations – Energy, Regulatory Research Associates" (May 24, 2023) at 18.

[54] *Id.*

Q. IS THE REDUCTION IN REGULATORY RISK ASSOCIATED WITH A FUTURE YEAR ALREADY INCORPORATED IN YOUR ROE ESTIMATES?

A. No. I use the gas utility proxy group shown in the TUS QE Report Ended June 30, 2024, which includes utilities from across the country. As noted above, less than a quarter of states allow the use of future test years, so Pike's regulatory risk is arguably lower than the proxy group.

Q. DOES PIKE HAVE ANY RATE MECHANISMS THAT CAN IMPROVE COST RECOVERY IN BETWEEN RATE CASES?

A. Yes. Pike has a series of rate mechanisms or adjustment clauses that allow it to recover associated costs in between cases, thereby reducing recovery lag and regulatory risk. Such mechanisms also reduce business risk because they provide more predictable earnings and consistent cash flow than otherwise. These rate mechanisms include the Gas Cost Rate, State Tax Adjustment Surcharge, and DSIC.[55]

Q. PLEASE EXPLAIN THE PURPOSE OF THE GAS COST RATE.

A. The purpose of the gas cost rate is to recover the costs associated with supplying gas to customers. It ensures that the company can cover the expenses incurred in purchasing and delivering gas, and it is adjusted annually or on an interim basis to reflect changes in these costs.[56] This charge essentially shifts the risk associated with market price swings onto customers.

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[55] Exhibit MLR-6 (Pike Response to OCA Interrogatory 5-6).
[56] Id.

Q. WHAT IS THE PURPOSE OF THE STATE TAX ADJUSTMENT SURCHARGE.

A. The State Tax Adjustment Surcharge is recomputed whenever Pike experiences a material change in any of the taxes used in calculating the surcharge.[57]

Q. WHAT IS THE PURPOSE OF THE DSIC?

A. The DSIC is a surcharge that appears on consumer bills as a line item and that is used to recover the reasonable and prudent costs incurred by the utility to repair, improve, or replace eligible property that is placed in service in between rate cases, subject to certain consumer protections. The DSIC permits Pike to recover eligible costs in between general rate cases and allows Pike to accelerate the replacement of aging infrastructure.[58]

Q. ARE THE ABOVE-REFERENCED RIDERS CURRENTLY IN EFFECT?

A. Yes.

Q. IS PIKE PROPOSING ANY NEW RATE ADJUSTMENT MECHANISMS IN ITS FILING IN THIS CASE?

A. Yes. Pike is seeking Commission approval for a Weather Normalization Adjustment ("WNA") Mechanism, which would adjust a customer's bill when there are variations in rates from set rates due to deviations in weather (i.e., temperature variations or heating degree day variations) from normal weather patterns that are used to set rates. This WNA would adjust current billings on a monthly billing basis as the bill is being calculated and would be applied to residential customer bills issued for the months of October through May.[59].

[57] Id.
[58] Id.
[59] Lenns and Lenns Direct, at 16.

Q. DO THESE RATE MECHANISMS REDUCE PIKE'S REGULATORY RISK?

A. Yes. Because the recovery in between rate cases is guaranteed for prudently incurred expenses, Pike's regulatory risk is comparable to the regulatory risk of other utilities in its proxy group.

Q. HOW DO INVESTORS VIEW THESE RATE MECHANISMS?

A. Investors view these rate mechanisms favorably because they reduce regulatory lag. As discussed above, S&P MI considers these rate mechanisms as constructive, but also looks at the frequency with which the adjustments occur and whether there is a true-up mechanism. S&P MI addresses the DSIC mechanism in particular as contributing to Pennsylvania's "Above average/2 rating," because it allows utilities to update rates for incremental infrastructure capital investment as often as quarterly.[60]

VII. <u>ROE METHODOLOGIES</u>

Q. WHAT METHODOLOGIES DO YOU USE TO DERIVE YOUR COST OF EQUITY RECOMMENDATION?

A. I use the Constant-Growth DCF model to form the basis of my recommendation of a 9.30% ROE, which is the rounded midpoint (9.27%) of the range of my DCF results for Pike. My recommendation is further supported by the average of the results of my CAPM analyses of 9.65%, which is within the range of my DCF results, demonstrating the reasonableness of my DCF analysis.

[60] S&P MI, "RRA Regulatory Focus Notes: Pa. regulators raise electric, waters' proxy equity returns" (February 10, 2025).

Q. WHAT IS THE PREDOMINANT ROE MODEL UTILIZED BY REGULATORY BODIES IN THE UNITED STATES?

A. For decades, the FERC and public utility commissions across the United States, including Pennsylvania, have relied primarily on the DCF model to develop a range of returns earned on investments in companies with corresponding risks for purposes of determining the ROE for regulated entities.[61] Although I use variants of the Constant-Growth DCF model and the CAPM, I rely on my Constant-Growth DCF to form the basis of my recommendation of a 9.30% ROE for Pike.

A. CONSTANT-GROWTH DISCOUNTED CASH FLOW MODEL

Q. PLEASE DESCRIBE THE CONSTANT-GROWTH DCF MODEL.

A. The Constant-Growth DCF model is based on the dividend discount model first proposed by J.B. Williams in 1938.[62] The model is based on the premise that since cash dividends are the only income from a share of stock held to infinity, the value of that stock will be the present value of its stream of dividends, where the discount rate is the market's required return. The model can be modified to take into account the (more common) situation whereby shares of stock are bought and sold, producing capital gains income in addition to dividend income. To simplify the mathematics of the model, expected future dividends are represented by applying a constant-growth rate to the current observable dividend. Mathematically, the present value of an asset (common stock) is expressed as:

$$P_0 = \frac{D_1}{(K-g)},$$

[61] S&P MI, ", RRA Regulatory Focus, FERC and Electric ROEs – 2022 Update" (September 26, 2022, at 3.

[62] J.B. Williams, *The Theory of Investment Value* (1938), at 45-48.

Where:

D_1 is the dividend payment in one year from today or the expected dividend;
K is the rate of return used by investors to discount future dividends; and
g is the growth rate of the dividend payment.

The estimated cost of equity, K, is specified as:

$$K = \frac{D_1}{P_0} + g \,,$$

Where:

D_1 is the expected dividend, represented by $D_1 = D_0\,(1 + g)$

Where:

D_0 is the current annual dividend per share.

Therefore, the market ROE capital is the sum of the dividend yield (anticipated dividend payments divided by the market price) and the expected growth in dividend income.

Q. PLEASE DESCRIBE HOW YOU DERIVE THE DIVIDEND YIELD COMPONENT OF YOUR DCF ANALYSIS.

A. The dividend yield in my DCF analysis is the annual dividend per share over the next 12 months, divided by the stock price average for different historical periods ended February 28, 2025. I first calculate the dividend yields using the 30-calendar day average of closing stock prices. I also use a 90-calendar day average of closing stock prices for capturing longer market trends.

In general, the most recent price of a security can be used to calculate the dividend yield because it represents current valuations in equity markets, calculating an average over time to mitigate any irregularities as necessary. However, using the average of a range of dates (e.g., 30 and 90 days) helps reduce the bias that might occur from day trading-driven irregularities or short-term volatility. The average 30-calendar day stock price for the proxy group is $77.19 per share, which is more than the 90-calendar day average stock price of $75.73 per share.[63]

I then estimate the expected dividend yield by applying the growth rate component of my Constant-Growth DCF analysis. I use three variants for calculating the growth rate component which I will discuss later in my testimony. These methods produce a range of expected dividend yields from 3.50% to 3.59% using the proxy group.[64]

Q. DO YOU MAKE ANY FURTHER ADJUSTMENTS TO YOUR EXPECTED DIVIDEND YIELD?

A. Yes. I adjust the dividend yield by one-half the expected growth to reflect growth over the coming year. Since I use annualized dividends, I make this adjustment to account for the fact that companies tend to announce changes in dividends at different times throughout the year.

Q. PLEASE DESCRIBE THE GROWTH RATE COMPONENT OF YOUR DCF ANALYSIS.

A. My first set of growth rates is based on published earnings per share ("EPS") forecasts because investors typically view earnings growth as an indicator of future dividend growth. Investors also incorporate other sources of information when setting their expectations of dividend growth, which I will discuss shortly.[65]

I calculate the estimated earnings growth rates by taking the average of analysts' forecasts (which typically cover roughly the next five years) from *Value Line*,

[63] Exhibit MLR-1, Schedule MLR-5a through Exhibit MLR-1, Schedule MLR-6f.
[64] Id.
[65] J.B. Williams, *The Theory of Investment Value* (1938), at 47.

S&P MI, and Zacks. The S&P MI and Zacks websites report results incorporating forward-looking surveys of securities analysts' EPS projections. *Value Line*, in contrast, uses a historical base period average value for 2022-2024 and a forecast for 2028-2030 to calculate its growth rates, and it is not a survey. The average expected earnings growth rate using the proxy group of companies is 6.56% [and median DCF results of 9.76% and 9.84%].[66]

However, I then refine my calculation of the growth rate by averaging *Value Line's* dividends per share ("DPS") and book value per share ("BVPS") estimates with the previously estimated earnings growth rate projections weighted equally. I include these three components of growth in my analysis because investors are not only concerned with earnings growth but also dividend and book value growth as an assurance that dividend growth will be sustained. Moreover, dividend growth rates are more stable than expected earnings growth. These calculations produce an average growth rate of 5.40% [and median DCF results of 8.83% and 8.85%].[67]

B. SUSTAINABLE-GROWTH DISCOUNTED CASH FLOW MODEL

Q. DO YOU EMPLOY OTHER METHODS TO DERIVE GROWTH RATES IN YOUR DCF MODEL?

A. Yes. I also use the sustainable growth method to estimate the rate of dividend growth. The standard DCF model assumes only one source of equity financing, namely the

[66] Exhibit MLR-1, Schedule MLR-5a and Exhibit MLR-1, Schedule MLR-5c.
[67] Exhibit MLR-1, Schedule MLR-5b and Exhibit MLR-1, Schedule MLR-5d.

retention of earnings. Growth in earnings and dividends, however, can also be achieved by the sale of new common equity.[68] The basic Constant-Growth DCF model of:

$$K = \frac{D_1}{P} + g$$

can be rewritten to assume that external sources of financing influence investor expectations of dividend growth, and is represented as the following:

$$K = \frac{D_1}{P} + br + sv$$

Therefore:

$$G = br + sv,$$

Where:

G is the retention growth rate;
b is the portion of retained earnings or 1 minus payout ratio;
r is the earned rate of return;
s represents the funds raised from the sale of stock as a fraction of existing common equity; and
v is the fraction of funds raised from the sale of stock that accrues to current shareholders.

I use *Value Line* expectations regarding retention ratios and ROEs for five years into the future to derive estimates for b and r, which in turn are used to calculate the expected internal growth component, br. To incorporate external financing growth, sv, I use *Value Line* data to derive the market-to-book ratio (which is an actual, observed figure) and expected growth in the number of outstanding shares. The average

[68] This expanded version of the DCF model allows for the value of stocks to vary from book values. If the stock prices equal book value, then the equity held by new shareholders is equal to the funds they invest and the existing shareholders' equity is not changed. If, however, stock prices are greater than book value, a portion of the funds accrues to the existing shareholders, thereby increasing their expectations of dividend growth in the future. David Parcell, *The Cost of Capital – A Practitioner's Guide* (2010), at 144-145.

sustainable growth rates for my proxy group is 5.25% (30-calendar day stock prices) and 5.18% (90-calendar day stock prices).[69]

Q. DO YOU APPLY A REASONABLENESS SCREEN TO YOUR INDIVIDUAL ROE RESULTS USING THE DCF METHOD?

A. Yes. After adding the growth-rate estimates and the dividend-yield estimates for each company in my proxy group to obtain the individual ROE estimates, I examined individual company ROE results for reasonableness and whether some results are extreme outliers. Thus, in lieu of relying on the average of my proxy group results for each model, I use the median. The median is the middle value of a set of data and is not skewed by outliers.

Q. PLEASE SUMMARIZE YOUR DCF MODEL RESULTS.

A. As shown in Table 3 below, I employ three different methods for deriving the growth rate in the DCF model, yielding three sets of estimates of the ROE for my proxy group. First, I use the Constant-Growth DCF model using only EPS growth rates. When I assume that investors are only concerned with earnings growth when valuing a company's stock, thereby only using EPS growth in the DCF model, I derive ROE estimates of 9.76% (30-calendar day stock prices) and 9.84% (90-calendar day stock prices).[70]

Second, I use the Constant-Growth DCF model using EPS, DPS, and BVPS growth rates. Once I allow for other sources of growth, such as DPS and BVPS growth rates, to influence investors' expectations of the return on a particular equity, my analyses yield lower results. For instance, incorporating DPS and BVPS growth rates

[69] Exhibit MLR-1, Schedule MLR-6c and Exhibit MLR-1, Schedule MLR-6f.
[70] Exhibit MLR-1, Schedule MLR-5a and Exhibit MLR-1, Schedule MLR-5c.

results in median ROE estimates of 8.83% (30-calendar day stock prices) and 8.85% (90-calendar day stock prices).[71]

Third, I use the Sustainable-Growth DCF model. When I allow for both internal and external funding sources to drive growth in investor income, for my sustainable growth rate model, I derive median ROE results of 8.74% (30-calendar day stock prices) and 8.71% (90-calendar day stock prices), after adjusting for reasonable growth rates.[72] The overall range of ROE estimates using my DCF is 8.71% to 9.84%, with a midpoint of 9.27%.

TABLE 3. RENO DCF RESULTS (AVERAGE RESULTS)

Estimated Return on Equity	**ROE**		
DCF Methodology	30-Day Stock Price	90-Day Stock Price	Midpoint
Constant-Growth DCF (EPS Growth)	9.76%	9.84%	
Constant-Growth DCF (DPS, EPS and BVPS)	8.83	8.85	
Sustainable-Growth DCF	8.74	8.71	
DCF Range (Min. & Max.)[1]	**8.71%**	**9.84%**	**9.27%**

[1] ROE range (minimum and maximum values) for the 30-day and 90-day DCF results.

C. CAPITAL ASSET PRICING MODEL

Q. DO YOU USE ANY OTHER METHODOLOGIES TO ESTIMATE THE ROE FOR PIKE?

A. Yes. I also apply the CAPM to derive a total of three ROE estimates, which serve as a check of the reasonableness of my DCF results. However, my recommended ROE is

[71] Exhibit MLR-1, Schedule MLR-5b and Exhibit MLR-1, Schedule MLR-5d.
[72] Exhibit MLR-1, Schedule MLR-6c and Exhibit MLR-1, Schedule MLR-6f.

not based on my CAPM results. My CAPM results range from 8.06% to 11.24% with a midpoint of 9.65%.

Q. PLEASE DESCRIBE THE CAPM.

A. The CAPM is a version of the "risk premium" approach that is rooted in modern portfolio theory. It recognizes that common equity capital is riskier than debt from an investor's perspective because debt holders are typically paid before shareholders, and as such, investors require higher returns on stocks than on bonds to be compensated for the additional risk.[73] The cost of common equity is represented by the following equation:

$$K_e = R_f + \beta_s * RP,$$

Where:

K_e is the cost of equity;

R_f is the yield on risk-free securities;

β_s or Beta coefficient ("Beta") is a company-specific measure that reflects the movement in a company's stock price relative to movements in a composite group of companies representing the stock market. Beta measures the investment risk that cannot be eliminated by holding a diverse portfolio of assets; and

RP is the equity risk premium ("ERP") demanded by shareholders to accept equity relative to debt.

Q. PLEASE DESCRIBE THE RISK-FREE RATE YOU USE IN YOUR CAPM ANALYSIS.

A. The first term in the CAPM is the risk-free rate (R_f). I use the yield on the 30-year T-bond observed over a recent 30-day period ended February 28, 2025, of 4.70%, based

[73] The CAPM is generally superior to the simple risk premium method because the CAPM recognizes the risk of a particular company or industry through the use of betas, whereas the simple risk premium method assumes the same risk premium for all companies exhibiting similar bond ratings.

on recent market information.[74] I also include in one of my CAPM analyses the Kroll (formerly Duff & Phelps) Normalized Risk-Free Rate of 3.50%.[75]

Q. HOW DO YOU CALCULATE THE EQUITY RISK PREMIUM?

A. In each of my three CAPM analyses, I use different estimates of the ERP that range from 5.00% to 7.17%. For the high end of this range, I use the Kroll estimate of the historical arithmetic average of real market returns over the period 1926 to 2023, which is the total return on common stocks (S&P 500) including capital appreciation, less the income returns on T-bond investments.[76]

Kroll also provides an updated Ibbotson & Chen supply-side model, which found that the market risk premium based on the S&P 500 was influenced by an abnormal experience of price-to-earnings ("P/E") ratios relative to earnings and dividend growth over the last 30 years. Thus, Kroll adjusted this market risk premium and published a long-horizon, supply-side ERP of 6.22%.[77]

Kroll also recommends a forward-looking ERP that was derived in conjunction with a normalized risk-free rate. Thus, my final CAPM analysis uses the Kroll Recommended U.S. ERP of 5.00% and Normalized Risk-Free Rate of 3.50%.[78] Therefore, the estimated ERP used across my three CAPM methods ranges from 5.00% to 7.17%.

[74] Federal Reserve, "Selected Interest Rates" (Daily), available at https://www.federalreserve.gov/releases/h15/.
[75] Kroll, "Cost of Capital in the Current Environment" (January 2025).
[76] Exhibit MLR-1, Schedule MLR-7a and Exhibit MLR-1, Schedule MLR-7b.
[77] Exhibit MLR-1, Schedule MLR-7c and Exhibit MLR-1, Schedule MLR-7d.
[78] Exhibit MLR-1, Schedule MLR-7e and Exhibit MLR-1, Schedule MLR-7f; Kroll, "Cost of Capital in the Current Environment" (January 2025).

Q. HOW DO YOU ACCOUNT FOR THE VARIABILITY IN EQUITY MARKETS?

A. To capture investors' expected equity market returns, I focus on longer trends in stock market returns from 1928 to 2023. This period shows annual stock returns over multiple business cycles, avoiding the influence of any given period.[79]

Q. HOW DO YOU ADJUST THE EQUITY RISK PREMIUM TO ACCOUNT FOR COMPANY-SPECIFIC RISK?

A. I multiply company-specific betas by the ERPs to account for company-specific risk. I rely on *Value Line* betas because *Value Line* is widely used by the utility regulatory community and investment community in general. It is also known that *Value Line* adjusts its betas to account for the long-term tendencies of stocks to converge to a beta of one (1.0).[80] As a result, *Value Line* betas tend to have higher values than betas provided by some other sources. The average *Value Line* beta for the proxy group is 0.91. A beta value of 0.91 means that the stock price movement is less than the movement, in percentage terms, of the overall stock market. The price of a gas utility stock is, therefore, less volatile and less risky than the overall market.

Q. WHAT ARE THE RESULTS OF YOUR CAPM ANALYSES?

A. As shown in Table 4 below, applying the same risk-free rates, market risk premium, and betas from the proxy group, I estimate expected returns ranging from 8.20% to 11.44%.

[79] A business cycle typically includes an expansion and a recession that can vary in duration.

[80] Marshall Blume investigated the regression tendency of betas and reached the conclusion that betas have the tendency to approach a value of one (1) over time. That is, high-beta portfolios tend to decline over time toward one (1), while low-beta portfolios tend to increase to one (1). Marshall Blume, "Betas and Their Regression Tendencies," Journal of Finance (1975), at 785-796.

TABLE 4. CAPM ESTIMATED ROE RESULTS

	ERP	Beta-Adjusted ERP	Risk-Free Rate	CAPM ROE	Max	Midpoint
CAPM (Hist. L-T ERP)	7.17	6.54	4.70	11.24%		
CAPM (Supply-Side ERP)	6.22	5.68	4.70	10.37%		
CAPM (Kroll Recommended ERP)	5.00	4.56	3.50	8.06%		
CAPM Range				8.06%	11.24%	9.65%

VIII. ROR AND ROE RESULTS SUMMARY

Q. PLEASE SUMMARIZE YOUR ROR RESULTS.

A. For Pike, I recommend an overall ROR of 7.80%, which is composed of (1) a capital structure of 50.63% equity, 40.72% long-term debt, and 8.64% short-term debt; (2) a cost of long-term debt of 6.00% and a cost of short-term debt of 7.50%; and (3) an ROE of 9.30%.

Q. HOW DOES YOUR PROPOSED ROR OF 7.80% COMPARE TO RECENT AND HISTORICAL ALLOWED ROR VALUES APPROVED BY REGULATORY COMMISSIONS ACROSS THE COUNTRY?

A. According to S&P MI, the average allowed ROR for distribution natural gas utilities in Calendar Year (CY) 2024 was 7.26%, with a median value of 7.21%, a minimum of 5.80%, and a maximum of 8.80%. For CY 2023, these values were slightly lower, with an average ROR of 7.00%.[81]

While I acknowledge that ROR values for different utilities are influenced by factors such as approved ROE level, capital structure, and cost of debt, it is noteworthy

[81] Derived from data provided by S&P MI, reflecting only distribution natural gas utilities for which S&P MI reported an ROR value. See Exhibit MLR-1, Schedule MLR-8a and Exhibit MLR-1, Schedule MLR-8b.

that my proposed ROR of 7.80%, if approved by the Commission, would be significantly higher than those recently authorized by other state regulators.

Looking at a broader historical perspective, over the 10-year period from January 1, 2015, through January 1, 2025, the average ROR awarded by state regulators has been 7.06% across 330 general rate cases for distribution natural gas utilities.[82] Notably, in this same period, there have been only two dozen instances—out of 330 cases—where a state commission approved an ROR higher than my proposed 7.80%.[83]

By contrast, Pike's proposed ROR of 8.59% is inconsistent with recent regulatory precedent and exceeds the levels typically approved in the U.S. over the last decade. Over the past ten years, out of 330 rate cases in which a state regulator approved an ROR level, only five utilities were granted an ROR exceeding 8.37%.[84] While my proposed ROR of 7.80% is undoubtedly high, it remains more reasonable than Pike's request. I urge the Commission to adopt my proposed ROR, as it better aligns with recent regulatory trends while still accounting for the necessary financial considerations related to Pike.

Approving an ROR that significantly deviates from historical norms risks setting a precedent that could lead to unjustified rate increases for consumers and undermine regulatory consistency. A balanced approach—one that recognizes financial needs of Pike while staying grounded in recent precedent—is the best path forward for the Commission.

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[82] Derived from data provided by S&P MI, reflecting only distribution natural gas utilities for which S&P MI reported an ROR value. See Exhibit MLR-1, Schedule MLR-8c.

[83] Derived from data provided by S&P MI, reflecting only distribution natural gas utilities for which S&P MI reported an ROR value. See Exhibit MLR-1, Schedule MLR-8d.

[84] Derived from data provided by S&P MI, reflecting only distribution natural gas utilities for which S&P MI reported an ROR value. See Exhibit MLR-1, Schedule MLR-8e.

Q. PLEASE SUMMARIZE YOUR ROE RESULTS.

A. As shown in Table 5 below, my ROE recommendation of 9.30% is the rounded midpoint of my DCF results (9.28%) and falls with my DCF range of 8.71% to 9.84% and represents a fair and reasonable ROE for Pike for the reasons I have previously discussed. The minimum of my range is the minimum of my DCF results, and the maximum of my range is the maximum result derived from my DCF results. Moreover, my recommendation of 9.30% should be accepted as reasonable because it is only 35 basis points lower than the average of my CAPM results.

TABLE 5. ROE ESTIMATES (%)

DCF Methodology	**30-Day Stock Price**	**90-Day Stock Price**	**Midpoint**
Constant-Growth DCF (EPS Growth)	9.76	9.84	
Constant-Growth DCF (DPS, EPS and BVPS)	8.83	8.85	
Sustainable-Growth DCF	8.74	8.71	
DCF Range (Minimum & Maximum):	**8.71**	**9.84**	**9.27**
CAPM Methodology	**CAPM**	**Max**	**Midpoint**
Capital Asset Pricing Model (Lg. Stock ERP, 30-yr T-Bond Rate)	11.24		
Capital Asset Pricing Model (Supply-Side ERM, 30-yr T-Bond Rate)	10.37		
Capital Asset Pricing Model (Kroll Normalized Rate)	8.06		
CAPM Range (Minimum & Maximum):	**8.06**	**11.24**	**9.65**
Summary			
DCF-Based ROE Average			9.12
	Min	**Max**	**Midpoint**
ROE Range	8.71	9.84	9.27
Recommended ROE (%)			**9.30**

Q. IN PAST CASES, HAVE YOU RELIED ON THE MINIMUM OF YOUR DCF RESULTS TO SET THE MINIMUM OF YOUR ROE RANGE?

A. No. In past proceedings, I have relied on the average of my DCF results to set the minimum of my ROE range because I did not believe the lowest results to be reasonable. In this case, however, I do not feel that it is necessary to truncate the lower bound of my ROE range given the circumstances specific to Pike and current financial market conditions.

Q. WHY IS YOUR ROE RECOMMENDATION OF 9.30% BASED ON A RANGE DERIVED FROM YOUR DCF METHODOLOGIES?

A. I place more emphasis on my DCF-derived results because it is widely used by both the finance community and public utility commissions across the country and yields more reliable results. It is a forward-looking model that directly incorporates investors' expectations of company dividend income through current market pricing signals, particularly in the case of utility stocks where stock valuations are telling a different story than the general market. The DCF also reflects recent developments in management decisions regarding key financials reflected in expected dividend and earnings growth.

The CAPM results, by contrast, are largely reliant on financial market outcomes complicated by monetary policy and investors' expectations of inflation and economic growth over the long run. Specifically, the estimated risk-free rate has a direct impact on the estimated ROE and is largely influenced by the analyst's assumptions. Moreover, the CAPM lacks a direct and immediate link from stock prices to the results. Although the beta coefficient in the CAPM reflects changes in the ROE, such information is delayed. However, I rely on my CAPM results as a reasonableness check.

Q. HOW DOES YOUR RECOMMENDATION COMPARE TO RECENTLY ALLOWED EQUITY RETURNS?

A. My recommended ROE of 9.30% is in line with current allowed ROEs issued by regulatory commissions across the country. S&P MI reports that the average allowed equity return for natural gas utilities for 2024 was 9.71%, which is higher to the average for 2023 of 9.60%.[85] My recommended ROE of 9.30% is 41 basis-points lower than the average allowed ROE for gas utilities in 2024.

Q. HOW DOES PIKE'S ROE RECOMMENDATION COMPARE TO RECENTLY ALLOWED EQUITY RETURNS?

A. Pike's recommended ROE of 10.20% is 49 basis-points higher than the average allowed ROE for gas utilities for 2024. Thus, if the Commission grants Pike's recommended ROE, it would be an outlier relative to the average allowed ROE for gas utilities throughout the U.S.

Q. DOES THIS CONCLUDE YOUR DIRECT TESTIMONY?

A. Yes, it does. However, I reserve the right to supplement my testimony as new information becomes available.

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[85] S&P Global Market Intelligence, "RRA Regulatory Focus - Major Energy Rate Case Decisions in the US – January-December 2024" (February 4, 2025), at 3.

APPENDIX A: CURRICULUM VITAE AND QUALIFICATIONS

Maureen L. Reno

Maureen Reno is a seasoned expert with 24 years of experience in the field of public utility regulation. After she completed her Ph.D. studies in Economics at the University of New Hampshire, Ms. Reno launched her career in public utility regulation as a utility analyst and program manager at the New Hampshire Public Utilities Commission, where she worked for the next 10 years. In this capacity, she provided expert testimony on rate of return (to include return on equity) in electricity, natural gas, and water utility rate cases. Ms. Reno also led the development and implementation of New Hampshire's Renewable Portfolio Standard program, helping both owners of distributed generation and load serving entities meet compliance requirements and maneuver the dynamic wholesale energy and renewable energy certificate markets. In addition, she managed New Hampshire's participation in the Regional Greenhouse Gas Initiative. Finally, Ms. Reno served as an expert witness on financial issues regarding the regulation of electric, natural gas, and water utilities, to include cost of capital and return on shareholder equity.

Subsequently, Ms. Reno served as a Senior Energy Economist with the Union of Concerned Scientists. In this capacity, she developed clean energy financing policies and advocated for electricity sector solutions to global warming.

Since 2012, Ms. Reno has served as an independent consultant, working with other small businesses to advise government and industry clients on diverse utility-related matters. In addition, she has served as an expert witness on rate design and rate of return (to include return on equity) in numerous cases. Her testimony has been presented to public utility commissions across the United States, to include the Regulatory Commission of Alaska, Arizona Corporation Commission, California Public Utilities Commission, Delaware Public Service Commission, Georgia Public Service Commission, Kansas Corporation Commission, Missouri Public Service Commission, New Hampshire Public Utilities Commission, New Mexico Public Regulation Commission, North Carolina Utilities Commission, Oklahoma Corporation Commission, South Carolina Public Service Commission, and Public Utility Commission of Texas. Ms. Reno's testimony has been consistently accepted by public utility commissions.

Ms. Reno stays abreast of the latest developments in utility regulatory law and policy through her research and professional activities. Given the complexity of Federal and state regulations that affect her clients, Ms. Reno dedicates significant time and energy to reviewing regulatory developments enacted by the U.S. Department of Energy, the Federal Energy Regulatory Commission (FERC), and the U.S. Environmental Protection Agency. For instance, Ms. Reno recently evaluated Maryland's RPS in light of FERC rulings on PJM's Capacity Auction to assess the financial viability of renewable energy projects within Maryland.

EDUCATION

- Completed all course work and exam requirements towards the Doctorate of Philosophy in Economics – University of New Hampshire, Durham.
  Fields of Specialization: Industrial Organization and Environmental Economics
- Master of Arts in Economics – University of New Hampshire, Durham, 1998
- Bachelor of Arts in Economics – University of Maine, Orono, 1996

PROFESSIONAL EXPERIENCE

- Independent Consultant and Principal, Reno Energy Consulting Services, LLC (2016-Present)
- Rates and Market Policy Director, New Hampshire Office of the Consumer Advocate (2021-2022)
- Independent Consultant (2012-2016)
- Senior Energy Economist, Union of Concerned Scientists (2011-2012)
- Analyst, Program Manager, Utility Analyst, and Economist, New Hampshire Public Utilities Commission (2001-2011)
- Survey Manager, New Hampshire Small Business Development Center (1999-2001)
- Adjunct Instructor, University of New Hampshire (1999-2001)

PROFESSIONAL WORK

As an independent consultant (as a prime contractor with Reno Energy Consulting Services, LLC and subcontractor under Exeter Associates, TAHOEconomics, and Nordee Enterprise LLC), Ms. Reno:

- Reviewed, analyzed, and prepared oral and written testimony in electric, natural gas, and water utility rate cases on topics that include rate design (revenue decoupling mechanisms); rate of return (including return on equity, capital structure, and accounting adjustments), and mergers and acquisitions.

- Worked with solar power installer to assess return on investment and payback period for investments in energy storage that included analyzing customer load profiles, utility tariffs, tax credits, and potential revenues from wholesale markets and state programs.

- Prepared report that included assessment of electricity options and projected revenues and costs for the Army & Air Force Exchange Service's West Coast Distribution Center, which included analyzing Pacific Gas & Electric Company's tariffs and potential revenues from wholesale markets for investments in solar power and energy storage.

As the Rates and Market Policy Director at the New Hampshire Office of the Consumer Advocate, Ms. Reno:

- Reviewed and analyzed utility filings and prepared written recommendations in two natural gas utility proceedings pertaining to a revenue decoupling adjustment mechanism and a renewable natural gas contract.

- Reviewed and analyzed utility filings and provided oral testimony in an electric utility's electric vehicle make-ready program and proposed tariff rates.

- Reviewed, analyzed and prepared oral and written recommendations for the Consumer Advocate on utility requests for changes in energy service rate charges (electric default service and cost of gas) and other surcharges reflected in utility company tariffs.

As an independent consultant for Exeter Associates Inc., Ms. Reno:

- Preparing the financial analysis and ratepayer impacts of a long-term contract requirement under Maryland's RPS for the Power Plant Research Program (PPRP) on behalf of the Maryland Department of Natural Resources.

  Evaluated utility proposals for deployment, cost-benefit analysis, and cost recovery of Maryland's Statewide Electric Vehicle Portfolio on behalf of the Maryland Energy Administration through the PPRP in Case No. 9478 In the Matter of the Petition of the Electric Vehicle Work Group for Implementation of a Statewide Electric Vehicle Portfolio.

- Conducted research and drafted sections of regional energy market operations manuals for the US Department of Energy's Federal Energy Management Program. The reports focused on how federal facilities were pursuing renewable energy development under the different market constructs, such as by vertically integrated electric utilities, electric utilities with the PJM footprint, and electric utilities in California, and how those market constructs affected the prospects for future renewable energy development.

As an independent consultant for TAHOEconomics LLC, Ms. Reno:

- Provided written and oral testimony and legal briefs on behalf of the City of Clovis, New Mexico, in a water utility rate cases before the New Mexico Public Regulation Commission. Assessed EPCOR Water New Mexico Inc.'s weighted average cost of capital and estimated the rate of return on equity using discounted cash flow, risk premium, and capital asset pricing models.

As an independent consultant for Stephenson Strategic Communications, LLC, Ms. Reno:

- Provided consulting services to build support in New Hampshire for strong national climate and energy policies on behalf of a nationally recognized, non-profit environmental organization.
- Mobilized experts and leaders in New Hampshire to engage elected federal, state and local officials through targeted Senator visits, media interviews, public events, letters to the editor, and opinion and editorial articles.
- Communicated directly with targeted legislators and their staff to determine their positions on climate and clean air policies and address their concerns.

As an independent consultant for TrueLight Energy, LLC, Ms. Reno:

- Acted as director of regulatory affairs to expand upon current services to provide clients with guidance on how to navigate the dynamic deregulated electricity industry.
- Developed regulatory service product for clients, which includes ISO/utility tariff tracking and rate impact analysis, policy analysis, new market identification and participation in regulatory processes.
- Identified and originated new commercial opportunities in the U.S. to support principle product/service lines: retail supplier solutions; generation asset management; and sustainability management solutions for large energy users.
- Developed and implemented business development and business-to-business marketing strategies in coordination with senior management.

As a senior economist at the Union of Concerned Scientists, Ms. Reno:

- Promoted the development of clean energy technologies and policies in the electricity sector. Designed and evaluated energy policies at the state, regional, and national levels to maximize economic benefits and overcome market barriers to renewable energy.
- Evaluated and developed alternative financial policies to national and state renewable energy standards. Completed internal documents and research focusing on master limited partnerships and real estate investment trusts as possible sources of financing capital for renewable energy projects.
- Informed and enhanced coalition strategies by evaluating and developing appropriate responses to federal policy opportunities, including a low-carbon electricity standard, production tax credit, and other emerging opportunities.

- Evaluated the net benefits and opportunities for economic development in renewable energy manufacturing and the supply chain.

As an analyst and program manager at the New Hampshire Public Utilities Commission, Ms. Reno:

- Developed and managed New Hampshire’s RPS Program.

- Developed internal protocols for managing New Hampshire’s RPS program pursuant to PUC’s RPS program rules (N.H. Code of Administrative Rules PUC 2500), including designing resource eligibility application forms.

- Verified electricity providers’ compliance with New Hampshire’s RPS program and processed applications for renewable energy source eligibility.

- Prepared and submitted annual RPS compliance reports, including program evaluation and policy analysis, to the State legislature on behalf of the PUC.

- Monitored and forecasted renewable energy certificate market trends in New England and New Hampshire to estimate available revenues supporting rebate programs.

- Maintained an RPS program website and renewable energy sources database.

- Participated in various regional working groups, including the RGGI Allowance and Offset Market Groups, and the GIS Regulators’ Caucus to develop and maintain the NEPOOL GIS Operating Rules.

- Developed Greenhouse Gas Emissions Reduction Fund Cost Effectiveness Analysis model for request for proposal applicants.

As a utility analyst and economist at the New Hampshire Public Utilities Commission, Ms. Reno:

- Reviewed, analyzed and prepared oral and written recommendations in eight electric, natural gas and water utility rate cases in which she calculated each company’s weighted average cost of capital and estimated the rate of return on equity using discounted cash flow, risk premium, and capital asset pricing models.

- Advised the PUC on utilities’ debt financings, bond issuances, power plant retrofit, advanced/net metering, demand response, environmental disclosure, and incentives for in-state energy efficiency programs.

- Collaborated on behalf of the PUC with public and private entities to write New Hampshire’s RPS law (HB 873), state participation in RGGI (HB 1434) and the PUC’s RPS program rules (N.H. Code of Administrative Rules Puc 2500).

- Advised the Commissioners on the development of the RGGI carbon dioxide emission limits and the Allowance Auction Market.

- Prepared fiscal impact statements regarding proposed legislation and regulations in the State of New Hampshire using cost-benefit analysis.

As a Survey Manager for the New Hampshire Small Business Development Center, Ms. Reno:

- Designed and distributed a survey to collect data on the characteristics of New Hampshire manufacturers.

- Managed collection of survey data, designed a database for the data collected and oversaw data entry efforts.

- Analyzed the economic and behavioral factors that lead to the growth of New Hampshire manufacturing companies using multivariate regression, factor and cluster analysis of survey data.

As an Adjunct Instructor for the University of New Hampshire, Ms. Reno:

- Taught undergraduate courses in Principles of Macroeconomics and Microeconomics, including lectured on a daily basis, and developed lesson plans and teaching materials.
- Managed teaching assistant’s work correcting and grading testing materials and writing assignments.

UTILITY LITIGATION

State	Client	Citation/Utility	Industry	Topics
New Mexico	Bernalillo County (BC)	24-00089-UT/Public Service Co. of New Mexico	Electric	Cost of Capital and Return on Equity
South Carolina	U.S. Department of Defense (DoD)	2024-34-E/Dominion Energy South Carolina, Inc.	Electric	Cost of Capital and Return on Equity
New Mexico	BC	22-00058-UT/ Public Service Co. of New Mexico	Electric	Grid Modernization Cost-Benefit Analysis
Delaware	Public Service Commission Staff (DE PSC Staff)	23-0601/Artesian Water Company, Inc.	Water	Cost of Capital and Return on Equity
New Mexico	U.S. Department of Energy (DOE)	23-00255-UT/New Mexico Gas Company. Inc.	Natural Gas	Cost of Capital and Return on Equity
California	Small Business Utility Advocates	23-01-008/San Diego Gas & Electric Company	Electric	Rate Design & Cost of Service
Kansas	DoD	23-EKCE-775-RTS/Evergy Kansas Central, Inc. & Evergy Kansas Metro,	Electric	Cost of Capital and Return on Equity
Delaware	DE PSC Staff	22-0897/Delaware Power & Light	Electric	Cost of Capital and Return on Equity
Texas	DOE	54634/Southwestern Public Service Company	Electric	Cost of Capital, Return on Equity, and Rate Design Impacts on Risk
New Mexico	BC	22-00270-UT/ Public Service Co. of New Mexico	Electric	Cost of Capital, Return on Equity, and Rate Design Impacts on Risk
North Carolina	DoD	E-2, SUB 1300/ Duke Energy Progress, LLC	Electric	Cost of Capital, Return on Equity, and Rate Design Impacts on Risk
Georgia	DoD	44280/ Georgia Power Company	Electric	Cost of Capital, Return on Equity, and Rate Design Impacts on Risk

Texas	DoD	53601/ Oncor Electric Delivery Company	Electric	Cost of Capital and Return on Equity
New Hampshire	Office of the Consumer Advocate (NH OCA)	DE 21-078/ Eversource	Electric	Electric Vehicle Make-Ready and Demand Charge Alternative
Alaska	DoD	U-21-070/U-21-071/ Golden Heart Utilities, Inc. and College Utilities Corporation	Water, Wastewater	Cost of Capital and Return on Equity
New Hampshire	NH OCA	DG 21-104/ Northern Utilities, Inc.	Natural Gas	Rate Design: Revenue Decoupling Adjustment Mechanism and Impacts on Risk
New Hampshire	NH OCA	DG 21-036/ Liberty Utilities	Natural Gas	Cost-Effectiveness of a Renewable NG Supply Agreement
Texas	DoD	52195/ El Paso Electric Company	Electric	Cost of Capital and Return on Equity
New Mexico	BC	20-00222-UT/ Public Service Co. of New Mexico	Electric	Mergers & Acquisitions: Benefits and Risks
New Mexico	BC	20-00121-UT/ Public Service Co. of New Mexico	Electric	Rate Design: Decoupling Mechanism
New Mexico	Public Regulation Commission Staff	19-00170-UT/ Southwestern Public Service Company	Electric	Cost of Capital and Return on Equity
Georgia	DoD	42516/ Georgia Power Company	Electric	Cost of Capital, Return on Equity, and Rate Design Impacts on Risk
Arizona	DoD	E-01933A-19-0028/ Tucson Electric Power Company	Electric	Cost of Capital and Return on Equity
New Mexico	City of Clovis, NM	18-00124-UT/ EPCOR Water New Mexico Inc.	Water	Cost of Capital and Return on Equity
Oklahoma	DoD	PUD 201700151/ Public Service Co. of Oklahoma	Electric	Cost of Capital and Return on Equity
Oklahoma	DoD	PUD 201500208/ Public Service Co. of Oklahoma	Electric	Cost of Capital, Return on Equity, and

				Rate Design Impacts on Risk
Texas	DOE	43695/ Southwestern Public Service Company	Electric	Cost of Capital and Return on Equity
Missouri	DOE	ER-2014-0370/ Kansas City Power & Light Co.	Electric	Cost of Capital and Return on Equity
Texas	DOE	41791/ Entergy Texas, Inc.	Electric	Cost of Capital and Return on Equity
New Hampshire	Public Utilities Commission (NH PUC)	DE 05-178/ Unitil Energy Systems, Inc.	Electric	Cost of Capital and Return on Equity
New Hampshire	NH PUC	DE 04-177/ Public Service Co. of New Hampshire (generation assets)	Electric	Cost of Capital and Return on Equity
New Hampshire	NH PUC	DW 04-056/ Pennichuck Water Works, Inc.	Water	Cost of Capital and Return on Equity
New Hampshire	NH PUC	DE 03-200/ Public Service Co. of New Hampshire	Electric	Cost of Capital and Return on Equity
New Hampshire	NH PUC	DE 03-166/ Public Service Co. of New Hampshire	Electric	Financial Incentives Associated with a Power Plant Retrofit from Coal to Biomass
New Hampshire	NH PUC	DE 01-247/ Concord Electric Co. and Exeter & Hampton Electric Co.	Electric	Cost of Capital and Return on Equity
New Hampshire	NH PUC	DE 01-168/ Public Service Co. of New Hampshire	Electric	Refinancing of Long-term Debt, Short-term Debt Limit, and Utilization of Derivative Instruments
New Hampshire	NH PUC	DG 01-182/ Northern Utilities, Inc.	Natural Gas	Cost of Capital and Return on Equity
New Hampshire	NH PUC	DW 01-081/ Pennichuck Water Works, Inc.	Water	Cost of Capital and Return on Equity

UTILITY-RELATED MATTERS

State	Client	Description
New Jersey	Division of the Rate Counsel	Provided cost of capital and return on equity to client for settlement purposes in Jersey City Power & Light EnergizeNJ case EO-23110793.
California	Small Business Utility Advocates	Provided Comments on utility draft annual reports concerning California's RPS Rulemaking Case No. 18-07-003.
New Hampshire & Massachusetts	Nordee Enterprise LLC	Worked with solar power installer to assess return on investment and payback period for investments in energy storage that included analyzing customer load profiles, utility tariffs, tax credits, and potential revenues from wholesale markets and state programs.
New Hampshire	Office of the Consumer Advocate (OCA)	Negotiated Settlement terms in DE 21-119 Eversource Energy's Proposed Tariff Amendment to Residential Time-of-Day Rate
New Hampshire	OCA	Negotiated Settlement terms in DE 20-170 Electric Distribution Utilities' Electric Vehicle Time of Use Rates
New Hampshire	OCA	Evaluated utility proposal and ratepayer impacts of Liberty Utilities cost of gas proposal in DG 21-130 (EnergyNorth Natural Gas) and DG 21-132 (Liberty-Keene Division)
New Hampshire	OCA	Evaluated Liberty Utilities' Firm Transportation Agreement with Tennessee Gas Pipeline Company LLC in DG 21-008
Maryland	Department of Natural Resources (DNR)	Prepared the financial analysis and ratepayer impacts of a long-term contract requirement under Maryland's RPS. The report titled "Final Report Concerning the Maryland Renewable Portfolio Standard as Required by Chapter 393 of the Acts of the Maryland General Assembly of 2017" was publicly released in December 2019.
Maryland	Energy Administration (EA)	Evaluated utility proposals for deployment, cost-benefit analysis, and cost recovery of Maryland's Statewide Electric Vehicle Portfolio in Case No.

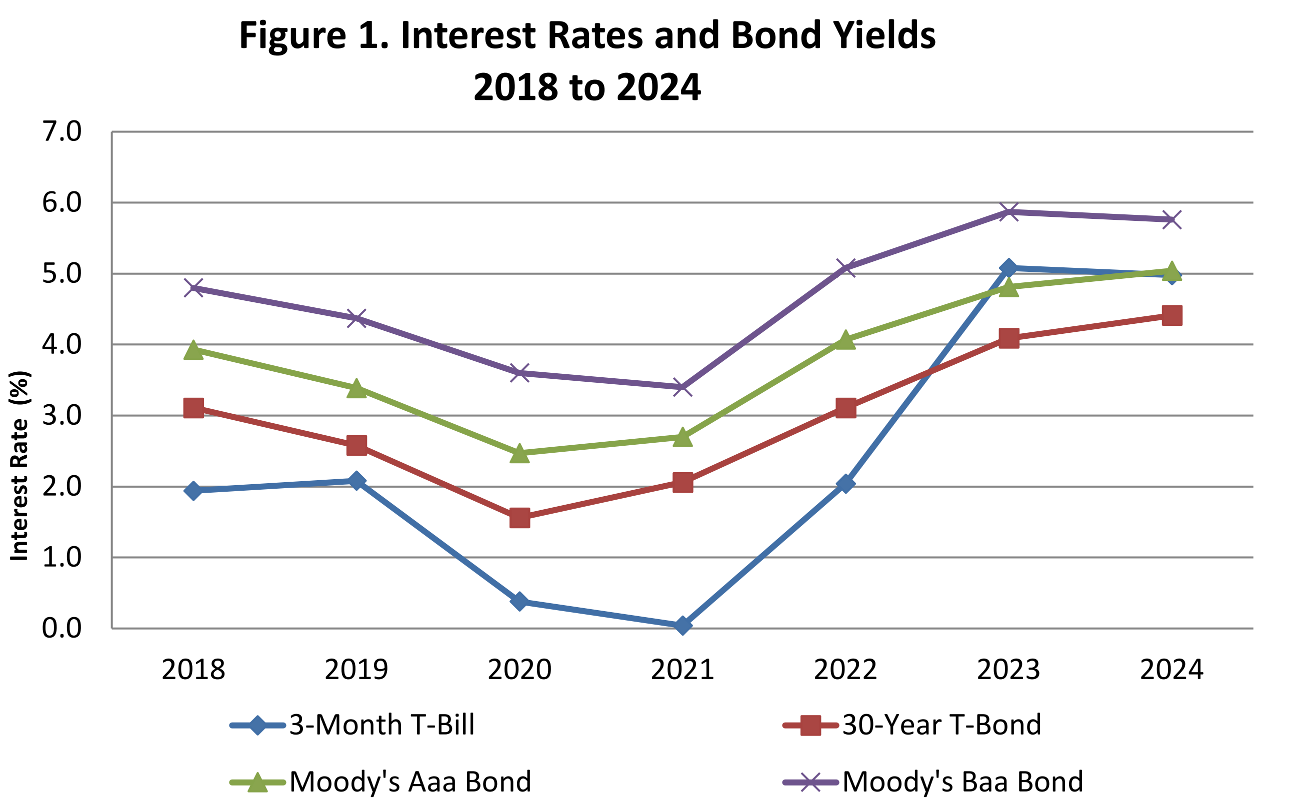
		9478 In the Matter of the Petition of the Electric Vehicle Work Group for Implementation of a Statewide Electric Vehicle Portfolio.
Federal	US Department of Energy (DOE)	Conducted research and drafted sections of regional energy market operations manuals for the US Department of Energy's Federal Energy Management Program. The reports focused on how federal facilities were pursuing renewable energy development under different market constructs, such as by vertically integrated electric utilities, electric utilities with the PJM footprint, and electric utilities in California.
New Hampshire	Derry Town Council	Oversaw town energy committee's involvement in various energy cost saving projects or initiatives, such as installing a large solar array on the town's landfill, updating streetlights with LED fixtures, building a new transfer station that meets LEED certification, installing an electric vehicle charging station downtown, and hosting/managing resident participation in two Solar Up campaigns.
New Hampshire	Derry Town Council	Advised town council on establishing the Derry Net Zero Task Force and town goal of becoming Net Zero by 2025.
Massachusetts	Union of Concerned Scientists (UCS)	Evaluated and developed alternative financial policies to national and state renewable energy standards. Completed internal documents and research focusing on master limited partnerships and real estate investment trusts as possible sources of financing capital for renewable energy projects.
Massachusetts	UCS	Manufacturing Supply Chain Analysis of Wind Power Systems
New Hampshire	Public Utilities Commission (PUC)	Developed internal protocols for managing New Hampshire's RPS program pursuant to NHPUC's RPS program rules (N.H. Code of Administrative Rules PUC 2500), including designing resource eligibility application forms.

New Hampshire	PUC	Verified electricity providers' compliance with New Hampshire's RPS program and processed applications for renewable energy source eligibility.
New Hampshire	PUC	Prepared and submitted annual RPS compliance reports to the State legislature on behalf of the NHPUC.
New Hampshire	PUC	Developed Greenhouse Gas Emissions Reduction Fund Cost Effectiveness Analysis model for grant proposals.
New Hampshire	PUC	Collaborated on behalf of the NHPUC with public and private entities to write New Hampshire's RPS law (HB 873), law concerning state participation in Regional Greenhouse Gas Initiative (RGGI) (HB 1434) and the NHPUC's RPS program rules (N.H. Code of Administrative Rules Puc 2500).
New Hampshire	PUC	Advised the Commissioners on the development of the RGGI carbon dioxide emission limits and the RGGI Allowance Auction Market.
New Hampshire	PUC	Assisted researchers at the University of New Hampshire in estimating the net benefits of New Hampshire's RPS and its participation in RGGI for the state legislature.

Schedule 1 - Historical Economic Trends (Percent Change from Previous Period)							
	2018	**2019**	**2020**	**2021**	**2022**	**2023**	**2024**
Real GDP	3.0	2.6	-2.2	6.1	2.5	2.9	2.8
GDP Price Index	2.3	1.7	1.3	4.5	7.1	3.6	2.4
Consumer Price Index	2.4	1.8	1.2	4.7	8.0	4.1	2.9
Personal Consumption Expenditures	2.0	1.4	1.1	4.1	6.6	3.8	2.5
Core Personal Consumption Exp.	1.9	1.6	1.3	3.6	5.4	4.1	2.8
Unemployment Rate	3.9	3.7	8.1	5.3	3.6	3.6	4.0
Employment/Population Ratio	60.4	60.8	56.8	58.4	60.0	60.3	60.1
Labor Force Participation Rate	62.9	63.1	61.7	61.7	62.2	62.6	62.6

Schedule 2a - Interest Rates and Bond Yields (2018 to 2024)							
	2018	2019	2020	2021	2022	2023	2024
3-Month T-Bill	1.94	2.08	0.38	0.04	2.04	5.08	4.98
10-Year T-Bond	2.91	2.14	0.89	1.45	2.95	3.96	4.21
30-Year T-Bond	3.11	2.58	1.56	2.06	3.11	4.09	4.41
Moody's Aaa Bond	3.93	3.39	2.47	2.70	4.07	4.81	5.04
Moody's Baa Bond	4.80	4.37	3.60	3.40	5.08	5.87	5.76
Prime Interest Rate	4.91	5.28	3.54	3.25	4.86	8.20	8.31
Federal Funds Rate	1.83	2.16	0.37	0.08	1.69	5.03	5.14

Source: Economic Indicators, January 2025, Prepared for the Joint Economic Committee by the Council of Economic Advisors at 30.
Moody's Baa-rated Corporate Bond Rates Source: https://fred.stlouisfed.org
Annual data reflects averages.

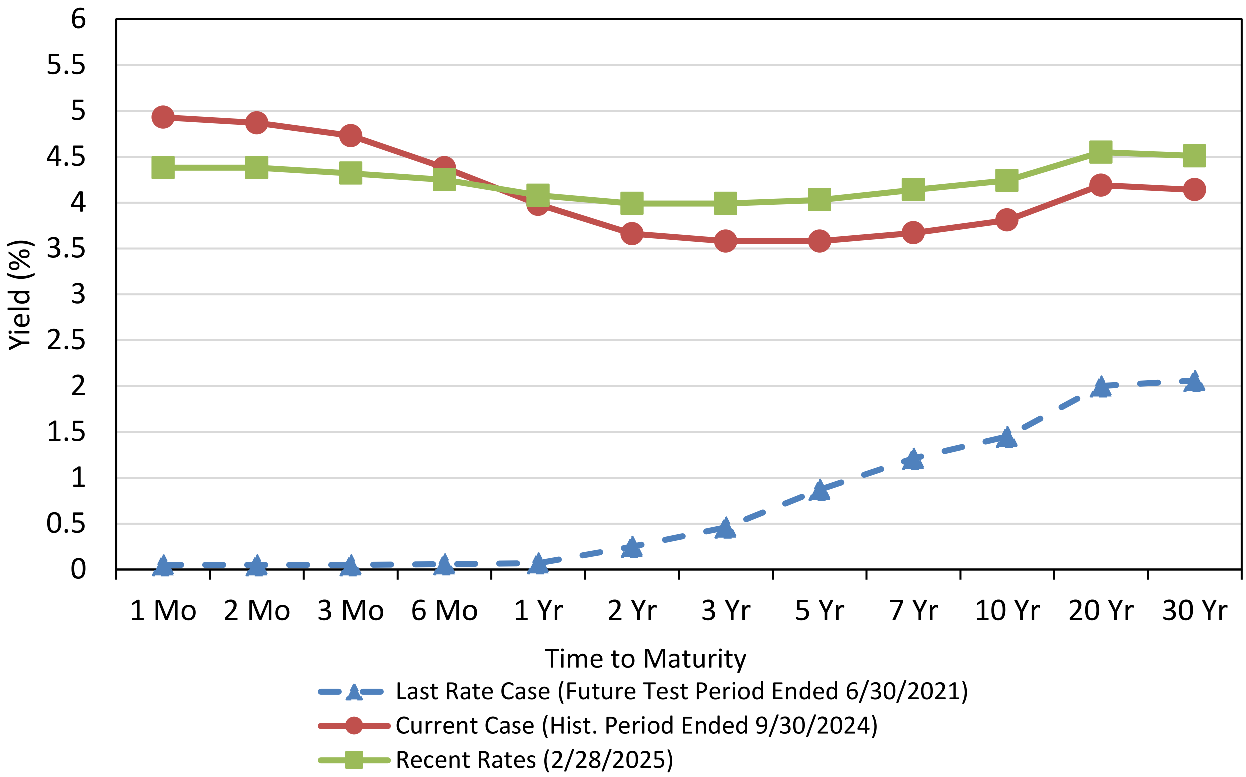


Source: Economic Indicators, April 2024 Prepared for the Joint Economic Committee by the Council of Economic Advisors and https://fred.stlouisfed.org

Schedule MLR-2b - Daily Yields on Treasury Securities

Time to Maturity	Last Rate Case (Future Test Period Ended 6/30/2021)	Current Case (Hist. Period Ended 9/30/2024)	Recent Rates (2/28/2025)
1 Mo	0.05	4.93	4.38
2 Mo	0.05	4.87	4.38
3 Mo	0.05	4.73	4.32
6 Mo	0.06	4.38	4.25
1 Yr	0.07	3.98	4.08
2 Yr	0.25	3.66	3.99
3 Yr	0.46	3.58	3.99
5 Yr	0.87	3.58	4.03
7 Yr	1.21	3.67	4.14
10 Yr	1.45	3.81	4.24
20 Yr	2	4.19	4.55
30 Yr	2.06	4.14	4.51

Figure 2. Treasury Security Yield Curve



Schedule MLR-2c - Daily Average TIPS Spread			
Date	Yield on 30-yr T-Bond	Yield on 30-yr T-Bond (Inflation Indexed)	30-Day TIPs Spread
12/2/2024	4.36	2.15	2.21
12/3/2024	4.4	2.17	2.23
12/4/2024	4.35	2.12	2.23
12/5/2024	4.33	2.13	2.2
12/6/2024	4.34	2.14	2.2
12/9/2024	4.39	2.18	2.21
12/10/2024	4.41	2.17	2.24
12/11/2024	4.48	2.22	2.26
12/12/2024	4.55	2.28	2.27
12/13/2024	4.61	2.33	2.28
12/16/2024	4.6	2.32	2.28
12/17/2024	4.59	2.33	2.26
12/18/2024	4.65	2.37	2.28
12/19/2024	4.74	2.47	2.27
12/20/2024	4.72	2.44	2.28
12/23/2024	4.78	2.47	2.31
12/24/2024	4.76	2.44	2.32
12/26/2024	4.76	2.43	2.33
12/27/2024	4.82	2.49	2.33
12/30/2024	4.77	2.47	2.3
12/31/2024	4.78	2.48	2.3
1/2/2025	4.79	2.48	2.31
1/3/2025	4.82	2.51	2.31
1/6/2025	4.85	2.53	2.32
1/7/2025	4.91	2.55	2.36
1/8/2025	4.91	2.55	2.36
1/9/2025	4.92	2.58	2.34
1/10/2025	4.96	2.6	2.36
1/13/2025	4.97	2.59	2.38
1/14/2025	4.98	2.61	2.37
1/15/2025	4.88	2.53	2.35
1/16/2025	4.84	2.51	2.33
1/17/2025	4.84	2.51	2.33
1/21/2025	4.8	2.48	2.32
1/22/2025	4.82	2.48	2.34
1/23/2025	4.87	2.5	2.37
1/24/2025	4.85	2.47	2.38
1/27/2025	4.76	2.4	2.36
1/28/2025	4.78	2.42	2.36
1/29/2025	4.79	2.42	2.37
1/30/2025	4.76	2.42	2.34

1/31/2025	4.83	2.46	2.37
2/3/2025	4.77	2.39	2.38
2/4/2025	4.75	2.37	2.38
2/5/2025	4.64	2.29	2.35
2/6/2025	4.65	2.3	2.35
2/7/2025	4.69	2.35	2.34
2/10/2025	4.71	2.36	2.35
2/11/2025	4.75	2.38	2.37
2/12/2025	4.83	2.46	2.37
2/13/2025	4.72	2.38	2.34
2/14/2025	4.69	2.36	2.33
2/18/2025	4.77	2.41	2.36
2/19/2025	4.76	2.4	2.36
2/20/2025	4.74	2.39	2.35
2/21/2025	4.67	2.35	2.32
2/24/2025	4.66	2.33	2.33
2/25/2025	4.55	2.27	2.28
2/26/2025	4.51	2.25	2.26
2/27/2025	4.56	2.3	2.26
2/28/2025	4.51	2.24	2.27
30-Day Average	**4.70**	**2.36**	**2.34**
90-Day Average	**4.71**	**2.39**	**2.32**

https://www.federalreserve.gov/releases/h15/

Schedule MLR-3 - Survey of Professional Forecasters (U.S. Quarterly and Annual Forecasts)									
	Percent (%) Growth at Annual Rates								
	Quaterly					Year-Over-Year			
	Q1 2025	Q2 2025	Q3 2025	Q4 2025	Q1 2026	2025	2026	2027	2028
Real Gross Domestic Product ("GDP")	2.50	2.10	2.00	2.10	2.20	2.40	2.20	1.80	2.00
Nominal GDP	5.00	4.70	4.70	4.50	4.50	4.80	4.50	N.A.	N.A.
GDP Price Index	2.50	2.50	2.40	2.60	2.70	2.30	2.50	N.A.	N.A.
Consumer Price Index ("CPI")	3.00	2.80	2.70	2.70	2.60	2.80	2.60	2.30	N.A.
CORE CPI	3.00	2.90	2.90	2.80	2.70	2.90	2.60	2.30	N.A.
Personal Consumption Expenditure ("PCE")	2.50	2.40	2.40	2.30	2.30	2.40	2.30	2.00	N.A.
CORE PCE	2.50	2.50	2.40	2.30	2.30	2.40	2.30	2.10	N.A.
Unemployment Rate	4.10	4.20	4.20	4.30	4.30	4.20	4.20	4.30	4.30
3-Month Treasury Bill	4.30	4.20	4.10	3.90	3.80	4.10	3.60	3.10	3.00
10-Year Treasury Bond	4.50	4.40	4.40	4.30	4.20	4.40	4.20	4.00	4.00
Moody's AAA Corp. Bond	5.30	5.24	5.16	5.11	5.10	5.20	5.20	N.A.	N.A.
Moody's BAA Corp. Bond	6.00	6.00	6.00	5.91	6.04	5.96	6.08	N.A.	N.A.

Source: Research Department, Federal Reserve Bank of Philadelphia, Survey of Professional Forecasters, First Quarter 2025, at 9 and 11.

Note: The figures above represent medians of 40 forecasters.

Schedule MLR-4 - Sample Characteristics					
Proxy Group	**VL Beta (1.00 = Market)**	**S&P Credit Rating**	**Moody's Credit Rating**	**Common Equity Ratio (2025)**	**Long-Term Debt Ratio (2025)**
Atmos Energy Corp	0.90	A-	A1	60.00	40.00
Chesapeake Utilities	0.85	NR	NR	53.00	47.00
New Jersey Resources Corp	1.00	NR	A1	43.50	56.50
Nisource Inc	0.95	BBB+	Baa2	46.00	54.00
Northwest Natural	0.90	A-	NR	45.00	55.00
ONE Gas Inc.	0.85	A-	A3	55.00	45.00
Southwest Gas	0.95	BBB	Baa1	45.00	55.00
Spire Inc.	0.90	BBB+	Baa2	43.00	53.00
Sample Average	**0.91**			**48.81**	**50.69**
Sample Median	**0.90**			**45.50**	**53.50**

Source: Value Line Investment Survey, Issue 3 (Natural Gas Utility), February 21, 2025.

Credit Ratings as of March 5, 2025; reporterd by S&P Global Market Intelligence.

Schedule MLR-5a - Constant Growth DCF Results, EPS Growth Method (30-Stock Price)									
Proxy Group	30-Day Stock Price Ave., P0	DPS (2025), D0	Current Div Yield, D0/P0	Expected Div Yield, D0/P0*(1+0.5g)	S&P Expected EPS Growth Next 5 yrs[1]	Zacks Expected EPS Growth Next 5 yrs[2]	VL Expected EPS Growth	Average Expected Earnings Growth Rate, g	1St DCF w/Earnings Growth, (D1/P0)+g
Atmos Energy Corp	145.97	3.48	2.38	2.47	7.44	7.10	6.00	6.85	9.31
Chesapeake Utilities	123.83	2.64	2.13	2.20	8.25	N/A	5.00	6.63	8.83
New Jersey Resources Corp	46.89	1.80	3.84	3.94	5.90	N/A	5.00	5.45	9.39
Nisource Inc	38.83	1.12	2.88	3.01	7.93	8.20	9.50	8.54	11.55
Northwest Natural	40.72	1.96	4.81	4.97	6.50	N/A	6.50	6.50	11.47
ONE Gas Inc.	71.85	2.68	3.73	3.80	2.63	4.70	4.00	3.78	7.58
Southwest Gas	76.31	2.48	3.25	3.40	10.55	6.60	10.00	9.05	12.45
Spire Inc.	73.16	3.14	4.29	4.41	6.82	5.80	4.50	5.71	10.12
Sample Average	**77.19**	**2.41**	**3.42**	**3.53**	**7.00**	**6.48**	**6.31**	**6.56**	**10.09**
Sample Median									**9.76**

Source: Value Line Investment Survey, Issue 3 (Natural Gas Utility), February 21, 2025.

Schedule MLR-5b - Constant Growth DCF Results, Expected EPS, DPS and BVPS Growth Method (30-Day Stock Price)

Proxy Group	30-Day Stock Price Ave., P0	DPS (2025), D0	Current Div Yield, D0/P0	Expected Div Yield, D0/P0*(1+0.5g)	Average Expected Earnings Growth Rate, g[1]	VL Expected DPS Growth	VL Expected BVPS Growth	Average Expected Growth Rate (EPS, DPS, BVPS), g	1st DCF using EPS, DPS, BV Growth Rates, (D1/P0)+g
Atmos Energy Corp	145.97	3.48	2.38	2.46	6.85	7.00	5.00	6.28	8.74
Chesapeake Utilities	123.83	2.64	2.13	2.20	6.63	7.50	6.00	6.71	8.91
New Jersey Resources Corp	46.89	1.80	3.84	3.93	5.45	5.00	4.50	4.98	8.92
Nisource Inc	38.83	1.12	2.88	2.97	8.54	4.50	5.00	6.01	8.99
Northwest Natural	40.72	1.96	4.81	4.90	6.50	0.50	4.00	3.67	8.57
ONE Gas Inc.	71.85	2.68	3.73	3.81	3.78	2.50	6.00	4.09	7.90
Southwest Gas	76.31	2.48	3.25	3.37	9.05	5.50	7.50	7.35	10.72
Spire Inc.	73.16	3.14	4.29	4.38	5.71	4.00	2.50	4.07	8.45
Sample Average	**77.19**	**2.41**	**3.42**	**3.50**	**6.56**	**4.56**	**5.06**	**5.40**	**8.90**
Sample Median									**8.83**

Source: Value Line Investment Survey, Issue 3 (Natural Gas Utility), February 21, 2025.

1. Average Expected EPS Growth from Schedule MLR-5a.

Schedule MLR-5c - Constant Growth DCF Results, EPS Growth Method (90-Day Stock Price)									
Proxy Group	90-Day Stock Price Ave., P0	DPS (2025), D0	Current Div Yield, D0/P0	Expected Div Yield, D0/P0*(1+0.5g)	S&P Expected EPS Growth Next 5 yrs[1]	Zacks Expected EPS Growth Next 5 yrs[2]	VL Expected EPS Growth	Average Expected Earnings Growth Rate, g	1St DCF w/Earnings Growth, (D1/P0)+g
Atmos Energy Corp	142.58	3.48	2.44	2.52	7.44	7.10	6.00	6.85	9.37
Chesapeake Utilities	123.36	2.64	2.14	2.21	8.25	N/A	5.00	6.63	8.84
New Jersey Resources Corp	47.13	1.80	3.82	3.92	5.90	N/A	5.00	5.45	9.37
Nisource Inc	37.49	1.12	2.99	3.11	7.93	8.20	9.50	8.54	11.66
Northwest Natural	40.50	1.96	4.84	5.00	6.50	N/A	6.50	6.50	11.50
ONE Gas Inc.	70.97	2.68	3.78	3.85	2.63	4.70	4.00	3.78	7.62
Southwest Gas	73.64	2.48	3.37	3.52	10.55	6.60	10.00	9.05	12.57
Spire Inc.	70.16	3.14	4.48	4.60	6.82	5.80	4.50	5.71	10.31
Sample Average	**75.73**	**2.41**	**3.48**	**3.59**	**7.00**	**6.48**	**6.31**	**6.56**	**10.16**
Sample Median									**9.84**

Source: Value Line Investment Survey, Issue 3 (Natural Gas Utility), February 21, 2025.

Schedule MLR-5d - Constant Growth DCF Results, Expected EPS, DPS and BVPS Growth Method (90-Day Stock Price)									
Proxy Group	**90-Day Stock Price Ave., P0**	**DPS (2025), D0**	**Current Div Yield, D0/P0**	**Expected Div Yield, D0/P0*(1+0.5g)**	**Average Expected Earnings Growth Rate, g[1]**	**VL Expected DPS Growth**	**VL Expected BVPS Growth**	**Average Expected Growth Rate (EPS, DPS, BVPS), g**	**1st DCF using EPS, DPS, BV Growth Rates, (D1/P0)+g**
Atmos Energy Corp	142.58	3.48	2.44	2.52	6.85	7.00	5.00	6.28	8.80
Chesapeake Utilities	123.36	2.64	2.14	2.21	6.63	7.50	6.00	6.71	8.92
New Jersey Resources Corp	47.13	1.80	3.82	3.91	5.45	5.00	4.50	4.98	8.90
Nisource Inc	37.49	1.12	2.99	3.08	8.54	4.50	5.00	6.01	9.09
Northwest Natural	40.50	1.96	4.84	4.93	6.50	0.50	4.00	3.67	8.60
ONE Gas Inc.	70.97	2.68	3.78	3.85	3.78	2.50	6.00	4.09	7.95
Southwest Gas	73.64	2.48	3.37	3.49	9.05	5.50	7.50	7.35	10.84
Spire Inc.	70.16	3.14	4.48	4.57	5.71	4.00	2.50	4.07	8.64
Sample Average	**75.73**	**2.41**	**3.48**	**3.57**	**6.56**	**4.56**	**5.06**	**5.40**	**8.97**
Sample Median									**8.85**

Source: Value Line Investment Survey, Issue 3 (Natural Gas Utility), February 21, 2025.

1. Average Expected EPS Growth from Schedule MLR-5c.

Schedule MLR-6a - Sustainable Growth DCF (Internal Growth Component)											
Proxy Group	**Expected DPS (28-30)**	**Expected EPS (28-30)**	**BVPS (2025)**	**Expected BVPS (28-30)**	**Book Value Growth**	**Expected ROE = EPS/BVPS**	**Adjustment Factor**	**Adjusted ROE, r**	**Payout Ratio, DPS/EPS**	**Retention Rate, b**	**Internal Growth Rate, r*b**
Atmos Energy Corp	4.45	8.65	83.50	97.30	0.031	8.89	1.02	9.03	0.51	0.49	4.38
Chesapeake Utilities	3.35	6.80	62.20	72.80	0.032	9.34	1.02	9.49	0.49	0.51	4.81
New Jersey Resources Corp	2.20	3.90	23.05	27.00	0.032	14.44	1.02	14.67	0.56	0.44	6.40
Nisource Inc	1.44	2.55	23.20	25.70	0.021	9.92	1.01	10.02	0.56	0.44	4.36
Northwest Natural	2.00	3.45	37.60	44.20	0.033	7.81	1.02	7.93	0.58	0.42	3.33
ONE Gas Inc.	2.90	5.25	55.95	69.45	0.044	7.56	1.02	7.72	0.55	0.45	3.46
Southwest Gas	3.00	4.85	54.25	58.65	0.016	8.27	1.01	8.33	0.62	0.38	3.18
Spire Inc.	3.70	5.25	53.05	57.80	0.017	9.08	1.01	9.16	0.70	0.30	2.70
Sample Average	**2.88**	**5.09**	**49.10**	**56.61**	**0.03**	**9.41**	**1.01**	**9.54**	**0.57**	**0.43**	**4.08**
Sample Median											**3.91**

Source: Value Line Investment Survey, Issue 3 (Natural Gas Utility), February 21, 2025.

Schedule MLR-6b - Sustainable Growth DCF (External Growth Component)									
Proxy Group	**30-Day Stock Price Ave., P0**	**BVPS (2025)**	**Market-to-Book Ratio, P0/BVPS**	**Comm Shares Outstanding (mil) 2024**	**Expected Comm Shares Outstanding in 5yrs**	**Growth in # Shares**	**Expected Growth in # of shares, s**	**Expected Profit of stock investment, v**	**External Growth, s*v**
Atmos Energy Corp	145.97	83.50	1.75	155.26	185.00	3.57	6.24	0.43	2.67
Chesapeake Utilities	123.83	62.20	1.99	23.00	25.00	1.68	3.35	0.50	1.67
New Jersey Resources Corp	46.89	23.05	2.03	99.46	105.00	1.09	2.22	0.51	1.13
Nisource Inc	38.83	23.20	1.67	470.00	525.00	2.24	3.75	0.40	1.51
Northwest Natural	40.72	37.60	1.08	41.00	50.00	4.05	4.39	0.08	0.34
ONE Gas Inc.	71.85	55.95	1.28	56.50	57.00	0.18	0.23	0.22	0.05
Southwest Gas	76.31	54.25	1.41	72.00	75.00	0.82	1.15	0.29	0.33
Spire Inc.	73.16	53.05	1.38	57.70	72.00	4.53	6.24	0.27	1.72
Sample Average	**77.19**	**49.10**	**1.57**	**121.87**	**136.75**	**2.27**	**3.44**	**0.34**	**1.18**
Sample Median									**1.32**

Source: Value Line Investment Survey, Issue 3 (Natural Gas Utility), February 21, 2025.

ScheduleMLR-6c - Sustainable Growth DCF (Results) (30-Day Stock Price)						
Proxy Group	**30-Day Stock Price Ave., P0**	**DPS (2025), D0**	**Currnet Div Yield, D0/P0**	**Expected Div Yield, D0/P0*(1+0.5g)**	**Sustainable Growth Rate, rb+sv[1]**	**Sustainable Growth DCF, (D1/P0)+rb+sv**
Atmos Energy Corp	145.97	3.48	2.38	2.47	7.05	9.52
Chesapeake Utilities	123.83	2.64	2.13	2.20	6.48	8.68
New Jersey Resources Corp	46.89	1.80	3.84	3.98	7.52	11.51
Nisource Inc	38.83	1.12	2.88	2.97	5.87	8.84
Northwest Natural	40.72	1.96	4.81	4.90	3.67	8.57
ONE Gas Inc.	71.85	2.68	3.73	3.80	3.51	7.30
Southwest Gas	76.31	2.48	3.25	3.31	3.51	6.82
Spire Inc.	73.16	3.14	4.29	4.39	4.42	8.81
Sample Average	**77.19**	**2.41**	**3.42**	**3.50**	**5.25**	**8.76**
Sample Median						**8.74**

1. See Schedule MLR-6a for internal growth component, rb and Schedule MLR-6b for external growth component, sv.

Source: Value Line Investment Survey, Issue 3 (Natural Gas Utility), February 21, 2025.

Schedule MLR-6d - Sustainable Growth DCF (Internal Growth Component)											
Proxy Group	Expected DPS (28-30)	Expected EPS (28-30)	BVPS (2025)	Expected BVPS (28-30)	Book Value Growth	Expected ROE = EPS/BVPS	Adjustment Factor	Adjusted ROE, r	Payout Ratio, DPS/EPS	Retention Rate, b	Internal Growth Rate, r*b
Atmos Energy Corp	4.45	8.65	83.50	97.30	0.031	8.89	1.02	9.03	0.51	0.49	4.38
Chesapeake Utilities	3.35	6.80	62.20	72.80	0.032	9.34	1.02	9.49	0.49	0.51	4.81
New Jersey Resources Corp	2.20	3.90	23.05	27.00	0.032	14.44	1.02	14.67	0.56	0.44	6.40
Nisource Inc	1.44	2.55	23.20	25.70	0.021	9.92	1.01	10.02	0.56	0.44	4.36
Northwest Natural	2.00	3.45	37.60	44.20	0.033	7.81	1.02	7.93	0.58	0.42	3.33
ONE Gas Inc.	2.90	5.25	55.95	69.45	0.044	7.56	1.02	7.72	0.55	0.45	3.46
Southwest Gas	3.00	4.85	54.25	58.65	0.016	8.27	1.01	8.33	0.62	0.38	3.18
Spire Inc.	3.70	5.25	53.05	57.80	0.017	9.08	1.01	9.16	0.70	0.30	2.70
Sample Average	**2.88**	**5.09**	**49.10**	**56.61**	**0.03**	**9.41**	**1.01**	**9.54**	**0.57**	**0.43**	**4.08**
Sample Median											**3.91**

Source: Value Line Investment Survey, Issue 3 (Natural Gas Utility), February 21, 2025.

Schedule MLR-6e - Sustainable Growth DCF - External Growth Component									
Proxy Group	90-Day Stock Price Ave., P0	BVPS (2025)	Market-to-Book Ratio, P0/BVPS	Comm Shares Outstanding (mil) 2024	Expected Comm Shares Outstanding in 5yrs	Growth in # Shares	Expected Growth in # of shares, s	Expected Profit of stock investment, v	External Growth, s*v
Atmos Energy Corp	142.58	83.50	1.71	155.26	185.00	3.57	6.09	0.41	2.52
Chesapeake Utilities	123.36	62.20	1.98	23.00	25.00	1.68	3.34	0.50	1.65
New Jersey Resources Corp	47.13	23.05	2.04	99.46	105.00	1.09	2.23	0.51	1.14
Nisource Inc	37.49	23.20	1.62	470.00	525.00	2.24	3.62	0.38	1.38
Northwest Natural	40.50	37.60	1.08	41.00	50.00	4.05	4.36	0.07	0.31
ONE Gas Inc.	70.97	55.95	1.27	56.50	57.00	0.18	0.22	0.21	0.05
Southwest Gas	73.64	54.25	1.36	72.00	75.00	0.82	1.11	0.26	0.29
Spire Inc.	70.16	53.05	1.32	57.70	72.00	4.53	5.99	0.24	1.46
Sample Average	**75.73**	**49.10**	**1.55**	**121.87**	**136.75**	**2.27**	**3.37**	**0.32**	**1.10**
Sample Median									**1.26**

Source: Value Line Investment Survey, Issue 3 (Natural Gas Utility), February 21, 2025.

Schedule MLR-6f - Sustainable Growth DCF (Results) (90-Day Stock Price)						
Proxy Group	**90-Day Stock Price Ave., P0**	**DPS (2025), D0**	**Current Div Yield, D0/P0**	**Expected Div Yield, D0/P0*(1+0.5g)**	**Sustainable Growth Rate, rb+sv[1]**	**Sustainable Growth DCF, (D1/P0)+rb+sv**
Atmos Energy Corp	142.58	3.48	2.44	2.52	6.91	9.43
Chesapeake Utilities	123.36	2.64	2.14	2.21	6.47	8.68
New Jersey Resources Corp	47.13	1.80	3.82	3.96	7.53	11.50
Nisource Inc	37.49	1.12	2.99	3.07	5.74	8.81
Northwest Natural	40.50	1.96	4.84	4.93	3.65	8.57
ONE Gas Inc.	70.97	2.68	3.78	3.84	3.50	7.35
Southwest Gas	73.64	2.48	3.37	3.43	3.47	6.90
Spire Inc.	70.16	3.14	4.48	4.57	4.16	8.73
Sample Average	**75.73**	**2.41**	**3.48**	**3.57**	**5.18**	**8.75**
Sample Median						**8.71**

1. See Schedule MLR-6d for internal growth component, rb and Schedule MLR-6e for external growth component, sv.

Source: Value Line Investment Survey, Issue 3 (Natural Gas Utility), February 21, 2025.

Schedule MLR-7a - CAPM & ECAPM Assumptions	
(Historical Large Stock Return, 30-yr T-Bond)	**%**
Historical L-T Equity Risk Premium (1926-2023): Arithmetic Ave.[1]	7.17
Yield on T-Bond (Risk-Free Rate)	4.70
VL Sample Beta	0.91
VL Beta Adjusted Risk Premium	6.54
CAPM ROE	**11.24**

1. www.costofcapital.kroll.com.

2. Risk-free Rate based on 30-day average of yield on 30-Year Treasury bonds. See Schedule MLR-7b. Source: https://www.federalreserve.gov/releases/h15/

Schedule MLR-7b - CAPM & ECAPM Results (Historical Large Stock, 30-yr T-Bond)				
Proxy Group	**Risk-Free Rate**	**VL Beta (1.00 = Market)**	**Historical L-T Equity Risk Premium**	**CAPM ROE**
Atmos Energy Corp	4.70	0.90	7.17	11.15
Chesapeake Utilities	4.70	0.85	7.17	10.79
New Jersey Resources Corp	4.70	1.00	7.17	11.87
Nisource Inc	4.70	0.95	7.17	11.51
Northwest Natural	4.70	0.90	7.17	11.15
ONE Gas Inc.	4.70	0.85	7.17	10.79
Southwest Gas	4.70	0.95	7.17	11.51
Spire Inc.	4.70	0.90	7.17	11.15
Sample Average	**4.70**	**0.91**	**7.17**	**11.24**

Source: Value Line Investment Survey, Issue 3 (Natural Gas Utility), February 21, 2025.

Schedule MLR-7c - CAPM & ECAPM Assumptions (Supply-Side ERP, 30-yr T-Bond)	%
Supply-Side Equity Risk Premium (1926-2023): Arithmetic Ave.[1]	6.22
Yield on T-Bond (Risk-Free Rate)	4.70
VL Sample Beta	0.91
VL Beta Adjusted Risk Premium	5.68
CAPM ROE	**10.37**

1. www.costofcapital.kroll.com.

2. Risk-free Rate based on 30-day average of yield on 30-Year Treasury bonds. See Schedule MLR-7d. Source: https://www.federalreserve.gov/releases/h15/

Schedule MLR-7d - CAPM & ECAPM Results (Supply-Side Equity ERP, 30-yr T-Bond)

Proxy Group	Risk-Free Rate	VL Beta (1.00 = Market)	Supply-Side Risk Premium	CAPM ROE
Atmos Energy Corp	4.70	0.90	6.22	10.29
Chesapeake Utilities	4.70	0.85	6.22	9.98
New Jersey Resources Corp	4.70	1.00	6.22	10.92
Nisource Inc	4.70	0.95	6.22	10.60
Northwest Natural	4.70	0.90	6.22	10.29
ONE Gas Inc.	4.70	0.85	6.22	9.98
Southwest Gas	4.70	0.95	6.22	10.60
Spire Inc.	4.70	0.90	6.22	10.29
Sample Average	**4.70**	**0.91**	**6.22**	**10.37**

Source: Value Line Investment Survey, Issue 3 (Natural Gas Utility), February 21, 2025.

Schedule MLR-7e - CAPM & ECAPM Assumptions (D&P Normalized RF Rate)	%
D&P Recommended US ERP[1]	5.00
D&P Normalized Risk-Free Rate[1]	3.50
VL Sample Beta	0.91
VL Beta Adjusted Risk Premium	4.56
CAPM ROE	**8.06**

1. Kroll, Cost of Capital in the Current Environment, January 2025 Update.

Schedule MLR-7f - CAPM & ECAPM Results (D&P Normalized RF Rate)

Proxy Group	Normalized Risk-Free Rate[1]	VL Beta (1.00 = Market)	Recommended Market Risk Premium[1]	CAPM ROE
Atmos Energy Corp	3.50	0.90	5.00	8.00
Chesapeake Utilities	3.50	0.85	5.00	7.75
New Jersey Resources Corp	3.50	1.00	5.00	8.50
Nisource Inc	3.50	0.95	5.00	8.25
Northwest Natural	3.50	0.90	5.00	8.00
ONE Gas Inc.	3.50	0.85	5.00	7.75
Southwest Gas	3.50	0.95	5.00	8.25
Spire Inc.	3.50	0.90	5.00	8.00
Sample Average	**3.50**	**0.91**	**5.00**	**8.06**

Source: Value Line Investment Survey, Issue 3 (Natural Gas Utility), February 21, 2025.

1. Kroll, Kroll Lowers Its Recommendations and Potential Upcoming Changes - February 8, 2024 Update.

Schedule MLR-8a: Natural Gas rate cases for CY 2024

where the state regulator approved an ROE, based on S&P MI data as of 3/18/2025

available at: S&P Capital IQ (https://www.capitaliq.spglobal.com/web/client?auth=inherit#office/screener?perspective=238101)

				Increase Requested						Increase Authorized												
State	Company	Case identification	Service	Date	Rate Change ($000)	Return on Rate Base (%)	Return on Equity (%)	Requested Equity Ratio (% of Total Capital)	Rate Base ($000)	Date	Rate Change ($000)	Return on Rate Base (%)	Return on Equity (%)	Equity Ratio (% of Total Capital)	Test Year End	Rate Base ($000)	Rate Base Valuation Method	Lag Months	Case Type	Decision Type	Phase-In? Yes/No	Interim Authorized? Yes/No
AK	ENSTAR Natu	D-U-22-081	Natural Gas	8/1/2022	5,041	8.32	12.95	54.11	293,178	p	1,345	7.74	11.88	54.11	12/31/2021	287,140	Average	20.53	Distribution	Fully Litigated	No	Yes
AR	Black Hills En	D-23-074-U	Natural Gas	12/4/2023	39,108	NA	10.50	48.51	973,441	10/1/2024	29,076	6.10	9.85	39.64	12/31/2023	958,604	Year-end	10.07	Distribution	Settled	No	No
AR	Summit Utilitie	D-23-079-U	Natural Gas	1/25/2024	101,194	6.98	11.00	48.25	1,228,404	11/21/2024	87,684	6.17	9.85	41.07	12/31/2024	1,205,447	Year-end	10.03	Distribution	Settled	No	No
CA	Southern Calif	A-22-04-011 (	Natural Gas	1/16/2024	NA	NA	10.50	NA	NA	10/17/2024	-28,900	7.49	10.08	NA		NA		9.17	Distribution	Fully Litigated	No	No
CO	Black Hills Co	D-23AL-0231(	Natural Gas	5/8/2023	26,105	7.52	10.49	51.00	394,314	3/24/2024	20,171	6.90	9.30	50.87	12/31/2022	378,440	Average	10.70	Distribution	Settled	No	No
CO	Public Service	D-24AL-0049(	Natural Gas	1/29/2024	169,571	7.52	10.10	55.00	4,190,512	10/25/2024	130,759	7.00	9.35	54.00	12/31/2023	NA	Average	9.00	Distribution	Fully Litigated	No	No
CT	Connecticut N	D-23-11-02 (C	Natural Gas	11/3/2023	19,703	7.95	10.20	55.00	602,269	11/18/2024	-24,610	7.25	9.15	53.00	12/31/2022	534,577	Average	12.70	Distribution	Fully Litigated	No	No
CT	The Southern	D-23-11-02 (S	Natural Gas	11/3/2023	43,239	7.70	10.20	53.00	876,932	11/18/2024	-10,716	7.06	9.15	53.00	12/31/2022	774,479	Average	12.70	Distribution	Fully Litigated	No	No
IA	MidAmerican	D-RPU-2023-	Natural Gas	6/12/2023	39,351	7.59	10.50	54.90	848,494	3/29/2024	29,645	7.11	NA	51.50	12/31/2022	845,632	Average	9.70	Distribution	Settled	No	No
IA	Interstate Pow	D-RPU-2023-	Natural Gas	10/12/2023	13,934	7.42	10.00	52.02	630,200	9/17/2024	10,000	7.18	9.65	51.00	9/30/2025	630,114	Average	11.37	Distribution	Settled	No	No
IA	Black Hills Iow	D-RPU-2024-	Natural Gas	5/1/2024	20,670	7.65	10.50	51.38	397,684	11/26/2024	14,961	7.21	NA	NA	12/31/2023	393,835	Year-end	6.97	Distribution	Settled	No	Yes
IL	Liberty Utilities	D-24-0043	Natural Gas	12/20/2023	4,148	8.41	10.80	54.00	75,432	10/31/2024	3,174	7.54	9.90	45.30	12/31/2024	74,745	Average	10.53	Distribution	Fully Litigated	No	No
IN	Northern India	Ca-45967	Natural Gas	10/25/2023	161,897	7.48	10.70	52.39	3,484,810	7/31/2024	120,948	6.98	9.75	52.39	12/31/2024	3,484,810	Year-end	9.33	Distribution	Settled	Yes	No
IN	Ohio Valley G	Ca-46011	Natural Gas	2/7/2024	12,062	9.44	11.00	83.18	68,109	11/6/2024	11,059	8.61	10.00	83.18	9/30/2025	68,078	Year-end	9.10	Distribution	Settled	Yes	No
KY	Columbia Gas	C-2024-0009	Natural Gas	5/16/2024	23,773	8.01	10.80	52.64	518,827	12/30/2024	14,293	7.41	9.75	52.64	12/31/2025	509,471	Average	7.60	Distribution	Settled	No	No
MA	Fitchburg Gas	DPU 23-81	Natural Gas	8/17/2023	11,278	8.17	10.75	52.26	121,686	6/28/2024	10,208	7.46	9.40	52.26	12/31/2022	121,536	Year-end	10.53	Distribution	Fully Litigated	Yes	No
MI	DTE Gas Con	C-U-21291	Natural Gas	1/8/2024	262,407	6.04	10.25	40.78	6,939,800	11/7/2024	113,788	5.80	9.80	39.59	9/30/2025	6,888,851	Average	10.13	Distribution	Fully Litigated	No	No
ND	MDU Resourc	C-PU-23-341	Natural Gas	11/1/2023	11,635	7.56	10.50	50.19	216,970	11/7/2024	9,444	7.26	9.90	50.19	12/31/2024	215,355	Average	12.40	Distribution	Settled	No	Yes
ND	Northern State	C-PU-23-367	Natural Gas	12/29/2023	8,463	7.52	10.20	52.50	167,970	11/7/2024	7,348	7.36	9.90	52.50	12/31/2024	NA	Average	10.47	Distribution	Settled	No	Yes
NJ	Public Service	D-GR231209	Natural Gas	12/29/2023	409,438	7.54	10.40	55.50	8,773,537	10/9/2024	270,800	7.07	9.60	55.00	5/31/2024	8,500,000	Year-end	9.50	Distribution	Settled	No	No
NJ	New Jersey N	D-GR240100	Natural Gas	1/31/2024	219,862	7.52	10.42	54.08	3,345,664	11/21/2024	157,000	7.08	9.60	54.00	6/30/2024	3,245,021	Year-end	9.83	Distribution	Settled	No	No
NJ	Elizabethtown	D-GR240201	Natural Gas	2/29/2024	70,254	8.33	10.75	57.00	1,813,360	11/21/2024	38,000	7.58	9.60	55.00	6/30/2024	1,773,000	Year-end	8.87	Distribution	Settled	No	No
NM	New Mexico G	C-23-00255-U	Natural Gas	9/14/2023	48,430	7.44	10.50	53.00	968,135	7/25/2024	30,000	6.79	9.38	52.00	9/30/2025	955,087	Average	10.50	Distribution	Settled	No	No
NV	Southwest Ga	D-23-09012 (N	Natural Gas	9/11/2023	10,473	7.26	10.00	50.00	227,060	4/8/2024	8,700	7.01	9.50	50.00	5/31/2023	NA	Year-end	7.00	Distribution	Settled	No	No
NV	Southwest Ga	D-23-09012 (S	Natural Gas	9/11/2023	63,504	7.25	10.00	50.00	1,780,733	4/8/2024	50,400	7.00	9.50	50.00	5/31/2023	NA	Year-end	7.00	Distribution	Settled	No	No
NV	Sierra Pacific	D-24-02027	Natural Gas	2/23/2024	12,201	7.90	10.34	55.19	280,510	9/18/2024	8,363	7.28	9.45	52.40	9/30/2023	277,481	Year-end	6.93	Distribution	Fully Litigated	No	No
NY	The Brooklyn	C-23-G-0225	Natural Gas	4/28/2023	466,486	7.09	9.80	48.00	7,353,223	8/15/2024	443,984	6.94	9.35	48.00	3/31/2025	7,311,967	Average	15.83	Distribution	Settled	Yes	No
NY	KeySpan Gas	C-23-G-0226	Natural Gas	4/28/2023	277,257	7.05	9.80	48.00	4,710,976	8/15/2024	246,468	6.86	9.35	48.00	3/31/2025	4,714,051	Average	15.83	Distribution	Settled	Yes	No
NY	Central Hudsc	C-23-G-0419	Natural Gas	7/31/2023	42,002	7.10	9.80	50.00	743,799	7/18/2024	27,307	6.92	9.50	48.00	6/30/2025	717,414	Average	11.77	Distribution	Fully Litigated	No	No
NY	National Fuel	C-23-G-0627	Natural Gas	10/31/2023	88,560	7.57	9.80	52.00	1,041,422	12/19/2024	57,291	7.30	9.70	48.00	9/30/2025	1,044,176	Average	13.83	Distribution	Settled	Yes	No
OH	Northeast Ohi	C-23-0154-GA	Natural Gas	3/31/2023	5,981	8.71	10.90	64.83	63,757	4/17/2024	2,395	7.64	9.75	51.42	9/30/2023	62,704	Date Certain	12.77	Distribution	Settled	No	No
OR	Northwest Nat	D-UG-490	Natural Gas	12/29/2023	152,345	7.41	10.10	50.00	2,123,961	10/25/2024	95,000	7.06	9.40	50.00	10/31/2025	2,090,000	Average	10.03	Distribution	Settled	No	No
SD	MDU Resourc	D-NG23-014	Natural Gas	8/15/2023	7,420	7.60	10.50	50.39	77,111	8/13/2024	5,369	7.01	NA	NA	12/31/2022	71,781	Average	12.13	Distribution	Settled	No	Yes
SD	NorthWestern	D-NG24-005	Natural Gas	6/21/2024	6,043	7.75	10.70	53.13	95,607	12/17/2024	4,599	6.91	NA	NA	12/31/2023	96,199	Average	5.97	Distribution	Settled	No	No
TN	Atmos Energy	D-24-00006	Natural Gas	1/30/2024	20,390	7.62	NA	62.38	554,055	7/29/2024	19,416	7.64	NA	62.38	9/30/2023	554,053	Average	6.03	Distribution	Settled	No	No
TN	Chattanooga (	D-24-00024	Natural Gas	4/19/2024	8,778	7.12	NA	49.23	275,667	8/12/2024	8,778	7.12	NA	49.23	12/31/2023	275,667	Average	3.83	Distribution	Settled	No	No
TN	Piedmont Nat	D-24-00036	Natural Gas	5/20/2024	25,374	7.04	NA	49.97	1,250,355	12/4/2024	20,329	7.07	NA	NA	12/31/2023	1,249,743	Average	6.60	Distribution	Settled	No	No
TX	Texas Gas Se	D-OSS-23-00	Natural Gas	6/30/2023	9,813	7.75	10.25	59.07	180,127	1/31/2024	5,875	7.42	9.70	59.07	12/31/2022	NA	Year-end	7.17	Distribution	Settled	No	No
TX	CenterPoint E	D-OSS-23-00	Natural Gas	10/30/2023	38,844	8.25	10.50	60.61	2,322,305	6/26/2024	5,000	7.82	9.80	60.61	6/30/2023	NA	Year-end	8.00	Distribution	Settled	No	No
TX	Texas Gas Se	D-OS-24-000	Natural Gas	6/3/2024	25,573	7.88	10.25	59.58	811,194	11/20/2024	19,300	7.55	9.70	59.58	12/31/2023	NA	Year-end	5.67	Distribution	Settled	No	No
WA	Avista Corpor	D-UG-240007	Natural Gas	1/18/2024	20,819	7.61	10.40	48.50	607,240	12/20/2024	18,200	7.32	9.80	48.50	6/30/2023	607,241	Average	11.23	Distribution	Fully Litigated	Yes	No
WI	Wisconsin Pul	D-6690-UR-1	Natural Gas	4/12/2024	42,881	8.16	10.00	54.68	926,985	12/19/2024	28,401	7.95	9.80	54.17	12/31/2026	907,259	Average	8.37	Distribution	Fully Litigated	Yes	No
WI	Wisconsin Ele	D-5-UR-111 (	Natural Gas	4/12/2024	88,479	8.96	10.00	56.88	1,479,687	12/19/2024	71,103	8.80	9.80	56.54	12/31/2026	1,454,775	Average	8.37	Distribution	Fully Litigated	Yes	No
WI	Wisconsin Ga	D-5-UR-111	Natural Gas	4/12/2024	98,269	9.02	10.00	53.26	2,127,998	12/19/2024	58,009	8.63	9.80	52.76	12/31/2026	2,049,082	Average	8.37	Distribution	Fully Litigated	Yes	No
WY	Black Hills Wy	D-30026-78-G	Natural Gas	5/18/2023	20,498	7.73	10.49	52.05	449,308	1/17/2024	15,143	7.33	9.85	51.00	12/31/2022	450,761	Year-end	8.13	Distribution	Settled	No	No

Return on Rate Base (%)	
Mean	7.26
Standard E	0.08
Median	7.21
Mode	7.00
Standard D	0.56
Sample Var	0.32
Kurtosis	2.23
Skewness	0.41
Range	3.00
Minimum	5.80
Maximum	8.80
Sum	326.73
Count	45.00

Schedule MLR-8b: Natural Gas rate cases for CY 2023

where the state regulator approved an ROE, based on S&P MI data as of 3/18/2025

available at: S&P Capital IQ (https://www.capitaliq.spglobal.com/web/client?auth=inherit#office/screener?perspective=238101)

				Increase Requested						Increase Authorized												
State	Company	Case identification	Service	Date	Rate Change ($000)	Return on Rate Base (%)	Return on Equity (%)	Requested Equity Ratio (% of Total Capital)	Rate Base ($000)	Date	Rate Change ($000)	Return on Rate Base (%)	Return on Equity (%)	Equity Ratio (% of Total Capital)	Test Year End	Rate Base ($000)	Rate Base Valuation Method	Lag Months	Case Type	Decision Type	Phase-In? Yes/No	Interim Authorized? Yes/No
AZ	Southwest Ga	D-G-01551A-:	Natural Gas	12/3/2021	90,730	7.08	9.90	51.00	2,642,068	p	54,283	6.73	9.30	50.00	8/31/2021	2,607,568	Year-end	13.87	Distribution	Settled	No	No
CA	Southern Calif	Advice Letter	Natural Gas	10/13/2023	77,000	7.67	10.50	52.00	NA	12/22/2023	77,000	7.67	10.50	52.00		NA		2.33	Distribution	Fully Litigated	No	No
CO	Atmos Energy	D-22AL-0348(	Natural Gas	8/5/2022	7,681	8.17	10.95	60.92	266,776	5/4/2023	-1,160	7.00	9.30	58.00	3/31/2022	229,565	Average	9.07	Distribution	Settled	No	No
DC	Washington G	FC-1169	Natural Gas	4/4/2022	52,966	7.39	10.40	53.69	728,902	12/15/2023	24,595	7.11	9.65	52.00	12/31/2021	580,402	Average	20.67	Distribution	Fully Litigated	No	No
FL	Florida Public	D-20220067-(	Natural Gas	5/24/2022	24,062	6.43	11.25	45.14	454,887	1/24/2023	17,153	5.97	10.25	45.16	12/31/2023	453,675	Average	8.17	Distribution	Fully Litigated	No	Yes
FL	Pivotal Utility I	20220069-GU	Natural Gas	5/31/2022	28,284	7.09	10.75	52.56	488,906	3/28/2023	23,308	6.44	9.50	59.60	12/31/2023	487,258	Average	10.03	Distribution	Fully Litigated	No	No
FL	Peoples Gas	D-20230023-(	Natural Gas	4/4/2023	127,624	7.42	11.00	47.49	2,366,788	11/9/2023	106,683	7.02	10.15	NA	12/31/2024	2,357,328	Average	7.30	Distribution	Fully Litigated	No	No
ID	Intermountain	C-INT-G-22-0	Natural Gas	12/1/2022	11,338	7.37	10.30	50.00	387,513	6/30/2023	3,050	6.97	9.50	50.00	12/31/2022	385,289	Average	7.03	Distribution	Settled	No	No
ID	Avista Corpor	C-AVU-G-23-I	Natural Gas	2/1/2023	2,890	7.59	10.25	50.00	211,166	8/31/2023	1,255	7.19	9.40	50.00	6/30/2022	206,562	Average	7.03	Distribution	Settled	Yes	No
IL	Ameren Illinois	D-23-0067	Natural Gas	1/6/2023	148,227	7.53	10.30	53.99	2,894,025	11/16/2023	111,800	6.85	9.44	50.00	12/31/2024	2,841,675	Average	10.47	Distribution	Fully Litigated	No	No
IL	The Peoples (	D-23-0069	Natural Gas	1/6/2023	401,055	7.12	9.90	54.00	4,783,366	11/16/2023	302,794	6.65	9.38	50.79	12/31/2024	4,193,982	Average	10.47	Distribution	Fully Litigated	No	No
IL	North Shore G	D-23-0068	Natural Gas	1/6/2023	16,587	7.37	9.90	54.00	428,585	11/16/2023	11,012	6.96	9.38	52.58	12/31/2024	422,113	Average	10.47	Distribution	Fully Litigated	No	No
IL	Northern Illinoi	D-23-0066	Natural Gas	1/3/2023	320,027	7.49	10.35	54.52	6,184,641	11/16/2023	223,033	6.68	9.51	50.00	12/31/2024	5,971,923	Average	10.57	Distribution	Fully Litigated	No	No
MD	Baltimore Gas	C-9692 (GAS	Natural Gas	2/17/2023	290,085	7.56	10.40	52.00	3,944,907	12/14/2023	228,786	6.74	9.45	52.00	12/31/2026	3,801,217	Average	10.00	Distribution	Fully Litigated	Yes	No
MD	Washington G	C-9704	Natural Gas	5/18/2023	45,155	7.73	10.75	52.60	1,489,354	12/14/2023	12,580	7.04	9.50	52.60	12/31/2022	1,399,947	Average	7.00	Distribution	Fully Litigated	No	No
ME	Northern Utiliti	D-2023-00051	Natural Gas	5/1/2023	11,757	7.74	10.35	52.01	320,533	9/20/2023	7,573	7.22	9.35	52.01	12/31/2022	NA		4.73	Distribution	Settled	No	No
MN	Northern State	D-G-002/GR-:	Natural Gas	11/1/2021	35,629	7.46	10.50	52.50	934,448	3/23/2023	20,888	6.97	9.57	52.50	12/31/2022	927,761	Average	16.90	Distribution	Settled	No	Yes
MN	Minnesota En	D-G-011/GR-:	Natural Gas	11/1/2022	40,322	7.07	10.30	53.00	482,450	10/26/2023	28,804	6.72	9.65	53.00	12/31/2023	470,073	Average	11.97	Distribution	Settled	No	Yes
MT	NorthWestern	D-2022-7-78 (	Natural Gas	8/8/2022	22,400	7.17	10.60	48.02	582,819	10/25/2023	14,060	6.67	9.55	48.02	12/31/2021	582,819	Average	14.77	Distribution	Settled	No	Yes
NY	Consolidated I	C-22-G-0065	Natural Gas	1/28/2022	402,200	7.14	10.00	50.00	9,696,958	7/20/2023	217,210	6.75	9.25	48.00	12/31/2023	9,647,004	Average	17.93	Distribution	Settled	Yes	No
NY	New York Sta	C-22-G-0318	Natural Gas	5/26/2022	30,053	6.95	10.20	50.00	797,035	10/12/2023	11,735	6.40	9.20	48.00	4/30/2024	766,460	Average	16.80	Distribution	Settled	Yes	No
NY	Rochester Ga	C-22-G-0320	Natural Gas	5/26/2022	32,208	7.24	10.20	50.00	669,945	10/12/2023	18,237	6.67	9.20	48.00	4/30/2024	643,022	Average	16.80	Distribution	Settled	Yes	No
OH	Columbia Gas	C-21-0637-G/	Natural Gas	6/30/2021	221,429	7.85	10.95	50.60	3,560,230	1/26/2023	68,192	7.08	9.60	50.60	12/31/2021	3,505,491	Date Certain	19.17	Distribution	Settled	No	No
OH	Duke Energy (	C-22-0507-G/	Natural Gas	6/30/2022	48,745	7.33	10.30	52.34	1,911,461	11/1/2023	31,690	6.96	9.60	52.32	12/31/2022	1,897,601	Date Certain	16.30	Distribution	Settled	No	No
OR	Avista Corpor	D-UG-461	Natural Gas	3/1/2023	10,991	7.59	10.25	50.00	351,283	10/26/2023	7,160	7.24	9.50	50.00	12/31/2024	340,336	Average	7.97	Distribution	Settled	No	No
SC	Dominion Ene	D-2023-70-G	Natural Gas	3/31/2023	5,457	8.23	10.38	54.78	1,058,866	9/20/2023	-5,128	7.74	9.49	54.78	9/30/2022	1,058,447	Year-end	5.77	Distribution	Settled	No	No
SC	Piedmont Nat	D-2023-7-G	Natural Gas	6/15/2023	13,624	6.94	9.30	54.05	561,024	10/5/2023	12,940	6.90	9.30	53.13	3/31/2023	558,583	Year-end	3.73	Distribution	Settled	No	No
SD	MidAmerican	D-NG22-005	Natural Gas	5/18/2022	7,037	7.60	10.75	53.33	152,187	3/28/2023	5,947	6.75	NA	NA	12/31/2021	153,482	Average	10.47	Distribution	Settled	Yes	Yes
TN	Atmos Energy	D-23-00008	Natural Gas	1/31/2023	27	7.58	NA	62.20	499,429	6/22/2023	-1,157	7.58	NA	62.20	9/30/2022	499,447	Average	4.73	Distribution	Fully Litigated	No	No
TN	Piedmont Nat	D-23-00035	Natural Gas	5/19/2023	41,561	6.95	9.80	50.09	1,143,947	12/4/2023	40,209	6.95	9.80	50.09	12/31/2022	1,140,671	Average	6.63	Distribution	Settled	No	No
TN	Chattanooga (	D-23-00029	Natural Gas	4/20/2023	12,044	7.12	9.80	49.23	245,515	10/6/2023	11,937	7.12	9.80	49.23	12/31/2022	NA		5.63	Distribution	Settled	No	No
TX	Texas Gas Se	D-OSS-22-00	Natural Gas	6/30/2022	12,995	7.77	10.25	59.74	589,396	1/19/2023	8,827	7.38	9.60	59.74	12/31/2021	588,546	Year-end	6.77	Distribution	Fully Litigated	No	No
WI	Northern State	D-4220-UR-1:	Natural Gas	4/28/2023	8,965	7.83	10.25	52.50	266,892	11/9/2023	5,394	7.58	9.80	52.50	12/31/2024	265,491	Average	6.50	Distribution	Fully Litigated	No	No
WI	Wisconsin Po	D-6680-UR-1:	Natural Gas	4/28/2023	16,500	7.65	10.00	56.25	532,027	11/9/2023	12,702	7.42	9.80	53.70	12/31/2025	532,232	Average	6.50	Distribution	Fully Litigated	Yes	No
WI	Madison Gas	D-3270-UR-1:	Natural Gas	4/28/2023	9,990	7.83	9.80	56.05	345,463	11/3/2023	8,586	7.80	9.70	56.06	12/31/2025	341,369	Average	6.30	Distribution	Fully Litigated	Yes	No
WV	Mountaineer (	C-23-0280-G-	Natural Gas	3/6/2023	37,649	7.98	10.90	54.17	422,187	12/21/2023	13,933	7.24	9.75	NA	12/31/2022	427,070	Average	9.67	Distribution	Settled	No	No
WY	Questar Gas (	D-30010-215-	Natural Gas	3/1/2023	2,067	7.28	10.30	51.56	71,120	11/7/2023	1,639	6.95	9.65	51.56	9/30/2022	71,118	Year-end	8.37	Distribution	Settled	No	No

Return on Rate Base (%)	
Mean	7.00
Standard E	0.06
Median	6.97
Mode	6.97
Standard D	0.39
Sample Var	0.15
Kurtosis	0.52
Skewness	0.01
Range	1.83
Minimum	5.97
Maximum	7.80
Sum	259.11
Count	37.00

Schedule MLR-8c: Natural Gas rate cases for CY 2015-2025

where the state regulator approved an ROE, based on S&P MI data as of 3/18/2025, available at: S&P Capital IQ (https://www.capitaliq.spglobal.com/web/client?auth=inherit#office/screener?perspective=238101)

				Increase Requested						Increase Authorized												
State	Company	Case identification	Service	Date	Rate Change ($000)	Return on Rate Base (%)	Return on Equity (%)	Requested Equity Ratio (% of Total Capital)	Rate Base ($000)	Date	Rate Change ($000)	Return on Rate Base (%)	Return on Equity (%)	Equity Ratio (% of Total Capital)	Test Year End	Rate Base ($000)	Rate Base Valuation Method	Lag Months	Case Type	Decision Type	Phase-In? Yes/No	Interim Authorized? Yes/No
AK	ENSTAR Nat	D-U-16-066	Natural Gas	6/1/2016	11,812	8.92	12.55	51.68	286,488	p	5,810	8.59	11.88	51.81	12/31/2015	274,140	Average	15.93	Distribution	Fully Litigated	No	Yes
AK	ENSTAR Nat	D-U-22-081	Natural Gas	8/1/2022	5,041	8.32	12.95	54.11	293,178	4/8/2024	1,345	7.74	11.88	54.11	12/31/2021	287,140	Average	20.53	Distribution	Fully Litigated	No	Yes
AR	Black Hills En	D-15-011-U	Natural Gas	4/1/2015	12,609	6.10	10.25	39.70	376,805	1/28/2016	8,015	5.33	9.40	39.46	3/31/2015	374,184	Year-end	10.07	Distribution	Settled	No	No
AR	CenterPoint E	D-15-098-U	Natural Gas	11/10/2015	29,951	5.52	10.30	38.97	703,212	9/2/2016	14,230	4.53	9.50	30.85	9/30/2015	691,040	Year-end	9.90	Distribution	Settled	No	No
AR	CenterPoint E	D-17-010-FR	Natural Gas	4/5/2017	8,005	4.58	NA	30.99	700,834	9/6/2017	7,638	4.58	NA	31.02	9/30/2018	699,067	Year-end	5.13	Distribution	Settled	No	No
AR	Black Hills En	D-17-071-U	Natural Gas	12/15/2017	18,544	6.06	10.20	42.46	547,723	10/5/2018	22,564	5.62	9.61	40.43	12/31/2017	546,157	Year-end	9.80	Distribution	Settled	No	No
AR	CenterPoint E	D-17-010-FR	Natural Gas	4/4/2018	5,261	4.66	NA	31.35	770,664	9/11/2018	5,123	4.69	NA	31.52	9/30/2019	769,091	Year-end	5.33	Distribution	Settled	No	No
AR	CenterPoint E	D-17-010-FR	Natural Gas	4/4/2019	8,332	4.72	NA	32.37	808,752	8/23/2019	7,300	4.68	NA	32.38	9/30/2020	807,334	Year-end	4.70	Distribution	Settled	No	No
AR	CenterPoint E	D-17-010-FR	Natural Gas	4/6/2020	-12,092	4.62	NA	33.07	872,808	9/28/2020	-12,092	4.62	NA	33.07	9/30/2021	872,808	Year-end	5.83	Distribution	Fully Litigated	No	No
AR	CenterPoint E	D-17-010-FR	Natural Gas	4/5/2021	12,605	4.37	NA	32.91	952,036	9/23/2021	-10,358	4.45	NA	32.27	9/30/2022	820,135	Year-end	5.70	Distribution	Fully Litigated	No	No
AR	Black Hills En	D-21-097-U	Natural Gas	12/10/2021	23,993	6.06	10.20	44.69	810,887	10/10/2022	18,837	5.32	9.60	45.00	12/31/2021	799,982	Year-end	10.13	Distribution	Fully Litigated	No	No
AR	Black Hills En	D-23-074-U	Natural Gas	12/4/2023	39,108	NA	10.50	48.51	973,441	10/1/2024	29,076	6.10	9.85	39.64	12/31/2023	958,604	Year-end	10.07	Distribution	Settled	No	No
AR	Summit Utilitie	D-23-079-U	Natural Gas	1/25/2024	101,194	6.98	11.00	48.25	1,228,404	11/21/2024	87,684	6.17	9.85	41.07	12/31/2024	1,205,447	Year-end	10.03	Distribution	Settled	No	No
AZ	Southwest Ga	D-G-01551A-	Natural Gas	5/2/2016	31,927	7.82	10.25	51.69	1,336,049	4/11/2017	16,000	7.42	9.50	51.70	11/30/2015	1,324,902	Year-end	11.47	Distribution	Settled	No	No
AZ	Southwest Ga	D-G-01551A-	Natural Gas	5/1/2019	80,770	7.57	10.15	51.10	2,065,823	12/9/2020	36,799	7.02	9.10	51.10	1/31/2019	1,930,612	Year-end	19.60	Distribution	Fully Litigated	No	No
AZ	Southwest Ga	D-G-01551A-2	Natural Gas	12/3/2021	90,730	7.08	9.90	51.00	2,642,068	1/23/2023	54,283	6.73	9.30	50.00	8/31/2021	2,607,568	Year-end	13.87	Distribution	Settled	No	No
CA	Southern Calif	Advice No. 51	Natural Gas	9/29/2017	-35,100	7.34	10.05	52.00	NA	10/30/2017	-35,100	7.34	10.05	52.00	12/31/2018	NA		1.03	Distribution	Settled	No	No
CA	San Diego Ga	Advice No. 26	Natural Gas	9/29/2017	-2,000	7.55	10.20	52.00	NA	10/26/2017	-2,000	7.55	10.20	52.00	12/31/2018	NA		0.90	Distribution	Settled	No	No
CA	San Diego Ga	A-19-04-017 (	Natural Gas	4/22/2019	NA	8.95	12.38	56.00	NA	12/19/2019	NA	7.55	10.20	52.00	12/31/2020	NA		8.03	Distribution	Fully Litigated	No	No
CA	Southern Calif	A-19-04-018	Natural Gas	4/22/2019	40,140	7.85	10.70	56.00	NA	12/19/2019	-3,000	7.30	10.05	52.00	12/31/2020	NA		8.03	Distribution	Fully Litigated	No	No
CA	Southwest Ga	A-19-08-015 (	Natural Gas	8/30/2019	6,800	7.44	10.50	53.00	NA	3/25/2021	3,000	7.11	10.00	52.00	12/31/2021	285,691	Average	19.10	Distribution	Settled	No	No
CA	Southwest Ga	A-19-08-015 (	Natural Gas	8/30/2019	1,500	7.76	10.50	53.00	NA	3/25/2021	0	7.44	10.00	52.00	12/31/2021	92,983	Average	19.10	Distribution	Settled	No	No
CA	Southwest Ga	A-19-08-015 (	Natural Gas	8/30/2019	4,500	7.76	10.50	53.00	NA	3/25/2021	3,400	7.44	10.00	52.00	12/31/2021	56,818	Average	19.10	Distribution	Settled	No	No
CA	San Diego Ga	A-21-08-014 (	Natural Gas	8/23/2021	-30	7.46	10.55	54.00	NA	11/3/2022	NA	7.55	10.20	52.00	12/31/2022	NA		14.57	Distribution	Fully Litigated	No	No
CA	Southern Calif	A-22-04-011	Natural Gas	4/20/2022	51,800	7.60	10.75	54.00	NA	12/15/2022	-36,000	7.10	9.80	52.00	12/31/2023	NA		7.97	Distribution	Fully Litigated	No	No
CA	Southern Calif	Advice Letter	Natural Gas	10/13/2023	77,000	7.67	10.50	52.00	NA	12/22/2023	77,000	7.67	10.50	52.00		NA		2.33	Distribution	Fully Litigated	No	No
CA	Southern Calif	A-22-04-011 (	Natural Gas	1/16/2024	NA	NA	10.50	NA	NA	10/17/2024	-28,900	7.49	10.08	NA		NA		9.17	Distribution	Fully Litigated	No	No
CO	Public Service	D-15AL-0135	Natural Gas	3/3/2015	108,300	7.76	10.30	56.00	1,347,700	2/16/2016	39,167	7.33	9.50	56.51	12/31/2014	1,416,470	Average	11.67	Distribution	Fully Litigated	Yes	Yes
CO	Public Service	D-17AL-0363	Natural Gas	6/2/2017	23,484	7.18	9.35	56.00	1,526,369	12/21/2018	21,983	7.12	9.35	54.60	12/31/2016	1,527,011	Average	18.90	Distribution	Fully Litigated	No	Yes
CO	Black Hills Co	D-19AL-0075	Natural Gas	2/1/2019	3,460	7.32	10.30	50.15	265,290	5/19/2020	-2,284	6.76	9.20	50.15	6/30/2018	231,334	Average	15.77	Distribution	Fully Litigated	No	No
CO	Public Service	D-20AL-0049	Natural Gas	2/5/2020	144,464	7.33	9.95	55.81	2,236,462	10/12/2020	94,159	6.84	9.20	55.62	9/30/2019	2,016,901	Year-end	8.33	Distribution	Settled	No	No
CO	Black Hills Co	D-21AL-0236	Natural Gas	6/1/2021	14,593	6.94	9.95	50.26	344,162	12/13/2021	6,498	6.56	9.20	50.26	12/31/2020	303,188	Average	6.50	Distribution	Settled	No	No
CO	Public Service	D-22AL-0046	Natural Gas	1/24/2022	202,054	7.39	10.25	55.66	3,603,971	10/25/2022	171,767	6.70	9.20	53.78	12/31/2021	3,396,298	Year-end	9.13	Distribution	Fully Litigated	No	No
CO	Atmos Energy	D-22AL-0348	Natural Gas	8/5/2022	7,681	8.17	10.95	60.92	266,776	5/4/2023	-1,160	7.00	9.30	58.00	3/31/2022	229,565	Average	9.07	Distribution	Settled	No	No
CO	Black Hills Co	D-23AL-0231	Natural Gas	5/8/2023	26,105	7.52	10.49	51.00	394,314	3/24/2024	20,171	6.90	9.30	50.87	12/31/2022	378,440	Average	10.70	Distribution	Settled	No	No
CO	Public Service	D-24AL-0049	Natural Gas	1/29/2024	169,571	7.52	10.10	55.00	4,190,512	10/25/2024	130,759	7.00	9.35	54.00	12/31/2023	NA	Average	9.00	Distribution	Fully Litigated	No	No
CT	The Southern	D-17-05-42	Natural Gas	6/30/2017	19,190	7.79	9.95	52.19	633,877	12/13/2017	11,193	7.42	9.25	52.19	12/31/2016	617,780	Average	5.53	Distribution	Settled	Yes	No
CT	Yankee Gas S	D-18-05-10	Natural Gas	6/15/2018	86,132	7.57	10.25	53.76	1,573,239	12/12/2018	30,158	7.06	9.30	53.76	12/31/2017	1,446,407	Average	6.00	Distribution	Settled	Yes	No
CT	Connecticut N	D-18-05-16	Natural Gas	6/29/2018	27,785	7.82	10.20	55.00	537,829	12/19/2018	19,747	7.32	9.30	55.00	12/31/2017	534,220	Average	5.77	Distribution	Settled	Yes	No
CT	Connecticut N	D-23-11-02 (C	Natural Gas	11/3/2023	19,703	7.95	10.20	55.00	602,269	11/18/2024	-24,610	7.25	9.15	53.00	12/31/2022	534,577	Average	12.70	Distribution	Fully Litigated	No	No
CT	The Southern	D-23-11-02 (S	Natural Gas	11/3/2023	43,239	7.70	10.20	53.00	876,932	11/18/2024	-10,716	7.06	9.15	53.00	12/31/2022	774,479	Average	12.70	Distribution	Fully Litigated	No	No
DC	Washington G	FC-1137	Natural Gas	2/26/2016	17,241	8.23	10.25	57.76	261,873	3/1/2017	8,510	7.57	9.25	55.70	9/30/2015	255,674	Average	12.30	Distribution	Fully Litigated	No	No
DC	Washington G	FC-1162	Natural Gas	1/13/2020	39,014	7.56	10.40	52.10	542,566	2/24/2021	19,500	7.05	9.25	52.10	12/31/2019	NA		13.60	Distribution	Settled	No	No
DC	Washington G	FC-1169	Natural Gas	4/4/2022	52,966	7.39	10.40	53.69	728,902	12/15/2023	24,595	7.11	9.65	52.00	12/31/2021	580,402	Average	20.67	Distribution	Fully Litigated	No	No
DE	Chesapeake U	D-15-1734	Natural Gas	12/21/2015	4,111	9.68	11.00	60.39	69,380	12/20/2016	2,250	7.53	9.75	NA	3/31/2016	NA		12.17	Distribution	Settled	No	Yes
DE	Delmarva Pov	D-17-0978	Natural Gas	8/17/2017	3,819	6.98	10.10	50.20	355,931	11/8/2018	-3,500	6.78	9.70	50.52	12/31/2017	NA		14.93	Distribution	Settled	No	Yes
DE	Delmarva Pov	D-20-0150	Natural Gas	2/21/2020	11,631	7.15	10.30	50.37	399,719	1/6/2021	6,700	6.80	9.60	50.37	3/31/2020	NA	Average	10.67	Distribution	Settled	No	Yes
DE	Delmarva Pov	D-22-0002	Natural Gas	1/14/2022	18,780	6.82	10.30	49.94	486,441	10/12/2022	13,400	6.57	9.60	49.94	12/31/2021	NA		9.03	Distribution	Settled	No	Yes
FL	Peoples Gas S	D-20200051-(	Natural Gas	6/8/2020	85,325	6.63	10.75	54.70	1,578,726	11/19/2020	58,000	5.93	9.90	54.70	12/31/2021	1,536,816	Average	5.47	Distribution	Settled	No	No
FL	Florida Public	D-20220067-(	Natural Gas	5/24/2022	24,062	6.43	11.25	45.14	454,887	1/24/2023	17,153	5.97	10.25	45.16	12/31/2023	453,675	Average	8.17	Distribution	Fully Litigated	No	Yes
FL	Pivotal Utility I	20220069-GU	Natural Gas	5/31/2022	28,284	7.09	10.75	52.56	488,906	3/28/2023	23,308	6.44	9.50	59.60	12/31/2023	487,258	Average	10.03	Distribution	Fully Litigated	No	No

Schedule MLR-8c: Natural Gas rate cases for CY 2015-2025

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				Increase Requested						Increase Authorized												
State	Company	Case identification	Service	Date	Rate Change ($000)	Return on Rate Base (%)	Return on Equity (%)	Requested Equity Ratio (% of Total Capital)	Rate Base ($000)	Date	Rate Change ($000)	Return on Rate Base (%)	Return on Equity (%)	Equity Ratio (% of Total Capital)	Test Year End	Rate Base ($000)	Rate Base Valuation Method	Lag Months	Case Type	Decision Type	Phase-In? Yes/No	Interim Authorized? Yes/No
FL	Peoples Gas S	D-20230023-(	Natural Gas	4/4/2023	127,624	7.42	11.00	47.49	2,366,788	11/9/2023	106,683	7.02	10.15	NA	12/31/2024	2,357,328	Average	7.30	Distribution	Fully Litigated	No	No
GA	Atlanta Gas Li	D-42315	Natural Gas	6/3/2019	90,323	7.94	10.75	55.00	3,187,734	12/19/2019	65,300	7.72	10.25	56.00	7/31/2020	NA	Average	6.63	Distribution	Fully Litigated	No	No
GA	Atlanta Gas Li	D-42315 (202	Natural Gas	7/1/2020	37,622	7.72	NA	56.00	3,608,710	1/1/2021	37,622	7.72	NA	56.00	12/31/2021	3,608,710	Average	6.13	Distribution	Fully Litigated	No	No
IA	Interstate Pow	D-RPU-2018-	Natural Gas	5/2/2018	19,797	7.49	9.80	53.00	509,024	12/13/2018	13,947	7.29	9.60	51.00	12/31/2017	491,446	Average	7.50	Distribution	Settled	No	Yes
IA	Interstate Pow	D-RPU-2019-	Natural Gas	3/1/2019	21,007	7.39	10.00	53.00	570,791	12/18/2019	11,800	7.02	9.60	51.00	12/31/2020	557,397	Average	9.73	Distribution	Settled	No	No
IA	Black Hills Iow	D-RPU-2021-	Natural Gas	6/1/2021	10,544	7.03	10.15	50.01	301,548	12/28/2021	5,907	6.75	9.60	50.01	12/31/2020	300,923		7.00	Distribution	Settled	No	Yes
IA	MidAmerican	D-RPU-2023-	Natural Gas	6/12/2023	39,351	7.59	10.50	54.90	848,494	3/29/2024	29,645	7.11	NA	51.50	12/31/2022	845,632	Average	9.70	Distribution	Settled	No	No
IA	Interstate Pow	D-RPU-2023-	Natural Gas	10/12/2023	13,934	7.42	10.00	52.02	630,200	9/17/2024	10,000	7.18	9.65	51.00	9/30/2025	630,114	Average	11.37	Distribution	Settled	No	No
IA	Black Hills Iow	D-RPU-2024-	Natural Gas	5/1/2024	20,670	7.65	10.50	51.38	397,684	11/26/2024	14,961	7.21	NA	NA	12/31/2023	393,835	Year-end	6.97	Distribution	Settled	No	Yes
ID	Avista Corpor	C-AVU-G-15-	Natural Gas	6/1/2015	4,871	7.62	9.90	50.00	130,837	12/18/2015	2,500	7.42	9.50	50.00	12/31/2014	131,925	Average	6.67	Distribution	Settled	No	No
ID	Intermountain	C-INT-G-16-2	Natural Gas	8/12/2016	10,166	7.42	9.90	50.00	236,926	4/28/2017	5,338	7.30	9.50	50.00	12/31/2016	235,527	Average	8.63	Distribution	Fully Litigated	No	No
ID	Avista Corpor	C-AVU-G-17-	Natural Gas	6/9/2017	5,617	7.81	9.90	50.00	146,447	12/28/2017	2,312	7.61	9.50	50.00	12/31/2016	145,940	Year-end	6.73	Distribution	Settled	Yes	No
ID	Avista Corpor	C-AVU-G-21-	Natural Gas	1/29/2021	1,002	7.30	9.90	50.00	174,708	9/1/2021	-700	7.05	9.40	50.00	12/31/2019	172,311	Average	7.17	Distribution	Settled	Yes	No
ID	Intermountain	C-INT-G-22-0	Natural Gas	12/1/2022	11,338	7.37	10.30	50.00	387,513	6/30/2023	3,050	6.97	9.50	50.00	12/31/2022	385,289	Average	7.03	Distribution	Settled	No	No
ID	Avista Corpor	C-AVU-G-23-	Natural Gas	2/1/2023	2,890	7.59	10.25	50.00	211,166	8/31/2023	1,255	7.19	9.40	50.00	6/30/2022	206,562	Average	7.03	Distribution	Settled	Yes	No
IL	The Peoples (	D-14-0225	Natural Gas	2/26/2014	100,541	7.21	10.25	50.33	1,759,289	1/21/2015	71,141	6.56	9.05	50.33	12/31/2015	1,669,698	Average	10.97	Distribution	Fully Litigated	No	No
IL	North Shore (	D-14-0224	Natural Gas	2/26/2014	6,524	6.89	10.25	50.48	219,786	1/21/2015	3,513	6.26	9.05	50.48	12/31/2015	217,184	Average	10.97	Distribution	Fully Litigated	No	No
IL	Ameren Illinois	D-15-0142	Natural Gas	1/23/2015	45,580	7.65	9.60	50.00	1,187,356	12/9/2015	44,506	7.65	9.60	50.00	12/31/2016	1,187,365	Average	10.67	Distribution	Settled	No	No
IL	Northern Illino	D-17-0124	Natural Gas	3/10/2017	184,489	7.87	10.70	54.50	2,516,692	1/31/2018	93,480	7.26	9.80	52.00	12/31/2018	2,422,250	Average	10.90	Distribution	Fully Litigated	No	No
IL	Ameren Illinois	D-18-0463	Natural Gas	1/31/2018	38,187	7.14	9.87	50.00	1,595,536	11/1/2018	31,738	7.14	9.87	50.00	12/31/2019	1,588,063	Average	9.13	Distribution	Settled	No	No
IL	Northern Illino	D-18-1775	Natural Gas	11/9/2018	180,233	7.27	9.86	54.20	3,447,728	10/2/2019	167,739	7.20	9.73	54.20	9/30/2020	3,446,880	Average	10.90	Distribution	Fully Litigated	No	No
IL	Ameren Illinois	D-20-0308	Natural Gas	2/21/2020	97,373	7.64	10.50	54.09	2,119,688	1/13/2021	76,129	7.14	9.67	52.00	12/31/2021	2,096,105	Average	10.90	Distribution	Fully Litigated	No	No
IL	Northern Illino	D-21-0098	Natural Gas	1/14/2021	292,008	7.29	10.35	54.46	4,738,395	11/18/2021	240,224	6.96	9.75	54.46	12/31/2022	4,652,130	Average	10.27	Distribution	Fully Litigated	No	No
IL	North Shore (	D-20-0810	Natural Gas	10/15/2020	6,138	6.91	10.00	52.50	355,343	9/8/2021	4,084	6.63	9.67	51.58	12/31/2021	353,391	Average	10.93	Distribution	Fully Litigated	No	No
IL	Ameren Illinois	D-23-0067	Natural Gas	1/6/2023	148,227	7.53	10.30	53.99	2,894,025	11/16/2023	111,800	6.85	9.44	50.00	12/31/2024	2,841,675	Average	10.47	Distribution	Fully Litigated	No	No
IL	The Peoples (	D-23-0069	Natural Gas	1/6/2023	401,055	7.12	9.90	54.00	4,783,366	11/16/2023	302,794	6.65	9.38	50.79	12/31/2024	4,193,982	Average	10.47	Distribution	Fully Litigated	No	No
IL	North Shore (	D-23-0068	Natural Gas	1/6/2023	16,587	7.37	9.90	54.00	428,585	11/16/2023	11,012	6.96	9.38	52.58	12/31/2024	422,113	Average	10.47	Distribution	Fully Litigated	No	No
IL	Northern Illino	D-23-0066	Natural Gas	1/3/2023	320,027	7.49	10.35	54.52	6,184,641	11/16/2023	223,033	6.68	9.51	50.00	12/31/2024	5,971,923	Average	10.57	Distribution	Fully Litigated	No	No
IL	Liberty Utilities	D-24-0043	Natural Gas	12/20/2023	4,148	8.41	10.80	54.00	75,432	10/31/2024	3,174	7.54	9.90	45.30	12/31/2024	74,745	Average	10.53	Distribution	Fully Litigated	No	No
IN	Northern India	Ca-44988	Natural Gas	9/27/2017	138,134	6.90	10.70	46.88	1,520,210	9/19/2018	107,300	6.50	9.85	46.88	12/31/2018	1,520,210	Year-end	11.90	Distribution	Settled	Yes	No
IN	Southern India	Ca-45447	Natural Gas	10/30/2020	27,929	5.98	10.15	45.74	469,328	10/6/2021	20,490	5.78	9.70	45.74	12/31/2021	469,328	Year-end	11.37	Distribution	Settled	Yes	No
IN	Indiana Gas C	Ca-45468	Natural Gas	12/18/2020	20,759	6.32	10.15	46.22	1,610,799	11/17/2021	-5,967	6.16	9.80	46.21	12/31/2021	1,610,799	Year-end	11.13	Distribution	Settled	Yes	No
IN	Northern India	Ca-45621	Natural Gas	9/29/2021	109,692	6.87	10.50	49.47	2,418,669	7/27/2022	71,800	6.55	9.85	49.47	12/31/2022	2,418,669	Year-end	10.03	Distribution	Settled	Yes	No
IN	Northern India	Ca-45967	Natural Gas	10/25/2023	161,897	7.48	10.70	52.39	3,484,810	7/31/2024	120,948	6.98	9.75	52.39	12/31/2024	3,484,810	Year-end	9.33	Distribution	Settled	Yes	No
IN	Ohio Valley G	Ca-46011	Natural Gas	2/7/2024	12,062	9.44	11.00	83.18	68,109	11/6/2024	11,059	8.61	10.00	83.18	9/30/2025	68,078	Year-end	9.10	Distribution	Settled	Yes	No
KS	Atmos Energy	D-19-ATMG-5	Natural Gas	6/28/2019	8,527	7.68	9.90	60.12	243,722	2/24/2020	3,067	7.03	9.10	56.32	3/31/2019	242,314	Year-end	8.03	Distribution	Fully Litigated	No	No
KY	Atmos Energy	C-2017-0034	Natural Gas	9/28/2017	1,764	7.72	10.30	52.57	427,151	5/3/2018	-1,891	7.41	9.70	52.57	3/31/2019	427,646	Average	7.23	Distribution	Fully Litigated	No	No
KY	Duke Energy I	C-2018-0026	Natural Gas	8/31/2018	10,542	7.18	9.90	50.76	313,675	3/27/2019	7,364	7.07	9.70	50.76	3/31/2020	313,424	Average	6.93	Distribution	Settled	No	No
KY	Atmos Energy	C-2018-0028	Natural Gas	9/28/2018	14,375	7.93	10.40	58.06	496,006	5/7/2019	-262	7.49	9.65	58.06	3/31/2020	424,929	Average	7.37	Distribution	Fully Litigated	No	No
KY	Duke Energy I	C-2021-0019	Natural Gas	6/1/2021	15,228	7.06	10.30	50.70	468,321	12/28/2021	9,171	6.54	9.38	51.34	12/31/2022	466,487	Average	7.00	Distribution	Settled	No	No
KY	Columbia Gas	C-2021-0018	Natural Gas	5/28/2021	26,695	7.48	10.30	52.64	446,223	12/28/2021	18,311	6.89	9.35	52.64	12/31/2022	431,140	Average	7.13	Distribution	Settled	No	No
KY	Atmos Energy	C-2021-0021	Natural Gas	6/30/2021	20,214	7.63	10.35	57.59	581,184	5/19/2022	4,256	6.82	9.23	54.50	12/31/2022	568,506	Average	10.77	Distribution	Fully Litigated	No	No
KY	Columbia Gas	C-2024-0009	Natural Gas	5/16/2024	23,773	8.01	10.80	52.64	518,827	12/30/2024	14,293	7.41	9.75	52.64	12/31/2025	509,471	Average	7.60	Distribution	Settled	No	No
LA	Entergy New (	D-UD-18-07 (	Natural Gas	9/21/2018	-919	7.92	10.75	52.20	120,126	11/7/2019	-2,500	7.09	9.35	50.00		NA		13.73	Distribution	Fully Litigated	No	No
MA	NSTAR Gas (	DPU 14-150	Natural Gas	12/17/2014	23,195	7.99	10.25	52.80	480,059	10/30/2015	15,831	7.72	9.80	52.10	12/31/2013	475,316	Year-end	10.57	Distribution	Fully Litigated	No	No
MA	Eversource G	DPU 15-50	Natural Gas	4/16/2015	49,700	8.50	10.95	53.54	590,143	10/7/2015	32,800	7.75	9.55	53.54	12/31/2014	580,400	Year-end	5.80	Distribution	Settled	Yes	No
MA	Liberty Utilities	DPU 15-75	Natural Gas	7/15/2015	11,779	8.59	10.40	55.00	70,713	2/10/2016	7,800	7.99	9.60	50.00	12/31/2014	69,900	Year-end	7.00	Distribution	Settled	Yes	No
MA	Fitchburg Gas	DPU 15-81	Natural Gas	6/16/2015	2,985	8.72	10.25	52.92	57,542	4/29/2016	1,635	8.46	9.80	52.17	12/31/2014	57,151	Year-end	10.60	Distribution	Fully Litigated	No	No
MA	Boston Gas C	DPU-17-170 (	Natural Gas	11/15/2017	136,521	7.54	10.50	53.04	1,733,498	9/28/2018	100,826	7.01	9.50	53.04	12/31/2016	1,727,444	Year-end	10.57	Distribution	Fully Litigated	No	No
MA	Colonial Gas (	DPU-17-170 (	Natural Gas	11/15/2017	25,637	7.71	10.50	53.04	411,479	9/28/2018	17,837	7.18	9.50	53.04	12/31/2016	410,442	Year-end	10.57	Distribution	Fully Litigated	No	No
MA	The Berkshire	DPU 18-40	Natural Gas	5/17/2018	4,065	8.94	10.35	61.48	95,831	1/18/2019	2,390	8.33	9.70	54.00	12/31/2017	NA		8.20	Distribution	Settled	No	No

Schedule MLR-8c: Natural Gas rate cases for CY 2015-2025

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				Increase Requested						Increase Authorized												
State	Company	Case identification	Service	Date	Rate Change ($000)	Return on Rate Base (%)	Return on Equity (%)	Requested Equity Ratio (% of Total Capital)	Rate Base ($000)	Date	Rate Change ($000)	Return on Rate Base (%)	Return on Equity (%)	Equity Ratio (% of Total Capital)	Test Year End	Rate Base ($000)	Rate Base Valuation Method	Lag Months	Case Type	Decision Type	Phase-In? Yes/No	Interim Authorized? Yes/No
MA	Fitchburg Gas	DPU 19-131	Natural Gas	12/17/2019	7,290	8.41	10.50	52.45	95,035	2/28/2020	4,596	7.99	9.70	52.45	12/31/2018	88,133	Year-end	2.43	Distribution	Settled	Yes	No
MA	NSTAR Gas (	DPU 19-120	Natural Gas	11/8/2019	34,971	7.60	10.45	54.84	809,579	10/30/2020	22,771	7.29	9.90	54.77	12/31/2018	780,121	Year-end	11.90	Distribution	Fully Litigated	Yes	No
MA	Eversource G	DPU 20-59	Natural Gas	7/2/2020	42,800	7.50	9.70	53.25	NA	10/7/2020	42,800	7.50	9.70	53.25		NA		3.23	Distribution	Settled	Yes	No
MA	Boston Gas C	DPU 20-120	Natural Gas	11/13/2020	219,008	7.41	10.50	53.44	3,019,435	9/30/2021	142,012	6.98	9.70	53.44	3/31/2020	2,898,874	Year-end	10.70	Distribution	Fully Litigated	Yes	No
MA	The Berkshire	DPU 22-20	Natural Gas	6/24/2022	10,745	7.91	10.50	58.35	117,617	10/27/2022	5,668	7.20	9.70	54.00	12/31/2020	NA		4.17	Distribution	Settled	Yes	No
MA	Fitchburg Gas	DPU 23-81	Natural Gas	8/17/2023	11,278	8.17	10.75	52.26	121,686	6/28/2024	10,208	7.46	9.40	52.26	12/31/2022	121,536	Year-end	10.53	Distribution	Fully Litigated	Yes	No
MD	Baltimore Gas	C-9406 (gas)	Natural Gas	11/6/2015	78,200	7.90	10.50	53.70	1,244,287	6/3/2016	47,890	7.23	9.65	51.90	11/30/2015	1,226,150	Average	7.00	Distribution	Fully Litigated	No	No
MD	Columbia Gas	C-9447	Natural Gas	4/14/2017	5,045	7.98	10.90	52.37	95,178	9/19/2017	2,400	7.35	9.70	NA	4/30/2017	NA		5.27	Distribution	Settled	No	No
MD	Washington G	C-9481	Natural Gas	5/15/2018	56,792	7.60	10.30	51.69	1,097,133	12/11/2018	29,074	7.30	9.70	51.69	3/31/2018	1,011,585	Average	7.00	Distribution	Fully Litigated	No	No
MD	Baltimore Gas	C-9484	Natural Gas	6/8/2018	82,781	7.46	10.50	52.85	1,703,424	1/4/2019	64,915	7.09	9.80	52.85	7/31/2018	1,646,011	Average	7.00	Distribution	Fully Litigated	No	No
MD	Washington G	C-9605	Natural Gas	4/22/2019	38,552	7.85	10.40	54.57	1,082,458	10/15/2019	27,000	7.42	9.70	53.50	3/31/2019	NA		5.87	Distribution	Settled	No	No
MD	Columbia Gas	C-9609	Natural Gas	5/22/2019	3,814	7.98	10.95	52.90	137,527	12/18/2019	951	7.26	9.60	52.90	6/30/2019	137,531	Average	7.00	Distribution	Fully Litigated	No	No
MD	Baltimore Gas	C-9610 (GAS	Natural Gas	5/24/2019	67,285	7.26	10.30	52.00	1,893,613	12/17/2019	54,000	6.97	9.75	NA	7/31/2019	NA		6.90	Distribution	Settled	No	No
MD	Columbia Gas	C-9644	Natural Gas	5/15/2020	6,343	7.87	10.95	52.64	156,042	11/7/2020	3,300	7.16	9.60	52.63	5/31/2020	NA	Average	5.87	Distribution	Settled	No	No
MD	Baltimore Gas	C-9645 (Gas)	Natural Gas	5/15/2020	91,060	7.09	10.10	52.00	2,972,042	12/16/2020	73,887	6.83	9.65	52.00	12/31/2023	2,443,182	Average	7.17	Distribution	Fully Litigated	Yes	No
MD	Washington G	C-9651	Natural Gas	8/28/2020	28,413	7.73	10.45	54.55	1,225,348	4/9/2021	13,146	7.09	9.70	52.03	3/31/2020	1,212,272	Average	7.47	Distribution	Fully Litigated	No	No
MD	Columbia Gas	C-9664	Natural Gas	5/14/2021	5,430	7.72	10.85	53.23	187,154	12/3/2021	2,425	7.06	9.65	52.95	5/31/2021	187,144	Average	6.77	Distribution	Fully Litigated	No	No
MD	Columbia Gas	C-9680	Natural Gas	5/13/2022	6,726	7.79	10.95	52.97	203,082	11/17/2022	4,801	7.11	9.65	52.97	5/31/2022	NA		6.27	Distribution	Settled	No	No
MD	Baltimore Gas	C-9692 (GAS	Natural Gas	2/17/2023	290,085	7.56	10.40	52.00	3,944,907	12/14/2023	228,786	6.74	9.45	52.00	12/31/2026	3,801,217	Average	10.00	Distribution	Fully Litigated	Yes	No
MD	Washington G	C-9704	Natural Gas	5/18/2023	45,155	7.73	10.75	52.60	1,489,354	12/14/2023	12,580	7.04	9.50	52.60	12/31/2022	1,399,947	Average	7.00	Distribution	Fully Litigated	No	No
ME	Maine Natural	D-2015-0000	Natural Gas	3/5/2015	6,000	7.50	10.00	50.00	NA	6/1/2016	2,456	7.28	9.55	50.00	9/30/2014	36,370	Average	15.13	Distribution	Settled	Yes	No
ME	Northern Utiliti	D-2017-0006	Natural Gas	5/31/2017	3,482	8.01	10.30	51.70	180,101	2/28/2018	-87	7.53	9.50	50.00	12/31/2016	170,896	Average	9.10	Distribution	Fully Litigated	No	No
ME	Northern Utiliti	D-2019-0009	Natural Gas	6/28/2019	7,071	8.00	10.50	52.91	231,315	3/26/2020	3,605	7.34	9.48	50.00	12/31/2018	227,279	Year-end	9.07	Distribution	Fully Litigated	No	No
ME	Northern Utiliti	D-2023-0005	Natural Gas	5/1/2023	11,757	7.74	10.35	52.01	320,533	9/20/2023	7,573	7.22	9.35	52.01	12/31/2022	NA		4.73	Distribution	Settled	No	No
MI	Michigan Gas	C-U-17880	Natural Gas	6/22/2015	6,671	6.18	10.50	39.43	223,655	12/11/2015	3,400	5.51	9.90	52.00	12/31/2016	NA		5.73	Distribution	Settled	No	No
MI	DTE Gas Con	C-U-17999	Natural Gas	12/18/2015	178,245	6.02	10.75	38.65	3,739,371	12/9/2016	122,269	5.76	10.10	38.65	10/31/2017	3,715,332	Average	11.90	Distribution	Fully Litigated	No	Yes
MI	Consumers E	C-U-18124	Natural Gas	8/1/2016	79,976	6.17	10.60	41.27	4,401,980	7/31/2017	29,211	5.97	10.10	41.27	12/31/2017	4,304,494	Average	12.13	Distribution	Fully Litigated	No	Yes
MI	DTE Gas Con	C-U-18999	Natural Gas	11/22/2017	38,121	5.75	10.50	38.30	4,256,672	9/13/2018	8,974	5.56	10.00	38.30	9/30/2019	4,236,432	Average	9.83	Distribution	Fully Litigated	No	No
MI	Consumers E	C-U-18424	Natural Gas	10/31/2017	82,560	6.17	10.75	40.91	5,437,581	8/28/2018	10,600	5.86	10.00	40.91	6/30/2019	NA	Average	10.03	Distribution	Settled	No	No
MI	Consumers E	C-U-20322	Natural Gas	11/30/2018	204,067	6.23	10.75	42.23	6,501,069	9/26/2019	143,531	5.84	9.90	41.78	9/30/2020	6,428,656	Average	10.00	Distribution	Fully Litigated	No	No
MI	DTE Gas Con	C-U-20940	Natural Gas	2/12/2021	176,647	5.59	10.25	39.92	5,608,295	12/9/2021	84,173	5.41	9.90	39.23	12/31/2022	5,537,080	Average	10.00	Distribution	Fully Litigated	No	No
MI	DTE Gas Con	C-U-21291	Natural Gas	1/8/2024	262,407	6.04	10.25	40.78	6,939,800	11/7/2024	113,788	5.80	9.80	39.59	9/30/2025	6,888,851	Average	10.13	Distribution	Fully Litigated	No	No
MN	CenterPoint E	D-G-008/GR-	Natural Gas	8/3/2015	54,106	7.94	10.30	53.43	912,820	5/5/2016	27,541	7.07	9.49	50.00	9/30/2016	893,113	Average	9.20	Distribution	Fully Litigated	No	Yes
MN	Minnesota En	D-G-011/GR-	Natural Gas	9/30/2015	14,846	7.64	10.30	50.32	249,709	9/29/2016	6,775	6.88	9.11	50.32	12/31/2016	234,395	Average	12.17	Distribution	Fully Litigated	No	Yes
MN	CenterPoint E	D-G-008/GR-	Natural Gas	8/2/2017	56,503	7.56	10.00	52.18	1,028,099	5/10/2018	3,913	7.12	NA	NA	9/30/2018	1,005,395	Average	9.37	Distribution	Settled	No	Yes
MN	Minnesota En	D-G-011/GR-	Natural Gas	10/13/2017	4,743	7.00	10.30	50.90	284,287	11/8/2018	3,101	6.70	9.70	50.90	12/31/2018	284,298	Average	13.03	Distribution	Fully Litigated	No	Yes
MN	CenterPoint E	D-G-008/GR-	Natural Gas	10/28/2019	62,032	7.41	10.15	51.39	1,306,656	1/14/2021	38,520	6.86	NA	NA	12/31/2020	1,307,721	Average	14.80	Distribution	Settled	No	Yes
MN	CenterPoint E	D-G-008/GR-	Natural Gas	11/1/2021	67,066	7.06	10.20	51.00	1,752,138	8/18/2022	48,500	6.65	9.39	51.00	12/31/2022	1,769,952	Average	9.67	Distribution	Settled	No	Yes
MN	Northern State	D-G-002/GR-	Natural Gas	11/1/2021	35,629	7.46	10.50	52.50	934,448	3/23/2023	20,888	6.97	9.57	52.50	12/31/2022	927,761	Average	16.90	Distribution	Settled	No	Yes
MN	Minnesota En	D-G-011/GR-	Natural Gas	11/1/2022	40,322	7.07	10.30	53.00	482,450	10/26/2023	28,804	6.72	9.65	53.00	12/31/2023	470,073	Average	11.97	Distribution	Settled	No	Yes
MO	Spire Missouri	C-GR-2017-0	Natural Gas	4/11/2017	60,456	7.50	10.35	54.20	1,315,951	2/21/2018	18,032	7.20	9.80	54.16	12/31/2016	1,220,579	Year-end	10.53	Distribution	Fully Litigated	No	No
MO	Missouri Gas I	C-GR-2017-0	Natural Gas	4/11/2017	52,233	7.50	10.35	54.20	843,676	2/21/2018	15,201	7.20	9.80	54.16	12/31/2016	807,347	Year-end	10.53	Distribution	Fully Litigated	No	No
MO	Spire Missouri	C-GR-2021-0	Natural Gas	12/11/2020	111,475	7.23	9.95	54.25	2,777,221	10/27/2021	72,228	6.37	9.37	49.86	9/30/2020	2,899,325	Year-end	10.67	Distribution	Fully Litigated	No	No
MT	NorthWestern	D-D2016.9.68	Natural Gas	9/30/2016	9,406	7.33	10.35	46.79	431,938	7/20/2017	5,154	6.96	9.55	46.79	12/31/2015	NA	Average	9.77	Distribution	Settled	No	No
MT	MDU Resourc	D2017.9.79	Natural Gas	9/25/2017	1,619	7.47	9.90	51.62	53,742	5/29/2018	975	7.21	9.40	51.62		NA		8.20	Distribution	Settled	No	No
MT	NorthWestern	D-2022-7-78 (	Natural Gas	8/8/2022	22,400	7.17	10.60	48.02	582,819	10/25/2023	14,060	6.67	9.55	48.02	12/31/2021	582,819	Average	14.77	Distribution	Settled	No	Yes
NC	Public Service	D-G-5, Sub 5	Natural Gas	3/31/2016	41,583	8.14	10.60	53.50	949,341	10/28/2016	19,054	7.53	9.70	52.00	12/31/2015	946,722	Year-end	7.03	Distribution	Settled	No	No
NC	Piedmont Nat	D-G-9, Sub 7	Natural Gas	4/1/2019	143,636	7.61	10.60	52.00	3,364,074	10/31/2019	82,820	7.14	9.70	52.00	12/31/2018	3,450,611	Year-end	7.10	Distribution	Settled	No	No
NC	Piedmont Nat	D-G-9, Sub 7	Natural Gas	3/22/2021	96,872	7.27	10.25	52.00	4,736,324	1/6/2022	67,315	6.90	9.60	51.60	12/31/2020	4,731,144	Year-end	9.67	Distribution	Settled	No	Yes
NC	Public Service	D-G-5 Sub 63	Natural Gas	4/1/2021	49,665	7.59	10.25	54.86	1,707,190	1/21/2022	29,464	7.07	9.60	51.60	12/31/2020	1,702,059	Year-end	9.83	Distribution	Settled	No	Yes
ND	MDU Resourc	C-PU-17-295	Natural Gas	7/21/2017	3,575	7.54	10.00	51.00	136,862	9/26/2018	2,500	7.24	9.40	51.00	12/31/2018	NA	Average	14.40	Distribution	Settled	No	Yes

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				Increase Requested						Increase Authorized													
State	Company	Case identification	Service	Date	Rate Change ($000)	Return on Rate Base (%)	Return on Equity (%)	Requested Equity Ratio (% of Total Capital)	Rate Base ($000)	Date	Rate Change ($000)	Return on Rate Base (%)	Return on Equity (%)	Equity Ratio (% of Total Capital)	Test Year End	Rate Base ($000)	Rate Base Valuation Method	Lag Months	Case Type	Decision Type	Phase-In? Yes/No	Interim Authorized? Yes/No
ND	MDU Resourc	C-PU-20-379	Natural Gas	8/26/2020	7,710	7.10	9.80	50.31	181,680	5/5/2021	6,886	6.85	9.30	50.31	12/31/2021	NA		8.40	Distribution	Settled	No	Yes
ND	MDU Resourc	C-PU-23-341	Natural Gas	11/1/2023	11,635	7.56	10.50	50.19	216,970	11/7/2024	9,444	7.26	9.90	50.19	12/31/2024	215,355	Average	12.40	Distribution	Settled	No	Yes
ND	Northern State	C-PU-23-367	Natural Gas	12/29/2023	8,463	7.52	10.20	52.50	167,970	11/7/2024	7,348	7.36	9.90	52.50	12/31/2024	NA	Average	10.47	Distribution	Settled	No	Yes
NE	Black Hills Ne	D-NG-109	Natural Gas	6/1/2020	15,655	6.96	10.00	50.00	503,792	1/26/2021	10,688	6.71	9.50	50.00	12/31/2019	502,652	Year-end	7.97	Distribution	Settled	No	Yes
NH	Northern Utiliti	D-DG-17-070	Natural Gas	6/5/2017	4,728	8.30	10.30	51.70	131,492	5/2/2018	939	7.59	9.50	51.70	12/31/2016	131,660	Year-end	11.03	Distribution	Settled	Yes	Yes
NH	Liberty Utilities	D-DG-17-048	Natural Gas	4/28/2017	14,500	7.36	9.40	50.00	252,000	4/27/2018	8,060	6.80	9.30	49.21	12/31/2016	244,389	Year-end	12.13	Distribution	Fully Litigated	Yes	Yes
NH	Liberty Utilities	D-DG-20-105	Natural Gas	7/31/2020	4,575	7.47	10.51	50.15	346,131	7/30/2021	6,294	6.96	9.30	52.00	12/31/2019	NA	Year-end	12.13	Distribution	Settled	Yes	Yes
NH	Northern Utiliti	D-DG-21-104	Natural Gas	8/2/2021	7,965	7.75	10.30	52.47	188,738	7/20/2022	6,091	7.20	9.30	52.00	12/31/2020	188,235	Year-end	11.73	Distribution	Settled	Yes	Yes
NJ	New Jersey N	D-GR-151113	Natural Gas	11/13/2015	112,853	7.65	11.00	53.66	1,400,000	9/23/2016	45,000	6.90	9.75	52.50	6/30/2016	1,374,000	Year-end	10.50	Distribution	Settled	NA	NA
NJ	Elizabethtown	D-GR-160908	Natural Gas	8/31/2016	20,124	7.17	10.25	49.15	728,894	6/30/2017	13,300	6.71	9.60	46.00	3/31/2017	720,000	Year-end	10.10	Distribution	Settled	No	No
NJ	South Jersey (	D-GR-170100	Natural Gas	1/27/2017	87,683	7.66	11.00	54.24	1,635,111	10/20/2017	39,500	6.80	9.60	52.50	8/31/2017	1,612,091	Year-end	8.87	Distribution	Settled	No	No
NJ	Public Service	D-GR1801003	Natural Gas	1/12/2018	246,766	7.36	10.30	54.00	4,242,984	10/29/2018	123,100	6.99	9.60	54.00	6/30/2018	4,035,000	Year-end	9.67	Distribution	Settled	No	No
NJ	New Jersey N	D-GR1903042	Natural Gas	3/28/2019	134,313	7.75	10.88	56.46	1,815,898	11/13/2019	62,200	6.95	9.60	54.00	8/31/2019	1,765,000	Year-end	7.67	Distribution	Settled	No	No
NJ	Elizabethtown	D-GR1904048	Natural Gas	4/18/2019	65,499	7.60	10.40	52.50	1,113,393	11/13/2019	34,000	7.13	9.60	51.50	8/31/2019	988,310	Year-end	6.97	Distribution	Settled	No	No
NJ	South Jersey (	D-GR2003024	Natural Gas	3/13/2020	73,332	7.38	10.40	54.18	2,220,732	9/23/2020	39,500	6.90	9.60	54.00	6/30/2020	2,133,631	Year-end	6.47	Distribution	Settled	No	No
NJ	New Jersey N	D-GR2103067	Natural Gas	3/30/2021	164,641	7.46	10.50	56.21	2,547,636	11/17/2021	79,269	6.84	9.60	54.00	8/31/2021	2,523,000	Year-end	7.73	Distribution	Settled	No	No
NJ	Elizabethtown	D-GR2112125	Natural Gas	12/28/2021	77,310	7.63	10.75	54.89	1,394,434	8/17/2022	37,515	6.83	9.60	52.00	8/31/2022	1,282,793	Year-end	7.73	Distribution	Settled	No	No
NJ	South Jersey (	D-GR2204025	Natural Gas	4/15/2022	82,331	7.77	10.75	57.00	2,551,297	12/21/2022	25,000	6.93	9.60	54.00	8/31/2022	2,394,117	Year-end	8.33	Distribution	Settled	No	No
NJ	Public Service	D-GR2312092	Natural Gas	12/29/2023	409,438	7.54	10.40	55.50	8,773,537	10/9/2024	270,800	7.07	9.60	55.00	5/31/2024	8,500,000	Year-end	9.50	Distribution	Settled	No	No
NJ	New Jersey N	D-GR2401007	Natural Gas	1/31/2024	219,862	7.52	10.42	54.08	3,345,664	11/21/2024	157,000	7.08	9.60	54.00	6/30/2024	3,245,021	Year-end	9.83	Distribution	Settled	No	No
NJ	Elizabethtown	D-GR2402015	Natural Gas	2/29/2024	70,254	8.33	10.75	57.00	1,813,360	11/21/2024	38,000	7.58	9.60	55.00	6/30/2024	1,773,000	Year-end	8.87	Distribution	Settled	No	No
NM	New Mexico G	C-19-00317-U	Natural Gas	12/23/2019	13,232	7.36	10.20	54.00	741,436	12/16/2020	4,500	6.65	9.38	52.00	12/31/2021	741,436	Average	11.97	Distribution	Settled	No	No
NM	New Mexico G	C-21-00267-U	Natural Gas	12/13/2021	40,742	6.89	10.10	53.00	880,236	11/30/2022	19,300	6.44	9.38	52.00	12/31/2023	809,153	Average	11.73	Distribution	Settled	No	No
NM	New Mexico G	C-23-00255-U	Natural Gas	9/14/2023	48,430	7.44	10.50	53.00	968,135	7/25/2024	30,000	6.79	9.38	52.00	9/30/2025	955,087	Average	10.50	Distribution	Settled	No	No
NV	Sierra Pacific	D-16-06007	Natural Gas	6/6/2016	-1,542	5.95	9.97	48.03	202,776	12/22/2016	-2,402	5.75	9.50	48.03	12/31/2015	NA		6.63	Distribution	Settled	No	No
NV	Southwest Ga	D-18-05031 (S	Natural Gas	5/29/2018	28,286	7.16	10.30	49.66	1,116,268	12/24/2018	9,215	6.65	9.25	49.66	1/31/2018	1,110,380	Year-end	6.97	Distribution	Fully Litigated	No	No
NV	Southwest Ga	D-18-05031 (N	Natural Gas	5/29/2018	1,362	7.51	10.30	49.66	136,142	12/24/2018	-2,123	6.98	9.25	49.66	1/31/2018	134,230	Year-end	6.97	Distribution	Fully Litigated	No	No
NV	Southwest Ga	D-20-02023 (S	Natural Gas	2/28/2020	35,821	6.89	10.00	49.26	1,352,568	9/25/2020	22,726	6.52	9.25	49.26	11/30/2019	1,325,236	Year-end	7.00	Distribution	Fully Litigated	No	No
NV	Southwest Ga	D-20-02023 (N	Natural Gas	2/28/2020	2,668	7.12	10.00	49.26	156,549	9/25/2020	551	6.75	9.25	49.26	11/30/2019	154,966	Year-end	7.00	Distribution	Fully Litigated	No	No
NV	Southwest Ga	D-23-09012 (N	Natural Gas	9/11/2023	10,473	7.26	10.00	50.00	227,060	4/8/2024	8,700	7.01	9.50	50.00	5/31/2023	NA	Year-end	7.00	Distribution	Settled	No	No
NV	Southwest Ga	D-23-09012 (S	Natural Gas	9/11/2023	63,504	7.25	10.00	50.00	1,780,733	4/8/2024	50,400	7.00	9.50	50.00	5/31/2023	NA	Year-end	7.00	Distribution	Settled	No	No
NV	Sierra Pacific	D-24-02027	Natural Gas	2/23/2024	12,201	7.90	10.34	55.19	280,510	9/18/2024	8,363	7.28	9.45	52.40	9/30/2023	277,481	Year-end	6.93	Distribution	Fully Litigated	No	No
NY	Central Hudsc	C-14-G-0319	Natural Gas	7/25/2014	5,897	6.82	9.00	48.00	282,750	6/17/2015	1,827	6.62	9.00	48.00	6/30/2016	268,927	Average	10.90	Distribution	Settled	Yes	No
NY	Orange and R	C-14-G-0494	Natural Gas	11/14/2014	44,227	7.51	9.75	48.00	403,453	10/15/2015	27,525	7.10	9.00	48.00	10/31/2016	366,048	Average	11.17	Distribution	Settled	Yes	No
NY	New York Sta	C-15-G-0284	Natural Gas	5/20/2015	36,868	7.32	10.06	50.00	546,419	6/15/2016	13,068	6.68	9.00	48.00	4/30/2017	530,086	Average	13.07	Distribution	Settled	Yes	No
NY	Rochester Ga	C-15-G-0286	Natural Gas	5/20/2015	22,230	8.15	10.06	50.00	432,609	6/15/2016	8,819	7.55	9.00	48.00	4/30/2017	415,088	Average	13.07	Distribution	Settled	Yes	No
NY	Consolidated I	C-16-G-0061	Natural Gas	1/29/2016	158,900	7.31	9.75	48.00	4,882,143	1/24/2017	-5,300	6.82	9.00	48.00	12/31/2017	4,841,000	Average	12.03	Distribution	Settled	Yes	No
NY	KeySpan Gas	C-16-G-0058	Natural Gas	1/29/2016	174,742	7.39	9.94	48.00	2,297,432	12/15/2016	112,002	6.42	9.00	48.00	12/31/2017	2,303,393	Average	10.70	Distribution	Settled	Yes	No
NY	The Brooklyn	C-16-G-0059	Natural Gas	1/29/2016	289,990	6.81	9.94	48.00	2,959,293	12/15/2016	272,090	6.15	9.00	48.00	12/31/2017	2,952,072	Average	10.70	Distribution	Settled	Yes	No
NY	National Fuel (	C-16-G-0257	Natural Gas	4/28/2016	41,697	7.81	10.20	48.00	718,137	4/20/2017	5,946	6.92	8.70	42.90	3/31/2018	704,011	Average	11.90	Distribution	Fully Litigated	No	No
NY	Niagara Moha	C-17-G-0239	Natural Gas	4/28/2017	69,677	6.93	9.79	48.00	1,222,037	3/15/2018	45,524	6.53	9.00	48.00	3/31/2019	1,231,782	Average	10.70	Distribution	Settled	Yes	No
NY	Central Hudsc	C-17-G-0460	Natural Gas	7/28/2017	22,220	6.99	9.50	50.00	380,366	6/14/2018	6,654	6.44	8.80	48.00	6/30/2019	368,521	Average	10.70	Distribution	Settled	Yes	No
NY	Orange and R	C-18-G-0068	Natural Gas	1/26/2018	-505	7.35	9.75	48.00	453,639	3/14/2019	-7,520	6.97	9.00	48.00	12/31/2019	454,013	Average	13.73	Distribution	Settled	Yes	No
NY	Consolidated I	C-19-G-0066	Natural Gas	1/31/2019	206,232	7.19	9.75	50.00	7,192,549	1/16/2020	83,923	6.61	8.80	48.00	12/31/2020	7,170,725	Average	11.67	Distribution	Settled	Yes	No
NY	The Brooklyn	C-19-G-0309	Natural Gas	4/30/2019	179,797	6.77	9.65	48.00	4,967,792	8/12/2021	-4,710	6.34	8.80	48.00	3/31/2021	4,921,871	Average	27.83	Distribution	Settled	Yes	No
NY	KeySpan Gas	C-19-G-0310	Natural Gas	4/30/2019	37,535	6.74	9.65	48.00	3,260,615	8/12/2021	-22,839	6.32	8.80	48.00	3/31/2021	3,243,777	Average	27.83	Distribution	Settled	Yes	No
NY	New York Sta	C-19-G-0379	Natural Gas	5/20/2019	4,087	6.61	9.50	50.00	658,314	11/19/2020	-514	6.10	8.80	48.00	3/31/2021	662,114	Average	18.30	Distribution	Settled	Yes	No
NY	Rochester Ga	C-19-G-0381	Natural Gas	5/20/2019	-1,794	7.07	9.50	50.00	491,382	11/19/2020	-1,127	6.62	8.80	48.00	3/31/2021	509,465	Average	18.30	Distribution	Settled	Yes	No
NY	Corning Natur	C-20-G-0101	Natural Gas	2/27/2020	6,031	7.28	10.20	50.77	71,810	5/19/2021	-766	6.28	8.80	48.00	1/31/2022	69,117	Average	14.90	Distribution	Fully Litigated	No	No
NY	Niagara Moha	C-20-G-0381	Natural Gas	7/31/2020	37,134	6.31	9.50	48.00	1,565,066	1/20/2022	12,523	6.08	9.00	48.00	6/30/2022	1,560,299	Average	17.93	Distribution	Settled	Yes	No
NY	Central Hudsc	C-20-G-0429	Natural Gas	8/27/2020	14,386	6.61	9.10	50.00	538,760	11/18/2021	4,580	6.48	9.00	50.00	6/30/2022	547,365	Average	14.93	Distribution	Settled	Yes	No

Schedule MLR-8c: Natural Gas rate cases for CY 2015-2025

where the state regulator approved an ROE, based on S&P MI data as of 3/18/2025, available at: S&P Capital IQ (https://www.capitaliq.spglobal.com/web/client?auth=inherit#office/screener?perspective=238101)

				Increase Requested						Increase Authorized												
State	Company	Case identification	Service	Date	Rate Change ($000)	Return on Rate Base (%)	Return on Equity (%)	Requested Equity Ratio (% of Total Capital)	Rate Base ($000)	Date	Rate Change ($000)	Return on Rate Base (%)	Return on Equity (%)	Equity Ratio (% of Total Capital)	Test Year End	Rate Base ($000)	Rate Base Valuation Method	Lag Months	Case Type	Decision Type	Phase-In? Yes/No	Interim Authorized? Yes/No
NY	Orange and R	C-21-G-0073	Natural Gas	1/29/2021	1,215	7.03	9.50	50.00	574,449	4/14/2022	660	6.77	9.20	48.00	12/31/2022	565,784	Average	14.67	Distribution	Settled	Yes	No
NY	Corning Natur	C-21-G-0394	Natural Gas	7/16/2021	6,555	7.17	10.20	49.69	78,629	6/16/2022	2,534	6.53	9.25	48.00	6/30/2023	75,825	Average	11.17	Distribution	Settled	Yes	No
NY	Consolidated	C-22-G-0065	Natural Gas	1/28/2022	402,200	7.14	10.00	50.00	9,696,958	7/20/2023	217,210	6.75	9.25	48.00	12/31/2023	9,647,004	Average	17.93	Distribution	Settled	Yes	No
NY	New York Sta	C-22-G-0318	Natural Gas	5/26/2022	30,053	6.95	10.20	50.00	797,035	10/12/2023	11,735	6.40	9.20	48.00	4/30/2024	766,460	Average	16.80	Distribution	Settled	Yes	No
NY	Rochester Ga	C-22-G-0320	Natural Gas	5/26/2022	32,208	7.24	10.20	50.00	669,945	10/12/2023	18,237	6.67	9.20	48.00	4/30/2024	643,022	Average	16.80	Distribution	Settled	Yes	No
NY	The Brooklyn	C-23-G-0225	Natural Gas	4/28/2023	466,486	7.09	9.80	48.00	7,353,223	8/15/2024	443,984	6.94	9.35	48.00	3/31/2025	7,311,967	Average	15.83	Distribution	Settled	Yes	No
NY	KeySpan Gas	C-23-G-0226	Natural Gas	4/28/2023	277,257	7.05	9.80	48.00	4,710,976	8/15/2024	246,468	6.86	9.35	48.00	3/31/2025	4,714,051	Average	15.83	Distribution	Settled	Yes	No
NY	Central Hudsc	C-23-G-0419	Natural Gas	7/31/2023	42,002	7.10	9.80	50.00	743,799	7/18/2024	27,307	6.92	9.50	48.00	6/30/2025	717,414	Average	11.77	Distribution	Fully Litigated	No	No
NY	National Fuel	C-23-G-0627	Natural Gas	10/31/2023	88,560	7.57	9.80	52.00	1,041,422	12/19/2024	57,291	7.30	9.70	48.00	9/30/2025	1,044,176	Average	13.83	Distribution	Settled	Yes	No
OH	Vectren Energ	18-0298-GA-A	Natural Gas	3/30/2018	34,021	7.97	10.75	51.06	627,591	8/28/2019	22,730	7.48	NA	NA	9/30/2018	622,298	Date Certain	17.20	Distribution	Settled	No	No
OH	Columbia Gas	C-21-0637-GA	Natural Gas	6/30/2021	221,429	7.85	10.95	50.60	3,560,230	1/26/2023	68,192	7.08	9.60	50.60	12/31/2021	3,505,491	Date Certain	19.17	Distribution	Settled	No	No
OH	Duke Energy	C-22-0507-GA	Natural Gas	6/30/2022	48,745	7.33	10.30	52.34	1,911,461	11/1/2023	31,690	6.96	9.60	52.32	12/31/2022	1,897,601	Date Certain	16.30	Distribution	Settled	No	No
OH	Northeast Ohi	C-23-0154-GA	Natural Gas	3/31/2023	5,981	8.71	10.90	64.83	63,757	4/17/2024	2,395	7.64	9.75	51.42	9/30/2023	62,704	Date Certain	12.77	Distribution	Settled	No	No
OK	CenterPoint E	Ca-PUD2015(	Natural Gas	3/13/2015	878	8.64	NA	49.86	49,669	11/4/2015	858	8.64	NA	49.86	12/31/2014	NA	Year-end	7.87	Distribution	Fully Litigated	No	No
OK	Oklahoma Na	Ca-PUD2015(	Natural Gas	7/8/2015	50,408	7.91	10.50	60.50	1,179,531	1/6/2016	29,995	7.31	9.50	60.50	3/31/2015	1,201,618	Year-end	6.07	Distribution	Settled	No	No
OK	Oklahoma Na	Ca-PUD2021(	Natural Gas	5/28/2021	28,693	7.53	9.95	58.55	1,716,145	11/30/2021	15,252	7.20	9.40	58.55	12/31/2020	1,726,463	Year-end	6.20	Distribution	Settled	No	No
OR	Avista Corpor	D-UG-284	Natural Gas	9/2/2014	9,140	7.77	9.90	51.00	198,448	4/9/2015	5,262	7.52	9.50	51.00	12/31/2015	189,376	Average	7.30	Distribution	Settled	No	No
OR	Avista Corpor	D-UG 288	Natural Gas	5/1/2015	6,100	7.72	9.90	50.00	NA	2/29/2016	4,460	7.46	9.40	50.00	12/31/2016	NA	Average	10.13	Distribution	Fully Litigated	No	No
OR	Avista Corpor	D-UG 325	Natural Gas	11/30/2016	6,748	7.80	9.90	50.00	240,750	9/13/2017	3,500	7.35	9.40	50.00	9/30/2018	229,932	Average	9.57	Distribution	Settled	No	No
OR	Northwest Na	D-UG-344	Natural Gas	12/29/2017	37,816	7.62	10.00	50.00	1,214,895	10/26/2018	24,860	7.32	9.40	50.00	10/31/2019	1,201,792	Average	10.03	Distribution	Settled	No	No
OR	Avista Corpor	D-UG 366	Natural Gas	3/15/2019	6,677	7.55	9.90	50.00	287,338	10/8/2019	3,616	7.24	9.40	50.00	12/31/2020	283,140	Year-end	6.90	Distribution	Settled	No	No
OR	Northwest Na	D-UG-388	Natural Gas	12/30/2019	63,346	6.97	9.40	50.00	1,466,232	10/16/2020	45,847	6.97	9.40	50.00	10/31/2021	1,450,677	Average	9.70	Distribution	Settled	No	No
OR	Avista Corpor	D-UG 389	Natural Gas	3/16/2020	5,685	7.24	9.40	50.00	304,664	12/10/2020	4,367	7.24	9.40	50.00	12/31/2021	305,026	Year-end	8.97	Distribution	Settled	No	No
OR	Cascade Natu	D-UG 390	Natural Gas	3/31/2020	4,508	7.08	9.40	50.00	132,614	1/6/2021	3,230	7.07	9.40	50.00	12/31/2020	130,095	Average	9.37	Distribution	Settled	No	No
OR	Avista Corpor	D-UG 433	Natural Gas	10/22/2021	3,774	7.35	9.90	50.00	315,957	8/2/2022	1,600	7.05	9.40	50.00	8/31/2023	315,957	Average	9.47	Distribution	Settled	No	No
OR	Northwest Na	D-UG-435	Natural Gas	12/17/2021	78,031	6.89	9.50	50.00	1,780,963	10/24/2022	62,654	6.84	9.40	50.00	10/31/2023	1,772,195	Average	10.37	Distribution	Settled	No	No
OR	Avista Corpor	D-UG-461	Natural Gas	3/1/2023	10,991	7.59	10.25	50.00	351,283	10/26/2023	7,160	7.24	9.50	50.00	12/31/2024	340,336	Average	7.97	Distribution	Settled	No	No
OR	Northwest Na	D-UG-490	Natural Gas	12/29/2023	152,345	7.41	10.10	50.00	2,123,961	10/25/2024	95,000	7.06	9.40	50.00	10/31/2025	2,090,000	Average	10.03	Distribution	Settled	No	No
PA	Columbia Gas	D-R-2020-301	Natural Gas	4/24/2020	100,437	7.98	10.95	54.19	2,401,427	2/19/2021	63,549	7.41	9.86	54.19	12/31/2021	2,329,124	Year-end	10.03	Distribution	Fully Litigated	No	No
PA	PECO Energy	D-R-2020-301	Natural Gas	9/30/2020	65,976	7.63	10.95	53.38	2,463,555	6/17/2021	29,118	7.26	10.24	53.38	6/30/2022	2,425,859	Year-end	8.67	Distribution	Fully Litigated	No	No
RI	The Narragan	D-4770 (gas)	Natural Gas	11/27/2017	15,451	7.67	10.10	50.97	765,221	8/24/2018	17,400	7.15	9.28	50.95	6/30/2017	788,687	Average	9.00	Distribution	Settled	Yes	No
SC	Dominion Ene	D-2017-6-G	Natural Gas	6/15/2017	9,022	8.15	NA	52.16	588,959	9/27/2017	8,634	8.15	NA	52.16	3/31/2017	588,953	Year-end	3.47	Distribution	Fully Litigated	No	No
SC	Dominion Ene	D-2016-6-G	Natural Gas	6/15/2016	4,387	8.07	NA	51.18	545,713	10/13/2016	4,086	8.11	NA	51.35	3/31/2016	545,701	Year-end	4.00	Distribution	Fully Litigated	No	No
SC	Piedmont Nat	D-2016-7-G	Natural Gas	6/15/2016	15,555	8.96	12.60	53.00	246,094	10/13/2016	8,300	7.68	10.20	53.00	3/31/2016	246,086	Year-end	4.00	Distribution	Settled	No	No
SC	Piedmont Nat	D-2017-7-G	Natural Gas	6/15/2017	17,224	8.87	12.60	53.00	304,797	9/27/2017	5,500	7.60	10.20	53.00	3/31/2017	304,077	Year-end	3.47	Distribution	Settled	No	No
SC	Dominion Ene	D-2018-6-G	Natural Gas	6/15/2018	-18,737	8.19	NA	53.13	604,576	9/26/2018	-19,717	8.05	NA	49.83	3/31/2018	604,600	Year-end	3.43	Distribution	Fully Litigated	No	No
SC	Piedmont Nat	D-2018-7-G	Natural Gas	6/15/2018	-3,953	8.87	NA	53.00	341,628	9/26/2018	-13,856	7.60	10.20	53.00	3/31/2018	341,418	Year-end	3.43	Distribution	Settled	No	No
SC	Piedmont Nat	D-2022-89-G	Natural Gas	4/1/2022	9,571	7.26	9.90	54.56	505,226	9/15/2022	1,659	6.80	9.30	52.20	12/31/2021	501,322	Year-end	5.57	Distribution	Settled	No	No
SC	Piedmont Nat	D-2019-7-G	Natural Gas	6/14/2019	12,941	8.88	12.60	55.35	365,779	10/2/2019	6,102	7.57	9.90	55.35	3/31/2019	365,709	Year-end	3.67	Distribution	Settled	No	No
SC	Piedmont Nat	D-2020-7-G	Natural Gas	6/15/2020	15,429	8.75	12.60	52.31	407,613	10/4/2020	7,085	7.23	9.80	52.31	3/31/2020	407,612	Year-end	3.70	Distribution	Settled	No	No
SC	Piedmont Nat	D-2021-7-G	Natural Gas	6/15/2021	17,282	NA	12.60	52.20	452,731	9/29/2021	7,442	7.07	9.80	52.20	3/31/2021	452,656	Year-end	3.53	Distribution	Settled	No	No
SC	Dominion Ene	D-2023-70-G	Natural Gas	3/31/2023	5,457	8.23	10.38	54.78	1,058,866	9/20/2023	-5,128	7.74	9.49	54.78	9/30/2022	1,058,447	Year-end	5.77	Distribution	Settled	No	No
SC	Piedmont Nat	D-2023-7-G	Natural Gas	6/15/2023	13,624	6.94	9.30	54.05	561,024	10/5/2023	12,940	6.90	9.30	53.13	3/31/2023	558,583	Year-end	3.73	Distribution	Settled	No	No
SD	MidAmerican	D-NG22-005	Natural Gas	5/18/2022	7,037	7.60	10.75	53.33	152,187	3/28/2023	5,947	6.75	NA	NA	12/31/2021	153,482	Average	10.47	Distribution	Settled	Yes	Yes
SD	MDU Resourc	D-NG23-014	Natural Gas	8/15/2023	7,420	7.60	10.50	50.39	77,111	8/13/2024	5,369	7.01	NA	NA	12/31/2022	71,781	Average	12.13	Distribution	Settled	No	Yes
SD	NorthWestern	D-NG24-005	Natural Gas	6/21/2024	6,043	7.75	10.70	53.13	95,607	12/17/2024	4,599	6.91	NA	NA	12/31/2023	96,199	Average	5.97	Distribution	Settled	No	No
TN	Atmos Energy	D-14-00146	Natural Gas	11/25/2014	5,889	8.58	10.70	55.93	254,734	5/11/2015	711	7.73	9.80	53.13	5/31/2016	247,958	Average	5.57	Distribution	Settled	No	No
TN	Chattanooga (	D-18-00017	Natural Gas	2/15/2018	6,199	7.83	11.25	49.23	157,795	10/15/2018	1,390	7.12	9.80	49.23	6/30/2019	149,740	Average	8.07	Distribution	Fully Litigated	NA	NA
TN	Atmos Energy	D-18-00067	Natural Gas	6/15/2018	-5,032	7.26	NA	51.40	351,848	12/4/2018	-5,032	7.26	NA	51.40	5/31/2019	351,848	Average	5.73	Distribution	Settled	No	No
TN	Atmos Energy	D-19-00018	Natural Gas	2/1/2019	861	7.79	NA	58.38	389,061	5/20/2019	24	7.79	NA	58.38	5/31/2020	389,061	Average	3.60	Distribution	Settled	No	No
TN	Chattanooga (	D-20-00049	Natural Gas	5/29/2020	5,187	7.12	NA	49.23	163,294	9/14/2020	4,759	7.12	NA	49.23	12/31/2019	163,380	Average	3.60	Distribution	Fully Litigated	No	No

Schedule MLR-8c: Natural Gas rate cases for CY 2015-2025

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				Increase Requested						Increase Authorized												
State	Company	Case identification	Service	Date	Rate Change ($000)	Return on Rate Base (%)	Return on Equity (%)	Requested Equity Ratio (% of Total Capital)	Rate Base ($000)	Date	Rate Change ($000)	Return on Rate Base (%)	Return on Equity (%)	Equity Ratio (% of Total Capital)	Test Year End	Rate Base ($000)	Rate Base Valuation Method	Lag Months	Case Type	Decision Type	Phase-In? Yes/No	Interim Authorized? Yes/No
TN	Piedmont Nat	D-20-00086	Natural Gas	7/2/2020	25,802	7.10	10.30	50.50	909,884	2/16/2021	16,250	6.85	9.80	50.50	12/31/2021	897,267	Average	7.63	Distribution	Settled	No	Yes
TN	Atmos Energy	D-21-00019	Natural Gas	2/1/2021	7,897	7.62	NA	59.88	421,389	7/19/2021	10,468	7.62	NA	59.88	9/30/2020	421,188	Average	5.60	Distribution	Settled	No	No
TN	Atmos Energy	D-22-00010	Natural Gas	2/1/2022	2,466	7.53	NA	60.59	447,448	6/20/2022	2,466	7.53	NA	60.59	9/30/2021	447,448	Average	4.63	Distribution	Fully Litigated	No	No
TN	Atmos Energy	D-23-00008	Natural Gas	1/31/2023	27	7.58	NA	62.20	499,429	6/22/2023	-1,157	7.58	NA	62.20	9/30/2022	499,447	Average	4.73	Distribution	Fully Litigated	No	No
TN	Piedmont Nat	D-23-00035	Natural Gas	5/19/2023	41,561	6.95	9.80	50.09	1,143,947	12/4/2023	40,209	6.95	9.80	50.09	12/31/2022	1,140,671	Average	6.63	Distribution	Settled	No	No
TN	Chattanooga (	D-23-00029	Natural Gas	4/20/2023	12,044	7.12	9.80	49.23	245,515	10/6/2023	11,937	7.12	9.80	49.23	12/31/2022	NA		5.63	Distribution	Settled	No	No
TN	Atmos Energy	D-24-00006	Natural Gas	1/30/2024	20,390	7.62	NA	62.38	554,055	7/29/2024	19,416	7.64	NA	62.38	9/30/2023	554,053	Average	6.03	Distribution	Settled	No	No
TN	Chattanooga (	D-24-00024	Natural Gas	4/19/2024	8,778	7.12	NA	49.23	275,667	8/12/2024	8,778	7.12	NA	49.23	12/31/2023	275,667	Average	3.83	Distribution	Settled	No	No
TN	Piedmont Nat	D-24-00036	Natural Gas	5/20/2024	25,374	7.04	NA	49.97	1,250,355	12/4/2024	20,329	7.07	NA	NA	12/31/2023	1,249,743	Average	6.60	Distribution	Settled	No	No
TX	Texas Gas Se	D-GUD-1050(	Natural Gas	3/31/2016	12,757	7.59	10.00	60.10	266,060	9/27/2016	8,804	7.28	9.50	60.10	9/30/2015	266,007	Year-end	6.00	Distribution	Fully Litigated	No	No
TX	CenterPoint E	D-GUD-1056	Natural Gas	11/16/2016	31,358	NA	10.25	55.15	NA	5/23/2017	16,500	8.02	9.60	55.15	6/30/2016	NA	Year-end	6.27	Distribution	Settled	No	No
TX	Atmos Energy	D-GUD-1077	Natural Gas	10/11/2018	4,300	8.39	10.50	60.18	2,574,000	5/21/2019	2,160	7.97	9.80	60.18	12/31/2017	2,572,769	Year-end	7.40	Distribution	Settled	No	No
TX	Atmos Energy	D-GUD-1090(	Natural Gas	9/27/2019	300	7.71	9.80	60.12	37,400	4/21/2020	-300	7.71	9.80	60.12		NA		6.90	Distribution	Settled	No	No
TX	Texas Gas Se	D-GUD-1092	Natural Gas	12/20/2019	17,047	7.93	10.00	62.12	473,468	8/4/2020	10,300	7.46	9.50	59.00	6/30/2019	NA		7.60	Distribution	Settled	No	No
TX	CenterPoint E	D-GUD-1092(	Natural Gas	11/14/2019	6,816	8.22	10.40	58.00	NA	6/16/2020	4,000	7.38	9.65	56.95	6/30/2019	280,513	Year-end	7.17	Distribution	Settled	No	No
TX	Texas Gas Se	D-OSS-22-00	Natural Gas	6/30/2022	12,995	7.77	10.25	59.74	589,396	1/19/2023	8,827	7.38	9.60	59.74	12/31/2021	588,546	Year-end	6.77	Distribution	Fully Litigated	No	No
TX	Texas Gas Se	D-OSS-23-00	Natural Gas	6/30/2023	9,813	7.75	10.25	59.07	180,127	1/31/2024	5,875	7.42	9.70	59.07	12/31/2022	NA	Year-end	7.17	Distribution	Settled	No	No
TX	CenterPoint E	D-OSS-23-00	Natural Gas	10/30/2023	38,844	8.25	10.50	60.61	2,322,305	6/26/2024	5,000	7.82	9.80	60.61	6/30/2023	NA	Year-end	8.00	Distribution	Settled	No	No
TX	Texas Gas Se	D-OS-24-000	Natural Gas	6/3/2024	25,573	7.88	10.25	59.58	811,194	11/20/2024	19,300	7.55	9.70	59.58	12/31/2023	NA	Year-end	5.67	Distribution	Settled	No	No
UT	Questar Gas (	D-19-057-02	Natural Gas	7/1/2019	17,523	7.73	10.50	55.00	1,804,265	2/25/2020	2,680	7.18	9.50	55.00	12/31/2020	1,793,539	Average	7.97	Distribution	Fully Litigated	Yes	No
UT	Questar Gas (	D-22-057-03	Natural Gas	5/2/2022	67,309	7.35	10.30	53.21	2,563,718	12/23/2022	47,756	6.86	9.60	51.00	12/31/2023	2,562,000	Average	7.83	Distribution	Fully Litigated	Yes	No
VA	Columbia Gas	C-PUE-2014-(	Natural Gas	4/30/2014	31,780	7.90	10.90	43.31	428,636	8/21/2015	25,200	7.35	9.75	42.01	12/31/2013	NA		15.93	Distribution	Settled	No	Yes
VA	Washington G	C-PUR-2018-	Natural Gas	7/31/2018	33,317	7.81	10.30	53.48	1,228,226	12/20/2019	13,200	7.22	9.20	53.48	12/31/2019	1,231,225	Average	16.90	Distribution	Fully Litigated	No	Yes
VA	Roanoke Gas	C-PUR-2018-	Natural Gas	10/10/2018	9,175	7.99	10.70	59.92	126,089	1/24/2020	7,250	7.28	9.44	59.64	12/31/2017	125,410	Average	15.70	Distribution	Fully Litigated	No	Yes
VA	Virginia Natura	C-PUR-2020-	Natural Gas	6/1/2020	60,103	7.75	10.35	54.00	1,059,154	9/14/2021	43,000	7.05	9.50	51.89	12/31/2019	NA		15.67	Distribution	Settled	No	Yes
WA	Avista Corpora	D-UG-150205	Natural Gas	2/9/2015	12,021	7.46	9.90	48.00	286,086	1/6/2016	10,824	7.29	9.50	48.50	9/30/2014	263,655		11.03	Distribution	Settled	No	No
WA	Cascade Natu	D-UG-152286	Natural Gas	12/1/2015	10,515	7.65	10.00	50.00	289,684	7/7/2016	4,000	7.35	NA	NA		NA		7.30	Distribution	Settled	No	No
WA	Puget Sound I	D-UG-170034	Natural Gas	1/13/2017	22,813	7.74	9.80	48.50	1,760,694	12/5/2017	16,633	7.60	9.50	48.50	9/30/2017	1,765,437	Average	10.87	Distribution	Settled	No	No
WA	Avista Corpora	D-UG-170486	Natural Gas	5/26/2017	7,600	7.76	9.90	50.00	319,539	4/26/2018	-2,100	7.50	9.50	48.50	12/31/2016	310,099	Average	11.17	Distribution	Fully Litigated	No	No
WA	Cascade Natu	D-UG-170929	Natural Gas	8/31/2017	-1,677	7.60	9.90	50.00	311,356	7/20/2018	-2,919	7.31	9.40	49.00	12/31/2016	280,727	Average	10.77	Distribution	Settled	No	No
WA	Northwest Na	D-UG-181053	Natural Gas	12/31/2018	8,312	7.63	10.30	49.50	186,479	10/21/2019	5,139	7.16	9.40	49.00	9/30/2018	173,750	Average	9.80	Distribution	Settled	No	No
WA	Cascade Natu	D-UG-190210	Natural Gas	3/29/2019	12,709	7.73	10.30	50.00	405,155	2/3/2020	6,500	7.24	9.40	49.10	12/31/2018	NA		10.37	Distribution	Settled	No	No
WA	Avista Corpora	D-UG-190335	Natural Gas	4/30/2019	12,935	7.52	9.90	50.00	398,990	3/25/2020	8,000	7.21	9.40	48.50	12/31/2018	NA		11.00	Distribution	Settled	No	No
WA	Puget Sound I	D-UG-190530	Natural Gas	6/20/2019	65,473	7.48	9.50	48.50	2,113,443	7/8/2020	42,931	7.39	9.40	48.50	12/31/2018	2,089,021	Year-end	12.80	Distribution	Fully Litigated	No	No
WA	Cascade Natu	D-UG-200568	Natural Gas	6/19/2020	7,393	7.22	9.80	50.40	451,939	5/18/2021	-391	6.95	9.40	49.10	12/31/2019	409,282	Year-end	11.10	Distribution	Fully Litigated	No	No
WA	Avista Corpora	D-UG-200901	Natural Gas	10/30/2020	10,666	7.43	9.90	50.00	441,923	9/27/2021	8,078	7.12	9.40	48.50	12/31/2019	441,923	Average	11.07	Distribution	Settled	No	No
WA	Northwest Na	D-UG-200994	Natural Gas	12/18/2020	9,406	6.91	9.40	49.00	247,287	10/21/2021	8,000	6.81	NA	NA		NA		10.23	Distribution	Settled	Yes	No
WA	Cascade Natu	D-UG-210755	Natural Gas	9/30/2021	13,699	6.93	9.40	49.10	470,566	8/23/2022	7,189	6.85	9.40	47.00	12/31/2020	470,412	Year-end	10.90	Distribution	Settled	No	No
WA	Avista Corpora	D-UG-220054	Natural Gas	1/21/2022	10,922	7.31	10.25	48.50	514,942	12/12/2022	7,500	7.03	NA	NA		510,148		10.83	Distribution	Settled	Yes	No
WA	Puget Sound I	D-UG-220067	Natural Gas	1/31/2022	142,993	7.39	9.90	49.00	2,963,664	12/22/2022	70,563	7.16	9.40	49.00	6/30/2021	2,580,839	Average	10.83	Distribution	Settled	Yes	No
WA	Avista Corpora	D-UG-240007	Natural Gas	1/18/2024	20,819	7.61	10.40	48.50	607,240	12/20/2024	18,200	7.32	9.80	48.50	6/30/2023	607,241	Average	11.23	Distribution	Fully Litigated	Yes	No
WI	Wisconsin Pul	D-6690-UR-1:	Natural Gas	4/17/2015	9,134	7.81	10.20	50.52	377,015	11/19/2015	-6,225	7.80	10.00	50.47	12/31/2016	368,902	Average	7.20	Distribution	Fully Litigated	No	No
WI	Northern State	D-4220-UR-1:	Natural Gas	5/29/2015	5,873	8.07	10.20	52.59	111,187	12/3/2015	4,227	7.81	10.00	52.49	12/31/2016	114,157	Average	6.27	Distribution	Fully Litigated	No	No
WI	Madison Gas	D-3270-UR-1:	Natural Gas	4/8/2016	5,593	8.30	10.20	58.06	172,590	11/9/2016	3,083	7.88	9.80	57.16	12/31/2017	175,781	Average	7.17	Distribution	Fully Litigated	No	No
WI	Wisconsin Po	D-6680-UR-1:	Natural Gas	5/20/2016	9,378	7.84	10.00	52.20	284,260	11/18/2016	9,378	7.84	10.00	52.20	12/31/2018	284,260	Average	6.07	Distribution	Settled	Yes	No
WI	Northern State	D-4220-UR-1:	Natural Gas	5/4/2017	11,991	7.84	10.00	52.53	138,449	12/7/2017	9,912	7.56	9.80	51.45	12/31/2018	137,660	Average	7.23	Distribution	Fully Litigated	No	No
WI	Wisconsin Po	D-6680-UR-1:	Natural Gas	5/24/2018	0	6.97	10.00	NA	386,922	9/14/2018	0	6.97	10.00	52.00	12/31/2020	386,922	Average	3.77	Distribution	Settled	No	No
WI	Madison Gas	D-3270-UR-1:	Natural Gas	7/17/2018	4,078	7.10	9.80	56.06	250,743	9/20/2018	4,078	7.10	9.80	56.06	12/31/2020	250,743	Average	2.17	Distribution	Settled	Yes	No
WI	Wisconsin Pul	D-6690-UR-1:	Natural Gas	3/28/2019	16,239	7.97	10.35	51.46	583,981	10/31/2019	9,594	7.22	10.00	51.96	12/31/2020	581,525		7.23	Distribution	Settled	No	No
WI	Wisconsin Ele	D-05-UR-109	Natural Gas	3/28/2019	20,372	9.60	10.35	53.99	723,990	10/31/2019	15,711	7.49	10.00	54.46	12/31/2020	722,392		7.23	Distribution	Settled	No	No
WI	Wisconsin Ga	D-05-UR-109	Natural Gas	3/28/2019	14,759	8.66	10.30	51.52	1,403,771	10/31/2019	1,618	7.32	10.20	52.02	12/31/2020	1,404,705		7.23	Distribution	Settled	No	No

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				Increase Requested						Increase Authorized											
State	Company	Case identification	Service	Date	Rate Change ($000)	Return on Rate Base (%)	Return on Equity (%)	Requested Equity Ratio (% of Total Capital)	Rate Base ($000)	Date	Rate Change ($000)	Return on Rate Base (%)	Return on Equity (%)	Equity Ratio (% of Total Capital)	Test Year End	Rate Base ($000)	Rate Base Valuation Method	Lag Months	Case Type	Decision Type	Phase-In? Yes/No	Interim Authorized? Yes/No
WI	Northern State	D-4220-UR-1	Natural Gas	5/23/2019	-3,200	7.74	10.00	52.52	160,915	9/4/2019	1,080	7.74	10.00	52.52	12/31/2020	160,915	Average	3.47	Distribution	Settled	Yes	No
WI	Madison Gas	D-3270-UR-1	Natural Gas	8/28/2020	6,670	7.08	9.80	55.00	282,360	11/24/2020	6,670	7.07	9.80	55.00	12/31/2021	282,360	Average	2.93	Distribution	Settled	No	No
WI	Wisconsin Po	D-6680-UR-1	Natural Gas	5/1/2020	0	NA	NA	NA	NA	12/23/2020	0	7.14	10.00	52.53	12/31/2021	480,947	Average	7.87	Distribution	Fully Litigated	No	No
WI	Wisconsin Po	D-6680-UR-1	Natural Gas	5/5/2021	15,397	7.44	10.00	52.50	488,656	11/18/2021	15,397	7.44	10.00	52.50	12/31/2023	488,656	Average	6.57	Distribution	Settled	Yes	No
WI	Northern State	D- 4220-UR-1	Natural Gas	7/2/2021	12,958	7.31	10.00	52.50	223,260	11/18/2021	12,958	7.31	10.00	52.50	12/31/2023	223,260	Average	4.63	Distribution	Settled	Yes	No
WI	Wisconsin Ele	D-5-UR-110 (	Natural Gas	4/28/2022	50,689	8.32	10.00	54.57	1,082,756	12/29/2022	46,079	8.29	9.80	58.22	12/31/2023	1,065,821	Average	8.17	Distribution	Fully Litigated	No	No
WI	Wisconsin Ga	D-5-UR-110	Natural Gas	4/28/2022	60,136	8.13	10.20	52.71	1,667,742	12/29/2022	46,487	8.03	9.80	52.70	12/31/2023	1,626,876	Average	8.17	Distribution	Fully Litigated	No	No
WI	Wisconsin Pul	D-6690-UR-1	Natural Gas	4/28/2022	30,284	7.53	10.00	53.00	783,410	12/22/2022	26,382	7.54	9.80	53.40	12/31/2023	773,034	Average	7.93	Distribution	Fully Litigated	No	No
WI	Northern State	D-4220-UR-1	Natural Gas	4/28/2023	8,965	7.83	10.25	52.50	266,892	11/9/2023	5,394	7.58	9.80	52.50	12/31/2024	265,491	Average	6.50	Distribution	Fully Litigated	No	No
WI	Wisconsin Po	D-6680-UR-1	Natural Gas	4/28/2023	16,500	7.65	10.00	56.25	532,027	11/9/2023	12,702	7.42	9.80	53.70	12/31/2025	532,232	Average	6.50	Distribution	Fully Litigated	Yes	No
WI	Madison Gas	D-3270-UR-1	Natural Gas	4/28/2023	9,990	7.83	9.80	56.05	345,463	11/3/2023	8,586	7.80	9.70	56.06	12/31/2025	341,369	Average	6.30	Distribution	Fully Litigated	Yes	No
WI	Wisconsin Pul	D-6690-UR-1	Natural Gas	4/12/2024	42,881	8.16	10.00	54.68	926,985	12/19/2024	28,401	7.95	9.80	54.17	12/31/2026	907,259	Average	8.37	Distribution	Fully Litigated	Yes	No
WI	Wisconsin Ele	D-5-UR-111 (	Natural Gas	4/12/2024	88,479	8.96	10.00	56.88	1,479,687	12/19/2024	71,103	8.80	9.80	56.54	12/31/2026	1,454,775	Average	8.37	Distribution	Fully Litigated	Yes	No
WI	Wisconsin Ga	D-5-UR-111	Natural Gas	4/12/2024	98,269	9.02	10.00	53.26	2,127,998	12/19/2024	58,009	8.63	9.80	52.76	12/31/2026	2,049,082	Average	8.37	Distribution	Fully Litigated	Yes	No
WV	Mountaineer (	C-15-0003-G-	Natural Gas	1/5/2015	12,168	8.62	10.38	49.83	204,782	10/13/2015	7,700	7.96	9.75	45.50	9/30/2014	202,256	Average	9.37	Distribution	Settled	No	No
WV	Mountaineer (	C-19-0316-G-	Natural Gas	3/6/2019	19,342	7.90	10.70	53.72	258,906	12/26/2019	12,420	7.24	9.75	NA	12/31/2018	258,200	Average	9.83	Distribution	Settled	No	No
WV	Hope Gas, Inc	C-20-0746-G-	Natural Gas	9/30/2020	28,213	6.91	10.25	49.05	244,827	7/27/2021	13,113	5.98	9.54	47.45	12/31/2019	208,570	Average	10.00	Distribution	Fully Litigated	No	No
WV	Mountaineer (	C-23-0280-G-	Natural Gas	3/6/2023	37,649	7.98	10.90	54.17	422,187	12/21/2023	13,933	7.24	9.75	NA	12/31/2022	427,070	Average	9.67	Distribution	Settled	No	No
WY	Black Hills No	D-30011-97-G	Natural Gas	11/17/2017	1,212	8.00	10.20	54.00	13,025	7/16/2018	968	7.75	9.60	54.00	6/30/2017	12,905	Year-end	8.03	Distribution	Settled	No	No
WY	MDU Resourc	D-30013-351-	Natural Gas	5/23/2019	1,052	7.75	10.30	52.08	15,378	1/15/2020	828	7.08	9.35	51.25	12/31/2018	14,870	Year-end	7.90	Distribution	Settled	No	No
WY	Black Hills Wy	D-30026-2-GI	Natural Gas	6/3/2019	16,122	7.54	10.40	50.23	354,367	12/11/2019	13,204	6.98	9.40	50.23	12/31/2018	354,363	Year-end	6.37	Distribution	Settled	No	No
WY	Questar Gas (	D-30010-187-	Natural Gas	11/1/2019	3,520	7.46	10.50	55.00	62,074	8/21/2020	1,521	7.11	9.35	55.00	12/31/2019	60,546	Year-end	9.80	Distribution	Settled	No	No
WY	Questar Gas (	D-30010-215-	Natural Gas	3/1/2023	2,067	7.28	10.30	51.56	71,120	11/7/2023	1,639	6.95	9.65	51.56	9/30/2022	71,118	Year-end	8.37	Distribution	Settled	No	No
WY	Black Hills Wy	D-30026-78-G	Natural Gas	5/18/2023	20,498	7.73	10.49	52.05	449,308	1/17/2024	15,143	7.33	9.85	51.00	12/31/2022	450,761	Year-end	8.13	Distribution	Settled	No	No

Return on Rate Base (%)	
Mean	7.06
Standard E	0.04
Median	7.11
Mode	7.07
Standard D	0.64
Sample Var	0.41
Kurtosis	3.51
Skewness	(1.11)
Range	4.35
Minimum	4.45
Maximum	8.80
Sum	2,328.78
Count	330.00

Schedule MLR-8d: Natural Gas rate cases for CY 2015-2025 (Only ROR rates higher than 7.80%)
where the state regulator approved an ROE, based on S&P MI data as of 3/18/2025, available at: S&P Capital IQ (https://www.capitaliq.spglobal.com/web/client?auth=inherit#office/screener?perspective=238101)

				Increase Requested						Increase Authorized												
State	Company	Case identification	Service	Date	Rate Change ($000)	Return on Rate Base (%)	Return on Equity (%)	Requested Equity Ratio (% of Total Capital)	Rate Base ($000)	Date	Rate Change ($000)	Return on Rate Base (%)	Return on Equity (%)	Equity Ratio (% of Total Capital)	Test Year End	Rate Base ($000)	Rate Base Valuation Method	Lag Months	Case Type	Decision Type	Phase-In? Yes/No	Interim Authorized? Yes/No
AK	ENSTAR Natu	D-U-16-066	Natural Gas	6/1/2016	11,812	8.92	12.55	51.68	286,488	p	5,810	8.59	11.88	51.81	12/31/2015	274,140	Average	15.93	Distribution	Fully Litigated	No	Yes
IN	Ohio Valley G	Ca-46011	Natural Gas	2/7/2024	12,062	9.44	11.00	83.18	68,109	11/6/2024	11,059	8.61	10.00	83.18	9/30/2025	68,078	Year-end	9.10	Distribution	Settled	Yes	No
MA	Liberty Utilities	DPU 15-75	Natural Gas	7/15/2015	11,779	8.59	10.40	55.00	70,713	2/10/2016	7,800	7.99	9.60	50.00	12/31/2014	69,900	Year-end	7.00	Distribution	Settled	Yes	No
MA	Fitchburg Gas	DPU 15-81	Natural Gas	6/16/2015	2,985	8.72	10.25	52.92	57,542	4/29/2016	1,635	8.46	9.80	52.17	12/31/2014	57,151	Year-end	10.60	Distribution	Fully Litigated	No	No
MA	The Berkshire	DPU 18-40	Natural Gas	5/17/2018	4,065	8.94	10.35	61.48	95,831	1/18/2019	2,390	8.33	9.70	54.00	12/31/2017	NA		8.20	Distribution	Settled	No	No
MA	Fitchburg Gas	DPU 19-131	Natural Gas	12/17/2019	7,290	8.41	10.50	52.45	95,035	2/28/2020	4,596	7.99	9.70	52.45	12/31/2018	88,133	Year-end	2.43	Distribution	Settled	Yes	No
OK	CenterPoint E	Ca-PUD2015	Natural Gas	3/13/2015	878	8.64	NA	49.86	49,669	11/4/2015	858	8.64	NA	49.86	12/31/2014	NA	Year-end	7.87	Distribution	Fully Litigated	No	No
SC	Dominion Ene	D-2017-6-G	Natural Gas	6/15/2017	9,022	8.15	NA	52.16	588,959	9/27/2017	8,634	8.15	NA	52.16	3/31/2017	588,953	Year-end	3.47	Distribution	Fully Litigated	No	No
SC	Dominion Ene	D-2016-6-G	Natural Gas	6/15/2016	4,387	8.07	NA	51.18	545,713	10/13/2016	4,086	8.11	NA	51.35	3/31/2016	545,701	Year-end	4.00	Distribution	Fully Litigated	No	No
SC	Dominion Ene	D-2018-6-G	Natural Gas	6/15/2018	-18,737	8.19	NA	53.13	604,576	9/26/2018	-19,717	8.05	NA	49.83	3/31/2018	604,600	Year-end	3.43	Distribution	Fully Litigated	No	No
TX	CenterPoint E	D-GUD-10567	Natural Gas	11/16/2016	31,358	NA	10.25	55.15	NA	5/23/2017	16,500	8.02	9.60	55.15	6/30/2016	NA	Year-end	6.27	Distribution	Settled	No	No
TX	Atmos Energy	D-GUD-1077	Natural Gas	10/11/2018	4,300	8.39	10.50	60.18	2,574,000	5/21/2019	2,160	7.97	9.80	60.18	12/31/2017	2,572,769	Year-end	7.40	Distribution	Settled	No	No
TX	CenterPoint E	D-OSS-23-00	Natural Gas	10/30/2023	38,844	8.25	10.50	60.61	2,322,305	6/26/2024	5,000	7.82	9.80	60.61	6/30/2023	NA	Year-end	8.00	Distribution	Settled	No	No
WI	Wisconsin Pu	D-6690-UR-1	Natural Gas	4/17/2015	9,134	7.81	10.20	50.52	377,015	11/19/2015	-6,225	7.80	10.00	50.47	12/31/2016	368,902	Average	7.20	Distribution	Fully Litigated	No	No
WI	Northern State	D-4220-UR-1	Natural Gas	5/29/2015	5,873	8.07	10.20	52.59	111,187	12/3/2015	4,227	7.81	10.00	52.49	12/31/2016	114,157	Average	6.27	Distribution	Fully Litigated	No	No
WI	Madison Gas	D-3270-UR-1	Natural Gas	4/8/2016	5,593	8.30	10.20	58.06	172,590	11/9/2016	3,083	7.88	9.80	57.16	12/31/2017	175,781	Average	7.17	Distribution	Fully Litigated	No	No
WI	Wisconsin Po	D-6680-UR-1	Natural Gas	5/20/2016	9,378	7.84	10.00	52.20	284,260	11/18/2016	9,378	7.84	10.00	52.20	12/31/2018	284,260	Average	6.07	Distribution	Settled	Yes	No
WI	Wisconsin Ele	D-5-UR-110 (	Natural Gas	4/28/2022	50,689	8.32	10.00	54.57	1,082,756	12/29/2022	46,079	8.29	9.80	58.22	12/31/2023	1,065,821	Average	8.17	Distribution	Fully Litigated	No	No
WI	Wisconsin Ga	D-5-UR-110	Natural Gas	4/28/2022	60,136	8.13	10.20	52.71	1,667,742	12/29/2022	46,487	8.03	9.80	52.70	12/31/2023	1,626,876	Average	8.17	Distribution	Fully Litigated	No	No
WI	Madison Gas	D-3270-UR-1	Natural Gas	4/28/2023	9,990	7.83	9.80	56.05	345,463	11/3/2023	8,586	7.80	9.70	56.06	12/31/2025	341,369	Average	6.30	Distribution	Fully Litigated	Yes	No
WI	Wisconsin Pu	D-6690-UR-1	Natural Gas	4/12/2024	42,881	8.16	10.00	54.68	926,985	12/19/2024	28,401	7.95	9.80	54.17	12/31/2026	907,259	Average	8.37	Distribution	Fully Litigated	Yes	No
WI	Wisconsin Ele	D-5-UR-111 (	Natural Gas	4/12/2024	88,479	8.96	10.00	56.88	1,479,687	12/19/2024	71,103	8.80	9.80	56.54	12/31/2026	1,454,775	Average	8.37	Distribution	Fully Litigated	Yes	No
WI	Wisconsin Ga	D-5-UR-111	Natural Gas	4/12/2024	98,269	9.02	10.00	53.26	2,127,998	12/19/2024	58,009	8.63	9.80	52.76	12/31/2026	2,049,082	Average	8.37	Distribution	Fully Litigated	Yes	No
WV	Mountaineer	C-15-0003-G-	Natural Gas	1/5/2015	12,168	8.62	10.38	49.83	204,782	10/13/2015	7,700	7.96	9.75	45.50	9/30/2014	202,256	Average	9.37	Distribution	Settled	No	No

Schedule MLR-8e: Natural Gas rate cases for CY 2015-2025 (Only ROR rates higher than 8.59%)

where the state regulator approved an ROE, based on S&P MI data as of 3/18/2025

available at: S&P Capital IQ (https://www.capitaliq.spglobal.com/web/client?auth=inherit#office/screener?perspective=238101)

				Increase Requested						Increase Authorized												
State	Company	Case identification	Service	Date	Rate Change ($000)	Return on Rate Base (%)	Return on Equity (%)	Requested Equity Ratio (% of Total Capital)	Rate Base ($000)	Date	Rate Change ($000)	Return on Rate Base (%)	Return on Equity (%)	Equity Ratio (% of Total Capital)	Test Year End	Rate Base ($000)	Rate Base Valuation Method	Lag Months	Case Type	Decision Type	Phase-In? Yes/No	Interim Authorized? Yes/No
AK	ENSTAR Nat	D-U-16-066	Natural Gas	6/1/2016	11,812	8.92	12.55	51.68	286,488	p	5,810	8.59	11.88	51.81	12/31/2015	274,140	Average	15.93	Distribution	Fully Litigated	No	Yes
IN	Ohio Valley G	Ca-46011	Natural Gas	2/7/2024	12,062	9.44	11.00	83.18	68,109	11/6/2024	11,059	8.61	10.00	83.18	9/30/2025	68,078	Year-end	9.10	Distribution	Settled	Yes	No
OK	CenterPoint E	Ca-PUD2015	Natural Gas	3/13/2015	878	8.64	NA	49.86	49,669	11/4/2015	858	8.64	NA	49.86	12/31/2014	NA	Year-end	7.87	Distribution	Fully Litigated	No	No
WI	Wisconsin Ele	D-5-UR-111 (	Natural Gas	4/12/2024	88,479	8.96	10.00	56.88	1,479,687	12/19/2024	71,103	8.80	9.80	56.54	12/31/2026	1,454,775	Average	8.37	Distribution	Fully Litigated	Yes	No
WI	Wisconsin Ga	D-5-UR-111	Natural Gas	4/12/2024	98,269	9.02	10.00	53.26	2,127,998	12/19/2024	58,009	8.63	9.80	52.76	12/31/2026	2,049,082	Average	8.37	Distribution	Fully Litigated	Yes	No

Pennsylvania Public Utility Commission v. Pike County Light & Power Company – Gas Division; Docket No. R-2024-3052357

PIKE COUNTY LIGHT & POWER COMPANY – GAS DIVISIONS' RESPONSES TO OFFICE OF CONSUMER ADVOCATE INTERROGATORIES AND REQUESTS FOR PRODUCTION OF DOCUMENTS, SET 5

4. Referencing Lenns and Lenns Direct Testimony at 23:11-21 and Exhibit E-2, Schedule 3, provide support for the Company's proposed return on equity of 10.20%. Include relevant case numbers and PUC decisions in your response, along with copies of all supporting PUC decisions and all filed rate of return testimony.

RESPONSE: Refer to the "DSIC Charge Return on Equity" attachment provided. The Company stated in the testimony that the 10.20% is the rounded return on equity from the Gas Distribution System Improvement Charge ("DSIC") Eligible Utilities Return on Equity Summary, which is included on page 15 of 30 on the PDF file. The return on equity published is 10.15%. This report is published on the Pennsylvania Public Utility Commission's website under the "Filing & Resources" section, then under the "Reports" you will see "Quarterly Earnings Summary Reports." This report is published every quarter with the commission approved return on equity number.

PROVIDED BY: Matthew Lenns, Controller

DATE: March 3, 2025

Pennsylvania Public Utility Commission v. Pike County Light & Power Company – Gas Division; Docket No. R-2024-3052357

PIKE COUNTY LIGHT & POWER COMPANY – GAS DIVISIONS' RESPONSES TO OFFICE OF CONSUMER ADVOCATE INTERROGATORIES AND REQUESTS FOR PRODUCTION OF DOCUMENTS, SET 5

3. Referencing Lenns and Lenns Direct Testimony at 22:21 to 23:1, provide support and all underlying documentation and live excel files for the referenced 50/50 split between debt and equity of other companies.

RESPONSE: Refer to the "CEC – Capital Structure" Excel attachment provided for the referenced 50/50 split between debt and equity of the other regulated companies included in Corning Energy Corporation as of September 30, 2022, 2023 and 2024.

PROVIDED BY: Matthew Lenns, Controller

DATE: March 3, 2025

Corning Energy Corporaion
Capitalzation Structures - for the 12 months ended September 30, 2024, 2023 and 2022

CNG	As of September 30, 2024			As of September 30, 2023			As of September 30, 2022		
		Amount	Percent		Amount	Percent		Amount	Percent
Long Term Debt:	$	40,986,396	41.36%	$	33,457,269	38.30%	$	33,784,002	40.07%
Short Term Debt		8,920,167	9.00%		11,056,149	12.66%		10,023,439	11.89%
Proprietary Capital									
Common Stock		11,323,855			11,323,855			11,323,855	
Paid In Capital		25,056,346			17,564,045			16,947,952	
Retained Earnings		12,806,104			13,955,957			12,229,653	
Total Proprietary Capital:		49,186,305	49.64%		42,843,857	49.04%		40,501,460	48.04%
Total Capitalization	$	99,092,868	100.00%	$	87,357,275	100.00%	$	84,308,901	100.00%

Pike	As of September 30, 2024			As of September 30, 2023			As of September 30, 2022		
		Amount	Percent		Amount	Percent		Amount	Percent
Long Term Debt:	$	17,584,425	44.69%	$	15,285,318	44.42%	$	14,542,993	46.43%
Short Term Debt		2,006,792	5.10%		2,617,121	7.61%		2,004,314	6.40%
Proprietary Capital									
Common Stock		-			-			-	
Paid In Capital		12,450,000			9,950,000			9,600,000	
Retained Earnings		7,303,955			6,556,768			5,173,799	
Total Proprietary Capital:		19,753,955	50.21%		16,506,768	47.97%		14,773,799	47.17%
Total Capitalization	$	39,345,172	100.00%	$	34,409,207	100.00%	$	31,321,106	100.00%

LGC	As of September 30, 2024			As of September 30, 2023			As of September 30, 2022		
		Amount	Percent		Amount	Percent		Amount	Percent
Long Term Debt:	$	6,414,257	53.33%	$	5,591,314	44.33%	$	5,992,918	44.47%
Short Term Debt		265,311	2.21%		1,368,632	10.85%		1,223,473	9.08%
Proprietary Capital									
Common Stock		-			-			-	
Paid In Capital		60,000			-			-	
Retained Earnings		5,288,170			5,652,326			6,259,495	
Total Proprietary Capital:		5,348,170	44.47%		5,652,326	44.82%		6,259,495	46.45%
Total Capitalization	$	12,027,738	100.00%	$	12,612,272	100.00%	$	13,475,886	100.00%

HoldCo	As of September 30, 2024			As of September 30, 2023			As of September 30, 2022		
		Amount	Percent		Amount	Percent		Amount	Percent
Long Term Debt:	$	70,000,000	63.40%	$	-	0.00%	$	-	0.00%
Short Term Debt		12,000,000	10.87%		-	0.00%		-	0.00%
Proprietary Capital									
Common Stock		100			100			100	
Paid In Capital		44,627,806			39,877,806			38,268,398	
Retained Earnings		(16,218,103)			(14,600,354)			(14,159,759)	
Total Proprietary Capital:		28,409,803	25.73%		25,277,552	100.00%		24,108,739	100.00%
Total Capitalization	$	110,409,803	100.00%	$	25,277,552	100.00%	$	24,108,739	100.00%

Pennsylvania Public Utility Commission v. Pike County Light & Power Company – Gas Division; Docket No. R-2024-3052357

PIKE COUNTY LIGHT & POWER COMPANY – GAS DIVISIONS' RESPONSES TO OFFICE OF CONSUMER ADVOCATE INTERROGATORIES AND REQUESTS FOR PRODUCTION OF DOCUMENTS, SET 5

17. Please provide a copy of all the major bond rating agency reports that cover the parent company and Company that were issued from the past five years, to the most currently available.

RESPONSE: Corning Energy Company has had only one bond rating, which was provided as part of the debt refinancing executed on September 12, 2024. The rating was performed by the Kroll Bond Rating Agency, LLC ("KBRA"). Refer to the "Q17" attachments provided for the issuer obligation rating letter and final rating report.

PROVIDED BY: Matthew Lenns, Controller, and Charles Lenns, Senior Vice President & Chief Financial Officer

DATE: March 3, 2025

Corning Energy Corporation

$50 Million Series A Senior Secured Notes due 2034
$20 Million Series B Senior Secured Notes due 2036

Analytical Contacts

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Table of Contents

Assignment of Ratings

KBRA assigns its unpublished BB issuer rating to Corning Energy Corporation. KBRA also assigns its unpublished BBB- issue rating to Corning Energy's $50 million Series A senior secured notes and $20 million Series B senior secured notes. The Outlook is Stable.

Corning Energy is a natural gas and electric distributor with three operating businesses – Corning Natural Gas Corporation, Pike County Light & Power, and Leatherstocking Gas Company. To assign the rating, KBRA applied its General Corporate Global Rating Methodology, published on November 28, 2017; Corporate Instrument Notching Global Methodology, published on September 9, 2020; and ESG Global Rating Methodology, published on June 16, 2021. This report is based on information regarding the issuer and its issuance as of September 10, 2024.

Issuer Rating	
Entity	**KBRA Rating/Outlook**
Corning Energy Corporation	BB/Stable

Corning Energy Corporation		
Securities	**PPN**	**KBRA Rating/Outlook**
$50 Million, 6.29% fixed rate, Series A Senior Secured Notes due 2034	21931# AA4	BBB-/Stable
$20 Million, 6.37% fixed rate, Series B Senior Secured Notes due 2036	21931# AB2	BBB-/Stable

Transaction Overview

Corning Energy Corporation (Corning Energy) has engaged KBRA to rate $50 million, 6.29% fixed rate, Series A senior secured notes due 2034 and $20 million, 6.37% fixed rate, Series B senior secured notes due 2036. The proceeds of the issuance will be used to refinance the existing debt of the company's three regulated utility subsidiaries and consolidate all debt at Corning Energy.

The notes have a bullet maturity. Corning Energy will have an option to prepay the notes prior to maturity at a price equal to the principal amount plus a Make-Whole amount determined at the time of prepayment. As a part of the transaction, the company will also solicit a new $30 million revolving credit facility provided by Citizens Bank, which KBRA is not rating. The target closing date of the transaction is September 12, 2024.

Under the transaction structure, the subsidiaries will not be co-borrowers or guarantors under the notes. The notes will be secured only by the stock of each of the issuer subsidiaries; no assets of any of the subsidiaries are pledged.

For financial covenants, the company is subject to a consolidated indebtedness to capitalization of less than 65%, which is often seen in regulated utility financings. For any future priority debt issuance, priority debt is not allowed to exceed 15% of consolidated capitalization. For subsidiary debt, the subsidiaries are subject to a debt cap of $2 million in the case of Leatherstocking or Pike, and $5 million in the case of Corning Gas. The company is also subject to an interest coverage ratio of 2.0x.

Company History and Overview

Found in 1904, Corning Energy Corporation is a natural gas and electric utility holding company with three operating businesses: Corning Natural Gas Corporation, Pike County Light & Power, and Leatherstocking Gas Company. The company serves approximately 21,000 customers across a handful of regions in New York state and Pennsylvania. As of 2023, the company generated approximately $47 million in revenue and $13 million in EBITDA. The three subsidiaries of Corning Energy are currently authorized for a total rate base of $136.5 million by its two regulators, New York Public Service Commission (NYPSC) and Pennsylvania Public Utility Commission (PAPUC). The company was publicly traded on the New York Stock Exchange (NYSE) until the recent acquisition by Argo Infrastructure Partners, LP in 2022.

Corning Natural Gas Corporation (CNGC) – 62% of Full-Year (FY) 2023 Revenue and EBITDA

CNGC is the largest of Corning Energy's subsidiaries and operates as a natural gas distribution company with 434 miles of mains, delivering natural gas to approximately 15,000 residential, commercial, industrial, and municipal customers and currently employing 65 people. CNGC deliveries are made across towns and villages, over 400 square miles, through the southern tier and central regions of New York state. CNGC annually transports approximately 8 billion cubic feet (Bcf) of natural gas to commercial, industrial, residential, and wholesale customers. The subsidiary provides gas delivery and transportation services to two other utilities, NYSEG and BEGWS, as well as other local gas producers in New York and Pennsylvania. CNGC also has contracts with Coring Incorporated and Woodhill Municipal Gas Company, a small local utility, to provide maintenance service on their gas lines. The pipeline for CNGC is 434 miles with transport and delivery capacity of 8 Bcf and storage capacity of 736,000 Dth. CNGC is under the jurisdiction of the New York Public Service Commission (NYPSC), which oversees and sets rates for New York gas distribution companies. Currently, CNGC accounts for approximately $89 million, or 65% of Corning Energy's total rate base. For CNGC, the company filed its rate case on July 31, 2024, in which it requested a $13.1 million increase in total rate base to be spread equally across four years. The case is expected to be settled in June 2025.

Pike County Light & Power (PCL&P) – 34% of FY2023 Revenue and 33% of EBITDA
Pike was acquired by the company in 2016 from Orange & Rockland Utilities, Inc., a local utility company owned by ConEdison. Pike provides electric service to approximately 4,900 customers and natural gas services to 1,300 customers. The subsidiary has 11 employees. The natural gas distribution pipeline is 20 miles with transport and delivery capacity of approximately 137,000 Mcf. The subsidiary is an electric and gas utility regulated by Pennsylvania Public Utilities Commission (PAPUC). Pike accounts for approximately $36 million, or 27% of Corning Energy's total rate base. Pike anticipates filing two new rate cases in Q4 2024, which are expected to take effect in summer of 2025.

Leatherstocking Gas Company (LGC) – 4% of FY2023 Revenue and 5% of EBITDA
Headquartered in Montrose, Pennsylvania, Leatherstocking was created in 2014 in a partnership with Mirabito Regulated Industries and was fully acquired in 2020. The subsidiary distributes gas in Susquehanna and Bradford Counties within Pennsylvania. The subsidiary serves approximately 500 customers with four employees. Leatherstocking is also regulated by the PAPUC. Leatherstocking accounts for approximately $11 million, or 8% of Corning Energy's total rate base. Leatherstocking filed with its most recent rate case in July 2022 and was approved in February 2023 for a $645,000 increase in total revenues.

As mentioned, Corning Energy was acquired by Argo Infrastructure Partners, LP in July 2022. Argo Infrastructure Partners, LP is an independent infrastructure investment manager that invests in industries such as regulated utilities, energy, renewables, and transportation. Argo manages over $5 billion of capital on behalf of its institutional investor partners. The company's managed assets include four contracted power generation assets, three utilities serving over 600,000 customers, two electric transmission systems, and one energy storage network.

Key Credit Considerations

	+/−
Credit Enhancing Regulatory Oversight The presence of multiple state regulators that oversees and restricts the financial endeavors of regulated utility operating companies, limits the amount of total debt in the capital structure and other financial policies that decreases the credit risk.	+
Continuous Growth in Rate Base Corning Energy has seen continuous, incremental growth in its rate base across all three of its subsidiaries. The company expects to continue to see gradual growth, primarily from its Pennsylvania service territory, driven by ongoing initiatives to transition residential customers to natural gas usage.	+
Long-standing Presence and Customer Relationships Corning Energy has a long-standing presence within the city of Corning given its operating history of over 100 years. As a result, the company also benefits from established customer relationships in its service territory.	+
Pending Rate Cases CNGC and Pike have upcoming rate cases in 2024 where the company is requesting increases in its rate base. An increase in the company's rate base would be viewed positively; however, it is not expected to be resolved until 2025. An unfavorable rate case outcome is possible, particularly in New York, which could result in limited rate increases or evidence of an increasing regulatory focus on transitioning away from natural gas.	+/-
Limited Scale and Geographic Diversity Corning Energy operates in small scale service territories in the states of New York and Pennsylvania. The limited scale and lack of diversity restricts the company's long-term growth opportunities.	-
Shifting Regulatory Attitude	-

The state of New York has recently been emphasizing a transition to renewable energy to meet its climate change targets outlined in the Climate Leadership and Community Protection Act (CLCPA) passed in 2019. This could heavily impact the company's profitability considering most of its revenue is generated by its operations in New York at CNGC. This is partially offset by the fact that the state of Pennsylvania maintains a favorable view on the expansion of natural gas usage in the region.	
Limited Operating Track Record under a Private Sponsor Corning Energy Corporation has operated as a public company since 2013 with a high level of oversight. With the recent acquisition by Argo Infrastructure Partners, there could potentially be changes in the way the company operates and its financial policies, partially offset by the oversight provided by the utility regulators.	**-**

Issuer Rating Rationale

The BB issuer rating reflects Corning Energy's overall Average business risk profile and a financial risk score of 9.90.

Corning Energy's business risk profile is characterized by its ownership of three utility subsidiaries that benefit from a monopolistic position within their service territories as a regulated utility provider with operations in two states, New York and Pennsylvania. As a result, the company benefits from revenue stability and a cost-of-service model. The company has a long operating track record within its regions of operations with established customer relationships. However, the company has limited corporate scale, which restricts its competitiveness emphasized by the lack of large economic hubs in the region of its operations and the presence of larger utility competitors within the states of New York and Pennsylvania. In comparison to Corning Energy, the larger competitors are better positioned to politically navigate and combat changes in regulations and policies that adversely impact their operations. Additionally, the service territories are also vulnerable to changes in economic activity and downturns as a result of limited population of largely lower middle income residents The company has primarily been restricted to incremental growth that resulted primarily from the regulated nature of its business. Additionally, although the company has long-standing customer relationships, gas volumes are concentrated among its C&I customers which could present challenges for long-term sustainability of customer rates and volumes. Currently, the company has constructive relationships with both its regulators. However, the regulatory environment is a factor KBRA will continue to monitor for further negative developments considering the growing focus on the transition to renewable energy sources, especially in the state of New York. So far, the state of New York has demonstrated continued initiative to further the state's climate change initiatives and meet its emission targets. With continued legislation, the company faces the potential significant regulations that will challenge the ability for future favorable rate cases and growth of its operations in New York.

Corning Energy's financial risk profile reflects its limited size and scale compared to most utility holding companies, given the small service territory of its regulated subsidiaries. The company benefits from adequate profitability as a result of the nature and cost-of-service model for its regulated utilities operations that allows the company to recover prudent costs, as well as earn a return on capital. Following the proposed issuance, Corning Energy is expected to benefit from a cleaner capital structure with debt consolidated at HoldCo level. However, the company's leverage is significant particularly given its scale that reduces overall financial flexibility and buffers.

Rating Table

Business Risk Profile	AAA	AA	A	BBB	BB	B	CCC or below
Strong	<1.5	1.5-4.5	3-7.5	6-10.5	9.5-13.5	--	--
Average Risk	--	<1.5	<3	3-9.5	7.5-12	9-16.5	≥18
Weak	--	--	--	<3	<7.5	<9	<18

Notching Analysis

KBRA applied its [Corporate Instrument Notching Global Methodology](), updated September 9, 2020, to determine the potential for a notching adjustment of the issue rating based on the issuer rating.

To complete the analysis, KBRA considered recovery in the event of a distressed sale. KBRA notes that defaults involving a utility company with a significant amount of cash flow from regulated operations often involve unique dynamics that are not broadly applicable. Nevertheless, KBRA considered a range of datapoints across the utility industry and other industries with similar business risk characteristics. An EBITDA haircut was applied, along with a distressed sales multiple. Overall KBRA calculates an expected range of recovery that supports two notches of uplift for the senior secured notes relative to the issuer rating.

Outlook

The Stable Outlook reflects KBRA's expectation that Corning Energy will continue to operate with predictable cashflows through its regulated utility operations and generate sufficient cash to meet its debt obligations. The outlook further reflects KBRA's expectation that Corning Energy will continue to see incremental growth over the medium term while prudently managing capital expenditures and overall liquidity.

Sensitivities for Rating Change

An upgrade could occur if Corning Energy delivers sustained growth in regulated rate base across its operating subsidiaries, including significant increases in customer counts and gas volumes from its utility operations in Pennsylvania. This would likely occur through favorable rate case outcomes and franchise expansion. KBRA will look for the company to diversify its cash flows away from the evolving regulatory environment in New York State, as well as reduce overall volume concentration to major C&I customers.	+
A downgrade could occur if Corning Energy's EBITDA/Interest falls below 3.0x for a sustained period, the company experiences significant operational disruptions, or there is a large population or economic activity outflow from its service territories. A downgrade could also occur should New York State introduce legislation that accelerates the transition to alternative energy sources without addressing the future role of natural gas utilities in the state.	-

Business Risk – Average Risk

Business Risk Summary: Corning Energy Corporation		
Determinant	**Weight**	**Business Risk Comment**
Industry Risk	25%	**Strong**: The essential nature of the services provided and the nature of the regulatory protection in which the utility companies are granted natural monopolies with little competition in their service territories. In addition, the regulatory environment is typically supportive, allowing utility companies the opportunity to recover and earn a rate of return based on the costs to provide services.
Competitive Risk	25%	**Average**: This reflects the company's monopolistic position through the ownership of regulated utilities operations, offset by its limited corporate scale and market share and concentrated customer base.
Growth and Corporate Development Risk	15%	**Average**: This reflects the company's focus on incremental organic growth over time in its Pennsylvania service territory, challenging growth prospects in New York, and overall limited capital to allocate to expansion initiatives.
Liquidity and Financial Flexibility Risk	15%	**Average**: In KBRA's opinion, the liquidity and cash flow profile of the company is sufficient to meet its ongoing obligations. The company's liquidity position is expected to benefit from the reimbursement of prudently managed costs and capital expenditures.
Regulatory and Jurisdictional Risk	10%	**Average**: This reflects the fact that Corning Energy generates its revenues and cash flows from its operations in regulated utilities sector, which is subject to a comprehensive regulatory regime. In addition, the company is expected to face additional regulations given an evolving, regulatory environment that is shifting towards the use of renewable energy sources.
Organizational Form, Structure & Ownership Considerations	10%	**Average**: Following its acquisition by Argo Infrastructure in 2022, Corning Energy operates as a private company under the ownership of a private sponsor. As such, the company does not benefit from the same level of oversight as a publicly traded corporation, although KBRA notes that it is subject to more independent oversight than other private companies given its

		status as a regulated utility and the presence of the state regulators, NYPSC and PAPUC.
Total	**100%**	

Industry Risk – 25% – Strong Risk

KBRA views the utility industry risk in the U.S. to be strong, given the essential nature of the services provided and the nature of the regulatory protection in which the utility companies are granted natural monopolies in their service territories with little competition. In addition, the regulatory environment is typically supportive granting utility companies the opportunity to recover and earn a rate of return based on the costs to provide services.

In the U.S., there are generally two types of utilities companies, private and public. Private utilities, called investor-owned utilities (IOU), are private entities that are either owned by public investors or are privately held but are regulated at both the federal level and the state level by regulatory commissions. The Federal Energy Regulatory Commission (FERC) and the various states regulatory commission are responsible for the regulatory oversight of the utilities. These commissions set the retail rates that are charged by the IOUs for their service. The need for regulation of utilities arises primarily because of the natural monopoly characteristics of the industry. To ensure the delivery of safe, adequate, and reliable electric services, the commissions have granted the IOUs exclusive rights to be the sole provider within a region. The retail rates are set at prices that are sufficient to compensate the regulated utility for the costs that it incurs to fulfill its obligation to serve. Usually, the nature of the retail rate is based on a rate of return provision over the utility's cost of service.

The other type of utilities, publicly-owned utilities (POU), are member-owned cooperatives or government- or municipally-owned utilities. POUs are generally exempt from regulation by state regulatory commissions because they are assumed to have the customers' (who are also the owners or voters) best interests in mind when setting rates and service standards. A few states do subject publicly owned utilities to regulatory oversight.

In the U.S, there are approximately 3,200 utilities operating in the U.S., roughly 200 of them are IOUs. The IOUs provide power to almost 75% of all consumers. Utilities' role in the U.S. are usually in three functions: (i) production (gas) or generation (electricity); (ii) transmission; and (iii) distribution. In the U.S., only a small fraction of the 3,200 utilities performs (or have) all three functions. Most of the major IOUs do own generation, transmission, and distribution; however, very few of these own enough generating resources to meet all of their needs. Very few of the POUs own their own generation or transmission. Instead, they rely on other publicly owned generation and transmission (G&T) utilities or IOUs to provide those functions for them. As a result, the vast majority of utilities rely on power purchases agreements (PPA) from others with generation assets to deliver and transmit electric power across the transmission grid to local utility substations connected to distribution lines that serve end user.

Under the regulatory regime, industry revenues and profitability are relatively stable since the regulatory commissions have deemed electricity and natural gas service providers to be natural monopolies because of the economies of scale and the significant capital necessary to build and maintain power plants, transmission and distribution lines and natural gas pipes and plants. As an IOU under the U.S. utility regulatory regime, Corning Energy has limited exposure to the effect of market risks due to its role as a regulated monopoly within its service territories. As such, KBRA scores the company's exposure to market forces and structural risk as Strong.

Within its regulated operations, Corning Energy does not compete on the basis of price or quality; instead, regulation replaces competition as a determinant of price. Corning Energy provides a largely unnegotiable rate for its gas service to the customers based on a formula-based rate plan that includes allowed rate of return over its capital expenditures, operations and maintenance costs, financing costs, and the related costs of service. The company is required to file a rate case with NYPSC and PAPUC that details these projected costs and the rates that will be subsequently charged to customers are then determined in a regulatory proceeding. Currently, Corning Energy operates under a regime in which it is authorized by the NYPSC to earn a return on equity (ROE) of 9.25% as of its most recent rate case filing.

Positive relations with the regulators usually allow utilities to recover prudent capital costs in the charged rates. With positive relations with its regulators, an IOU can typically expect stable cash flows even if there is a slight lag in recovering regulatory approved costs. Specifically pertaining to Pike, the company also benefits from recovery mechanism for its infrastructure investments called Distribution System Improvement Charge (DSIC). The company is able to recover costs related to its capital investment projects, up to 5% of total annual revenues, without the need to file a base rate case, which typically takes at least nine months to be approved. The DSIC mechanism is in place to encourage utilities to invest in needed upgrades and replacement of aging infrastructure by providing faster recovery costs. In order to utilize this recovery mechanism, Corning Energy must submit a Long-Term Investment Infrastructure Plan (LTIPP) for PAPUC approval, which outlines the projects, estimated costs, and forecast timeline of completion. As LTIPP projects are completed, the company can submit the costs to be reimbursed. Therefore, KBRA scores the company's investment requirements and capital intensity as Strong.

At all three of the company's subsidiaries, commodity costs can be passed through to the customers. Corning Energy also has several mechanisms in place to protect itself and by extension, its customers, from shifts in commodity pricing. At CNGC, customer billing rates are adjusted each month to take into account monthly changes in commodity costs. At Pike and Leatherstocking, customer gas rates are adjusted annually, and electric customer rates are twice per year. The company also expects that any fluctuations in cost would receive favorable treatment from the regulators. In addition to hedging its gas supply contracts, during the summer the company typically purchases gas at a cheaper rate and stores up to one heating season supply of gas. Corning Energy also benefits from its close proximity to the Marcellus gas fields, which provides the company with multiple gas pipeline companies to choose from when purchasing gas inventories, further reducing its exposure. In view of this, KBRA views Corning Energy as having limited commodity volatility exposure and scores commodity volatility as Strong.

Competitive Risk – 25% – Average Risk

KBRA scores the competitive risk of Corning Energy as Average, reflecting the core competitive strength afforded to regulated utilities by their control over a service territory, offset by its limited corporate scale and market scale. Additionally, the company's concentrated customer base hinders the overall, long-term sustainability of customer rates and volumes. Although the company has to navigate several operational risks, KBRA believes the company is sufficiently positioned to manage these challenges, supported by certain protections to profitability due to the nature of the regulated utilities rate case filings.

Corning Energy is a small, regulated utility company serving a handful of regions in the states of New York and Pennsylvania. Although the company does not benefit from an extensive corporate scale seen with larger utility holding companies, KBRA scores the company's size & scale as Average, reflecting the exclusivity of the company's service territories it operates in. However, KBRA scores the company's market share as Weak, given the significantly larger competitors with regulated utility operations in both New York and Pennsylvania. In New York State, larger competitors in the region include National Grid, New York State Electric & Gas (NYSEG), Central Hudson Gas & Electric, Rochester Gas & Electric (RG&E), Con Edison, and KeySpan Long Island. These competitors provide services in more highly populated service territories, authorized for a significantly larger rate base, and overall generate greater revenues. National Grid and its various subsidiaries provide natural gas to approximately 600,000 customers in New York with a total rate base of $20.7 billion. NYSEG serves approximately 272,000 natural gas customers with a service territory that spans 40% of upstate New York, and a total rate base of $3.9 billion as of 2022. RG&E provides natural gas services to approximately 320,000 customers across nine counties of New York. In Pennsylvania, the largest providers of natural gas services include Columbia Gas of PA Inc, Natural Fuel Gas, PECO Energy Company, and Philadelphia Gas Works. Columbia Gas provides natural gas to over 445,000 customers in 26 counties in Pennsylvania. Natural Fuel Gas distributes and transports natural gas to hundreds of thousands of customers in Western New York and Northwestern Pennsylvania. PECO provides natural gas distribution service to more than 552,000 customers in southeastern Pennsylvania. Philadelphia Gas Works delivers natural gas to 500,000 customers. The competitors within the two states are substantially larger in terms of customer base, service territory, rate base and also better positioned to navigate and combat future changes in regulations and policy impacting their natural gas operations.

KBRA scores the company's diversity as Average. Corning Energy's customer base across the three subsidiaries consists primarily of residential, commercial, and industrial customers. The company's customer base also includes customers in the transportation sector and has wholesale and local production contracts that also generate a portion of total consolidated revenues. Based on FY 2023 audited data for Corning Energy, as a percentage of total revenues, residential customers accounted for 58.6%, commercial for 23.6%, transportation for 10.6%, with the remaining coming from wholesale contracts (4.6%), industrial customers (1.6%), local production (0.5%), and streetlights (0.4%).

The largest operating utility subsidiary, CNGC, does have significant customer concentration to Corning Inc., which accounts for approximately 49% of total gas volumes sold dating back to January 2019. This is higher customer concentration than we typically see for the average utility company and when compared to peers. Given that CNGC is currently the company's primary generator of revenue and EBITDA, this materially exposes the company's revenues and overall profitability if Corning Inc. no longer continues to be a customer. If this occurred, the company would have difficult sustaining gas volumes at current levels, resulting in higher customer rates to offset loss in volumes which could lead to additional customer churn as energy substitutes become more attractive. This is partially offset by Corning

Energy's long-standing relationship with Corning Inc. and the fact that Corning Inc. is one of the most integral businesses within the city of Corning and its economy. As a result, KBRA views the risk of Corning Inc. leaving the region in the near term as minimal due to Corning Inc's public statement in support of the community. Corning Inc. has also been a leader in initiatives such as revitalization efforts, partnerships with local organizations, and philanthropic investments to help develop and strengthen the local economy. Additionally, CNGC is also concentrated in terms of customer type as a percentage of total gas volumes. Through January 2019 to April 2024, contracted commercial customers accounted for approximately 55% of total gas volumes, with 23% coming from residential, and 18% from transportation customers. The customer concentration at CNGC is mitigated, though only partially, by the well-diversified, unconcentrated customer base at Pike and Leatherstocking.

Corning Energy's customer base is primarily made up of local businesses and retail franchises in its service territory region. For example, Walmart, ShopRite, Home Depot but also local schools, districts, and farms. Corning Energy has long-standing customer relationships with some of the largest employers and economic contributors to the regions they operate in. For CNGC, some of the subsidiary's customers, such as Corning Inc. and Correlle Brands, are major businesses and employers within the city of Corning. CNGC also has multiyear gas pipeline contracts with various counties in the region including Williams and Bath and large industrial, energy, and infrastructure companies such as Kinder Morgan, Repsol, and Eastern Pipeline Company. CNGC also has contracts with counterparties such as New York State Electric & Gas (NYSEG), Corning Inc., Correlle Brands, and Greek Peak ski resort. Pike has multiyear gas and electric supply contracts with entities such as Orange & Rockland. Leatherstocking has customer gas purchase contracts with corporations like Cargill. Overall, despite Corning Energy's small corporate scale, the company has customer relationships with corporations and businesses that have a material impact on the region's economy and community; therefore, KBRA scores the company's contractual revenues, cash flows, and counterparty exposures as Average.

KBRA scores the company's pricing power as Strong considering its monopoly within its service territory and operations within the regulated utility industry. The company operates under a cost-of-service model that determines the rates it charges customers and provides the opportunity for return on investment. This framework is overseen by the NYPSC for CNGC and the PAPUC for Pike and Leatherstocking. Accordingly, a utility's relationship with its regulator is a key competitive factor, considering the direct impact it has on its cash flow generation. KBRA believes that Corning Energy currently has productive relationships with its regulators, with an authorized ROE of 9.25% in New York and consistent, favorable negotiated settlements at Pike and Leatherstocking that has resulted in increasing revenues over the last few years. However, overall authorized ROE is on the lower end of the spectrum for what is seen for utility peers. More importantly, KBRA expects the relationship with regulators, especially the NYPSC, to weaken as the commission is required to tighten regulations on utility companies as the state pursues its climate change initiatives. In Pennsylvania rate cases, the negotiated settlements are a result of "black box" settlements. In black box settlements, the company has proposed, negotiated, and settled with regulators for a blanket rate base increase rather than a specified ROE based on itemized costs in traditional rate cases. These negotiations typically result in an increase in the overall rate base.

KBRA scores the company's operational risk as Average. Corning Energy does have a long operating history track record of 100 years; however, the company must manage a number of operational risks present in its business model especially considering its small scale. One of those challenges is increasing labor costs. Corning Energy has experienced an increase in labor costs, especially with contractors. Under New York state Labor Law, contractors and subcontractors must pay the prevailing rate of wage and supplements to all workers under a public work contract. Employers must pay the prevailing wage rate set for the locality where the work is performed. This applies to all laborers, workers, or mechanics employed under a public work contract. The wage schedules are issued on a county-by-county and annual basis and contain the pay rates for each work classification. Corning Energy has navigated this challenge by reducing the amount of contractors it employs and using it in-house workforce to complete more projects to limit its exposure to increases in labor costs.

Additionally, Corning Energy demonstrated a degree of resiliency in economic downturns and low-probability events, most recently the COVID-19 pandemic. During the pandemic, the company did not have any interruptions in providing its services or incur any regulatory fines or penalties. The company did face the challenge of customers being unable to pay their bills due to loss of employment and due to moratoriums on customer service interruptions with the aid of regulators. During the pandemic, regulators provided cash and liquidity to Corning Energy and other utilities in order to prevent service interruptions and financial hardships. However, given the demographics of Corning, New York, economic activity outflows and downturns are ongoing exposures for the company. As of July 2023, Corning, New York is estimated to have a population of 10,612 which is a slight decrease of 0.2% from the previous year. The city is made up of lower middle income residents with the median income at approximately $59,500 compared to the median income of approximately $76,000 in the New York State.

Geographically, Corning Energy is located on top of the Marcellus Shale gas fields in Pennsylvania. This gives the company a competitive and operational advantage when purchasing and moving supplies to and through its pipeline compared to other competitors that have to account for and accommodate the logistics of shipping supplies. In addition, their location also provides a degree of protection from increasing gas prices. With the Marcellus Shale gas fields, there are a variety of gas pipeline companies to choose from, which offers Corning Energy some flexibility when purchasing its gas inventories in terms of pricing.

Growth and Corporate Development Risk – 10% – Average Risk

KBRA views the growth and corporate development risk as Average. For the company's revenues overall, growth is largely a function of growth in the economy and demand among the customer base. To increase, they would have to experience increased demand from current customers or expand their customer base, leading to additional approved capital projects, incur higher prudently incurred costs or acquire additional service territory in the regions they operate in. Additionally, the management team has indicated that they do not plan on currently pursuing acquisitions to expand their business and expects that growth will primarily come from incremental organic growth driven by their current initiatives to transition residential customers in Pennsylvania to natural gas usage. Overall, growth in the company is restricted by the limited amount of capital the company has to direct toward expansion initiatives.

KBRA scores the company's organic growth as Average. Corning Energy generated $43.5 million in revenues and $16.7 million in EBITDA as of last 12 months (LTM) Q2 2024. For all three subsidiaries, the company has seen continuous increases in rate base. Corning Energy has already been approved for an $8.2 million increase in total revenues through 2026. This results in an incremental increase in total revenues of $2.7 million or approximately 6% annually, beginning in 2024. CNGC accounts for $1.7 million of the total increase in revenues, $0.8 million comes from Pike, and $0.2 million from Leatherstocking. Nevertheless, future organic growth is anticipated to be gradual and will primarily come from the company's service territory in Pennsylvania. At Leatherstocking, the company expects to see significant growth in the customer base, an approximately 30% increase, by 2028. The growth is attributed to natural gas conversion opportunities, particularly among the residential customers, in the service territory. Also at Leatherstocking, the company expects to see additional customer growth through their ongoing program to provide gas appliance financing for its customers, an initiative that is funded by the United States Department of Agriculture. On the other hand, future growth prospects in the company's service territory in New York and at CNGC are expected to be extremely limited with increasing obstacles being created by the regulatory environment.

KBRA scores the company's M&A-driven growth as Average. The company has stated that there is limited capital to pursue expansion initiatives in the near term. Historically, Corning Energy has executed several growth initiatives and acquisitions that proved positive for the growth of the company. In 2014, the company partnered with Mirabito Regulated Industries in a joint venture to form LGC. A few years later, Corning Energy purchased Mirabito's 50% ownership in LGC, becoming the sole owner in 2020. In 2016, Corning Energy acquired Pike Country Light and Power from Orange & Rockland Utilities, Inc. The acquisition expanded the company's operations in Pennsylvania and provided diversity to its business lines with the entrance into electric market.

KBRA scores the company's diversity as Average. Corning Energy has limited diversity in terms of business segments and overall, the company is limited in its capacity to diversity, considering lack of financial resources to dedicate toward expansion, restricted and slow growth in the customer base, and that the support for expansion in its natural gas segment is primarily confined to Pennsylvania, given the NYPSC support for shifting away from natural gas in the state of New York. Additionally, Corning Energy has a degree of diversity in terms of its regulators as opposed to being subject to the regulations and requirements of one regulator. Although the NYPSC has shifted its focus to the transition toward renewable energy sources, the PAPUC remains very supportive of the natural gas providing Corning Energy with growth opportunities.

Liquidity and Financial Flexibility – 10% – Average Risk

KBRA views the liquidity and financial flexibility score of Corning Energy as Average. The company generated $7 million in cash from operations as of LTM Q2 2024 and its largest uses of cash were capital expenditures ($15 million) and purchase of securities ($3 million). In KBRA's opinion, the liquidity and cash flow profile of the company is sufficient to meet its ongoing obligations.

With regulated utilities, there is typically a regulatory lag in recovering natural gas distribution expenditures that can limit the company's ability to build liquidity and its financial flexibility in the interim. As of LTM Q2 2024, the company's sources of cash included $0.2 million of cash on balance sheet and $7 million of available cash from operations. During the same period, Corning Energy's primary use of cash was $15 million in capital expenditures. KBRA views positively the fact that a significant amount of the company's sources is backed by a regulatory revenue requirement and that the company generally limits growth investments to projects that are approved for eventual addition to the regulated rate base. As such KBRA scores the company's sources/uses as Average.

KBRA scores the company's access to capital markets as Average reflecting the company's small scale and limited track record of raising financial in capital markets. Additionally, the Corning Energy is now a privately held company owned by a private sponsor which limits its ability to access public debt or equity markets, restricting its options to raise capital from private placements with lenders that specialize in lower middle market lending. KBRA believes that it would be difficult for the company to find alternative sources of liquidity under unfavorable market conditions. However, the company does not have tight covenant restrictions and was able to raise alternative liquidity in the form of preferred shares for additional financing for the Argo acquisition transaction, as such KBRA scores the company's alternative liquidity as Average.

KBRA scores the company's ability to build liquidity from internal cash flows as Average reflecting the presence of a cost service model and the regulatory provision for the company to earn a rate of return on its rate base. The company is expected to be able to generate sufficient cash from operations through prudently managed costs to provide its regulated services to customers.

Regulatory and Jurisdictional Risk – 10% – Average Risk

KBRA scores the regulatory and jurisdictional risk of Corning Energy as Average. A significant amount of the company's revenues and cash flow is generated from its natural gas operations, which are subjected to a comprehensive regulatory regime and oversight and exposure to legal issues and risks that pose a threat to overall profitability.

While KBRA typically views regulatory support for regulated utilities as Strong, reflecting the stability of the business model and the opportunity to earn supportive returns, KBRA scores Corning Energy's regulatory support as Average. The Average score reflects the fact 62% of the company's revenues and EBITDA and 65% of its total approved rate base is attributable to its operations at CNGC based in New York in a regulatory regime that is shifting toward the use of alternative, renewable energy resources rather than natural gas. On July 18, 2019, the Climate Leadership and Community Protection Act (CLCPA) was signed into law, requiring New York to reduce economywide greenhouse gas emissions by 40% by 2030 and no less than 85% by 2050 from 1990 levels. In May 2023, New York state became the first state in the country to pass a law prohibiting the use of fossil fuel equipment in new construction, a mandate that will take effect in 2026 for new buildings of seven stories or less, and in 2029 for larger buildings. Most recently, the state of New York continued its initiative toward a carbon neutral economy by 2050 by introducing the New York Home Energy Affordable Transition (HEAT) Act into legislation. The legislation seeks to limit a requirement known as the "obligation to serve" where utilities automatically provide gas to new customers who request it, and to curb the expansion of gas infrastructure. This legislation would grant NYPSC new authority to phase out gas use and rollback long-standing subsidies for new gas hookups, essentially decreasing New York citizens' statutory right to gas service, including capping the expansion of gas distribution systems beginning 2026 and giving the NYPSC new authority to decommission parts of the system, provided that the commission determines that retirement is necessary to achieve New York's emission reduction and climate justice goals. Although the New York HEAT Act did not get passed in the recent vote, this is the second time it went up for a vote in the Senate and provides further evidence that New York state will continue to pursue its focus of transitioning away from the use of nonrenewable energy sources.

Corning Energy does benefit from the regulatory support of its second regulator. In Pennsylvania, the PAPUC has a much more favorable outlook for the natural gas industry and its expansion, with support for the continuation of drilling new natural gas wells and with natural gas utilities being approved for significant investments in their infrastructure. However, the service territory and operations in Pennsylvania is smaller than in New York and although there are opportunities for the company to grow its operations in the region, it will take significant time to do so to offset the risks posed by the regulatory environment in New York.

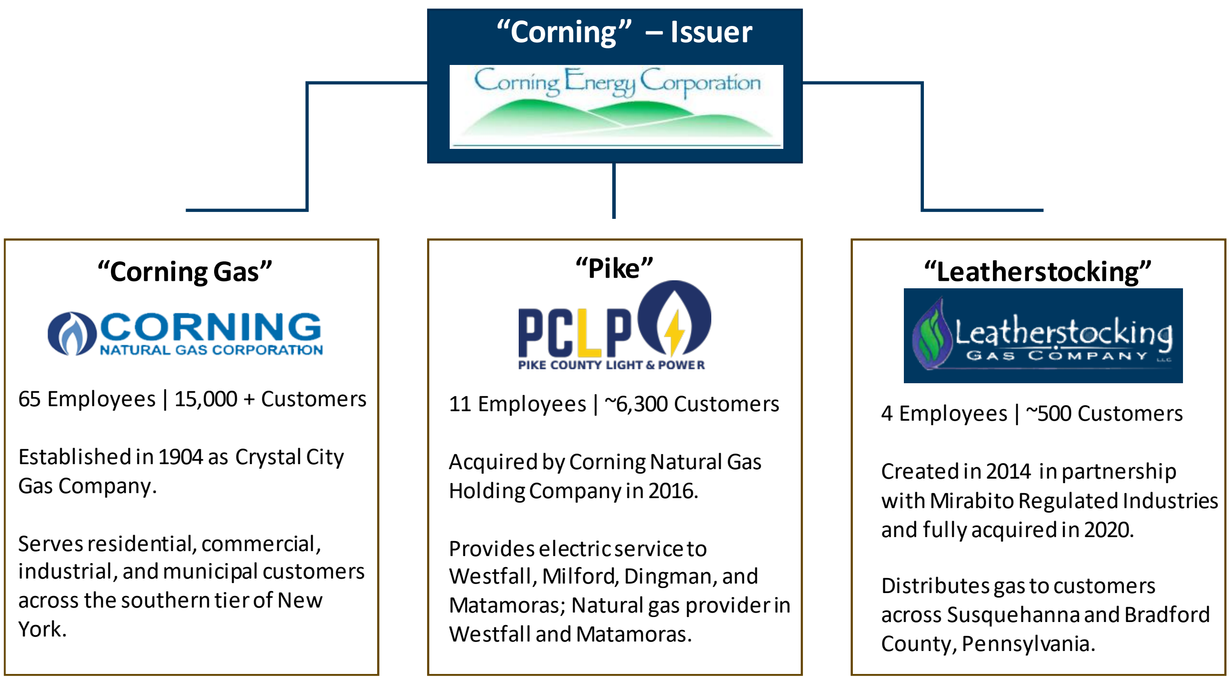
Furthermore, while the regulatory regime affords the company some profitability protection that provides stability to its cash flows, continued legislation and tightening regulatory hurdles impacting Corning Energy's largest subsidiary would deteriorate that protection. Coupled with the adverse legislations mentioned above, KBRA scores the company's legal issues and risks as Average.

KBRA scores the company's permitting process and ease of business development and compliance standards and requirements as Average. Despite past rate case resolutions, the process of obtaining a rate base increase can be lengthy and involves no guarantees of success. Additionally, while the company does operate in a clear and consistent regulatory framework, the approval process for new projects, programs, and rate adjustments can be involved. Requests from utilities can be rejected or settled by the state regulators after a considerable amount of resources have been invested in order to submit filings and documentation and to advocate for various business initiatives. Further, there are no assurances that the company's regulators will approve the recovery of all costs incurred for its operations, including costs for construction, operation and maintenance, and compliance with current regulations. Additionally, as a regulated utility company, Corning Energy is subject to a high level of compliance requirements as a result of regulators.

Organizational Form, Structure, and Ownership Considerations – 10% – Average Risk

KBRA views the organizational form, structure, and ownership as Average. Following its recent acquisition by Argo Infrastructure in 2022, Corning Energy operates as a private company under the ownership of a private sponsor. As such, the company does not benefit from the same level of oversight as a publicly traded corporation, although KBRA notes that it is subject to more independent oversight than most other private companies given its status as a regulated utility and the presence of two regulators, NYPSC and PAPUC. While KBRA believes that private ownership can indicate the potential for aggressive financial policies, the risk is reduced in this case given the nature of the regulated utilities business model and limitations imposed by the regulators. KBRA scores the company's type of corporate form as Average.

KBRA scores the company's overall corporate structure as Average, considering that the group structure is simple and easily understood, with Corning Energy Corporation being the ultimate parent and legal issuer for the senior secured notes. This reflects direct ownership of the subsidiaries and operating assets that generate the necessary cash flow to meet obligations and the expected lack of affiliated transactions, off-balance sheet obligations, or money pools.



With the operating subsidiaries generating the necessary cash flows to meet obligations, there is some reliance on affiliates; however, in KBRA's view, Corning Energy is positioned to manage obligations across its subsidiaries. Furthermore, each operating subsidiary has limitations on the amount of debt they can maintain. The subsidiaries are subject to debt caps of $2 million in the case of Pike and Leatherstocking and $5 million for Corning Gas. With these limitations in place, KBRA scores the company's reliance on affiliates/position in the group as Average.

Corning Energy's management team consists of industry professionals that have been with the company for a long duration. Additionally, KBRA believes that the regulatory oversight of the utilities industry further reduces governance risk through a high level of oversight, required annual rate case filings, and limitations on financial policymaking. KBRA scores the company's guarantees or subsidies as Average.

ESG Management

KBRA typically analyzes environmental, social, and governance (ESG) factors through the lens of how management teams plan for and manage relevant ESG risks and opportunities. More information on KBRA's approach to ESG risk management in corporate ratings can be found here. Over the medium term, corporate issuers will need to prioritize ESG risk management and disclosure with the likelihood of expansions in ESG-related regulation and rising investor focus on ESG issues.

KBRA analyzes many sector- and issuer-specific ESG issues but our analysis is often anchored around three core topics: climate change, with particular focus on greenhouse gas emissions; stakeholder preferences; and cybersecurity. Under environmental, as the effects of climate change evolve and become more severe, issuers are increasingly facing an emerging array of challenges and potential opportunities that can influence financial assets, operations, and capital planning. Under social, the effects of stakeholder preferences on ESG issues can impact the demand for an issuer's product and services, the strength of its global reputation and branding, its relationship with employees, consumers, regulators, and lawmakers, and, importantly, its cost of and access to capital. Under governance, as issuers continue to become more reliant on technology, cybersecurity planning and information management are necessary for most issuers, regardless of size and industry.

Environmental

KBRA anticipates that the global shift towards reducing emissions will pressure regulators and government agencies to find cost-effective solutions to reduce greenhouse gas (GHG) emissions. As a utility engaged in the distribution of natural gas, Corning Energy's operations are likely to be impacted by these regulatory efforts.

Through the Climate Leadership and Community Protection Act (CLCPA), New York created greenhouse gas emissions targets to reduce economywide emissions by 40% by 2030 and no less than 85% by 2050 from 1990 levels. The state has been proactive in initiating follow-up legislation to achieve the outlined targets. In Pennsylvania, the regulators and state are more in favor of the natural gas industry and its expansion, with support for the continuation of drilling of new natural gas wells and with natural gas utilities being approved for significant investments in their infrastructure.

Social

Corning Energy has a well-established presence in the city of Corning and long-standing relationships with the local communities, customers, regulators, and other key stakeholders in the areas it operates in.

Governance

Corning Energy benefits from an experienced management team that have been in the industry and with the company for a significant period of time. The company's private sponsor, Argo Infrastructure, has a limited track record of governance, having acquired the company recently in 2022. However, Argo Infrastructure is experienced in investing in the energy and infrastructure sectors with no major reported issued so far.

Within the regulated utilities industry, the regulators are aware of the sensitive nature of customer information and the increasing risk that cybersecurity attacks pose. The NYPSC has set minimum standards that all utility companies in the region must adhere to. The requirements include utility companies signing a date security agreement (DSA) to govern the exchange of customer information electronically. The PAPUC publishes guidelines for its utility companies, outlining the best practices for cybersecurity which provides methods for proactive prevention and steps to take should an attack occur.

Financial Risk

KBRA formed its view on the financial risk profile of Corning Energy based on a view of financial results, presentations, regulatory filings, and management projections. KBRA was provided access to the management team as part of the process.

The financial risk score of 9.9 is based on pro forma LTM Q2 2024 financial data. The most recent LTM data was selected to represent the company's financial risk profile to reflect the new amount of debt in the capital structure and expected growth of the company on a go-forward basis. Corning Energy's financial risk profile is characterized by its limited corporate scale within the utilities sector, stable revenues, and a significant amount of financial leverage given the company's size and scale.

Determinants	Pro Forma LTM Q2 2024	Score
Sales		
Revenues (Mn)	$43.5	18
Profitability		
EBIT Margin	24.7%	6
Return on Average Assets	9.7%	3
Cash Flow		
Free Cash Flow/Debt	17.9%	6
Retained Cash Flow/Debt	47.6%	3
Capital Structure & Leverage		
Debt/EBITDA	4.5x	12
Debt/Book Capital	48.6%	9
Coverage		
EBIT/Interest	2.5x	15
EBITDA/Interest	3.9x	15
Financial Policy		
Unencumbered Assets/Total Assets	56.2%	12
Financial Risk Score		**9.90**

Size -10%
For a utility operating company, revenue is a good representation for size and market share because its revenue is composed of reimbursable costs and a margin approved by its regulators. These reimbursable costs are composed of the prudent costs that the company undertakes in order to reliably deliver gas and electric services within its service territory. Corning Energy generated revenue of $43.5 million as of LTM Q2 2024 across its various subsidiaries, reflecting its small size compared to other utilities with regulated operations in the U.S. However, the company has seen consistent, incremental growth in its rate bases across all its subsidiaries.

Profitability -20%
Corning Energy's profitability profile is defined by consistent, double-digit margins. The profitability profile is underpinned by the cost-of-service model used in the company's operations in regulated utilities, which sets stable regulated rates of return that the utility is allowed to achieve on its recovered costs. KBRA expects that Corning Energy's profitability profile will remain appropriate for the rating category.

Cash Flow Analysis -20%
Corning Energy has consistently generated positive cash flows, albeit small in amount as a result of the scale of its operations. As of LTM Q2 2024, the company generated $7 million of cash from operations with capital expenditures of $15 million. On an ongoing basis, capital expenditures are expected remain stable within the same range, as the company primarily focuses on maintenance requirements of its current operations instead of allocating capital to expansion initiatives. The company's capital expenditures are expected to receive favorable rate recovery treatment, increasing the total rate base for its subsidiaries and as a result the company's earned return.

Capital Structure & Leverage -20%
Corning Energy has averaged a debt/book capital of 43.2% and a debt/EBITDA of 4.7x over the last four years and has remained in compliance with its regulatory capital range of 65%. On a pro forma basis for the proposed senior notes, debt/EBITDA is expected to be 4.5x in line with the historical average, which is a significant amount of leverage given the company's size and scale.

Interest Coverage -20%

In KBRA's view, the company has an adequate ability to meet its debt service obligations. Corning Energy has adequate coverage metrics for a regulated utility, with EBIT and EBITDA covering its interest payments 2.5x and 3.9x, respectively. Overall, the company's coverage metrics are expected to remain consistent given the stable nature of the company's revenues and cash flows.

Financial Policy -10%

The quantitative metrics associated with financial policy reflect the choices that management makes regarding the company's financial structure, the use of cash and relative attractiveness of profitable reinvestments in the business versus the payout to investors. Financial policy is an indication of the firm's desired or intended financial position and performance, and management's policies and risk appetite. At its heart, financial policy can either be a contributor or impediment to access to outside capital.

Corning Energy's capital structure is subject to limitations imposed by its regulators. The company is required to maintain a maximum debt to total capitalization of 65% by regulators, which restricts the potential for cash leakage and is a credit positive. As of LTM Q2 2024, the company's total debt/book capital is 49%. Additionally, this limits the financial policy impacts of the company's private sponsor.

Additional Rating Determinants

Country Risk & Transfer and Convertibility Risk

Corning Energy's operations are entirely within the U.S. KBRA analyzed the country risk inherent in the issuer rating assigned herein and concluded that the country risk exposure is minimal.

The ratings described in this report are unpublished, confidential ratings that will not be published or otherwise made publicly available by KBRA. This report is provided with the understanding that the Issuer will maintain the existence and content of this report as confidential, and will not use these ratings to market any securities, except to disclose this report to a limited number of investors, each of which (A) is bound by appropriate confidentiality obligations and has a need to know such information, (B) is a sophisticated financial institution with experience in evaluating investments such as the debt instruments described in this report and has performed its own evaluation of the transaction structure and the underlying assets, and (C) will not be relying on the rating for its investment decision, but requested and will use the report to satisfy regulatory requirements, the conditions of internal investment authorizations, or for purposes supplemental to the foregoing. The ratings set forth in this report are subject to all of the terms and conditions set forth in KBRA's website, which any party receiving this report or the ratings described herein should review and understand.

Pennsylvania Public Utility Commission v. Pike County Light & Power Company – Gas Division; Docket No. R-2024-3052357

PIKE COUNTY LIGHT & POWER COMPANY – GAS DIVISIONS' RESPONSES TO OFFICE OF CONSUMER ADVOCATE INTERROGATORIES AND REQUESTS FOR PRODUCTION OF DOCUMENTS, SET 8

3. Referencing Pike Response to OCA Set 5, Question 17. Confirm or deny that the KBRA credit ratings assigned to CEC and its series A and B senior secured notes are comparable to the rating scales assigned by Standard & Poor's.

RESPONSE: The KBRA credit ratings assigned to CEC and its series A and B senior secured notes are comparable to rating scales assigned by Standard & Poor's.

PROVIDED BY: Charles Lenns, Senior Vice President & Chief Financial Officer

DATE: March 24, 2025

Pennsylvania Public Utility Commission v. Pike County Light & Power Company – Gas Division; Docket No. R-2024-3052357

PIKE COUNTY LIGHT & POWER COMPANY – GAS DIVISIONS' RESPONSES TO OFFICE OF CONSUMER ADVOCATE INTERROGATORIES AND REQUESTS FOR PRODUCTION OF DOCUMENTS, SET 5

6. Provide a list of clauses, rate mechanisms, trackers and/or riders that the PUC allows the Company to employ to recover costs between general rate cases. Include relevant docket numbers and copies of the corresponding PUC decisions.

RESPONSE: The Company has the following rate mechanisms, trackers and/or riders that are allowed by the PUC to employe to recover costs between general rate cases:

<u>Pike Gas</u>:

A) <u>Gas Cost Rate</u> – The gas cost rate is applied to each CCF (100 cubic feet) of gas supplied in accordance with the tariff. Each gas cost rate is computed and applied to customers' bills for a one year period during the billing periods of November through October, however the rate may be revised on an interim basis subject to the approval of the Pennsylvania Public Utility Commission. The most recent gas cost rate filed and approved with the Commission went into effect on November 1, 2024, and is included in docket number M-2024-3050971. Refer to the "GCR Approval Letter – 10.21.24" attachment provided for a copy of the secretarial letter from the Commission indicating approval.

B) <u>State Tax Adjustment Surcharge</u> – this surcharge is recomputed using the elements prescribed by the Commission whenever the Company experiences a material change in any of the taxes used in calculation of the surcharge. The most recent amount filed and approved with the Commission went into effect on January 1, 2025, and is included in docket number R-2024-3052657. Refer to the "STAS Gas Approval Letter – 1.02.25" attachment provided for a copy of the secretarial letter from the Commission indicating approval.

C) <u>Distribution System Improvement Charge ("DSIC")</u> – this charge is applied to recover the reasonable and prudent costs incurred to repair, improve, or replace eligible property which is completed and placed in service and recorded in the individual accounts, as noted below, between base rate cases and to provide the Company with the resources to accelerate the replacement of aging infrastructure. The most recent amount filed and approved with the Commission went into effect on January 1, 2025, and is included in docket number M-2024-3052549. Refer to the "DSIC Gas Approval Letter – 12.19.24" attachment provided for a copy of the secretarial letter from the Commission indicating approval.

<u>Pike Electric:</u>

A) <u>Default Service Charge</u> – this charge is used to recover all costs associated with purchasing energy, capacity and ancillary services incurred by the Company in providing electric power supply to default service customers. The default service plan was most recently re-approved

PIKE COUNTY LIGHT & POWER COMPANY – GAS DIVISIONS' RESPONSES TO OFFICE OF CONSUMER ADVOCATE INTERROGATORIES AND REQUESTS FOR PRODUCTION OF DOCUMENTS, SET 5

by the Commission in the recommended decision in docket number P-2023-3039927. Refer to the "Default Service Program Recommended Decision" attachment provided for details. This charge consists of the Market Price of Electric Supply and the Electric Supply Adjustment Charge, and are separately stated on customer bills. These charges are updated on a semi-annual basis and approved by the Commission prior to update. The most recent semi-annual update filed and approved with the Commission went into effect on December 1, 2024, and is included in docket number M-2024-3052190. Refer to the "DSC December 2024 Approval Letter – 11.22.24" attachment provided for a copy of the secretarial letter from the Commission indicating approval.

B) State Tax Adjustment Surcharge – this surcharge is recomputed using the elements prescribed by the Commission whenever the Company experiences a material change in any of the taxes used in calculation of the surcharge. The most recent amount filed and approved with the Commission went into effect on January 1, 2025, and is included in docket number R-2024-3052656. Refer to the "STAS Electric Approval Letter – 1.02.25" attachment provided for a copy of the secretarial letter from the Commission indicating approval.

C) Distribution System Improvement Charge ("DSIC") – this charge is applied to recover the reasonable and prudent costs incurred to repair, improve, or replace eligible property which is completed and placed in service and recorded in the individual accounts, as noted below, between base rate cases and to provide the Company with the resources to accelerate the replacement of aging infrastructure. The most recent amount filed and approved with the Commission went into effect on January 1, 2025, and is included in docket number M-2024-3052547. Refer to the "DSIC Electric Approval Letter – 12.19.24" attachment provided for a copy of the secretarial letter from the Commission indicating approval.

PROVIDED BY: Matthew Lenns, Controller

DATE: March 3, 2025

BEFORE THE
PENNSYLVANIA PUBLIC UTILITY COMMISSION

Pennsylvania Public Utility Commission	:	
	:	Docket No. R-2024-3052357
v.	:	
	:	
Pike County Light & Power Company (Gas)	:	

VERIFICATION

I, Maureen L. Reno, hereby state that the facts above set forth in my Direct Testimony, OCA Statement 2, are true and correct to the best of my knowledge, information, and belief and that I expect to be able to prove the same at a hearing held in this matter. I understand that the statements herein are made subject to the penalties of 18 Pa.C.S. § 4904 (relating to unsworn falsification to authorities).

DATED: April 3, 2025

Signature: Maureen L. Reno
Maureen L. Reno

Address: 19 Hope Hill Road,
Derry, New Hampshire 03038

OCA St. No. 3

BEFORE THE

PENNSYLVANIA PUBLIC UTILITY COMMISSION

Pennsylvania Public Utility Commission	**)**	
v.	**)**	**Docket No. R-2024-3052357**
Pike County Light & Power Company (Gas)	**)**	

DIRECT TESTIMONY OF

KARL RICHARD PAVLOVIC

ON BEHALF OF

THE PENNSYLVANIA OFFICE OF CONSUMER ADVOCATE

April 3, 2025

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I. STATEMENT OF QUALIFICATIONS

Q. PLEASE STATE YOUR NAME AND BUSINESS ADDRESS.

A. My name is Karl Richard Pavlovic. My business address is 22 Brooks Avenue, Gaithersburg, MD 20877.

Q. BY WHOM AND IN WHAT CAPACITY ARE YOU EMPLOYED?

A. I am Managing Director of and a Senior Consultant with PCMG and Associates LLC ("PCMG"). PCMG is an association of experts in economics, accounting, finance, and utility regulation and policy, with over 75 years of collective experience providing assistance to counsel and expert testimony regarding the regulation of electric, gas, water, and wastewater utilities.

Q. HAVE YOU PREPARED A SUMMARY OF YOUR QUALIFICATIONS AND EXPERIENCE?

A. Yes. Exhibit KRP-1 to my testimony summarizes my qualifications and experience.

Q. HAVE YOU PREVIOUSLY SUBMITTED TESTIMONY IN REGULATORY PROCEEDINGS?

A. Yes. Exhibit KRP-1 also contains a complete list of my engagements as an expert and/or expert witness in matters before state and federal regulatory agencies. I have submitted testimony to the Federal Communications Commission, the Federal Energy Regulatory Commission, the Alaska Public Utilities Commission, the Alberta Utilities Commission, the California Public Utilities Commission, the Delaware Public Service Commission, the Public Service Commission of the District of Columbia, the Hawaii Public Utilities Commission, the Illinois Commerce Commission, the Kansas Corporation Commission, the Maine Public Utilities Commission, the Maryland Public Service Commission, the

Massachusetts Department of Public Utilities, the Missouri Public Service Commission, and the North Dakota Public Service Commission.

Q. PLEASE SUMMARIZE YOUR ELECTRIC AND GAS REGULATORY EXPERIENCE.

A. For most of my career I have performed analyses of and submitted testimony regarding electric and gas utility least-cost planning, reliability, cost of service, rate design, and weather-emergency response. Specifically regarding gas utilities, I have testified on: (a) integrated resource planning, (b) weather emergency response and recovery, (c) class cost of service and rate design, and (d) infrastructure-related expense and investment recovery mechanisms.

II. PURPOSE OF TESTIMONY

Q. ON WHOSE BEHALF ARE YOU TESTIFYING?

A. I am testifying on behalf of the Pennsylvania Office of Consumer Advocate (OCA).

Q. WHAT IS THE PURPOSE OF YOUR TESTIMONY?

A. My testimony responds to the Pike County Light and Power (PCLP) Gas Division's proposed allocated class cost of service studies, revenue allocations, rate designs and proposed weather normalization adjustment (WNA) in this proceeding.

III. DISCUSSION

A. SUMMARY

Q. PLEASE SUMMARIZE THE SUBSTANCE OF YOUR TESTIMONY.

A. As detailed below, I find that:

- There is no basis in theory, system design and operating practice, or empirical quantitative data to support PCLP's use of the minimum-size method to classify as customer-related any portion of its distribution mains costs in account 376 in its gas cost of service study (GCOSS), and I recommend that the Commission reject PCLP's GCOSS results as a guide for class revenue distribution in this proceeding;
- PCLP's GCOSS without minimum-size classification produces results that are consistent with the principle of cost causation, and I recommend that the Commission accept the results of PCLP's GCOSS <u>without</u> minimum-size classification as a guide for class revenue distribution;
- Revenue distribution to PCLP's customer classes guided by the GCOSS <u>without</u> minimum-size classification is just and reasonable;
- To provide residential customers with (1) an incentive to engage in conservation; and (2) the ability to exercise control over a significant portion of their monthly gas distribution bill PCLP's rate districts' residential customer charges should remain at their current levels.
- PCLP's proposed weather normalization adjustment (WNA) will (1) provide no real benefit to residential customers, (2) not meet a legitimate financial need of PCLP, and

(3) reduce PCLP's incentive to seek efficiency savings in its operations. For these reasons, I recommend that the Commission reject the proposed WNA.

B. COST ALLOCATION AND RATE DESIGN

Q. WHAT IS THE RELATIONSHIP BETWEEN COST ALLOCATION AND RATE DESIGN?

A. In regulatory theory and practice the relationship between cost allocation and rate design and the utility's recovery of its approved revenue requirement is conceptually simple. If a utility's costs of providing service are not accurately allocated to its rate classes and rate class costs are not accurately reflected in the rate classes' tariff billing charges, then the utility will either over or under recover its costs of service or revenue requirement. The less accurately the costs are reflected in the rate classes' tariff billing charges, the greater the utility's under or over recovery of its costs will be. Additionally, on a conceptual basis, a utility's costs should be allocated consistent with the principle of cost causation. Regarding gas utilities, the primary drivers of costs are (1) the number of customers served by the utility's production and delivery system, (2) customer demand on the system, and (3) the volume of gas delivered to customers.

In this proceeding, the revenue requirement, class costs and tariff rates at issue concern PCLP's retail distribution delivery system serving customers in Pennsylvania. Consequently, the fundamental issue is whether PCLP's proposed customer class cost allocations and tariff rates (1) accurately reflect the customer costs, demand costs, and commodity costs of its customers and (2) thus minimize the likelihood of either under or over recovery of PCLP's gas revenue requirement.

C. TARIFF RATE CLASSES AND RATE STRUCTURES

Q. WHAT TARIFF RATE CLASSES AND RATE STRUCTURES DOES PCLP PROPOSE?

A. PCLP proposes five tariff rate classes. PCLP's proposed base rate structures consist of a fixed monthly customer charge and a CCF volumetric delivery charge.[1] The tariff rate classes and rate structures are shown in Table 1 below.

Q. ARE ALL FIVE TARIFF RATE CLASSES INCLUDED IN THE CUSTOMER CLASSES USED IN PCLP'S GCOSS?

A. Yes.

Table 1 – PCLP GCOSS Customer Classes		
Rate Class	**Customer Charge**	**Delivery Charge**
SC1 Residential Space Heating	X	X
SC1 Residential Domestic	X	X
SC1 Residential Other	X	X
SC2 General Service Commercial	X	X
SC2 Commercial Space Heating	X	X

Q. DO YOU HAVE ANY CRITICISMS OF PCLP'S PROPOSED RATE CLASSES AND RATE STRUCTURES?

A. I do not have any criticisms of PCLP's proposed tariff rate classes and rate structures, but as discussed below, I have concerns about PCLP's rate design for residential customers in so far as it proposes to increase the residential customer charge.

[1] Exhibit G-8, pages 3-4.

D. GAS COST OF SERVICE STUDY

Q. HAVE YOU EXAMINED PCLP'S GCOSS?

A. Yes. PCLP's GCOSS[2] is based on PCLP's historical test year ending September 30, 2024. The GCOSS consists of single excel workbook that PCLP provided with three substantive tabs: (1) Cost of Service, (2) Functions and (3) Unbundled.[3] The GCOSS follows a four-step procedure of (1) functionalization of costs, (2) classification of functionalized costs as demand-related, commodity-related or customer-related, (3) direct assignment or allocation to classes of the classified functionalized costs using demand, commodity and customer allocators, and (4) calculation of class rates of return and relative rates of return under present rates. The GCOSS use the minimum-size method to classify distribution mains in plant account 376 as consisting of both a customer-related component (54.93%) and a demand-related component (46.97%), with the customer component allocated to classes on number of customers and the demand component allocated to classes on demand.[4]

Q. WHAT IS THE MINIMUM-SIZE SYSTEM METHOD OF CLASSIFICATION AND ALLOCATION?

A. It is one of two methods for classification of distribution costs that are described in both the NARUC Gas Distribution Rate Design Manual and the NARUC Electric Utility Cost

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[2] Exhibit G-6.
[3] Q1 - Pike GCOS 12-24-24P.xlsx.
[4] Statement No.1, Direct Testimony of Paul M. Normand (Normand Direct), page 10 line 14 to page 11 line 3; Exhibit G-6, Schedule PMN-4-G, page 3 lines 12-14.

Allocation Manual: (1) the minimum-size method,[5] which PCLP uses; and (2) the minimum-intercept method, which PCLC does not use.[6] The objective of the minimum-size method is to classify distribution plant and associated operating costs, in this case distribution mains to determine the cost driver of each rate base item and operating cost — namely demand or customers — and allocate the plant and operating costs purportedly consistent with the principle of cost causation. PCLP applies the minimum-size method to distribution mains in plant account 376.

The minimum-size system method assumes that a minimum-size distribution system can be built to serve the minimum loading requirements of the system's customers.[7] This assumption is addressed below. The NARUC Manuals describe how to calculate the minimum-size and cost of a given distribution system.[8] The calculated minimum-size system costs for each distribution plant type are classified as customer-related and allocated to classes based on the number of customers. The remaining cost of each plant type is classified as demand-related and allocated based on demand.

Q. HAVE YOU IDENTIFIED ANY COST CLASSIFICATION ERRORS IN THE GCOSS?

A. Yes. In the classification step, as I noted above, PCLP uses the minimum-size system method to classify a portion of the distribution mains as both demand-related and customer-related. Classifying any portion of distribution mains as customer-related contravenes the

[5] National Association of Regulatory Utility Commissioners (NARUC) Gas Distribution Rate Design Manual (NARUC Gas Manual) 1989, page 22; National Association of Regulatory Utility Commissioners (NARUC) Electric Utility Cost Allocation Manual (NARUC Electric Manual) 1992, pages 90-92.
[6] NARUC Gas Manual, pages 22-23); NARUC Electric Manual, pages 92-94.
[7] NARUC Gas Manual, page 22; NARUC Electric Manual, page 90.
[8] NARUC Gas Manual, page 22; NARUC Electric Manual, pages 91-92.

principle of cost causation, which is the guiding principle of all regulated utility cost of service studies.[9]

Q. WHAT SUPPORT DOES PCLP OFFER FOR ITS USE OF THE MINIMUM-SIZE METHOD OF CLASSIFICATION?

A. None. To investigate what support there might be for PCLP's use of the minimum-size method of classification of distribution facilities I requested in a data request PCLP's planning, design, and operating standards and procedures applicable to the distribution mains the costs of which are recorded in plant account 376.[10]

Q. WHY DID YOU REQUEST PCLP'S PLANNING, DESIGN AND OPERATING STANDARDS AND PROCEDURES FOR PLANT ACCOUNTS 364-368?

A. PCLP's foundational assumption in using the minimum-size method is that the number of customers on the distribution system causes at least a portion of the costs recorded in distribution mains plant account 376. With PCLP's planning, design, and operating standards and procedures for plant account 376, it is possible to confirm or disconfirm PCLP's assumption that customers are the cause of a portion of the costs of the facilities in its plant account 376. If the number of customers is not a factor in the planning, design and operation of PCLP's account 376 distribution mains, then there is in fact no support for PCLP's application of minimum-size classification of the costs in plant account 376. Based on my inspection of PCLP's response to OCA-7-3, the response clearly demonstrates that the number of customers on PCLP distribution system plays no role in the design, planning, and operation of PCLP's distribution system recorded in account 376.

[9] NARUC Gas Manual, page 20; NARUC Electric Manual, pages 12-13.
[10] OCA Interrogatory 7.3.

Therefore, the number of customers on PCLP's gas system is not a cause of any portion of the facilities the costs of which are recorded in account 376.

Q. WHAT IS YOUR RECOMMENDATION RELATING TO PCLP'S USE OF THE MINIMUM-SIZE SYSTEM METHOD IN THE GCOSS?

A. As I explain below, I recommend that PCLP's use of the minimum-size classification method to classify the distribution costs in Account 376 as customer-related be rejected. This is because PCLP has not provided any quantitative evidence that customers, as opposed to demand for gas, are in fact the cause or driver of any portion of its costs associated with distribution mains.

Q. IS THE MINIMUM-SIZE METHOD COMMONLY USED BY GAS UTILITIES?

A. At the time that the NARUC Gas Manual was first published in 1989, the minimum-size method was widely used by gas utilities in North America, hence its inclusion in the NARUC Gas Manual, which has not been revised since its original publication. Today it is commonly, but not universally, used by gas utilities.

Q. IS THE COMMON USE OF THE MINIMUM-SIZE METHOD OF CLASSIFICATION RELEVANT TO DETERMINING THE PROPER CLASSIFICATION OF DISTRIBUTION SYSTEM COSTS FOR PCLP IN THIS PROCEEDING?

A. No. Selection of the appropriate classification method(s) for a utility's gas distribution system for costing purposes depends on the specific design and operating characteristics of the distribution system consistent with the principle of cost causation, not on whether other utilities in other jurisdiction use a specific classification method nor on whether the utility has used a specific classification method in prior proceedings. Regulatory costing is a forward-looking exercise. The only relevant question is whether the classification method reflects the cost causation inherent in the planning, design, and operation of PCLP's distribution system. Again, as I explain below, the minimum-size method of classification does not reflect the planning, design, and operation of PCLP's distribution system.

Q. WHAT IS THE COST CAUSATION THAT DEFINES THE CLASSIFICATION OF GAS DISTRIBUTION ACCOUNTS AS CUSTOMER-RELATED?

A. As clearly articulated in Bonbright's Principles of Public Utility Rates,[11] under the principle of cost causation, customer-related costs are "those operating and capital costs found to vary with number of customers."[12] Operationally defined, customer-related costs are the "costs of connecting another customer or the savings in costs of not connecting the customer."[13] Per the NARUC Gas Manual, customer costs are those operating capital costs found to vary directly with the number of customers served rather than with the amount of utility service supplied … [t]hey include the expenses of metering, reading, billing, collecting, and accounting, as well as those cost associated with the capital investment in metering and in customers' service connections."[14] PCLP's GCOSS properly classifies the costs of services, meters, meter installations and house and industrial regulators (accounts 380 – 385) as customer-related.[15] The GCOSS errs only in classifying a portion of the distribution mains costs as customer-related, rather than properly as demand-related.

[11] Bonbright et al, Principles of Public Utility Rates, 1988.
[12] Bonbright, page 490; also see NARUC Manual Electric Utility Cost Allocation Manual, 1992, page 90, "The customer component of distribution facilities is the portion of costs which varies with the number of customers."
[13] Bonbright, page 490.
[14] NARUC Gas Manual, page 22; see also page 23 "only facilities, such as meters, regulators and service taps, are considered to be customer related, as they vary directly with the number of customers on the system."
[15] Exhibit G-6, page 3 lines 17-21.

Q. WHAT IS THE COST CAUSATION THAT DEFINES THE CLASSIFICATION OF GAS DISTRIBUTION ACCOUNTS AS DEMAND-RELATED?

A. As Bonbright also explains, it is theoretically impossible for the capital costs of distribution system facilities upstream of the facilities to be classified as customer-related because the connection of a new customer (or disconnection of an existing customer) has no measurable impact on the costs of those facilities.[16] Since the costs of the distribution facilities upstream of customer-related facilities do not and cannot vary with the number of customers connected to the distribution system, for the purposes of embedded cost analysis, those costs are properly classified as demand-related, because those costs do "var[y] continuously (and, perhaps, even more or less directly) with the maximum demand imposed on this system as measured by peak load."[17] Per the NARUC Gas Manual, demand related costs "are related to maximum system requirements which the system is designed to serve during short intervals and do not directly vary with the number of customers or their annual usage."[18] PCLP's GCOSS properly classifies the costs of distribution land and land rights and measuring and regulating stations (accounts 374 and 375) as demand-related.[19] As stated above, the GCOSS generally classifies plant correctly, except for its classification of the distribution mains costs in account 376 as customer-related, rather than properly classified as demand-related.

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[16] Bonbright, page 491.
[17] Bonbright, page 492; see also NARUC Electric Manual, page 90, "Classifying distribution plant as a demand cost assigns investment … based upon its contribution to some total peak load ,,, [because] costs are incurred to serve area load, rather than a specific number of customers."
[18] NARUC Gas Manual, pages 23 and 24.
[19] Exhibit G-6, Schedule PMN-4-G, page 3 lines 11 and 16.

Q. DOES THE NARUC GAS MANUAL PROVIDE ANY EXPLANATION OR DEMONSTRATION THAT A PORTION OF DISTRIBUTION COSTS VARIES WITH OR IS CAUSED BY THE NUMBER OF CUSTOMERS?

A. No. The NARUC Gas Manual simply assumes without explanation or demonstration that the minimum-size method and the minimum-intercept method identify and quantify a portion of distribution costs that varies with or is caused by the number of customers.

Q. HAS PCLP PROVIDED ANY EMPIRICAL QUANTITATIVE EVIDENCE THAT ANY PORTION OF ITS DISTRIBUTION SYSTEM COSTS VARY WITH THE NUMBER OF CUSTOMERS?

A. No. Nor has PCLP provided any evidence to support (1) its reliance on the NARUC Manuals' minimum-size classification method, contrary to Bonbright's demonstration that minimum-size classification contradicts the principle of cost causation which underlies all utility cost studies; and (2) its assumption that customers are a cost factor that causes some portion of the costs of assets recorded in its plant account 376.

Q. WHAT DO YOU CONCLUDE REGARDING PCLP'S USE OF THE MINIMUM-SIZE SYSTEM METHOD TO CLASSIFY A PORTION OF ITS DISTRIBUTION MAINS COSTS AS CUSTOMER-RELATED AND ALLOCATE THOSE COSTS TO CUSTOMER CLASSES BASED ON THE NUMBER OF CUSTOMERS?

A. As explained above, there is no basis in theory, system design and operation practice, or empirical quantitative data to support PCLP's use of the minimum-size system method to classify as customer-related any portion of its distribution costs. PCLP's distribution costs do not vary with the number of customers – additions and deletions of customers do not cause those costs to increase or decrease. Thus, I conclude that the Company's distribution mains costs in plant account 376 are properly classified as 100 percent demand-related and properly allocated to classes using PCLP's demand allocation factors.

Q. WHAT IS THE IMPACT ON PCLP'S GCOSS CUSTOMER CLASSES OF ELIMINATING THE MINIMUM-SIZE CLASSIFICATION OF PCLP'S DISTRIBUTION MAINS COSTS?

A. As a general matter, minimum-size classification of distribution costs increases the costs allocated to rate classes with large numbers of customers (i.e., the residential rate classes) and decreases costs allocated to rate classes with small numbers of customers. Because the number of customers in a rate class is not a cause or driver of distribution costs, minimum-size classification <u>over allocates</u> costs to rate classes with large numbers of customers (i.e., the residential rate classes) and <u>under allocates</u> costs to rate classes with small numbers of customers. The effect of this misallocation of costs can be seen by comparing the class rates of return and relative rates of return calculated by PCLP's GCOSS to those calculated by eliminating minimum-size classification from PCLP's GCOSS.

Q. WHAT IS THE PURPOSE OF THE RELATIVE RATE OF RETURN METRIC?

A. Relative rate of return is the commonly used metric by which fair cost apportionment is measured and evaluated. PCLP's GCOSS calculates the overall rate of return and relative rate or return for PCLP's electric system and the rates of return and relative rates of return for each class. A class relative rate of return of 1.00 indicates that the class is earning the overall rate of return. A class relative rate of return less than 1.00 indicates that the class is underearning or under recovering its cost of service, i.e., the revenue generated by rates is not covering the full cost of service to the class. A class relative rate of return greater than 1.00 indicates that the class is overearning or over recovering its cost of service, i.e., the revenue generated by rates is more than covering the full cost of service to the class. Relative rates of return are used as a guide for allocating the revenue increase to classes so as to move each class closer to full recovery. Table 2 below compares the class rates of return and relative rates of return under PCLP's GCOSS with and without minimum-size classification.

Table 2 - PCLP Rates of Return (ROR) and Relative Rates of Return (RROR) by Customer Class Under Current Rates – With and Without Minimum-Size Classification

Customer Class	**With Minimum System[20]**		**Without Minimum System[21]**	
	ROR	**RROR**	**ROR**	**RROR**
SC1 Residential Space Heating	3.40%	0.79	3.58%	0.84
SC1 Residential Domestic	0.63%	0.15	0.62%	0.15
SC1 Residential Other	3.76%	0.88	3.94%	0.92
SC2 General Service Commercial	19.84%	4.63	12.28%	2.86
SC2 Commercial Space Heating	8.56%	2.00	6.16%	1.44
Total	4.29%	1.00	4.29%	1.00

Compared to the PCLP GCOSS, the PCLP GCOSS without minimum-size classification, which allocates distribution costs on demand only, results in higher rates of return and relative rates of return for the SC1 RSH and SC1 RO customer classes, lower rate of return and relative rate of return for the SC2 GSC and SC2 CSH customer classes, and the same rate of return and relative rate of return for the SC1 RD customer class. The relative rates of return of the SC2 GSH, SC2 CSH customer classes are higher than 1.00 indicating that

[20] Exhibit G-6, Schedule PMN-3-G, page 1 lines 7 and 8,
[21] Exhibit KRP-2, lines 7 and 8.

these classes are over earning under PCLP's current rates. The relative rates of return for the SC1 RSH, SC1 RD and SC1 RO customer classes are lower than 1.00 indicating that these classes are under earning under PCLP's current rates.

Q. HAVE YOU IDENTIFIED ANY ERRORS IN THE COST ALLOCATORS IN PCLP'S GCOSS?

A. No.

Q. WHAT DO YOU CONCLUDE AND RECOMMEND REGARDING PCLP'S GCOSS?

A. I conclude that PCLP's GCOSS produces results that are inconsistent with the principle of cost causation, because contrary to the minimum-size method's assumption, the number of customers is neither a cause nor a driver of distribution mains costs. I also conclude that PCLP's GCOSS without minimum-size classification produces results that are consistent with the principle of cost causation, because demand is both the cause and the driver of PCLP's gas distribution mains costs. I recommend that the Commission adopt the GCOSS without minimum-size classification as a guide for determining PCLP's class revenue allocation and tariff rates.

E. PCLP'S CUSTOMER CLASS REVENUE DISTRIBUTIONS

Q. HAVE YOU EXAMINED PCLP'S PROPOSED CLASS REVENUE DISTRIBUTION?

A. Yes. The testimony[22] and exhibits[23] of witness Normand also present PCLP's class rate design. Regarding class revenue responsibility distribution, witness Normand states that "First, we determined the total costs incurred to serve each customer class using the future test year September 30, 2025, Exhibit E-7. Next, we examined the embedded cost of service at the Company's uniform ROR (equalized annual increase) and compared these results to the revenues currently produced by each customer class, Exhibit E-6, Schedule PMN-3-E."[24] Table 3 compares the class revenue distribution under current rates and PCLP's proposed revenue distribution.

Table 3 - PCLP Current Revenue Distribution and Proposed Revenue Distribution[25]

Customer Class	Current	Proposed	Percent Increase
SC1 Residential Space Heating	863,119	1,723,140	99.6%
SC1 Residential Domestic	26,369	51,209	94.2%
SC1 Residential Other	3,578	7,150	99.8%
SC2 General Service Commercial	82,879	106,165	28.1%
SC2 Commercial Space Heating	110,389	141,021	27.7%
Total	1,086,334	2,028,685	86.8%

[22] Normand Direct, page 17 line 18 to page 19 line 18.
[23] Exhibit G-7, page 1; Exhibit G-8, pages 1 and 2; Exhibit 6, Schedule PMN-3-E.
[24] Normand Direct, page 18 lines 5-9.
[25] Exhibit G-8, pages 1 and 2.

Q. HOW DO PCLP'S PROPOSED CLASS REVENUE DISTRIBUTIONS IMPACT CLASS RATES OF RETURN?

A. Table 4 below shows the impact of PCLP's proposed revenue distributions on class rates of return and relative rates of return for PCLP's customer classes. Examination of the relative rate of return results in Table 4, reveals that for most of PCLP's customer classes the proposed class revenue requirement represent minimal movement towards relative rates of return of 1.00, leaving most classes either heavily overearning or heavily underearning measured against the relative rates of return from PCLP's minimum-size GCOSS.

Table 4 – PCLP Rates of Return (ROR) and Relative Rates of Return (RROR) by Customer Class – COSS Compared to PCLP Proposed Class Revenue Distribution[26]

Customer Class	PCLP COSS With Minimum System		PCLP Class Revenue Distribution	
	ROR	RROR	ROR	RROR
SC1 Residential Space Heating	3.40%	0.79	8.88%	1.03
SC1 Residential Domestic	0.63%	0.15	9.84%	1.15
SC1 Residential Other	3.76%	0.88	8.79%	1.02
SC2 General Service Commercial	19.84%	4.63	7.04%	0.82
SC2 Commercial Space Heating	8.56%	2.00	7.10%	0.83
Total	4.29%	1.00	8.59%	1.00

Q. DO YOU AGREE WITH PCLP'S PROPOSED CLASS REVENUE DISTRIBUTION?

A. No, for two reasons. First, they are based on PCLP's minimum-size GCOSS which, as I explained above, is not consistent with or reflective of actual cost causation. Second,

[26] Exhibit G-6, lines 7, 8 and 34.

residential classes that were under earning are now over earning and the commercial classes that were over earning are now under earning.

Q. HAVE YOU CALCULATED CLASS REVENUE REQUIREMENTS BASED ON PCLP'S GCOSS WITHOUT MINIMUM-SIZE CLASSIFICATION?

A. Yes. I have developed the OCA recommended class revenue distribution based on the relative rates of return of the GCOSS without minimum size adjusted so as to move the relative rate of return halfway to full cost recovery, 1.00. The resulting relative rates of return and rates of return are shown in Table 5 below.

Table 5 - Class Rates of Return (ROR) and Relative Rates of Return (RROR) by Customer Class – GCOSS without minimum-size compared to OCA Recommended

Customer Class	Without Minimum System[27]		OCA Recommended[28]	
	ROR	RROR	ROR	RROR
SC1 Residential Space Heating	3.58%	0.84	7.88%	0.92
SC1 Residential Domestic	0.62%	0.15	4.92%	0.57
SC1 Residential Other	3.94%	0.92	8.24%	0.96
SC2 General Service Commercial	12.28%	2.86	16.60%	1.93
SC2 Commercial Space Heating	6.16%	1.44	10.47%	1.22
Total	4.29%	1.00	8.59%	1.00

Table 6 below shows the OCA recommended class revenue distributions that result from the adjusted relative rates of return in Table 5.

[27] Exhibit KRP-2, lines 7 and 8.
[28] Exhibit KRP-2, lines 41 and 42.

Table 6 - PCLP Current Revenue Distribution and OCA Recommended Revenue Distribution[29]				
Customer Class	**Current**	**Proposed**	**Percent Increase**	**Class Percent Distribution**
SC1 Residential Space Heating	863,119	1,551,870	79.8%	76.5%
SC1 Residential Domestic	26,369	40,754	54.6%	2.0%
SC1 Residential Other	3,578	6,551	83.1%	0.3%
SC2 General Service Commercial	82,879	185,343	123.6%	9.1%
SC2 Commercial Space Heating	110,389	244,167	121.2%	12.0%
Total	1,086,334	2,028,685	86.8%	100.0%

Q. WHAT DO YOU CONCLUDE AND RECOMMEND REGARDING PCLP'S CLASS REVENUE INCREASE DISTRIBUTIONS?

A. I conclude that PCLP's proposed class revenue distributions should be rejected because they are based on the GCOSS that is inconsistent with the principle of cost causation. I recommend that the Commission accept the adjusted non-minimum system GCOSS's class revenue distributions because they are based on the GCOSS without minimum-size that is with the principle of cost causation and uniformly move all classes toward full cost recovery.

Q. DO YOU HAVE A SCALE BACK PROPOSAL?

A. Yes. I recommend that, if the Commission does not adopt PCLP's proposed overall revenue requirement, for whatever overall revenue requirement is ultimately adopted by the Commission, the revenue be scaled back and distributed to the classes based on the class revenue distribution percentages in Table 6.

[29] Exhibit KRP-2, lines 47-50.

Q. HAVE YOU CALCULATED CUSTOMER CLASS REVENUE DISTRIBUTIONS CONSISTENT WITH OCA WITNESS ROGER'S RECOMMENDED REVENUE REQUIREMENT?

A. Yes. I have applied the class revenue distribution percentages from Table 6 to witness Normand's current revenues plus witness Roger's recommended revenue increase of $762,100.[30] The results are shown in Table 7 below.

Table 7 - PCLP Current Revenue Distribution and OCA Recommended Revenue Distribution Scaled Back per OCA Recommended Revenue Requirement[31]

Customer Class	Current	Proposed	Percent Increase	Class Percent Distribution
SC1 Residential Space Heating	787,612	1,446,126	67.55%	39.77%
SC1 Residential Domestic	24,120	41,611	57.80%	8.98%
SC1 Residential Other	3,265	5,864	63.90%	41.92%
SC2 General Service Commercial	72,092	152,230	83.68%	7.03%
SC2 Commercial Space Heating	97,289	201,841	82.85%	1.59%
Total	984,378	1,847,672	70.08%	100.00%

F. CLASS TARIFF RATES

Q. WHAT ARE PCLP'S PROPOSED TARIFF RATES?

A. PCLP's proposed tariff rates for each customer class are shown in Exhibit E-8.[32] The tariff rates are based on the PCLP class revenue distributions in Table 4 above.

[30] Direct Testimony of Jennifer Rogers, Schedule JLR-1.
[31] Exhibit KRP-3.
[32] Exhibit E-8, pages 3-10.

Q. DO YOU AGREE WITH PCLP'S PROPOSED RATE DISTRICT CLASS TARIFF RATES?

A. No. The tariff rates for all PCLP's rate classes should be decreased consistent with the OCA class revenue distributions in Table 7.

Q. WHAT SPECIFIC CUSTOMER CHARGES DOES PCLP PROPOSE FOR RESIDENTIAL CUSTOMERS?

A. As shown in Table 8 below, PCLP proposes to increase Residential customer charges by 18.8% from $8.00 to $9.50 with the remainder of the revenue increase to be recovered through the volumetric Ccf delivery charge for each customer class.

Table 8 – Comparison of PCLP Current and Proposed Residential Customer Charges[33]

Customer Class	Current Customer Charge	Proposed Customer Charge	Percent Increase
SC1 Residential Space Heating	$8.00	$9.50	18.8%
SC1 Residential Domestic	$8.00	$9.50	18.8%
SC1 Residential Other	$8.00	$9.50	18.8%

Q. WHAT IS YOUR RECOMMENDATION REGARDING THE RESIDENTIAL CUSTOMER CHARGES?

A. I recommend that the residential customer charges be left at their current level.

[33] Exhibit E-8, page 3.

Q. WHY DO RECOMMEND THAT THE RESIDENTIAL CUSTOMER CHARGES REMAIN AT THEIR CURRENT LEVEL?

A. As shown in Table 8, PCLP's proposed residential customer charges represent an 18.8% increase over the current charges, which would represent significant and unacceptable rate shock to no discernible ratemaking benefit. A fixed monthly customer charge sends no real actionable price signal to residential customers. No residential customer chooses either to take service or to take a given amount of service based on the customer charge. Thus, the ratemaking principle of efficiency provides no basis to set the customer charge at one level or another. On the other hand, if the residential customer charge is left unchanged, the increased revenue approved in this proceeding will be recovered through the volumetric delivery charge, where it will definitely send a real actionable price signal regarding conservation and customers' control over their monthly bills. Placing all of the increase in the volumetric distribution charge will provide residential customers with both (1) an increased incentive to engage in conservation and (2) the ability to exercise control over a larger portion of their monthly electric distribution bill. For all these reasons I recommend that the residential customer charges remain at their current level as shown in Table 8 above.

Q. HAS THE COMMISSION RECENTLY ISSUED ANY DECISIONS AS TO INCREASED CUSTOMER CHARGES?

A. Yes. Columbia proposed an increase in its existing monthly customer charge in Docket No. R-2020-3018835. In that proceeding the Administrative Law Judge (ALJ) found that Columbia's proposed increase in the residential customer charge was contrary to the Commission's goal of encouraging customers to conserve energy and denied the

Company's requested increase in the monthly customer charge. The Commission adopted the ALJ's decision regarding the residential customer charge.[34]

G. WEATHER NORMALIZATION ADJUSTMENT

Q. WHAT IS PCLP'S PROPOSED WEATHER NORMALIZATION ADJUSTMENT?

A. PCLP's gas panel testimony presents the proposed weather normalization adjustment mechanism.[35] PCLP proposes a mechanism that would (1) be applied to PCLP's three residential customer classes, (2) be applied to residential bills in the month that it was incurred, and (3) be applied in the billing months of October through May.[36] The proposed adjustment would take effect at the conclusion of the current proceeding[37] and would appear as a separate line item surcharge on the monthly bills received by residential customers.[38]

Q. WHAT ARE THE MECHANICS OF THE WEATHER NORMALIZATION ADJUSTMENT?

A. PCLP's recovery of its revenue requirement is via monthly bills that consist of a tariff fixed customer charge and a volumetric delivery charge, as discussed above. The delivery charge portion of a customer's monthly bill is calculated by applying the delivery charge to the volume of gas consumed by the customer in a given month. A customer's consumption of gas for heating purposes is a function of the ambient temperature, particularly during the

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[34] *Pa. P.U.C. v. Columbia Gas of Pennsylvania, Inc.*, Docket No. R-2020-3018835, Order at 264-65 (Feb. 19, 2021).
[35] Statement No.2, Direct Testimony of Accounting Panel, Chuck Lenns and Mathew Lenns (Lenns Direct), page 10 line 20 to page 16 line 10; see also PCLP responses to OCA Interrogatory Set 2 (Gas).
[36] Lenns Direct, page 15 line 13 to page 16 line 10.
[37] PCLP response to OCA Interrogatory 2-5.
[38] PCLP response to OCA Interrogatory 2-18.

months of October through May in northeast Pennsylvania. The delivery charge for a customer class is set based on PCLP's forecast of weather-related consumption.

If, for example, the SC1 RSH class consumes **less** gas than PCLP has forecast in setting the delivery charge, per the WNA, PCLP will apply the delivery charge to the forecast consumption minus the actual consumption and calculate a **positive** surcharge to appear as a separate line item on the bills of the SC1 RSH customers' bills for the month in which the shortfall occurred. That is to say that the SCI RSH customer bills will be **higher** than they otherwise would have been without the WNA.

Conversely, if the SC1 RSH class consumes **more** gas than PCLP has forecast in setting the delivery charge, PCLP will apply the delivery charge to the forecast consumption minus the actual consumption and calculate a **negative** surcharge to appear as a separate line item on the bills of the SC1 RSH customers' bills for the month in which the shortfall occurred. That is to say that the SCI RSH customer bills will be **lower** than they otherwise would have been without the WNA.

Q. WHAT ARE THE POLICY GOALS THAT PCLP SEEKS TO PURSUE WITH THE WNA?

A. PCLP states that the policy goals of the WNA mechanism are (1) to reduce the volatility of customer bills; and (2) to better manage PCLP's cash during warm periods.[39]

[39] PCLP response to OCA Interrogatory 2-1.

Q. WILL THE WNA REDUCE THE MONTHLY VOLATILITY OF AN INDIVIDUAL RESIDENTIAL CUSTOMER'S BILL?

A. The WNA will only reduce an individual customer's monthly bill volatility if, for example, an individual SC1 RSH customer's monthly consumption volatility matches the customer class monthly consumption volatility, as determined by variations from "normal" weather, of the customer's SC1 RSH class as a whole. If the customer's occupancy pattern changes month to month or the customer actively pursues conservation measures (thermostat settings and/or building insulation) that mute the consumption effects of ambient temperature volatility, then such customers could see their monthly bill volatility actually increase as the WNA follows the ups and downs of the class as a whole. This is more generally a significant downside to the WNA in that it will obscure the delivery charge price signal that incentivizes conservation and control over monthly bills irrespective of whether the individual customer's month to month consumption volatility matches that of the class as a whole.

Q. WILL THE WNA ENABLE BETTER MANAGEMENT OF PCLP'S CASH DURING WARM PERIODS?

A. Managing PCLP's cash during warm periods simply means increasing PCLP's revenues during warm periods with unforecasted, decreased gas consumption. Every utility, indeed every well managed business, maintains a line of credit with which it can smooth out the ups and downs of cash for expected and unexpected day-to-day expenditures. The risk of shortfalls in available cash is mitigated by the interest the utility pays as it draws from its line of credit. The WNA shifts some of that risk onto customers by effectively borrowing cash from customers in periods of unforecast, decreased consumption and only perhaps paying it back to customers in periods of unforecasted, increased consumption. The WNA does not, in any way, speak to an unfulfilled financial need of PCLP.

Q. WHERE DOES A REVENUE SURCHARGE LIKE THE WNA FIT IN THE RATE BASE/RATE OF RETURN MODEL UNDER WHICH PCLP IS REGULATED?

A. In the rate base/rate of return model there are two components that make up the revenue requirement that is then translated into individual tariff charges for recovery: (1) operating expenses; and (2) return calculated by applying a rate of return to rate base. When a Commission authorizes a rate of return it sets the rate of return that provides the utility the opportunity, not a guarantee, to earn that rate of return through the charges for services to customers based on that revenue requirement calculated using the authorized rate of return. This sets for the utility an incentive to achieve its authorized rate of return via efficiency savings in expenses. Revenue surcharges like the WNA, which decouple a portion of revenues from the provision of tariffed services reduce that incentive to reduce the costs of service via efficiency savings, i.e., least cost operations.

Q. DOES ANOTHER OCA WITNESS DISCUSS THE EFFECT OF DECOUPLING REVENUES ON THE RISK EXPERIENCED BY PCLP WITH RESPECT TO EARNING ITS RATE OF RETURN ON RATE BASE?

A. Yes. OCA witness Reno, in OCA Statement 2,[40] further discusses the impact that implementation of risk-reducing mechanisms, such as the WNA, has on a utility's rate of return by reducing risks associated with traditional ratemaking concerns such as regulatory lag. Ms. Reno also comments on how a combined gas and electric utility, such as PCLP,

[40] Reno testimony, OCA Statement 2, pages 34 and 40.

may face reduced risk already, which may alleviate the need for a mechanism such as the WNA.

Q. IS THE WNA MECHANISM PROPOSED BY PCLP THE SAME AS WNAS WHICH ARE CURRENTLY IN EFFECT IN PENNSYLVANIA?

A. No. There are a few key areas where PCLP's proposal differs. Notably, PCLP proposes to include a "Heat Sensitivity Factor" which represents the difference between actual sales and the cumulative, non-weather sensitive usage PCLP calculates for its customer base.[41] No other WNA in Pennsylvania includes this "factor". Non-weather sensitive usage will be determined on a per-class basis, not on an individual per-customer basis, unlike in other WNAs in Pennsylvania.[42] Further, PCLP does not propose to include a deadband to controls for minor variations in weather. A deadband is a fixed percentage (or collar) around the forecasted number of normal heating degree days (HDDs) in which no WNA charges or credits will be issued and has been implemented as part of every authorized WNA in Pennsylvania.

Q. IF THESE DIFFERENCES WERE CORRECTED, WOULD YOU RECOMMEND APPROVAL OF THE WNA?

A. No. I do not believe that correcting these differences would be sufficient to warrant approval of the WNA. However, in the alternative, should the Commission decide to authorize a WNA for Pike Gas, these corrections should be made so that the authorized WNA excludes the proposed "Heat Sensitivity Factor" and includes a deadband of 5%.

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[41] PCLP Response to OCA Interrogatory 2-2.
[42] PCLP Response to OCA Interrogatory 2-15.

Q. DID PCLP PROVIDE ANY ANALYSIS WHICH REPRESENTS HOW THE WNA IS LIKELY TO AFFECT RESIDENTIAL RATEPAYERS?

A. Yes.

Table 9 – PCLP Projections of WNA Revenues During 2023-2024 Heating Season for Residential Customers[43]

Month	Number of Customers	Weather Adjustment to Consumption (CCF)	Base Rate Revenue Adjustment
October	1214	5,661	$3,660.20
November	1218	2,723	$1,760.46
December	1219	15,182	$9,816.47
January	1219	23,519	$15,207.58
February	1221	22,516	$14,558.53
March	1223	29,042	$18,778.84
April	1222	8,545	$5,525.39
May	1224	11,458	$7,408.50
Total:	**1220**	**118,645**	**$76,715.96**

Q. WHAT DOES THIS ANALYSIS SHOW?

A. This analysis shows that, if the WNA had been in effect from October 2023 through May 2024, PCLP would have billed for an additional approximately 118,645 CCF of throughput. Considering PCLP's data provided that the actual throughput was 846,131 CCF during this period, this is an increase of approximately 14% (118,645 / 846,131). As a result, PCLP's residential customer base, as a whole, would have paid for 14% more gas than they used, resulting in distorted price signals for residential customers and creating additional volatility, as highlighted above in my testimony.

[43] PCLP Response to OCA Interrogatory 2-2.

Q. **DOES THE COMMISSION HAVE CERTAIN POLICY FACTORS THAT IT CONSIDERS WHEN RULING ON ALTERNATIVE RATEMAKING MECHANISMS SUCH AS THE WNA?**

A. I have been informed by counsel that, yes, there are 14 policy factors that the Commission considers when ruling on alternative ratemaking mechanisms such as the proposed WNA, which can be found at 52 Pa. Code Sections 69.3301 and 69.3302.

Q. **DID PCLP SUBMIT AN ANALYSIS AS TO THE APPLICATION OF THESE POLICY FACTORS TO ITS PROPOSED WNA?**

A. No. Pike submitted no analysis with its rate filing to support its proposed WNA, including one which addressed the Commission's policy factors with respect to alternative ratemaking mechanisms.

Q. **DOES PCLP'S PROPOSED WNA WARRANT APPROVAL UNDER THESE POLICY FACTORS?**

A. No. While not all of these factors are relevant in this proceeding, and I have been informed by counsel that no single policy factor is dispositive, I do not believe the proposed WNA aligns with the Commission's policy factors.

Q. **WHAT SPECIFIC POLICY FACTORS DID YOU ADDRESS ABOVE?**

A. I address all relevant policy factors in an exhibit attached to my testimony, OCA Exhibit KRP-4.

Q. **WHAT IS YOUR RECOMMENDATION REGARDING PCLP'S PROPOSED WNA?**

A. As discussed above, I recommend that the Commission not approve the proposed WNA because (1) it will provide no benefit to residential customers, (2) it does not meet a legitimate financial need of PCLP, and (3) it will reduce PCLP's incentive to seek efficiency savings in its operations. Alternatively, should the Commission decide to authorize a WNA for Pike Gas, the Commission should direct that the authorized WNA exclude the proposed "Heat Sensitivity Factor" and include a deadband of 5%.

Q. **DOES THIS CONCLUDE YOUR TESTIMONY?**

A. Yes. However, I reserve the right to supplement this testimony if further information is provided by PCLP.

KARL RICHARD PAVLOVIC, Ph.D.

Education

Purdue University – MA and Ph.D. in Philosophy

Karl-Ruprecht Universität, Heidelberg, Germany – graduate study

Yale University – BA in Philosophy

Positions

Senior Consultant – PCMG and Associates	2015-Present
Senior Consultant – Snavely King Majoros and Associates	2010-2014
Director – FTI Consulting	2008-2010
President – DOXA, Inc	1994-2008
Partner – Snavely King and Associates	1983-1994
Assistant Professor – University of Florida-Gainesville	1978-1983

Professional Experience

Dr. Pavlovic provides clients with economic and policy analyses of commercial operations and expert testimony in support of litigation, negotiation and strategic planning. His analyses and testimony are distinguished by systematic articulation and testing of assumptions, thorough evaluation of data, innovative application of statistical tools and economic principles, and clarity and precision of presentation. Dr. Pavlovic has provided expert testimony on the operations, costs and revenues of gas and electric utilities, the impacts of restructuring wholesale and retail electric markets, effects of mergers, the operation and competitiveness of petroleum and electric markets, the market valuation of crude oil, electric and gas reliability, and the performance of energy efficiency, renewable energy, and peak reduction programs.

Major projects directed by Dr. Pavlovic have included: analytical assistance to counsel and testimony on all aspects of the restructuring of wholesale and retail electric markets in the Eastern Interconnection; technical representation of the District of Columbia People's Counsel on the DC PSC's Pepco Productivity Improvement Working Group and various PJM working groups; impact evaluation study of pilot energy efficiency and renewable energy programs in the District of Columbia; analysis of petroleum markets, expert testimony, and coordination of technical testimony in the Trans-Alaska Pipeline quality bank litigation; Independent Technical Review of the economic models used by the US Army Corps of Engineers for the Ohio River System Investment Plan; assistance to a major independent telephone company in the formulation and implementation of corporate strategic plans, applications for long-distance authority, and settlement negotiations with major domestic and foreign carriers.

By education and professional experience Dr. Pavlovic has expertise in formal and mathematical logic, statistics, economics, financial analysis, econometrics, and computer modeling. With 33 years' experience as a consultant and expert witness, Dr. Pavlovic has in-depth knowledge of commercial and industrial operations in the energy, transportation, and telecommunications industries and is familiar with a wide range of experimental and investigative methods in science and engineering.

Regulatory Projects and Appearances

1. In re: the Application of Otter Tail Power Company for Authority to Increase Rates for Electric Utility Service in North Dakota (2024) - (Appearance: cost of service and rate design on behalf of the North Dakota Public Service Commission Advocacy Staff)
   ND PSC Case No. PU-20-441

2. In re: 2023 Gas System Enhancement Program Plan Filings for the Commonwealth's Natural Gas Distribution Companies (2024) - (Appearance: cost and project compliance with tariff on behalf of the Massachusetts Attorney General Office of Ratepayer Advocacy)
   MA Department of Public Utilities Docket Nos. D.P.U. 23-GSEP-01 to 23-GSEP-06

3. In re: the Application of Northern States Power Company for Advance Determination of Prudence – 345kV Big Stone to Sherburne (2024) - (Appearance: need, necessity and conformance with North Dakota Statutes and Regulation on behalf of the North Dakota Public Service Commission Advocacy Staff)
   ND PSC Case No. PU-23-329

4. Pennsylvania Office of Consumer Advocate: Monitor, Review and Report on Electric and Natural Gas Filings to the FERC (2024)
   Federal Energy Regulatory Agency Dockets

5. In re: Petition of Veolia Water New Jersey, Inc. for an Increase in Rates for Water Service and Other Tariff Changes (2023) - (Appearance: cost of service and rate design on behalf of the New Jersey Rate Counsel)
   NJ BPU Docket No. WR23110790

6. In re: the Application of Northern States Power Company for Advance Determination of Prudence – Brookings County to Lyon County and Helena to Hampton 345 kV Second Circuit (2023) - (Appearance: need, necessity and conformance with North Dakota Statutes and Regulation on behalf of the North Dakota Public Service Commission Advocacy Staff)
   ND PSC Case No. PU-23-295

7. In re: the Application of Northern States Power Company for Advance Determination of Prudence - Sherburne County 345 kV Transmission Line (2023) - (Appearance: need, necessity and conformance with North Dakota Statutes and Regulation on behalf of the North Dakota Public Service Commission Advocacy Staff)
   ND PSC Case No. PU-23-142

8. In re: Petition of Middlesex Water Company for an Increase in Rates for Water Service and Other Tariff Changes (2023) - (Appearance: cost of service and rate design on behalf of the Township of East Brunswick, New Jersey)
   NJ BPU Docket No. WR23050292

9. In re: Petition of NSTAR Gas Company d/b/a Eversource Energy for Approval of its 2022 Gas System Enhancement Plan Reconciliation Filing (2023) - (Appearance: prudence/used and useful, accounting, cost of service and rate design on behalf of the Massachusetts Attorney General Office of Ratepayer Advocacy)
   MA Department of Public Utilities Docket No. D.P.U. 23-GREC-06

10. In re: Petition of Eversource Gas Company of Massachusetts d/b/a Eversource Energy for Approval of its 2022 Gas System Enhancement Plan Reconciliation Filing (2023) - (Appearance: prudence/used and useful, accounting, cost of service and rate design on behalf of the Massachusetts Attorney General Office of Ratepayer Advocacy)
   MA Department of Public Utilities Docket No. D.P.U. 23-GREC-05

11. In re: Petition of Berkshire Gas Company for Approval of its 2022 Gas System Enhancement Plan Reconciliation Filing (2023) - (Appearance: prudence/used and useful, accounting, cost of service and rate design on behalf of the Massachusetts Attorney General Office of Ratepayer Advocacy)
   MA Department of Public Utilities Docket No. D.P.U. 23-GREC-02

12. In re: Pittsburgh Water and Sewer Authority General Base Rate Increase Filing (2023) – (Appearance: gas and electric cost of service and rate design on behalf of the Pennsylvania Office of Consumer Advocate)
   PA Public Utility Commission Docket Nos. R-2023-3039920 et al

13. In re: UGI Electric Company General Base Rate Increase Filing (2023) – (Appearance: electric cost of service and rate design on behalf of the Pennsylvania Office of Consumer Advocate)
   PA Public Utility Commission Docket Nos. R-2022-3037368

14. In re: Application of Hawaii Water Service Company, Inc. for Approval of a General Rate Increase for its Pukalani Wastewater Diviion and Certain Tariff Changes (2023) – (Appearance: cost of service and rate design on behalf of the Hawaii Division of Consumer Advocacy)
   HI Public Utilities Commission Docket No. 2022-0186

15. In re: Application of Lanai Water Company, Inc. for Review and Approval of Rate Increases; Revised Rate Schedules; and Changes to its Tariff (2023) – (Appearance: cost of service and rate design on behalf of the Hawaii Division of Consumer Advocacy)
   HI Public Utilities Commission Docket No. 2022-0233

16. In re: Application of Southern Maryland Electric Cooperative, Inc., for Authority to Revise Its Rates and Charges for Electric Service and Certain Rate Design Changes (2023) – (Appearance: cost of service and rate design on behalf of the Maryland Office of the People's Counsel)
    MD PSC Case No. 9688

17. In re: Application of San Diego Gas & Electric Company for Authority to Establish Its Authorized Cost of Capital for Utility Operations for 2023 (2022) – (Appearance: business risk and cost of equity on behalf of Utility Consumers' Action Network)
    CA Public Utilities Commission Application 22-04-012

18. In re: Valley Energy, Inc. General Base Rate Increase Filing (2022) – (Appearance: gas cost of service and rate design on behalf of the Pennsylvania Office of Consumer Advocate)
    PA Public Utility Commission Docket Nos. R-2022-3032300

19. In re: Citizens' Electric Company General Base Rate Increase Filing (2022) – (Appearance: electric cost of service and rate design on behalf of the Pennsylvania Office of Consumer Advocate)
    PA Public Utility Commission Docket Nos. R-2022-3032369

20. In re: PECO Energy Company (Gas Division) General Base Rate Increase Filing (2022) – (Appearance: gas and electric cost of service and rate design on behalf of the Pennsylvania Office of Consumer Advocate)
    PA Public Utility Commission Docket Nos. R-2022-3031113

21. In re: Petition of Eversource Gas Company of Massachusetts d/b/a Eversource Energy for Approval of its 2021 Gas System Enhancement Plan Reconciliation Filing (2022) - (Appearance: prudence/used and useful, accounting, cost of service and rate design on behalf of the Massachusetts Attorney General Office of Ratepayer Advocacy)
    MA Department of Public Utilities Docket No. D.P.U. 22-GREC-05

22. In re: Petition of Liberty Utilities (New England Natural Gas Company Corp.) d/b/a Liberty for Approval of its 2021 Gas System Enhancement Plan Reconciliation Filing (2022) - (Appearance: prudence/used and useful, accounting, cost of service and rate design on behalf of the Massachusetts Attorney General Office of Ratepayer Advocacy)
    MA Department of Public Utilities Docket No. D.P.U. 22-GREC-04

23. In re: Petition of Berkshire Gas Company for Approval of its 2021 Gas System Enhancement Plan Reconciliation Filing (2022) - (Appearance: prudence/used and useful, accounting, cost of service and rate design on behalf of the Massachusetts Attorney General Office of Ratepayer Advocacy)
    MA Department of Public Utilities Docket No. D.P.U. 22-GREC-02

24. In re: Nova Scotia Power 2022-2024 General Rate Application (2022) - (Appearance: cost of service on behalf of the Nova Scotia Utility and Review Board)
    NS UARB M10431

25. In re: the Application of Northern States Power Company for Authority to Increase Rates for Natural Gas Service in North Dakota (2021) - (Appearance: cost of service and rate design on behalf of the North Dakota Public Service Commission Advocacy Staff)
    ND PSC Case No. PU-20-441

26. In re: Application of San Diego Gas & Electric Company for Authority to Establish Its Authorized Cost of Capital for Utility Operations for 2022 and to Reset the Annual Cost of Capital Mechanism (2021) – (Appearance: wildfire risk accounting and ratemaking on behalf of Utility Consumers' Action Network)
    CA Public Utilities Commission Application 21-08-014

27. In re: Petition of HPBS, Inc. for review and approval of Central Scheduling System (CSS) charge increase and revised CSS schedule (2021) – (Appearance: rate design on behalf of the Hawaii Department of Commerce and Consumer Affairs)
    HI DCCA Docket No. PTP-2021-001

28. In re: Petition of NSTAR Gas Company d/b/a Eversource Energy for Approval of its 2020 Gas System Enhancement Plan Reconciliation Filing (2021) - (Assistance to Counsel: prudence/used and useful, accounting, cost of service and rate design on behalf of the Massachusetts Attorney General Office of Ratepayer Advocacy)
    MA Department of Public Utilities Docket No. D.P.U. 21-GREC-06

29. In re: Petition of Eversource Gas Company of Massachusetts d/b/a Eversource Energy for Approval of its 2020 Gas System Enhancement Plan Reconciliation Filing (2021) - (Assistance to Counsel: prudence/used and useful, accounting, cost of service and rate design on behalf of the Massachusetts Attorney General Office of Ratepayer Advocacy)
    MA Department of Public Utilities Docket No. D.P.U. 21-GREC-05

30. In re: Petition of Berkshire Gas Company for Approval of its 2020 Gas System Enhancement Plan Reconciliation Filing (2021) - (Assistance to Counsel: prudence/used and useful, accounting, cost of service and rate design on behalf of the Massachusetts Attorney General Office of Ratepayer Advocacy)
    MA Department of Public Utilities Docket No. D.P.U. 20-GREC-02

31. In re: the Application of Northern States Power Company for Authority to Increase Rates for Electric Service in North Dakota (2021) - (Appearance: cost of service and rate design on behalf of the North Dakota Public Service Commission Advocacy Staff)
    ND PSC Case No. PU-20-441

32. In re: Pike County Light & Power Company 2020 General Base Rate Increase Filing – (Appearance: gas and electric cost of service and rate design on behalf of the Pennsylvania Office of Consumer Advocate)
    PA Public Utility Commission Docket Nos. R-2020-3022134 and R-2020-3022135

33. In re: Young Brothers LLC's Application for Approval of a New Cost of Service Model (2020) – (Appearance: cost of service on behalf of the Hawaii Division of Consumer Advocacy)
    HI Public Utilities Commission Docket No. 2020-0135

34. In re: Petition of NSTAR Gas Company d/b/a Eversource Energy for Approval of its 2019 Gas System Enhancement Plan Reconciliation Filing (2020) - (Assistance to Counsel: prudence/used and useful, accounting, cost of service and rate design on behalf of the Massachusetts Attorney General Office of Ratepayer Advocacy)
    MA Department of Public Utilities Docket No. D.P.U. 20-GREC-06

35. In re: Petition of Bay State Gas Company d/b/a Columbia Gas of Massachusetts for Approval of its 2019 Gas System Enhancement Plan Reconciliation Filing (2020) - (Assistance to Counsel: prudence/used and useful, accounting, cost of service and rate design on behalf of the Massachusetts Attorney General Office of Ratepayer Advocacy)
    MA Department of Public Utilities Docket No. D.P.U. 20-GREC-05

36. In re: Petition of Berkshire Gas Company for Approval of its 2019 Gas System Enhancement Plan Reconciliation Filing (2020) - (Assistance to Counsel: prudence/used and useful, accounting, cost of service and rate design on behalf of the Massachusetts Attorney General Office of Ratepayer Advocacy)
    MA Department of Public Utilities Docket No. D.P.U. 20-GREC-02

37. In re: Pittsburgh Water and Sewer Authority 2020 General Base Rate Increases 2020 – (Appearance: multi-year rate plan and performance-based ratemaking on behalf of the Pennsylvania Office of Consumer Advocate)
    PA Public Utility Commission Docket Nos. R-2020-3017970 and R-2020-3017951

38. In re: Commonwealth Edison Company Petition for approval of a Revision to Integrated Distribution Company Implementation Plan Creation of Rate Residential Time of Use Pricing Pilot ("Rate RTOUP") – On Rehearing (2020) – (Appearance: price signal and customer response on behalf of the Illinois Attorney General)
    IL Commerce Commission Docket Nos. 18-1725/18-1824

39. In re: Hawaii Electric Company, Inc. Application for Approval of a General Rate Increase and Revised Rate Schedules and Rules (2019) - (Appearance: cost of service and rate design on behalf of the Hawaii Division of Consumer Advocacy)
    HI Public Utilities Commission Docket No. 2019-0085

40. In re: Application of San Diego Gas & Electric Company for Authority to: (i) Adjust its Authorized Return on Common Equity, (ii) Adjust its Authorized Embedded Costs of Debt and Preferred Stock, (iii) Adjust its Authorized Capital Structure; (iv) Increase its Overall Rate of Return, (v) Modify its Adopted Cost of Capital Mechanism Structure, and (vi) Revise its Electric Distribution and Gas Rates Accordingly, and for Related Substantive and Procedural Relief (2019) – (Appearance: wildfire risk accounting and ratemaking on behalf of Utility Consumers' Action Network)
    CA Public Utilities Commission Application 19-04-017

41. In re: Proposed Amendments to N.J.A.C. 14:9 Adoption of Water and Sewer Uniform System of Accounts (2019) – (Assistance to counsel: water and sewer accounting on behalf of the Division of Rate Counsel)
    NJ Board of Public Utilities Docket Nos. WX19050612 and WX19050613

42. In re: Petition of Public Service Electric and Gas Company for Approval of Gas Base Rate Adjustments Pursuant to its Gas System Modernization Program (2019) – (Assistance to Counsel: infrastructure replacement accounting)
    NJ Board of Public Utilities Docket No. GE19040522

43. In re: Petition of NSTAR Gas Company d/b/a Eversource Energy for Approval of its 2018 Gas System Enhancement Plan Reconciliation Filing (2019) - (Assistance to Counsel: prudence/used and useful, accounting, cost of service and rate design on behalf of the Massachusetts Attorney General Office of Ratepayer Advocacy)
    MA Department of Public Utilities Docket No. D.P.U. 19-GREC-06

44. In re: Petition of Bay State Gas Company d/b/a Columbia Gas of Massachusetts for Approval of its 2018 Gas System Enhancement Plan Reconciliation Filing (2019) - (Assistance to Counsel: prudence/used and useful, accounting, cost of service and rate design on behalf of the Massachusetts Attorney General Office of Ratepayer Advocacy)
    MA Department of Public Utilities Docket No. D.P.U. 19-GREC-05

45. In re: The Application of Potomac Electric Power Company for Adjustments to Its Retail Rates for the Distribution of Electric Energy (2019) – (Appearance: cost of service and rate design on behalf of the Maryland Office of People's Counsel)
    MD Public Service Commission Case No. 9602

46. In re: PECO Energy Company Non-Bypassable Transmission Service Charge (NBT) Semiannual Adjustment (2019) - (Appearance: accounting, cost of service and rate design on behalf of the Pennsylvania Office of Consumer Advocate)
    PA Public Utility Commission Docket No. M-2018-3005860

47. In re: PECO Energy Company Transmission Formula Rate Application (2018) - (Appearance: accounting, cost of service and rate design on behalf of the Pennsylvania Office of Consumer Advocate)
    Federal Energy Regulatory Commission Docket ER17-1519-000

48. In re: Petition of NSTAR Gas Company d/b/a Eversource Energy for Approval of its 2017 Gas System Enhancement Plan Reconciliation Filing (2018) - (Appearance: prudence/used and useful, accounting, cost of service and rate design on behalf of the Massachusetts Attorney General Office of Ratepayer Advocacy)
    MA Department of Public Utilities Docket No. D.P.U. 18-GREC-06

49. In re: Petition of Bay State Gas Company d/b/a Columbia Gas of Massachusetts for Approval of its 2017 Gas System Enhancement Plan Reconciliation Filing (2018) - (Appearance: prudence/used and useful, accounting, cost of service and rate design on behalf of the Massachusetts Attorney General Office of Ratepayer Advocacy)
    MA Department of Public Utilities Docket No. D.P.U. 18-GREC-05

50. In re: The Application of the Potomac Edison Company for Adjustments to Its Retail Rates for the Distribution of Electric Energy (2018) – (Appearance: cost of service and rate design on behalf of the Maryland Office of People's Counsel)
    MD Public Service Commission Case No. 9490

51. In re: Rate Applications of Kansas City Power & Light – Missouri and Kansas City Power & Light – Greater Missouri Operations (2018) – (Appearance: consolidated operations, cost of service and rate design on behalf of the Missouri Office of Public Counsel)
    MO Public Service Commission Case Nos. ER-2018-0145 and ER-2018-0146

52. In re: The Application of Potomac Electric Power Company for Adjustments to Its Retail Rates for the Distribution of Electric Energy (2018) – (Appearance: cost of service and rate design on behalf of the Maryland Office of People's Counsel)
    MD Public Service Commission Case No. 9472

53. In re: Mid-Atlantic Interstate Transmission, L.L.C. 2018 Transmission Formula Rate Protocol Filings (2018) - (Analysis and Advice to Counsel: accounting)
    Federal Energy Regulatory Commission Docket ER17-211-000

54. In re: The Gas Company d/b/a Hawaii Gas Application for Approval of Rate Increases and Revised Rate Schedules and Rules (2017) - (Appearance: cost of service and rate design on behalf of the Hawaii Division of Consumer Advocacy)
    HI Public Utilities Commission Docket No. 2017-0105

55. In re: Montana-Dakota Utilities Co., Application to Increase Natural Gas Rates (2017) - (Appearance: cost of service and rate design on behalf of the North Dakota Public Service Commission Staff)
    ND Public Service Commission Case No. PU-12-813

56. In re: The Application of Delmarva Power and Light Company for Adjustments to Its Retail Rates for the Distribution of Electric Energy (2017) – (Appearance: cost of service and rate design on behalf of the Maryland Office of People's Counsel)
    MD Public Service Commission Case No. 9455

57. In re: Petition of NSTAR Gas Company d/b/a Eversource Energy for Approval of its 2016 Gas System Enhancement Plan Reconciliation Filing (2017) - (Appearance: prudence/used and useful and plant accounting on behalf of the Massachusetts Attorney General Office of Ratepayer Advocacy)
    MA Department of Public Utilities Docket No. D.P.U. 17-GREC-06

58. In re: Petition of Bay State Gas Company d/b/a Columbia Gas of Massachusetts for Approval of its 2016 Gas System Enhancement Plan Reconciliation Filing (2017) - (Appearance: prudence/used and useful and plant accounting on behalf of the Massachusetts Attorney General Office of Ratepayer Advocacy)
    MA Department of Public Utilities Docket No. D.P.U. 17-GREC-05

59. In re: In the matter of the application of Columbia Gas of Maryland, Inc. for Authority to Increase Rates and Charges (2017) - (Appearance: cost of service and rate design on behalf of the Maryland Office of People's Counsel)
    MD Public Service Commission Case No. 9447

60. In re: PJM Interconnection, L.L.C. - PECO Energy Company Transmission Formula Rate Application (2017) - (Analysis and Advice to Counsel: accounting, cost of service and rate design)
    Federal Energy Regulatory Commission Docket ER17-1519-000

61. In re: Northern Illinois Gas Company d/b/a Nicor Gas Company Proposed General Increase in Gas Rates (2017) - (Appearance: prudence/used and useful and plant accounting re. accelerated asset replacement program on behalf of the Illinois Citizens Utility Board)
    IL Commerce Commission Docket No. 17-0124

62. In re: The Application of Potomac Electric Power Company for Adjustments to Its Retail Rates for the Distribution of Electric Energy (2017) - (Appearance: cost of service and rate design on behalf of the Maryland Office of People's Counsel)
    MD Public Service Commission Case No. 9443

63. In re: PJM Interconnection, L.L.C. - Rockland Electric Company Transmission Rate Application (2017) (Analysis and Advice to Counsel: accounting, cost of service and rate design on behalf of the New Jersey Division of Rate Counsel)
    Federal Energy Regulatory Commission Docket ER17-856-000

64. In re: PJM Interconnection, L.L.C. - Mid-Atlantic Interstate Transmission, L.L.C. Transmission Formula Rate Application (2016) - (Analysis and Advice to Counsel: accounting, cost of service and rate design on behalf of the Pennsylvania Office of Consumer Advocate)
    Federal Energy Regulatory Commission Docket ER17-211-000

65. In re: The Application of Delmarva Power and Light Company for Adjustments to Its Retail Rates for the Distribution of Electric Energy (2016) – (Appearance: cost of service and rate design on behalf of the Maryland Office of People's Counsel)
    MD Public Service Commission Case No. 9424

66. In re: The Application of Potomac Electric Power Company for Adjustments to Its Retail Rates for the Distribution of Electric Energy (2016) – (Appearance: cost of service and rate design on behalf of the Maryland Office of People's Counsel)
    MD Public Service Commission Case No. 9418

67. In re: Petition of Fitchburg Gas and Electric Light Company d/b/a Unitil for Approval of its 2015 Gas System Enhancement Plan Reconciliation Filing (2016) - (Analysis and Advice to Counsel: prudence/used and useful and plant accounting on behalf of the Massachusetts Attorney General Office of Ratepayer Advocacy)
    MA Department of Public Utilities Docket No. D.P.U. 16-GREC-01

68. In re: Petition of Bay State Gas Company d/b/a Columbia Gas of Massachusetts for Approval of its 2015 Gas System Enhancement Plan Reconciliation Filing (2016) - (Appearance: prudence/used and useful and plant accounting on behalf of the Massachusetts Attorney General Office of Ratepayer Advocacy)
    MA Department of Public Utilities Docket No. D.P.U. 16-GREC-05

69. In re: Petition for Approval of Gas Infrastructure Contract Between Public Service Company of New Hampshire d/b/a Eversource Energy and Algonquin Gas Transmission, LLC (2016) - (Appearance: compliance with statutes and regulations, prudence, cost/benefit, and ratemaking on behalf of the New Hampshire Office of Consumer Advocate)
    NH Public Utilities Commission Docket No. DE 16-241

70. In re: Central Maine Power Company, Annual Compliance Filing and Price Change (2016) - (Analysis and Advice to Counsel: tax normalization regulatory asset on behalf of the Maine Office of the Public Advocate)
    ME Public Service Commission Docket No. 2016-00035

71. In re: Bulletin 2015-10 Generic Proceeding to Establish Parameters for the Next Generation PBR Plans (2016) - (Appearance: productivity adjustments/performance based ratemaking on behalf of the Alberta Utilities Consumer Advocate)
    Alberta Utilities Commission Proceeding 20414

72. In re: Emera Maine, Proposed Rate Increase in Rates (2016) - (Analysis and Advice to to Counsel: evaluation of management audit of implementation of Customer Information System on behalf of the Maine Office of the Public Advocate)
    ME Public Service Commission Docket No. 2015-00360

73. In re: The Merger of the Southern Company and AGL Resources Inc.- Joint Application of the Southern Company, AGL Resources Inc., and Pivotal Utility Holdings, Inc., d/b/a Elkton Gas (2015-2016) - (Appearance: earnings, synergy savings, rates, operations, supply procurement, safety, and reliability on behalf of the Maryland Office of People's Counsel)
    MD Public Service Commission Case No. 9404

74. In re: Petition of Bay State Gas Company d/b/a Columbia Gas of Massachusetts for Approval of Firm Transportation Agreements with Millennium Pipeline Company, LLC (2015-2016) - (Analysis, Advice to Counsel, and Assistance on Brief: compliance with gas supply plan, rates, and reliability on behalf of the Massachusetts Attorney General Office of Ratepayer Advocacy)
    MA Department of Public Utilities Docket No. D.P.U. 15-142

75. In re: Petition of Boston Gas Company and Colonial Gas Company d/b/a National Grid for Approval of Precedent Agreements with Millennium Pipeline Company, LLC (2015-2016)
    - (Analysis, Advice to Counsel, and Assistance on Brief: compliance with gas supply plan, rates, and reliability on behalf of the Massachusetts Attorney General Office of Ratepayer Advocacy)
    MA Department of Public Utilities Docket No. D.P.U. 15-130

76. In re: Petition of Boston Gas Company and Colonial Gas Company d/b/a National Grid for Approval of Agreements for LNG or Liquefaction Services with GDF Suez Gas NA, LLC; Northeast Energy Center, LLC; Gaz Metro LNG, L.P.; and National Grid LNG (2015- 2016) - (Analysis and Advice to Counsel: compliance with gas supply plan, rates, and reliability on behalf of the Massachusetts Attorney General Office of Ratepayer Advocacy)
    MA Department of Public Utilities Docket No. D.P.U. 15-129

77. In re: Columbia Gas of Massachusetts CY2014 Targeted Infrastructure Reinvestment Factor Compliance Filing (2015) - (Appearance: PBR tracker design/rates, prudence/used and useful, plant accounting on behalf of the Massachusetts Attorney General Office of Ratepayer Advocacy)
    MA Department of Public Utilities Docket No. D.P.U. 15-55

78. ENMAX Energy Corporation (EEC) 2015-2016 Regulated Rate Option Non-Energy Tariff Application (2015-2016) - (Appearance: cost allocation, rate design, non-energy risk on behalf of the Alberta Utilities Consumer Advocate)
    Alberta Utilities Commission Proceeding 20480

79. In the Matter of the Merger of Exelon Corporation and Pepco Holdings, Inc. (2014) - (Advice to Counsel: impact on customers on behalf of the New Jersey Division of Rate Counsel)
    NJ Board of Public Utilities BPU Docket No. EM1406

80. In re: Application of Baltimore Gas and Electric Company For Adjustments To Its Electric and Gas Base Rates (2014) (Analysis and Advice to Counsel in Settlement: earnings, investment tracker, cost allocation and rate design on behalf of the Maryland Office of People's Counsel)
    MD Public Service Commission Case No. 9355

81. In re: Columbia Gas of Massachusetts CY2013 Targeted Infrastructure Reinvestment Factor Compliance Filing (2014) - (Appearance: PBR tracker design/rates, prudence/used and useful, plant accounting on behalf of the Massachusetts Attorney General Office of Ratepayer Advocacy)
    MA Department of Public Utilities Docket No. D.P.U. 14-83

82. In re: Potential Business Combination of Entergy Louisiana, LLC and Entergy Gulf States Louisiana, L.L.C. (2014-2015) - (Analysis and Advice to Counsel: impact on rates and consolidation of rates on behalf of the Louisiana Public Service Commission Staff)
    LA Public Service Commission Docket No.U-33244

83. In the Matter of the Application of Ohio Power Company to Adopt a Final Implementation Plan for the Retail Stability Rider (2014) - (Analysis and Advice to Counsel: rate design)
    OH Public Utilities Commission Case No. 14-1186-EL-RDR

84. In re: Examination of Long-Term Natural Gas Hedging Proposals (2014-2015) - (Analysis and Advice to Counsel: natural gas procurement on behalf of the Louisiana Public Service Commission Staff)
    LA Public Service Commission Docket No.R-32975-LPSC, ex parte

85. In re: 2013 Integrated Resource Planning Process for Southwestern Electric Power Company Pursuant to General Order Dated April, 20, 2012 (2014-2015 - (Analysis and Advice to Counsel: IRP design and evaluation on behalf of the Louisiana Public Service Commission Staff)
    LA Public Service Commission Docket No. I-33013 SWEPCO, ex parte

86. In the Matter of the Application of Columbia Gas of Maryland, Inc. for Authority to Adopt an Infrastructure Replacement Surcharge Mechanism (2013-2014) - (Appearance: PBR tracker design/rates, prudence/used and useful, plant accounting on behalf of the Maryland Office of People's Counsel)
    MD Public Service Commission Case No. 9332

PCMG and Associates LLC

87. In the Matter of the Application of Baltimore Gas and Electric Company for Approval of a Gas System Strategic Infrastructure Development and Enhancement Plan and Accompanying Cost Recovery Mechanism (2013-2014) - (Appearance: PBR tracker design/rates, prudence/used and useful, plant accounting on behalf of the Maryland Office of People's Counsel)
    MD Public Service Commission Case No. 9331

88. In the Matter of the Application of Delmarva Power & Light Company for an Increase in Electric Base Rates and Miscellaneous Tariff Changes (2013-2014) - (Appearance: earnings, investment tracker design/rates, cost allocation and rate design on behalf of the Delaware Public Service Commission Staff)
    DE Public Service Commission Docket No. 13-115

89. In the Matter of the Application of Northern States Power Company for Authority to Increase Rates for Electric Service in North Dakota (2013) - (Appearance: cost allocation and rate design on behalf of the North Dakota Public Service Commission Staff)
    ND Public Service Commission Case No. PU-12-813

90. In the Matter of the Application of Columbia Gas of Maryland, Inc. for Authority to Increase Rates and Charges (2013) - (Appearance: expense tracker design/rates and evaluation on behalf of the Maryland Office of People's Counsel)
    MD Public Service Commission Case No. 9316

Pike County Light & Power Company
Gas Class Cost of Service Study
12 Months Ending September 30,2024

SCH	LINE NO.	DESCRIPTION (a)	ALLOCATION BASIS (b)	TOTAL GAS COMPANY (c)	Total Residential SC1 (a)	Total Commercial SC2 (e)	Residential Space Heating Rate 231 (f)	Residential Domestic Rate 631 (g)	Residential Other Rate 531 & 731 (h)	General Service Commercial Rate 162 (i)	Commercial Space Heating Rate 331 (j)
RRW	1	**DISTRIBUTION REVENUE REQUIREMENTS**									
RRW	2										
RRW	3	PRESENT RATE OF RETURN (EXISTING RATES)									
RRW	4	--									
RRW	5	Rate Base		7,003,414	5,791,754	1,211,660	5,584,163	184,506	23,084	384,672	826,988
RRW	6	Net Operating Income (Present Rates)		300,104	201,917	98,188	199,858	1,150	909	47,223	50,965
RRW	7	Rate of Return @ Present Rates		4.29%	3.49%	8.10%	3.58%	0.62%	3.94%	12.28%	6.16%
RRW	8	Relative Rate of Return		1.00	0.81	1.89	0.84	0.15	0.92	2.86	1.44
RRW	9	Sales Revenue at Present Rates		1,086,334	893,067	193,268	863,119	26,369	3,578	82,879	110,389
RRW	10	Revenue Present Rates $/Ccf		$711.8354	$799.8246	$471.9309	$798.2741	$854.6320	$796.5648	$453.9848	$486.3658
RRW	11	Revenue Required - $/Month/Customer		$66,002.46	$57,784.98	$192,497.60	$58,445.23	$42,056.61	$59,637.37	$276,262.96	$156,802.13
RRW	12										
RRW	13										
RRW	14	CLAIMED RATE OF RETURN									
RRW	15	--									
RRW	16	Claimed Rate of Return		8.59%	8.59%	8.59%	8.59%	8.59%	8.59%	8.59%	8.59%
RRW	17	Return Required for Claimed Rate of Return		917,310	758,029	159,281	730,730	24,280	3,019	51,898	107,383
RRW	18	Sales Revenue Required @ Claimed ROR		2,028,685	1,738,406	290,278	1,670,056	61,517	6,833	94,019	196,259
RRW	19	Sales Revenue Deficiency		942,350	845,339	97,011	806,937	35,148	3,255	11,140	85,870
RRW	20	Percent Increase Required		86.75%	94.66%	50.20%	93.49%	133.29%	90.96%	13.44%	77.79%
RRW	21	Annual Booked Throughput Sales (Ccf)		1,526,104	1,116,578	409,525	1,081,232	30,855	4,492	182,559	226,966
RRW	22	Sales Revenue Required $/Ccf		$1,329.3230	$1,556.9047	$708.8170	$1,544.5868	$1,993.7706	$1,521.0851	$515.0088	$864.7052
RRW	23	Sales Revenue Deficiency $/Ccf		$617.4877	$757.0801	$236.8860	$746.3127	$1,139.1386	$724.5204	$61.0240	$378.3394
RRW	24										
RRW	25										
RRW	26	PROPOSED RATE OF RETURN									
RRW	27	--									
RRW	28	Rate Base at Future Test Year 09/30/2025		10,679,156	8,824,837	1,854,320	8,507,029	282,662	35,146	604,182	1,250,137
RRW	29	Proposed Base Gas Sales Revenues		2,028,685	1,781,499	247,186	1,723,140	51,209	7,150	106,165	141,021
RRW	30	Base Sales Revenue Deficiency		942,351	888,432	53,919	860,021	24,840	3,572	23,286	30,633
RRW	31	Return Required for Proposed Revenue		2,028,685	1,738,406	290,278	1,670,056	61,517	6,833	94,019	196,259
RRW	32	Percent Increase Required at Proposed Rates		86.75%	99.48%	27.90%	99.64%	94.20%	99.81%	28.10%	27.75%
RRW	33	Proposed Rate of Return		19.00%	19.70%	15.65%	19.63%	21.76%	19.44%	15.56%	15.70%
RRW	34	Relative Rate of Return		1.00	1.04	0.82	1.03	1.15	1.02	0.82	0.83
RRW	35	Rate of Return		8.59%			8.88%	9.84%	8.79%	7.04%	7.10%
RRW	36	percent increase		86.75%			99.64%	94.20%	99.81%	28.10%	27.75%
RRW	37	percent distribution									
RRW	38										
RRW	39	PCLP Revenue Guided by GCOSS without Minimum System									
RRW	40	Relative rate of Return					0.84	0.15	0.92	2.86	1.44
RRW	41	Adjusted 50% => 1.00					0.92	0.57	0.96	1.93	1.22
RRW	42	Rate of Return		8.59%			7.88%	4.92%	8.24%	16.60%	10.47%
RRW	43	Rate Base at Future Test Year 09/30/2025		10,679,156			8,507,029	282,662	35,146	604,182	1,250,137
RRW	44	Return		918,554			670,547	13,906	2,896	100,290	130,914
RRW	45	Sales Revenue at Present Rates Rates		1,086,334			863,119	26,369	3,578	82,879	110,389
RRW	46	Proposed Revenue		2,004,888			1,533,667	40,275	6,474	183,169	241,303
RRW	47	Proposed Revenue Reconciled to PCLP	101.19%	2,028,685			1,551,870	40,754	6,551	185,343	244,167
RRW	48	Sales at Present Rates		1,086,334			863,119	26,369	3,578	82,879	110,389
RRW	49	percent increase		86.75%			79.80%	54.55%	83.08%	123.63%	121.19%
RRW	50	percent distribution		100.00%			76.50%	2.01%	0.32%	9.14%	12.04%

Customer Class	Current	Recommended	Percent Increase	Class Percent Distribution
SC1 Residential Space Heating	863,119	1,446,126	67.55%	76.50%
SC1 Residential Domestic	26,369	41,611	57.80%	2.00%
SC1 Residential Other	3,578	5,864	63.90%	0.30%
SC2 General Service Commercial	82,879	152,230	83.68%	9.10%
SC2 Commercial Space Heating	110,389	201,841	82.85%	12.00%
Total	1,086,334	1,847,672	70.08%	100.00%

OCA Revenue Requirement Increase 762,100

Pike County Light & Power
Response to Distribution Rates – Statement of Policy
Proposed Weather Normalization Adjustment

52 Pa. Code § 69.3302. Distribution rate considerations.

(a) In determining just and reasonable alternative distribution ratemaking mechanisms and rate designs that promote the purpose and scope of this statement of policy and the objectives of 66 Pa. C.S. § 1330 (relating to alternative ratemaking for utilities), the Commission may consider, among other relevant factors, the following:

(1) How the ratemaking mechanism and rate design align revenues with cost causation principles as to both fixed and variable costs.

> **<u>OCA:</u>** PCLP's proposed WNA represents a clear misalignment between revenue and cost causation because it bills customers based upon hypothetical usage, and not on actual, cost-based usage. The WNA applies to the variable portion of a customer bill which recovers some of PCLP's fixed costs and, therefore, does not align with cost causation as to fixed and variable costs.

(2) How the ratemaking mechanism and rate design impact the fixed utility's capacity utilization.

> **<u>OCA:</u>** The proposed WNA is unrelated to capacity utilization since the determining metric for the charge is weather, not utilization.

(3) Whether the ratemaking mechanism and rate design reflect the level of demand associated with the customer's anticipated consumption levels.

> **<u>OCA:</u>** PCLP's proposed WNA does not reflect the level of demand associated with customers' anticipated consumption levels. First, PCLP proposes to calculate its WNA using variables which are not customer-specific, namely the base load and heat sensitivity factors which are used to establish non-weather-sensitive usage. This differs from other WNAs in effect in Pennsylvania and creates further separation between each customer's anticipated consumption and their resultant bill. Second, the WNA results in customers seeing bills increase when usage is lower due to normal weather and bills decrease when usage is higher due to colder than normal weather. If the WNA is generating revenue, it inherently does not accurately reflect the level of demand associated with customers' anticipated consumption levels, because that means demand was less than anticipated.

(4) How the ratemaking mechanism and rate design limit or eliminate interclass and intraclass cost shifting.

> **OCA:** PCLP's proposed WNA does not affect inter- or intraclass cost shifting.

(5) How the ratemaking mechanism and rate design limit or eliminate disincentives for the promotion of efficiency programs.

> **OCA:** The proposed WNA disincentivizes energy efficiency programs because it imposes a disconnect between cost-savings for customers to participate in energy efficiency programming. The disincentive exists in that by relying upon temperature variances to impose a WNA regardless of reduced usage that may otherwise result from participation in an energy efficiency program, the WNA inserts an artificial variable that would mitigate at least some cost-savings contingent on the weather.

(6) How the ratemaking mechanism and rate design impact customer incentives to employ efficiency measures and distributed energy resources.

> **OCA:** PCLP's proposed WNA could provide a disincentive for customers to engage in energy efficiency measures by diluting price signals which should result from bill savings due to such measures. Namely, a portion of customers' bill savings from such measures will be forfeited to the Company because the efficiency measures occurred when weather was warmer-than-normal and, therefore, bills were higher. Because customers will not see the full value of energy efficiency investments during warmer-than-normal periods, the proposed WNA may disincentivize energy efficiency measures.

(7) How the ratemaking mechanism and rate design impact low-income customers and support consumer assistance programs.

> **OCA:** PCLP's WNA will impact low-income customers because it will increase bills for low-income customers during warmer-than-normal weather and create greater volatility in customers' bills, making it more difficult to plan and budget for natural gas bills.

(8) How the ratemaking mechanism and rate design impact customer rate stability principles.

> **OCA:** As proposed, PCLP's proposed WNA will increase monthly bill volatility for customers whose usage does not precisely match the monthly consumption volatility for their rate class as a whole. Rather, customers who use more or less natural gas than the average customer will see their bill vary more as the proposed WNA follows the ups and downs of the rate class as a whole. This obscures the

delivery charge price signal and makes it harder for a customer to predict what their monthly bill will be based on their usage alone.

(9) How weather impacts utility revenue under the ratemaking mechanism and rate design.

> **<u>OCA:</u>** Weather will directly impact PCLP's revenue under the proposed WNA.

(10) How the ratemaking mechanism and rate design impact the frequency of rate case filings and affect regulatory lag.

> **<u>OCA:</u>** PCLP has presented no basis to conclude that the proposed WNA will benefit customers by reducing the frequency of rate case filings or otherwise having an effect on regulatory lag.

(11) If or how the ratemaking mechanism and rate design interact with other revenue sources, such as Section 1307 automatic adjustment surcharges, 66 Pa.C.S. § 1307 (relating to sliding scale of rates; adjustments), riders such as 66 Pa.C.S. § 2804(9) (relating to standards for restructuring of electric industry) or system improvement charges, 66 Pa.C.S. § 1353 (relating to distribution system improvement charge).

> **<u>OCA:</u>** The WNA will not interact with other revenue sources.

(12) Whether the alternative ratemaking mechanism and rate design include appropriate consumer protections.

> **<u>OCA:</u>** PCLP has proposed no consumer protections for its WNA. Other Pennsylvania NGDCs which have implemented WNAs have adopted consumer protection measures, including the implementation of a deadband, the exclusion of May from the months in effect, and a cap on WNA revenues during certain shoulder months. PCLP has proposed no such protections.

(13) Whether the alternative ratemaking mechanism and rate design are understandable to consumers.

> **<u>OCA:</u>** PCLP has provided no evidence that the WNA is understandable to consumers.

(14) How the ratemaking mechanism and rate design will support improvements in utility reliability.

> **<u>OCA:</u>** PCLP has not presented any evidence that implementing the WNA will support improvements in its reliability.

BEFORE THE
PENNSYLVANIA PUBLIC UTILITY COMMISSION

Pennsylvania Public Utility Commission	:	
	:	Docket No. R-2024-3052357
v.	:	
	:	
Pike County Light & Power Company (Gas)	:	

VERIFICATION

I, Karl R. Pavlovic, hereby state that the facts above set forth in my Direct Testimony, OCA Statement 3, are true and correct to the best of my knowledge, information, and belief and that I expect to be able to prove the same at a hearing held in this matter. I understand that the statements herein are made subject to the penalties of 18 Pa.C.S. § 4904 (relating to unsworn falsification to authorities).

DATED: April 3, 2025

Signature: Karl R. Pavlovic

Address: 22 Brooks Avenue,
Gaithersburg, MD 20877

COMMONWEALTH OF PENNSYLVANIA

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May 1, 2025

Via Electronic Mail
Administrative Law Judge Marta Guhl (mguhl@pa.gov)
Administrative Law Judge Alphonso Arnold III (alphonarno@pa.gov)
Office of Administrative Law Judge
Pennsylvania Public Utility Commission
Commonwealth Keystone Building
400 North Street, 2nd Floor
Harrisburg, PA 17120

Re: Pennsylvania Public Utility Commission
v.
Pike County Light & Power Company - Gas
Docket No. R-2024-3052357

Dear Honorable Judges Guhl and Arnold:

Please find enclosed a copy of the Rebuttal Testimony being submitted on behalf of the Office of Consumer Advocate in this proceeding, as follows:

- OCA Statement 3R: Rebuttal Testimony of Karl Pavlovic
- Exhibits
- Verification of Karl Pavlovic

Copies have been served on the parties as indicated on the enclosed Certificate of Service.

Respectfully submitted,

/s/ Jacob D. Guthrie
Jacob D. Guthrie, Esq.
Assistant Consumer Advocate
PA Attorney I.D. # 334367
Email: JGuthrie@paoca.org

Enclosures

cc: Secretary Matthew L. Homsher (Cover Letter and Certificate of Service Only)
Certificate of Service

CERTIFICATE OF SERVICE

Pennsylvania Public Utility Commission	:	
	:	
v.	:	Docket No. R-2024-3052357
	:	
Pike County Light & Power Company - Gas	:	
	:	

I hereby certify that I have this day served a true copy of the following documents, the Office of Consumer Advocate's Rebuttal Testimony, as follows:

- OCA Statement 3R: Rebuttal Testimony of Karl Pavlovic
- Exhibits
- Verification of Karl Pavlovic

upon parties of record in this proceeding in accordance with the requirements of 52 Pa. Code § 1.54 (relating to service by a participant), in the manner and upon the persons listed below.

Dated this 1st day of May, 2025.

<u>SERVICE BY E-MAIL ONLY</u>

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Dated: May 1, 2025

OCA St. No. 3R

BEFORE THE

PENNSYLVANIA PUBLIC UTILITY COMMISSION

Pennsylvania Public Utility Commission	**)**	
v.	**)**	**Docket No. R-2024-3052357**
Pike County Light & Power Company (Gas)	**)**	

REBUTTAL TESTIMONY OF

KARL RICHARD PAVLOVIC

ON BEHALF OF

THE PENNSYLVANIA OFFICE OF CONSUMER ADVOCATE

May 1, 2025

TABLE OF CONTENTS

I. STATEMENT OF QUALIFICATIONS

Q. PLEASE STATE YOUR NAME AND BUSINESS ADDRESS.

A. My name is Karl Richard Pavlovic. My business address is 22 Brooks Avenue, Gaithersburg, MD 20877.

Q. ARE YOU THE SAME KARL RICHARD PAVLOVIC WHO SUBMITTED DIRECT TESTIMONY ON APRIL 3, 2025 IN THIS PROCEEDING?

A. Yes. Exhibit KRP-1 to my April 3, 2025 direct testimony summarizes my qualifications and experience and contains a complete list of my engagements as an expert and/or expert witness in matters before state and federal regulatory agencies.

II. PURPOSE OF REBUTTAL TESTIMONY

Q. ON WHOSE BEHALF ARE YOU TESTIFYING?

A. I am testifying on behalf of the Pennsylvania Office of Consumer Advocate ("OCA").

Q. WHAT IS THE PURPOSE OF YOUR TESTIMONY?

A. My rebuttal testimony corrects Table 7 in my OCA St. No. 3 Direct Testimony and responds to the Statement No. 1 Direct Testimony of Mark D. Ewen regarding (1) OSBA's support and acceptance of PCLP's minimum-size method of classification and allocation of mains to classes and (2) OSBA's proposed class revenue allocation.

Q. HOW IS YOUR TESTIMONY ORGANIZED?

A. My testimony is organized as follows. Section III A summarizes my findings, conclusions and recommendations. Section III B corrects Table 7 from my Direct Testimony. Section III C addresses OSBA's acceptance of the minimum-size method of classification and allocation of mains. Section III D addresses OSBA's proposed class revenue allocation.

Q. ARE YOU SPONSORING ANY EXHIBITS?

A. Yes. I am sponsoring a single exhibit.

- Exhibit KRP- 1R - Corrected Exhibit KRP-3 to my direct testimony.

III. DISCUSSION

A. SUMMARY

Q. PLEASE SUMMARIZE THE SUBSTANCE OF YOUR TESTIMONY.

A. As detailed below.

- I recommend the Commission reject OSBA's use of the GCOSS as a guide to revenue allocation.
- I recommend the Commission reject OSBA's proposed revenue allocation.

B. CORRECTED TABLE 7 IN OCA STATEMENT NO. 3

Q. WHAT ARE THE CORRECTIONS YOU ARE MAKING TO TABLE 7?

A. Table 7[1] was intended to reproduce Exhibit KRP-3. In that regard there are two corrections.

First, left to right the first, third and fourth columns of Table 7 do not reflect the entries in the first, third and fourth columns of Exhibit KRP-3. Table 7 (Revised) below shows this correction.

Second, the second column of both Table 7 and Exhibit KRP-3 does not reflect OCA witness Roger's recommended revenue increase of $762,400.[2] The second column

[1] OCA Statement No. 3 Direct Testimony of Karl Richard Pavlovic (Pavlovic Direct), page 20, lines 5-7.
[2] OCA Statement No. 1 Direct Testimony of Jennifer Rogers, Schedule JLR-1.

of Table 7 (Revised) below also shows this correction. Exhibit KRP-1R to this testimony shows this correction to Exhibit KRP-3 (Revised).

OCA St. No. 3 Table 7 (Revised) - PCLP Current Revenue Distribution and OCA Recommended Revenue Distribution Scaled Back per OCA Recommended Revenue Requirement[3]				
Customer Class	**Current**	**Proposed**	**Percent Increase**	**Class Percent Distribution**
SC1 Residential Space Heating	863,119	1,446,355	67.57%	76.50%
SC1 Residential Domestic	26,369	41,617	57.83%	2.00%
SC1 Residential Other	3,578	5,865	63.92%	0.30%
SC2 General Service Commercial	82,879	152,257	83.71%	9.10%
SC2 Commercial Space Heating	110,389	201,877	82.88%	12.00%
Total	1,086,334	1,847,972	70.11%	100.00%

C. OSBA's ACCEPTANCE OF PCLP's MINIMUM-SIZE METHOD

Q. WHAT IS WITNESS EWEN'S TESTIMONY REGARDING PCLP'S MINIMUM-SIZE METHOD?

A. In testimony, witness Ewen appears to state that PCLP does not include a customer component for mains,[4] which I presume is a typographical error for later he correctly states that PCLP uses a peak demand allocator for mains costs classified as demand-related and number of customers for customer-related mains costs[5] and because he uses PCLP's GCOSS to calculate revenue-costs ratios as a guide to revenue allocation.[6] Witness Ewen

[3] Exhibit KRP-3.
[4] OSBA Statement No. 1 Direct Testimony of Mark D. Ewen (Ewen Direct), page 5 line 21.
[5] Ewen Direct, page 6 lines 27 – 29.
[6] Ewen Direct, page 7 lines 13 – 18.

then states that he takes no exception to the method because the Commission has previously accepted PCLP's use of the minimum-size method,[7] but offers no evidence in support of either his or PCLP's use of the minimum-size method.

Q. WHAT IS YOUR RESPONSE TO WITNESS EWEN'S TESTIMONY REGARDING PCLP's USE OF THE MINIMUM-SIZE METHOD?

A. My response is two-fold. First, as I demonstrated in my direct testimony, there is no basis in theory, system design and operating practice, or empirical quantitative data to support PCLP's use of the minimum-size method to classify as customer-related any portion of its distribution mains costs.[8] As evidence of this, when I requested PCLP's planning, design, and operating standards and procedures for Plant Account 376, the documents provided clearly demonstrate that the number of customers on PCLP's distribution system plays no role in how PCLP designs, plans, and operates the plant recorded in this account number.[9] Second, as I explained in my direct testimony the fact that PCLP has used the minimum-size method in past rate proceedings is not dispositive because cost classification in a rate proceeding is a forward-looking exercise that depends only on the planning, design and operation of a gas distribution system.[10] As the Commission has previously noted, the best-suited cost of service methodology depends on the circumstances on a case-by-case basis.[11]

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[7] Ewen Direct, page 7 lines 1 – 13.
[8] Pavlovic Direct, page 7 line 15 to page 13 line 3.
[9] Pavlovic Direct, page 8 line 9 to page 9 line 2.
[10] Pavlovic Direct, page 9 line 15 to page 10 line 5.
[11] Pennsylvania Public Utility Commission v. PECO Energy – Gas Division, R-2020-3018929, 7/17/21 Opinion and Order at 230 - "We agree with PAIEUG that the inherent distinctions between utilities and rate cases may result in different methodologies to be reasonable for different reasons. In other words, the best-suited ACCOSS may depend on the circumstances of the situation on a case-by-case basis."

Q. WHAT IS YOUR RECOMMENDATION REGARDING OSBA ACCEPTANCE OF PCLP'S GCOSS AS A GUIDE TO REVENUE ALLOCATION?

A. For the reasons above I recommend the Commission reject OSBA's use of the GCOSS as a guide to revenue allocation.

D. OSBA'S CLASS REVENUE ALLOCATION

Q. WHAT CLASS REVENUE ALLOCATION DOES OSBA PROPOSE?

A. Witness Ewen does not present in his testimony a proposed class revenue allocation, instead he provides only a proposed allocation of the revenue increase to classes.[12] He does, however, calculate both in his workpapers.[13] Examination of his workpaper calculations reveals that the total and class current revenues he uses to calculate his proposed revenue allocation in his workpapers[14] are not the current revenues in PLCP's cost study.[15] In Table 1R below I have calculated the class revenue allocation implied by his proposed allocation of the increase in revenue using PCLP's current revenues. As a consequence, the class revenue increases in Table 1R deviate slightly from the class revenue increases shown in Witness Ewens Table IEc-4.

[12] Ewen Direct, page 10 Table IEc-3 and page 11 Table IEc-4.
[13] IEc WP1 PCL&P Gas ECOSS Replication.xlsx, tab HTY to FTY, rows 58 and 60.
[14] IEc WP1 PCL&P Gas ECOSS Replication.xlsx, tab HTY to FTY, row 50.
[15] PCLP Exhibit G-6, Schedule PMN-2-G, page 1, line 6

Table 1R - OSBA Proposed Class Revenue Allocation					
Customer Class	**Current**[16]	**Proposed Revenue Increase**[17]	**Proposed Revenue Allocation**	**Percent Increase**	**Class Percent Distribution**
SC1 Residential Space Heating	863,119	909,400	1,772,519	105.36%	84.80%
SC1 Residential Domestic	26,369	44,100	70,469	167.24%	3.37%
SC1 Residential Other	3,578	3,650	7,228	102.01%	0.35%
SC2 General Service Commercial	82,879	3,500	86,379	4.22%	4.13%
SC2 Commercial Space Heating	110,389	43,200	153,589	39.13%	7.35%
Total	1,086,334	1,003,850	2,090,184	92.41%	100.00%

Q. HOW AND WHY DID OSBA DEVELOP THE REVENUE INCREASES IN TABLE 1R?

A. Witness Ewen states that the proposed revenue allocation brings the revenues of the combined SC1 and combined SC2 classes into line with the combined costs of the classes per PCLP's minimum-size GCOSS.[18] As can be seen in his Table IEc-4 which measures cost by revenue/cost ratio where full cost recovery is a ratio of 1.00.[19]

Q. HOW DO OSBA'S PROPOSED REVENUE INCREASE PERCENTAGES COMPARE TO THOSE OF PCLP AND OCA?

A. Table 2R below compares class by class the percentage increases proposed by OSBA, PCLP and OCA.

[16] Exhibit G-8, pages 1 and 2.
[17] Ewen Direct, page 11, Table IEc-4.
[18] Ewen Direct, page 11 lines 2-5..
[19] Ewen Direct, page 11, Table IEc-4.

Table 2R - Comparison of OSBA Revenue Increase Percentages with the Revenue Increase Percentages proposed by PCLP and OCA			
Customer Class	**OSBA**	**PCLP[20]**	**OCA[21]**
SC1 Residential Space Heating	105.36%	99.6%	79.8%
SC1 Residential Domestic	167.24%	94.2%	54.6%
SC1 Residential Other	102.01%	99.8%	83.1%
SC2 General Service Commercial	4.22%	28.1%	123.6%
SC2 Commercial Space Heating	39.13%	27.7%	121.2%
Total	92.41%	86.8%	86.8%

The OCA percentages are based on PCLP's GCOSS without minimum-size classification and allocation adjusted so as to move the relative rate of return halfway to full cost recovery.[22]

Q. HOW DOES OSBA'S PROPOSED REVENUE ALLOCATION COMPARE TO PCLP'S AND OCA'S PROPOSED CLASS REVENUE ALLOCATIONS?

A. Table 3R below compares OSBA's revenue allocation with PCLP's revenue allocation and OCA's revenue allocation which is based on PCLP's GCOSS without minimum-size classification and allocation as noted above.

[20] Pavlovic Direct, page 16, Table 3..
[21] Pavlovic Direct, page 19, Table 6.
[22] Pavlovic Direct, page 18, lines 5-8 and Table 5.

Table 3R - Comparison of OSBA Revenue Allocation with the Revenue Allocations proposed by PCLP and OCA			
Customer Class	**OSBA**	**PCLP**[23]	**OCA**[24]
SC1 Residential Space Heating	1,772,519	1,723,140	1,551,870
SC1 Residential Domestic	70,469	51,209	40,754
SC1 Residential Other	7,228	7,150	6,551
SC2 General Service Commercial	86,379	106,165	185,343
SC2 Commercial Space Heating	153,589	141,021	244,167
Total	2,090,184	2,028,685	2,028,685

Q. WHAT IS YOUR RESPONSE TO OSBA'S PROPOSED REVENUE ALLOCATION?

A. My response is three-fold.

First, I note that OSBA's proposed revenue allocation rests on an overall revenue that is $61,499 ($2,090,184 minus $2,028,685) higher than PCLP's and OCA's revenue. Witness Ewen provides no explanation for this discrepancy.

Second, OSBA's proposed revenue allocation takes as a guide PCLP's minimum-size GCOSS, which is not consistent with cost causation and thereby over allocates costs to the SC1 classes and under allocates costs to the SC2 classes.[25] Thus, as I noted in my direct testimony regarding PCLP's revenue allocation,[26] under OSBA's revenue allocation the SC1 classes that underearned will now over earn and the SC2 classes that over earned will now underearn.

23 Exhibit G-8, pages 1 and 2.
24 Pavlovic Direct, page 19, Table 6 and Exhibit KRP-2.
25 Pavlovic Direct, page 13 lines 4-16.
26 Pavlovic Direct, page 17 line 12 to page 18 line 2.

Third, as can be seen in Table 2R above, OSBA's proposed class revenue allocations impose truly massive revenue increases on the residential classes and much reduced increases on the commercial classes.

Q. WHAT IS YOUR RECOMMENDATION REGARDING OSBA'S PROPOSED REVENUE ALLOCATION?

A. For the reasons above I recommend the Commission reject OSBA's proposed revenue allocation.

Q. DOES THIS CONCLUDE YOUR TESTIMONY?

A. Yes. However, I reserve the right to supplement this testimony if further information is provided by OSBA.

Exhibit KRP-1R

Customer Class	Current	Recommended	Percent Increase	Class Percent Distribution
SC1 Residential Space Heating	863,119	1,446,355	67.57%	76.50%
SC1 Residential Domestic	26,369	41,617	57.83%	2.00%
SC1 Residential Other	3,578	5,865	63.92%	0.30%
SC2 General Service Commercial	82,879	152,257	83.71%	9.10%
SC2 Commercial Space Heating	110,389	201,877	82.88%	12.00%
Total	1,086,334	1,847,972	70.11%	100.00%

OCA Revenue Requirement Increase 762,400

BEFORE THE
PENNSYLVANIA PUBLIC UTILITY COMMISSION

Pennsylvania Public Utility Commission	:	Docket No. R-2024-3052357
v.	:	
Pike County Light & Power Company (Gas)	:	

VERIFICATION

I, Karl R. Pavlovic, hereby state that the facts above set forth in OCA Statement 3R, the Rebuttal Testimony of Karl R. Pavlovic, are true and correct to the best of my knowledge, information, and belief and that I expect to be able to prove the same at a hearing held in this matter. I understand that the statements herein are made subject to the penalties of 18 Pa.C.S. § 4904 (relating to unsworn falsification to authorities).

DATED: May 1, 2025

Signature: Karl R. Pavlovic

Karl R. Pavlovic

Address: 22 Brooks Avenue,
Gaithersburg, MD 20877

Exhibit KRP-1R

Customer Class	Current	Recommended	Percent Increase	Class Percent Distribution
SC1 Residential Space Heating	863,119	1,446,355	67.57%	76.50%
SC1 Residential Domestic	26,369	41,617	57.83%	2.00%
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<u>OCA Revenue Requirement Increase</u> 762,400

OCA St. No. 3-SR

BEFORE THE

PENNSYLVANIA PUBLIC UTILITY COMMISSION

Pennsylvania Public Utility Commission	)	
v.	)	**Docket No. R-2024-3052357**
Pike County Light & Power Company (Gas)	)	

REBUTTAL TESTIMONY OF

KARL RICHARD PAVLOVIC

ON BEHALF OF

THE PENNSYLVANIA OFFICE OF CONSUMER ADVOCATE

May 15, 2025

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I. STATEMENT OF QUALIFICATIONS

Q. PLEASE STATE YOUR NAME AND BUSINESS ADDRESS.

A. My name is Karl Richard Pavlovic. My business address is 22 Brooks Avenue, Gaithersburg, MD 20877.

Q. ARE YOU THE SAME KARL RICHARD PAVLOVIC WHO SUBMITTED DIRECT AND REBUTTAL TESTIMONIES ON APRIL 3, 2025 AND MAY 1, 2025 IN THIS PROCEEDING?

A. Yes. Exhibit KRP-1 to my April 3, 2025 direct testimony summarizes my qualifications and experience and contains a complete list of my engagements as an expert and/or expert witness in matters before state and federal regulatory agencies.

II. PURPOSE OF SURREBUTTAL TESTIMONY

Q. ON WHOSE BEHALF ARE YOU TESTIFYING?

A. I am testifying on behalf of the Pennsylvania Office of Consumer Advocate ("OCA").

Q. WHAT IS THE PURPOSE OF YOUR TESTIMONY?

A. My surrebuttal testimony addresses (1) PCLP Statement No. 1-R Rebuttal Testimony of Paul M. Normand which responds to OCA's recommendations that PCLP's minimum-size GCOSS be rejected and the residential customer charge remain at its current level; (2) PCLP's Statement No. 2 Rebuttal Testimony of Charles and Matthew Lenns which argues against OCA's weather normalization adjustment (WNA) recommendation; and (3) OSBA Statement No. 1-R Rebuttal Testimony of Mark D. Ewen which responds to OCA's rejection of PCLP's minimum-size GCOSS and OCA's proposed class revenue allocation.

Q. HOW IS YOUR TESTIMONY ORGANIZED?

A. My testimony is organized as follows. Section III.A summarizes my findings, conclusions and recommendations. Section III.B addresses PCLP's and OSBA's GCOSS rebuttal testimonies. Section III.C addresses PCLP's residential customer charge rebuttal testimony. Section III.D addresses OSBA's revenue allocation rebuttal testimony.

Q. ARE YOU SPONSORING ANY EXHIBITS?

A. No.

III. DISCUSSION

A. SUMMARY

Q. PLEASE SUMMARIZE THE SUBSTANCE OF YOUR SURREBUTTAL TESTIMONY.

A. As detailed below:

- The rebuttal testimonies of PCLP and OSBA provide no grounds for modification or withdrawal of my recommendation that the Commission reject PCLP's GCOSS with minimum-size classification and allocation and accept PCLP's GCOSS without minimum-size classification and allocation as a guide to revenue allocation.
- The rebuttal testimony of PCLP provides no grounds for modification or withdrawal of my recommendation that the residential customer charge be maintained at its current level in order to incentivize residential customer conservation and give residential customers greater control over their distribution bills.
- The rebuttal testimony of PCLP provides no grounds for modification or withdrawal of my recommendation that the Commission reject PCLP's proposed WNA.

B. PCLP AND OSBA GCOSS REBUTTAL TESTIMONY

1. PCLP GCOSS REBUTTAL TESTIMONY

Q. WHAT WAS YOUR DIRECT TESTIMONY REGARDING PCLP'S GCOSS WITH MINIMUM-SIZE CLASSIFICATION AND ALLOCATION?

A. In my direct testimony I demonstrated that there is no basis in theory, system design and operating practice, or empirical quantitative data to support PCLP's use of the minimum-size method to classify as customer-related any portion of mains distribution plant costs account 376.[1] I concluded that the PCLP's mains distribution costs in plant account 376 are properly classified as 100 percent demand-related and properly allocated to classes using PCLP's demand allocation factors.[2]

Q. WHAT IS PCLP'S REBUTTAL TESTIMONY REGARDING ITS GCOSS WITH MINIMUM-SIZE CLASSIFICATION AND ALLOCATION OF ACCOUNT 376?

A. Witness Normand's rebuttal testimony consists of four assertions that are intertwined with his response to OCA's residential customer charge proposal, which I discuss below. First, he states that he used the minimum-size method to calculate a customer component (1) to provide continuity with PCLP's last GCOSS; and (2) to recognize that the vast majority of PCLP's mains are 2" or less, closer to customers and influenced by population density, while the larger mains are much more peak demand related.[3] Second, he states that the primary purpose of the smaller mains (2" or less), which he names "local facilities," is to

[1] OCA Statement No. 3 Direct Testimony of Karl Richard Pavlovic (Pavlovic Direct), page 7 line 15 to page 12 line 14.
[2] Pavlovic Direct, page 12 line 15 to page 4 line 3.
[3] PCLP Statement No. 1-R Rebuttal Testimony of Paul M. Normand (Normand Rebuttal), page 4 lines 2-12.

connect customers to the gas grid which makes those local facilities more related to customer counts than their demand load.[4] Third, on that basis he disagrees with my testimony that PCLP's use of the minimum-size classification of any portion of PCLP's mains as customer-related contravenes the principle of cost causation.[5] Fourth, he disagrees with my testimony that the minimum-size method does not reflect the planning, design and operation of PCLP's distribution system by asserting that the "major factor driving mains investment is design day [demand]" followed by customer density and geography.[6]

Q. WHAT IS YOUR RESPONSE TO WITNESS NORMAND'S REBUTTAL TESTIMONY?

A. My response is four-fold.

First, as to continuity as I explained in my direct testimony the fact that PCLP used the minimum-size method in the past is not dispositive because cost classification in a rate proceeding is a forward-looking exercise that depends only on the planning, design and operation of a gas distribution system.[7] As the Commission has previously noted, the best-suited cost of service methodology depends on the circumstances on a case-by-case basis.[8]

Second, witness Normand provides no evidence supporting his assertion that because smaller mains are closer to customers than primary facilities, they entail customer-related costs in addition to their demand-related costs.

[4] Normand Rebuttal, page 8 lines 5-12.
[5] Normand Rebuttal, page 8 lines12-14; see also Pavlovic Direct, page 7 line 17 to page 8 line 2.
[6] Normand Rebuttal, page 8 lines 15-22; see also Pavlovic Direct, page 10 lines 2-5.
[7] Pavlovic Direct, page 9 line 19 to page 10 line 4.
[8] Pennsylvania Public Utility Commission v. PECO Energy – Gas Division, R-2020-3018929, 7/17/21 Opinion and Order at 230 - "We agree with PAIEUG that the inherent distinctions between utilities and rate cases may result in different methodologies to be reasonable for different reasons. In other words, the best-suited ACCOSS may depend on the circumstances of the situation on a case-by-case basis."

Third, witness Normand conflates the word “related” with the technical cost analysis terms “demand-related” and “customer-related.” That customers are undisputedly related physically to the distribution system to which they are connected, does not constitute evidence that they are a cost causative factor of the distribution system. More importantly, with this conflation he commits the fallacy of begging the question by assuming at the outset that customers are a cost causative factor for the distribution system.

Fourth, witness Normand’s assertions (1) that the principle of cost causation is not contravened by minimum-size classification of PCLP’s mains; and (2) that PCLP’s minimum does reflect the planning, design and operation of PCLP’s distribution system both rest on his unsupported and fallacious assumption that there is a customer-related component to PCLP’s mains.

Q. WHAT DO YOU CONCLUDE REGARDING WITNESS NORMAND’S GCOSS REBUTTAL TESTIMONY?

A. For the reasons above, I conclude that witness Normand’s rebuttal testimony provides no grounds for modification or withdrawal of my recommendation in my direct testimony that the Commission: (1) reject PCLP’s GCOSS with minimum-size classification and allocation; and (2) accept PCLP’s GCOSS without minimum-size classification and allocation as a guide to revenue allocation.

2. OSBA GCOSS REBUTTAL TESTIMONY

Q. WHAT IS OSBA'S REBUTTAL TESTIMONY REGARDING THE GCOSS WITH MINIMUM-SIZE CLASSIFICATION AND ALLOCATION OF ACCOUNT 376?

A. OSBA witness Ewen's rebuttal testimony consists of (1) two rationales that purport to support the GCOSS's assumption that there is a customer cost component to PCLP's mains;[9] (2) the assertion that the GCOSS with minimum-size classification is consistent with PLCP's previous proceedings;[10] and (3) the assertion that OCA IR-7-3 provides no evidence that demand is the only cause or driver of PCLP's distribution mains.[11]

The first rationale is the case of an existing distribution system expanding into a new area to connect new customers.[12] Witness Ewen states that in such an expansion the system will incur the additional costs to increase mains footage to connect to the new customers. Next, he asserts, without supporting evidence, that some of these additional costs are related to increased demand and some to the need to interconnect customers. He then reasons backwards that most of the existing distribution system consists of such expansions and concludes that most of the distribution system is related to both demand and customers.

The second rationale rests on the assertion that more footage of mains is required to interconnect many small customers than to connect one larger customer with the same aggregate load, asserting that this conceptual argument is supported by an aggregate industry statistical analysis.[13]

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[9] OSBA Statement No. 1-R Rebuttal Testimony of Mark D. Ewen (Ewen Rebuttal), page 2 lines 18-26 and page 2 line 27 to page 3 line 3.
[10] Ewen Rebuttal, page 3 lines 4-7.
[11] Ewen Rebuttal, page 3 lines 11-23; see also Pavlovic Direct, page 8 line 3 to page 9 line 2.
[12] Ewen Rebuttal, page 2 lines 18-26.
[13] Ewen Rebuttal, page 2, line 27 to page 3 line 3.

Q. WHAT IS YOUR RESPONSE TO WITNESS EWEN'S REBUTTAL TESTIMONY?

A. My response is four-fold.

First, regarding the first rationale, witness Ewen conflates the word "related" with the technical cost analysis terms "demand-related" and "customer-related." That customers are undisputedly related physically to the distribution system to which they are connected, does not constitute evidence that they are a cost causative factor of the distribution system. More importantly, with this conflation witness Ewen commits the fallacy of begging the question by assuming at the outset that customers are a cost causative factor for the distribution system.

Second, regarding the second rationale, there are two problems. First, as he admits, the argument is a conceptual thought experiment that is easily countered with the observation that less mains footage would be required to serve many small customers in a densely populated urban area than to serve a single larger customer with the same aggregate load in a rural area. Second, the statistical analysis he cites is a regression analysis of the number of customers and miles of mains that found a statistically significant correlation between the number of customers and miles of mains.[14] However, correlation does not prove causation and the cited study is not evidence that the number of customers is a cost causative factor for gas mains.

Third, as I pointed out above, that PCLP used the minimum-size method in the past is not dispositive because cost classification in a rate proceeding is a forward-looking exercise

[14] OCA-OSBA-I-1.

that depends only on the planning, design and operation of a natural gas distribution system.[15]

Fourth, regarding OCA IR-7-3, I conclude from that document that the number of customers plays no role in PCLP's design, planning, and operation of its gas distribution system, not as witness Ewen has it that the sole cause or driver of costs associated with distribution mains.

Q. WHAT DO YOU CONCLUDE REGARDING WITNESS EWEN'S GCOSS REBUTTAL TESTIMONY?

A. For the reasons above, I conclude that OSBA witness Ewen's rebuttal testimony provides no grounds for modification or withdrawal of my recommendation in my direct testimony that the Commission reject PCLP's GCOSS with minimum-size classification and allocation and accept PCLP's GCOSS without minimum-size classification and allocation as a guide to revenue allocation.

C. PCLP RESIDENTIAL CUSTOMER CHARGE REBUTTAL TESTIMONY

Q. WHAT WAS YOUR DIRECT TESTIMONY REGARDING THE RESIDENTIAL CUSTOMER CHARGE?

A. In my direct testimony, I explained that PCLP's proposed increase to the residential customer charge provides no discernible rate making benefit because the customer charge is not a real actionable price signal to residential customers.[16] Placing the proposed rate

[15] Pavlovic Direct, page 10 lines 10-22.
[16] Pavlovic Direct, page 22 lines 3-9.

increase in the volumetric charge, which is an actionable price signal, will provide residential customers with an increased incentive to engage in conservation and the ability to exercise control over a larger portion of their monthly natural gas distribution bill and for those reasons I recommended maintaining the residential customer charge at its current level.[17]

Q. WHAT IS PCLP'S REBUTTAL TESTIMONY REGARDING THE RESIDENTIAL CUSTOMER CHARGE?

A. Witness Normand states that he does not agree with my recommendation because, as he calculates it, the current and proposed residential customer charges are only a very small fraction of the actual service lateral and metering costs to connect the customer to the gas grid, resulting in a volumetric rate for fixed cost recovery.[18] To support this proposition he relies on four points.

First, he notes that natural gas distribution costs are fixed costs and have no relationship to volumetric consumption and then asserts that the use of volumetric charges results in subsidies that move cost recovery away from true cost of service as shown by the GCOSS.[19]

Second, he prepares and presents Table GR2 that for each customer class compares left-to-right (1) the current customer <u>charge</u>, (2) the GCOSS calculated customer <u>cost</u> of services and meters, (3) the GCOSS calculated total customer <u>cost</u> and (4) the proposed

[17] Pavlovic Direct, page 22 lines 9-17.
[18] Normand Rebuttal, page 9 lines 1-8.
[19] Normand Rebuttal, page 3 lines 1-5.

customer charge. To be clear, the total customer cost includes both (i) the customer cost of services and meters and (ii) the minimum-size customer cost of mains.[20]

Third, witness Normand notes that per Table GR2 the current and proposed customer charges are a very small fraction of the calculated cost of services and meters and that the proposed customer charges recover only a small portion of the customer cost of services and meters which are in turn lower than the total customer costs.[21]

Fourth, he asserts that it is important to note that the customer costs of services and meters are many times more than the customer charges, which means that the proposed customer charges are justified and the unrecovered customer costs are recovered through the volumetric charge.[22]

Q. WHAT IS YOUR RESPONSE TO PCLP WITNESS NORMAND'S REBUTTAL TESTIMONY?

A. My response is three-fold.

First, PCLP witness Normand does not anywhere in his rebuttal testimony, address my testimony that the customer charge is not a real actionable price signal, while the volumetric charge is a real actionable price signal.

Second, I note that witness Normand does not define "subsidies." Presumably, he views these to be negative outcomes, but so long as they are undefined, it is not possible for OCA or the Commission to either affirm or deny that they are actionable negative outcomes. It

[20] Normand Rebuttal, page 5 lines 1-4 and Table GR2, citing to Exhibit G-6, Schedule PMN-5-g, page 4 lines 26 and 27 and Exhibit G-8, pages 3 and 4).
[21] Normand Rebuttal, page 5 lines 5-11.
[22] Normand Rebuttal, page 6, lines 1-11.

is also impossible to weigh the undefined and unsupported purported negative outcomes against the positive outcomes of incentivizing residential customer conservation and greater residential customer control over distribution bills that result from recovering customer costs through the volumetric charge.

Third, witness Normand asserts that both customer costs and local facilities cost should be recovered through the fixed customer charge but offers no evidence other than his unsupported assertion that not recovering these costs through the customer charge leads to the undefined purported negative outcome of subsidies.

Q. WHAT DO YOU CONCLUDE REGARDING WITNESS NORMAND'S REBUTTAL TESTIMONY?

A. For the reasons above, I conclude that witness Normand's rebuttal testimony provides no grounds for modification or withdrawal of my recommendation in my direct testimony that the residential customer charge be maintained at its current level in order to incentivize customer conservation and give customers greater control over their distribution bills.

D. PCLP'S WEATHER NORMALIZATION ADJUSTMENT REBUTTAL TESTIMONY

Q. WHAT WAS YOUR DIRECT TESTIMONY REGARDING THE PROPOSED WEATHER NORMALIZATION ADJUSTMENT?

A. In my direct testimony, I laid out my understanding of PCLP's proposed weather normalization adjustment (WNA),[23] noting that it: (1) would likely increase the volatility

[23] Pavlovic Direct, page 23 line 4 to page 24 line18.

of an individual customer's bill;[24] (2) would obscure the delivery charge price signal incentivizing conservation and bill control;[25] (3) does not address an unfulfilled PCLP financial cash flow need;[26] (4) would reduce PCLP's incentive to reduce the costs of service via efficiency savings;[27] (5) would have resulted in residential customers as a whole paying for 14% more gas than they used if it was in effect from October 2023 through May 2024;[28] and (6) fails to address all 14 policy factors the Commission considers when ruling on alternative rate making mechanisms such as the proposed WNA.[29] I recommended that the Commission not adopt the proposed WNA[30] and in the alternative the Commission exclude the proposed Heat Sensitivity Factor and include a deadband of 5%.[31]

Q. WHAT IS PCLP'S REBUTTAL TESTIMONY RGARDING YOUR WNA TESTIMONY?

A. PCLP witnesses Charles and Matthew Lenns assert (1) that the WNA mechanism will benefit residential customers because it provides PCLP a full and fair opportunity to earn the revenue requirement set by the Commission thus allowing PCLP to go longer between rate cases;[32] (2) that from a financial perspective the WNA offsets the risk of recovery of fixed costs through volumetric rates and thus provides PCLP with a full and fair opportunity to earn the revenue requirement set by the Commission;[33] (3) that the WNA will have no impact on PCLP's drive to achieve efficiencies because PCLP is always trying

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[24] Pavlovic Direct, page 25 lines 1-10.
[25] Pavlovic Direct, page 25, lines 10-14.
[26] Pavlovic Direct, page 25 line 15 to page 26 line 2.
[27] Pavlovic Direct, page 26 lines 3-14.
[28] Pavlovic Direct, page 28 lines 1-12.
[29] Pavlovic Direct, page 29 lines 1-19 and Exhibit KRP-4.
[30] Pavlovic Direct, page 30 lines 1-8.
[31] Pavlovic Direct, page 27 lines 3-20.
[32] PCLP Statement No. 2-r Rebuttal Testimony of Charles and Matthew Lenns (Lenns Rebuttal), page 34 lines 5-14.
[33] Lenns Rebuttal, page 34 line 15 to page 35 line 2.

to reduce its operating costs and thus extend the period between rate cases;[34] (4) that the PCLP will eliminate the heat sensitivity factor and use the mechanism of other Pennsylvania utilities;[35] (5) that the OCA proposed deadband of 5% would negate the value of the WNA;[36] and (6) that the $76,716 paid by customers under the WNA hypothetically applied to the period October 2023 through May 2024 that is calculated in Table 9 of my testimony would have raised PCLP's overall rate of return from 3.34% to 4.14%.[37]

Q. WHAT IS YOUR RESPONSE TO PCLP'S REBUTTAL TESTIMONY?

A. My response is five-fold.

First, witnesses Lenns' points 1 and 2 simply spin my criticisms of PCLP's WNA into the highly speculative benefit of extending the period between future rate cases and do so by admitting that the WNA will improve PCLP's ability to achieve the revenue requirement set by the Commission.

Second, witnesses Lenns' point 3 together with their points 1 and 2 actually validates my testimony that the WNA will reduce PCLP's incentive to pursue the operating cost efficiencies they otherwise would pursue in the absence of the WNA.

Third, regarding eliminating the heat sensitivity factor, saying that PCLP will replace it with the mechanisms used by other Pennsylvania utilities does not address my primary recommendation that PCLP's request to implement a WNA should be denied due to the

[34] Lenns Rebuttal, page 35, lines 3-10.
[35] Lenns Rebuttal, page 36 lines 1-4.
[36] Lenns Rebuttal, page 36 lines 5-9.
[37] Lenns Rebuttal, page 36 line 10 to page 37 line 2.

concerns raised in my direct testimony, as such concerns are applicable independent of how the WNA is calculated.

Fourth, saying that the 5% deadband would negate the value of the WNA, is an admission that the primary purpose of the WNA is to improve PCLP's recovery of its revenue requirement to the detriment of the benefits of the real actionable price signal: the volumetric charge.

Fifth, the fact that the hypothetical WNA applied to the year ending September 30, 2024 would have moved PCLP's realized rate of return from 3.34% to 4.14% only underscores PCLP's actual purpose in proposing the WNA, viz., to improve its recovery of its revenue requirement by charging customers for service that they don't in fact receive.

Q. WHAT DO YOU CONCLUDE REGARDING PCLP'S REBUTTAL TESTIMONY?

A. For the reasons given above I conclude that witnesses Lenns' rebuttal testimony provides no grounds for modification or withdrawal of my recommendation that the Commission reject PCLP's proposed WNA.

Q. DOES THIS CONCLUDE YOUR TESTIMONY?

A. Yes. However, I reserve the right to supplement this testimony if further information is provided by either PCLP or OSBA.

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Pennsylvania Public Utility Commission	:	Docket No. R-2024-3052357
v.	:	
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VERIFICATION

I, Karl R. Pavlovic, hereby state that the facts above set forth in my Surrebuttal Testimony, OCA Statement 3SR, are true and correct to the best of my knowledge, information, and belief and that I expect to be able to prove the same at a hearing held in this matter. I understand that the statements herein are made subject to the penalties of 18 Pa.C.S. § 4904 (relating to unsworn falsification to authorities).

DATED: May 15, 2025

Signature: */s/Karl R. Pavlovic*

Karl R. Pavlovic

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