March 31, 2022

Filed Electronically and Via Hand Delivery

Harry Lanphear, Administrative Director
Maine Public Utilities Commission
State House Station 18
242 State Street,
Augusta, ME 04333

Re: SUMMIT NATURAL GAS OF MAINE, INC., PETITION FOR APPROVAL OF AN ALTERNATIVE RATE PLAN (35-A M.R.S. § 4706)
Docket No. 2022-00025

Dear Mr. Lanphear,

Summit Natural Gas of Maine, Inc. ("Summit" or the "Company") hereby submits its petition for approval of an alternative rate plan pursuant to 35-A M.R.S § 4706, and Chapter 120 of the Maine Public Utilities Commission's (the "Commission") regulations. With this request, the Company provides eight copies of the complete filing. The Company coordinated with the Commission Staff in advance to determine the desired number of printed copies.

The Company is requesting the Commission approve a seven-year rate plan designed to put the Company on a path towards customer contributions that will provide a return of expenses. The proposed increase in distribution rates among residential and business customers in year 1 of the rate plan will increase revenues by $2,846,969 based upon a test year ending June 30, 2021 and a proposed 8.15 percent return on rate base. Summit is not seeking the full recovery of the revenue requirement in year 1. If Summit's proposal is approved as requested, there will be a 30 percent increase in distribution and service and facility rates from existing rates. The proposed rate plan would permit annual increases in years 2-7 up to an annual cap of 15 percent, but annual increases could be less than that cap. There are no significant changes in rate design as part of this filing. Summit is requesting an effective date of January 1, 2023.

In support of Summit's Petition for an Alternative Rate Plan, the Company submits the following documentation in addition to this letter.

- Petition for Approval of an Alternative Rate Plan that includes the history and procedural record of the Company's initial Rate Plan, a summary of the proposed plan, and the benefits with the associated proposal.

- Chapter 120 Materials including proposed revisions to the tariff in both redline and clean formats.

- An overview of the proposal and the policy statement of the Company, as well as an introduction of witnesses and a summary of the terms of the proposed Rate Plan, as well as discrete rate case issues, and bill impacts are provided by Mr. Tyson Porter, Senior Director of Regulatory Finance and Rates.

- A description of and support for the Company's revenue requirement, allocated cost of service study, and rate design, as well as weather normalization and pro forma billing determinants are included in the testimony of Mr. Ronald J. Amen, Managing Partner at Atrium Economics.

- An explanation of the Company's customer service operations and customer service metrics, including Summit's net promoter scores are presented by Mr. Fred Kirkwood, Chief Customer Officer.

- A summary of the business development and growth activities in the state as well as an overview of competition in the Company's service territory is presented by Mr. Matthew Jacobson, Director of Sales and Marketing.

- An overview of the build out of Summit's operations and personnel in Maine, the development of policies as well as the Company's safety performance is provided by Mr. Jason Weekley, Senior Vice President and Chief Operations Officer.

- An analysis of the Company's return on equity is presented by Mr. Dylan W. D'Ascendis of ScottMadden, Inc.

Summit looks forward to working with the Commission, its Staff and intervenors in this proceeding.

Please feel free to contact me should you have any questions.

Sincerely,

Andrew S. Hagler
Senior Counsel
cc: Service List (via CMS)

STATE OF MAINE
PUBLIC UTILITIES COMMISSION

SUMMIT NATURAL GAS OF MAINE, INC. Petition for Approval of an Alternative Rate Plan (35-A M.R.S. § 4706)	Docket No. 2022-00025 PETITION

Summit Natural Gas of Maine, Inc. ("Summit" or "Company") seeks approval of an alternative rate plan pursuant to 35-A M.R.S.A. § 4706.

I. Introduction

Since commencement of its operations as Maine's newest natural gas utility Summit's rates have been established and adjusted pursuant to a rate plan approved by the Commission in January 2013. See *Summit Natural Gas of Maine, Inc., Petition for Authority to Provide Natural Gas Service, Docket 2012-00258,* Order Approving Stipulation (Jan. 29, 2013) (Order). By its terms, the existing rate plan will remain in effect through December 31, 2022. Summit now seeks approval of a new rate plan to become effective January 1, 2023.

At the time the rate plan was developed, Summit had not yet commenced operations and therefore there was no traditional "test-year" of historical operating results for use as a reference in the ratemaking analysis. Nonetheless, as the Commission observed, virtually all of the customers to which the new utility would market gas service could "satisfy their energy needs using other fuels … and can reduce their energy costs by adding natural gas as a resource." (Order at 12.) The Commission therefore concluded that "it makes little sense to apply all the traditional metrics for establishing that rates are "just and reasonable." (*Id.* at 12.) Indeed, the Commission acknowledged that the Summit rate plan would likely produce rates that, viewed through the lens of traditional cost-of-service principals, "would either qualify as either excessive or insufficiently compensatory relative to costs." (*Id.* at 12.)

In contrast to the 2012 proceeding to establish initial rates for a new utility, Summit is now able to develop test year schedules based on actual operations. The traditional revenue requirements analysis based on the test year schedules demonstrate that Summit is not earning sufficient revenues to cover the expense of operating and maintaining its system, let alone provide an opportunity for the Company's investors to earn a reasonable return on rate base. The rate plan Summit submits for Commission approval is designed to make the former, but not the latter, possible over time. Specifically, Summit requests that the Commission approve a seven-year rate plan designed to put the Company on a path towards customer contributions that will provide a *return of* expenses. As a growth utility, Summit will continue to aggressively market gas service to add new customers to its system. The Company is still growing into its system and does not, through the proposed rate plan, request rates that will afford in an opportunity to earn a reasonable *return on* rate base.

II. The Alternative Rate Plan Statute

Pursuant to 35-A M.R.S.A. § 4706(1)(A), the Commission may approve "[m]ultiyear rate making plans that cap or otherwise establish mechanisms for future rate or revenue changes." Further, in approving such a plan:

> the commission may consider the costs of regulation, the benefits of the rate plan to the utility and to ratepayers, the impact on economic development, the reallocation of risk between investors and ratepayers, the development of a competitive market for gas services that are not natural monopolies and any other factor relevant to the establishment or authorization of an alternative rate-making mechanism. Prior to adopting an alternative rate-making mechanism, the commission shall consider the need for a rate case in order to establish a base line for the alternative rate-making mechanism.

§ 4706 (1).

An alternative rate plan "need not conform with chapter 3 [of Title 35-A] to the extent that the provisions of chapter 3 require the use of rate-base, rate-of-return or any other specific form of regulation of the rates of a gas utility." See § 4706(2). Further, "[p]rior to adopting an alternative rate-making mechanism, the commission shall consider the need for a rate case in order to establish a base line for the alternative rate-making mechanism." *Id*. While the Commission is not required to conduct a rate case for the purpose of establishing a "base line" for an alternative rate plan, the "commission shall, in order to ensure that rates at the starting point of the plan are just and reasonable, conduct a revenue requirement and earning review …[and] at its discretion, may conduct the review in a manner designed to minimize the cost of the review to ratepayers." See § 4706 (3). Finally, to encourage rate flexibility, the Commission "may authorize a gas utility to implement a program under which [t]he utility may change its schedule with limited notice to the commission…[and] enter into contracts for the sale of gas, transmission and distribution services and related management services with limited or no prior approval by the commission." See § 4706 (5).

III. The Need for a New, Flexible Rate Plan

A fully litigated rate case is not necessary for the Commission to conclude that Summit is under-earning. The Chapter 120 materials, together with the expert testimony and exhibits of Mr. Ronald J. Amen and Mr. Dylan W. D'Ascendis, demonstrate that for the 12-month Test Year ending June 30, 2021, rates under the soon-to-expire rate plan are insufficient to afford the Company a reasonable opportunity to recover its cost of providing service and a reasonable return on rate base. Summit believes that there will come a point in these proceedings where the parties are able to conclude that the rate plan the Company is proposing is unlikely, over its term, to produce through rates, revenues of a sufficient amount that are fully compensatory (e.g., including a reasonable return on equity) if the Commission *were to apply* a traditional cost-of-service analysis to evaluate the reasonableness of an alternative rate plan under 35-A § 4706. Under § 4706, the Commission is authorizing to conduct its review of the reasonableness of Summit's rate plan in a way such as to minimize the cost of the review, and it is not required to establish a definitive revenue requirement, as it would under in in a traditional rate case, in order to conclude that the proposed alternative rate plan is reasonable.

As Mr. Tyson Porter explains in his direct testimony, Summit does not seek a Commission determinate of its rate base because its proposed rate plan is not designed to create an opportunity for the Company to earn a return on rate base even approaching the level to which it would be entitled under a traditional return on equity analysis.

III. The Proposed Rate Plan

The elements of the proposed rate plan are quite simple. There is no mandated cost adjustment mechanism. There is no inflation adjustment (which is notable in light of prevailing, historical inflation rates). There is no "decoupling" feature. There is no weather normalization rider. Indeed, there are no formulas incorporated into the rate plan.

Instead, the rate plan, which includes a seven-year stay out provision, simply calls for the Commission to establish starting point rates to remain in effect for at least one year, and to provide the discretion for Summit to implement annual rate increases up an annual cap of 15 percent. Summit's rate plan proposal is designed to phase-in increased customer contribution toward the Company's operating cost, allowing Summit to continue to grow while forgoing rates that would permit the Company an opportunity to earn a reasonable return on its investment in that system.

IV. The Benefits of the Rate Plan

Since its inception, SNGME has created an opportunity for previously unserved regions of Maine to choose gas service as an alternative to unregulated heating oil and propane as a source of heating for homes and businesses. The Company has invested substantial sums to build a new system that make this customer choice possible. Further, it has invested in significant, shareholder-funded, incentive offerings that have helped customers electing gas service afford the expense of converting or replacing their heating systems so that they can take advantage of natural gas. Natural gas is a cleaner and generally more affordable heating fuel than propane or heating oil. Summit is proud of its accomplishments over the past decade, and it is committed to continue growing into its distribution system by engaging in targeted efforts to encourage new customers to connect to that system. The Company remains a growth utility, and while the necessity for increased rates is never welcome, Summit is committed to spreading the expenses of operating its facilities across an increasing customer base and continuing to provide safe and reliable gas service to customers with a high level of customer service and satisfaction.

V. Conclusion

For the foregoing reasons, as well as those provided in the Company's Direct Testimony, Summit respectfully requests that the Commission approve the proposed rate plan and grant such other and further relief as the Commission deems just and equitable in the circumstances.

Respectfully submitted,

Dated: March 31, 2022

Andrew S. Hagler
Senior Counsel
Summit Utilities, Inc.
2 DeLorme Drive; Suite 100
Yarmouth, Maine 04096

Summit Natural Gas of Maine, Inc. Docket No. 2022-00025

Section 5.C.1 of Chapter 120 requires Summit Natural Gas of Maine, Inc. to provide a cover sheet showing: "the name of the public utility; the proposed effective date of the new rates; the adjusted gross revenue subject to Commission jurisdiction; and the percent change in gross revenue subject to Commission jurisdiction."

Summit Natural Gas of Maine, Inc. ("Summit" or "the Company") is proposing to increase revenue, effective January 1, 2023, by $2,846,969, which represents an increase of roughly 16 percent over Summit's test year gross revenue of $17,612,030. In addition, Summit's plan would allow for annual increases, subject to a cap, of up to 15 percent. If Summit were to seek the maximum increase on an annual basis through the life of the rate plan, it could result in an additional $16,187,980 of increased revenue.

Summit Natural Gas of Maine, Inc.

Docket No. 2022-00025

Schedules

Pursuant to 65-407 C.M.R. Ch. 120, § 5(C)(2), Summit Natural Gas of Maine, Inc will provide the schedule pages implementing the new rates.

As part of this filing, the Company is providing redline and clean tariff sheets in accordance with 65-407 C.M.R. Ch. 120, § 5(2). The Company is also providing the proposed 2023 Rate Plan.

SUMMIT NATURAL GAS OF MAINE, INC. ME PUC No. 2022-00025

~~Revision 1~~ Revision 2 Sheet No. 32
Cancels ~~Original~~ Revision 1 Sheet No. 32

TERMS AND CONDITIONS

NATURAL GAS SERVICE

SERVICE LATERAL CONNECTION AND DISTRIBUTION MAIN POLICY

SERVICE LINE CONSTRUCTION POLICY (continued)

These estimated installation dates will be established based upon the following three factors:

(a) Date on which a Complete Application is accomplished (earlier completed service requests will be ahead in priority relative to requests received later);
(b) Geographic proximity to the Company's planned mainline construction (service requests located closer to the mainline will be ahead in priority relative to requests located farther from the mainline); and
(c) Geographic proximity to other applicants who are seeking service within the calendar year.

For Complete Applications not received by June 1 of a particular year, the application will be treated as a Complete Application for the following calendar year.

~~SERVICE LINE METRIC PENALTY~~ D

~~In the event the Company does not provide service by the "estimated installation date" given to a particular customer under the Service Line Construction Policy, the Company shall remit a one-time payment to that customer in the amount of $50 per week up to a maximum overall payment of $250. This payment may, in the Company's sole discretion, be provided as a credit on the Customer's billing account once service is provided. The Company may, in its sole discretion, not remit any service line metric payment to a customer who has received other financial assistance from the Company in excess of the amount to which the customer would otherwise be entitled under this provision.~~

Issue Date: June 19, 2015 Issued by:

Effective Date: April 1, 2022 Title: President

SUMMIT NATURAL GAS OF MAINE, INC.
2 Delorme Drive
Yarmouth, Maine 04096

ME PUC No. 2021-00025

~~Revision 8~~ Sheet No. 100
Cancels ~~Revision 7~~ Sheet No. 100

NATURAL GAS RATES
RESIDENTIAL GAS SERVICE
SCHEDULE RG

APPLICABILITY

Applicable to residential gas service customers in the municipalities of Richmond, Gardiner, Farmingdale, Hallowell, Augusta, Sidney, Belgrade, Oakland, Fairfield, Waterville, Skowhegan, Norridgewock, Madison, China, Albion, Windsor, Winslow, Randolph, Cumberland, Yarmouth and Falmouth. In accordance with the Company's Rate Plan approved in Commission Docket No. 2012-00258, if the Company receives requests for service or otherwise intends to provide service, outside of these municipalities, the Company may: (1) file a proposal for rates that would apply to that service or, (2) provide service pursuant to these rates. The Company has no obligation to provide service pursuant to the rates to any customer outside of the municipalities listed above.

RATE

Service and Facility Charge, per customer (per meter): ~~$21.91/mo~~ $28.48/mo I

Distribution Charge, all gas used: ~~$0.985/therm~~ $1.28/therm I

These rates are subject to annual adjustment in accordance with the Company's Rate Plan approved in Commission Docket No. ~~2012-00258~~. 2022-00025 T

PAYMENT

Bills for gas service are due per the Company's Terms and Conditions on file with the Maine Public Utilities Commission and the Rules and Regulations of the Maine Public Utilities Commission.

LOW-INCOME ASSISTANCE T

Residential heating customers who are participants of the Low-Income Home Energy Assistance Program ("LIHEAP") administered by the Maine State Housing Authority and who do not receive government housing subsidies are eligible for a reduced rate. Qualifying customers shall receive a 28% discount on the monthly Service and Facility Charge and Distribution Charge. The Company will automatically enroll eligible customers upon receipt of LIHEAP funds, with such enrollment effective until November 30 of the following year. Customers who are eligible for LIHEAP assistance but do not receive funds due to LIHEAP funding limitations will also be eligible for the program and can be enrolled by sending the Company proof of eligibility for LIHEAP assistance. Refer to Tariff Sheet 112.1 for Low-Income Assistance charges.

Issue Date: 3/30/2021

Issued by:

Effective Date: ~~6/1/2021~~ 4/1/2022

Title: Kurt Adams, President

SUMMIT NATURAL GAS OF MAINE, INC.
2 Delorme Drive
Yarmouth, Maine 04096

ME PUC No. 2021-000~~25~~

Revision ~~8~~ 9 Sheet No. 101
Cancels Revision ~~7~~ 8 Sheet No. 101

NATURAL GAS RATES
SMALL COMMERCIAL GAS SERVICE
SCHEDULE SC

APPLICABILITY

Applicable to Small Commercial Service (Non-Residential Service) with expected annual consumption less than 1,500 Dth per year in the municipalities of Richmond, Gardiner, Farmingdale, Hallowell, Augusta, Sidney, Belgrade, Oakland, Fairfield, Waterville, Skowhegan, Norridgewock, Madison, China, Albion, Windsor, Winslow, Randolph, Cumberland, Yarmouth and Falmouth. In accordance with the Company's Rate Plan approved in Commission Docket No. 2012-00258, if the Company receives requests for service or otherwise intends to provide service, outside of these municipalities, the Company may: (1) file a proposal for rates that would apply to that service or, (2) provide service pursuant to these rates. The Company has no obligation to provide service pursuant to the rates to any customer outside of the municipalities listed above.

RATE

Service and Facility Charge, per customer (per meter): ~~$36.13/mo~~ $46.97/mo I

Distribution Charge, all gas used: ~~$0.869/therm~~ $1.130/therm I

These rates are subject to annual adjustment in accordance with the Company's Rate Plan approved in Commission Docket No. ~~2012-00258~~ 2022-00025 T

PAYMENT

Bills for gas service are due per the Company's Terms and Conditions on file with the Maine Public Utilities Commission and the Rules and Regulations of the Maine Public Utilities Commission.

Issue Date: 3/30/2021

Issued by:

Effective Date: ~~6/1/2021~~ 4/1/2022

Title: Kurt Adams, President

SUMMIT NATURAL GAS OF MAINE, INC. ME PUC No. 2021-00025

2 Delorme Drive
Yarmouth, Maine 04096

Revision ~~8~~ 9 Sheet No. 102
Cancels Revision ~~7~~ 8 Sheet No. 102

NATURAL GAS RATES
LARGE COMMERCIAL GAS SERVICE
SCHEDULE LC

APPLICABILITY

Applicable to Large Commercial Service (Non-Residential Service) with expected annual consumption of 1,500 Dth or more per year in the municipalities of Richmond, Gardiner, Farmingdale, Hallowell, Augusta, Sidney, Belgrade, Oakland, Fairfield, Waterville, Skowhegan, Norridgewock, Madison, China, Albion, Windsor, Winslow, Randolph, Cumberland, Yarmouth and Falmouth. In accordance with the Company's Rate Plan approved in Commission Docket No. 2012-00258,if the Company receives requests for service or otherwise intends to provide service, outside of these municipalities, the Company may: (1) file a proposal for rates that would apply to that service or, (2) provide service pursuant to these rates. The Company has no obligation to provide service pursuant to the rates to any customer outside of the municipalities listed above.

RATE

Service and Facility Charge, per customer (per meter): ~~$312.17/mo~~ $405.82/mo I

Distribution Charge, all gas used: ~~$0.639/therm~~ $0.832/therm I

These rates are subject to annual adjustment in accordance with the Company's Rate Plan approved in Commission Docket No. ~~2012-00258~~. 2022-00025 T

PAYMENT

Bills for gas service are due per the Company's Terms and Conditions on file with the Maine Public Utilities Commission and the Rules and Regulations of the Maine Public Utilities Commission.

Issue Date: 3/30/2021 Issued by: [signature]

Effective Date: ~~6/1/2021~~ 4/1/2022 Title: Kurt Adams, President

SUMMIT NATURAL GAS OF MAINE, INC. ME PUC No. 2022-00025

Revision 2 Sheet No. 32
Cancels Revision 1 Sheet No. 32

TERMS AND CONDITIONS

NATURAL GAS SERVICE

SERVICE LATERAL CONNECTION AND DISTRIBUTION MAIN POLICY

SERVICE LINE CONSTRUCTION POLICY (continued)

These estimated installation dates will be established based upon the following three factors:

(a) Date on which a Complete Application is accomplished (earlier completed service requests will be ahead in priority relative to requests received later);
(b) Geographic proximity to the Company's planned mainline construction (service requests located closer to the mainline will be ahead in priority relative to requests located farther from the mainline); and
(c) Geographic proximity to other applicants who are seeking service within the calendar year.

For Complete Applications not received by June 1 of a particular year, the application will be treated as a Complete Application for the following calendar year.

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D

Issue Date: June 19, 2015 Issued by:

Effective Date: April 1, 2022 Title: President .

ME PUC No. 2022-00025

SUMMIT NATURAL GAS OF MAINE, INC.
2 Delorme Drive
Yarmouth, Maine 04096

Revision 9 Sheet No. 100
Cancels Revision 8 Sheet No. 100

NATURAL GAS RATES
RESIDENTIAL GAS SERVICE
SCHEDULE RG

APPLICABILITY

Applicable to residential gas service customers in the municipalities of Richmond, Gardiner, Farmingdale, Hallowell, Augusta, Sidney, Belgrade, Oakland, Fairfield, Waterville, Skowhegan, Norridgewock, Madison, China, Albion, Windsor, Winslow, Randolph, Cumberland, Yarmouth and Falmouth. In accordance with the Company's Rate Plan approved in Commission Docket No. 2012-00258, if the Company receives requests for service or otherwise intends to provide service, outside of these municipalities, the Company may: (1) file a proposal for rates that would apply to that service or, (2) provide service pursuant to these rates. The Company has no obligation to provide service pursuant to the rates to any customer outside of the municipalities listed above.

RATE

Service and Facility Charge, per customer (per meter): $28.48/mo I

Distribution Charge, all gas used: $1.28/therm I

These rates are subject to annual adjustment in accordance with the Company's Rate Plan approved in Commission Docket No. 2022-00025. T

PAYMENT

Bills for gas service are due per the Company's Terms and Conditions on file with the Maine Public Utilities Commission and the Rules and Regulations of the Maine Public Utilities Commission.

LOW-INCOME ASSISTANCE T

Residential heating customers who are participants of the Low-Income Home Energy Assistance Program ("LIHEAP") administered by the Maine State Housing Authority and who do not receive government housing subsidies are eligible for a reduced rate. Qualifying customers shall receive a 28% discount on the monthly Service and Facility Charge and Distribution Charge. The Company will automatically enroll eligible customers upon receipt of LIHEAP funds, with such enrollment effective until November 30 of the following year. Customers who are eligible for LIHEAP assistance but do not receive funds due to LIHEAP funding limitations will also be eligible for the program and can be enrolled by sending the Company proof of eligibility for LIHEAP assistance. Refer to Tariff Sheet 112.1 for Low-Income Assistance charges.

Issue Date: 3/30/2021 Issued by:

EffectiveDate: 4/1/2021 Title: Kurt Adams, President

SUMMIT NATURAL GAS OF MAINE, INC.
2 Delorme Drive
Yarmouth, Maine 04096

ME PUC No. 2022-00025

Revision 9 Sheet No. 101

Cancels Revision 8 Sheet No. 101

NATURAL GAS RATES
SMALL COMMERCIAL GAS SERVICE
SCHEDULE SC

APPLICABILITY

Applicable to Small Commercial Service (Non-Residential Service) with expected annual consumption less than 1,500 Dth per year in the municipalities of Richmond, Gardiner, Farmingdale, Hallowell, Augusta, Sidney, Belgrade, Oakland, Fairfield, Waterville, Skowhegan, Norridgewock, Madison, China, Albion, Windsor, Winslow, Randolph, Cumberland, Yarmouth and Falmouth. In accordance with the Company's Rate Plan approved in Commission Docket No. 2012-00258, if the Company receives requests for service or otherwise intends to provide service, outside of these municipalities, the Company may: (1) file a proposal for rates that would apply to that service or, (2) provide service pursuant to these rates. The Company has no obligation to provide service pursuant to the rates to any customer outside of the municipalities listed above.

RATE

Service and Facility Charge, per customer (per meter): $46.97/mo I

Distribution Charge, all gas used: $1.130/therm I

These rates are subject to annual adjustment in accordance with the Company's Rate Plan approved in Commission Docket No. 2022 00025. T

PAYMENT

Bills for gas service are due per the Company's Terms and Conditions on file with the Maine Public Utilities Commission and the Rules and Regulations of the Maine Public Utilities Commission.

Issue Date: 3/30/2021 Issued by:

Effective Date: 4/1/2022 Title: Kurt Adams, President

SUMMIT NATURAL GAS OF MAINE, INC.
2 Delorme Drive
Yarmouth, Maine 04096

ME PUC No. 2022-000 25

Revision 9 Sheet No. 102

Cancels Revision 8 Sheet No. 102

NATURAL GAS RATES
LARGE COMMERCIAL GAS SERVICE
SCHEDULE LC

APPLICABILITY

Applicable to Large Commercial Service (Non-Residential Service) with expected annual consumption of 1,500 Dth or more per year in the municipalities of Richmond, Gardiner, Farmingdale, Hallowell, Augusta, Sidney, Belgrade, Oakland, Fairfield, Waterville, Skowhegan, Norridgewock, Madison, China, Albion, Windsor, Winslow, Randolph, Cumberland, Yarmouth and Falmouth. In accordance with the Company's Rate Plan approved in Commission Docket No. 2012-00258,if the Company receives requests for service or otherwise intends to provide service, outside of these municipalities, the Company may: (1) file a proposal for rates that would apply to that service or, (2) provide service pursuant to these rates. The Company has no obligation to provide service pursuant to the rates to any customer outside of the municipalities listed above.

RATE

Service and Facility Charge, per customer (per meter): $405.82/mo I

Distribution Charge, all gas used: $0.832/therm I

These rates are subject to annual adjustment in accordance with the Company's Rate Plan approved in Commission Docket No. 2022-00025. T

PAYMENT

Bills for gas service are due per the Company's Terms and Conditions on file with the Maine Public Utilities Commission and the Rules and Regulations of the Maine Public Utilities Commission.

Issue Date: 3/30/2021 Issued by:

Effective Date: 4/1/2022 Title: Kurt Adams, President

SUMMIT NATURAL GAS OF MAINE

2023 RATE PLAN

1. **Effective Date and Term**. Summit Natural Gas of Maine's ("Summit" or the "Company") Rate Plan will go into effect on January 1, 2023 upon approval in Docket No. 2022-00025, and remain in effect through December 31, 2029, unless earlier terminated pursuant to Paragraph 3 hereof.

2. **Applicability**. This Rate Plan applies to the municipalities of Richmond, Gardiner, Farmingdale, Hallowell, Randolph, Augusta, Sidney, Belgrade, Oakland, Fairfield, Waterville, Skowhegan, Norridgewock, Madison, China, Albion, Windsor, Winslow, Cumberland, Yarmouth, and Falmouth. If Summit receives requests for service, or otherwise intends to provide service, outside of these municipalities, Summit may: (1) file with the Commission a proposal for rates and terms that would apply to that service; or (2) provide service pursuant to the rates and terms of this Rate Plan. Summit has no obligation to provide service pursuant to the rates and terms of this Rate Plan to any customer outside of the municipalities listed in this Paragraph.

3. **Stay-Out; Off-Ramps**. Summit will not file a base rate proceeding pursuant to35-A M.R.S. § 307 that has a rate effective date earlier than January 1, 2030, unless the Rate Plan is suspended or terminated pursuant to this Paragraph. Notwithstanding this stay-out period, Summit reserves the right to file a petition for temporary rate relief pursuant to 35-A M.R.S. § 1322. In the event Summit petitions for temporary rate relief pursuant to Section 1322, and the Commission grants temporary rate relief by Order, the Commission may in that proceeding reopen, modify, or terminate the Rate Plan, notwithstanding 35-A M.R.S. § 4706(6).

4. Distribution Rates. Effective January 1, 2023, Summit's Distribution Rates and Monthly Charge per rate class shall be as described below:

Rate Class	Distribution Rate (per Therm)	Monthly Charge
Residential	$1.281	$28.48
Small Commercial (a commercial distribution customer with annual consumption of less than 1500 Dth)	$1.130	$46.97
Large Commercial (a commercial distribution customer with annual consumption of 1500 Dth or more)	$0.831	$405.82
Firm Transportation	Rate to be determined by Special Rate Agreement with the customer	
Interruptible Transportation	Rate to be determined by Special Rate Agreement with the customer	

Further, Small Commercial and Large Commercial customers may elect to take transportation-only service at the same Distribution Rate as for sales customers in those rate classes.

At the discretion of Summit, and upon 30 days written notice to the Commission, Summit may adjust the Distribution Rates and Monthly Charge annually up to the cap as described in Sections 5 and 6 below.

5. Annual Adjustment and Cap. Beginning January 1, 2024, and annually thereafter during the term of the Rate Plan, Summit may in its sole discretion adjust rates in accordance with the Rate Plan, without the need for a base rate case pursuant to 35-A M.R.S. § 307.

Consistent with the provisions of this Rate Plan, Summit may adjust the Distribution Rate and/or the Monthly Charge for any Rate Class annually, provided that any increase does not exceed the annual cap as provided in the table below. Nothing in this Rate Plan shall obligate

Summit to adjust Distribution Rates and Monthly Charges at the same percentages for any year during the Rate Plan.

	2024	2025	2026	2027	2028	2029
Distribution Charge	15%	15%	15%	15%	15%	15%
Monthly Charge	15%	15%	15%	15%	15%	15%

6. Special Rate Agreements. Unless specifically requested by Summit, Commission approval will not be required for Summit to enter into special rate agreements with customers. Summit will file, in Docket No. 2022-00025, for informational purposes any special rate contracts it enters into with customers. When the contract is filed, Summit will indicate its view of the relationship of the contract price to short-run marginal cost, and, if the contract rate is lower than short-run marginal cost, will indicate why, in Summit's view, it is appropriate to enter into the contract.

7. Costs Not Covered by Rate Plan. The Rate Plan does not apply to recovery of cost of gas supplied to those customers to whom Summit is responsible to supply gas in addition to Local Distribution Company delivery service. The cost of gas adjustment will be completed per Chapter 430 of the Commission's Rules.

8. Commission Authority. Nothing in this rate plan diminishes the Commission's authority, to ensure that Summit is providing safe, adequate, and reliable service during this Rate Plan term.

Summit Natural Gas of Maine, Inc.

Docket No. 2022-00025

Statement of Test Year

Section 5.C.3.a of Chapter 120 requires Summit Natural Gas of Maine, Inc. to provide a statement of the test year to be used:

Summit's test year spanned July 1, 2020 through June 30, 2021.

Summit Natural Gas of Maine, Inc.

Docket No. 2022-00025

Annual Report

Section 5.C.3.b of Chapter 120 requires Summit to provide "an annual report for the test year, or the equivalent compilation in the same form and detail if the test year is a period other than a calendar year."

Attached please find a copy of the "Annual Report for Gas Utilities of Summit Natural Gas of Maine Inc. to the Public Utilities Commission of the State of Maine for the Year Ended December 31, 2020."

ANNUAL REPORT

FOR GAS UTILITIES

OF

Name ____ Summit Natural Gas of Maine, Inc

Address__ 442 Civic Center Drive, Suite 10000, Augusta, ME 04330

TO THE

PUBLIC UTILITIES COMMISSION

OF THE

STATE OF MAINE

FOR THE

YEAR ENDED DECEMBER 31, 2020

PART I : IDENTIFICATION

01 Exact Legal Name of Respondent Summit Natural Gas of Maine, Inc	**02 Year of Report** December 31, 2020

03 Previous Name and Date of Change (If name changed during year) N/A
04 Address of Principal Business Office at End of Year (Street, City, State, Zip Code) 10825 East Geddes Avenue, Suite 410, Centennial, CO 80112

05 Name of Contact Person Matthew Kaply	**06 Title of Contact Person** Senior Director of Regulatory Affairs

07 Address of Contact Person (Street, City, State, Zip Code) 442 Civic Center Drive, Augusta, ME 04330

08 Telephone and Email of Contact Person 207-621-8000 Ext. 430 Mkaply@summitnaturalgas.com	**09 This Report Is** (1) An Original **(2) A Resubmission**	**10 Date of Report (Mo, Da, Yr)** 04/29/2021

11 Name of Officer Having Custody of the Books of Account Steven Birchfield	**12 Title of Officer** Executive Vice President & Chief Financial Officer

13 Address of Officer Where Books of Account Are Kept (Street, City, State, Zip code)

14 Name of State Where Respondent is Incorporated CO	**15 Date of Incorporation (Mo, Da, Yr)** December 16, 2011	**16 If applicable, Reference to Law Incorporated Under** N/A

17 Explanation of Manner and Extent of Corporate Control (If the respondent controls or is controlled by any other corporation, business trust, or similar organization) Summit Utilities, Inc.

PART II: ATTESTATION

The undersigned officer certifies that he/she has examined the accompanying report; that to the best of his/her knowledge, information, and belief, all statements of fact contained in the accompanying report are true and the accompanying report is a correct statement of the business and affairs of the above named respondent in respect to each and every matter set forth therein during the period from and including January 1 to and including December 31 of the year of the report.

01 Name Steven Birchfield	**03 Signature**	**04 Date Signed** **(Mo, Da, Yr)**
02 Title Executive Vice President & Chief Financial Officer		

Name of Respondent Summit Natural Gas of Maine, Inc	This Report Is: (1) An Original **(2) A Resubmission**	Date of Report (Mo, Da, Yr) 04/29/2021	Year of Report December 31, 2020

GENERAL INFORMATION

1. Provide name and title of officer having custody of the general corporate books of account and address of office where the general corporate books are kept, and address of office where any other corporate books of account are kept, if different from that where the general corporate books are kept.

Steven Birchfield
Executive Vice President & Chief Financial Officer
Summit Natural Gas of Maine, Inc.
10825 E. Geddes Avenue, Suite 410, Centennial, CO 80112

2. Provide the name of the State under the laws of which the respondent is incorporated, and date of incorporation. If incorporated under a special law, give reference to such law. If not incorporated, state that fact and give the type of organization and the date organized.

State of Colorado Incorporated: December 16, 2011

3. If at any time during the year the property of respondent was held by a receiver or trustee, give (a) name of receiver or trustee, (b) date such receiver or trustee took possession, (c) the authority by which the receivership or trusteeship was created, and (d) date when possession by receiver or trustee ceased.

Not Applicable

4. State the classes of utility and other services furnished by respondent during the year in each State in which the respondent operated.

Natural Gas Distribution

5. Have you engaged as the principal accountant to audit your financial statements an accountant who is not the principal accountant for your previous year's certified financial statements:

NO

(1) Yes...Enter the date when such independent accountant was initially engaged:
(2) **No, PricewaterhouseCoopers LLP was the auditor for both years.**

Name of Respondent Summit Natural Gas of Maine, Inc	This Report Is: (1) An Original **(2) A Resubmission**	Date of Report (Mo, Da, Yr) 04/29/2021	Year of Report December 31, 2020

AFFILIATED INTERESTS

Include on this page, a summary listing of all affiliated interests of the respondent and its parent. Indicate the relationship to the parent and the respondent and the percentage owned by the corporate group. (Refer to M.R.S.A. §707 for the definition of affiliated interests.

Summit Natural Gas of Maine, Inc. is a wholly owned subsidiary of Summit Utilities, Inc.
Summit Natural Gas of Maine, Inc. does not own an interest in any other entity.
Affiliated Interests, wholly owned by Summit Utilities, Inc.

Peaks Renewables, Inc.
Wolf Creek Energy, LLC
Summit LDC Holdings, LLC

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year of Report
Summit Natural Gas of Maine, Inc	(1) An Original **(2) A Resubmission**	04/29/2021	December 31, 2020

OFFICERS

1. Report below he name, title and salary for each executive officer whose salary is $50,000 or more. An "executive officer" of a respondent includes its president, secretary, treasurer, and vice president in charge of a principal business unit, division function (such as sales, administration or finance), and any other person who performs similarly policy-making functions.

2. If a change was made during the year in the incumbent of any position, show name of the previous incumbent, and date the change in incumbency was made.

3. Utilities which are required to file the same data with he Securities and Exchange Commission, may substitute a copy of item 4 of Regulation S-K (identified as this page). The substitute page(s) should be the same size as this page.

4 Report below any additional companies where the officer holds office along with their title.

Line No.	Ti le (a)	Name of Officer (b)	Other Companies Officer Of with Title (c)
2	President and Chief Executive Officer	Kurt W. Adams	President and Chief Executive Officer of Summit Utilities, Inc., Colorado Natural Gas, Inc., Summit Natural Gas of Maine, Inc., Summit Natural Gas of Missouri, Inc., Peaks Renewables, Inc.
6	Executive Vice President and Chief Financial Officer	Steven E. Birchfield	Executive Vice President and Chief Financial Officer of Summit Utilities, Inc. Colorado Natural Gas, Inc., Summit Natural Gas of Maine, Inc., Summit Natural Gas of Missouri, Inc., Peaks Renewables, Inc.
11	Senior Vice President, Chief Legal Officer and Secretary	Hallie F. Gilman	Senior Vice President, Chief Legal Officer and Secretary of Summit Utilities, Inc. Colorado Natural Gas, Inc., Summit Natural Gas of Maine, Inc., Summit Natural Gas of Missouri, Inc., Peaks Renewables, Inc.
16	President	Kurt W. Adams	A. O. G. Corporation, Arkansas Oklahoma Gas Corporation and Summit LDC Holdings, LLC
19	Vice President and Treasurer	Steven E. Birchfield	A. O. G. Corporation, Arkansas Oklahoma Gas Corporation and Summit LDC Holdings, LLC
22	Vice President and Secretary	Hallie F. Gilman	A. O. G. Corporation and Arkansas Oklahoma Gas Corporation
25	Senior Vice President and Secretary	Hallie F. Gilman	Summit LDC Holdings, LLC

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year of Report
Summit Natural Gas of Maine, Inc	(1) An Original **(2) A Resubmission**	04/29/2021	December 31, 2020

DIRECTORS

1. Report below the information called for concerning each director of the respondent who held office at any time during the year. Include in column (a), abbreviated titles of the directors who are officers of the respondent.

2. Designate members of the Executive Committee by an asterisk and the Chairman of the Executive Committee by a double asterisk.

Name (and Title) of Director (a)	Principal Business Address (b)	No. of Directors Meetings During Year (c)	Fees During Year (d)
Robert J. Carroll, Chairman Resigned 9/10/20	10825 E. Geddes Avenue, Suite 410, Centennial, CO 8(	3	$93,750
Kurt W. Adams, Director, Pres., CEO	10825 E. Geddes Avenue, Suite 410, Centennial, CO 8(	5	
Henry W Fayne, Chairman, effective 9/11/20	10825 E. Geddes Avenue, Suite 410, Centennial, CO 8(	5	$106,250
Andrew (Landy) E. Gilbert, Director	10825 E. Geddes Avenue, Suite 410, Centennial, CO 8(	5	
Armando A. Pena, Director Resigned 9/10/20	10825 E. Geddes Avenue, Suite 410, Centennial, CO 8(	3	$75,000
Kathleen D. Alexander, Director	10825 E. Geddes Avenue, Suite 410, Centennial, CO 8(	5	$100,000
Colette D. Honorable, Director Resigned 9/17/20	10825 E. Geddes Avenue, Suite 410, Centennial, CO 8(	3	$75,000
Matthew J. LeBlanc, Alternate Director term ended 12/16/20	10825 E. Geddes Avenue, Suite 410, Centennial, CO 8(	0	
Daniel M. Mitaro, Alternate effective 12/16/20	10825 E. Geddes Avenue, Suite 410, Centennial, CO 8(	1	
Cheryl F. Campbell, Director, effective 9/11/20	10825 E. Geddes Avenue, Suite 410, Centennial, CO 8(	2	$50,000
Thomas H. Graham, Director, effective 9/11/20	10825 E. Geddes Avenue, Suite 410, Centennial, CO 8(	2	$50,000

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year of Report
Summit Natural Gas of Maine, Inc	(1) An Original **(2) A Resubmission**	04/29/2021	December 31, 2020

1. Give the names and addresses of the 10 security holders of the respondent who, at the date of the latest closing of the stock book or compilation of the list of stockholders of the respondent, prior to the end of the year, had the highest voting powers in the respondent, and state the number of votes which each would have had the right to cast on that date if a meeting were then in order. If any such holder held in trust, give in a footnote the known particulars of the trust (whether voting trust, etc.), duration of trust and principal holders of beneficiary interests in the trust. If he stock book was not closed or a list of stockholders was not compiled within one year prior to the end of the year, or if other class of security has become vested with voting rights, then show such 10 security holders as of the close of the year. Arrange the names of the security holders in the order of voting power, commencing with the highest. Show in column (a) the titles of officers and directors included in such list of 10 security holders.

2. If any security other than stock carries voting rights, explain in a supplemental statement the circumstances whereby such security became vested with voting rights and give other important particulars (details) concerning the voting rights of such security. State whether voting rights are actual or contingent: of contingent, describe the contingency.

3. If any class or issue of security has any special privileges in the election of directors, trustees or managers, or in the determination of corporate action by any method, explain briefly in a footnote.

4. Furnish par iculars (details) concerning any options, warrants, or rights outstanding at the end of the year for others to purchase securities of the respondent or any securities or other assets owned by the respondent, including prices, expira ion dates, and other material information relating to exercise of the options, warrants, or rights. Specify the amount of such securities or assets so entitled to be purchased by any officer, director, associated company, or any of he ten largest security holders. This instruction is inapplicable to convertible securities or to any securities substantially all of which are outstanding in the hands of the general public where the options, warrants, or rights were issued on a prorata basis.

1. Give the date of the latest closing of the stock book prior to the end of the year, and state the purpose of such closing:	2. State the total number of votes cast at he latest general meeting prior to the end of the year for elec ion of the directors of the respondent and number of such votes cast by proxy Total: By proxy:	3. Give the date and place of such Meeting:

Line No.	Name (Title) and Address of Security Holder (a)	VOTING SECURITIES Number of votes as of (date): Total Votes (b)	Common Stock (c)	Preferred Stock (d)	Other (e)
4	TOTAL votes of all voting securities	1	10,000		
5	TOTAL numbers of security holders	1	10,000		
6	TOTAL votes of security holders listed below	1	10,000		
7					
8					
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Name of Respondent	This Report Is:	Date of Report	Year of Report
Summit Natural Gas of Maine, Inc	(1) An Original **(2) A Resubmission**	(Mo, Da, Yr) 04/29/2021	December 31, 2020

IMPORTANT CHANGES DURING THE YEAR

Give particulars (details) concerning the matters indicated below. Make he statements explicit and precise, and number them in accordance with the inquiries. Each inquiry should be answered. Enter "none" or "not applicable" where applicable. If information which answers an inquiry is given elsewhere in the report, make a reference to he schedule in which it appears.

1. List changes in and important additions to franchise area.
   None

2. Acquisi ion of ownership in other companies by reorganization, merger, or consolidation with o her companies: Give names of companies involved, par iculars concerning the transactions, name of he Commission authorizing the transaction, and reference to commission au horization.
   None

3. Purchase or sale of an opera ing unit or system: Give a brief description of the property, and of the transactions relating hereto, and reference to Commission authorization, if any was required.
   None

4. List important leaseholds that have been acquired given, assigned or surrendered: Give effec ive dates, lengths of terms, names of parties, rents, and other conditions. State name of Commission authorizing lease and give reference to such authorization.
   None

5. Important extension or reduction of transmission or distribu ion system: State territory added or relin-quished and date opera ions began or ceased and give reference to Commission authoriza ion, if any was required.
   None

6. Obligations incurred or assumed by respondent as guarantor for the performance by another of any agreement or obligation, including ordinary commercial paper maturing on demand or not later than one year after date of issue: State on behalf of whom the obliga ion was assumed and amount of the obligation. Give reference to Commission authorization if any was required.
   None

7. Changes in articles of incorporation or amendments to charter: Explain the nature and purpose of such changes or amendments.
   None

8. State briefly he status of any materially important legal proceedings pending at he end of the year, and the results of any such proceedings culminated during the year.
   None

9. Describe briefly any materially important trans-actions of the respondent not disclosed elsewhere in this report in which an officer, director, security holder reported on page 6, voting trustee, associated company or known associate of any of these persons was a party or in which any such person had a material interest.
   None

10. If he important changes during the year relating to the respondent company appearing in the annual report to stockholders are applicable in every respect and furnish the data required by instructions 1 to 9 above, such notes may be attached to this page.
   None

Name of Respondent	This Report is:	Date of Report	Year of Report
Summit Natural Gas of Maine, Inc	(1) An Original	(Mo, Da, Yr)	
	(2) A Resubmission	04/29/2021	December 31, 2020

PART III: COMPARATIVE BALANCE SHEET

Line No.	Title of Account (a)	Ref. Page No. (b)	Balance at Beginning of Year (c)	Balance at End of Year (d)
	UTILITY PLANT			
02	Utility Plant (101-106, 114)	20-21	363,885,448	373,480,850
03	Construction Work in Progress (107)	20-21	455,227	2,509,087
04	TOTAL Utility Plant (Enter Total of lines 2 and 3)		364,340,675	375,989,936
05	(Less) Accum. Prov. for Depr. Amort. Depl. (108, 111, 115)	20-21	(38,796,642)	(47,401,248)
06	Net Utility Plant (Enter total of line 04 less 05)	-	325,544,033	328,588,688
07	Nuclear Fuel (120.1-120.4, 120.6)	-		
08	(Less) Accum. Prov. for Amort. of Nucl. Fuel Assemblies (120.5)	-		
09	Net Nuclear Fuel (Enter Total of Line 7 less 8)	-		
10	Net Utility Plant (Enter Total of lines 6 and 9)	-	325,544,033	328,588,688
11	Utility Plant Adjustments (116)			
12	Gas Stored Underground-Noncurrent (117)			
13	OTHER PROPERTY AND INVESTMENTS			
14	Nonutility Property (121)			
15	(Less) Accum. Prov. for Depr. and Amort. (122)			
16	Investments In Associated Companies (123)			
17	Investments In Subsidiary Companies (123.1)			
18	(For Cost of Account 123.1, See Footnote Page 224, line 42)	-		
19	Noncurrent Portion of Allowances	-		
20	O her Investments (124)			
21	Special Funds (125 - 128)	-		
22	TOTAL O her Property and Investments (Total lines 14-17, 19-21)	-	0	0
23	CURRENT AND ACCRUED ASSETS:			
24	Cash (131)	-	919,386	567,392
25	Special Deposits (132-134)	-	79,523	210,360
26	Working Funds (135)	-	200	0
27	Temporary Cash Investments (136)		100,314	3,332
28	Notes Receivable (141)	-	72,681	11,200
29	Customer Accounts Receivable (142)		1,960,231	1,214,252
30	O her Accounts Receivable (143)	-	(6,741)	2,569
31	(Less) Accum. Prov. for Uncollectible Acct.-Credit (144)	-	(6,137)	(39,316)
32	Notes Receivable from Associated Companies (145)	-		
33	Accounts Receivable from Assoc. Companies (146)	-	1,348,317	2,312,407
34	Fuel Stock (151)	-		
35	Fuel Stock Expenses Undistributed (152)	-		
36	Residuals (Elec) and Extracted Products (Gas) (153)	-		
37	Plant Materials and Operating Supplies (154)	-	2,405,847	2,415,301
38	Merchandise (155)	-		
39	O her Materials and Supplies (156)	-		
40	Nuclear Materials Held for Sale (157)	-		
41	Allowances (158.1 and 158.2)	-		
42	(Less) Noncurrent Por ion of Allowances	-		
43	Stores Expense Undistributed (163)	-		
44	Gas Stored Underground - Current (164.1)			
45	Liquefied Natural Gas Stored and Held for Processing (164.2-164.3)			
46	Prepayments (165)		329,363	114,919
47	Advances for Gas (166-167)			
48	Interest and Dividends Receivable (171)	-		
49	Rents Receivable (172)	-		
50	Accrued U ility Revenues (173)	-	1,565,587	1,817,496
51	Miscellaneous Current and Accrued Assets (174)	-	39,730	58,399
52	TOTAL Current and Accrued Assets (Enter Total of lines 24 thru 51)	-	8,808,298	8,688,313

Name of Respondent	This Report is:	Date of Report	Year of Report
Summit Natural Gas of Maine, Inc	(1) An Original	(Mo, Da, Yr)	December 31, 2020
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COMPARATIVE BALANCE SHEET (ASSETS AND OTHER DEBITS) (Continued)

Line No.	Title of Account (a)	Ref. Page No. (b)	Balance at Beginning of Year (c)	Balance at End of Year (d)
53	DEFERRED DEBITS			
54	Unamortized Debt Expense (181)	-		
55	Extraordinary Property Losses (182.1)			
56	Unrecovered Plant and Regulatory Study Costs (182.2)			
57	O her Regulatory Assets (182 3)	29	13,349,534	14,501,473
58	Prelim. Survey and Investigation Charges (Electric) (183)	-		
59	Prelim. Sur. and Invest. Charges (Gas) (183.1, 183.2)			
60	Clearing Accounts (184)	-		
61	Temporary Facilities (185)	-		
62	Miscellaneous Deferred Debits (186)	30	7,437,058	7,437,058
63	Def. Losses from Disposition of U ility Plt. (187)	-		
64	Research, Devel. and Demonstration Expend. (188)			
65	Unamortized Loss on Reacquired Debt (189)	-		
66	Accumulated Deferred Income Taxes (190)			
67	Unrecovered Purchased Gas Costs (191)	-		
68	TOTAL Deferred Debits i(Enter Total of lines 54 thru 67)		20,786,592	21,938,531
69	TOTAL Assets and other Debits (Enter Total of lines 10, 11, 12, 22, 52, and 68)		355,138,922	359,215,532

(SUBSTITUTE PAGE FOR PART III)

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year of Report
Summit Natural Gas of Maine, Inc	(1) An Original **(2) A Resubmission**	04/29/2021	December 31, 2020

COMPARATIVE BALANCE SHEET (LIABILITIES AND CREDITS) (Continued)

Line No.	Title of Account (a)	Ref. Page No. (b)	Balance at Beginning of Year (c)	Balance at End of Year (d)
1	PROPRIETARY CAPITAL			
2	Common Stock Issued (201)		1,920,131	1,920,131
3	Preferred Stock Issued (204)			
4	Capital Stock Subscribed (202, 205)			
5	Stock Liability for Conversion (203, 206)			
6	Premium on Capital Stock (207)		277,817,908	293,267,908
7	Other Paid-In Capital (208-211)			
8	Installments Received on Capital Stock (212)			
9	(Less) Discount on Capital Stock (213)			
10	(Less) Capital Stock Expense (213)			
11	Retained Earnings (215, 215.1, 216)	15-16	(56,521,711)	(66,432,274)
12	Unappropriated Undistributed Subsidiary Earnings (216.1)	15-16		
13	(Less) Reacquired Capital Stock (217)			
14	TOTAL Proprietary Capital (Enter Total of lines 2 thru 14)	-	223,216,328	228,755,765
15	LONG-TERM DEBT			
16	Bonds (221)	31-32		
17	(Less) Reacquired Bonds (222)	31-32		
18	Advances from Associated Companies (223)	31-32		
19	Other Long-Term Debt (224)	31-32	125,000,000	125,057,399
20	Unamortized Premium on Long-Term Debt (225)			
21	(Less) Unamortized Discount on Long-Term Debt-Debit. (226)			
22	TOTAL Long-Term Debt (Enter Total of lines 16 thru 21)	-	125,000,000	125,057,399
23	OTHER NONCURRENT LIABILITIES			
24	Obligations Under Capital Leases - Noncurrent (227)	-		
25	Accumulated Provision for Property Insurance (228.1)	-		
26	Accumulated Provision for Injuries and Damages (228.2)	-		
27	Accumulated Provision for Pensions and Benefits (228.3)	-		
28	Accumulated Miscellaneous Operating Provision (228.4)	-		
29	Accumulated Provision for Rate Refunds (229)	-		
30	TOTAL Other Noncurrent Liabilities (Enter Total of lines 25 thru 29)			
31	CURRENT AND ACCRUED LIABILITIES			
32	Notes Payable (231)	-		
33	Accounts Payable (232)	-	376,039	475,542
34	Notes Payable to Associated Companies (233)	-		
35	Accounts Payable to Associated Companies (234)	-	241,980	297,708
36	Customer Deposits (235)	-	13,507	15,460
37	Taxes Accrued (236)	34-35	1,152,764	1,226,942
38	Interest Accrued (237)	-		
39	Dividends Declared (238)	-		
40	Matured Long-Term Debt (239)	-		
41	Matured Interest (240)	-		
42	Tax Collections Payable (241)	-	34,795	26,305
43	Miscellaneous Current and Accrued Liabilities (242)		5,103,509	3,360,410
44	Obligations Under Capital Leases-Current (243)	-		
45	TOTAL Current and Accrued Liabilities (Enter Total of lines 32 thru 44)	-	6,922,594	5,402,367

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year of Report
Summit Natural Gas of Maine, Inc	(1) An Original **(2) A Resubmission**	04/29/2021	December 31, 2020

COMPARATIVE BALANCE SHEET (LIABILITIES AND CREDITS) (Continued)

Line No.	Title of Account (a)	Ref. Page No. (b)	Balance at Beginning of Year (c)	Balance at End of Year (d)
46	DEFERRED CREDITS			
47	Customer Advances for Construction (252)			
48	Accumulated Deferred Investment Tax Credits (255)			
49	Deferred Gains from Disposition of Utility Plant (256)			
50	Other Deferred Credits (253)	36		
51	Other Regulatory Liabilities (254)	37		
52	Unamortized Gain on Reacquired Debt (257)			
53	Accumulated Deferrred Income Taxes (281-283)			
54	TOTAL Deferred Credits (Enter Total of lines 47 thru 53)		0	0
55				
56				
57				
58				
59				
60				
61				
62				
63				
64				
65				
66				
67				
68	TOTAL Liabilities and Other Credits (Enter Total of lines 14, 22, 30			
	45 and 54)		355,138,923	359,215,532

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year of Report
Summit Natural Gas of Maine, Inc	(1) An Original **(2) A Resubmission**	04/29/2021	December 31, 2020

STATEMENT OF INCOME FOR THE YEAR

1. Report amounts for accounts 412 and 413, Revenue and Expenses from Utility Plant Leased to Others, in another utility column (i,k,m,o) in a similar manner to a utility department. Spread the amount(s) over lines 02 thru 24 as appropriate. Include these amounts in columns (c) and (d) totals.
2. Report amounts in account 414, Other Utility Operating Income, in the same manner as accounts 412 and 413 above.
3. Report data for lines 7,9, and 10 for Natural Gas companies using accounts 404.1,404.2,404.3, 407.1 and 407.2.
4. Use page 122 for important notes regarding the statement of income for any account thereof.
5. Give concise explanations concerning unsettled rate proceedings where a contingency exists such that refunds of a material amount may need to be made to the utility's customers or which may result in a material refund to the utility with respect to power or gas purchases. State for each year affected the gross revenues or costs to which the contingency relates and the tax effects together with an explanation of the major factors which affect the rights of the utility to retain such revenues or recover amounts paid with respect to power and gas purchases.
6. Give concise explanations concerning significant amounts of any refunds made or received during the year

Line No.	Account (a)	(Ref.) Page No. (b)	TOTAL Current Year (c)	TOTAL Previous Year (d)
1	UTILITY OPERATING INCOME			
2	Operating Revenues (400)	38-39	17,072,565	19,985,864
3	Operating Expenses			
4	Operation Expenses (401)	41-46	11,873,588	14,490,317
5	Maintenance Expenses (402)	41-46	519,498	384,064
6	Depreciation Expense (403)		8,445,080	8,319,215
7	Amort. & Depl. of Utility Plant (404-405)		176,676	176,676
8	Amort. of Utility Plant Acq. Adj. (406)			
9	Amort of Property Losses, Unrecovered Plant and			
	Regulatory Study Costs (407)			
10	Amort. of Conversion Expenses (407)			
11	Regulatory Debits (407.3)			
12	(Less) Regulatory Credits (407.4)			
13	Taxes Other Than Income Taxes (408.1)	34-35	2,720,541	2,693,196
14	Income Taxes - Federal (409.1)	34-35		
15	- Other (409.1)	34-35		
16	Provision for Deferred Income Taxes (410.1)			
17	(Less) Provision for Deferred Income Taxes-Cr. (411.1)		(3,464,346)	(3,219,342)
18	Investment Tax Credit Adj. - Net (411.4)			
19	(Less) Gains from Disp. of Utility Plant (411.6)			
20	Losses from Disp. of Utility Plant (411.7)			
21	(Less) Gains from Disposition of Allowances (411.8)			
22	Losses from Disposition of Allowances (411.9)			
23	TOTAL Utility Operating Expenses		20,271,037	22,844,124
	(Enter Total of lines 4 thru 22)			
24	Net Utility Operating Income (Enter Total of		(3,198,472)	(2,858,260)
	line 2 less 23) (Carry forward to page 117, line 25)			

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year of Report
Summit Natural Gas of Maine, Inc	(1) An Original **(2) A Resubmission**	04/29/2021	December 31, 2020

STATEMENT OF INCOME FOR THE YEAR (Continued)

resulting from settlement of any rate proceeding affecting revenues received or costs incurred for power or gas purchases, and a summary of the adjustments made to balance sheet, income, and expense accounts.

7. If any notes appearing in the report to stockholders are applicable to this Statement of Income, such notes may be attached at page 19.

8. Enter on page 19 a concise explanation of only those changes in accounting methods made during the year which had an effect on net income, including the basis of allocations and apportionments from those used in the preceding year. Also give the approximate dollar effect of such changes.

9. Explain in a footnote if the previous year's figures are different from that reported in prior reports.

10. If the columns are insufficient for reporting additional utility departments, supply the appropriate account titles, lines 2 to 23, and report the information in the blank space on page 19 or in a supplemental statement

ELECTRIC UTILITY		GAS UTILITY		OTHER UTILITY		
Current Year (e)	Previous Year (f)	Current Year (g)	Previous Year (h)	Current Year (i)	Previous Year (j)	Line No.
[redacted]						1
		17,072,565	19,985,864			2
[redacted]						3
		11,873,588	14,490,317			4
		519,498	384,064			5
		8,445,080	8,319,215			6
		176,676	176,676			7
						8
						9
						10
						11
						12
		2,720,541	2,693,196			13
		0	0			14
		0	0			15
		0	0			16
						17
		0	0			18
						19
						20
						21
						22
		20,271,037	22,844,124			23
		(3,198,472)	(2,858,260)			24

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year of Report
Summit Natural Gas of Maine, Inc	(1) An Original **(2) A Resubmission**	04/29/2021	December 31, 2020

STATEMENT OF INCOME FOR THE YEAR

Line No.	Account (a)	(Ref.) Page No. (b)	TOTAL Current Year (c)	TOTAL Previous Year (d)
25	Net Utility Operating Income (Carried forward from page 12)		-3,198,472	-2,858,260
26	Other Income and Deductions			
27	Other Income			
28	Nonutility Operating Income			
29	Revenues from Merchandising, Jobbing, and Contract Work (415)			
30	(Less) Costs and Exp. of Merch., Job, & Contract Work (416)			
31	Revenues From Nonutilty Operations (417)		766	7
32	(Less) Expenses of Nonutility Operations (417.1)			-150,000
33	Nonoperating Rental Income (418)			7
34	Equity in Earnings of Subsidiary Companies (418.1)			
35	Interest and Dividend Income (419)		8,377	13,478
36	Allowance for Other Funds Used During Construction (419.1)			
37	Miscellaneous Nonoperating Income (421)		3,190	2,548
38	Gain on Disposition of Property (421.1)			
39	TOTAL Other Income (Enter Total of lines 29 thru 38)		12,333	(133,960)
40	Other Income Deductions			
41	Loss on Disposition of Property (421.2)			
42	Miscellaneous Amortization (425)			
43	Miscellaneous Income Deductions (426.1-426.5)		131,372	120,561
44	TOTAL Other Income Deductions (Total of lines 41 thru 43)		131,372	120,561
45	Taxes Applic. to Other Income and Deductions			
46	Taxes Other Than Income Taxes (408.2)			
47	Income Taxes - Federal (409.2)			
48	Income Taxes - Other (409.2)			
49	Provision for Deferred Inc. Taxes (410.2)			
50	(Less) Provision for Deferred Income Taxes - Cr. (411.2)			
51	Investment Tax Credit Adj. - Net (411.5)			
52	(Less) Investment Tax Credits (420)			
53	TOTAL Taxes on Other Inc. and Ded. (Total of 46 thru 52)		0	0
54	Net Other Income and Deductions (Enter Total of lines 39,44,53)		(119,039)	(254,521)
55	Interest Charges			
56	Interest on Long-Term Debt (427)		6,590,278	6,582,680
57	Amort. of Debt Disc. and Expense (428)			
58	Amortization of Loss on Reaquired Debt (428.1)			
59	(Less) Amort. of Premium on Debt-Credit (429)			
60	(Less) Amortization of Gain on Reaquired Debt-Credit (429.1)			
61	Interest on Debt to Assoc. Companies (430)			
62	Other Interest Expense (431)		2,775	(254)
63	(Less) Allowance for Borrowed Funds Used During Const.- Cr.(432)			
64	Net Interest Charges (Enter Total of lines 56 thru 63)		6,593,053	6,582,426
65	Income Before Extraordinary Items (Enter Total of lines 25, 54, and 64)		(9,910,564)	(9,695,206)
66	Extraordinary Items			
67	Extraordinary Income (434)			
68	(Less) Extraordinary Deductions (435)			
69	Net Extraordinary Items (Enter Total of line 67 less line 68)			
70	Income Taxes - Federal and Other (409.3)			
71	Extraordinary Items After Taxes (Enter Total of line 69 less line 70)			
72	Net Income (Enter Total of lines 65 and 71)		(9,910,564)	(9,695,206)

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year of Report
Summit Natural Gas of Maine, Inc	(1) An Original **(2) A Resubmission**	04/29/2021	December 31, 2020

STATEMENT OF RETAINED EARN NGS FOR THE YEAR

1. Report all changes in appropriated retained earnings, unappropriated retained earnings, and unappropriated undistributed subsidiary earnings for the year.
2. Each credit and debit during the year should be identified as to the retained earnings account in which recorded (Accounts 433, 436-439 inclusive). Show the contra primary account affected in column (b).
3. State the purpose and amount for each reservation or appropriation of retained earnings.
4. List first Account 439, Adjustments to Retained Earnings, reflecting adjustments to the opening balance of retained earnings. Follow by credit, then debit items, in that order.
5. Show dividends for each class and series of capital stock.
6. Show separately the State and Federal income tax effect of items shown in Account 439, Adjustments to Retained Earnings.
7. Explain in a footnote the basis for determining the amount reserved or appropriated. If such reservation or appropriation is to be recurrent, state the number and annual amounts to be reserved or appropriated as well as the totals eventually to be accumulated.
8. If any notes appearing in the report to stockholders are applicable to this statement, attach them at page 19.

Line No.	tem (a)	Contra Primary Account Affected (b)	Amount (c)
	UNAPPROPRIATED RETA NED EARNINGS (Account 216)		
1	Balance-Beginning of Year		(56 521 710)
2	Changes (Identify by prescribed retained earnings accounts)		
3	Adjustments to Retained Earnings (Account 439)		
4	Credit:		(9,910,564.03)
5	Credit:		
6	Credit:		
7	Credit:		
8	Credit:		
9	TOTAL Credits to Retained Earnings (Account 439)(Enter Total of lines 4 thru 8)		(9,910,564)
10	Debit:		
11	Debit:		
12	Debit:		
13	Debit:		
14	Debit:		
15	TOTAL Debits to Retained Earnings (Account 439)(Enter Total of lines 10 thru 14)		0
16	Balance Transferred from Income (Account 433 less Account 418.1)		
17	Appropriations of Retained Earnings (Account 436)		
18			
19			
20			
21			
22	TOTAL Appropriations of Retained Earnings (Account 436)(Total of lines 18 thru 21)		
23	Dividends Declared-Preferred Stock (Account 437)		
24			
25			
26			
27			
28			
29	TOTAL Dividends Declared-Preferred Stock (Account 437)(Total of lines 24 thru 28)		
30	Dividends Declared-Common Stock (Account 438)		
31			
32			
33			
34			
35			
36	TOTAL Dividends Declared-Common Stock (Account 438)(Total of lines 31 thru 35)		
37	Transfers from Acct. 216.1 Unappropriated Undistributed Subsidiary Earnings		
38	Balance-End of Year (Total of lines 01, 09, 15, 16, 22, 29, 36 and 37)		(66,432,274)

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year of Report
Summit Natural Gas of Maine, Inc	(1) An Original (2) **A Resubmission**	04/29/2021	December 31, 2020

STATEMENT OF RETAINED EARNINGS FOR THE YEAR (Continued)

Line No.	Item (a)	4 Amount (b)
	APPROPRIATED RETAINED EARN NGS (Account 215) State balance and purpose of each appropriated retained earnings amount at end of year and give accounting entries for any applications of appropriated retained earnings during the year.	
39		
40		
41		
42		
43		
44		
45	TOTAL Appropriated Retained Earnings (Account 215)	
	APPROPRIATED RETAINED EARNINGS-AMORTIZATION RESERVE, FEDERAL (Account 215.1) State below the total amount set aside through appropriations of retained earnings, as of the end of the year, in compliance with the provisions of Federally granted hydroelectric project licenses held by the respondent. If any reductions or changes other than the normal annual credits hereto have been made during the year, explain such items in a footnote.	
46	TOTAL Appropriated Retained Earnings-Amortization Reserve, Federal (Account 215.1)	
47	TOTAL Appropriated Retained Earnings (Accounts 215,215.1)(Enter Total of lines 45 & 46)	
48	TOTAL Retained Earnings (Account 215,215.1,216) (Enter Total of lines 38 and 47)	(66,432,274)
	UNAPPROPRIATED UNDISTR BUTED SUBSIDIARY EARNINGS (216.1)	
49	Balance-Beginning of Year (Debit or Credit)	
50	Equity in Earnings for Year (Credit) (Account 418.1)	
51	(Less) Dividends Received (Debit)	
52	Other Changes (Explain)	
53	Balance-End of Year (Total of lines 49 thru 52)	

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year of Report
Summit Natural Gas of Maine, Inc.	(1) An Original (2) **A Resubmissio**	**4/29/2021**	December 31, 2020

Return on Common Equity on Investments Subject to Commission Jurisdiction

Each Local Distribution Company providing end use Natural Gas Service, shall provide the information requested on

Line No.	Maine Commission Jurisdiction	For Years Ended December 31, 2016	2017	2018	2019
1	Total Net Income	$ (9,127,188)	$ (10,214,871)	$ (9,584,988)	$ (9,695,206)
2	Adjustments to reflect income from activites not subject to Commission jurisdiction	[redacted]			
3					
4	Other Nonutiilty Income				
5					
6					
7					
8					
9					
10					
11	Total Net Income from Commission Jurisdiction	$ (9,127,188)	$ (10,214,871)	$ (9,584,988)	$ (9,695,206)
12					
13	Total Common Equity				
14	Adjustments to reflect Common Equity on investments not subject to Commission Jurisdiction (Show how calculated)	[redacted]			
15					
16	Common Equity for Non-Utility Invesment	202,813,000	199,646,523	199,911,534	223,216,328
17	Other Common Equity				
18					
19					
20					
21					
22	Total Common Equity for Investments Subject to Commission Jurisdiction	202,813,000	199,646,523	199,911,534	223,216,328
23					
24	Return on Common Equity Subject to Commission Jurisdiction (Line 11/Line 22)	-5%	-5%	-5%	-4%
25					
26	Rate Base				

Name of Respondent	This Report Is:	Date of Report	Year of Report
Summit Natural Gas of Maine, Inc	(1) An Original **(2) A Resubmission**	(Mo, Da, Yr) 04/29/2021	December 31, 2020

STATEMENT OF CASH FLOWS

1. If the notes to the cash flow statement in the respondents annual stockholders report are applicable to this statement, such notes should be attached to page 19. Information about noncash investing and financing activities should be provided on page 19. Provide also on page 19 a reconciliation between "Cash and Cash Equivalents at End of Year" with related amounts on the balance sheet.
2. Under "Other" specify significant amounts and group others.
3. Operating Activities-Other: Include gains and losses pertaining to operating activities only. Gains and losses pertaining to investing and financing activities should be reported in those activities. Show on page 19 the amounts of interest paid (net of amounts capitalized) and income taxes paid.

Line No.	DESCRIPTION (See instructions for Explanation of Codes) (a)	Amount (b)
1	Net Cash Flow from Operating Activities:	
2	Net Income for Northern (from page 14)	(9,910,564)
3	Noncash Charges (Credits) to Income:	
4	Depreciation and Depletion	8,621,755
5	Amortization of (Specify) Other	
6		
7		
8	Deferred Income Taxes (Net)	(3,464,346)
9	Investment Tax Credit Adjustments (Net)	
10	Net (Increase) Decrease in Receivables	769,847
11	Net (Increase) Decrease in Inventory	(9,454)
12	Net Increase (Decrease) in Fuel Purchase Commitments	
13	Net Increase (Decrease) in Accounts Payable	37,391
14	Net (Increase) Decrease in Other Assets	1,347,909
15	Net Increase (Decrease) in Other Liabilities	(1,555,945)
16	(Less) Allowance for Other Funds Used During Construction	
17	(Less) Undistributed Earnings from Subsidiary Companies	
	Other: Miscellaneous	
18		
19	Net Increase (Decrease) in Accrued Interest Expense	
20	Net (Increase) Decrease in Deferred Fuel Costs	
21	Net Cash Provided by (Used in) Operating Activities	
22	(Total of lines 2 thru 20)	(4,163,407)
23		
24	Cash Flows from Investment Activities:	
25	Construction and Acquisition of Plant (including land):	
26	Gross Additions to Utility Plant (less nuclear fuel)	(11,666,411)
27	Gross Additions to Nuclear Fuel	
28	Gross Additions to Common Utility Plant	
29	Gross Additions to Nonutility Plant	
30	(Less) Allowance for Other Funds Used During Construction	
31	Other:	(130,838)
32		
33		
34	Cash Outflows for Plant (Total of lines 26b thru 33)	(11,797,248)
35		
36	Acquisition of Other Noncurrent Assets (d)	
37	Proceeds from Disposal of Noncurrent Assets (d)	
38		
39	Investments in and Advances to Assoc. and Subsidiary Companies	
40	Contributions and Advances from Assoc. and Subsidiary Companies	
41	Disposition of Investments in (and Advances to)	
42	Associated and Subsidiary Companies	
43		
44	Purchase of Investment Securities (a)	
45	Proceeds from Sales of Investment Securities (a)	

Name of Respondent	This Report Is:	Date of Report	Year of Report
Summit Natural Gas of Maine, Inc	(1) An Original **(2) A Resubmission**	(Mo, Da, Yr) 04/29/2021	December 31, 2020

STATEMENT OF CASH FLOWS (Continued)

4. Investing Activities
Include at Other (line 31) net cash outflow to acquire other companies. Provide a reconciliation of assets acquired with liabilities assumed on page 19.
Do not include on this statement the dollar amount of leases capitalized per USofA General Instruction 20; instead provide a reconciliation of the dollar amount of leases capitalized with the plant cost on page 19

5. Codes used:
(a) Net proceeds or payments.
(b) Bonds, debentures and other long-term
(c) Include commercial paper.
(d) Identify separately such items as investments, fixed assets, intangibles, etc.

6. Enter on page 19 clarifications and explanations

Line No.	DESCRIPTION (See Instruction No. 5 for Explanation of Codes) (a)	Amount (b)
46	Loans Made or Purchased	
47	Collections on Loans	
48		
49	Net (Increase) Decrease in Receivables	
50	Net (Increase) Decrease in Inventory	
51	Net (Increase) Decrease in	
52	Allowances Held for Speculation	
53	Net Increase (Decrease) in Payables and Accrued Expenses	
54	Other:	
55		
56	Net Cash Provided by (Used in) Investing Activities	
57	(Total of lines 34 thru 55)	(11,797,248)
58		
59	Cash Flows from Financing Activities:	
60	Proceeds from Issuance of:	
61	Long-Term Debt (b)	
62	Preferred Stock	
63	Common Stock	
64	Other:	15,511,480
65		
66	Net Increase in Short-Term Debt (c)	
67	Other:	
68		
69		
70	Cash Provided by Outside Sources (Total of lines 61 thru 69)	15,511,480
71		
72	Payments for Retirement of:	
73	Long-Term Debt (b)	
74	Preferred Stock	
75	Common Stock	
76	Other:	
77		
78	Net Decrease in Short-Term Debt (c)	0
79		
80	Dividends on Preferred Stock	
81	Dividends on Common Stock	
82	Net Cash Provided by (Used in) Financing Activities	
83	(Total of lines 70 thru 81)	15,511,480
84		
85	Net Increase (Decrease) in Cash and Cash Equivalents	
86	(Total of lines 22, 57 and 83)	(449,176)
87		
88	Cash and Cash Equivalents at Beginning of Year	1,019,899
89		
90	Cash and Cash Equivalents at End of Year	570,724

Summit Natural Gas of Maine, Inc.
Notes to Financial Statements
December 31, 2020 and 2019

1. Description of Business and Basis of Presentation

Summit Natural Gas of Maine, Inc. ("SNG-ME" or the "Company"), a Colorado corporation, is an operating public utility subject to the jurisdiction of the Public Utilities Commissions of the state of Maine ("MPUC") with respect to its retail gas operations. SNG-ME is a wholly owned subsidiary of Summit Utilities, Inc. ("Summit"). SNG-ME develops, owns, and operates natural gas local distribution systems.

SNG-ME holds a Certificate of Authority to Furnish Natural Gas granted by the MPUC for the municipalities of Richmond, Gardiner, Farmingdale, Hallowell, Augusta, Sidney, Belgrade, Oakland, Fairfield, Waterville, Norridgewock, Skowhegan, Madison, China, Albion, Windsor, Winslow, Randolph, Cumberland, Falmouth, and Yarmouth in the state of Maine.

Management's Plans with Respect to Liquidity and Capital Resources
For the years ended December 31, 2020 and 2019, the Company experienced a net loss of $9.9 million and $9.7 million, respectively, and positive working capital of $0.8 million and negative working capital of $0.5 million, respectively. The Company has a recent history of net losses, operating cash flow losses, and forecasts continued losses related to the expansion of the business.

The Company is a portfolio investment of IIF US Holdings 2 LP. In order to meet its operating and other cash flow needs, the Company has a written commitment from IIF US Holdings 2 LP to provide both operational and financial support for at least 12 months and a day from the date that these financial statements are available to be issued to ensure the Company has adequate liquidity to meet its obligations and fund its operations in the event that such financing or working capital requirements arise.

Regulatory Accounting
The Company prepares its financial statements in accordance with accounting principles generally accepted in the United States of America ("GAAP"), for rate regulated utilities, which recognize the economic effects of rate regulation. A regulated entity may defer recognition of a cost (a regulatory asset) or recognize an obligation (a regulatory liability) if it is probable that, through the ratemaking process, there will be a corresponding increase or decrease in revenues. Accordingly, the Company records regulatory assets when required by a regulatory order or when it is probable, based on regulatory precedent, that future rates will allow for recovery of a regulatory asset. The Company records regulatory liabilities based on the expectation the amounts will be returned to customers in future rates, or because the amounts were collected in rates prior to the costs being incurred. Estimates of recovering deferred costs and returning deferred credits are based on specific ratemaking decisions or precedent for each item. Regulatory assets and liabilities are amortized consistent with treatment in the rate-setting process.

The Company uses the Federal Energy Regulatory Commission's ("FERC") Uniform System of Accounts Prescribed for Natural Gas Companies, subject to the provisions of the Natural Gas Act, in determining its accounting policies and practices.

Use of Estimates in the Preparation of Financial Statements
The preparation of financial statements in conformity with GAAP requires management to make estimates, judgments, and assumptions that affect the amounts reported in the financial statements and accompanying notes. The estimates, judgments, and assumptions the Company makes in preparing the financial statements are based on information available at the time. Actual results could differ from the estimates, judgments, and assumptions that the Company uses in the preparation of the financial statements. The more significant areas requiring the use of estimates, judgments, and assumptions relate to the impairment assessments regarding long-lived assets,

allowance for doubtful accounts, accruing unbilled revenues and determining the useful lives of assets. In addition, the Company uses estimates in the allocation of labor, general and administrative expenses from parent, certain overhead costs, and management's plans with respect to liquidity and capital resources.

Cash and cash equivalents
The Company considers all highly liquid instruments purchased with an original maturity of three months or less to be cash equivalents. The Company continually monitors its positions with, and the credit quality of, the financial institutions with which it invests.

Concentrations
The Company grants credit in the normal course of business to its customers. During the years ended December 31, 2020 and 2019, one customer accounted for more than 10% of total revenues with a total concentration of 14% and 13% respectively, of gross revenues.

Accounts Receivable
The Company's accounts receivable are primarily related to sales of natural gas. Credit is extended based on prior experience with the customer and evaluation of the customer's financial condition. Accounts receivable are generally due within 30 days. The Company assesses the collectability of the accounts by taking into consideration historical experience. Any amounts subsequently collected are recognized as a reduction to bad debt expense.

Due to the impacts of COVID-19 on its customers in 2020, the Company experienced an increase in past due receivable balances. The receivable balances were evaluated as of December 31, 2020 and an additional allowance was recorded in the year. The MPUC has not authorized the capitalization of additional bad debt expense related to COVID-19.

As of December 31, 2020 and 2019, the Company had an insignificant allowance for doubtful accounts, which is presented as a reduction to the accounts receivable balance.

Property, Plant, and Equipment
Property, plant, and equipment is stated at cost. For constructed plant, costs include contracted services, direct labor, materials, an allowance for funds used during construction, allocations of certain overhead costs related to construction, and certain costs approved by the MPUC associated with residential and commercial incentives.

Additions that extend the useful life of the assets are capitalized, while maintenance and repairs that do not improve or extend the useful life of the respective assets are charged to operations as incurred. The Company transfers costs in construction in progress to property, plant, and equipment as construction is completed.

Provisions for depreciation of property, plant, and equipment for financial accounting purposes are based on composite rates applied to the various classes of depreciable property. Depreciation

expense is provided using the straight-line method based on estimated service lives of 3 to 50 years for property, plant, and equipment.

The cost of units of property retired, together with cost of removal, less salvage, is charged against accumulated depreciation. Currently, the Company has no legal requirements under its agreement with the MPUC to remove, reclaim, or retire its utility plant assets.

Customer Rebates
The Company has capitalized residential and commercial rebates and included these costs in natural gas distribution plant. The capitalization is based on expected recovery and approval from the MPUC. Rebate costs relate to funds paid to induce customers to obtain the Company's services and to administer the rebate program. For the years ended December 31, 2020 and 2019, the Company capitalized to natural gas plant amounts related to rebates of $0.5 million and $0.6 million, respectively.

Materials and Supplies
Materials and supplies consist of pipe and plant related inventory and are valued at cost using the weighted average cost method. The costs are moved to natural gas distribution plant or operating expense as the materials and supplies are used.

Long-Lived Assets
The Company reviews long-lived assets for impairment whenever events and circumstances indicate a decline in the recoverability of their carrying values. The Company estimates the

indicate a decline in the recoverability of their carrying values. The Company estimates the expected undiscounted future cash flows related to these assets and compares such cash flows to the carrying value to determine recoverability. If the carrying value exceeds the estimated undiscounted cash flows, the Company will adjust the assets to fair value. The factors used to determine fair value include estimates of future revenues, related transportation and distribution costs, taxes, and future customers and usage. For the years ended December 31, 2020 and 2019, the Company recorded no impairments, respectively.

Restricted Cash
In connection with the Company's construction of natural gas distribution plant, the Company is required by various governmental bodies to place funds in escrow during the construction period. Upon the expiration of specified completion periods, funds will be released back to the Company, less any associated permit fees. As of December 31, 2020 and 2019, there was $0.2 million and $0.1 million, respectively, in various escrow accounts.

Intangible Assets
As of December 31, 2020 and 2019, intangible assets consisted of customer relationships of $1.6 million and $1.8 million, respectively, net of accumulated amortization of $1.0 million and $0.8 million, respectively. These assets are considered to have 15-year lives based on the life of the underlying contracts. Amortization expense related to intangible assets for the years ended December 31, 2020 and 2019 was $0.2 million and $0.2 million, respectively. The estimated future amortization expense of intangible assets as of December 31, 2020 is as follows:

(in thousands)

Year Ending December 31,		
2021	$	177
2022		177
2023		177
2024		177
2025		177
Thereafter		707
	$	1,592

Purchased Gas Cost
The Company accounts for purchased gas costs in accordance with procedures authorized by the MPUC. Purchased gas costs that are different from those provided for in present rates and approved by the MPUC are accumulated and recovered or credited through future rate changes.

Derivative Instruments
The Company enters into derivative instruments to reduce risk in connection with changes in natural gas prices. Certain natural gas contracts that meet the definition of a derivative may be exempted from derivative accounting as the contracts meet the normal purchases or normal sales exemption.

Revenue Recognition
On January 1, 2019, the Company adopted ASU 2014-09 (Topic 606), *Revenue from Contracts with Customers* and related pronouncements ("ASC 606"). The underlying principle of the guidance requires entities to recognize revenue depicting the transfer of goods or services to customers at amounts the entity is expected to be entitled to in exchange for those goods or services. The ASU also prescribes a five-step approach to revenue recognition: (1) identify the contract(s) with the customer; (2) identify the separate performance obligations in the contract(s); (3) determine the transaction price; (4) allocate the transaction price to separate performance obligations; and (5) recognize revenue when, or as, each performance obligation is satisfied. The Company applied the five-step method outlined in the ASC 606 to all in-scope revenue streams. The implementation of the new revenue standard did not result in changes to how the Company currently recognizes revenue, and therefore, no cumulative effect or adjustment to the opening balances of retained earnings was required. The implementation resulted in changes to the disclosures and is reflected in Note 8.

Income Taxes
Deferred income taxes are recorded for timing differences between items of income or expense reported on the financial statements and those reported for income tax purposes using the asset/liability method of accounting for income taxes. Deferred income taxes are recognized for

the future tax consequences attributable to differences between the financial statement carrying

amounts of existing assets and liabilities and their respective tax bases and for tax loss and credit carryforwards. Deferred tax assets and liabilities are measured using enacted tax rates expected to apply to taxable income in the years in which those temporary differences are expected to be recovered or settled. If the Company concludes that it is more likely than not that some portion, or all, of the deferred tax assets will not be realized, the balance of deferred tax assets is reduced by a valuation allowance.

The Company files a consolidated federal tax return with Summit, and deferred income taxes are allocated on a benefits-for-loss basis.

2. Property, Plant, and Equipment

The following is a summary of property, plant, and equipment:

(in thousands)	December 31, 2020	December 31, 2019
Natural gas plant	$ 364,368	$ 355,448
Office furniture	641	641
Vehicles	2,737	2,237
Computers, software, and other equipment	3,085	2,911
Construction work in progress	2,508	455
Property, plant, and equipment, at cost	373,339	361,692
Less: Accumulated depreciation	(46,343)	(37,917)
Total property, plant, and equipment, net	$ 326,996	$ 323,775

During the years ended December 31, 2020 and 2019, the Company recorded $8.4 million and $8.3 million, respectively, of depreciation expense related to property, plant, and equipment, which was recorded in depreciation and amortization on the statement of loss and comprehensive loss.

3. Regulatory Accounting

Regulatory Assets

Regulatory assets represent probable future revenue associated with certain costs that may be recovered from customers through the ratemaking process. The Company has recorded these assets in accordance with GAAP. If the Company were required to terminate application of regulatory accounting for all of its regulated operations, the Company would have to record these amounts as expense on its statement of loss at that time.

In accordance with ASC 740, the enactment of TCJA on December 22, 2017 required revaluation of federal deferred tax assets and liabilities using the new lower corporate statutory tax rate of 21%. As a result of the revaluation, deferred tax assets were decreased by $7.4 million and a regulatory asset of $7.4 million was established. This net regulatory asset will generally be amortized over the remaining life of the related assets, for the fixed asset related portion, using the normalization principles as specifically prescribed in the TCJA. For the remaining amount not related to fixed assets, the prescribed method of amortization has not been determined.

4. Related Party Notes Payable

In 2020 and 2019, the Company had related party notes with Summit's investors for $125.0 million and $125.0 million, respectively. Principal is due on December 31, 2022 but interest payable is callable at the discretion of Summit's investors. The notes bear interest at 5.2%.

For the years ended December 31, 2020 and 2019, the Company incurred interest expense of $6.6 million and $6.6 million, respectively, related to these notes. As of December 31, 2020, and 2019, the Company had unpaid interest in amounts of $0.0 million and $1.5 million, respectively, which is included in related party interest payable on the balance sheets.

5. Operating Leases

The Company rents certain office equipment and office space under noncancelable agreements accounted for as operating leases. The Company is responsible for the operating expenses incurred by the landlord on each of the leases. Rent expense for the years ended December 31, 2020 and 2019 was $0.3 million and $0.2 million, respectively, which is included in operating, general and administrative expenses on the statement of loss.

Future minimum payments under operating leases having an initial or remaining noncancelable term in excess of one year are as follows:

(in thousands)

Year Ending December 31,		
2021	$	268
2022		264
2023		198
2024		104
2025		44
Total future minimum lease payments	$	878

6. Employee Benefit Plan

The Company participates in Summit's qualified retirement plan (the "Plan") under Section 401(k) of the IRC. Employees become eligible to participate in the Plan upon attaining 21 years of age and completing at least three months of service. Prior service is counted toward the eligibility requirement. Upon attainment of eligibility, entry into the Plan occurs the first day of the month following the month during which the eligibility requirements are satisfied. The Company may make a discretionary matching contribution and/or discretionary profit-sharing contribution each year. For the years ended December 31, 2020 and 2019, the discretionary contribution to the Plan totaled $0.1 million and $0.1 million, respectively.

7. Revenue

Revenue from customers is recognized when the obligation to the customer is satisfied and in the amount expected to be received in exchange for transferring goods or providing services. The transaction price is determined per a set price agreed upon in the contract or regulatory tariffs. Revenue from contracts with customers contain one performance obligation that is generally satisfied over time, using the output method based on usage.

Revenue includes gas distributed or transported but not billed (unbilled revenue). The accrued unbilled revenue balance is based on estimates of gas distributed or transported during the period from the last meter reading and management judgment is required for a number of factors used in this calculation, including customer use and weather factors. Meters are read, and customers are billed on a cycle billing basis that does not necessarily coincide with the calendar month. The Company's cost-of-gas tariffs approved by the state Commission provide for the recovery or refund of accumulated differences between the recoverable costs of gas, as defined, and the revenues designated for recovery of such costs. These recoveries are subject to periodic review by the state Commission.

8. Commitments and Contingencies

Gas Purchase Agreements

Consistent with agreed upon gas purchase methodologies approved by the MPUC, the Company uses gas purchase agreements to limit customer rate volatility. In addition, these purchase agreements provide an element of stability to the Company's cash flows in an environment of volatile gas prices and help manage the Company's exposure to natural gas price volatility. These commitments qualify for the normal purchase exclusion in accordance with derivative accounting. As of December 31, 2020, the Company had outstanding commitments to purchase 147,500 dekatherms of natural gas at fixed and market rates on the purchase date. The contracts call for various daily volumes and expire monthly through February 2021.

Litigation

In the normal course of business, the Company is party to a litigation from time to time. The Company maintains insurance to cover certain claims and believes that resolution of currently pending litigation will not have a material adverse effect on its financial position, cash flows, or results of operations.

9. Income Taxes

The Company recognizes deferred tax liabilities and assets for the expected future tax consequences of events that have been included in the financial statements or tax returns. Deferred tax liabilities and assets are determined based on the differences between the financial statement and tax basis of assets and liabilities using the enacted tax rates in effect for the year in which the differences are expected to reverse. The measurement of deferred tax assets is reduced, if necessary, by the amount of any tax benefits that are not expected to be realized based on available evidence. The Company's temporary differences result primarily from depreciation and amortization and the allowance for doubtful accounts.

Income tax benefit included in the statements of loss:

	Year Ended December 31,	
(in thousands)	2020	2019
Federal		
Deferred	$ (2,600)	$ (2,514)
State		
Deferred	(864)	(705)
Total income tax benefit	$ (3,464)	$ (3,219)

The Company has the following deferred tax assets and deferred tax liabilities:

	December 31,	
(in thousands)	2020	2019
Deferred tax assets		
Net operating loss carry forwards	$ 35,854	$ 33,133
Other	106	56
Total deferred tax assets	35,960	33,189
Deferred tax liabilities		
Property, plant, and equipment	(19,571)	(17,963)
Income tax regulatory assets	(1,888)	(1,877)
Total deferred tax liabilities	(21,459)	(19,840)
Net deferred tax asset	$ 14,501	$ 13,349

The Company has net operating loss carryforwards of approximately $135.6 million as of December 31, 2020. $106.4 million of these net operating loss carryforwards expire in 2033 through 2037. $29.2 million of the net operating loss carryforwards do not expire. Utilization of the net operating loss carryforwards will be subject to certain limitations under Section 382 of the Internal Revenue Code ("IRC") of 1986, as amended, and other limitations under state tax laws. As discussed in Note 1, the Company files a consolidated federal return with Summit, and deferred income taxes and net operating loss carryforwards are allocated on a benefits-for-loss basis for financial statement disclosure purposes only. No significant uncertain tax positions were identified as of any date on or before December 31, 2020. The Company reports interest and penalties related to income taxes within the other loss and interest expense sections on the statements of operations. As of December 31, 2020, the Company has not recognized any interest or penalties related to uncertain tax benefits. As of December 31, 2020, the Company's earliest open tax year is 2013.

The following is a reconciliation of the statutory federal income tax rate applied to pre-tax accounting net loss:

	Year Ended December 31, 2020	2019
Statutory rate	21.0 %	21.0 %
State tax	5.1	4.2
Effect of permanent differences	(0.1)	(0.1)
Other	(0.1)	(0.2)
Effective tax rate	25.9 %	24.9 %

10. Related Party Transactions

As of December 31, 2020, and 2019, the Company had \$0.3 million and \$0.2 million due to Summit, respectively. The amounts relate to payments of certain costs on behalf of the Company by Summit, including capital expenditures, operating costs, and payroll. Summit also allocates shared costs to the Company.

The Company files a consolidated tax return with Summit, and deferred income taxes are allocated on a benefits-for-loss basis. As of December 31, 2020 and 2019, the Company had \$2.3 million and \$1.3 million, respectively, due from Summit related to the utilization of the Company's losses in connection with income/loss allocation on a consolidated basis, respectively.

During the years ended December 31, 2020 and 2019, the Company periodically loaned employees to related entities, which then reimbursed the Company for those costs, with no markup, which are presented net on the statement of loss and on the balance sheets in due from/due to parent.

11. Accounting Standards

Recently Issued Accounting Pronouncements
In June 2016, the FASB issued ASU 2016-13 *Financial Instruments — Credit Losses (Topic 326): Measurement of Credit Losses on Financial Instruments*. The update requires the measurement of all expected credit losses for financial assets held at the reporting date based on historical experience, current conditions, and reasonable and supportable forecasts. The inputs currently used to estimate credit losses will still be utilized, however they may be adapted to reflect the full amount of expected losses, should there be a difference. The update is effective for fiscal years beginning after December 15, 2022, including interim periods within those fiscal years. The Company is currently evaluating the provisions of this guidance and assessing its impact on the Company's financial statements and disclosures and does not believe this standard will have a material impact on the Company's financial statements and disclosures.

In February 2016, the FASB issued ASU No. 2016-02, *Leases*, which will require lessees to recognize a right-of-use asset and a lease liability for all leases that are not short-term in nature. For a lessor, the accounting applied is largely unchanged from previous guidance. The new rules will be effective for the Company for the year ending December 31, 2022. The Company is currently in the process of evaluating the impact of adoption of the new rules on the Company's financial condition, results of operations, and cash flows.

12. Subsequent Events

The Company has evaluated all subsequent events through March XX, 2021, which is the date the financial statements were available to be issued. There were no additional material subsequent events that required recognition or additional disclosure in these financial statements.

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year of Report
Summit Natural Gas of Maine, Inc	(1) An Original **(2) A Resubmission**	04/29/2021	December 31, 2020

SUMMARY OF UTILITY PLANT AND ACCUMULATED PROVISIONS
FOR DEPRECIATION, AMORTIZATION, AND DEPLETION

Line No.	Item (a)	Total (b)
1	UTILITY PLANT	
2	In Service	
3	Plant in Service (Classified_	373,480,850
4	Property Under Capital Leases	
5	Plant Purchased or Sold	
6	Completed Construction not Classified	
7	Experimental Plant Unclassified	
8	Total Utility Plant (Total of lines 3 thru 7)	373,480,850
9	Leased to Others	
10	Held for Future Use	
11	Construction Work in Progress	2,509,087
12	Acquisition Adjustments	
13	Total Utility Plant (Totals of lines 8 hru 12)	375,989,936
14	Accumulated Provisions for Depreciation, Amortization & Depletion	(47,401,248)
15	Net Utility Plant (Totals of lines 13 and 14)	328,588,688
16	DETAIL OF ACCUMULATED PROVISIONS FOR DEPRECIATION, AMORTIZATION AND DEPLETION	
17	In Service:	
18	Depreciation	(46,343,420)
19	Amortization and Depletion of Producing Natural Gas Land and Land Rights	
20	Amortization of Underground Storage Land and Land Rights	
21	Amortization of Other Utility Plant	(1,057,829)
22	Total In Service (Totals of lines 18 thru 21)	(47,401,248)
23	Leased to Others	
24	Depreciation	
25	Amortization and Depletion	
26	Total Leased to Others (Totals off lines 24 and 25)	
27	Held for Future Use	
28	Depreciation	
29	Amortization	
30	Total Held for Future Use (Totals of lines 28 and 29)	
31	Abandonment of Leases (Natural Gas)	
32	Amortization of Plant Acquisition Adjustment	
33	Total Accum Provisions (Should agree with lien 14 above) (Total of lines 22, 26, 30, 31, and 32)	(47,401,248)

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year of Report
Summit Natural Gas of Maine, Inc	(1) An Original (2) **A Resubmission**	04/29/2021	December 31, 2020

SUMMARY OF UTILITY PLANT AND ACCUMULATED PROVISIONS
FOR DEPRECIATION, AMORTIZATION, AND DEPLETION

Electric (c)	Gas (d)	Other (Specify) (e)	Common (f)	Line No.
[redacted]	[redacted]	[redacted]	[redacted]	1
[redacted]	[redacted]	[redacted]	[redacted]	2
	373,480,850			3
				4
				5
				6
				7
	373,480,850			8
				9
				10
	2,509,087			11
				12
	375,989,936			13
	(47,401,248)			14
	328,588,688			15
[redacted]	[redacted]	[redacted]	[redacted]	16
				17
	(46,343,420)			18
[redacted]		[redacted]	[redacted]	19
[redacted]		[redacted]	[redacted]	20
	(1,057,829)			21
	(47,401,248)			22
[redacted]	[redacted]	[redacted]	[redacted]	23
				24
				25
				26
[redacted]	[redacted]	[redacted]	[redacted]	27
				28
				29
				30
[redacted]		[redacted]	[redacted]	31
				32
	(47,401,248)			33

Name of Respondent	This Report is:	Date of Report (Mo, Da, Yr)	Year of Report
Summit Natural Gas of Maine, Inc	(1) An Original (2) **A Resubmission**	04/29/2021	December 31, 2020

GAS PLANT IN SERVICE (Accounts 101, 102, 103, and 106)

1. Report below the original cost of gas plant in service according to the prescribed accounts.
2. In addition to Account 101, Gas Plant in Service(Classified), this page and the next include Account 102, Gas Plant Purchased or Sold; Account 103, Experimental Gas Plant Unclassified; and Account 106, Completed Construction Not Classified-Gas.
3. Include in column (c) or (d), as appropriate, corrections of additions and retirements for the current or preceding year.
4. Enclose in parentheses credit adjustments of plant accounts to indicate the negative effect of such accounts.
5. Classify Account 106 according to prescribed accounts, on an estimated basis if necessary, and include the entries in column (c). Also to be included in column (c) are entries for reversals of tentative distributions of prior year reported in column (b). Likewise if the respondent has a significant amount of plant retirements which have not been classified to primary accounts at the end of the year, include in column (d) a tentative distribution of such retirements, on an estimated basis, with appropriate contra entry to he account for accumulated depreciation provision. Include also in column (d) reversals of tentative distributions or prior year of unclassified retirements. Attach supplemental statement showing the account distribution of these tentative classifications in columns (c) and (d), including the reversals

Line No.	Account (a)		Balance at Beginning of Year (b)	Additions (c)
1		1. Intangible Plant		
2	301	Organization		
3	302	Franchises and Consents	115,838	
4	303	Miscellaneous Intangible Plant	2,650,000	
5		TOTAL Intangible Plant	2,765,838	0
6		2. Production Plant		
7		Natural Gas Production and Gathering Plant		
8	325.1	Producing Lands		
9	325.2	Producing Leaseholds		
10	325.3	Gas Rights		
11	325.4	Rights-of-Way		
12	325.5	Other Land and Land Rights		
13	326	Gas Well Structures		
14	327	Field Compressor Station Structures		
15	328	Field Meas. and Reg. Sta. Structures		
16	329	Other Structures		
17	330	Producing Gas Wells-Well Construction		
18	331	Producing Gas Wells-Well Equipment		
19	332	Field Lines		
20	333	Field Compressor Station Equipment		
21	334	Field Meas. and Reg. Sta. Equipment		
22	335	Drilling and Cleaning Equipment		
23	336	Purification Equipment		
24	337	Other Equipment		
25	338	Unsuccessful Exploration and Devel. Costs		
26		TOTAL Production and Gathering Plant	0.00	0
27		Products Extraction Plant		
28	340	Land and Land Rights		
29	341	Structures and Improvements		
30	342	Extraction and Refining Equipment		
31	343	Pipe Lines		
32	344	Compressor Equipment		
33	345	Gas Meas. and Reg. Equipment		
34	346	Compressor Equipment		
35	347	Other Equipment		
36		TOTAL Products Extraction Plant		
37		TOTAL Nat. Gas Production Plant		
38		Mfd. Gas Prod. Plant (Submit Suppl. Statement)		
39		TOTAL Production Plant	0	0

Name of Respondent Summit Natural Gas of Maine, Inc		Date or Report (Mo, Da, Yr) 04/29/2021	Year of Report December 31, 2020

GAS PLANT IN SERVICE (Accounts 101, 102, 103, and 106)

of the prior years tentative account distributions of these amounts. Careful observance of the above instructions and the texts of Accounts 101 and 106 will avoid serious omissions of the reported amount of respondent's plant actually in service at end of year.

6. Show in column (f) reclassifications or transfers within utility plant accounts. Include also in column (f) the additions or reductions of primary account classifications arising from distribution of amounts initially recorded in Account 102. In showing the clearance of Account 102, include in column (d) the amounts with respect to accumulated provision for depreciation, acquisition adjustments, etc., and show in column (f) only the offset to the debits or credits distributed in column (f) to primary account classifications.

7. For Account 300, state the nature and use of plant included in this account and if substantial in amount submit a supplementary statement showing the subaccount classification of such plant conforming to the requirements of these pages.

8. For each amount comprising the reported balance and changes in Account 102, state the property purchased or sold, name of vendor or purchaser, and date of transaction.

Retirements (d)	Adjustments (e)	Transfers (f)	Balance at End of Year (g)		Line No.
[redacted]					1
			0	301	2
			115,838	302	3
			2,650,000	303	4
0	0	0	2,765,838		5
[redacted]					6
					7
				325.1	8
				325.2	9
				325.3	10
				325.4	11
			0	325.5	12
				326	13
				327	14
			0	328	15
				329	16
				330	17
				331	18
				332	19
				333	20
				334	21
				335	22
				336	23
			0	337	24
				338	25
0	0	0	0		26
[redacted]					27
				340	28
				341	29
				342	30
				343	31
				344	32
				345	33
				346	34
				347	35
					36
					37
					38
0	0	0	0		39

Name of Respondent	This Report is:	Date of Report (Mo, Da, Yr)	Year of Report
Summit Natural Gas of Maine, Inc	(1) An Original **(2) A Resubmission**	04/29/2021	December 31, 2020

GAS PLANT IN SERVICE (Accounts 101, 102, 103, and 106) (Continued)

Line No.	Account (a)		Balance at Beginning of Year (b)	Additions (c)
40		3. Natural Gas Storage and Processing Plant		
41		Underground Storage Plant		
42	350.1	Land		
43	350.2	Rights-of-Way		
44	351	Structures and Improvements		
45	352	Wells		
46	352.1	Storage Leaseholds and Rights		
47	352.2	Reservoirs		
48	352.3	Non-recoverable Natural Gas		
49	353	Lines		
50	354	Compressor Station Equipment		
51	355	Measuring and Reg. Equipment		
52	356	Purification Equipment		
53	357	Other Equipment		
54		TOTAL Underground Storage Plant		
55		Other Storage Plant		
56	360	Land and Land Rights		
57	361	Structures and Improvements		
58	362	Gas Holders		
59	363	Purification Equipment		
60	363.1	Liquefaction Equipment		
61	363.2	Vaporizing Equipment		
62	363.3	Compressor Equipment		
63	363.4	Meas. and Reg. Equipment		
64	363.5	O her Equipment		
65		TOTAL Other Storage Plant	0	0
66		Base Load Liquefied Natural Gas Terminating and Processing Plant		
67	364.1	Land and Land Rights		
68	364.2	Structures and Improvements		
69	364.3	LNG Processing Terminal Equipment		
70	364.4	LNG Transportation Equipment		
71	364.5	Measuring and Regulating Equipment		
72	364.6	Compressor Station Equipment		
73	364.7	Communications Equipment		
74	364.8	Other Equipment		
75		TOTAL Base Load Liquefied Natural Gas,		
76		Terminating and Processing Plant		0
77		TOTAL Nat. Gas Storage and Proc. Plant		0
78		4. Transmission Plant		
79	365.1	Land and Land Rights		
80	365.2	Rights-of-Way		
81	366	Structures and Improvements		
82	367	Mains		
83	368	Compressor Station Equipment		
84	369	Measuring and Reg. Sta. Equipment		
85	370	Communication Equipment		
86	371	Other Equipment		
87		TOTAL Transmission Plant	0	0

Name of Respondent	This Report is:	Date or Report (Mo, Da, Yr)	Year of Report
Summit Natural Gas of Main	(1) An Original (2) **A Resubmission**	04/29/2021	December 31, 2020

GAS PLANT IN SERVICE (Accounts 101, 102, 103, and 106) (Continued)

Retirements (d)	Adjustments (e)	Transfers (f)	Balance at End of Year (g)		Line No.
					40
					41
				350.1	42
				350.2	43
				351	44
				352	45
				352.1	46
				352.2	47
				352.3	48
				353	49
				354	50
				355	51
				356	52
				357	53
					54
					55
			0	360	56
			0	361	57
			0	362	58
				363	59
				363.1	60
				363.2	61
			0	363.3	62
				363.4	63
				363.5	64
0	0		0		65
					66
				364.1	67
				364.2	68
				364.3	69
				364.4	70
				364.5	71
				364.6	72
				364.7	73
				364.8	74
					75
					76
					77
					78
				365.1	79
			0	365.2	80
				366	81
			0	367	82
				368	83
			0	369	84
				370	85
				371	86
0	0	0	0		87

Name of Respondent	This Report is:	Date of Report (Mo, Da, Yr)	Year of Report
Summit Natural Gas of Maine, Inc	(1) An Original **(2) A Resubmission**	04/29/2021	December 31, 2020

GAS PLANT IN SERVICE (Accounts 101, 102, 103, and 106) (Continued)

Line No.		Account (a)	Balance at Beginning of Year (b)	Additions (c)
88		5. Distribution Plant		
89	374	Land and Land Rights	2,554,277	
90	375	Structures and Improvements		
91	376	Mains	291,582,147	5,101,906
92	377	Compressor Station Equipment	0	
93	378	Meas. and Reg. Sta. Equip.-General	21,576,479	25,723
94	379	Meas. and Reg. Sta. Equip.-City Gate		
95	380	Services	26,900,303	2,519,485
96	381	Meters	3,179,428	184,981
97	382	Meter Installations	2,148,782	258,060
98	383	House Regulators	353,032	101,285
99	384	House Reg. Installations		
100	385	Industrial Meas. and Reg. Sta. Equipment		
101	386	Other Prop. on Customers' Premises	4,331,350	449,592
102	387	Other Equipment		
103		TOTAL Distribution Plant	352,625,798	8,641,032
104		6. General Plant		
105	389	Land and Land Rights		
106	390	Structures and Improvements	727,010	119,149
107	391	Office Furniture and Equipment	3,551,482	38,277
108	392	Transportation Equipment	2,237,443	499,802
109	393	Stores Equipment		
110	394	Tools, Shop, and Garage Equipment	722,487	7,496
111	395	Laboratory Equipment		
112	396	Power Operated Equipment	1,139,789	163,030
113	397	Communication Equipment	115,600	10,581
114	398	Miscellaneous Equipment	0	
115		Subtotal	8,493,811	838,336
116	399	Other Tangible Property		
117		TOTAL General Plant	8,493,811	838,336
118		TOTAL (Accounts 101 and 106)	363,885,447	9,479,368
119		Gas Plant Purchased (See Instr. 8)		
120		(Less) Gas Plant Sold (See Instr. 8)		
121		Experimental Gas Plant Unclassified		
122		TOTAL Gas Plant in Service	363,885,447	9,479,368

Name of Respondent	This Report is:	Date or Report (Mo, Da, Yr)	Year of Report
Summit Natural Gas of Main	(1) An Original (2) **A Resubmission**	04/29/2021	December 31, 2020

GAS PLANT IN SERVICE (Accounts 101, 102, 103, and 106) (Continued)

Retirements (d)	Adjustments (e)	Transfers (f)	Balance at End of Year (g)		Line No.
[redacted]					88
			2,554,277	374	89
			0	375	90
			296,684,053	376	91
				377	92
			21,602,202	378	93
				379	94
19,079			**29,400,709**	380	95
			3,364,409	381	96
189			**2,406,653**	382	97
216			**454,101**	383	98
				384	99
				385	100
			4,780,942	386	101
			0	387	102
19,484	0	0	361,247,346		103
[redacted]					104
			0	389	105
			846,159	390	106
		135,518	3,725,277	391	107
			2,737,245	392	108
			0	393	109
			729,983	394	110
				395	111
			1,302,819	396	112
			126,181	397	113
				398	114
0	0	135,518	9,467,665		115
				399	116
0	0	135,518	9,467,665		117
19,484	0	135,518	373,480,850		118
					119
					120
					121
19,484	0	135,518	373,480,850		122

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year of Report
Summit Natural Gas of Maine, Inc	(1) An Original **(2) A Resubmission**	04/29/2021	December 31, 2020

ACCUMULATED PROVISION FOR DEPRECIATION OF GAS UTILITY PLANT (Account 108)

1. Explain in a footnote any important adjustments during year.
2. Explain in a footnote any difference between the amount for book cost of plant retired, line 11, column (c), and that reported for gas plant in service, pages 22-27, column (d), excluding retirements of non-depreciable property.
3. The provisions of Account 108 in the Uniform System of Accounts require that retirements of depreciable plant be recorded when such plant is removed from service. If the respondent has a significant amount of plant retired at year end which has not been recorded and/or classified to the various reserve functional classifications, make preliminary closing entries to tentatively functionalize the book cost of the plant retired. In addition, include all costs included in retirement work in progress at year end in the appropriate functional classifications.
4. Show separately interest credits under a sinking fund or similar method of depreciation accounting.

Section A. Balances and Changes During Year

Line No.	Item (a)	Total (c+d+e) (b)	Division (c)	Division (d)	Gas Plant Leased to Others (e)
1	Balance Beginning of Year	38,797,732	38,797,732		
2	Depreciation Provisions for Year, Charged to				
3	(403) Depreciation Expense	8,621,755	8,621,755		
4	Exp. of Gas Plt. Leas. to Others	0			
5	Transportation Expenses-	0			
	Clearing	0			
6	Other Clearing Accounts	0	0		
7	Other Accounts (Specify):	4,190	4,190		
8					
9	TOTAL Deprec. Prov. for Year	8,625,945	8,625,945	0	
	(Enter Total of lines 3 thru 8)	8,625,945	8,625,945	0	
10	Net Charges for Plant Retired:	0			
11	Book Cost of Plant Retired	0			
12	Cost of Removal	0			
13	Salvage (Credit)	(19,485)	(19,485)		
14	TOTAL Net Chrgs. for Plant Ret.	(19,485)	(19,485)	0	
	(Enter Total of lines 11 thru 13)				
15	Other Debit or Cr. Items (Describe)				
16	Adjust. to Reserve				
17	Balance End of Year (Enter				
	Total of lines 1,9,14,15, and 16)	47,404,192	47,404,192	0	

Section B. Balances at End of Year According to Functional Classifications

Line No.	Item (a)	Total (c+d+e) (b)	Division (c)	Division (d)	Gas Plant Leased to Others (e)
18	Production-Manufactured Gas	0			
19	Prod. and Gathering-Natural	0			
	Gas	0			
20	Products Extraction-Natural	0			
	Gas	0			
21	Underground Gas Storage	0			
22	Other Storage Plant	0			
23	Base Load LNG Term. and	0			
	Proc. Plt.	0			
24	Transmission	0			
25	Distribution	0			
26	General	0			
27	TOTAL (Enter Total of lines 18 thru 26)	0	0	0	

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year of Report
Summit Natural Gas of Maine, Inc	(1) An Original **(2) A Resubmission**	04/29/2021	December 31, 2020

OTHER REGULATORY ASSETS (ACCOUNT 182.3)

1. Report below the details called for concerning other regulatory assets which are created through the ratemaking actions of regulatory agencies (and not included in other accounts).

2. For regulatory assets being amortized, show period of amortization in column (a).

3. Minor items (5% of the Balance at End of Year for Account 182.3 or amounts less than $250,000, whichever is less) may be grouped by classes.

4. Report separately any "Deferred Regulatory Commission Expenses"

Line No.	Description and Purpose of Other Regulatory Assets	Balance at Beginning of Year	Debits	Written off During Year		Balance at End of Year
				Account Charged	Amount	
	(a)	(b)	(c)	(d)	(e)	(f)
1						
2						
3						
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39						
40	TOTAL					0

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year of Report
Summit Natural Gas of Maine, Inc	(1) An Original (2) **A Resubmission**	04/29/2021	December 31, 2020

MISCELLANEOUS DEFERRED DEBITS (ACCOUNT 186)

1. Report below the details called for concerning miscellaneous deferred debits.

2. For any deferred debit being amortized, show period of amortization in column (a).

3. Minor items amounts less than $250,000 may be grouped by classes.

Line No.	Description of Miscellaneous Deferred Debits	Balance at Beginning of Year	Debits	Credits: Account Charged	Credits: Amount	Balance at End of Year
	(a)	(b)	(c)	(d)	(e)	(f)
1	Deferral due to Tax Cut Jobs Act	7,437,058				7,437,058
2						
3	Regulatory asset created by the 35% to 21% revaluation of deferred taxes related to NOL's, pension and other rate base/cost of service.					
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38						
39	Miscellaneous Work in Progress					
40	TOTAL					0

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year of Report
Summit Natural Gas of Maine, Inc	(1) An Original **(2) A Resubmission**	04/29/2021	December 31, 2020

LONG-TERM DEBT (Accounts 221, 222, 223, and 224)

1. Report by balance sheet the particulars (details) concerning long-term debt included in Accounts 221, Bonds, 222, Reacquired Bonds, 223, Advances from Associated Companies, and 224, Other Long-Term Debt. If information to meet the stock exchange reporting requirement outlined in column (a) is available from the SEC 10-K Report Form filing, a specific reference to the report form (i.e. year and company title) may be reported in column (a) provided the fiscal years for both the 10-K report and this report are compatible.

2. For bonds assumed by the respondent, include in column (a) the name of the issuing company as well as a description of the bonds.

3. For advances from Associated Companies, report separately advances on notes and advances on open accounts. Designate demand notes as such. Include in column (a) names of associated companies from which advances were received.

4. For receivers' certificates, show in column (a) the name of the court and date of court order under which such certificates were issued.

Line No.	Class and Series of Obligation and Name of Stock Exchange (a)	Nominal Date of Issue (b)	Date of Maturity (c)	Outstanding (Total amount outstanding without reduction for amounts held by respondent) (d)
1	Promissory Notes with Summit Investors	03/15/2018		125,000,000.00
2				
3				
4				
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38				0

Name of Respondent	This Report is:	Date of Report (Mo, Da, Yr)	Year of Report
Summit Natural Gas of Maine, Inc	(1) An Original (2) **A Resubmission**	04/29/2021	December 31, 2020

LONG-TERM DEBT (Accounts 221, 222,, 223, and 224) (Continued)

5. In a supplemental statement, give explanatory particulars (details) for Accounts 223 and 224 of net changes during the year. With respect to long-term advances, show for each company: (a) principal advanced during year, (b) interest added to principal amount, and (c) principal repaid during year. Give Commission authorization numbers and dates.

6. If the respondent has pledged any of its long-term debt securities, give particulars (details) in a footnote, including name of the pledgee and purpose of the pledge.

7. If the respondent has any long-term securities which have been nominally issued and are nominally outstanding at end of year, describe such securities in a footnote.

8. If interest expense was incurred during the year on any obligations retired or reacquired before end of year, include such interest expense in column (f). Explain in a footnote any difference between the total of column (f) and the total of Account 427, Interest on Long-Term Debt and Account 430, Interest on Debt to Associated Companies.

9. Give particulars (details) concerning any long-term debt authorized by a regulatory commission but not yet issued.

INTEREST FOR YEAR		HELD BY RESPONDENT		Redemption Price Per $100 at End of Year	Line No.
Rate (in %) (e)	Amount (f)	Reacquired Bonds (Acct. 222) (g)	Sinking and Other Funds (h)	(i)	
5.20%	6,590,277.78				1
					2
					3
					4
					5
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	6,590,278				38

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year of Report
Summit Natural Gas of Maine, Inc	(1) An Original **(2) A Resubmission**	04/29/2021	December 31, 2020

RECONCILIATION OF REPORTED NET INCOME WITH TAXABLE INCOME FOR FEDERAL INCOME TAXES

1. Report the reconciliation of reported net income for the year with taxable income used in computing Federal income tax accruals and show computation of such tax accruals. Include in the reconciliation, as far as practicable, the same detail as furnished on Schedule M-1 of the tax return for the year. Submit a reconciliation even though there is no taxable income for he year. Indicate clearly the nature of each reconciling amount.

2. If the utility is a member of a group which files consolidated Federal tax return, reconcile reported net income with taxable net income as if a separate return were to be filed, indica ing, however, intercompany amounts to be eliminated in such a consolidated return. State names of group members, tax assigned to each group member, and basis of allocation, assignment, or sharing of the consolidated tax among the group members.

Line No.	Particulars (Details) (a)	Amount (b)
	Maine	
1	Net Income for the Year (Page 117)	(9,910,564)
2	Reconciling Items for the Year	[redacted]
3	Federal Income Taxes	(3,464,346)
4	Taxable Income Not Reported on Books	[redacted]
5		
6		
7		
8		
9	Deduc ions Recorded on Books Not Deducted for Return	[redacted]
10	Meals & Entertainment	4,017
11	Political Contributions	89,650
12		
13		
14	Income Recorded on Books Not Included in Return	[redacted]
15	Accrued vacation	5,682
16	Accounting method change	4,375,510
17	Allowance for bad debts	33,181
18	Accrued medical	5,284
	Accrued COVID Payroll Tax	114,798
19		
20	Deduc ions on Return Not Charged Against Book Income	[redacted]
21	Accrued bonuses	(39,894)
22	Accrued professional fees	(5,950)
23	Depreciation and amor ization	(10,306,326)
24		
25		
26		
	Maine	
27	Federal Tax Net Income	(19,098,958)
28	Show Computation of Tax:	
29		
30		
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41		
42		

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year of Report
Summit Natural Gas of Maine, Inc	(1) An Original **(2) A Resubmission**	04/29/2021	December 31, 2020

TAXES ACCRUED, PREPAID AND CHARGED DUR NG YEAR

1. Give particulars (details) of the combined prepaid and accrued tax accounts and show the total taxes charged to operations and other accounts during the year. Do not include gasoline and other sales taxes which have been charged to the accounts to which the taxed material was charged. If the actual or estimated amounts of such taxes are known, show the amounts in a footnote and designate whether estimated or actual amounts.

2. Include on this page taxes paid during the year and charged direct to final accounts, (not charged to prepaid or accrued taxes). Enter the amounts in both columns (d) and (e). The balancing of this page is not affected by the inclusion of these taxes.

3. Include in column (d) taxes charged during the year, taxes charged to operations and other accounts through (a) accruals credited to taxes accrued, (b) amounts credited to proportions of prepaid taxes chargeable to current year, and (c) taxes paid and charged direct to operations or accounts other than accrued and prepaid tax accounts.

		BALANCE AT BEGINN NG OF YEAR	
Line No.	Kind of Tax (See Instruction 5)	Taxes Accrued (Account 236)	Prepaid Taxes (Incl. in Account 165)
	(a)	(b)	(c)
1	Property Taxes	1,152,764	
2			
3			
4			
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17			
18	TOTAL	0	

DISTRIBUTION OF TAXES CHARGED (Show utility department where applicable and account charged.)

Line No.	Electric (Accounts 408.1, 409.1)	Gas (Accounts 408.1, 409.1)	Other Utility Departments (Account 408.1, 409.1)	Other Income and Deductions (Account 408.2, 409.2)
	(i)	(j)	(k)	(l)
1				
2				
3				
4				
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11				
12				
13				
14				
15				
16				
17				
18	TOTAL			

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year of Report
Summit Natural Gas of Maine, Inc	(1) An Original (2) **A Resubmission**	04/29/2021	December 31, 2020

TAXES ACCRUED, PREPAID AND CHARGED DURING YEAR (Continued)

4. List the aggregate of each kind of tax in such manner that the total tax for each State and subdivision can readily be ascertained.
5. If any tax (Exclude Federal and state income taxes) covers more than one year, show the required information separately for each tax year, identifying the year in column (a).
6. Enter all adjustments of the accrued and prepaid tax accounts in column (f) and explain each adjustment in a footnote. Designate debit adjustments by parentheses.
7. Do not include on this page entries with respect to deferred income taxes or taxes collected through payroll deduction or otherwise pending transmittal of such taxes to the taxing authority.
8. Show in column (i) thru (p) how the taxed accounts were distributed. Show both the utility department and number of account charged. For taxes charged to utility plant, show the number of the appropriate balance sheet plant account or subaccount.
9. For any tax apportioned to more than one utility department or account, state in a footnote the basis (necessity) of apportioning such tax.
10. For MPUC reporting purposes, taxes greater than $25,000 should be reported separately -- others may be combined.

Taxes Charged During Year	Taxes Paid During Year	Adjustments	BALANCE AT END OF YEAR: Taxes Accrued (Account 236)	BALANCE AT END OF YEAR: Prepaid Taxes (Incl. in Account 165)	Line No.
(d)	(e)	(f)	(g)	(h)	
2,657,011	2,582,832		1,226,942.25		1
					2
					3
			0		4
					5
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					13
					14
					15
					16
					17
0	0	0	0	0	18

DISTRIBUTION OF TAXES CHARGED (Show utility department where applicable and account charged.)

Extraordinary Items (Account 409.3)	Other Utility Opn. Income (Account 408.1, 409.1)	Adjustment to Ret. Earnings (Account 439)	Other		Line No.
(m)	(n)	(o)	(p)		
					1
					2
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					18

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year of Report
Summit Natural Gas of Maine, Inc	(1) An Original **(2) A Resubmission**	04/29/2021	December 31, 2020

MISCELLANEOUS DEFERRED CREDITS (ACCOUNT 253)

1. Report below the details called for concerning miscellaneous deferred credits

2. For any deferred credit being amortized, show period of amortization in column (a).

3. Minor items amounts less than $150,000 may be grouped by classes.

Line No.	Description of Other Deferred Credits (a)	Balance at Beginning of Year (b)	Debits: Contra Account (c)	Debits: Amount (d)	Credits (e)	Balance at End of Year (f)
1	EMTA over collection	169,531.98		69,035	55,798	156,295
2						
3						
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38						
39						
40	TOTAL					0

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year of Report
Summit Natural Gas of Maine, Inc	(1) [ ] An Original (2) [x] A Resubmission	04/29/2021	December 31, 2020

1. Report below the particulars (details) called for concerning other regulatory liabilities which are created through the ratemaking actions of regulatory agencies and not includable in other amounts).

2. For regulatory liabilities being amortized, show period of amortization in column (a).

3. Minor items (5% of the Balance at End of Year for Account 254 or amounts less than $50,000, whichever is less) may be grouped by classes.

Line No.	Description and Purpose of Other Regulatory Liabilities	Balance at Beg of Year	DEBITS		Credits	Balance at End of Year
			Account Credited	Amount		
	(a)	(b)	(c)	(d)	(b)	(e)
1						
2						
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40						
41						
42	TOTAL			0	0	0

NAME OF RESPONDENT: Summit Natural Gas of Maine, Inc	This Report Is: (1) An Original (2) **A Resubmission**	Date of Report 04/29/2021	Year of Report December 31, 2020

GAS OPERAT NG REVENUES (Account 400)

1. Report below natural gas operating revenues for each prescribed account, and manufactured gas revenues in total.
2. Natural gas means either natural gas unmixed or any mixture of natural and manufactured gas.
3. Report number of customers, columns (f) and (g), on the basis of meters, in addition to the number of flat rate accounts; except that where separate meter readings are added for billing purposes, one customer should be counted for each group of meters added. The average number of customers means the average of twelve figures at the close of each month.
4. Report quantities of natural gas sold in Mcf (14.73 psia at 60 F). If billings are on a therm basis, give the Btu contents of the gas sold and the sales converted to Mcf.
5. If increases or decreases from previous year columns (c), (e) and (g), are not derived from previously reported figures explain any inconsistencies in a footnote.

Line No.	Title of Account	OPERAT NG REVENUES					
		Total		BASE (Distribution)		GAS (Cost of Gas Rates)	
		Amount for Year	Amount for Prev Yr	Amount for Year	Amount for Prev Yr	Amount for Year	Amount for Prev Yr
	(a)	(b)	(c)	(d)	(e)	(f)	(g)
1	GAS SERVICE REVENUES						
2	480 Residential Sales	$4,724,690	$6,067,032	$3,261,830	$3,550,878	$1,462,860	$2,516,154
3	481 Commercial & Industrial Sales						
4	Small (or Comm.) (See Instr.6)	$7,190,549	10,367,062	4,067,070	4,711,668	3,123,480	5,655,394
5	Large (or Ind.) (See Instr. 6)						
6	482 Other Sales to Public Authorities						
7	484 Unbilled Revenue	195 234	(1 414 830)	177 120	(650 967)	18 113	(763 863)
8	TOTAL Sales to Ultimate Consumers	12,110,473	15,019,263	7,506,020	7,611,579	4,604,453	7,407,684
9	483 Sales for Resale						
10	TOTAL Natural Gas Service Revenues	12,110,473	15,019,263	7,506,020	7,611,579	4,604,453	7,407,684
11	Revenues from Manufactured Gas						
12	TOTAL Gas Service Revenues	12,110,473	15,019,263	7,506,020	7,611,579	4,604,453	7,407,684
13							
14	485 Intracompany Transfers	[redacted]					
15	487 Forfeited Discounts						
16	488 Misc. Service Revenues						
17	489.1 Rev. from Trans. of Gas of Others through Gathering Facilities						
18	489.2 Rev. from Trans. of Gas of Others through Transmission Facilities						
19	489.3 Rev. from Trans. of Gas of Others through Distribution Facilities						
20	489.4 Rev. from Storing Gas of Others						
21	490 Sales of Prod. Ext. from Nat. Gas						
22	491 Rev. from Nat. Gas Proc. by Others						
23	492 Incidental Gasoline and Oil Sales						
24	493 Rent from Gas Property						
25	494 Interdepartmental Rents						
26	495 Other Gas Revenues						
27	TOTAL Other Operating Revenues	4,962,092	4,966,601	4,962,092	4,966,601	0	0
28	TOTAL Gas Operating Revenues	$17,072,565	$19,985,864	$12,468,112	$12,578,180	$4,604,453	$7,407,684
29	(Less) 496 Provision for Rate Refunds						
30	TOTAL Gas Operating Revenues Net of Provision for Refunds	$17 072 565	$19 985 864	$12 468 112	$12 578 180	$4 604 453	$7 407 684
31	Dist. Type Sales by States (Inc. Main Line Sales to Resid and Comm Cust)	$11,915,239	$16,434,093	$7,328,899	$3,550,878	$4,586,340	$2,516,154
32	Main Line Industrial Sales (Incl. Main Line Sales to Pub. Authorities)	0	0	0	0	0	0
33	Sales for Resale						
34	Other Sales to Pub. Auth. (Local Dist. Only)						
35	Unbilled Revenues	195 234	(1 414 830)	177 120	(650 967)	18 113	(763 863)
36	TOTAL (Same as Line 10 Columns (b) and (d)	$12 110 473	$15 019 263	$7 506 020	$2 899 911	$4 604 453	$1 752 290

Name of Respondent	This Report Is:	Date of Report	Year of Report
Summit Natural Gas of Maine	(1) An Original **(2) A Resubmission**	04/29/2021	December 31, 2020

GAS OPERATING REVENUES (Account 400) (Continued)

6. Commercial and Industrial Sales. Account 481, may be classified according to the basis of classification (Small or Commercial, and Large or Industrial) regularly used by the respondent if such basis of classification is not generally greater than 200,000 Mcf per year or approximately 800 Mcf per day of normal requirements. (See Account 481 of the Uniform System of Accounts. Explain basis of classification in a footnote.)

7. See page 7, Important Changes During Year, for important new territory added and important rate increases or decreases.

MCF OF NATURAL GAS SOLD		AVG. NO. OF GAS CUSTOMERS PER MO.		
Quantity for Year (h)	Quantity for Previous Yr. (i)	Number for Year (j)	Number for Previous Year (k)	Line No.
				1
250,531	267,223	3,067	2,807	2
537,321	602,271	826	730	3
				4
				5
				6
				7
787,853	869,494	3,893	3,537	8
				9
787,853	869,494	3,893	3,537	10
				11
				12
				13
[redacted]				14
				15
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				21
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				23
				24
				25
				26
				27
				28
				29
				30
250,531				31
0				32
				33
				34
0				35
250,531				36

Name of Respondent Summit Natural Gas of Maine, Inc	This Report Is: (1) An Original **(2) A Resubmission**	Date of Report (Mo, Da, Yr) 04/29/2021	Year of Report December 31, 2020

REVENUES FROM TRANSPORTATION OF GAS OF OTHERS THROUGH DISTRIBUTION FACILITIES (ACCOUNT 489.3)

1. Report revenues and Dth of gas delivered by zone of Delivery by Rate Schedule. Total by Zone of Delivery and for all zones. If respondent does not have separate zones, provide totals by rate schedule.
2. Revenues for penalties including penalties for unauthorized overruns must be reported separately.
3. Other revenues include reservation charges received plus usage charges for transportation and hub services.
4. Delivered Dth of gas must not be adjusted for discounting,
5. Each incremental rate schedule and each individually certified rate schedule must be separately reported.

Line No.	Zone of Delivery, Rate Schedule	OTHER REVENUES		TOTAL OPERAT NG REVENUES		DEKATHERM OF NATURAL GAS	
		Amount for Current Year	Amount for Previous Year	Amount for Current Year	Amount for Previous Year	Amount for Current Year	Amount for Previous Year
	(a)	(b)	(c)	(d)	(e)	(f)	(g)
1	[redacted]						
2							
3							
4							
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NAME OF RESPONDENT: Summit Natural Gas of Maine, Inc	This Report Is: (1) An Original (2) **A Resubmission**	Date of Report 04/29/2021	Year of Report December 31, 2020

GAS OPERATING REVENUES by Tariff Sheets

1 Complete the following information for the calendar year ending December 31 according to the column headings.

2 The average number of customers should be the number of bills rendered during the year divided by the number of billing periods during the year (12 if all billings are made monthly).

Line No.	(a)		Revenue (b)	MCF (c)	Average Number of Customers (d)	Average Ccf Use per Customer (e)	Revenue per Ccf Sold (f)	Number of Customers Added During Year (g)
1	GAS SERVICE TAR FFS							
2	Residential Sales							
2A	Base Revenues	Distribution	2,520,118	250,531	3,067	817	101	270
2B	Energy Revenues	CGA	1,483,249	250,531	3,067	817	59	270
2C	Other Revenues	Facility Fixed Fee	859,889					
2D	Total Residential		4,863,256	250,531	3,067	817		270
3								
4	Commercial and Industrial Sales Service							
5	Small C&I Firm Sales & Service Customers							
5A	Base Revenues	Distribution	3,024,891	398,877	793	5,030	76	82
5B	Energy Revenues	CGA	2,312,067	398,877	793	5,030	58	82
5C	Other Revenues	Facility Fixed Fee	607,890					
5D	Total Small C&I		5 944 849	398 877	793	5 030		82
6	Large C&I Firm Sales & Service Customers							
6A	Base Revenues							0
6B	Energy Revenues							
6C	Other Revenues							
6D	Total Large C&I		0	0	0	0	0	0
7	Total Commercial and Industrial Sales		5 944 849	398 877	793	5 030	0	82
8	Total Sales Service		10,808,104	649,408	3,860	5,847	0	352
9								
10	Commercial and Industrial Transportation Service							
11	Small C&I Firm Transportation Service Customers		[redacted]					
11A	Base Revenues							
11B	Other Revenues							
11C	Total Small C&I							
12	Large C&I Firm Transportation Service Customers							
12A	Base Revenues							
12B	Other Revenues							
12C	Total Large C&I							
20	Total Commercial and Industrial Transportation		4,953,717	3,223,850	8	4,029,813		0
21								
19B	Interruptible Sales							
19C	Base Revenues							
20	Energy Revenues							
20A	Other Revenues							
20B	Total Interruptible Sales		0	0	0	0	0	0
20C								
21	Negotiated Service							
21A	Base Revenues	Distribution	[redacted]					
21B	Energy Revenues	CGA						
21C	Other Revenues	Facility Fixed Fee						
22	Total Negotiated Service							
22A								
22B								
22C								
23								
24								
25	Total Revenues		17 072 565	4 011 703	3 901	4 077 612		352

Name of Respondent	This Report Is:	Date of Report	Year of Report
Summit Natural Gas of Maine, Inc	(1) An Original **(2) A Resubmission**	04/29/2021	December 31, 2020

GAS OPERATION AND MAINTENANCE EXPENSES

If the amount for previous year is not derived from previously reported figures, explain in footnotes.

Line No.	Account (a)	Amount for Current Year (b)	Amount for Previous Year (c)
1	1. PRODUCTION EXPENSES		
2	**A. Manufactured Gas Production**		
3	Manufactured Gas Production (Submit Supplemental Statement)		
4	**B. Natural Gas Production**		
5	**B1. Natural Gas Production and Gathering**		
6	**Operation**		
7	750 Operation Supervision and Engineering		
8	751 Production Maps and Records		
9	752 Gas Wells Expenses		
10	753 Field Lines Expenses		
11	754 Field Compressor Station Expenses		
12	755 Field Compressor Station Fuel and Power		
13	756 Field Measuring and Regulating Station Expenses		
14	757 Purification Expenses		
15	758 Gas Well Royalties		
16	759 Other Expenses		
17	760 Rents		
18	TOTAL Operation (Enter Total of lines 7 thru 17)	0	0
19	**Maintenance**		
20	761 Maintenance Supervision and Engineering		
21	762 Maintenance of Structures and Improvements		
22	763 Maintenance of Producing Gas Wells		
23	764 Maintenance of Field Lines		
24	765 Maintenance of Field Compressor Station Equipment		
25	766 Maintenance of Field Meas. and Reg. Sta. Equipment		
26	767 Maintenance of Purification Equipment		
27	768 Maintenance of Drilling and Cleaning Equipment		
28	769 Maintenance of Other Equipment		
29	TOTAL Maintenance (Enter Total of lines 20 thru 28)	0	0
30	TOTAL Natural Gas Production and Gathering (Total of lines 18 and 29)	0	0
31	**B2. Products Extraction**		
32	**Operation**		
33	770 Operation Supervision and Engineering		
34	771 Operation Labor		
35	772 Gas Shrinkage		
36	773 Fuel		
37	774 Power		
38	775 Materials		
39	776 Operation Supplies and Expenses		
40	777 Gas Processed by Others		
41	778 Royalties on Products Extracted		
42	779 Marketing Expenses		
43	780 Products Purchased for Resale		
44	781 Variation in Products Inventory		
45	(Less) 782 Extracted Products Used by the Utility-Credit		
46	783 Rents		
47	TOTAL Operation (Enter Total of lines 33 thru 46)	0	0

Name of Respondent	This Report Is:	Date of Report	Year of Report
Summit Natural Gas of Maine, Inc	(1) An Original **(2) A Resubmission**	04/29/2021	December 31, 2020

GAS OPERATION AND MAINTENANCE EXPENSES (Continued)

Line No.	Item (a)	Amount for Current Year (b)	Amount for Previous Year (c)
	B2. Products Extraction (Continued)		
48	**Maintenance**		
49	784 Maintenance Supervision and Engineering		
50	785 Maintenance of Structures and Improvements		
51	786 Maintenance of Extraction and Refining Equipment		
52	787 Maintenance of Pipe Lines		
53	788 Maintenance of Extracted Products Storage Equipment		
54	789 Maintenance of Compressor Equipment		
55	790 Maintenance of Gas Measuring and Reg. Equipment		
56	791 Maintenance of Other Equipment		
57	TOTAL Maintenance (Enter Total of lines 49 thru 56)	0	0
58	TOTAL Products Extraction (Enter Total of lines 47 and 57)	0	0
59	**C. Exploration and Development**		
60	**Operation**		
61	795 Delay Rentals		
62	796 Nonproductive Well Drilling		
63	797 Abandoned Leases		
64	798 Other Exploration		
65	TOTAL Exploration and Development (Enter Total of lines 61 thru 64)	0	0
	D. Other Gas Supply Expenses		
66	**Operation**		
67	800 Natural Gas Well Head Purchases		
68	800.1 Natural Gas Well Head Purchases, Intracompany Transfers		
69	801 Natural Gas Field Line Purchases		
70	802 Natural Gasoline Plant Outlet Purchases		
71	803 Natural Gas Transmission Line Purchases		
72	804 Natural Gas City Gate Purchases	4,842,021	6,172,352
73	804.1 Liquefied Natural Gas Purchases		
74	805 Other Gas Purchases		
75	(Less) 805.1 Purchased Gas Cost Adjustments	(263,753)	1,416,248
76			
77	TOTAL Purchased Gas (Enter Total of lines 67 to 75)	4,578,268	7,588,600
78	806 Exchange Gas		
79	**Purchased Gas Expenses**		
80	807.1 Well Expenses-Purchased Gas		
81	807.2 Operation of Purchased Gas Measuring Stations		
82	807.3 Maintenance of Purchased Gas Measuring Stations		
83	807.4 Purchased Gas Calculations Expenses		
84	807.5 Other Purchased Gas Expenses		
85	TOTAL Purchased Gas Expenses (Enter Total of lines 80 thru 84)	0	0
86	808.1 Gas Withdrawn from Storage-Debit		
87	Unbilled Revenue Costs		
88	809.1 Withdrawals of Liquefied Natural Gas for Processing-Debit		
89	(Less) 809.2 Deliveries of Natural Gas for Processing-Credit		
90	**Gas Used in Utility Operations-Credit**		
91	810 Gas Used for Compressor Station Fuel-Credit		
92	811 Gas Used for Products Extraction-Credit		
93	812 Gas Used for Other Utility Operations-Credit		
94	TOTAL Gas Used in Utility Operations-Credit (Total of lines 91 thru 93)	0	0
95	813 Other Gas Supply Expenses	25,535	970,233
96	TOTAL Other Gas Supply Exp. (Total of lines 77,78,85,86 thru 89,94,9	4,603,804	8,558,833
97	TOTAL Production Expenses (Enter Total of lines 3,30,58,65, and 96)	$4,603,804	$8,558,833

Name of Resondent	This Report Is:	Date of Report	Year of Report
Summit Natural Gas of Maine, Inc	(1) An Original **(2) A Resubmission**	04/29/2021	December 31, 2020

GAS OPERATION AND MAINTENANCE EXPENSES (Continued)

Line No.	Account (a)	Amount for Current Year (b)	Amount for Previous Year (c)
98	**2. NATURAL GAS STORAGE, TERMINALING AND PROCESSING EXPENSES**		
99	**A. Underground Storage Expenses**		
100	**Operation**		
101	814 Operation Supervision and Engineering		
102	815 Maps and Records		
103	816 Wells Expenses		
104	817 Lines Expense		
105	818 Compressor Station Expenses		
106	819 Compressor Station Fuel and Power		
107	820 Measuring and Regulating Station Expenses		
108	821 Purification Expenses		
109	822 Exploration and Development		
110	823 Gas Losses		
111	824 Other Expenses		
112	825 Storage Well Royalties		
113	826 Rents		
114	TOTAL Operation (Enter Total of lines 101 thru 113)	0	0
115	**Maintenance**		
116	830 Maintenance Supervision and Engineering		
117	831 Maintenance of Structures and Improvements		
118	832 Maintenance of Reservoirs and Wells		
119	833 Maintenance of Lines		
120	834 Maintenance of Compressor Station Equipment		
121	835 Maintenance of Measuring and Regulating Station Equipment		
122	836 Maintenance of Purification Equipment		
123	837 Maintenance of Other Equipment		
124	TOTAL Maintenance (Enter Total of lines 116 thru 123)	0	0
125	TOTAL Underground Storage Expenses (Total of lines 114 and 124	0	0
126	**B. Other Storage Expenses**		
127	**Operation**		
128	840 Operation Supervision and Engineering		
129	841 Operation Labor and Expenses		
130	842 Rents		
131	842.1 Fuel		
132	842.2 Power		
133	842.3 Gas Losses		
134	TOTAL Operation (Enter Total of lines 128 thru 133)	0	0
135	**Maintenance**		
136	843.1 Maintenance Supervision and Engineering		
137	843.2 Maintenance of Structures and Improvements		
138	843.3 Maintenance of Gas Holders		
139	843.4 Maintenance of Purification Equipment		
140	843.5 Maintenance of Liquefaction Equipment		
141	843.6 Maintenance of Vaporizing Equipment		
142	843.7 Maintenance of Compressor Equipment		
143	843.8 Maintenance of Measuring and Regulating Equipment		
144	843.9 Maintenance of Other Equipment		
145	TOTAL Maintenance (Enter Total of lines 136 thru 144)	0	0
146	TOTAL Other Storage Expenses (Enter Total of lines 134 and 145)	0	0

Name of Respondent	This Report Is:	Date of Report	Year of Report
Summit Natural Gas of Maine, Inc	(1) An Original **(2) A Resubmission**	04/29/2021	December 31, 2020

GAS OPERATION AND MAINTENANCE EXPENSES (Continued)

Line No.	Account (a)	Amount for Current Year (b)	Amount for Previous Year (c)
147	**C. Liquefied Natural Gas Terminaling and Processing Expenses**		
148	**Operation**		
149	844.1 Operation Supervision and Engineering		
150	844.2 LNG Processing Terminal Labor and Expenses		
151	844.3 Liquefaction Processing Labor and Expenses		
152	844.4 Liquefaction Transportation Labor and Expenses		
153	844.5 Measuring and Regulating Labor and Expenses		
154	844.6 Compressor Station Labor and Expenses		
155	844.7 Communication System Expenses		
156	844.8 System Control and Load Dispatching		
157	845.1 Fuel		
158	845.2 Power		
159	845.3 Rents		
160	845.4 Demurrage Charges		
161	(Less) 845.5 Wharfage Receipts-Credit		
162	845.6 Processing Liquefied or Vaporized Gas by Others		
163	846.1 Gas Losses		
164	846.2 Other Expenses		
165	TOTAL Operation (Enter Total of lines 149 thru 164)	0	0
166	**Maintenance**		
167	847.1 Maintenance Supervision and Engineering		
168	847.2 Maintenance of Structures and Improvements		
169	847.3 Maintenance of LNG Processing Terminal Equipment		
170	847.4 Maintenance of LNG Transportation Equipment		
171	847.5 Maintenance of Measuring and Regulating Equipment		
172	847.6 Maintenance of Compressor Station Equipment		
173	847.7 Maintenance of Communication Equipment		
174	847.8 Maintenance of Other Equipment		
175	TOTAL Maintenance (Enter Total of lines 167 thru 174)	0	0
176	TOTAL Liquefied Nat Gas Terminaling and Processing Exp (Lines 165 & 175)	0	0
177	TOTAL Natural Gas Storage (Enter Total of lines 125, 146, and 176)	0	0
178	**3. TRANSMISSION EXPENSES**		
179	**Operation**		
180	850 Operation Supervision and Engineering		
181	851 System Control and Load Dispatching		
182	852 Communication System Expenses		
183	853 Compressor Station Labor and Expenses		
184	854 Gas for Compressor Station Fuel		
185	855 Other Fuel and Power for Compressor Stations		
186	856 Mains Expenses	11,454	4,984
187	857 Measuring and Regulating Station Expenses	44,482	13,997
188	858 Transmission and Compression of Gas by Others		
189	859 Other Expenses	2,949	4,431
190	860 Rents	1,599	
191	TOTAL Operation (Enter Total of lines 180 thru 190)	60,484	23,412

Name of Respondent	This Report Is:	Date of Report	Year of Report
Summit Natural Gas of Maine, Inc	(1) An Original **(2) A Resubmission**	04/29/2021	December 31, 2020

GAS OPERATION AND MAINTENANCE EXPENSE (Continued)

Line No.	Account (a)	Amount for Current Year (b)	Amount for Previous Year (c)
	3. TRANSMISSION EXPENSES (Continued)		
192	**Maintenance**		
193	861 Maintenance Supervision and Engineering		
194	862 Maintenance of Structures and Improvements		
195	863 Maintenance of Mains	105,409	199,813
196	864 Maintenance of Compressor Station Equipment		
197	865 Maintenance of Measuring and Reg. Station Equipment	8,275	13,192
198	866 Maintenance of Communication Equipment	8,538	1,023
199	867 Maintenance of Other Equipment		
200	TOTAL Maintenance (Enter Total of lines 193 thru 199)	122,221	214,029
201	TOTAL Transmission Expenses (Enter Total of lines 191 and 200)	182,705	237,441
202	**4. DISTRIBUTION EXPENSES**		
203	**Operation**		
204	870 Operation Supervision and Engineering		
205	871 Distribution Load Dispatching	114	4,181
206	872 Compressor Station Labor and Expenses	566	630
207	873 Compressor Station Fuel and Power		
208	874 Mains and Services Expenses	418,270	545,442
209	875 Measuring and Regulating Station Expenses-General	169,148	210,526
210	876 Measuring and Regulating Station Expenses-Industrial	49,554	24,880
211	877 Measuring and Regulating Station Expenses-City Gate Check Station		
212	878 Meter and House Regulator Expenses	394,744	328,026
213	879 Customer Installations Expenses	16,208	30,933
214	880 Other Expenses	112,801	120,339
215	881 Rents	4,068	14,487
216	TOTAL Operation (Enter Total of lines 204 thru 215)	1,165,472	1,279,446
217	**Maintenance**		
218	885 Maintenance Supervision and Engineering	48,881	11,835
219	886 Maintenance of Structures and Improvements		
220	887 Maintenance of Mains	329,490	189,795
221	888 Maintenance of Compressor Station Equipment		
222	889 Maintenance of Meas. and Reg. Sta. Equip.-General		
223	890 Maintenance of Meas. and Reg. Sta. Equip.-Industrial		
224	891 Maintenance of Meas. and Reg. Sta. Equip.-City Gate Check Station		
225	892 Maintenance of Services	13,960	25,808
226	893 Maintenance of Meters and House Regulators		
227	894 Maintenance of Other Equipment	4,945	(57,403)
228	TOTAL Maintenance (Enter Total of lines 218 thru 227)	397,277	170,035
229	TOTAL Distribution Expenses (Enter Total of lines 216 and 228)	$1,562,749	$1,449,481
230	**5. CUSTOMER ACCOUNTS EXPENSES**		
231	**Operation**		
232	901 Supervision		
233	902 Meter Reading Expenses	16,785	22,529
234	903 Customer Records and Collection Expenses	398,333	372,095
235	904 Uncollectible Accounts	67,115	10,848
236	905 Miscellaneous Customer Accounts Expenses		
237	TOTAL Customer Accounts Expenses (Enter Total of lines 232 thru 236)	$482,233	$405,472

Name of Resondent	This Report Is:	Date of Report	Year of Report
Summit Natural Gas of Maine, Inc	(1) An Original **(2) A Resubmission**	04/29/2021	December 31, 2020

GAS OPERATION AND MAINTENANCE EXPENSES (Continued)

Line No.		Amount for Current Year (b)	Amount for Previous Year (c)
238	**6. CUSTOMER SERVICE AND INFORMATIONAL EXPENSES**		
239	**Operation**		
240	907 Supervision		
241	908 Customer Assistance Expenses	852,998	1,022,927
242	909 Informational and Instructional Expenses	26,458	15,535
243	910 Miscellaneous Customer Service and Informational Expenses		
244	TOTAL Customer Service and Information Expenses (Lines 240 thru 243)	$879,456	$1,038,462
245	**7. SALES EXPENSES**		
246	**Operation**		
247	911 Supervision		
248	912 Demonstration and Selling Expenses	2,099,399	2,046,807
249	913 Advertising Expenses	3,439	13,366
250	916 Miscellaneous Sales Expenses		
251	TOTAL Sales Expenses (Enter Total of lines 247 thru 250)	$2,102,838	$2,060,172
252	**8. ADMINISTRATIVE AND GENERAL EXPENSES**		
253	**Operation**		
254	920 Administrative and General Salaries	$1,743,470	$1,823,689
255	921 Office Supplies and Expenses	694,313	789,386
256	(Less) (922) Administrative Expenses Transferred-Cr.	(4,942,268)	(4,882,896)
257	923 Outside Services Employed	553,376	302,548
258	924 Property Insurance	325,184	390,341
259	925 Injuries and Damages		0
260	926 Employee Pensions and Benefits	15,175	11,668
261	927 Franchise Requirements		
262	928 Regulatory Commission Expenses	223,403	390,557
263	(Less) (929) Duplicate Charges-Cr.		
264	930.1 General Advertising Expenses		
265	930.2 Miscellaneous General Expenses	3,503,851	3,025,602
266	931 Rents	292,655	285,598
267	TOTAL Operation (Enter Total of lines 254 thru 266)	2,409,157	2,136,494
268	**Maintenance**		
269	935 Maintenance of General Plant	170,144	136,807
270	TOTAL Administrative and General Exp (Total of lines 267 and 269)	$2,579,301	$2,273,300
271	TOTAL Gas O. and M. Exp (Lines 97, 177, 201, 229, 237, 244, 251, and 270)	$12,393,086.18	$16,023,161

NUMBER OF GAS DEPARTMENT EMPLOYEES

1. The data on number of employees should reported for the payroll period ending nearest to October 31, or any payroll period ending 60 days before or after October 31.
2. If the respondent's payroll for the reporting period includes any special construction personnel, include such employees on line 3, and show the number of such special construction employees in a footnote.
3. The number of employees assignable to the gas department from joint functions of combination utilities may be determined by estimate, on the basis of employee equivalents. Show the estimated number of equivalent employees attr buted to the gas department from joint functions.

1.	Payroll Period Ended (Date)	12/31/2020	
2.	Total Regular Full-Time Employees		33.00
3.	Total Part-Time and Temporary Employees		0.00
4.	Total Employees		33.00

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year of Report
Summit Natural Gas of Maine, Inc	(1) An Original **(2) A Resubmission**	04/29/2021	December 31, 2020

REGULATORY COMMISSION EXPENSES

1. Report particulars (details) of regulatory commission expenses incurred during the current year (or incurred in previous years, if being amortized) relating to cases before a regulatory body or cases in which such a body was a party.

2. In columns (b) and (c), indicate whether the expenses were assessed by a regulatory body or were otherwise incurred by the utility.

Line No.	Description (Furnish name of regulatory commission and the docket or case number, and a description of the case.) (a)	Assessed by Regulatory Commission (b)	Expenses of Utility (c)	Total Expenses to Date (d)	In Account 186 at Beginning of Year (e)
1	None				
2					
3					
4					
5					
6					
7					
8					
9					
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38					
39					
40	TOTAL				0

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year of Report
Summit Natural Gas of Maine, Inc	(1) An Original **(2) A Resubmission**	04/29/2021	December 31, 2020

REGULATORY COMMISSION EXPENSES (Continued)

3. Show in column (k) any expenses incurred in prior years which are being amortized. List in column (a) the period of amortization.
4. The totals of columns (e), (I), (k), and (l) must agree with the totals shown at the bottom of page 233 for Account 186.
5. List in column (f), (g), and (h) expenses incurred during year which were charged currently to income, plant or other accounts.
6. Minor items (less than $25,000) may be grouped.

Line No.	Expenses Incurred During Year				Amortized During Year		Deferred In Account 186 at End of Year	Line No.
	Charged Currently To			Deferred to Account 186	Contra Account	Amount		
	Department (f)	Account No (g)	Amount (h)	(I)	(j)	(k)	(l)	
1	None							1
2								2
3								3
4								4
5								5
6								6
7								7
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33								33
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35								35
36								36
37								37
38								38
39								39
40	TOTAL							40

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year of Report
Summit Natural Gas of Maine, Inc	(1) An Original **(2) A Resubmission**	04/29/2021	December 31, 2020

CHARGES FOR OUTSIDE PROFESSIONAL AND OTHER CONSULTATIVE SERVICES

1. Report the information specified below for all charges made during the year included in any account (including plant accounts) for outside consultative and other professional services. These services include rate, management, construction, engineering, research, financial, legal, valuation, accounting, purchasing, advertising, labor relations and public relations, rendered for the respondent under written or oral arrangement, for which aggregate payments were made during the year to any corporation, partnership, organization of any kind, or individual (other than for services as an employee or for payments made for medical and related services) amounting to more than $250,000, including payments for legislative services, except those which should be reported in Account 426.4, Expenditures for Certain Civic, Political and Related Activities.
   (a) Name of person or organization rendering service.
   (b) Total charges for the year.

2. Designate associated companies with an asterisk in column (b).

Line No.	Description (a)	* (b)	Amount (in dollars) (c)
1	Consulting		78,802
2	Legal		82,080
3	Audit and Tax Fees		121,146
4			
5			
6			
7			
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39			
40	TOTAL		282,028

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year of Report
Summit Natural Gas of Maine, Inc	(1) An Original **(2) A Resubmission**	04/29/2021	December 31, 2020

GAS ACCOUNTS - NATURAL GAS

1. The purpose of this schedule is to account for the quantity of natural gas received and delivered by the respondent.
2. Natural gas means either natural gas unmixed or any mixture of natural and manufactured gas.
3. Enter in column (c) the Dth as reported in the schedules indicated for the items of receipts and deliveries.
4. Indicate in a footnote the quantities of bundled sales and transportation gas and specify the on which such quantities are listed.
5. If the respondent operates two or more systems which are not interconnected, submit separate pages for this purpose. Use copies of this page as necessary.
6. Also indicate by footnote the quantities of gas not subject to Commission regulation which did not incur FERC regulatory costs by showing (1) the local distribution volumes another jurisdictional pipeline delivered to the local distribution company portion of the reporting pipeline (2) the quantities that the reporting pipeline transported or sold through its local distribution facilities or intrastate facilities and which the reporting pipeline received received through gathering facilities or intrastate facilities, but not through any of the interstate of the reporting pipeline, and (3) the gathering line quantities that were not destined for interstate market or that were not transported through any interstate portion of the reporting pipeline.
7. Also indicate in a footnote (1) the system supply quantities of gas that are stored by the reporting pipeline, during the reporting year and also reported as sales, transportation and compression volumes by the reporting pipeline during the same reporting year which the reporting pipeline intends to sell or transport in a future reporting year, and (3) contract storage quantities.
8. Also indicate the volumes of pipeline production field sales included in both the company's total sales figures and total transportation figure.

Line No.	Item (a)	Ref Page No. (b)	Amount of Dth (c)
1	Name of System		
2	**GAS RECEIVED**		
3	Gas Purchases (Accounts 800-805)		826,524
4	Gas of Others Received for Gathering (Account 489.1)		
5	Gas of Others Received for Transmission (Account 489.2)		
6	Gas of Others Received for Distribution (Account 489.3)		3,457,611
7	Gas of Others Received for Contract Storage (Account 489.4)		
8	Exchanged Gas Received from Others (Account 806)		
9	Gas Received as Imbalances (Account 806)		
10	Receipts of Respondent's Gas Transported by Others (Account 858)		
11	Other Gas Withdrawn from Storage (Explain)		
12	Gas Received from Shippers as Compressor Station Fuel		
13	Gas Received from Shippers as Lost and Unaccounted for		
14	Other Receipts (Specify)		
15	Total Receipts (Total of lines 3 thru 14)		4,284,135
16	**GAS DELIVERED**		
17	Gas Sales (Accounts 480-484)		821,208
18	Deliveries of Gas Gathered for Others (Account 489.1)		
19	Deliveries of Gas Transported for Others (Account 489.2)		
20	Deliveries of Gas Distributed for Others (Account 489.3)		3,435,373
21	Deliveries of Contract Storage Gas (Account 489.4)		
22	Exchange Gas Delivered to Others (Account 806)		
23	Exchange Gas Delivered as Imbalances (Account 806)		
24	Deliveries of Gas to Others for Transportation (Account 858)		
25	Other Gas Delivered to Storage (Explain)		
26	Gas Used for Compressor Station Fuel		
27	Other Deliveries (Specify)		
28	Total Deliveries (Total of lines 17 thru 27)		4,256,581
29	**GAS UNACCOUNTED FOR**		
30	Production System Losses		
31	Gathering System Losses		
32	Transmission System Losses		
33	Distribution System Losses		27,554
34	Storage System Losses		
35	Other Losses (Specify)		
36	Total Unaccounted For (Total of Lines 30 thru 35)		27,554
37	Total Deliveries & Unaccounted For (Total of lines 28 and 36)		4,284,135

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year of Report
Summit Natural Gas of Maine, Inc	(1) An Original **(2) A Resubmission**	04/29/2021	December 31, 2020

Chapter 830 Reporting Requirements
Political Activities, Institutional Advertising, Promotional Advertising and Promotional Allowances

Include on this page all information required by Chapter 830 of the Public Utilities Commission's Rules.

Account 426.4-Political Activities	$	89,650

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year of Report
Summit Natural Gas of Maine, Inc	(1) An Original **(2) A Resubmission**	04/29/2021	December 31, 2020

Promotional Programs Offered

Include on this page a listing of promotional programs offered during the reporting year and new programs offered as of the date of this report.

Program Title to Description	Date(s) Program Offered
Incentive Rebate (Tariff) up to $1,500.00	Customer must be a Summit Natural Gas Customer and have gas flowing. Tariff ends in Jauary 2023
Summit Incentive Rebate(Tariff) up to $1,500.00	Customer must be a Summit Natural Gas Customer and have gas flowing. Tariff ends in Jauary 2023

Name of Respondent	This Report Is:	Date of Report	Year of Report
Summit Natural Gas of Maine, Inc	(1) An Original **(2) A Resubmission**	(Mo, Da, Yr) 04/29/2021	December 31, 2020

Chapter 820 Reporting Requirements
Summary of Affiliated Transactions

Provide a reporting of all transactions with affilitiates during the past year in accordance with the requirements of Chapter 820 of the Public Utilities Commission's Rules and Regulations.

Summit Utilities Inc (Parent Company)

Services (direct labor charges & overhead) provided by parent company include Administration, Fleet, Executive, Accounting, FP&A, Treasury, Human Resources, Information Systems, Legal, Corporate Affairs, Regulatory, Energy Efficiency, Customer Care - Collections, Marketing, Business Development, Engineering, Compliance, Integrity, Operations, Safety, Gas Supply Management and Procurement.

Summit Natural Gas of Maine Inc

Services (direct labor) provided to sister and parent companies include Business Development, Compliance, Engineering, Gas Control and Operations.

Indirect overhead is allocated to each subsidiary based on the Distrigas formula. The Distrigas formula takes the prior month plant-in-service balance, current month payroll expense, and prior month revenues of each operating company (each weighted 1/3) to calculate each subsidiary's overhead proporionate share. This proportionate share is then multiplied by the current month parent company overhead expenses in order to allocate a portion of the overhead expenses to each subsidiary. Overhead distributed via the Distrigas formula includes Shared Services labor, employee benefits, vehicle expenses, and G&A expenses. Shared Services provided by the parent company include Finance & Accounting, Admin, IT, HR, Payroll, Billing, Regulatory, Executive, Legal, and Procurement not previously allocated through direct identification.

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year of Report
Summit Natural Gas of Maine, Inc	(1) An Original (2) **A Resubmission**	04/29/2021	December 31, 2020

RESIDENTIAL AND COMMERCIAL SPACE HEATING CUSTOMERS

A residential space heating customer is a customer whose major fuel for heating is gas.

Line No.	Item (a)	Residential (b)	Commercial (c)
1	Average Number of Space Heating Customers for the Year (Estimate if not known. Designate with an asterisk if estimated.)		
2	For Space Heating Only, Estimated Average Mcf (14.73 psia at 60 F) per Customer for the Year		
3	Number of Space Heating Customers Added During the Year		
4	Number of Unfilled Applications for Space Heating at End of Year		

INTERRUPTIBLE, OFF PEAK, AND FIRM GAS AND TRANSPORTATION SALES TO DISTRIBUTION SYSTEM INDUSTRIAL CUSTOMERS

1. Report below the average number of interruptible, off-peak, and firm industrial customers on local distribution systems of the respondent, and the Mcf of gas sales to these customers for the year. Include transportation only customer information as well.
2. Interruptible customers are those to whom service may be interrupted under terms of the customer's gas contract, or to whom service is required to be interrupted, regardless of contractual arrangements in emergency periods by law, ordinance, directive, or other requirements of government authority. State in a footnote the basis on which interruptible customers are reported.
3. Off peak sales are seasonal and other sales which do not occur during wintertime demands.
4. Report pressure base of gas volumes at 14.73 psia at 60 F.

Line No.	Item (a)	Number/Amount (b)
1	Interruptible Customers	
2	Average Number of Customers for the Year	
	Sales Customers	
	Transportation Only Customers	
3	Mcf of Gas Sold or Transported for the Year	
	Sales Customers	8
	Transportation Only Customers	3,223,850
4	Off Peak Customers	
5	Average Number of Customers for the Year	
	Sales Customers	
	Transportation Only Customers	
6	Mcf of Gas Sold or Transported for the Year	
	Sales Customers	
	Transportation Only Customers	
7	Firm Customers	
8	Average Number of Customers for the Year	
	Sales Customers	
	Transportation Only Customers	
9	Mcf of Gas Sold or Transported for the Year	
	Sales Customers	
	Transportation Only Customers	
10	Total Industrial Customers	
11	Average Number of Customers for the Year	
	Sales Customers	
	Transportation Only Customers	
12	Mcf of Gas Sold or Transported for the Year	
	Sales Customers	
	Transportation Only Customers	

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year of Report
Summit Natural Gas of Maine, Inc	(1) An Original **(2) A Resubmission**	04/29/2021	December 31, 2020

Number of Customer's Meters
(Active)

City or Town	Number of Meters
Cumberland/Yarmouth/Falmouth	2,318
Kennebec Valley	1,873

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year of Report
Summit Natural Gas of Maine, Inc	(1) An Original **(2) A Resubmission**	04/29/2021	December 31, 2020

LIQUEFIED PETROLEUM GAS OPERATIONS

1. Report the information called for below concerning plants which produce gas from liquefied gas (LPG).

2. For columns (b) and (c), the plant cost and operation and maintenance expenses of any liquefied petroleum gas installation which is only an adjunct of a manufactured gas plant, may include or exclude (as appropriate) the plant cost and expenses of any plant used jointly with the manufactured plant facilities on the basis of predominant use. Indicate in a footnote how the plant cost and expense for the liquefied petroleum plant described above are reported.

Line No.	Identification of Plant and Year Installed	Cost of Plant (Land, struc, equip.)	Expenses	
			Operation Maintenance, Rents	Cost of LPG
	(a)	(b)	(c)	(d)
1	None			
2				
3				
4				
5				
6				
7				
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37				
38				
39				
40	TOTAL			0

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year of Report
Summit Natural Gas of Maine, Inc	(1) An Original **(2) A Resubmission**	04/29/2021	December 31, 2020

LIQUEFIED PETROLEUM GAS OPERATIONS (continued)

3. (continued) Designate any plant held under a ti le other than full ownership and in a footnote state name of owner or co-owner, nature of respondent's title and percent ownership if jointly owned.
4. For column (g) report the Mcf that is mixed with natural gas or which is substituted for deliveries normally made from natural gas. Natural gas means either natural gas unmixed or any mixture of natural and manufactured gas or mixture of natural gas and gasified LPG.
5. If any plant was not operated during the past year, give details in a footnote, and state whether the book cost of plant or any portion thereof, has been retired in the books of account or what disposition of the plant and its book cost is contemplated.
6. Report pressue base of gas at 14.73 psia at 60 F. Indicate the Btu content in a footnote.

Gallons of LPG Used (e)	Gas Produced Amount of MMBTU (f)	Amount of MMBTU Mixed with Natural Gas (g)	LPG Storage Cap. Gallons (h)	Function of Plant (Base load, peaking, etc.) (I)	Line No.
					1
					2
					3
					4
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Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year of Report
Summit Natural Gas of Maine, Inc	(1) An Original (2) **A Resubmission**	04/29/2021	December 31, 2020

AUXILIARY PEAKING FACILITIES

1. Report below auxiliary facilities of the respondent for meeting seasonal peak demands on the respondent's system, such as underground storage projects, liquefied petroleum gas installations, gas liquefaction plant, oil gas sets, etc.
2. For column (c), for underground storage projects, report the delivery capacity on February 1 of the hea ing season overlapping he year-end for which this report is submitted. For other facilities, report the maximum daily delivery capacities.
3. For column (d), include or exclude (as appropriate) the cost of any plant used jointly with another facility on he basis of predominant use, unless the auxiliary peaking facility is a separate plant as contemplated by general instruction 12 of the Uniform System of Accounts.

Line No.	Location of Facility (a)	Type of Facility (b)	Maximum Daily Delivery Capacity of Facility, Mcf at 14.73 psia at 60 (c)	Cost of Facility (in dollars) (d)	Was Facility Operated on Day of Highest Transmission Peak Delivery? Yes (e)	No (f)
1	None					
2						
3						
4						
5						
6						
7						
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Name of Respondent	This Report Is:	Date of Report	Year of Report
Summit Natural Gas of Maine, Inc	(1) An Original **(2) A Resubmission**	04/29/2021	December 31, 2020

GAS PURCHASES (Accounts 800, 800.1, 801, 802, 803, 804, 804.1, 805, 805.1)

1. Provide totals for the following accounts:
800 Natural Gas Well Head Purchases
800.1 Natural Gas Well Head Purchases, Intracompany Transfers
801 Natural Gas Field Line Purchases
802 Natural Gas Gasoline Plant Outlet Purchases
803 Natural Gas Transmission Line Purchases
804 Natural Gas City Gate Purchases
804.1 Liquefied Natural Gas Purchases
805 Other Gas Purchases
805.1 Purchase Gas Cost Adjustments

The totals shown in columns (b) and (c) should agree with the books of account. Reconcile any differences in a footnote.

2. State in column (b) the volume of purchased gas as finally measured for the purpose of determining the amount payable for the gas. Include current year receipts of makeup gas that was paid for in previous years.

3. State in column (c) the dollar amount (omit cents) paid and previously paid for the volume of gas shown in column (b).

4. State in column (d) the average cost per Mcf to the nearest hundredth of a cent. (Average means column (c) divided by column (b) multiplied by 100.)

Line No.	Account Title (a)	Gas Purchased - Dth (14.73 psia at 60F) (b)	Cost of Gas (in dollars) (c)	Average Cost per Dth (To nearest .01 of a cent) (d)
1	800 - Natural Gas Well Head Purchases			
2	800.1 - Natural Gas Well Head Purchases, Intracompany Transfers			
3	801 - Natural Gas Field Line Purchases			
4	802 - Natural Gas Gasoline Plant Outlet Purchases			
5	803 - Natural Gas Transmission Line Purchases			
6	804 - Natural Gas City Gate Purchases	4,284,135.00	4,842,021	1.13
7	804.1 - Liquefied Natural Gas Purchases			
8	805 - Other Gas Purchases			
9	805.1 - Purchase Gas Cost Adjustments			
10	Total (Enter Total of Lines 1 through 9)	4,284,135	4,842,021	

Notes to Gas Purchases

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year of Report
Summit Natural Gas of Maine, Inc	(1) An Original **(2) A Resubmission**	04/29/2021	December 31, 2020

Conversion Factor Used

1. Provide a summary of how data from the customer meters is converted to data used to calculate customer bills
2. Report below by month any factors used to convert data read by customer meters into data used to calculate customer bills and indicate the source of that factor.

	BTU Factors
January	1.0507
February	1.0449
March	1.0448
April	1.0435
May	1.0419
June	1.0353
July	1.0334
August	1.0295
September	1.0352
October	1.0385
November	1.0329
December	1.0376

Summit Natural Gas of Maine, Inc.

Docket No. 2022-00025

Annual Report

Section 5.C.3.b of Chapter 120 requires Summit to provide "an annual report for the test year, or the equivalent compilation in the same form and detail if the test year is a period other than a calendar year."

Attached please find a copy of the "Annual Report for Gas Utilities of Summit Natural Gas of Maine Inc. to the Public Utilities Commission of the State of Maine for the Year Ended December 31, 2021."

ANNUAL REPORT

FOR GAS UTILITIES

OF

Name __ Summit Natural Gas of Maine, Inc

Address__ 442 Civic Center Drive, Suite 10000, Augusta, ME 04330

TO THE

PUBLIC UTILITIES COMMISSION

OF THE

STATE OF MAINE

FOR THE

YEAR ENDED DECEMBER 31, 2021

PART I : IDENTIFICATION

01 Exact Legal Name of Respondent Summit Natural Gas of Maine, Inc	**02 Year of Report** December 31, 2021
03 Previous Name and Date of Change (If name changed during year) N/A	
04 Address of Principal Business Office at End of Year (Street, City, State, Zip Code) 10825 East Geddes Avenue, Suite 410, Centennial, CO 80112	
05 Name of Contact Person Michelle Moorman Applegate	**06 Title of Contact Person** Senior Director of Regulatory Affairs
07 Address of Contact Person (Street, City, State, Zip Code) 442 Civic Center Drive, Augusta, ME 04330	

08 Telephone and Email of Contact Person 720-981-2123 Ext. 1160 Mapplegate@summitutilities.com	**09 This Report Is** **(1) An Original** (2) A Resubmission	**10 Date of Report (Mo, Da, Yr)** 3/30/22

11 Name of Officer Having Custody of the Books of Account Steven Birchfield	**12 Title of Officer** Executive Vice President & Chief Financial Officer
13 Address of Officer Where Books of Account Are Kept (Street, City, State, Zip code) 10825 E. Geddes Avenue, Suite 410, Centennial, CO 80112	

14 Name of State Where Respondent is Incorporated CO	**15 Date of Incorporation (Mo, Da, Yr)** December 16, 2011	**16 If applicable, Reference to Law Incorporated Under** N/A

17 Explanation of Manner and Extent of Corporate Control (If the respondent controls or is controlled by any other corporation, business trust, or similar organization)

PART II: ATTESTATION

The undersigned officer certifies that he/she has examined the accompanying report; that to the best of his/her knowledge, information, and belief, all statements of fact contained in the accompanying report are true and the accompanying report is a correct statement of the business and affairs of the above named respondent in respect to each and every matter set forth therein during the period from and including January 1 to and including December 31 of the year of the report.

01 Name Steven Birchfield	**03 Signature** DocuSigned by: Steve Birchfield 3A6A3F2C32A44EB...	**04 Date Signed (Mo, Da, Yr)** 3/30/2022
02 Title Executive Vice President & Chief Financial Officer		

Name of Respondent Summit Natural Gas of Maine, Inc	This Report Is: (1) An Original (2) A Resubmission	Date of Report (Mo, Da, Yr) 3/30/22	Year of Report December 31, 2021

GENERAL INFORMATION

1. Provide name and title of officer having custody of the general corporate books of account and address of office where the general corporate books are kept, and address of office where any other corporate books of account are kept, if different from that where the general corporate books are kept.

Steven Birchfield
Executive Vice President & Chief Financial Officer
Summit Natural Gas of Maine, Inc.
10825 E. Geddes Avenue, Suite 410, Centennial, CO 80112

2. Provide the name of the State under the laws of which the respondent is incorporated, and date of incorporation. If incorporated under a special law, give reference to such law. If not incorporated, state that fact and give the type of organization and the date organized.

State of Colorado Incorporated: December 16, 2011

3. If at any time during the year the property of respondent was held by a receiver or trustee, give (a) name of receiver or trustee, (b) date such receiver or trustee took possession, (c) the authority by which the receivership or trusteeship was created, and (d) date when possession by receiver or trustee ceased.

Not Applicable

4. State the classes of utility and other services furnished by respondent during the year in each State in which the respondent operated.

Natural Gas Distribution

5. Have you engaged as the principal accountant to audit your financial statements an accountant who is not the principal accountant for your previous year's certified financial statements:

No
(1) Yes...Enter the date when such independent accountant was initially engaged:
(2) ***No, PricewaterhouseCoopers LLP was the auditor for both years.***

Name of Respondent	This Report Is:	Date of Report	Year of Report
Summit Natural Gas of Maine, Inc	(1) An Original (2) A Resubmission	(Mo, Da, Yr) 3/30/22	December 31, 2021

AFFILIATED INTERESTS

Include on this page, a summary listing of all affiliated interests of the respondent and its parent. Indicate the relationship to the parent and the respondent and the percentage owned by the corporate group. (Refer to M.R.S.A. §707 for the definition of affiliated interests.

Summit Natural Gas of Maine, Inc. is a wholly owned subsidiary of Summit Utilities, Inc.
Summit Natural Gas of Maine, Inc. does not own an interest in any other entity.
Affiliated Interests, wholly owned by Summit Utilities, Inc.

Peaks Renewables, Inc.
Wolf Creek Energy, LLC
Summit LDC Holdings, LLC
Southern Col Holdco, LLC

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year of Report
Summit Natural Gas of Maine, Inc	(1) An Original (2) A Resubmission	3/30/22	December 31, 2021

OFFICERS

1. Report below the name, title and salary for each executive officer whose salary is $50,000 or more. An "executive officer" of a respondent includes its president, secretary, treasurer, and vice president in charge of a principal business unit, division function (such as sales, administration or finance), and any other person who performs similarly policy-making functions.

2. If a change was made during the year in the incumbent of any position, show name of the previous incumbent, and date the change in incumbency was made.

3. Utilities which are required to file the same data with the Securities and Exchange Commission, may substitute a copy of item 4 of Regulation S-K (identified as this page). The substitute page(s) should be the same size as this page.

4 Report below any additional companies where the officer holds office along with their title.

Line No.	Title (a)	Name of Officer (b)	Other Companies Officer Of with Title (c)
1			
2	President and Chief Executive Officer	Kurt W. Adams	President and Chief Executive Officer of Summit Utilities, Inc., Colorado Natural Gas, Inc., Summit Natural Gas of Maine, Inc., Summit Natural Gas of Missouri, Inc., Peaks Renewables, Inc. (Presi Summit Utilities Arkansas, Inc., Summit Utilities Oklahoma
8	Executive Vice President and Chief Financial Officer	Steven E. Birchfield	Executive Vice President and Chief Financial Officer of Summit Utilities, Inc. Colorado Natural Gas, Inc., Summit Natural Gas of Maine, Inc., Summit Natural Gas of Missouri, Inc., Peaks Renewables, Inc. Summit Utilities Arkansas, Inc., Summit Utilities Oklahoma
14	Senior Vice President, Chief Legal Officer and Secretary	Hallie F. Gilman	Senior Vice President, Chief Legal Officer and Secretary of Summit Utilities, Inc. Colorado Natural Gas, Inc., Summit Natural Gas of Maine, Inc., Summit Natural Gas of Missouri, Inc., Peaks Renewables, Inc. Summit Utilities Arkansas, Inc., Summit Utilities Oklahoma Title changed from Sr. VP to Executive VP on 12/9/21
21	President	Kurt W. Adams	A. O. G. Corporation, Arkansas Oklahoma Gas Corporation Summit LDC Holdings, LLC, Southern Col Holdco, LLC, and Southern Col Midco, LLC
25	Vice President and Treasurer	Steven E. Birchfield	A. O. G. Corporation, Arkansas Oklahoma Gas Corporation, Summit LDC Holdings, LLC, Southern Col Holdco, LLC, and Southern Col Midco, LLC
29	Vice President and Secretary	Hallie F. Gilman	A. O. G. Corporation and Arkansas Oklahoma Gas Corporation Southern Col Holdco, LLC, and Southern Col Midco, LLC
32	Senior Vice President and Secretary	Hallie F. Gilman	Summit LDC Holdings, LLC
34	President and Chief Executive Officer	Angus S. King III	Peaks Renewables, Inc. (effective 12/9/21)

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year of Report
Summit Natural Gas of Maine, Inc	(1) An Original (2) A Resubmission	3/30/22	December 31, 2021

DIRECTORS

1. Report below the information called for concerning each director of the respondent who held office at any time during the year. Include in column (a), abbreviated titles of the directors who are officers of the respondent.

2. Designate members of the Executive Committee by an asterisk and the Chairman of the Executive Committee by a double asterisk.

Name (and Title) of Director (a)	Principal Business Address (b)	No. of Directors Meetings During Year (c)	Fees During Year (d)
Kurt W. Adams, Director, Pres., CEO	10825 E. Geddes Avenue, Suite 410, Centennial, CO 80112	7	
Henry W Fayne, Chairman	10825 E. Geddes Avenue, Suite 410, Centennial, CO 80112	7	$125,000
Andrew (Landy) E. Gilbert, Director	10825 E. Geddes Avenue, Suite 410, Centennial, CO 80112	7	
Kathleen D. Alexander, Director	10825 E. Geddes Avenue, Suite 410, Centennial, CO 80112	7	$100,000
Daniel M. Mitaro, Alternate	10825 E. Geddes Avenue, Suite 410, Centennial, CO 80112	6	
Cheryl F. Campbell, Director	10825 E. Geddes Avenue, Suite 410, Centennial, CO 80112	7	$100,000
Thomas H. Graham, Director	10825 E. Geddes Avenue, Suite 410, Centennial, CO 80112	7	$100,000

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year of Report
Summit Natural Gas of Maine, Inc	(1) An Original (2) A Resubmission	3/30/22	December 31, 2021

1. Give the names and addresses of the 10 security holders of the respondent who, at the date of the latest closing of the stock book or compilation of the list of stockholders of the respondent, prior to the end of the year, had the highest voting powers in the respondent, and state the number of votes which each would have had the right to cast on that date if a meeting were then in order. If any such holder held in trust, give in a footnote the known particulars of the trust (whether voting trust, etc.), duration of trust and principal holders of beneficiary interests in the trust. If the stock book was not closed or a list of stockholders was not compiled within one year prior to the end of the year, or if other class of security has become vested with voting rights, then show such 10 security holders as of the close of the year. Arrange the names of the security holders in the order of voting power, commencing with the highest. Show in column (a) the titles of officers and directors included in such list of 10 security holders.
2. If any security other than stock carries voting rights, explain in a supplemental statement the circumstances whereby such security became vested with voting rights and give other important particulars (details) concerning the voting rights of such security. State whether voting rights are actual or contingent: of contingent, describe the contingency.
3. If any class or issue of security has any special privileges in the election of directors, trustees or managers, or in the determination of corporate action by any method, explain briefly in a footnote.
4. Furnish particulars (details) concerning any options, warrants, or rights outstanding at the end of the year for others to purchase securities of the respondent or any securities or other assets owned by the respondent, including prices, expiration dates, and other material information relating to exercise of the options, warrants, or rights. Specify the amount of such securities or assets so entitled to be purchased by any officer, director, associated company, or any of the ten largest security holders. This instruction is inapplicable to convertible securities or to any securities substantially all of which are outstanding in the hands of the general public where the options, warrants, or rights were issued on a prorata basis.

1. Give the date of the latest closing of the stock book prior to the end of the year, and state the purpose of such closing:	2. State the total number of votes cast at the latest general meeting prior to the end of the year for election of the directors of the respondent and number of such votes cast by proxy Total: By proxy:	3. Give the date and place of such Meeting:

Line No.	Name (Title) and Address of Security Holder (a)	VOTING SECURITIES Number of votes as of (date): Total Votes (b)	Common Stock (c)	Preferred Stock (d)	Other (e)
4	TOTAL votes of all voting securities	1	10,000		
5	TOTAL numbers of security holders	1	10,000		
6	TOTAL votes of security holders listed below	1	10,000		
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Name of Respondent	This Report Is:	Date of Report	Year of Report
Summit Natural Gas of Maine, Inc	(1) An Original (2) A Resubmission	(Mo, Da, Yr) 3/30/22	December 31, 2021

IMPORTANT CHANGES DURING THE YEAR

Give particulars (details) concerning the matters indicated below. Make the statements explicit and precise, and number them in accordance with the inquiries. Each inquiry should be answered. Enter "none" or "not applicable" where applicable. If information which answers an inquiry is given elsewhere in the report, make a reference to the schedule in which it appears.

1. List changes in and important additions to franchise area.
   None

2. Acquisition of ownership in other companies by reorganization, merger, or consolidation with other companies: Give names of companies involved, particulars concerning the transactions, name of the Commission authorizing the transaction, and reference to commission authorization.
   None

3. Purchase or sale of an operating unit or system: Give a brief description of the property, and of the transactions relating thereto, and reference to Commission authorization, if any was required.
   None

4. List important leaseholds that have been acquired given, assigned or surrendered: Give effective dates, lengths of terms, names of parties, rents, and other conditions. State name of Commission authorizing lease and give reference to such authorization.
   None

5. Important extension or reduction of transmission or distribution system: State territory added or relinquished and date operations began or ceased and give reference to Commission authorization, if any was required.
   None

6. Obligations incurred or assumed by respondent as guarantor for the performance by another of any agreement or obligation, including ordinary commercial paper maturing on demand or not later than one year after date of issue: State on behalf of whom the obligation was assumed and amount of the obligation. Give reference to Commission authorization if any was required.
   None

7. Changes in articles of incorporation or amendments to charter: Explain the nature and purpose of such changes or amendments.
   None

8. State briefly the status of any materially important legal proceedings pending at the end of the year, and the results of any such proceedings culminated during the year.
   None

9. Describe briefly any materially important transactions of the respondent not disclosed elsewhere in this report in which an officer, director, security holder reported on page 6, voting trustee, associated company or known associate of any of these persons was a party or in which any such person had a material interest.
   None

10. If the important changes during the year relating to the respondent company appearing in the annual report to stockholders are applicable in every respect and furnish the data required by instructions 1 to 9 above, such notes may be attached to this page.
    None

	This Report is:	Date of Report	Year of Report
	(1) An Original	(Mo, Da, Yr)	
	(2) A Resubmission	3/30/22	December 31, 2021

Title of Account (a)	Ref. Page No. (b)	Balance at Beginning of Year (c)	Balance at End of Year (d)
UTILITY PLANT			
Utility Plant (101-106, 114)	20-21	373,480,850	385,275,717
Construction Work in Progress (107)	20-21	2,509,087	937,811
TOTAL Utility Plant (Enter Total of lines 2 and 3)		375,989,936	386,213,528
(Less) Accum. Prov. for Depr. Amort. Depl. (108, 111, 115)	20-21	(47,401,248)	(54,637,074)
Net Utility Plant (Enter total of line 04 less 05)	-	328,588,688	331,576,453
Nuclear Fuel (120.1-120.4, 120.6)	-		
(Less) Accum. Prov. for Amort. of Nucl. Fuel Assemblies (120.5)	-		
Net Nuclear Fuel (Enter Total of Line 7 less 8)	-		
Net Utility Plant (Enter Total of lines 6 and 9)	-	328,588,688	331,576,453
Utility Plant Adjustments (116)			
Gas Stored Underground-Noncurrent (117)			
OTHER PROPERTY AND INVESTMENTS			
Nonutility Property (121)			
(Less) Accum. Prov. for Depr. and Amort. (122)			
Investments In Associated Companies (123)			
Investments In Subsidiary Companies (123.1)			
(For Cost of Account 123.1, See Footnote Page 224, line 42)	-		
Noncurrent Portion of Allowances	-		
Other Investments (124)			
Special Funds (125 - 128)	-	0	314,114
TOTAL Other Property and Investments (Total lines 14-17, 19-21)	-	0	314,113.6
CURRENT AND ACCRUED ASSETS:			
Cash (131)	-	567,392	873,688
Special Deposits (132-134)	-	210,360	
Working Funds (135)	-	0	
Temporary Cash Investments (136)		3,332	3,371
Notes Receivable (141)	-	11,200	8,773
Customer Accounts Receivable (142)		1,214,252	1,184,491
Other Accounts Receivable (143)	-	2,569	2,391
(Less) Accum. Prov. for Uncollectible Acct.-Credit (144)	-	(39,316)	(5,377)
Notes Receivable from Associated Companies (145)	-		
Accounts Receivable from Assoc. Companies (146)	-	2,312,407	1,450,195
Fuel Stock (151)	-		
Fuel Stock Expenses Undistributed (152)	-		
Residuals (Elec) and Extracted Products (Gas) (153)	-		
Plant Materials and Operating Supplies (154)	-	2,415,301	2,141,985
Merchandise (155)	-		
Other Materials and Supplies (156)	-		
Nuclear Materials Held for Sale (157)	-		
Allowances (158.1 and 158.2)	-		
(Less) Noncurrent Portion of Allowances	-		
Stores Expense Undistributed (163)	-		
Gas Stored Underground - Current (164.1)			
Liquefied Natural Gas Stored and Held for Processing (164.2-164.3)			
Prepayments (165)		114,919	156,851
Advances for Gas (166-167)			
Interest and Dividends Receivable (171)	-		
Rents Receivable (172)	-		
Accrued Utility Revenues (173)	-	1,817,496	2,246,259
Miscellaneous Current and Accrued Assets (174)	-	58,399	28,587
TOTAL Current and Accrued Assets (Enter Total of lines 24 thru 51)	-	8,688,313	8,091,214

	This Report is: (1) An Original (2) A Resubmission	Date of Report (Mo, Da, Yr) 3/30/22	Year of Report December 31, 2021

Title of Account (a)	Ref. Page No. (b)	Balance at Beginning of Year (c)	Balance at End of Year (d)
DEFERRED DEBITS			
Unamortized Debt Expense (181)	-		
Extraordinary Property Losses (182.1)			
Unrecovered Plant and Regulatory Study Costs (182.2)			
Other Regulatory Assets (182.3)	29	12,375,280	13,836,629
Prelim. Survey and Investigation Charges (Electric) (183)	-		
Prelim. Sur. and Invest. Charges (Gas) (183.1, 183.2)			
Clearing Accounts (184)	-		
Temporary Facilities (185)	-		
Miscellaneous Deferred Debits (186)	30	7,437,058	7,459,818
Def. Losses from Disposition of Utility Plt. (187)	-		
Research, Devel. and Demonstration Expend. (188)			
Unamortized Loss on Reacquired Debt (189)	-		
Accumulated Deferred Income Taxes (190)			
Unrecovered Purchased Gas Costs (191)	-		809,629
TOTAL Deferred Debits i(Enter Total of lines 54 thru 67)		19,812,338	22,106,075
TOTAL Assets and other Debits (Enter Total of lines 10, 11, 12, 22, 52, and 68)		357,089,338.44	362,087,856

(SUBSTITUTE PAGE FOR PART III)

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year of Report
Summit Natural Gas of Maine, Inc	(1) An Original (2) A Resubmission	3/30/22	December 31, 2021

COMPARATIVE BALANCE SHEET (LIABILITIES AND CREDITS) (Continued)

Line No.	Title of Account (a)	Ref. Page No. (b)	Balance at Beginning of Year (c)	Balance at End of Year (d)
1	PROPRIETARY CAPITAL			
2	Common Stock Issued (201)		1,920,131	1,920,131
3	Preferred Stock Issued (204)			
4	Capital Stock Subscribed (202, 205)			
5	Stock Liability for Conversion (203, 206)			
6	Premium on Capital Stock (207)		293,267,908	307,667,908
7	Other Paid-In Capital (208-211)			
8	Installments Received on Capital Stock (212)			
9	(Less) Discount on Capital Stock (213)			
10	(Less) Capital Stock Expense (213)			
11	Retained Earnings (215, 215.1, 216)	15-16	(68,558,467)	(78,386,852)
12	Unappropriated Undistributed Subsidiary Earnings (216.1)	15-16		
13	(Less) Reacquired Capital Stock (217)			
14	TOTAL Proprietary Capital (Enter Total of lines 2 thru 14)	-	226,629,572	231,201,187
15	LONG-TERM DEBT			
16	Bonds (221)	31-32		
17	(Less) Reacquired Bonds (222)	31-32		
18	Advances from Associated Companies (223)	31-32		
19	Other Long-Term Debt (224)	31-32	125,057,399	125,000,000
20	Unamortized Premium on Long-Term Debt (225)			
21	(Less) Unamortized Discount on Long-Term Debt-Debit. (226)			
22	TOTAL Long-Term Debt (Enter Total of lines 16 thru 21)	-	125,057,399	125,000,000
23	OTHER NONCURRENT LIABILITIES			
24	Obligations Under Capital Leases - Noncurrent (227)	-		
25	Accumulated Provision for Property Insurance (228.1)	-		
26	Accumulated Provision for Injuries and Damages (228.2)	-		
27	Accumulated Provision for Pensions and Benefits (228.3)	-		
28	Accumulated Miscellaneous Operating Provision (228.4)	-		
29	Accumulated Provision for Rate Refunds (229)	-		
30	TOTAL Other Noncurrent Liabilities (Enter Total of lines 25 thru 29)			
31	CURRENT AND ACCRUED LIABILITIES			
32	Notes Payable (231)	-		
33	Accounts Payable (232)	-	475,542	560,056
34	Notes Payable to Associated Companies (233)	-		
35	Accounts Payable to Associated Companies (234)	-	297,708	58,147
36	Customer Deposits (235)	-	15,460	14,984
37	Taxes Accrued (236)	34-35	1,226,942	1,142,444
38	Interest Accrued (237)	-		
39	Dividends Declared (238)	-		
40	Matured Long-Term Debt (239)	-		
41	Matured Interest (240)	-		
42	Tax Collections Payable (241)	-	26,305	35,612
43	Miscellaneous Current and Accrued Liabilities (242)		3,360,410	3,931,138
44	Obligations Under Capital Leases-Current (243)	-		
45	TOTAL Current and Accrued Liabilities (Enter Total of lines 32 thru 44)	-	5,402,367	5,742,381.25

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year of Report
Summit Natural Gas of Maine, Inc	(1) An Original (2) A Resubmission	3/30/22	December 31, 2021

COMPARATIVE BALANCE SHEET (LIABILITIES AND CREDITS) (Continued)

Line No.	Title of Account (a)	Ref. Page No. (b)	Balance at Beginning of Year (c)	Balance at End of Year (d)
46	DEFERRED CREDITS			
47	Customer Advances for Construction (252)			
48	Accumulated Deferred Investment Tax Credits (255)			
49	Deferred Gains from Disposition of Utility Plant (256)			
50	Other Deferred Credits (253)	36		144,288
51	Other Regulatory Liabilities (254)	37		
52	Unamortized Gain on Reacquired Debt (257)			
53	Accumulated Deferrred Income Taxes (281-283)			
54	TOTAL Deferred Credits (Enter Total of lines 47 thru 53)		0	144,288
55				
56				
57				
58				
59				
60				
61				
62				
63				
64				
65				
66				
67				
68	TOTAL Liabilities and Other Credits (Enter Total of lines 14, 22, 30			
	45 and 54)		357,089,338	362,087,856

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year of Report
Summit Natural Gas of Maine, Inc	(1) An Original (2) A Resubmission	3/30/22	December 31, 2021

STATEMENT OF INCOME FOR THE YEAR

1. Report amounts for accounts 412 and 413, Revenue and Expenses from Utility Plant Leased to Others, in another utility column (i,k,m,o) in a similar manner to a utility department. Spread the amount(s) over lines 02 thru 24 as appropriate. Include these amounts in columns (c) and (d) totals.
2. Report amounts in account 414, Other Utility Operating Income, in the same manner as accounts 412 and 413 above.
3. Report data for lines 7,9, and 10 for Natural Gas companies using accounts 404.1,404.2,404.3, 407.1 and 407.2.
4. Use page 122 for important notes regarding the statement of income for any account thereof.
5. Give concise explanations concerning unsettled rate proceedings where a contingency exists such that refunds of a material amount may need to be made to the utility's customers or which may result in a material refund to the utility with respect to power or gas purchases. State for each year affected the gross revenues or costs to which the contingency relates and the tax effects together with an explanation of the major factors which affect the rights of the utility to retain such revenues or recover amounts paid with respect to power and gas purchases.
6. Give concise explanations concerning significant amounts of any refunds made or received during the year

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year of Report
Summit Natural Gas of Maine, Inc	(1) An Original (2) A Resubmission	3/30/22	December 31, 2021

STATEMENT OF INCOME FOR THE YEAR (Continued)

resulting from settlement of any rate proceeding affecting revenues received or costs incurred for power or gas purchases, and a summary of the adjustments made to balance sheet, income, and expense accounts.
7. If any notes appearing in the report to stockholders are applicable to this Statement of Income, such notes may be attached at page 19.
8. Enter on page 19 a concise explanation of only those changes in accounting methods made during the year which had an effect on net income, including the basis of allocations and apportionments from those used in the preceding year. Also give the approximate dollar effect of such changes.
9. Explain in a footnote if the previous year's figures are different from that reported in prior reports.
10. If the columns are insufficient for reporting additional utility departments, supply the appropriate account titles, lines 2 to 23, and report the information in the blank space on page 19 or in a supplemental statement

Line No.	Account (a)	(Ref.) Page No. (b)	TOTAL Current Year (c)	TOTAL Previous Year (d)	ELECTRIC UTILITY Current Year (e)	ELECTRIC UTILITY Previous Year (f)	GAS UTILITY Current Year (g)	GAS UTILITY Previous Year (h)	OTHER UTILITY Current Year (i)	OTHER UTILITY Previous Year (j)	Line No.
1	UTILITY OPERATING INCOME										1
2	Operating Revenues (400)	38-39	18,583,819	17,072,565			18,583,819	17,072,565			2
3	Operating Expenses										3
4	Operation Expenses (401)	41-46	12,556,419	11,873,588			12,556,419	11,873,588			4
5	Maintenance Expenses (402)	41-46	497,930	519,498			497,930	519,498			5
6	Depreciation Expense (403)		8,656,538	8,445,080			8,656,538	8,445,080			6
7	Amort. & Depl. of Utility Plant (404-405)		176,676	176,676			176,676	176,676			7
8	Amort. of Utility Plant Acq. Adj. (406)										8
9	Amort of Property Losses, Unrecovered Plant and Regulatory Study Costs (407)										9
10	Amort. of Conversion Expenses (407)										10
11	Regulatory Debits (407.3)										11
12	(Less) Regulatory Credits (407.4)										12
13	Taxes Other Than Income Taxes (408.1)	34-35	2,578,626	2,720,541			2,578,626	2,720,541			13
14	Income Taxes - Federal (409.1)	34-35									14
15	- Other (409.1)	34-35									15
16	Provision for Deferred Income Taxes (410.1)		(2,911,544)	(2,359,655)			(2,911,544)	(2,359,655)			16
17	(Less) Provision for Deferred Income Taxes-Cr. (411.1)										17
18	Investment Tax Credit Adj. - Net (411.4)										18
19	(Less) Gains from Disp. of Utility Plant (411.6)										19
20	Losses from Disp. of Utility Plant (411.7)										20
21	(Less) Gains from Disposition of Allowances (411.8)										21
22	Losses from Disposition of Allowances (411.9)										22
23	TOTAL Utility Operating Expenses (Enter Total of lines 4 thru 22)		21,554,645	21,375,728			21,554,645	21,375,728			23
24	Net Utility Operating Income (Enter Total of line 2 less 23) (Carry forward to page 117, line 25)		(2,970,825.05)	(4,303,163)			(2,970,825)	(4,303,163)			24

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year of Report
Summit Natural Gas of Maine, Inc	(1) An Original (2) A Resubmission	3/30/22	December 31, 2021

STATEMENT OF INCOME FOR THE YEAR

Line No.	Account (a)	(Ref.) Page No. (b)	TOTAL Current Year (c)	TOTAL Previous Year (d)
25	Net Utility Operating Income (Carried forward from page 12)		-2,970,825	-4,303,163
26	Other Income and Deductions			
27	Other Income			
28	Nonutility Operating Income			
29	Revenues from Merchandising, Jobbing, and Contract Work (415)			
30	(Less) Costs and Exp. of Merch., Job, & Contract Work (416)			
31	Revenues From Nonutilty Operations (417)		1,920	766
32	(Less) Expenses of Nonutility Operations (417.1)			
33	Nonoperating Rental Income (418)			
34	Equity in Earnings of Subsidiary Companies (418.1)			
35	Interest and Dividend Income (419)		1,941	8,377
36	Allowance for Other Funds Used During Construction (419.1)			
37	Miscellaneous Nonoperating Income (421)		(4)	3,190
38	Gain on Disposition of Property (421.1)			
39	TOTAL Other Income (Enter Total of lines 29 thru 38)		3,857	12,333
40	Other Income Deductions			
41	Loss on Disposition of Property (421.2)			
42	Miscellaneous Amortization (425)			
43	Miscellaneous Income Deductions (426.1-426.5)		266,413	131,372
44	TOTAL Other Income Deductions (Total of lines 41 thru 43)		266,413	131,372
45	Taxes Applic. to Other Income and Deductions			
46	Taxes Other Than Income Taxes (408.2)			
47	Income Taxes - Federal (409.2)			
48	Income Taxes - Other (409.2)			
49	Provision for Deferred Inc. Taxes (410.2)			
50	(Less) Provision for Deferred Income Taxes - Cr. (411.2)			
51	Investment Tax Credit Adj. - Net (411.5)			
52	(Less) Investment Tax Credits (420)			
53	TOTAL Taxes on Other Inc. and Ded. (Total of 46 thru 52)		0	0
54	Net Other Income and Deductions (Enter Total of lines 39,44,53)		(262,556)	(119,039)
55	Interest Charges			
56	Interest on Long-Term Debt (427)		6,590,278	6,590,278
57	Amort. of Debt Disc. and Expense (428)			
58	Amortization of Loss on Reaquired Debt (428.1)			
59	(Less) Amort. of Premium on Debt-Credit (429)			
60	(Less) Amortization of Gain on Reaquired Debt-Credit (429.1)			
61	Interest on Debt to Assoc. Companies (430)			
62	Other Interest Expense (431)		4,726	2,775
63	(Less) Allowance for Borrowed Funds Used During Const.- Cr.(432)			
64	Net Interest Charges (Enter Total of lines 56 thru 63)		6,595,004	6,593,053
65	Income Before Extraordinary Items (Enter Total of lines 25, 54, and 64)		(9,828,385)	(11,015,255)
66	Extraordinary Items			
67	Extraordinary Income (434)			
68	(Less) Extraordinary Deductions (435)			
69	Net Extraordinary Items (Enter Total of line 67 less line 68)			
70	Income Taxes - Federal and Other (409.3)			
71	Extraordinary Items After Taxes (Enter Total of line 69 less line 70)			
72	Net Income (Enter Total of lines 65 and 71)		(9,828,385)	(11,015,255)

Name of Respondent	This Report Is:	Date of Report	Year of Report
Summit Natural Gas of Maine, Inc	(1) An Original (2) A Resubmission	(Mo, Da, Yr) 3/30/22	December 31, 2021

STATEMENT OF RETAINED EARNINGS FOR THE YEAR

1. Report all changes in appropriated retained earnings, unappropriated retained earnings, and unappropriated undistributed subsidiary earnings for the year.
2. Each credit and debit during the year should be identified as to the retained earnings account in which recorded (Accounts 433, 436-439 inclusive). Show the contra primary account affected in column (b).
3. State the purpose and amount for each reservation or appropriation of retained earnings.
4. List first Account 439, Adjustments to Retained Earnings, reflecting adjustments to the opening balance of retained earnings. Follow by credit, then debit items, in that order.
5. Show dividends for each class and series of capital stock.
6. Show separately the State and Federal income tax effect of items shown in Account 439, Adjustments to Retained Earnings.
7. Explain in a footnote the basis for determining the amount reserved or appropriated. If such reservation or appropriation is to be recurrent, state the number and annual amounts to be reserved or appropriated as well as the totals eventually to be accumulated.
8. If any notes appearing in the report to stockholders are applicable to this statement, attach them at page 19.

Line No.	Item (a)	Contra Primary Account Affected (b)	Amount (c)
	UNAPPROPRIATED RETAINED EARNINGS (Account 216)		
1	Balance-Beginning of Year		(68,558,467)
2	Changes (Identify by prescribed retained earnings accounts)		
3	Adjustments to Retained Earnings (Account 439)		
4	Credit:		(9,828,385)
5	Credit:		
6	Credit:		
7	Credit:		
8	Credit:		
9	TOTAL Credits to Retained Earnings (Account 439)(Enter Total of lines 4 thru 8)		(9,828,385)
10	Debit:		
11	Debit:		
12	Debit:		
13	Debit:		
14	Debit:		
15	TOTAL Debits to Retained Earnings (Account 439)(Enter Total of lines 10 thru 14)		0
16	Balance Transferred from Income (Account 433 less Account 418.1)		
17	Appropriations of Retained Earnings (Account 436)		
18			
19			
20			
21			
22	TOTAL Appropriations of Retained Earnings (Account 436)(Total of lines 18 thru 21)		
23	Dividends Declared-Preferred Stock (Account 437)		
24			
25			
26			
27			
28			
29	TOTAL Dividends Declared-Preferred Stock (Account 437)(Total of lines 24 thru 28)		
30	Dividends Declared-Common Stock (Account 438)		
31			
32			
33			
34			
35			
36	TOTAL Dividends Declared-Common Stock (Account 438)(Total of lines 31 thru 35)		
37	Transfers from Acct. 216.1, Unappropriated Undistributed Subsidiary Earnings		
38	Balance-End of Year (Total of lines 01, 09, 15, 16, 22, 29, 36 and 37)		(78,386,852)

Name of Respondent	This Report Is:	Date of Report	Year of Report
Summit Natural Gas of Maine, Inc	(1) An Original (2) A Resubmission	(Mo, Da, Yr) 3/30/22	December 31, 2021

STATEMENT OF RETAINED EARNINGS FOR THE YEAR (Continued)

Line No.	Item (a)	Amount (b)
	APPROPRIATED RETAINED EARNINGS (Account 215)	
	State balance and purpose of each appropriated retained earnings amount at end of year and give accounting entries for any applications of appropriated retained earnings during the year.	
39		
40		
41		
42		
43		
44		
45	TOTAL Appropriated Retained Earnings (Account 215)	
	APPROPRIATED RETAINED EARNINGS-AMORTIZATION RESERVE, FEDERAL (Account 215.1)	
	State below the total amount set aside through appropriations of retained earnings, as of the end of the year, in compliance with the provisions of Federally granted hydroelectric project licenses held by the respondent. If any reductions or changes other than the normal annual credits hereto have been made during the year, explain such items in a footnote.	
46	TOTAL Appropriated Retained Earnings-Amortization Reserve, Federal (Account 215.1)	
47	TOTAL Appropriated Retained Earnings (Accounts 215,215.1)(Enter Total of lines 45 & 46)	
48	TOTAL Retained Earnings (Account 215,215.1,216) (Enter Total of lines 38 and 47)	(78,386,852)
	UNAPPROPRIATED UNDISTRIBUTED SUBSIDIARY EARNINGS (216.1)	
49	Balance-Beginning of Year (Debit or Credit)	
50	Equity in Earnings for Year (Credit) (Account 418.1)	
51	(Less) Dividends Received (Debit)	
52	Other Changes (Explain)	
53	Balance-End of Year (Total of lines 49 thru 52)	

Name of Respondent	This Report Is:	Date of Report	Year of Report
[Utility Name]	(1) An Original (2) A Resubmission	(Mo, Da, Yr) 3/30/22	December 31, 2021

Return on Common Equity on Investments Subject to Commission Jurisdiction

Each Local Distribution Company providing end use Natural Gas Service, shall provide the information requested on this

Line No.	Maine Commission Jurisdiction	For Years Ended December 31, 2018	2019	2020	2021
1	Total Net Income	$ (9,584,988)	$ (9,695,206)	$ (11,015,255)	(9,828,385)
2	Adjustments to reflect income from activites not subject to Commission jurisdiction (specify):	[redacted]			
3					
4	Other Nonutiilty Income				
5					
6					
7					
8					
9					
10					
11	Total Net Income from Commission Jurisdiction	$ (9,584,988)	$ (9,695,206)	$ (11,015,255)	$ (9,828,385)
12					
13	Total Common Equity				
14	Adjustments to reflect Common Equity on investments not subject to Commission Jurisdiction (Show how calculated)	[redacted]			
15					
16	Common Equity for Non-Utility Invesment	199,646,523	222,194,826	226,629,572	231,201,187
17	Other Common Equity				
18					
19					
20					
21					
22	Total Common Equity for Investments Subject to Commission Jurisdiction	199,646,523	222,194,826	226,629,572	231,201,187
23					
24	Return on Common Equity Subject to Commission Jurisdiction (Line 11/Line 22)	-5%	-4%	-5%	-4%
25					
26	Rate Base				

Name of Respondent	This Report Is:	Date of Report	Year of Report
Summit Natural Gas of Maine, Inc	(1) An Original (2) A Resubmission	(Mo, Da, Yr) 3/30/22	December 31, 2021

STATEMENT OF CASH FLOWS

1. If the notes to the cash flow statement in the respondents annual stockholders report are applicable to this statement, such notes should be attached to page 19. Information about noncash investing and financing activities should be provided on page 19. Provide also on page 19 a reconciliation between "Cash and Cash Equivalents at End of Year" with related amounts on the balance sheet.
2. Under "Other" specify significant amounts and group others.
3. Operating Activities-Other: Include gains and losses pertaining to operating activities only. Gains and losses pertaining to investing and financing activities should be reported in those activities. Show on page 19 the amounts of interest paid (net of amounts capitalized) and income taxes paid.

Line No.	DESCRIPTION (See instructions for Explanation of Codes) (a)	Amount (b)
1	Net Cash Flow from Operating Activities:	
2	Net Income for Northern (from page 14)	(9,828,385)
3	Noncash Charges (Credits) to Income:	
4	Depreciation and Depletion	8,833,213
5	Amortization of (Specify) Other	
6		
7		
8	Deferred Income Taxes (Net)	(1,461,349)
9	Investment Tax Credit Adjustments (Net)	
10	Net (Increase) Decrease in Receivables	(4,000)
11	Net (Increase) Decrease in Inventory	273,315
12	Net Increase (Decrease) in Fuel Purchase Commitments	
13	Net Increase (Decrease) in Accounts Payable	64,883
14	Net (Increase) Decrease in Other Assets	(834,872)
15	Net Increase (Decrease) in Other Liabilities	785,833
16	(Less) Allowance for Other Funds Used During Construction	
17	(Less) Undistributed Earnings from Subsidiary Companies	
	Other: Miscellaneous	
18		
19	Net Increase (Decrease) in Accrued Interest Expense	
20	Net (Increase) Decrease in Deferred Fuel Costs	
21	Net Cash Provided by (Used in) Operating Activities	
22	(Total of lines 2 thru 20)	(2,171,361)
23		
24	Cash Flows from Investment Activities:	
25	Construction and Acquisition of Plant (including land):	
26	Gross Additions to Utility Plant (less nuclear fuel)	(11,820,979)
27	Gross Additions to Nuclear Fuel	
28	Gross Additions to Common Utility Plant	
29	Gross Additions to Nonutility Plant	
30	(Less) Allowance for Other Funds Used During Construction	
31	Other:	(103,753)
32		
33		
34	Cash Outflows for Plant (Total of lines 26b thru 33)	(11,924,732)
35		
36	Acquisition of Other Noncurrent Assets (d)	
37	Proceeds from Disposal of Noncurrent Assets (d)	
38		
39	Investments in and Advances to Assoc. and Subsidiary Companies	
40	Contributions and Advances from Assoc. and Subsidiary Companies	
41	Disposition of Investments in (and Advances to)	
42	Associated and Subsidiary Companies	
43		
44	Purchase of Investment Securities (a)	
45	Proceeds from Sales of Investment Securities (a)	

Name of Respondent	This Report Is:	Date of Report	Year of Report
Summit Natural Gas of Maine, Inc	(1) An Original (2) A Resubmission	(Mo, Da, Yr) 3/30/22	December 31, 2021

STATEMENT OF CASH FLOWS (Continued)

4. Investing Activities
Include at Other (line 31) net cash outflow to acquire other companies. Provide a reconciliation of assets acquired with liabilities assumed on page 19.
Do not include on this statement the dollar amount of leases capitalized per USofA General Instruction 20; instead provide a reconciliation of the dollar amount of leases capitalized with the plant cost on page 19

5. Codes used:
(a) Net proceeds or payments.
(b) Bonds, debentures and other long-term
(c) Include commercial paper.
(d) Identify separately such items as investments, fixed assets, intangibles, etc.

6. Enter on page 19 clarifications and explanations

Line No.	DESCRIPTION (See Instruction No. 5 for Explanation of Codes) (a)	Amount (b)
46	Loans Made or Purchased	
47	Collections on Loans	
48		
49	Net (Increase) Decrease in Receivables	
50	Net (Increase) Decrease in Inventory	
51	Net (Increase) Decrease in	
52	Allowances Held for Speculation	
53	Net Increase (Decrease) in Payables and Accrued Expenses	
54	Other:	
55		
56	Net Cash Provided by (Used in) Investing Activities	
57	(Total of lines 34 thru 55)	(11,924,732)
58		
59	Cash Flows from Financing Activities:	
60	Proceeds from Issuance of:	
61	Long-Term Debt (b)	
62	Preferred Stock	
63	Common Stock	
64	Other:	14,400,000
65		
66	Net Increase in Short-Term Debt (c)	
67	Other:	2,428
68		
69		
70	Cash Provided by Outside Sources (Total of lines 61 thru 69)	14,402,428
71		
72	Payments for Retirement of:	
73	Long-Term Debt (b)	
74	Preferred Stock	
75	Common Stock	
76	Other:	
77		
78	Net Decrease in Short-Term Debt (c)	0
79		
80	Dividends on Preferred Stock	
81	Dividends on Common Stock	
82	Net Cash Provided by (Used in) Financing Activities	
83	(Total of lines 70 thru 81)	14,402,428
84		
85	Net Increase (Decrease) in Cash and Cash Equivalents	
86	(Total of lines 22, 57 and 83)	306,335
87		
88	Cash and Cash Equivalents at Beginning of Year	570,724
89		
90	Cash and Cash Equivalents at End of Year	877,059

Notes to Financial Statements

Name of Respondent: Summit Natural Gas of Maine, Inc

Year of Report December 31, 2021

Summit Natural Gas of Maine, Inc.
Notes to Financial Statements
December 31, 2021 and 2020

1. Description of Business and Basis of Presentation

Summit Natural Gas of Maine, Inc. ("SNG-ME" or the "Company"), a Colorado corporation, is an operating public utility subject to the jurisdiction of the Public Utilities Commissions of the state of Maine ("MPUC") with respect to its retail gas operations. SNG-ME is a wholly owned subsidiary of Summit Utilities, Inc. ("Summit"). SNG-ME develops, owns, and operates natural gas local distribution systems.

SNG-ME holds a Certificate of Authority to Furnish Natural Gas granted by the MPUC for the municipalities of Richmond, Gardiner, Farmingdale, Hallowell, Augusta, Sidney, Belgrade, Oakland, Fairfield, Waterville, Norridgewock, Skowhegan, Madison, China, Albion, Windsor, Winslow, Randolph, Cumberland, Falmouth, and Yarmouth in the state of Maine.

Management's Plans with Respect to Liquidity and Capital Resources
For the years ended December 31, 2021 and 2020, the Company experienced a net loss of $9.8 million and $11.0 million, respectively, and working capital of $1.0 million and $0.8 million, respectively. The Company has a recent history of net losses, operating cash flow losses, and forecasts continued losses related to the expansion of the business.

The Company is a portfolio investment of IIF US Holdings 2 LP. In order to meet its operating and other cash flow needs, the Company has a written commitment from IIF US Holdings 2 LP to provide both operational and financial support for at least 12 months and a day from the date that these financial statements are available to be issued to ensure the Company has adequate liquidity to meet its obligations and fund its operations in the event that such financing or working capital requirements arise.

Regulatory Accounting
The Company prepares its financial statements in accordance with accounting principles generally accepted in the United States of America ("GAAP"), for rate regulated utilities, which recognize the economic effects of rate regulation. A regulated entity may defer recognition of a cost (a regulatory asset) or recognize an obligation (a regulatory liability) if it is probable that, through the ratemaking process, there will be a corresponding increase or decrease in revenues. Accordingly, the Company records regulatory assets when required by a regulatory order or when it is probable, based on regulatory precedent, that future rates will allow for recovery of a regulatory asset. The Company records regulatory liabilities based on the expectation the amounts will be returned to customers in future rates, or because the amounts were collected in rates prior to the costs being incurred. Estimates of recovering deferred costs and returning deferred credits are based on specific ratemaking decisions or precedent for each item. Regulatory assets and liabilities are amortized consistent with treatment in the rate-setting process.

The Company uses the Federal Energy Regulatory Commission's ("FERC") Uniform System of Accounts Prescribed for Natural Gas Companies, subject to the provisions of the Natural Gas Act, in determining its accounting policies and practices.

Summit Natural Gas of Maine, Inc.
Notes to Financial Statements
December 31, 2021 and 2020

Use of Estimates in the Preparation of Financial Statements
The preparation of financial statements in conformity with GAAP requires management to make estimates, judgments, and assumptions that affect the amounts reported in the financial statements and accompanying notes. The estimates, judgments, and assumptions the Company makes in preparing the financial statements are based on information available at the time. Actual results could differ from the estimates, judgments, and assumptions that the Company uses in the preparation of the financial statements. The more significant areas requiring the use of estimates

preparation of the financial statements. The more significant areas requiring the use of estimates, judgments, and assumptions relate to the impairment assessments regarding long-lived assets, allowance for doubtful accounts, accruing unbilled revenues and determining the useful lives of assets. In addition, the Company uses estimates in the allocation of labor, general and administrative expenses from parent, certain overhead costs, and management's plans with respect to liquidity and capital resources.

Cash and cash equivalents
The Company considers all highly liquid instruments purchased with an original maturity of three months or less to be cash equivalents. The Company continually monitors its positions with, and the credit quality of, the financial institutions with which it invests.

Concentrations
The Company grants credit in the normal course of business to its customers. During the years ended December 31, 2021 and 2020, one customer accounted for more than 10% of total revenues with a total concentration of 13% and 14% respectively, of gross revenues.

Accounts Receivable
The Company's accounts receivable are primarily related to sales of natural gas. Credit is extended based on prior experience with the customer and evaluation of the customer's financial condition. Accounts receivable are generally due within 30 days. The Company assesses the collectability of the accounts by taking into consideration historical experience. Any amounts subsequently collected are recognized as a reduction to bad debt expense.

Due to the impacts of COVID-19 on its customers in 2020, the Company experienced an increase in past due receivable balances. The receivable balances were evaluated as of December 31, 2021 and 2020 and an additional allowance was recorded in the year ended December 31, 2020. The MPUC has not authorized the capitalization of additional bad debt expense related to COVID-19.

As of December 31, 2021 and 2020, the Company had an insignificant allowance for doubtful accounts, which is presented as a reduction to the accounts receivable balance.

Property, Plant, and Equipment
Property, plant, and equipment is stated at cost. For constructed plant, costs include contracted services, direct labor, materials, an allowance for funds used during construction, allocations of certain overhead costs related to construction, and certain costs approved by the MPUC associated with residential and commercial incentives.

Additions that extend the useful life of the assets are capitalized, while maintenance and repairs that do not improve or extend the useful life of the respective assets are charged to operations as incurred. The Company transfers costs in construction in progress to property, plant, and equipment as construction is completed.

Provisions for depreciation of property, plant, and equipment for financial accounting purposes are based on composite rates applied to the various classes of depreciable property. Depreciation expense is provided using the straight-line method based on estimated service lives of 3 to 50 years for property, plant, and equipment.

The cost of units of property retired, together with cost of removal, less salvage, is charged against accumulated depreciation. Currently, the Company has no legal requirements under its agreement with the MPUC to remove, reclaim, or retire its utility plant assets.

Customer Rebates
The Company has capitalized residential and commercial rebates and included these costs in natural gas distribution plant. The capitalization is based on expected recovery and approval from the MPUC. Rebate costs relate to funds paid to induce customers to obtain the Company's services and to administer the rebate program. For the years ended December 31, 2021 and 2020, the Company capitalized to natural gas plant amounts related to rebates of $0.8 million and $0.5 million, respectively.

Materials and Supplies
Materials and supplies consist of pipe and plant related inventory and are valued at cost using the weighted average cost method. The costs are moved to natural gas distribution plant or operating expense as the materials and supplies are used.

Long-Lived Assets
The Company reviews long-lived assets for impairment whenever events and circumstances indicate a decline in the recoverability of their carrying values. The Company estimates the expected undiscounted future cash flows related to these assets and compares such cash flows to the carrying value to determine recoverability. If the carrying value exceeds the estimated undiscounted cash flows, the Company will adjust the assets to fair value. The factors used to determine fair value include estimates of future revenues, related transportation and distribution costs, taxes, and future customers and usage. For the years ended December 31, 2021 and 2020, the Company recorded no impairments.

Restricted Cash
In connection with the Company's construction of natural gas distribution plant, the Company is required by various governmental bodies to place funds in escrow during the construction period. Upon the expiration of specified completion periods, funds will be released back to the Company, less any associated permit fees. As of December 31, 2021 and 2020, there was $0.3 million and $0.2 million, respectively, in various escrow accounts.

Intangible Assets
As of December 31, 2021 and 2020, intangible assets consisted of customer relationships of $1.4 million and $1.6 million, respectively, net of accumulated amortization of $1.2 million and $1.0 million, respectively. These assets are considered to have 15-year lives based on the life of the underlying contracts. Amortization expense related to intangible assets for the years ended December 31, 2021 and 2020 was $0.2 million and $0.2 million, respectively.

The estimated future amortization expense of intangible assets as of December 31, 2021 is as follows:

(in thousands)

Year Ending December 31,		
2022	$	177
2023		177
2024		177
2025		177
2026		177
Thereafter		530
	$	1,415

Purchased Gas Cost
The Company accounts for purchased gas costs in accordance with procedures authorized by the MPUC. Purchased gas costs that are different from those provided for in present rates and approved by the MPUC are accumulated and recovered or credited through future rate changes.

Derivative Instruments
The Company enters into derivative instruments to reduce risk in connection with changes in interest rates and natural gas prices. Certain natural gas contracts that meet the definition of a derivative may be exempted from derivative accounting as the contracts meet the normal purchases or normal sales exemption.

Revenue Recognition
On January 1, 2019, the Company adopted ASU 2014-09 (Topic 606), *Revenue from Contracts with Customers* and related pronouncements ("ASC 606"). The underlying principle of the guidance requires entities to recognize revenue depicting the transfer of goods or services to customers at amounts the entity is expected to be entitled to in exchange for those goods or services. The ASU also prescribes a five-step approach to revenue recognition: (1) identify the contract(s) with the customer; (2) identify the separate performance obligations in the contract(s); (3) determine the transaction price; (4) allocate the transaction price to separate performance obligations; and (5) recognize revenue when, or as, each performance obligation is satisfied. The Company applied the five-step method outlined in the ASC 606 to all in-scope revenue streams. The implementation resulted in changes to the disclosures and is reflected in Note 7.

Income Taxes

Deferred income taxes are recorded for timing differences between items of income or expense reported on the financial statements and those reported for income tax purposes using the asset/liability method of accounting for income taxes. Deferred income taxes are recognized for the future tax consequences attributable to differences between the financial statement carrying amounts of existing assets and liabilities and their respective tax bases and for tax loss and credit carryforwards. Deferred tax assets and liabilities are measured using enacted tax rates expected to apply to taxable income in the years in which those temporary differences are expected to be recovered or settled. If the Company concludes that it is more likely than not that some portion, o all, of the deferred tax assets will not be realized, the balance of deferred tax assets is reduced by a valuation allowance.

The Company files a consolidated tax return with Summit, and deferred income taxes are allocated on a benefits-for-loss basis.

2. Revision from Prior Years

In 2021, Summit performed an in-depth analysis of the effective state tax rates and the effect they have on deferred tax asset and deferred tax liability balances and evaluated how rates are reflected on the individual state tax returns. Because each of the states that SUI files in differ in how taxable income is calculated (consolidated, stand-alone, single filing, etc.), the provision should reflect those different treatments through the calculation of effective rates. It is Summit's belief that this change in approach more accurately reflects those differences in state filings, and, in turn, the value of tax effected deferred tax assets and deferred tax liabilities.

In addition, Summit analyzed the carryforward balance of each entity's NOL and the allocation of those NOL's and determined it would be appropriate to allocate to the entities that ultimately created those losses from previous years and will benefit from those losses in future years.

Summit evaluated the impact of the changes and has revised the Company's opening accumulated deficit for the $1.0 million cumulative impact of the change prior to 2020. The following table reflects the amounts as previously reported along with the corrections and the resulting revised amounts as of and for the year ended December 31, 2020:

	As of and for the Year Ended December 31, 2020		
(in thousands)	As reported previously	Adjustment	As Adjusted
Income tax benefit	$ 3,464	$ (1,105)	$ 2,359
Net loss	(9,910)	(1,105)	(11,015
Deferred tax asset	14,501	(2,126)	12,375
Total noncurrent assets	353,164	(2,126)	351,038
Total assets	359,215	(2,126)	357,089
Accumulated deficit	(66,432)	(2,126)	(68,558
Total stockholder's equity	228,756	(2,126)	226,630
Total liabilities and stockholder's equity	359,215	(2,126)	357,089

3. Property, Plant, and Equipment

The following is a summary of property, plant, and equipment:

(in thousands)	December 31, 2021	December 31, 2020
Natural gas plant	$ 376,252	$ 364,368
Office furniture	409	641
Vehicles	2,758	2,737
Computers, software, and other equipment	3,207	3,085
Construction work in progress	938	2,508
Property, plant, and equipment, at cost	383,564	373,339
Less: Accumulated depreciation	(53,403)	(46,343)
Total property, plant, and equipment, net	$ 330,161	$ 326,996

During the years ended December 31, 2021 and 2020, the Company recorded $8.6 million and $8.4 million, respectively, of depreciation expense related to property, plant, and equipment, which was recorded in depreciation and amortization on the statement of loss.

4. Regulatory Accounting

Regulatory Assets
Regulatory assets represent probable future revenue associated with certain costs that may be recovered from customers through the ratemaking process. The Company has recorded these assets in accordance with GAAP. If the Company were required to terminate application of regulatory accounting for all of its regulated operations, the Company would have to record these amounts as expense on its statement of loss at that time.

In accordance with ASC 740, the enactment of TCJA on December 22, 2017 required revaluation of federal deferred tax assets and liabilities using the new lower corporate statutory tax rate of 21%. As a result of the revaluation, deferred tax assets were decreased by $7.4 million and a regulatory asset of $7.4 million was established. This net regulatory asset will generally be amortized over the remaining life of the related assets, for the fixed asset related portion, using the normalization principles as specifically prescribed in the TCJA. For the remaining amount not related to fixed assets, the prescribed method of amortization has not been determined.

5. Related Party Notes Payable

In 2021 and 2020, the Company had related party notes with Summit's investors for $125.0 million and $125.0 million, respectively. Principal is due on December 31, 2022 but interest payable is callable at the discretion of Summit's investors. The notes bear interest at 5.2%.

For the years ended December 31, 2021 and 2020, the Company incurred interest expense of $6.6 million and $6.6 million, respectively, related to these notes. As of December 31, 2021 and 2020, the Company had unpaid interest in amounts of $0.0 million and $0.0 million, respectively.

6. Operating Leases

The Company rents certain office equipment and office space under noncancelable agreements accounted for as operating leases. The Company is responsible for the operating expenses incurred by the landlord on each of the leases. Rent expense for the years ended December 31, 2021 and 2020 was $0.3 million and $0.3 million, respectively, which is included in operating, general and administrative expenses on the statement of loss.

Future minimum payments under operating leases having an initial or remaining noncancelable term in excess of one year are as follows:

(in thousands)

Year Ending December 31,		
2022	$	264
2023		198
2024		104
2025		44
Total future minimum lease payments	$	610

7. Employee Benefit Plan

The Company participates in Summit's qualified retirement plan (the "Plan") under Section 401(k) of the IRC. Employees become eligible to participate in the Plan upon attaining 21 years of age and completing at least three months of service. Prior service is counted toward the eligibility requirement. Upon attainment of eligibility, entry into the Plan occurs the first day of the month following the month during which the eligibility requirements are satisfied. The Company may make a discretionary matching contribution and/or discretionary profit-sharing contribution each year. For the years ended December 31, 2021 and 2020, the discretionary contribution to the Plan totaled $0.2 million and $0.1 million, respectively.

8. Revenue

Revenue from customers is recognized when the obligation to the customer is satisfied and in the amount expected to be received in exchange for transferring goods or providing services. The transaction price is determined per a set price agreed upon in the contract or regulatory tariffs. Revenue from contracts with customers contain one performance obligation that is generally satisfied over time, using the output method based on usage.

Revenue includes gas distributed or transported but not billed (unbilled revenue). The accrued unbilled revenue balance is based on estimates of gas distributed or transported during the period from the last meter reading and management judgment is required for a number of factors used in this calculation, including customer use and weather factors. Meters are read, and customers are billed on a cycle billing basis that does not necessarily coincide with the calendar month. The Company's cost-of-gas tariffs approved by the state Commission provide for the recovery or refund of accumulated differences between the recoverable costs of gas, as defined, and the revenues designated for recovery of such costs. These recoveries are subject to periodic review by the state Commission.

9. Commitments and Contingencies

Gas Purchase Agreements

Consistent with agreed upon gas purchase methodologies approved by the MPUC, the Company uses gas purchase agreements to limit customer rate volatility. In addition, these purchase agreements provide an element of stability to the Company's cash flows in an environment of volatile gas prices and help manage the Company's exposure to natural gas price volatility. These commitments qualify for the normal purchase exclusion in accordance with derivative accounting. As of December 31, 2021, the Company had outstanding commitments to purchase 177,000 dekatherms of natural gas at fixed and market rates on the purchase date. The contracts call for various daily volumes and expire monthly through February 2022.

Litigation

In the normal course of business, the Company is party to a litigation from time to time. The Company maintains insurance to cover certain claims and believes that resolution of currently pending litigation will not have a material adverse effect on its financial position, cash flows, or results of operations.

10. Income Taxes

The Company recognizes deferred tax liabilities and assets for the expected future tax consequences of events that have been included in the financial statements or tax returns. Deferred tax liabilities and assets are determined based on the differences between the financial statement and tax basis of assets and liabilities using the enacted tax rates in effect for the year in which the differences are expected to reverse. The measurement of deferred tax assets is reduced, if necessary, by the amount of any tax benefits that are not expected to be realized based on available evidence. The Company's temporary differences result primarily from depreciation and amortization and the allowance for doubtful accounts.

Income tax benefit included in the statements of loss:

(in thousands)	Year Ended December 31, 2021	2020
Federal		
Deferred	$ (2,687)	$ (2,600)
State		
Deferred	(225)	241
Total income tax benefit	$ (2,912)	$ (2,359)

The Company has the following deferred tax assets and deferred tax liabilities:

(in thousands)	December 31, 2021	2020
Deferred tax assets		
Net operating loss carry forwards	$ 34,340	$ 31,516
Other	114	91
Total deferred tax assets	34,454	31,607
Deferred tax liabilities		
Property, plant, and equipment	(18,925)	(17,540)
Income tax regulatory assets	(1,692)	(1,692)
Total deferred tax liabilities	(20,617)	(19,232)
Net deferred tax asset	$ 13,837	$ 12,375

The Company has net operating loss carryforwards of approximately $147.4 million as of December 31, 2021 which expire in 2033 through 2037. The Company has net operating loss carryforwards of $41.1 million that will not expire. Utilization of the net operating loss carryforwards will be subject to certain limitations under Section 382 of the Internal Revenue Code ("IRC") of 1986, as amended, and other limitations under state tax laws. As discussed in Note 1, the Company files a consolidated return with Summit, and deferred income taxes and net operating loss carryforwards are allocated on a benefits-for-loss basis for financial statement disclosure purposes only. No significant uncertain tax positions were identified as of any date on or before December 31, 2021. The Company reports interest and penalties related to income taxes within the other loss and interest expense sections on the statements of operations. As of December 31, 2021, the Company has not recognized any interest or penalties related to uncertain tax benefits. As of December 31, 2021, the Company's earliest open tax year is 2013.

The following is a reconciliation of the statutory federal income tax rate applied to pre-tax accounting net loss:

	Year Ended December 31,	
	2021	2020
Statutory rate	21.0 %	21.0 %
State tax	1.7	5.1
State rate correction	0.0	(8.3)
Effect of permanent differences	(0.1)	(0.1)
Other	0.3	(0.1)
Effective tax rate	22.9 %	17.6 %

11. Related Party Transactions

As of December 31, 2021 and 2020, the Company had $0.1 million and $0.3 million due to Summit, respectively. The amounts relate to payments of certain costs on behalf of the Company by Summit, including capital expenditures, operating costs, and payroll. Summit also allocates shared costs to the Company.

The Company files a consolidated tax return with Summit, and deferred income taxes are allocated on a benefits-for-loss basis. As of December 31, 2021 and 2020, the Company had $1.4 million and $2.3 million, respectively, due from Summit related to the utilization of the Company's losses in connection with income/loss allocation on a consolidated basis, respectively.

During the years ended December 31, 2021 and 2020, the Company periodically loaned employees to related entities, which then reimbursed the Company for those costs, with no markup, which are presented net on the statement of loss and on the balance sheets in due from/due to parent.

12. Accounting Standards

Recently Issued Accounting Pronouncements
In June 2016, the FASB issued ASU 2016-13 *Financial Instruments — Credit Losses (Topic 326): Measurement of Credit Losses on Financial Instruments*. The update requires the measurement of all expected credit losses for financial assets held at the reporting date based on historical experience, current conditions, and reasonable and supportable forecasts. The inputs currently used to estimate credit losses will still be utilized, however they may be adapted to reflect the full amount of expected losses, should there be a difference. The update is effective for fiscal years beginning after December 15, 2022, including interim periods within those fiscal years. The Company is currently evaluating the provisions of this guidance and assessing its impact on the Company's financial statements and disclosures.

In February 2016, the FASB issued ASU No. 2016-02, *Leases*, which will require lessees to recognize a right-of-use asset and a lease liability for all leases that are not short-term in nature. For a lessor, the accounting applied is largely unchanged from previous guidance. The new rules will be effective for the Company for the year ending December 31, 2022. The Company is currently in the process of evaluating the impact of adoption of the new rules on the Company's financial condition, results of operations, and cash flows.

Summit Natural Gas of Maine, Inc.
Notes to Financial Statements
December 31, 2021 and 2020

13. Subsequent Events

The Company has evaluated all subsequent events through XXXXX, 2022, which is the date the financial statements were available to be issued. There were no material subsequent events that required recognition or additional disclosure in these financial statements.

Name of Respondent	This Report Is:	Date of Report	Year of Report
Summit Natural Gas of Maine, Inc	(1) An Original (2) A Resubmission	(Mo, Da, Yr) 3/30/22	December 31, 2021

SUMMARY OF UTILITY PLANT AND ACCUMULATED PROVISIONS
FOR DEPRECIATION, AMORTIZATION, AND DEPLETION

Line No.	Item (a)	Total (b)
1	UTILITY PLANT	
2	In Service	
3	Plant in Service (Classified_	385,275,717
4	Property Under Capital Leases	
5	Plant Purchased or Sold	
6	Completed Construction not Classified	
7	Experimental Plant Unclassified	
8	Total Utility Plant (Total of lines 3 thru 7)	385,275,717
9	Leased to Others	
10	Held for Future Use	
11	Construction Work in Progress	937,811
12	Acquisition Adjustments	
13	Total Utility Plant (Totals of lines 8 thru 12)	386,213,528
14	Accumulated Provisions for Depreciation, Amortization & Depletion	(54,637,074)
15	Net Utility Plant (Totals of lines 13 and 14)	331,576,453
16	DETAIL OF ACCUMULATED PROVISIONS FOR DEPRECIATION, AMORTIZATION AND DEPLETION	
17	In Service:	
18	Depreciation	(53,402,570)
19	Amortization and Depletion of Producing Natural Gas Land and Land Rights	
20	Amortization of Underground Storage Land and Land Rights	
21	Amortization of Other Utility Plant	(1,234,504)
22	Total In Service (Totals of lines 18 thru 21)	(54,637,074)
23	Leased to Others	
24	Depreciation	
25	Amortization and Depletion	
26	Total Leased to Others (Totals off lines 24 and 25)	
27	Held for Future Use	
28	Depreciation	
29	Amortization	
30	Total Held for Future Use (Totals of lines 28 and 29)	
31	Abandonment of Leases (Natural Gas)	
32	Amortization of Plant Acquisition Adjustment	
33	Total Accum Provisions (Should agree with lien 14 above) (Total of lines 22, 26, 30, 31, and 32)	(54,637,074)

Name of Respondent	This Report Is:	Date of Report	Year of Report
Summit Natural Gas of Maine, Inc	(1) An Original (2) A Resubmission	(Mo, Da, Yr) 3/30/22	December 31, 2021

SUMMARY OF UTILITY PLANT AND ACCUMULATED PROVISIONS
FOR DEPRECIATION, AMORTIZATION, AND DEPLETION

Electric (c)	Gas (d)	Other (Specify) (e)	Common (f)	Line No.
				1
				2
	385,275,717			3
				4
				5
				6
				7
	385,275,717			8
				9
				10
	937,811			11
				12
	386,213,528			13
	(54,637,074)			14
	331,576,453			15
				16
				17
	(53,402,570)			18
				19
				20
	(1,234,504)			21
	(54,637,074)			22
				23
				24
				25
				26
				27
				28
				29
				30
				31
				32
	(54,637,074)			33

Name of Respondent	This Report is:	Date of Report (Mo, Da, Yr)	Year of Report
Summit Natural Gas of Maine, Inc	(1) An Original (2) A Resubmission	3/30/22	December 31, 2021

GAS PLANT IN SERVICE (Accounts 101, 102, 103, and 106)

1. Report below the original cost of gas plant in service according to the prescribed accounts.
2. In addition to Account 101, Gas Plant in Service(Classified), this page and the next include Account 102, Gas Plant Purchased or Sold; Account 103, Experimental Gas Plant Unclassified; and Account 106, Completed Construction Not Classified-Gas.
3. Include in column (c) or (d), as appropriate, corrections of additions and retirements for the current or preceding year.
4. Enclose in parentheses credit adjustments of plant accounts to indicate the negative effect of such accounts.
5. Classify Account 106 according to prescribed accounts, on an estimated basis if necessary, and include the entries in column (c). Also to be included in column (c) are entries for reversals of tentative distributions of prior year reported in column (b). Likewise if the respondent has a significant amount of plant retirements which have not been classified to primary accounts at the end of the year, include in column (d) a tentative distribution of such retirements, on an estimated basis, with appropriate contra entry to the account for accumulated depreciation provision. Include also in column (d) reversals of tentative distributions or prior year of unclassified retirements. Attach supplemental statement showing the account distribution of these tentative classifications in columns (c) and (d), including the reversals of the prior years tentative account distributions of these amounts. Careful observance of the above instructions and the texts of Accounts 101 and 106 will avoid serious omissions of the reported amount of respondent's plant actually in service at end of year.
6. Show in column (f) reclassifications or transfers within utility plant accounts. Include also in column (f) the additions or reductions of primary account classifications arising from distribution of amounts initially recorded in Account 102. In showing the clearance of Account 102, include in column (d) the amounts with respect to accumulated provision for depreciation, acquisition adjustments, etc., and show in column (f) only the offset to the debits or credits distributed in column (f) to primary account classifications.
7. For Account 300, state the nature and use of plant included in this account and if substantial in amount submit a supplementary statement showing the subaccount classification of such plant conforming to the requirements of these pages.
8. For each amount comprising the reported balance and changes in Account 102, state the property purchased or sold, name of vendor or purchaser, and date of transaction.

Line No.		Account (a)	Balance at Beginning of Year (b)	Additions (c)	Retirements (d)	Adjustments (e)	Transfers (f)	Balance at End of Year (g)		Line No.
1		1. Intangible Plant								1
2	301	Organization							301	2
3	302	Franchises and Consents	115,838					115,838	302	3
4	303	Miscellaneous Intangible Plant	2,650,000					2,650,000	303	4
5		TOTAL Intangible Plant	2,765,838	0	0	0	0	2,765,838		5
6		2. Production Plant								6
7		Natural Gas Production and Gathering Plant								7
8	325.1	Producing Lands							325.1	8
9	325.2	Producing Leaseholds							325.2	9
10	325.3	Gas Rights							325.3	10
11	325.4	Rights-of-Way							325.4	11
12	325.5	Other Land and Land Rights							325.5	12
13	326	Gas Well Structures							326	13
14	327	Field Compressor Station Structures							327	14
15	328	Field Meas. and Reg. Sta. Structures							328	15
16	329	Other Structures							329	16
17	330	Producing Gas Wells-Well Construction							330	17
18	331	Producing Gas Wells-Well Equipment							331	18
19	332	Field Lines							332	19
20	333	Field Compressor Station Equipment							333	20
21	334	Field Meas. and Reg. Sta. Equipment							334	21
22	335	Drilling and Cleaning Equipment							335	22
23	336	Purification Equipment							336	23
24	337	Other Equipment							337	24
25	338	Unsuccessful Exploration and Devel. Costs							338	25
26		TOTAL Production and Gathering Plant	0	0	0	0	0	0		26
27		Products Extraction Plant								27
28	340	Land and Land Rights							340	28
29	341	Structures and Improvements							341	29
30	342	Extraction and Refining Equipment							342	30
31	343	Pipe Lines							343	31
32	344	Compressor Equipment							344	32
33	345	Gas Meas. and Reg. Equipment							345	33
34	346	Compressor Equipment							346	34
35	347	Other Equipment							347	35
36		TOTAL Products Extraction Plant								36
37		TOTAL Nat. Gas Production Plant								37
38		Mfd. Gas Prod. Plant (Submit Suppl. Statement)								38
39		TOTAL Production Plant	0	0	0	0	0	0		39

Name of Respondent	This Report is:	Date of Report (Mo, Da, Yr)	Year of Report
Summit Natural Gas of Maine, Inc	(1) An Original (2) A Resubmission	3/30/22	December 31, 2021

GAS PLANT IN SERVICE (Accounts 101, 102, 103, and 106) (Continued)

Line No.		Account (a)	Balance at Beginning of Year (b)	Additions (c)	Retirements (d)	Adjustments (e)	Transfers (f)	Balance at End of Year (g)		Line No.
40		3. Natural Gas Storage and Processing Plant								40
41		Underground Storage Plant								41
42	350.1	Land							350.1	42
43	350.2	Rights-of-Way							350.2	43
44	351	Structures and Improvements							351	44
45	352	Wells							352	45
46	352.1	Storage Leaseholds and Rights							352.1	46
47	352.2	Reservoirs							352.2	47
48	352.3	Non-recoverable Natural Gas							352.3	48
49	353	Lines							353	49
50	354	Compressor Station Equipment							354	50
51	355	Measuring and Reg. Equipment							355	51
52	356	Purification Equipment							356	52
53	357	Other Equipment							357	53
54		TOTAL Underground Storage Plant								54
55		Other Storage Plant								55
56	360	Land and Land Rights						0	360	56
57	361	Structures and Improvements						0	361	57
58	362	Gas Holders						0	362	58
59	363	Purification Equipment							363	59
60	363.1	Liquefaction Equipment							363.1	60
61	363.2	Vaporizing Equipment							363.2	61
62	363.3	Compressor Equipment						0	363.3	62
63	363.4	Meas. and Reg. Equipment							363.4	63
64	363.5	Other Equipment							363.5	64
65		TOTAL Other Storage Plant	0	0	0	0		0		65
66		Base Load Liquefied Natural Gas Terminating and Processing Plant								66
67	364.1	Land and Land Rights							364.1	67
68	364.2	Structures and Improvements							364.2	68
69	364.3	LNG Processing Terminal Equipment							364.3	69
70	364.4	LNG Transportation Equipment							364.4	70
71	364.5	Measuring and Regulating Equipment							364.5	71
72	364.6	Compressor Station Equipment							364.6	72
73	364.7	Communications Equipment							364.7	73
74	364.8	Other Equipment							364.8	74
75		TOTAL Base Load Liquefied Natural Gas,								75
76		Terminating and Processing Plant		0						76
77		TOTAL Nat. Gas Storage and Proc. Plant								77
78		4. Transmission Plant								78
79	365.1	Land and Land Rights							365.1	79
80	365.2	Rights-of-Way						0	365.2	80
81	366	Structures and Improvements							366	81
82	367	Mains						0	367	82
83	368	Compressor Station Equipment							368	83
84	369	Measuring and Reg. Sta. Equipment	0	101,909				101,909	369	84
85	370	Communication Equipment							370	85
86	371	Other Equipment							371	86
87		TOTAL Transmission Plant	0	101,909	0	0	0	101,909		87

Name of Respondent	This Report is:	Date of Report	Year of Report
	(1) An Original	(Mo, Da, Yr)	

Summit Natural Gas of Mair (2) A Resubmission 3/30/22 December 31, 2021

GAS PLANT IN SERVICE (Accounts 101, 102, 103, and 106) (Continued)

Line No.		Account (a)	Balance at Beginning of Year (b)	Additions (c)	Retirements (d)	Adjustments (e)	Transfers (f)	Balance at End of Year (g)		Line No.
88		5. Distribution Plant								88
89	374	Land and Land Rights	2,554,277					2,554,277	374	89
90	375	Structures and Improvements							375	90
91	376	Mains	296,684,053	7,465,650				304,149,703	376	91
92	377	Compressor Station Equipment							377	92
93	378	Meas. and Reg. Sta. Equip.-General	21,602,202	45,780			5,290	21,653,272	378	93
94	379	Meas. and Reg. Sta. Equip.-City Gate							379	94
95	380	Services	29,400,710	2,438,280	50,762			31,788,228	380	95
96	381	Meters	3,364,410	179,915			(13,561)	3,530,764	381	96
97	382	Meter Installations	2,406,653	446,602	2,362			2,850,892	382	97
98	383	House Regulators	454,100	145,823	12,291			587,632	383	98
99	384	House Reg. Installations							384	99
100	385	Industrial Meas. and Reg. Sta. Equipment							385	100
101	386	Other Prop. on Customers' Premises	4,780,942	830,400				5,611,342	386	101
102	387	Other Equipment							387	102
103		TOTAL Distribution Plant	361,247,347	11,552,451	65,415		(8,271)	372,726,112		103
104		6. General Plant								104
105	389	Land and Land Rights							389	105
106	390	Structures and Improvements	846,160	300,738	83,696			1,063,202	390	106
107	391	Office Furniture and Equipment	3,725,277	115,520	512,265		287,668	3,616,200	391	107
108	392	Transportation Equipment	2,737,245	526,939	426,118	(79,786)		2,758,280	392	108
109	393	Stores Equipment							393	109
110	394	Tools, Shop, and Garage Equipment	729,983	37,367	387,077		(9,273)	371,000	394	110
111	395	Laboratory Equipment							395	111
112	396	Power Operated Equipment	1,302,819	595,226	74,675			1,823,370	396	112
113	397	Communication Equipment	126,181	22,875	93,960		(5,290)	49,806	397	113
114	398	Miscellaneous Equipment							398	114
115		Subtotal	9,467,665	1,598,665	1,577,790	(79,786)	273,105	9,681,858		115
116	399	Other Tangible Property							399	116
117		TOTAL General Plant	9,467,665	1,598,665	1,577,790	(79,786)	273,105	9,681,858		117
118		TOTAL (Accounts 101 and 106)	373,480,850	13,253,025	1,643,205	(79,786)	264,834	385,275,717		118
119		Gas Plant Purchased (See Instr. 8)								119
120		(Less) Gas Plant Sold (See Instr. 8)								120
121		Experimental Gas Plant Unclassified								121
122		TOTAL Gas Plant in Service	373,480,850	13,253,025	1,643,205	(79,786)	264,834	385,275,717		122

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year of Report
Summit Natural Gas of Maine, Inc	(1) An Original (2) A Resubmission	3/30/22	December 31, 2021

ACCUMULATED PROVISION FOR DEPRECIATION OF GAS UTILITY PLANT (Account 108)

1. Explain in a footnote any important adjustments during year.
2. Explain in a footnote any difference between the amount for book cost of plant retired, line 11, column (c), and that reported for gas plant in service, pages 22-27, column (d), excluding retirements of non-depreciable property.
3. The provisions of Account 108 in the Uniform System of Accounts require that retirements of depreciable plant be recorded when such plant is removed from service. If the respondent has a significant amount of plant retired at year end which has not been recorded and/or classified to the various reserve functional classifications, make preliminary closing entries to tentatively functionalize the book cost of the plant retired. In addition, include all costs included in retirement work in progress at year end in the appropriate functional classifications.
4. Show separately interest credits under a sinking fund or similar method of depreciation accounting.

Section A. Balances and Changes During Year

Line No.	Item (a)	Total (c+d+e) (b)	Division (c)	Division (d)	Gas Plant Leased to Others (e)
1	Balance Beginning of Year	47,404,192	47,404,192		
2	Depreciation Provisions for Year, Charged to				
3	(403) Depreciation Expense	8,833,213	8,833,213		
4	Exp. of Gas Plt. Leas. to Others	0			
5	Transportation Expenses-	0			
	Clearing	0			
6	Other Clearing Accounts	0	0		
7	Other Accounts (Specify):	8,936	8,936		
8					
9	TOTAL Deprec. Prov. for Year	8,842,149	8,842,149		
	(Enter Total of lines 3 thru 8)	8,842,149	8,842,149		
10	Net Charges for Plant Retired:	0			
11	Book Cost of Plant Retired	(1,643,205)	(1,643,205)		
12	Cost of Removal	(40,224)	(40,224)		
13	Salvage (Credit)	79,368	79,368		
14	TOTAL Net Chrgs. for Plant Ret. (Enter Total of lines 11 thru 13)	(1,604,061)	(1,604,061)		
15	Other Debit or Cr. Items (Describe)				
16	Adjust. to Reserve				
17	Balance End of Year (Enter Total of lines 1,9,14,15, and 16)	54,642,280	54,642,280		

Section B. Balances at End of Year According to Functional Classifications

Line No.	Item (a)	Total (c+d+e) (b)	Division (c)	Division (d)	Gas Plant Leased to Others (e)
18	Production-Manufactured Gas	0			
19	Prod. and Gathering-Natural	0			
	Gas	0			
20	Products Extraction-Natural	0			
	Gas	0			
21	Underground Gas Storage	0			
22	Other Storage Plant	0			
23	Base Load LNG Term. and	0			
	Proc. Plt.	0			
24	Transmission	0			
25	Distribution	0			
26	General	0			
27	TOTAL (Enter Total of lines 18 thru 26)	0	0		

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year of Report
Summit Natural Gas of Maine, Inc	(1) An Original (2) A Resubmission	3/30/22	December 31, 2021

OTHER REGULATORY ASSETS (ACCOUNT 182.3)

1. Report below the details called for concerning other regulatory assets which are created through the ratemaking actions of regulatory agencies (and not included in other accounts).

2. For regulatory assets being amortized, show period of amortization in column (a).

3. Minor items (5% of the Balance at End of Year for Account 182.3 or amounts less than $250,000, whichever is less) may be grouped by classes.

4. Report separately any "Deferred Regulatory Commission Expenses"

Line No.	Description and Purpose of Other Regulatory Assets	Balance at Beginning of Year	Debits	Written off During Year		Balance at End of Year
				Account Charged	Amount	
	(a)	(b)	(c)	(d)	(e)	(f)
1	NONE					
2						
3						
4						
5						
6						
7						
8						
9						
10						
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12						
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39						
40	TOTAL					0

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year of Report
Summit Natural Gas of Maine, Inc	(1) An Original (2) A Resubmission	3/30/22	December 31, 2021

MISCELLANEOUS DEFERRED DEBITS (ACCOUNT 186)

1. Report below the details called for concerning miscellaneous deferred debits.

2. For any deferred debit being amortized, show period of amortization in column (a).

3. Minor items amounts less than $250,000 may be grouped by classes.

Line No.	Description of Miscellaneous Deferred Debits	Balance at Beginning of Year	Debits	Credits: Account Charged	Credits: Amount	Balance at End of Year
	(a)	(b)	(c)	(d)	(e)	(f)
1	Deferral due to Tax Cut Jobs Act	7,437,058				7,437,058
2						
3	Regulatory asset created by the 35% to 21% revaluation of deferred taxes related to NOL's, pension and other rate base/cost of service.					
4						
5	Rate case costs (amortization to begin in 2022)	0	22,760			22,760
6						
7						
8						
9						
10						
11						
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38						
39	Miscellaneous Work in Progress					
40	TOTAL					7,459,818

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year of Report
Summit Natural Gas of Maine, Inc	(1) An Original (2) A Resubmission	3/30/22	December 31, 2021

LONG-TERM DEBT (Accounts 221, 222, 223, and 224)

1. Report by balance sheet the particulars (details) concerning long-term debt included in Accounts 221, Bonds, 222, Reacquired Bonds, 223, Advances from Associated Companies, and 224, Other Long-Term Debt. If information to meet the stock exchange reporting requirement outlined in column (a) is available from the SEC 10-K Report Form filing, a specific reference to the report form (i.e. year and company title) may be reported in column (a) provided the fiscal years for both the 10-K report and this report are compatible.

2. For bonds assumed by the respondent, include in column (a) the name of the issuing company as well as a description of the bonds.
3. For advances from Associated Companies, report separately advances on notes and advances on open accounts. Designate demand notes as such. Include in column (a) names of associated companies from which advances were received.
4. For receivers' certificates, show in column (a) the name of the court and date of court order under which such certificates were issued.

Line No.	Class and Series of Obligation and Name of Stock Exchange (a)	Nominal Date of Issue (b)	Date of Maturity (c)	Outstanding (Total amount outstanding without reduction for amounts held by respondent (d)
1	Promissory Notes with Summit Investors	03/15/2018		125,000,000
2				
3				
4				
5				
6				
7				
8				
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37				
38				125,000,000

Name of Respondent	This Report is:	Date of Report (Mo, Da, Yr)	Year of Report
Summit Natural Gas of Maine, Inc	'(1) An Original (2) A Resubmission	3/30/22	December 31, 2021

LONG-TERM DEBT (Accounts 221, 222,, 223, and 224) (Continued)

5. In a supplemental statement, give explanatory particulars (details) for Accounts 223 and 224 of net changes during the year. With respect to long-term advances, show for each company: (a) principal advanced during year, (b) interest added to principal amount, and (c) principal repaid during year. Give Commission authorization numbers and dates.
6. If the respondent has pledged any of its long-term debt securities, give particulars (details) in a footnote, including name of the pledgee and purpose of the pledge.

7. If the respondent has any long-term securities which have been nominally issued and are nominally outstanding at end of year, describe such securities in a footnote.
8. If interest expense was incurred during the year on any obligations retired or reacquired before end of year, include such interest expense in column (f). Explain in a footnote any difference between the total of column (f) and the total of Account 427, Interest on Long-Term Debt and Account 430, Interest on Debt to Associated Companies.
9. Give particulars (details) concerning any long-term debt authorized by a regulatory commission but not yet issued.

INTEREST FOR YEAR		HELD BY RESPONDENT		Redemption Price Per $100 at End of Year (i)	Line No.
Rate (in %) (e)	Amount (f)	Reacquired Bonds (Acct. 222) (g)	Sinking and Other Funds (h)		
5.20%	6,590,278				1
					2
					3
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	6,590,278				38

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year of Report
Summit Natural Gas of Maine, Inc	(1) An Original (2) A Resubmission	3/30/22	December 31, 2021

RECONCILIATION OF REPORTED NET INCOME WITH TAXABLE INCOME
FOR FEDERAL INCOME TAXES

1. Report the reconciliation of reported net income for the year with taxable income used in computing Federal income tax accruals and show computation of such tax accruals. Include in the reconciliation, as far as practicable, the same detail as furnished on Schedule M-1 of the tax return for the year. Submit a reconciliation even though there is no taxable income for the year. Indicate clearly the nature of each reconciling amount.

2. If the utility is a member of a group which files consolidated Federal tax return, reconcile reported net income with taxable net income as if a separate return were to be filed, indicating, however, intercompany amounts to be eliminated in such a consolidated return. State names of group members, tax assigned to each group member, and basis of allocation, assignment, or sharing of the consolidated tax among the group members.

Line No.	Particulars (Details) (a)	Amount (b)
	Maine	
1	Net Income for the Year (Page 117)	(9,828,385)
2	Reconciling Items for the Year	[redacted]
3	Federal Income Taxes	(2,911,544)
4	Taxable Income Not Reported on Books	[redacted]
5		
6		
7		
8		
9	Deductions Recorded on Books Not Deducted for Return	[redacted]
10	Meals & Entertainment	4,814
11	Political Contributions	75,175
12		
13		
14	Income Recorded on Books Not Included in Return	[redacted]
15	Asset (gain)/loss	130,279
16	Charitable contributions	38,936
17	Amortization expense	3,101
	481(a) adjustment	4,419,513
18	Accrued COVID Payroll Tax	
19	Deductions on Return Not Charged Against Book Income	[redacted]
20	Accrued bonus	(71,489)
21	Accrued vacation	(10,344)
22	Allowance for bad debts	(33,939)
23	Depreciation expense	(10,614,385)
24	Accrued medical	(36,430)
25	Deferred gain/loss	(12,007)
26	Accrued COVID payroll tax	(57,399)
	Maine	
27	Federal Tax Net Income	(18,904,105)
28	Show Computation of Tax:	
29		
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42		

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year of Report
Summit Natural Gas of Maine, Inc	(1) An Original (2) A Resubmission	3/30/22	December 31, 2021

TAXES ACCRUED, PREPAID AND CHARGED DURING YEAR

1. Give particulars (details) of the combined prepaid and accrued tax accounts and show the total taxes charged to operations and other accounts during the year. Do not include gasoline and other sales taxes which have been charged to the accounts to which the taxed material was charged. If the actual or estimated amounts of such taxes are known, show the amounts in a footnote and designate whether estimated or actual amounts.

2. Include on this page taxes paid during the year and charged direct to final accounts, (not charged to prepaid or accrued taxes). Enter the amounts in both columns (d) and (e). The balancing of this page is not affected by the inclusion of these taxes.

3. Include in column (d) taxes charged during the year, taxes charged to operations and other accounts through (a) accruals credited to taxes accrued, (b) amounts credited to proportions of prepaid taxes chargeable to current year, and (c) taxes paid and charged direct to operations or accounts other than accrued and prepaid tax accounts.

Line No.	Kind of Tax (See Instruction 5)	Balance at Beginning of Year: Taxes Accrued (Account 236)	Balance at Beginning of Year: Prepaid Taxes (Incl. in Account 165)
	(a)	(b)	(c)
1	Property Taxes	1,226,942.25	
2			
3			
4			
5			
6			
7			
8			
9			
10			
11			
12			
13			
14			
15			
16			
17			
18	TOTAL	0	

DISTRIBUTION OF TAXES CHARGED (Show utility department where applicable and account charged.)

Line No.	Electric (Accounts 408.1, 409.1)	Gas (Accounts 408.1, 409.1)	Other Utility Departments (Account 408.1, 409.1)	Other Income and Deductions (Account 408.2, 409.2)
	(i)	(j)	(k)	(l)
1				
2				
3				
4				
5				
6				
7				
8				
9				
10				
11				
12				
13				
14				
15				
16				
17				
18	TOTAL			

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year of Report
Summit Natural Gas of Maine, Inc	(1) An Original (2) A Resubmission	3/30/22	December 31, 2021

TAXES ACCRUED, PREPAID AND CHARGED DURING YEAR (Continued)

4. List the aggregate of each kind of tax in such manner that the total tax for each State and subdivision can readily be ascertained.

5. If any tax (Exclude Federal and state income taxes) covers more than one year, show the required information separately for each tax year, identifying the year in column (a).

6. Enter all adjustments of the accrued and prepaid tax accounts in column (f) and explain each adjustment in a footnote. Designate debit adjustments by parentheses.

7. Do not include on this page entries with respect to deferred income taxes or taxes collected through payroll deduction or otherwise pending transmittal of such taxes to the taxing authority.

8. Show in column (i) thru (p) how the taxed accounts were distributed. Show both the utility department and number of account charged. For taxes charged to utility plant, show the number of the appropriate balance sheet plant account or subaccount.

9. For any tax apportioned to more than one utility department or account, state in a footnote the basis (necessity) of apportioning such tax.

10. For MPUC reporting purposes, taxes greater than $25,000 should be reported separately -- others may be combined.

Taxes Charged During Year	Taxes Paid During Year	Adjustments	Balance at End of Year: Taxes Accrued (Account 236)	Balance at End of Year: Prepaid Taxes (Incl. in Account 165)	Line No.
(d)	(e)	(f)	(g)	(h)	
2,513,923.53	(2,598,422.06)		1,142,443.72		1
					2
					3
					4
					5
					6
					7
					8
					9
					10
					11
					12
					13
					14
					15
					16
					17
0	0	0	0	0	18

DISTRIBUTION OF TAXES CHARGED (Show utility department where applicable and account charged.)

Extraordinary Items (Account 409.3)	Other Utility Opn. Income (Account 408.1, 409.1)	Adjustment to Ret. Earnings (Account 439)	Other		Line No.
(m)	(n)	(o)	(p)		
					1
					2
					3
					4
					5
					6
					7
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					9
					10
					11
					12
					13
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					17
					18

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year of Report
Summit Natural Gas of Maine, Inc	(1) An Original (2) A Resubmission	3/30/22	December 31, 2021

MISCELLANEOUS DEFERRED CREDITS (ACCOUNT 253)

1. Report below the details called for concerning miscellaneous deferred credits

2. For any deferred credit being amortized, show period of amortization in column (a).

3. Minor items amounts less than $150,000 may be grouped by classes.

Line No.	Description of Other Deferred Credits (a)	Balance at Beginning of Year (b)	Debits: Contra Account (c)	Debits: Amount (d)	Credits (e)	Balance at End of Year (f)
1	EMTAR over collection	156,295		12,007		144,288
2						
3						
4						
5						
6						
7						
8						
9						
10						
11						
12						
13						
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33						
34						
35						
36						
37						
38						
39						
40	TOTAL					144,288

Name of Respondent	This Report Is:	Date of Report	Year of Report
Summit Natural Gas of Maine, Inc	(1) ☐ An Original (2) ☐ A Resubmission	(Mo, Da, Yr) 3/30/22	December 31, 2021

1. Report below the particulars (details) called for concerning other regulatory liabilities which are created through the ratemaking actions of regulatory agencies and not includable in other amounts).

2. For regulatory liabilities being amortized, show period of amortization in column (a).

3. Minor items (5% of the Balance at End of Year for Account 254 or amounts less than $50,000, whichever is less) may be grouped by classes.

Line No.	Description and Purpose of Other Regulatory Liabilities (a)	Balance at Beg of Year (b)	DEBITS Account Credited (c)	DEBITS Amount (d)	Credits (b)	Balance at End of Year (e)
1	None					
2						
3						
4						
5						
6						
7						
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34						
35						
36						
37						
38						
39						
40						
41						
42	TOTAL			0	0	0

NAME OF RESPONDENT: Summit Natural Gas of Maine, Inc	This Report Is: (1) An Original (2) A Resubmission	Date of Report 3/30/22	Year of Report December 31, 2021

GAS OPERATING REVENUES (Account 400)

1. Report below natural gas operating revenues for each prescribed account, and manufactured gas revenues in total.
2. Natural gas means either natural gas unmixed or any mixture of natural and manufactured gas.
3. Report number of customers, columns (f) and (g), on the basis of meters, in addition to the number of flat rate accounts; except that where separate meter readings are added for billing purposes, one customer should be counted for each group of meters added. The average number of customers means the average of twelve figures at the close of each month.
4. Report quantities of natural gas sold in Mcf (14.73 psia at 60 F). If billings are on a therm basis, give the Btu contents of the gas sold and the sales converted to Mcf.
5. If increases or decreases from previous year columns (c), (e) and (g), are not derived from previously reported figures explain any inconsistencies in a footnote.

Line No.	Title of Account	OPERATING REVENUES					
		Total		BASE (Distribution)		GAS (Cost of Gas Rates)	
		Amount for Year	Amount for Prev Yr	Amount for Year	Amount for Prev Yr	Amount for Year	Amount for Prev Yr
	(a)	(b)	(c)	(d)	(e)	(f)	(g)
1	GAS SERVICE REVENUES						
2	480 Residential Sales	5,271,779	$4,724,690	$3,641,092	$3,261,830	$1,630,688	$1,462,860
3	481 Commercial & Industrial Sales						
4	Small (or Comm.) (See Instr.6)	4,257,557	3,902,462.74	2,583,969	2,348,487	1,673,589	1,553,976
5	Large (or Ind.) (See Instr. 6)	3,673,389	3,288,086.51	1,957,298	1,718,583	1,716,091	1,569,504
6	482 Other Sales to Public Authorities						
7	484 Unbilled Revenue	453,998	195,234	95,629	177,120	358,369	18,113
8	TOTAL Sales to Ultimate Consumers	13,656,723	12,110,473	8,277,987	7,506,020	5,378,736	4,604,453
9	483 Sales for Resale						
10	TOTAL Natural Gas Service Revenues	13,656,723	12,110,473	8,277,987	7,506,020	5,378,736	4,604,453
11	Revenues from Manufactured Gas						
12	TOTAL Gas Service Revenues	13,656,723	12,110,473	8,277,987	7,506,020	5,378,736	4,604,453
13							
14	485 Intracompany Transfers	[redacted]					
15	487 Forfeited Discounts						
16	488 Misc. Service Revenues						
17	489.1 Rev. from Trans. of Gas of Others through Gathering Facilities						
18	489.2 Rev. from Trans. of Gas of Others through Transmission Facilities						
19	489.3 Rev. from Trans. of Gas of Others through Distribution Facilities						
20	489.4 Rev. from Storing Gas of Others						
21	490 Sales of Prod. Ext. from Nat. Gas						
22	491 Rev. from Nat. Gas Proc. by Others						
23	492 Incidental Gasoline and Oil Sales						
24	493 Rent from Gas Property						
25	494 Interdepartmental Rents						
26	495 Other Gas Revenues						
27	TOTAL Other Operating Revenues	4,927,096	4,962,092	4,927,096	4,962,092	0	0
28	TOTAL Gas Operating Revenues	$18,583,819	$17,072,565	$13,205,084	$12,468,112	$5,378,736	$4,604,453
29	(Less) 496 Provision for Rate Refunds						
30	TOTAL Gas Operating Revenues Net of Provision for Refunds	$18,583,819	$17,072,565	$13,205,084	$12,468,112	$5,378,736	$4,604,453
31	Dist. Type Sales by States (Inc. Main Line Sales to Resid and Comm Cus	$9,529,337	$8,627,152	$6,225,060	$5,610,317	$3,304,276	$3,016,836
32	Main Line Industrial Sales (Incl. Main Line Sales to Pub. Authorities)	3,673,389	3,288,087	1,957,298	1,718,583	1,716,091	1,569,504
33	Sales for Resale						
34	Other Sales to Pub. Auth. (Local Dist. Only)						
35	Unbilled Revenues	453,998	195,234	95,629	177,120	358,369	18,113
36	TOTAL (Same as Line 10, Columns (b) and (d)	$13,656,723	$12,110,473	$8,277,987	$7,506,020	$5,378,736	$4,604,453

Name of Respondent	This Report Is:	Date of Report	Year of Report
Summit Natural Gas of Maine	(1) An Original (2) A Resubmission	3/30/22	December 31, 2021

GAS OPERATING REVENUES (Account 400) (Continued)

6. Commercial and Industrial Sales. Account 481, may be classified according to the basis of classification (Small or Commercial, and Large or Industrial) regularly used by the respondent if such basis of classification is not generally greater than 200,000 Mcf per year or approximately 800 Mcf per day of normal requirements. (See Account 481 of the Uniform System of Accounts. Explain basis of classification in a footnote.)

7. See page 7, Important Changes During Year, for important new territory added and important rate increases or decreases.

MCF OF NATURAL GAS SOLD		AVG. NO. OF GAS CUSTOMERS PER MO.		
Quantity for Year (h)	Quantity for Previous Yr. (i)	Number for Year (j)	Number for Previous Year (k)	Line No.
				1
272,921	250,531	3,646	3,067	2
562,285	537,321	1,033	826	3
				4
				5
				6
				7
835,206	787,853	4,679	3,893	8
				9
835,206	787,853	4,679	3,893	10
				11
				12
				13
				14
[redacted]				15
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Name of Respondent	This Report Is:	Date of Report	Year of Report
Summit Natural Gas of Maine, Inc	(1) An Original (2) A Resubmission	(Mo, Da, Yr) 3/30/22	December 31, 2021

REVENUES FROM TRANSPORTATION OF GAS OF OTHERS THROUGH DISTRIBUTION FACILITIES (ACCOUNT 489.3)

1. Report revenues and Dth of gas delivered by zone of Delivery by Rate Schedule. Total by Zone of Delivery and for all zones. If respondent does not have separate zones, provide totals by rate schedule.
2. Revenues for penalties including penalties for unauthorized overruns must be reported separately.
3. Other revenues include reservation charges received plus usage charges for transportation and hub services.
4. Delivered Dth of gas must not be adjusted for discounting,
5. Each incremental rate schedule and each individually certified rate schedule must be separately reported.

Line No.	Zone of Delivery, Rate Schedule	OTHER REVENUES		TOTAL OPERATING REVENUES		DEKATHERM OF NATURAL GAS	
		Amount for Current Year	Amount for Previous Year	Amount for Current Year	Amount for Previous Year	Amount for Current Year	Amount for Previous Year
	(a)	(b)	(c)	(d)	(e)	(f)	(g)
1	[redacted]						
2							
3							
4							
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NAME OF RESPONDENT:	This Report Is:	Date of Report	Year of Report
Summit Natural Gas of Maine, Inc	(1) An Original (2) A Resubmission	3/30/22	December 31, 2021

GAS OPERATING REVENUES by Tariff Sheets

1 Complete the following information for the calendar year ending December 31 according to the column headings.

2 The average number of customers should be the number of bills rendered during the year divided by the number of billing periods during the year (12 if all billings are made monthly).

Line No.			Revenue	MCF	Average Number of Customers	Average Ccf Use per Customer	Revenue per Ccf Sold	Number of Customers Added During Year
	(a)		(b)	(c)	(d)	(e)	(f)	(g)
1	GAS SERVICE TARIFFS							
2	Residential Sales							
2A	Base Revenues	Distribution	2,723,851	272,921	3,646	749	100	389
2B	Energy Revenues	CGA	1,752,180	272,921	3,646	749	64	389
2C	Other Revenues	Facility Fixed Fee & Other	956,019					
2D	Total Residential		5,432,050	272,921	3,646	749		389
3								
4	Commercial and Industrial Sales Service							
5	Small C&I Firm Sales & Service Customers							
5A	Base Revenues	Distribution	2,148,425	257,843	919	2,806	83	123
5B	Energy Revenues	CGA	1,653,034	257,843	919	2,806	64	123
5C	Other Revenues	Facility Fixed Fee & Other	402,684					
5D	Total Small C&I		4,204,143	257,843	919	2,806	147	123
6	Large C&I Firm Sales & Service Customers							
6A	Base Revenues	Distribution	1,464,259	210,820	77	40,438	69	4
6B	Energy Revenues	CGA	1,418,086	210,820	77	40,438	67	4
6C	Other Revenues	Facility Fixed Fee & Other	289,141					
6D	Total Large C&I		3,171,487	210,820	77	80,875	137	4
7	Total Commercial and Industrial Sales		7,375,629	468,663	996	83,681	284	127
8	Total Sales Service		12,807,679	741,584	4,642	84,429	284	516
9								
10	Commercial and Industrial Transportation Service							
11	Small C&I Firm Transportation Service Customers		[redacted]					
11A	Base Revenues							
11B	Other Revenues							
11C	Total Small C&I							
12	Large C&I Firm Transportation Service Customers							
12A	Base Revenues							
12B	Other Revenues							
12C	Total Large C&I							
20	Total Commercial and Industrial Transportation		4,919,716	2,601,053	8	3,251,316	19	0
21								
19B	Interruptible Sales							
19C	Base Revenues							
20	Energy Revenues							
20A	Other Revenues							
20B	Total Interruptible Sales		0	0	0	0	0	0
20C								
21	Negotiated Service		[redacted]					
21A	Base Revenues	Distribution						
21B	Energy Revenues	CGA						
21C	Other Revenues	Facility Fixed Fee						
22	Total Negotiated Service							
22A								
22B								
22C								
23								
24								
25	Total Revenues		18,583,819	3,436,259	4,687	3,386,352	394	517

Name of Respondent	This Report Is:	Date of Report	Year of Report
Summit Natural Gas of Maine, Inc	(1) An Original (2) A Resubmission	3/30/22	December 31, 2021

GAS OPERATION AND MAINTENANCE EXPENSES

If the amount for previous year is not derived from previously reported figures, explain in footnotes.

Line No.	Account (a)	Amount for Current Year (b)	Amount for Previous Year (c)
1	1. PRODUCTION EXPENSES		
2	**A. Manufactured Gas Production**		
3	Manufactured Gas Production (Submit Supplemental Statement)		
4	**B. Natural Gas Production**		
5	**B1. Natural Gas Production and Gathering**		
6	**Operation**		
7	750 Operation Supervision and Engineering		
8	751 Production Maps and Records		
9	752 Gas Wells Expenses		
10	753 Field Lines Expenses		
11	754 Field Compressor Station Expenses		
12	755 Field Compressor Station Fuel and Power		
13	756 Field Measuring and Regulating Station Expenses		
14	757 Purification Expenses		
15	758 Gas Well Royalties		
16	759 Other Expenses		
17	760 Rents		
18	TOTAL Operation (Enter Total of lines 7 thru 17)	0	0
19	**Maintenance**		
20	761 Maintenance Supervision and Engineering		
21	762 Maintenance of Structures and Improvements		
22	763 Maintenance of Producing Gas Wells		
23	764 Maintenance of Field Lines		
24	765 Maintenance of Field Compressor Station Equipment		
25	766 Maintenance of Field Meas. and Reg. Sta. Equipment		
26	767 Maintenance of Purification Equipment		
27	768 Maintenance of Drilling and Cleaning Equipment		
28	769 Maintenance of Other Equipment		
29	TOTAL Maintenance (Enter Total of lines 20 thru 28)	0	0
30	TOTAL Natural Gas Production and Gathering (Total of lines 18 and 29)	0	0
31	**B2. Products Extraction**		
32	**Operation**		
33	770 Operation Supervision and Engineering		
34	771 Operation Labor		
35	772 Gas Shrinkage		
36	773 Fuel		
37	774 Power		
38	775 Materials		
39	776 Operation Supplies and Expenses		
40	777 Gas Processed by Others		
41	778 Royalties on Products Extracted		
42	779 Marketing Expenses		
43	780 Products Purchased for Resale		
44	781 Variation in Products Inventory		
45	(Less) 782 Extracted Products Used by the Utility-Credit		
46	783 Rents		
47	TOTAL Operation (Enter Total of lines 33 thru 46)	0	0

Name of Respondent	This Report Is:	Date of Report	Year of Report
Summit Natural Gas of Maine, Inc	(1) An Original (2) A Resubmission	3/30/22	December 31, 2021

GAS OPERATION AND MAINTENANCE EXPENSES (Continued)

Line No.	Item (a)	Amount for Current Year (b)	Amount for Previous Year (c)
	B2. Products Extraction (Continued)		
48	**Maintenance**		
49	784 Maintenance Supervision and Engineering		
50	785 Maintenance of Structures and Improvements		
51	786 Maintenance of Extraction and Refining Equipment		
52	787 Maintenance of Pipe Lines		
53	788 Maintenance of Extracted Products Storage Equipment		
54	789 Maintenance of Compressor Equipment		
55	790 Maintenance of Gas Measuring and Reg. Equipment		
56	791 Maintenance of Other Equipment		
57	TOTAL Maintenance (Enter Total of lines 49 thru 56)	0	0
58	TOTAL Products Extraction (Enter Total of lines 47 and 57)	0	0
59	**C. Exploration and Development**		
60	**Operation**		
61	795 Delay Rentals		
62	796 Nonproductive Well Drilling		
63	797 Abandoned Leases		
64	798 Other Exploration		
65	TOTAL Exploration and Development (Enter Total of lines 61 thru 64)	0	0
	D. Other Gas Supply Expenses		
66	**Operation**		
67	800 Natural Gas Well Head Purchases		
68	800.1 Natural Gas Well Head Purchases, Intracompany Transfers		
69	801 Natural Gas Field Line Purchases		
70	802 Natural Gasoline Plant Outlet Purchases		
71	803 Natural Gas Transmission Line Purchases		
72	804 Natural Gas City Gate Purchases	6,497,951	4,842,021
73	804.1 Liquefied Natural Gas Purchases		
74	805 Other Gas Purchases		
75	(Less) 805.1 Purchased Gas Cost Adjustments	(1,238,163)	(263,753)
76			
77	TOTAL Purchased Gas (Enter Total of lines 67 to 75)	5,259,788	4,578,268
78	806 Exchange Gas		
79	**Purchased Gas Expenses**		
80	807.1 Well Expenses-Purchased Gas		
81	807.2 Operation of Purchased Gas Measuring Stations		
82	807.3 Maintenance of Purchased Gas Measuring Stations		
83	807.4 Purchased Gas Calculations Expenses		
84	807.5 Other Purchased Gas Expenses		
85	TOTAL Purchased Gas Expenses (Enter Total of lines 80 thru 84)	0	0
86	808.1 Gas Withdrawn from Storage-Debit		
87	Unbilled Revenue Costs		
88	809.1 Withdrawals of Liquefied Natural Gas for Processing-Debit		
89	(Less) 809.2 Deliveries of Natural Gas for Processing-Credit		
90	**Gas Used in Utility Operations-Credit**		
91	810 Gas Used for Compressor Station Fuel-Credit		
92	811 Gas Used for Products Extraction-Credit		
93	812 Gas Used for Other Utility Operations-Credit		
94	TOTAL Gas Used in Utility Operations-Credit (Total of lines 91 thru 93)	0	0
95	813 Other Gas Supply Expenses	130,366	25,535
96	TOTAL Other Gas Supply Exp. (Total of lines 77,78,85,86 thru 89,94,9	5,390,155	4,603,804
97	TOTAL Production Expenses (Enter Total of lines 3,30,58,65, and 96)	$5,390,155	$4,603,804

Name of Resondent	This Report Is:	Date of Report	Year of Report
Summit Natural Gas of Maine, Inc	(1) An Original (2) A Resubmission	3/30/22	December 31, 2021

GAS OPERATION AND MAINTENANCE EXPENSES (Continued)

Line No.	Account (a)	Amount for Current Year (b)	Amount for Previous Year (c)
98	**2. NATURAL GAS STORAGE, TERMINALING AND PROCESSING EXPENSES**		
99	**A. Underground Storage Expenses**		
100	**Operation**		
101	814 Operation Supervision and Engineering		
102	815 Maps and Records		
103	816 Wells Expenses		
104	817 Lines Expense		
105	818 Compressor Station Expenses		
106	819 Compressor Station Fuel and Power		
107	820 Measuring and Regulating Station Expenses		
108	821 Purification Expenses		
109	822 Exploration and Development		
110	823 Gas Losses		
111	824 Other Expenses		
112	825 Storage Well Royalties		
113	826 Rents		
114	TOTAL Operation (Enter Total of lines 101 thru 113)	0	0
115	**Maintenance**		
116	830 Maintenance Supervision and Engineering		
117	831 Maintenance of Structures and Improvements		
118	832 Maintenance of Reservoirs and Wells		
119	833 Maintenance of Lines		
120	834 Maintenance of Compressor Station Equipment		
121	835 Maintenance of Measuring and Regulating Station Equipment		
122	836 Maintenance of Purification Equipment		
123	837 Maintenance of Other Equipment		
124	TOTAL Maintenance (Enter Total of lines 116 thru 123)	0	0
125	TOTAL Underground Storage Expenses (Total of lines 114 and 124)	0	0
126	**B. Other Storage Expenses**		
127	**Operation**		
128	840 Operation Supervision and Engineering		
129	841 Operation Labor and Expenses		
130	842 Rents		
131	842.1 Fuel		
132	842.2 Power		
133	842.3 Gas Losses		
134	TOTAL Operation (Enter Total of lines 128 thru 133)	0	0
135	**Maintenance**		
136	843.1 Maintenance Supervision and Engineering		
137	843.2 Maintenance of Structures and Improvements		
138	843.3 Maintenance of Gas Holders		
139	843.4 Maintenance of Purification Equipment		
140	843.5 Maintenance of Liquefaction Equipment		
141	843.6 Maintenance of Vaporizing Equipment		
142	843.7 Maintenance of Compressor Equipment		
143	843.8 Maintenance of Measuring and Regulating Equipment		
144	843.9 Maintenance of Other Equipment		
145	TOTAL Maintenance (Enter Total of lines 136 thru 144)	0	0
146	TOTAL Other Storage Expenses (Enter Total of lines 134 and 145)	0	0

Name of Respondent	This Report Is:	Date of Report	Year of Report
Summit Natural Gas of Maine, Inc	(1) An Original (2) A Resubmission	3/30/22	December 31, 2021

GAS OPERATION AND MAINTENANCE EXPENSES (Continued)

Line No.	Account (a)	Amount for Current Year (b)	Amount for Previous Year (c)
147	**C. Liquefied Natural Gas Terminaling and Processing Expenses**		
148	**Operation**		
149	844.1 Operation Supervision and Engineering		
150	844.2 LNG Processing Terminal Labor and Expenses		
151	844.3 Liquefaction Processing Labor and Expenses		
152	844.4 Liquefaction Transportation Labor and Expenses		
153	844.5 Measuring and Regulating Labor and Expenses		
154	844.6 Compressor Station Labor and Expenses		
155	844.7 Communication System Expenses		
156	844.8 System Control and Load Dispatching		
157	845.1 Fuel		
158	845.2 Power		
159	845.3 Rents		
160	845.4 Demurrage Charges		
161	(Less) 845.5 Wharfage Receipts-Credit		
162	845.6 Processing Liquefied or Vaporized Gas by Others		
163	846.1 Gas Losses		
164	846.2 Other Expenses		
165	TOTAL Operation (Enter Total of lines 149 thru 164)	0	0
166	**Maintenance**		
167	847.1 Maintenance Supervision and Engineering		
168	847.2 Maintenance of Structures and Improvements		
169	847.3 Maintenance of LNG Processing Terminal Equipment		
170	847.4 Maintenance of LNG Transportation Equipment		
171	847.5 Maintenance of Measuring and Regulating Equipment		
172	847.6 Maintenance of Compressor Station Equipment		
173	847.7 Maintenance of Communication Equipment		
174	847.8 Maintenance of Other Equipment		
175	TOTAL Maintenance (Enter Total of lines 167 thru 174)	0	0
176	TOTAL Liquefied Nat Gas Terminaling and Processing Exp (Lines 165 & 175)	0	0
177	TOTAL Natural Gas Storage (Enter Total of lines 125, 146, and 176)	0	0
178	**3. TRANSMISSION EXPENSES**		
179	**Operation**		
180	850 Operation Supervision and Engineering		
181	851 System Control and Load Dispatching		
182	852 Communication System Expenses		
183	853 Compressor Station Labor and Expenses		
184	854 Gas for Compressor Station Fuel		
185	855 Other Fuel and Power for Compressor Stations		
186	856 Mains Expenses	57,236	11,454
187	857 Measuring and Regulating Station Expenses	44,282	44,482
188	858 Transmission and Compression of Gas by Others		
189	859 Other Expenses	23,300	2,949
190	860 Rents	850	1,599
191	TOTAL Operation (Enter Total of lines 180 thru 190)	125,669	60,484

Name of Respondent	This Report Is:	Date of Report	Year of Report
Summit Natural Gas of Maine, Inc	(1) An Original (2) A Resubmission	3/30/22	December 31, 2021

GAS OPERATION AND MAINTENANCE EXPENSE (Continued)

Line No.	Account (a)	Amount for Current Year (b)	Amount for Previous Year (c)
	3. TRANSMISSION EXPENSES (Continued)		
192	**Maintenance**		
193	861 Maintenance Supervision and Engineering		
194	862 Maintenance of Structures and Improvements		
195	863 Maintenance of Mains	8,919	105,409
196	864 Maintenance of Compressor Station Equipment		
197	865 Maintenance of Measuring and Reg. Station Equipment	261,252	8,275
198	866 Maintenance of Communication Equipment	2,132	8,538
199	867 Maintenance of Other Equipment		
200	TOTAL Maintenance (Enter Total of lines 193 thru 199)	272,302	122,221
201	TOTAL Transmission Expenses (Enter Total of lines 191 and 200)	397,971	182,705
202	**4. DISTRIBUTION EXPENSES**		
203	**Operation**		
204	870 Operation Supervision and Engineering		
205	871 Distribution Load Dispatching		114
206	872 Compressor Station Labor and Expenses		566
207	873 Compressor Station Fuel and Power		
208	874 Mains and Services Expenses	406,315	418,270
209	875 Measuring and Regulating Station Expenses-General	81,192	169,148
210	876 Measuring and Regulating Station Expenses-Industrial	32,622	49,554
211	877 Measuring and Regulating Station Expenses-City Gate Check Station		
212	878 Meter and House Regulator Expenses	343,299	394,744
213	879 Customer Installations Expenses	9,051	16,208
214	880 Other Expenses	31,142	112,801
215	881 Rents	312	4,068
216	TOTAL Operation (Enter Total of lines 204 thru 215)	903,934	1,165,472
217	**Maintenance**		
218	885 Maintenance Supervision and Engineering	60,549	48,881
219	886 Maintenance of Structures and Improvements		
220	887 Maintenance of Mains	127,422	329,490
221	888 Maintenance of Compressor Station Equipment		
222	889 Maintenance of Meas. and Reg. Sta. Equip.-General		
223	890 Maintenance of Meas. and Reg. Sta. Equip.-Industrial		
224	891 Maintenance of Meas. and Reg. Sta. Equip.-City Gate Check Station		
225	892 Maintenance of Services	35,253	13,960
226	893 Maintenance of Meters and House Regulators		
227	894 Maintenance of Other Equipment	2,404	4,945
228	TOTAL Maintenance (Enter Total of lines 218 thru 227)	225,627	397,277
229	TOTAL Distribution Expenses (Enter Total of lines 216 and 228)	$1,129,562	$1,562,749
230	**5. CUSTOMER ACCOUNTS EXPENSES**		
231	**Operation**		
232	901 Supervision		
233	902 Meter Reading Expenses	12,535	16,785
234	903 Customer Records and Collection Expenses	298,110	398,333
235	904 Uncollectible Accounts	23,050	67,115
236	905 Miscellaneous Customer Accounts Expenses		
237	TOTAL Customer Accounts Expenses (Enter Total of lines 232 thru 236)	$333,695	$482,233

Name of Resondent	This Report Is:	Date of Report	Year of Report
Summit Natural Gas of Maine, Inc	(1) An Original (2) A Resubmission	3/30/22	December 31, 2021

GAS OPERATION AND MAINTENANCE EXPENSES (Continued)

Line No.		Amount for Current Year (b)	Amount for Previous Year (c)
238	**6. CUSTOMER SERVICE AND INFORMATIONAL EXPENSES**		
239	**Operation**		
240	907 Supervision		
241	908 Customer Assistance Expenses	925,867	852,998
242	909 Informational and Instructional Expenses	33,989	26,458
243	910 Miscellaneous Customer Service and Informational Expenses		
244	TOTAL Customer Service and Information Expenses (Lines 240 thru 243)	$959,856	$879,456
245	**7. SALES EXPENSES**		
246	**Operation**		
247	911 Supervision		
248	912 Demonstration and Selling Expenses	2,323,831	2,099,399
249	913 Advertising Expenses	3,090	3,439
250	916 Miscellaneous Sales Expenses		
251	TOTAL Sales Expenses (Enter Total of lines 247 thru 250)	$2,326,921	$2,102,838
252	**8. ADMINISTRATIVE AND GENERAL EXPENSES**		
253	**Operation**		
254	920 Administrative and General Salaries	1,695,184	1,743,470
255	921 Office Supplies and Expenses	595,676	694,313
256	(Less) (922) Administrative Expenses Transferred-Cr.	(4,171,853)	(4,942,268)
257	923 Outside Services Employed	702,177	553,376
258	924 Property Insurance	435,793	325,184
259	925 Injuries and Damages		
260	926 Employee Pensions and Benefits	15,929	15,175
261	927 Franchise Requirements		
262	928 Regulatory Commission Expenses	268,794	223,403
263	(Less) (929) Duplicate Charges-Cr.		
264	930.1 General Advertising Expenses		
265	930.2 Miscellaneous General Expenses	2,596,874	3,503,851
266	931 Rents	285,103	292,655
267	TOTAL Operation (Enter Total of lines 254 thru 266)	2,423,678	2,409,157
268	**Maintenance**		
269	935 Maintenance of General Plant	92,512	170,144
270	TOTAL Administrative and General Exp (Total of lines 267 and 269)	$2,516,190	$2,579,301
271	TOTAL Gas O. and M. Exp (Lines 97, 177, 201, 229, 237, 244, 251, and 270)	$13,054,348.94	$12,393,086

NUMBER OF GAS DEPARTMENT EMPLOYEES

1. The data on number of employees should reported for the payroll period ending nearest to October 31, or any payroll period ending 60 days before or after October 31.
2. If the respondent's payroll for the reporting period includes any special construction personnel, include such employees on line 3, and show the number of such special construction employees in a footnote.
3. The number of employees assignable to the gas department from joint functions of combination utilities may be determined by estimate, on the basis of employee equivalents. Show the estimated number of equivalent employees attributed to the gas department from joint functions.

1.	Payroll Period Ended (Date)	12/31/2021
2.	Total Regular Full-Time Employees	37
3.	Total Part-Time and Temporary Employees	0
4.	Total Employees	37

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year of Report
Summit Natural Gas of Maine, Inc	(1) An Original (2) A Resubmission	3/30/22	December 31, 2021

REGULATORY COMMISSION EXPENSES

1. Report particulars (details) of regulatory commission expenses incurred during the current year (or incurred in previous years, if being amortized) relating to cases before a regulatory body or cases in which such a body was a party.

2. In columns (b) and (c), indicate whether the expenses were assessed by a regulatory body or were otherwise incurred by the utility.

Line No.	Description (Furnish name of regulatory commission and the docket or case number, and a description of the case.) (a)	Assessed by Regulatory Commission (b)	Expenses of Utility (c)	Total Expenses to Date (d)	In Account 186 at Beginning of Year (e)
1	None				
2					
3					
4					
5					
6					
7					
8					
9					
10					
11					
12					
13					
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39					
40	TOTAL				0

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year of Report
Summit Natural Gas of Maine, Inc	(1) An Original (2) A Resubmission	3/30/22	December 31, 2021

REGULATORY COMMISSION EXPENSES (Continued)

3. Show in column (k) any expenses incurred in prior years which are being amortized. List in column (a) the period of amortization.
4. The totals of columns (e), (I), (k), and (l) must agree with the totals shown at the bottom of page 233 for Account 186.
5. List in column (f), (g), and (h) expenses incurred during year which were charged currently to income, plant or other accounts.
6. Minor items (less than $25,000) may be grouped.

Line No.	Expenses Incurred During Year				Amortized During Year		Deferred In Account 186 at End of Year	Line No.
	Charged Currently To			Deferred to Account 186	Contra Account	Amount		
	Department (f)	Account No (g)	Amount (h)	(I)	(j)	(k)	(l)	
1	None							1
2								2
3								3
4								4
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39								39
40	TOTAL							40

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year of Report
Summit Natural Gas of Maine, Inc	(1) An Original (2) A Resubmission	3/30/22	December 31, 2021

CHARGES FOR OUTSIDE PROFESSIONAL AND OTHER CONSULTATIVE SERVICES

1. Report the information specified below for all charges made during the year included in any account (including plant accounts) for outside consultative and other professional services. These services include rate, management, construction, engineering, research, financial, legal, valuation, accounting, purchasing, advertising, labor relations and public relations, rendered for the respondent under written or oral arrangement, for which aggregate payments were made during the year to any corporation, partnership, organization of any kind, or individual (other than for services as an employee or for payments made for medical and related services) amounting to more than $250,000, including payments for legislative services, except those which should be reported in Account 426.4, Expenditures for Certain Civic, Political and Related Activities.
 (a) Name of person or organization rendering service.
 (b) Total charges for the year.

2. Designate associated companies with an asterisk in column (b).

Line No.	Description (a)	* (b)	Amount (in dollars) (c)
1	Consulting		135,531.11
2	Legal		4,863.50
3	Audit and Tax Fees		124,350.90
4			
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40	TOTAL		129,214

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year of Report
Summit Natural Gas of Maine, Inc	(1) An Original (2) **A Resubmission**	3/30/22	December 31, 2021

GAS ACCOUNTS - NATURAL GAS

1. The purpose of this schedule is to account for the quantity of natural gas received and delivered by the respondent.
2. Natural gas means either natural gas unmixed or any mixture of natural and manufactured gas.
3. Enter in column (c) the Dth as reported in the schedules indicated for the items of receipts and deliveries.
4. Indicate in a footnote the quantities of bundled sales and transportation gas and specify the on which such quantities are listed.
5. If the respondent operates two or more systems which are not interconnected, submit separate pages for this purpose. Use copies of this page as necessary.
6. Also indicate by footnote the quantities of gas not subject to Commission regulation which did not incur FERC regulatory costs by showing (1) the local distribution volumes another jurisdictional pipeline delivered to the local distribution company portion of the reporting pipeline (2) the quantities that the reporting pipeline transported or sold through its local distribution facilities or intrastate facilities and which the reporting pipeline received received through gathering facilities or intrastate facilities, but not through any of the inter-state of the reporting pipeline, and (3) the gathering line quantities that were not destined for interstate market or that were not transported through any interstate portion of the reporting pipeline.
7. Also indicate in a footnote (1) the system supply quantities of gas that are stored by the reporting pipeline, during the reporting year and also reported as sales, transportation and compression volumes by the reporting pipeline during the same reporting year which the reporting pipeline intends to sell or transport in a future reporting year, and (3) contract storage quantities.
8. Also indicate the volumes of pipeline production field sales included in both the company's total sales figures and total transportation figure.

Line No.	Item (a)	Ref Page No. (b)	Amount of Dth (c)
1	Name of System		
2	**GAS RECEIVED**		
3	Gas Purchases (Accounts 800-805)		863,656
4	Gas of Others Received for Gathering (Account 489.1)		
5	Gas of Others Received for Transmission (Account 489.2)		
6	Gas of Others Received for Distribution (Account 489.3)		2,704,287
7	Gas of Others Received for Contract Storage (Account 489.4)		
8	Exchanged Gas Received from Others (Account 806)		
9	Gas Received as Imbalances (Account 806)		
10	Receipts of Respondent's Gas Transported by Others (Account 858)		
11	Other Gas Withdrawn from Storage (Explain)		
12	Gas Received from Shippers as Compressor Station Fuel		
13	Gas Received from Shippers as Lost and Unaccounted for		
14	Other Receipts (Specify)		
15	Total Receipts (Total of lines 3 thru 14)		3,567,943
16	**GAS DELIVERED**		
17	Gas Sales (Accounts 480-484)		864,318
18	Deliveries of Gas Gathered for Others (Account 489.1)		
19	Deliveries of Gas Transported for Others (Account 489.2)		
20	Deliveries of Gas Distributed for Others (Account 489.3)		2,706,359
21	Deliveries of Contract Storage Gas (Account 489.4)		
22	Exchange Gas Delivered to Others (Account 806)		
23	Exchange Gas Delivered as Imbalances (Account 806)		
24	Deliveries of Gas to Others for Transportation (Account 858)		
25	Other Gas Delivered to Storage (Explain)		
26	Gas Used for Compressor Station Fuel		
27	Other Deliveries (Specify)		
28	Total Deliveries (Total of lines 17 thru 27)		3,570,677
29	**GAS UNACCOUNTED FOR**		
30	Production System Losses		
31	Gathering System Losses		
32	Transmission System Losses		
33	Distribution System Losses		(2,734)
34	Storage System Losses		
35	Other Losses (Specify)		
36	Total Unaccounted For (Total of Lines 30 thru 35)		(2,734)
37	Total Deliveries & Unaccounted For (Total of lines 28 and 36)		3,567,943

[redacted]

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year of Report
Summit Natural Gas of Maine, Inc	(1) An Original (2) A Resubmission	3/30/22	December 31, 2021

Chapter 830 Reporting Requirements
Political Activities, Institutional Advertising, Promotional Advertising and Promotional Allowances

Include on this page all information required by Chapter 830 of the Public Utilities Commission's Rules.

Account 426.4-Political Activities $ 76,265

In 2021, Summit Natural Gas of Maine, Inc. ("Company") retained a Government Affairs team to support the Company's government affairs and stakeholder engagement work. The vast majority of the cost of that team was spent on activities that fall outside the definition of "Political Activities" as defined by Chapter 83 of the Commission's Rules. In total $16,800 on activities that fall within the definition of "Political Activities". This amount included $14,700 for work in support of LD 9, An Act To Promote Renewable Energy by Authorizing a Power-to-fuel Pilot Program, and $2,100 for work on LD 989, An Act Regarding the Procurement of Renewable Natural Gas by Gas Utilities. The company also made $5,000 in political contributions. In addition to outside spending, a total of 7 hours was spent by internal resources on activities that fall within the definition of "Political Activities". One of those hours were spent by President and CEO, Kurt Adams, 2 of those hours were spent by the Vice President of Sustainability & Corporate Affairs, Lizzy Reinholt and 4 of those hours were spent by the Manager of External Affairs, Chace Jackson. That work was spent advocating in support of LD 9 and LD 989. The fully burdened labor cost for Mr. Adams, Ms. Reinholt, and Mr. Jackson's time was (confidential).

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year of Report
Summit Natural Gas of Maine, Inc	(1) An Original (2) A Resubmission	3/30/22	December 31, 2021

Promotional Programs Offered

Include on this page a listing of promotional programs offered during the reporting year and new programs offered as of the date of this report.

Program Title to Description	2021 Payments	Date(s) Program Offered
Incentive Rebate (Tariff) up to $1,500.00	$ 903,607	Customer must be a Summit Natural Gas Customer and have gas flowing. Tariff ends in Jauary 2023
Summit Incentive Rebate (Tariff) up to $1,500.00	$ 479,500	Customer must be a Summit Natural Gas Customer and have gas flowing. Tariff ends in Jauary 2023
Summit Residential Referral Program: $250 per referral	*Included in $903,607 above	Referrer must be active customer of Summit Natural Gas and Referral must convert primary heating system to natural gas
Summit Saturation Incentive Program: $500	*Included in $903,607 above	If at least 50% of potential new customers on a newly-served street with at least 10 potential customers sign up and begin receiving service by December 31, each customer received $500

Name of Respondent Summit Natural Gas of Maine, Inc	This Report Is: (1) An Original (2) A Resubmission	Date of Report (Mo, Da, Yr) 3/30/22	Year of Report December 31, 2021

Chapter 820 Reporting Requirements
Summary of Affiliated Transactions

Provide a reporting of all transactions with affilitiates during the past year in accordance with the requirements of Chapter 820 of the Public Utilities Commission's Rules and Regulations.

Summit Utilities Inc (Parent Company)

Services (direct labor charges & overhead) provided by parent company include Administration, Fleet, Executive, Accounting, FP&A, Treasury, Human Resources, Information Systems, Legal, Corporate Affairs, Regulatory, Energy Efficiency, Customer Care - Collections, Marketing, Business Development, Engineering, Compliance, Integrity, Operations, Safety, Gas Supply Management and Procurement.

Summit Natural Gas of Maine Inc

Services (direct labor) provided to sister and parent companies include Business Development, Compliance, Engineering, Gas Control and Operations.

Indirect overhead is allocated to each subsidiary based on the Distrigas formula. The Distrigas formula takes the prior month plant-in-service balance, current month payroll expense, and prior month revenues of each operating company (each weighted 1/3) to calculate each subsidiary's overhead proporionate share. This proportionate share is then multiplied by the current month parent company overhead expenses in order to allocate a portion of the overhead expenses to each subsidiary. Overhead distributed via the Distrigas formula includes Shared Services labor, employee benefits, vehicle expenses, and G&A expenses. Shared Services provided by the parent company include Finance & Accounting, Admin, IT, HR, Payroll, Billing, Regulatory, Executive, Legal, and Procurement not previously allocated through direct identification.

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year of Report
Summit Natural Gas of Maine, Inc	(1) An Original (2) A Resubmission	3/30/22	December 31, 2021

RESIDENTIAL AND COMMERCIAL SPACE HEATING CUSTOMERS

A residential space heating customer is a customer whose major fuel for heating is gas.

Line No.	Item (a)	Residential (b)	Commercial (c)
1	Average Number of Space Heating Customers for the Year (Estimate if not known. Designate with an asterisk if estimated.)		
2	For Space Heating Only, Estimated Average Mcf (14.73 psia at 60 F) per Customer for the Year		
3	Number of Space Heating Customers Added During the Year		
4	Number of Unfilled Applications for Space Heating at End of Year		

INTERRUPTIBLE, OFF PEAK, AND FIRM GAS AND TRANSPORTATION SALES TO DISTRIBUTION SYSTEM INDUSTRIAL CUSTOMERS

1. Report below the average number of interruptible, off-peak, and firm industrial customers on local distribution systems of the respondent, and the Mcf of gas sales to these customers for the year. Include transportation only customer information as well.
2. Interruptible customers are those to whom service may be interrupted under terms of the customer's gas contract, or to whom service is required to be interrupted, regardless of contractual arrangements in emergency periods by law, ordinance, directive, or other requirements of government authority. State in a footnote the basis on which interruptible customers are reported.
3. Off peak sales are seasonal and other sales which do not occur during wintertime demands.
4. Report pressure base of gas volumes at 14.73 psia at 60 F.

Line No.	Item (a)	Number/Amount (b)
1	Interruptible Customers	
2	Average Number of Customers for the Year	
	Sales Customers	
	Transportation Only Customers	8
3	Mcf of Gas Sold or Transported for the Year	
	Sales Customers	
	Transportation Only Customers	2,601,053
4	Off Peak Customers	
5	Average Number of Customers for the Year	
	Sales Customers	
	Transportation Only Customers	
6	Mcf of Gas Sold or Transported for the Year	
	Sales Customers	
	Transportation Only Customers	
7	Firm Customers	
8	Average Number of Customers for the Year	
	Sales Customers	
	Transportation Only Customers	
9	Mcf of Gas Sold or Transported for the Year	
	Sales Customers	
	Transportation Only Customers	
10	Total Industrial Customers	
11	Average Number of Customers for the Year	
	Sales Customers	
	Transportation Only Customers	
12	Mcf of Gas Sold or Transported for the Year	
	Sales Customers	
	Transportation Only Customers	

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year of Report
Summit Natural Gas of Maine, Inc	(1) An Original (2) A Resubmission	3/30/22	December 31, 2021

Number of Customer's Meters
(Active)

City or Town	Number of Meters
Cumberland/Yarmouth/Falmouth	2,785
Kennebec Valley	2,286

Name of Respondent	This Report Is:	Date of Report	Year of Report
Summit Natural Gas of Maine, Inc	(1) An Original (2) A Resubmission	(Mo, Da, Yr) 3/30/22	December 31, 2021

LIQUEFIED PETROLEUM GAS OPERATIONS

1. Report the information called for below concerning plants which produce gas from liquefied gas (LPG).

2. For columns (b) and (c), the plant cost and operation and maintenance expenses of any liquefied petroleum gas installation which is only an adjunct of a manufactured gas plant, may include or exclude (as appropriate) the plant cost and expenses of any plant used jointly with the manufactured plant facilities on the basis of predominant use. Indicate in a footnote how the plant cost and expense for the liquefied petroleum plant described above are reported.

Line No.	Identification of Plant and Year Installed	Cost of Plant (Land, struc, equip.)	Expenses	
			Operation Maintenance, Rents	Cost of LPG
	(a)	(b)	(c)	(d)
1	None			
2				
3				
4				
5				
6				
7				
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39				
40	TOTAL			0

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year of Report
Summit Natural Gas of Maine, Inc	(1) An Original (2) A Resubmission	3/30/22	December 31, 2021

LIQUEFIED PETROLEUM GAS OPERATIONS (continued)

3. (continued) Designate any plant held under a title other than full ownership and in a footnote state name of owner or co-owner, nature of respondent's title and percent ownership if jointly owned.
4. For column (g) report the Mcf that is mixed with natural gas or which is substituted for deliveries normally made from natural gas. Natural gas means either natural gas unmixed or any mixture of natural and manufactured gas or mixture of natural gas and gasified LPG.
5. If any plant was not operated during the past year, give details in a footnote, and state whether the book cost of plant or any portion thereof, has been retired in the books of account or what disposition of the plant and its book cost is contemplated.
6. Report pressue base of gas at 14.73 psia at 60 F. Indicate the Btu content in a footnote.

Gallons of LPG Used (e)	Gas Produced: Amount of MMBTU (f)	Gas Produced: Amount of MMBTU Mixed with Natural Gas (g)	LPG Storage Cap. Gallons (h)	Function of Plant (Base load, peaking, etc.) (I)	Line No.
					1
					2
					3
					4
					5
					6
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Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year of Report
Summit Natural Gas of Maine, Inc	(1) An Original (2) A Resubmission	3/30/22	December 31, 2021

AUXILIARY PEAKING FACILITIES

1. Report below auxiliary facilities of the respondent for meeting seasonal peak demands on the respondent's system, such as underground storage projects, liquefied petroleum gas installations, gas liquefaction plant, oil gas sets, etc.
2. For column (c), for underground storage projects, report the delivery capacity on February 1 of the heating season overlapping the year-end for which this report is submitted. For other facilities, report the maximum daily delivery capacities.
3. For column (d), include or exclude (as appropriate) the cost of any plant used jointly with another facility on the basis of predominant use, unless the auxiliary peaking facility is a separate plant as contemplated by general instruction 12 of the Uniform System of Accounts.

Line No.	Location of Facility (a)	Type of Facility (b)	Maximum Daily Delivery Capacity of Facility, Mcf at 14.73 psia at 60 (c)	Cost of Facility (in dollars) (d)	Was Facility Operated on Day of Highest Transmission Peak Delivery? Yes (e)	No (f)
1	None					
2						
3						
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Name of Respondent	This Report Is:	Date of Report	Year of Report
Summit Natural Gas of Maine, Inc	(1) An Original (2) A Resubmission	3/30/22	December 31, 2021

GAS PURCHASES (Accounts 800, 800.1, 801, 802, 803, 804, 804.1, 805, 805.1)

1. Provide totals for the following accounts:
   - 800 Natural Gas Well Head Purchases
   - 800.1 Natural Gas Well Head Purchases, Intracompany Transfers
   - 801 Natural Gas Field Line Purchases
   - 802 Natural Gas Gasoline Plant Outlet Purchases
   - 803 Natural Gas Transmission Line Purchases
   - 804 Natural Gas City Gate Purchases
   - 804.1 Liquefied Natural Gas Purchases
   - 805 Other Gas Purchases
   - 805.1 Purchase Gas Cost Adjustments

The totals shown in columns (b) and (c) should agree with the books of account. Reconcile any differences in a footnote.

2. State in column (b) the volume of purchased gas as finally measured for the purpose of determining the amount payable for the gas. Include current year receipts of makeup gas that was paid for in previous years.
3. State in column (c) the dollar amount (omit cents) paid and previously paid for the volume of gas shown in column (b).
4. State in column (d) the average cost per Mcf to the nearest hundredth of a cent. (Average means column (c) divided by column (b) multiplied by 100.)

Line No.	Account Title (a)	Gas Purchased - Dth (14.73 psia at 60F) (b)	Cost of Gas (in dollars) (c)	Average Cost per Dth (To nearest .01 of a cent) (d)
1	800 - Natural Gas Well Head Purchases			
2	800.1 - Natural Gas Well Head Purchases, Intracompany Transfers			
3	801 - Natural Gas Field Line Purchases			
4	802 - Natural Gas Gasoline Plant Outlet Purchases			
5	803 - Natural Gas Transmission Line Purchases			
6	804 - Natural Gas City Gate Purchases	3,567,943	6,497,951	1.82
7	804.1 - Liquefied Natural Gas Purchases			
8	805 - Other Gas Purchases			
9	805.1 - Purchase Gas Cost Adjustments			
10	Total (Enter Total of Lines 1 through 9)	3,567,943	6,497,951	

Notes to Gas Purchases

Name of Respondent	This Report Is:	Date of Report	Year of Report
Summit Natural Gas of Maine, Inc	(1) An Original (2) A Resubmission	(Mo, Da, Yr) 3/30/22	December 31, 2021

Conversion Factor Used

1. Provide a summary of how data from the customer meters is converted to data used to calculate customer bills
2. Report below by month any factors used to convert data read by customer meters into data used to calculate customer bills and indicate the source of that factor.

	BTU Factors
January	1.0440
February	1.0416
March	1.0352
April	1.0427
May	1.0392
June	1.0386
July	1.0355
August	1.0328
September	1.0375
October	1.0394
November	1.079
December	1.0436

Summit Natural Gas of Maine, Inc.

Docket No. 2022-00025

Expenses, Revenues and Rate Base During the Test Year

Section 5.C.3.c of Chapter 120 requires Summit Natural Gas of Maine, Inc. to provide Expenses, revenues, and rate base during the test year, itemized by account number or functional grouping;

Section 5.C.3.c is supported in the exhibits of the Direct Testimony of Company Witness Mr. Ron Amen, Exhibits RJA 08 through RJA-17.1.

Summit Natural Gas of Maine, Inc.

Docket No. 2022-00025

Uncollectable Revenues of Test Year

Section 5.C.3.d of Chapter 120 requires Summit Natural Gas of Maine, Inc. to provide Uncollectible revenues for the test year, including bad debt expense, gross write-offs, and recoveries of prior write-offs;

Section 5.C.3.d is supported in the exhibits of the Direct Testimony of Company Witness Mr. Ron Amen, Exhibits RJA-13 and RJA-13.1.

Summit Natural Gas of Maine, Inc.
Docket No. 2022-00025
Uncollectable Revenues of Test Year

Line No	Description	Amount
	(a)	(b)
1	Bad Debt Expense	$ 70,843
2	Bad Debt Write-offs	(30,419)
3	Recoveries from Prior Write-offs	-
4		$ 40,425

Summit Natural Gas of Maine, Inc.

Docket No. 2022-00025

Number of Units of Service Billed

Section 5.C.3.e of Chapter 120 requires Summit Natural Gas of Maine, Inc. to provide Number of units of service billed for each rate element of service;

Section 5.C.3.e is supported in the exhibits of the Direct Testimony of Company Witness Mr. Ron Amen, Exhibit RJA-12.1.

Summit Natural Gas of Maine, Inc.

Docket No. 2022-00025

Adjustments to Test Year

Section 5.C.4 of Chapter 120 requires Summit Natural Gas of Maine, Inc. to provide

a. Proposed adjustments to test year expenses, revenues, and rate base; and

b. Statements, exhibits, or work papers showing the basis for each adjustment.

Adjustments are addressed in the exhibits of the Direct Testimony of Company Witnesses Mr. Porter and Mr. Amen and related schedules are included in the exhibits to the Direct Testimony of Mr. Amen, Exhibit RJA-17.1.

Summit Natural Gas of Maine, Inc.

Docket No. 2022-00025

Regulatory Proceeding Expenses

Section 5.C.5 of Chapter 120 requires Summit Natural Gas of Maine, Inc. to provide
For those utilities seeking recovery of regulatory proceeding expenses, a detailed description and accounting of those expenses, including identification of the proceeding(s), hours spent and fees charged pursuant to Chapter 850 of the Commission's Rules and Regulations (65-407 C.M.R. 850).

Summit is not seeking to recover rate case expenses in the proceeding.

Summit Natural Gas of Maine, Inc.

Docket No. 2022-00025

Comparative Revenue Statement

Section 5.C.6 of Chapter 120 requires Summit Natural Gas of Maine, Inc. to provide A comparative revenue statement showing operating results for the test year and the test year adjusted;

Comparative revenue statements are provided in the direct testimony of company witness Mr. Ron Amen, Exhibit RJA-17.1.

Summit Natural Gas of Maine, Inc.

Docket No. 2022-00025

Computation of Rate of Return

Section 5.C.7 of Chapter 120 requires Summit Natural Gas of Maine, Inc. to provide

a. **Rate of Return.**

(i) An exhibit showing the proposed rate of return and the capitalization ratios for each component of the capital structure; and

(ii) An exhibit showing the computation of the return requested on rate base.

b. **Proposed Revenue Requirements.**

An exhibit showing the computation of the total proposed revenue requirements of the public utility.

The requirements of 65-407 C.M.R. Ch. 120, § 5(C)(7)(a), the Rate of Return are included in the exhibits of the Direct Testimony of Company Witnesses Mr. Amen and Mr. D'Ascendis as follows:

- (7)(a)(i) – Exhibit DWD-1
- (7)(a)(ii) – Exhibit DWD-1
- (7)(b) – Exhibits RJA-17 and RJA-17.1

Summit Natural Gas of Maine, Inc.

Docket No. 2022-00025

Attrition and Elasticity

Section 5.C.8 of Chapter 120 requires Summit Natural Gas of Maine, Inc. to provide

a. Any adjustment proposed by the utility to compensate for attrition or erosion of earnings, and exhibits showing the basis for the adjustment.

b. Any adjustments proposed by the public utility to compensate for the effects of elasticity of demand, and exhibits showing the basis for the adjustment.

Summit is not seeking adjustments with respect to attrition or elasticity.

Summit Natural Gas of Maine, Inc.

Docket No. 2022-00025

Rate Design Changes

Section 5.C.9 of Chapter 120 requires Summit Natural Gas of Maine, Inc. to provide

a. A description of any significant changes in rate design, and exhibits showing the basis for the changes.

b. An exhibit showing the effect of the proposed rate changes on the various classes of customers and categories of service provided by the public utility, including:

(1) the total annual revenue change for each class of customers and category of service, expressed in dollars and as a percentage; and

(2) the change in typical bills for each class and category, expended in dollars and as a percentage.

The requirements of 65-407 C.M.R. Ch. 120, § 5(C)(9) are included in the exhibits of the Direct Testimony of Company Witnesses Mr. Amen and Mr. Porter* as follows:

- 9(a) – Exhibit RJA-20
- 9(b)(1) – Exhibit RJA-20
- 9(b)(2) – Exhibit RJA-21 and Exhibit RJA-22

*See page 16 of Mr. Porter's testimony

Summit Natural Gas of Maine, Inc.

Docket No. 2022-00025

Policy Statement

Section 5.C.10 of Chapter 120 requires Summit Natural Gas of Maine, Inc. to provide a concise statement of any positions, proposals, and adjustments to be offered in support of the rate filing which are known or believed by the public utility to be:

a. Contrary to the established policy of the Commission;

b. Matters as to which various decisions of the Commission are in conflict; or

c. Matters not previously resolved by Commission decisions.

Summit is advancing no positions, proposals or adjustments that are contrary to Commission policy, implicate conflicting Commission decisions or have not been previously resolved by Commission decision.

Summit Natural Gas of Maine, Inc.

Docket No. 2022-00025

Significant Changes in Operations

Section 5.C.11 of Chapter 120 requires Summit Natural Gas of Maine, Inc. to provide a brief description of any significant changes in the operations of the public utility since the time of its last general rate case.

There have been no significant changes in operations.

Summit Natural Gas of Maine, Inc.

Docket No. 2022-00025

Notice to Customers

Section 5.C.12 of Chapter 120 requires Northern to provide "copies of any notices sent or to be sent to the customers of the public utility in connection with the proposed general rate case pursuant to Chapter 110(6)(B)(1)(b) of the Commission's Rules (65-407 C.M.R. 110(6)(B)(1)(b)), with a description of the classes or groups of customers receiving each notice."

Please see the attached Notice to Customers.

Summit Natural Gas

March 31, 2022

Re: NOTICE TO CUSTOMERS REGARDING GENERAL RATE PROCEEDING PER CHAPTER 120 PERTAINING TO SUMMIT NATURAL GAS OF MAINE, INC., DOCKET NO. 2022-00025.

Dear Valued Summit Natural Gas of Maine Customer,

At Summit Natural Gas of Maine ("Summit"), every day we provide safe and reliable natural gas to thousands of Mainers for home heating, hot water, cooking and more. To do that, we must operate, maintain, and continuously improve and invest in more than 300 miles of pipeline while continuing to provide the quality customer service you've come to expect from your local natural gas utility company. These are the services that are paid for through our rates. As a valued customer, we are providing this letter to notify you that Summit is seeking approval from the Maine Public Utilities Commission ("MPUC") for a 7-year alternative rate plan that will increase rates for our Maine customers. The rate plan that was established in 2013 when Summit first began serving communities in Maine is expiring, and we are required by the MPUC to file a new rate plan.

Summit is proposing an effective date of January 1, 2023, for the new rate plan. This will require a submittal to the MPUC no later than March 31, 2022. This March 31 submittal will start a process of approval with the Maine Commission that could span up to 9 months. This process of review and discovery is important to ensure a fair rate plan for all parties involved. Summit also values this process because it is one in which you, the customer, can take part.

The proceeding at the MPUC in which it considers Summit's proposed rate plan will be a transparent process that includes ample opportunity for public input and participation along the way. Through the proceeding, the MPUC will review Summit's operations, financial statements, forecasts, and additional information to ultimately determine how much it costs us to serve our customers and how much we need to charge customers to cover these costs.

Over the previous decade Summit has taken great pride in our stellar customer service, the focus we place on growth and expansion, and finally, stable rates for those needing gas supply. While this proposed rate plan will increase rates for our Maine customers, it is paramount to Summit that we remain competitive and cost-effective throughout our service territory. Summit places great importance on our cost-effective, environmentally conscious service and we will continue to do so. We will also continue to focus on growth as this rate plan takes effect, as this ensures a healthy and low-cost ecosystem for all customers and businesses in Maine.

The proposed increase in distribution rates among residential and business customers in year 1 of the rate plan will increase revenues by approximately $2.8 million. If Summit's proposal is approved as requested, there will be a 30 percent increase in distribution and service & facility rates. The proposed rate plan would permit annual increases in years 2-7 up to an annual cap of 15 percent, but annual increases could be less than that cap. Under the proposed plan, the average monthly increases to Summit's distribution and service & facility rates, which do not include the cost of gas itself, would vary for different customer classes, as shown in the table below:

Year 1	Customer Class	Percentage Increase to Base Rates [1]	Average Dollar Increase to Monthly Base Rates Charges
2023	Residential	30%	$27.28
2023	Small Commercial	30%	$88.22
2023	Large Commercial	30%	$623.30

Years 2-7	Customer Class	Allowable Range for Percentage Increase to Base Rates [1]	Range for Average Dollar Increase to Monthly Base Rates Charges
2024	Residential	0% - 15%	$0.00 - $17.71
2025	Residential	0% - 15%	$0.00 - $20.37
2026	Residential	0% - 15%	$0.00 - $23.42
2027	Residential	0% - 15%	$0.00 - $26.93
2028	Residential	0% - 15%	$0.00 - $30.98
2029	Residential	0% - 15%	$0.00 - $35.60
2024	Small Commercial	0% - 15%	$0.00 - $57.45
2025	Small Commercial	0% - 15%	$0.00 - $65.91
2026	Small Commercial	0% - 15%	$0.00 - $75.73
2027	Small Commercial	0% - 15%	$0.00 - $87.21
2028	Small Commercial	0% - 15%	$0.00 - $100.37
2029	Small Commercial	0% - 15%	$0.00 - $115.27
2024	Large Commercial	0% - 15%	$0.00 - $405.70
2025	Large Commercial	0% - 15%	$0.00 - $464.48
2026	Large Commercial	0% - 15%	$0.00 - $535.67
2027	Large Commercial	0% - 15%	$0.00 - $616.72
2028	Large Commercial	0% - 15%	$0.00 - $707.85
2029	Large Commercial	0% - 15%	$0.00 - $814.85

Notes: (1) Percentage Increase to Base Rates includes distribution rates and service & facility charges.

Summit's existing rate plan has been in place since 2013, and as with most companies across Maine, Summit has experienced rising costs for labor, maintenance and goods and services over that time. In an effort to continue to provide safe, reliable service to Maine customers, rates will be adjusted to more accurately reflect the cost of business. These new rates will provide Summit the ability to advance our operations with regard to maintenance, operations and environmental innovation. Summit is seeking fair rates through which we will continue to provide excellent service to the businesses, hospitals, government buildings and residential houses in Maine that have come to rely on us for natural gas service.

We want to remind you that you have a right to participate in this proceeding. Summit customers may participate in this proceeding in any of the ways described below.

1. **You may register** on the Commission's Case Management System ("CMS") to receive a notice whenever a party submits a new filing related to this case (the docket number for the case is 2022-00025). Instructions on how to register and use CMS can be found at: http://www.maine.gov/mpuc/online/index.shtml

2. **You may appear as a public witness** at a hearing scheduled by the Commission. At the public witness hearing, you will have the option of giving your views on the proposed increase under oath.

3. **You may petition to intervene as a full party to the proceeding.** If the Commission approves your petition, you will be able to participate in all hearings and negotiations related to the case. Your petition **must be filed with the Commission no later than April 11, 2022**, and it must include 1) the name and docket number of this proceeding; 2) the manner in which you are affected by this proceeding; 3) a short and plain statement of the nature and extent of the participation you seek; and 4) a statement of the nature of the evidence or argument you intend to submit. You may also submit your petition in writing via U.S. mail to: Administrative Director, Maine Public Utilities Commission, 18 State House Station, Augusta, ME 04330-0018.

Petitions to intervene will be ruled on at an initial case conference scheduled by the Commission for April 13, 2022 at 1:30 p.m., as noticed by the Commission via CMS. The conference will be conducted online via the Microsoft Teams application. The Commission has also established a conference call number for those who are unable to attend via video, and interested persons not seeking intervention. The dial-in number is (207) 209-4724, and the conference ID is 923 828 051#

THE COMMISSION WILL NOT PUBLISH ANY FURTHER NEWSPAPER NOTICES OF THIS PROCEEDING OR ANY HEARINGS

4. **You may file public comments.** Any person may file comments on this case through the Commission's CMS. Directions for filing public comments can be found at http://www.maine.gov/mpuc/online/index.shtml

For more information about this proceeding, you may contact the Administrative Director of the Commission at (207) 287-3831, the Office of the Public Advocate, which represents ratepayers, at (207) 624-3687, or Customer Service at (800) 909-7642.

If you would like to learn more about this regulatory rate review, please visit our website at summitnaturalgasmaine.com/rate-case. There you will find Summit's answers to frequently asked questions, additional rate case documentation and more. You can also call Summit's customer service team at 800-909-7642. We are here to help!

We greatly appreciate the opportunity to be your natural gas provider, and are truly committed to providing you with safe, reliable, and affordable natural gas service. Our proposed alternative rate plan will help us to achieve that goal.

Summit Natural Gas of Maine, Inc.

Docket No. 2022-00025

Additional Content Required by Prior Orders

Section 5.C.13 of Chapter 120 requires Summit Natural Gas of Maine, Inc. to provide any information which the Commission has specifically ordered a particular public utility to provide for use in its next general rate case.

The Company does not believe there is any information which the Commission has specifically ordered Summit to provide for use in this proceeding.

Summit Natural Gas of Maine, Inc.

Docket No. 2022-00025

Basis for Omissions

Section 5.C.14 of Chapter 120 requires that where Summit Natural Gas of Maine, Inc. "contends that any of the information required by this section is not applicable, (Summit) must state the basis for that contention."

Summit does not contend that any of the information required by this section is not applicable.

BEFORE THE
MAINE PUBLIC UTILITIES COMMISSION

DIRECT TESTIMONY
OF
TYSON PORTER

SENIOR DIRECTOR OF REGULATORY FINANCE AND RATES

ON BEHALF OF
SUMMIT NATURAL GAS OF MAINE, INC.

DOCKET NO. 2022-00025

MARCH 31, 2022

TABLE OF CONTENTS

I. INTRODUCTION AND BACKGROUND

Q. STATE YOUR NAME AND BUSINESS ADDRESS

A. My name is Tyson Porter. My business address is 10825 E Geddes Ave., Suite 410, Centennial, Colorado, 80112.

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

A. I am employed by Summit Utilities, Inc. ("SUI") as the Senior Director of Regulatory Finance and Rates. In this capacity, I am responsible for preparing cost of service studies and developing accounting exhibits and testimony for use in applications for rate changes for SUI's subsidiaries, including Summit Natural Gas of Maine, Inc. ("Summit" or the "Company"). I prepare or oversee the preparation of regularly filed exhibits and reports on behalf of SUI's regulated subsidiaries to various regulatory commissions. I also provide data, answer inquiries, and assist representatives of the regulatory commissions in connection with their audits and reviews of SUI's regulated subsidiaries.

Q. ON WHOSE BEHALF ARE YOU TESTIFYING?

A. I am testifying on behalf of Summit.

II. STATEMENT OF QUALIFICATIONS

Q. PLEASE DESCRIBE YOUR EDUCATIONAL AND BUSINESS BACKGROUND.

A. After earning dual Bachelor of Science degrees in Business Administration and Accounting from the University of Kansas in 2006, I started my career as an auditor for EKS&H, a large Colorado-based accounting and business consulting firm, now Plant Moran. I was accountable for planning and conducting audits on public and private organizations, primarily in the energy sector, including gas utilities. In 2010, I left EKS&H to become a consultant to Southern Missouri Gas L.P., a gas utility serving customers in central and southern Missouri. In 2012, a subsidiary of SUI, Summit Natural Gas of Missouri, Inc. (then known as Missouri Gas Utility, Inc.), purchased all the assets of Southern Missouri Gas L.P. Following completion of the integration, I accepted a position with Summit as a Regulatory Analyst. In 2019, I was promoted to Director of Regulatory Finance and Rates, and in 2022, I was promoted to Senior Director.

Q. HAVE YOU PREVIOUSLY TESTIFIED BEFORE THIS COMMISSION?

A. Yes, I have provided testimony before the Maine Public Utilities Commission ("Commission") in Docket Nos. 2018-00006 and 2019-00185, and I have participated in several technical conferences related to Summit's cost of gas adjustments and its annual adjustments under its rate plan.

Q. HAVE YOU TESTIFIED BEFORE OTHER REGULATORY BODIES?

A. Yes. I have filed testimony before the Colorado Public Utilities Commission, the Missouri Public Service Commission, and the Oklahoma Corporation Commission.

III. PURPOSE AND SUMMARY OF TESTIMONY

Q. WHAT IS THE PURPOSE OF YOUR TESTIMONY?

A. The purpose of my testimony is to provide an overview of Summit's request in this proceeding for Commission approval of a proposed seven-year rate plan. In addition, I provide a brief history of Summit's natural gas utility service in Maine since 2013 and background on the rate plan under which the Company has operated during that time.

Q. PLEASE SUMMARIZE YOUR TESTIMONY.

A. Established as a new natural gas utility in 2013, Summit's business plan remains that of a growth utility, with an emphasis on adding customers to its system. The Company's revenues under a soon-to-expire alternative rate plan, which was not developed on the basis of a historical cost of service methodology, do not currently provide revenues that are sufficient to allow recovery of expenses, let alone a return on rate base. The proposed, new alternative rate plan is designed to increase the customer contribution towards the Company's operating expenses over time. Under the proposed plan, Summit's rates would increase by 30 percent above test-year rates in the first year of the plan and Summit would have the authority to implement increases in each of the following six years of the plan, up to an annual cap of 15 percent. The initial increase of 30 percent is inclusive of the 4 percent, capped increase that Summit expects to implement in June 2022 pursuant to the final annual adjustment under its existing rate plan. Summit is filing its request for that annual price adjustment in Docket No. 2022-00085, contemporaneously with its petition in this proceeding. In other words, as measured against December 31, 2022 rates, should the new rate plan be approved as filed, Summit's rates will increase on January 1, 2023 by 25 percent for all customer classes.

While the plan is intended to put rates on a path towards cost recovery, and may allow Summit to earn a modest return on equity, the plan does not include a reasonable return. In short, the rate plan will not satisfy Summit's revenue requirement as measured using traditional cost of service principles, and as described in greater detail below and in the testimony (and exhibits) of Summit's expert witnesses.

IV. INTRODUCTION OF WITNESSES

Q. PLEASE INTRODUCE THE WITNESSES WHO ARE SPONSORING TESTIMONY IN THIS PROCEEDING ON BEHALF OF SUMMIT.

A. In addition to my testimony summarized above, the Company is also submitting pre-filed direct testimony of the following witnesses:

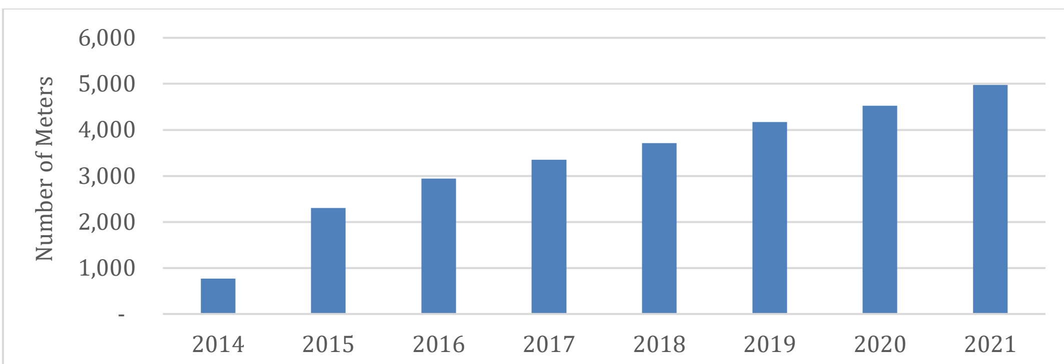
Witness	Summary of Testimony
Mr. Ronald Amen	Addresses Summit's revenue requirement, rate design and expected customer bill impacts resulting from the Company's proposed rate plan.
Mr. Dylan D'Ascendis	Provides ROE analysis and exhibits as well as the appropriate capital structure.
Mr. Matt Jacobson	Supports Summit's growth efforts to date and plans for future growth in the state.
Mr. Fred Kirkwood	Provides customer service metrics, the customer service operations, and the Company's net promoter score.
Mr. W. Jason Weekley	Provides an overview of the operational changes since the last rate plan as well as safety and damage prevention metrics.

V. COMPANY OVERVIEW

Q. PLEASE PROVIDE A BRIEF SUMMARY OF SUMMIT'S GAS DISTRIBUTION SERVICE BUSINESS.

A. Summit is a Colorado corporation formed in 2011, authorized to do business in Maine in 2012, and is wholly owned by SUI, which is a privately held company. The Commission authorized Summit to operate as a new local natural gas distribution company ("LDC") in Maine in 2013. See *Summit Natural Gas of Maine, Inc., Petition for Authority to Provide Natural Gas Service Pursuant to 35-A MRS Sections 2102, 2104 and 2105*, Docket No. 2012-00258, Order Approving Stipulation (Jan. 29, 2013). At that time, SUI owned and operated LDCs serving customers in Colorado and Missouri; SUI now owns and operates LDCs serving customers in Colorado, Missouri, Arkansas, Oklahoma and Texas in addition to Maine. Summit came to Maine to provide LDC service to significant industrial customers and communities that previously did not have access to natural gas as a heating fuel. Summit's initial focus was to build a new system, known as the Kennebec River Valley system ("KV"), consisting of a 13 mile, high pressure steel line from a tap on the Maritimes & Northeast Pipeline located in Windsor, Maine, to Augusta, Maine, and a 53-mile high pressure steel line from the same tap in Windsor, Maine to Sappi Fine Paper's Somerset Mill in Skowhegan, Maine, the Huhtamaki Mill in Waterville, Maine, and Madison Paper Industries and Backyard Farms in Madison, Maine. Along this steel backbone, Summit's focus was to also serve residential, commercial, industrial and local and state government customers by means of polyethylene mains and service lines in the municipalities of Richmond, Gardiner, Farmingdale, Hallowell, Randolph, Augusta, Sidney, Belgrade, Oakland, Fairfield, Waterville, Skowhegan, Norridgewock, Madison, China, Albion, and Windsor., In March 2014, the Commission approved Summit's request to also provide natural gas utility service in the municipalities of Cumberland, Yarmouth and Falmouth ("CYF"). See *Summit Natural Gas of Maine, Inc., Request for Approval to Provide Natural Gas Service in the Towns of Cumberland and Falmouth*, Docket No. 2014-00004, Order (Mar. 5, 2014). Since their initial construction, the KVC and CYF systems have experienced growth, both in terms of the number of customers served and the length of the mains installed to make natural gas service available to customers in the communities served by the Company. Today, Summit operates 182 miles of distribution pipeline and serves over 5,000 customers.

Customer Growth 2014-2021



Summit continues to be a growth utility with goals to increase uptake of gas service by customers with premises located along the path of the Company's existing distribution system and who wish to convert from other heating fuels (predominantly heating oil and to a lesser extent propane), and by extending the system to reach additional customers who desire natural gas service.

Q. PLEASE DESCRIBE THE COMPANY'S CURRENT RATE PLAN.

A. Summit's current rate plan was approved by the Commission pursuant to its January 29, 2013 Order Approving Stipulation in Docket No. 2012-000285 (the "2013 Rate Plan"). The rates Summit charges to its customers are set under that 10-year rate plan, which will expire on December 31, 2022. As is common in the context of new gas utilities, or existing utilities serving new service territories, Summit's 2013 Rate Plan was not designed to generate rates according to traditional regulated monopoly, cost of service ratemaking principles that are intended to establish prices that approximate those that would occur in a competitive (non-monopolistic) market. Instead, the reasonableness of the rates that the Commission, in 2013, authorized Summit to charge to customers that would connect to its as-yet unbuilt system was evaluated in the context of the higher prices of fuel oil and propane. Indeed, the Commission recognized it was approving a rate plan for Summit "that would likely, for a genuinely 'monopoly' provider, result in rates that would either qualify as excessive or insufficiently compensatory relative to costs." Id. at 12. The 2013 Rate Plan permits annual adjustments for inflation, mandated costs, and ROE sharing upon achieving a customer count target, subject to a total annual cap of 4 percent. Adjustments, if any, are calculated in April of each year. Since the inception of the 2013 Rate Plan, through April 2021, Summit's volumetric distribution rates increased approximately 16 percent, or an average of approximately 1.75 percent annually. During that same period, Summit's fixed monthly charge increased approximately 9.5 percent, or an average of approximately 1.05 percent annually. In addition to the rate adjustment mechanism, the 2013 Rate Plan includes a Service Installation metric that establishes a requirement that Summit make a one-time payment of up to $250 to customers who have enrolled to receive service but whose service line has not been installed by the estimated installation date established under a Service Line Construction Policy. Also included is a requirement that the Company report its success in arriving for service appointments within 30 minutes of the scheduled appointment time. The Rate Plan also required that Summit file with the Commission marketing materials of the cost components with respect to installing and using gas, and information about the possible range of commodity prices for natural gas and heating oil over the term of the Rate Plan using an independent third-party forecast. Finally, under the 2013 Rate Plan, Commission approval is not required for Summit to enter into special rate agreements ("SRAs") with customers. Instead, Summit is required to file with the Commission, for informational purposes, any SRAs it enters into with customers, along with short-run marginal cost information.

Q. HOW HAS THE 2013 RATE PLAN SERVED SUMMIT AND ITS CUSTOMERS?

A. Generally, the 2013 Rate Plan has served Summit and its customers well. Distribution rates have been predictable and, combined with cost of gas rates, have remained competitive with the price of heating oil and propane. Moreover, the ability of Summit's sales force to efficiently enter into SRAs, combined with the availability of Commission-approved, shareholder-funded conversion incentives, have been of significant value in marketing gas service to new customers thus increasing the number of Maine residents and businesses connected to the distribution system to satisfy their heating needs. On the other hand, the Commission was quite correct in its Order approving the 2013 Rate Plan that by establishing rates with the goal of making the cost of natural gas competitive in the market with alternative unregulated forms of heating fuel (heating oil and propane) there was a strong possibility that revenues would be insufficiently compensatory relative to costs.

Q. WHY IS THE COMPANY REQUESTING A NEW RATE PLAN?

A. As noted previously, the Company's 2013 Rate Plan will expire on December 31, 2022. Practically speaking, a new rate plan is needed to replace the expiring plan. The rate plan that the Company is proposing in this proceeding is designed to increase customer contribution to expenses while remaining cost competitive with alternative unregulated fuels and limiting rate shock for our customers. The proposed Rate Plan is updated to reflect a more mature utility and provides rate predictability during the plan term.

VI. SUMMIT'S PROPOSED RATE PLAN

Q. PLEASE GENERALLY DESCRIBE THE COMPANY'S PROPOSED RATE PLAN.

A. For its updated rate plan (the "2023 Rate Plan"), Summit proposes starting rates that represent a 30 percent increase in the current distribution rates and the monthly service and facilities charge. The Company also proposes an escalator by which Summit may, upon 30-days written notice to the Commission and to customers, increase distribution rates and monthly service and facilities charges rates by up to 15 percent per year over the seven-year term of the plan. No other rate adjustments will be made, and Summit will not seek a rate effective date for a general rate case (or renewal of the 2023 Rate Plan) until the proposed plan expires. The 2023 Rate Plan is intended to gradually increase customer contribution to operating expenses through predictable increases in distribution rates and the monthly service and facilities charges during the term of the plan. Summit intends that at the end of the seventh year of the Rate Plan (*i.e.*, by December 31, 2029) it will be earning revenues that may cover its expenses. The Company does not, however, anticipate that these revenues will be sufficient to provide a meaningful return on rate base even if the Company were to exercise its ability to implement the maximum 15 percent distribution rate increase in years two through seven.

Q. IS THE PROPOSED RATE PLAN DESIGNED TO ALLOW THE COMPANY TO RECOVER ITS REVENUE REQUIREMENT?

A. No. As discussed in greater detail in the Company's Petition, Summit has performed a traditional revenue requirement analysis for its distribution service as contemplated by 35-A M.R.S. § 4706(3). The purpose of such an analysis is to ensure that the rates charged pursuant to a rate plan are just and reasonable. As described in Mr. Amen's Direct Testimony, under a traditional rate of return analysis, the Company experienced a revenue deficiency of $40.1 million during the 12-month Test Year ending June 30, 2021. Summit is not, however, seeking to recover that revenue deficiency through the proposed 2023 Rate Plan. The Company continues to grow and it is important to remain competitive with heating oil and propane. In addition, the Company is sensitive to the total bill impact and has a desire to reduce customer rate shock. As a result, the proposed 2023 Rate Plan is designed to allow predictable increases in rates that will gradually increase annual revenues to a level that may permit the Company to recover its annual expenses by the end of the rate plan and, as discussed later in my testimony, perhaps earn a very modest return on equity.

Q. HOW MUCH OF THE REVENUE DEFICIENCY IS THE PROPOSED RATE PLAN DESIGNED TO ALLOW THE COMPANY TO RECOVER?

A. If accepted as proposed, the Rate Plan would allow the Company to recover 48 percent of its revenue deficiency, or $19 million by the conclusion of the seven-year term.

Q. IS THE PROPOSED RATE PLAN DESIGNED TO ALLOW SUMMIT A REASONABLE OPPORTUNITY TO EARN A RETURN ON EQUITY COMMENSURATE WITH OTHER GAS DISTRIBUTION COMPANIES?

A. No. Again, as discussed in the Company's Petition, Section 4706 requires an earnings review to ensure that any alternative rate-making mechanism approved by the Commission results in just and reasonable rates. Although Mr. D'Ascendis' Direct Testimony concludes that the Commission could authorize Summit a return on equity of 11.10 percent, the Company's proposed rate plan would produce a return on equity of about 2.47 percent at the end of its seven-year term of the Rate Plan. Those returns are far lower than those to which the Company is entitled under traditional ratemaking. Summit is proposing these returns during the Rate Plan to gradually move towards increased customer contribution to expenses while limiting rate shock and increasing customer counts by remaining competitive with fuel oil and propane.

Q. WHAT ARE THE SPECIFIC TERMS OF THE COMPANY'S PROPOSED RATE PLAN?

A. The 2013 Rate Plan included stepped rate increases, albeit structured in a different manner, and the Company felt that was a good model to follow in the 2023 Rate Plan. The proposed

Rate Plan provides the Company with the opportunity to gradually increase distribution rates and monthly service and facilities charges in a stepped manner to cover expenses and potentially earn a small return by the end of the term, but still reduce customer rate shock. The Rate Plan is designed to provide the Company with the flexibility to increase the distribution rates and the monthly service and facilities charge independently, which can help to levelize monthly bills and be responsive to changing economic situations.

The proposed 2023 Rate Plan rates compare favorably with rates that would result from the adoption of the revenue requirement and cost of service study provided in Mr. Amen's Direct Testimony. Further, the proposed Rate Plan does not include escalators for growth in customers, increases in expenses, inflation, etc. By the conclusion of the Rate Plan at the end of 2029, it is anticipated that the Company would be collecting revenues that cover expenses and earning a modest return on equity. The Company built in needed flexibility by proposing a capped increase each year, allowing the Company discretion to select an increase of between 0-15 percent in either or both the distribution charge and the monthly service and facilities charge, based on its consideration of growth, expenses and inflation metrics as well as the then-current state of economics and energy pricing in the state.

Summit's proposed rate plan is comprised of the following principal terms:

Term: Seven years, beginning January 1, 2023 and concluding December 31, 2029.

Starting Rates: Initial distribution rates (volumetric) and monthly service and facilities charge (non-volumetric) will increase 30 percent beginning January 1, 2023 per the table below. As I explained previously, the 30 percent increase is inclusive of the 4 percent increase Summit expects to implement in June 2022 pursuant to the last annual price adjustment permitted under the 2013 Rate Plan.

Proposed Rates in Year 1

Rate Class	Distribution Rate (per Therm)	Monthly Charge
Residential	$1.281	$28.48
Small Commercial (a commercial distribution customer with annual consumption of less than 1500 Dth)	$1.130	$46.97
Large Commercial (a commercial distribution customer with annual consumption of 1500 Dth or more)	$0.831	$405.82
Firm Transportation	Rate to be determined by Special Rate Agreement with the customer	
Interruptible Transportation	Rate to be determined by Special Rate Agreement with the customer	

Annual Rate Increases: At the discretion of Summit and upon 30 days written notice to the Commission, the Company may adjust the distribution rates and/or monthly charge up to the cap for each year. As discussed above, Summit is sensitive to competition from alternative fuels and rate impacts on our customers, which is why the Company included the cap and the option to increase rates below the cap.

Procedure: The Company will file a written notice with the Commission 30 days in advance of the annual rate increase. The increases are expected to be effective on January 1 of each year, with the last increase effective on January 1, 2029.

Stay Out: Summit will not file a general rate case with a proposed rate effective date prior to January 1, 2030.

Q. DOES THE PROPOSED RATE PLAN INCLUDE AN INTERCLASS CHANGE IN RATE DESIGN?

A. No. As Mr. Amen describes in his Direct Testimony, an allocated cost of service study was performed to determine the costs that Summit has incurred to serve its various customer classes, which informs how cost-based rates should be designed. The results of that study concluded that no interclass rate design change is warranted. Accordingly, the Company proposes to apply all rate increases during the rate plan equally across the fixed and volumetric charges for all customer classes.

Q. HOW DOES THE PROPOSED RATE PLAN DIFFER FROM THE COMPANY'S CURRENT RATE PLAN?

A. The 2013 Rate Plan was established prior to the Company initiating service in the state. It was set up in such a manner to establish guardrails for a new utility and included terms such as Service Installation Requirements, Customer Education, and a Service Line Construction Policy. These terms were meant to establish agreed upon operating practices for a new utility and prescribed details around metrics, contracts, and reporting to show that the Company was attracting and signing up customers. Further, the Service Line Construction Policy was meant to ensure the proper process was followed through the actual installation of customer service lines. The Company has matured in its processes and procedures over the last 10 years and has established itself in the state. Mr. W. Jason Weekley offers additional explanation of the Company's operational maturity in his Direct Testimony. A decade into the Company's operations, these terms are no longer needed in the proposed Rate Plan and they have been omitted.

The 2013 Rate Plan also included several calculations related to the annual rate adjustment that are no longer necessary. The 2013 Rate Plan included an ROE sharing provision, as well as an inflation index adjustment, and a mandated cost adjustment. These terms were all necessary at the time as the Company was seeking to implement market-based rates, and because it was an emerging company that could not conduct a full revenue requirement. The proposed Rate Plan in this proceeding is far more streamlined given that the Company is now mature in its operating procedures and business development processes.

Q. HOW WILL THE PROPOSED RATE PLAN BENEFIT SUMMIT AND ITS CUSTOMERS?

A. The proposed Rate Plan strikes a balance between the need for the Company to increase revenues to cover operational expenses, while limiting customer rate shock and remaining competitive with alternative fuels. Summit recognizes that it is not practical to seek recovery of the full revenue requirement at this time, and instead proposes a series of stepped increases that gradually increase the contributions that customers are making to the cost of operating the distribution system. Over the full course of the Rate Plan the Company may achieve recovery of its expenses with a modest return on rate base, while stepping up the customer contribution over time. During the course of the Rate Plan, the Company will continue to grow and add customers, and market and economic forces will undoubtedly inform whether it is able to implement allowed annual rate increases and at the same time maintain a positive customer growth trajectory. The Rate Plan offers growth-oriented flexibility that will benefit both the Company and its customers in terms of promoting increased use of the system.

VII. DISCRETE RATE CASE ISSUES

Q. HOW IS THIS SECTION OF YOUR TESTIMONY ORGANIZED?

A. This section of my testimony addresses discrete issues concerning the Company's rate case filing.

A. Chapter 120 Information

Q. HAS SUMMIT PROVIDED THE COMMISSION WITH THE INFORMATION REQUIRED FOR A GENERAL RATE CASE BY CHAPTER 120 OF THE COMMISSION'S RULES?

A. Yes, Summit's Chapter 120 information is provided as an attachment to the Petition.

Q. ARE SUMMIT'S 2020 AND 2021 ANNUAL REPORTS INCLUDED IN THE CHAPTER 120 INFORMATION?

A. Yes. Summit is using a test year ended June 30, 2021, to present its revenue requirements analysis in this filing. Given that the test year straddles the calendar years covered by the Company's 2020 and 2021 Annual Reports, Summit is providing both reports with its Chapter 120 information.

Q. DOES SUMMIT ANTICIPATE A REVISION OF THE FINANCIAL STATEMENTS FOR 2020?

A. Yes. Just a few business days before the scheduled filing of the Petition in this proceeding Summit learned that, to accommodate certain tax-related matters, the anticipated revisions to the financial statements will not affect the Company's rate plan proposal.

B. Revenue Requirements Issues

Q. HAS SUMMIT PERFORMED A REVENUE REQUIREMENTS ANALYSIS IN SUPPORT OF ITS PROPOSED RATE PLAN?

A. Yes. As noted above, Section 4706 requires a revenue requirements analysis to be performed to ensure that rates charged by a natural gas utility pursuant to an alternative ratemaking mechanism are just and reasonable. The Company's revenue requirement analysis is provided in Mr. Amen's Direct Testimony. This section of my Direct Testimony addresses several issues related to Mr. Amen's revenue requirements analysis.

Q. HAS THE COMPANY ADJUSTED DEPRECIATION RATES FOR THE PURPOSES OF ITS REVENUE REQUIREMENTS ANALYSIS?

A. Yes. The Company has been calculating annual depreciation using a 50-year life for mains and services. The Company intends these lives should be closer to 70 years for mains and 65 years for services and has updated its depreciation rates accordingly for the calculation of this revenue requirement. The proposed depreciation rates are more consistent with the actual useful life of the materials used for mains and services. The plant that these depreciation rates represent will live longer than the Rate Plan, and therefore the outcome is more appropriate for customers. Finally, this reduces the depreciation expense for the customers while still maintaining depreciation schedules that represent the appropriate useful life of the assets.

C. Rate Case Expense

Q. PLEASE DESCRIBE THE COMPANY'S ESTIMATED RATE CASE EXPENSE THAT WAS INCLUDED IN ITS REVENUE REQUIREMENT ANALYSIS.

A. Summit expects to incur approximately $550,000 in rate case expense for this proceeding. This is an estimate based on current invoices and assumes that this will be a fully litigated proceeding. Due to the unique circumstance of Summit's Rate Plan proposal, the Company is not presently seeking to recover the expenses under the proposed Rate Plan.

D. Capital Structure and Cost of Debt

Q. WHAT WAS THE COMPANY'S CAPITAL STRUCTURE AT THE END OF THE TEST YEAR AND WHAT IS THIS COST OF ITS LONG-TERM DEBT?

A. As of the end of the Test Year (June 30, 2021), the Company's capital structure was approximately 65 percent common equity and 35 percent debt. The cost of debt is 5.20 percent, which is the interest rate on a promissory note held by SUI's shareholder.

Q. IS THE COMPANY WILLING TO ACCEPT A HYPOTHETICAL CAPITAL STRUCTURE IN THIS PROCEEDING?

A. Yes. As discussed in greater detail in Mr. D'Ascendis' Direct Testimony, Summit's cost of capital analysis is based on a hypothetical 50/50 debt to equity ratio.

E. Rate Base

Q. IS SUMMIT SEEKING A DETERMINATION IN THIS PROCEEDING FROM THE COMMISSION AFFIRMING THE COMPANY'S RATE BASE?

A. No, Summit is not seeking a rate base determination from the Commission in this proceeding. The Company, which is the youngest of Maine's natural gas utilities, continues to focus on attracting new customers to take advantage of the benefits natural gas offers to consumers in an effort to help defray the cost of the Company's distribution service. The Company works diligently to attract new customers to take service, including infill customers that are already located on an existing gas main, that will contribute to the Company's fixed operating costs. All customers benefit from the addition of new customers, and Summit continuously works to educate potential customers about the benefits of natural gas and the incentives available to them in an effort to enroll them as new gas customers. The Company's efforts to expand its customer base is discussed in detail in Mr. Matthew Jacobson's Direct Testimony. Given the relative youth of the Company's distribution system and the ongoing efforts to maximize customer use of the available system capacity, the Company is not seeking any finding with regard to rate base in this proceeding. No such finding is necessary because Summit's proposed Rate Plan is designed to put the Company on a path towards the recovery of expenses without any expectation that the Company would earn a return on rate base that approaches even the lower limit of the range that would likely be approved in a traditional cost-of-service rate case. The purpose of the Company's filed rate base and cost of capital testimony is to demonstrate that when measured against traditional ratemaking methodology, the requested rate plan is reasonable for customers and the Company. Summit has been operating without a prior determination of its rate base, and no such a finding is required for the Commission to conclude that the proposed Rate Plan is reasonable.

F. Ratemaking Treatment of Special Rate Agreements

Q. HOW HAS SUMMIT TREATED SPECIAL RATE AGREEMENTS FOR RATEMAKING PURPOSES IN ITS REVENUE REQUIREMENT ANALYSIS?

A. To attract customer load sufficient to support the cost of constructing and operating a new distribution network, the Company has entered into special rate agreements ("SRAs") with several commercial and industrial customers. As the Commission is aware, new gas utilities commonly enter into SRAs with customers to serve as "anchor" customers for the distribution system. For the purposes of accounting for revenue associated with the SRAs, the Company has adjusted small commercial and large commercial SRA revenue such that all discounts from tariffed distribution rates have been removed. In other words, for ratemaking purposes, revenue from SRA customers has been adjusted to tariffed rates. Revenue associated with transportation SRAs has been applied to the revenue requirements at the actual revenue amounts, as there is no standard transportation rate in the Company's tariff.

Q. HAS THE COMPANY INCLUDED REDLINED AND CLEAN TARIFF SHEETS THAT INCLUDE ALL CHANGES MADE AS A RESULT OF THIS PROCEEDING?

A. Yes. The Company is filing draft tariff sheets in both redline and clean format, as required by Chapter 120 of the Commission's rules. The tariff changes include updated rate sheets for all customer classes as well as changes related to the updated Rate Plan.

VIII. BILL IMPACTS

Q. HAS THE COMPANY PREPARED A BILL IMPACTS ANALYSIS FOR ITS PROPOSED RATE PLAN?

A. Yes. A bill impacts analysis is provided in Mr. Amen's Direct Testimony as Exhibit RJA-18 and RJA-19. Based on the proposal in this proceeding, bill impacts for the first year of the rate plan, and the range of possible bill impacts for the out years of the plan (depending on whether and to what degree Summit were to implement annual increases up to the 15 percent cap in years 2-7) are provided in the table below.

Bill Impacts

Year 1	Customer Class	Percentage Increase to Base Rates [1]	Average Dollar Increase to Monthly Base Rates Charges
2023	Residential	30%	$27.28
2023	Small Commercial	30%	$88.22
2023	Large Commercial	30%	$623.30

Years 2-7	Customer Class	Allowable Range for Percentage Increase to Base Rates [1]	Range for Average Dollar Increase to Monthly Base Rates Charges
2024	Residential	0% - 15%	$0.00 - $17.71
2025	Residential	0% - 15%	$0.00 - $20.37
2026	Residential	0% - 15%	$0.00 - $23.42
2027	Residential	0% - 15%	$0.00 - $26.93
2028	Residential	0% - 15%	$0.00 - $30.98
2029	Residential	0% - 15%	$0.00 - $35.60
2024	Small Commercial	0% - 15%	$0.00 - $57.45
2025	Small Commercial	0% - 15%	$0.00 - $65.91
2026	Small Commercial	0% - 15%	$0.00 - $75.73
2027	Small Commercial	0% - 15%	$0.00 - $87.21
2028	Small Commercial	0% - 15%	$0.00 - $100.37
2029	Small Commercial	0% - 15%	$0.00 - $115.27
2024	Large Commercial	0% - 15%	$0.00 - $405.70
2025	Large Commercial	0% - 15%	$0.00 - $464.48
2026	Large Commercial	0% - 15%	$0.00 - $535.67
2027	Large Commercial	0% - 15%	$0.00 - $616.72
2028	Large Commercial	0% - 15%	$0.00 - $707.85
2029	Large Commercial	0% - 15%	$0.00 - $814.85

Notes: (1) Percentage Increase to Base Rates includes distribution rates and service & facility charges.

IX. CONCLUSION

Q. DO YOU HAVE ANY CONCLUDING STATEMENTS?

A. Yes. Summit is proposing a multi-year rate plan that has been designed to meet the operating expense needs of the Company while protecting customers from rate shock and allowing the Company to continue to grow by remaining competitive with alternative fuels. Although the rate plan will not result in the Company recovering its full revenue requirement or a return on equity that is commensurate with other firms of similar risk, Summit believes that the proposed rate plan will allow it to continue to provide safe, reliable service while customers will experience predictable rate increases that will allow them to begin to gradually assume greater responsibility for the cost of service pursuant to rates that are just and reasonable.

Q. DOES THIS CONCLUDE YOUR TESTIMONY?

A. Yes, it does.

BEFORE THE
MAINE PUBLIC UTILITIES COMMISSION

DIRECT TESTIMONY

OF

FRED KIRKWOOD

CHIEF CUSTOMER OFFICER

ON BEHALF OF

SUMMIT NATURAL GAS OF MAINE, INC.

DOCKET NO. 2022-00025

MARCH 31, 2022

TABLE OF CONTENTS

I. INTRODUCTION AND BACKGROUND

Q. **STATE YOUR NAME AND BUSINESS ADDRESS**

A. My name is Fred Kirkwood. My business address is 115 N. 12th Street, Fort Smith, Arkansas.

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

A. I am employed by Summit Utilities, Inc. ("SUI") as Chief Customer Officer. In this capacity, I am responsible for overseeing all customer service activities of SUI and its local natural gas distribution subsidiaries, including Summit Natural Gas of Maine, Inc. ("Summit" or the "Company"). I oversee customer experience, including call-center, collections, and billing operations in addition to overseeing our business development and energy efficiency teams for the entire SUI platform, including Summit.

Q. ON WHOSE BEHALF ARE YOU TESTIFYING?

A. I am testifying on behalf of Summit.

II. STATEMENT OF QUALIFICATIONS

Q. PLEASE DESCRIBE YOUR EDUCATIONAL AND BUSINESS BACKGROUND.

A. I earned a Bachelor of Business Administration Degree in Business Management from Central State University in Oklahoma in 1983. I have more than 35 years of experience working with residential and commercial customers in the natural gas industry. I began my career at the Arkansas Oklahoma Gas Corporation ("AOG") in 1986 as a Customer Development Representative. During my time at AOG I have also developed energy efficiency programs and the compressed natural gas ("CNG") vehicle program for the Company's operations fleet and commercial CNG filling stations. I was actively engaged in the integration efforts following AOG's 2017 acquisition by SUI. My role at SUI is of national scope as I oversee the customer service operations for the entire platform, with customers in Arkansas, Oklahoma, Colorado, Missouri, Texas and Maine.

Q. HAVE YOU PREVIOUSLY TESTIFIED BEFORE THIS COMMISSION?

A. No.

III. PURPOSE AND SUMMARY OF TESTIMONY

Q. PLEASE SUMMARIZE YOUR TESTIMONY.

A. My testimony highlights Summit's experience and ability to provide outstanding customer service to its current and future customers in Maine. I discuss the Company's customer service operations and metrics used to evaluate the quality of our customer service. I will also describe future initiatives that will enhance customer interaction and improve our already high level of customer service quality.

IV. CUSTOMER SERVICE OVERVIEW

Q. PLEASE DESCRIBE SUMMIT AND ITS MISSION AS IT RELATES TO CUSTOMER SERVICE AND SATISFACTION.

A. SUI and all its subsidiaries are committed to providing superior service to our customers that rivals the best in the industry. Our customer service team is dedicated to making our customers' lives better in every state SUI serves. We strive to give customers direct and timely access to knowledgeable representatives who efficiently and accurately resolve customer inquiries the first time.

Q. PLEASE DESCRIBE HOW SUMMIT MEASURES CUSTOMER SATISFACTION.

A. Summit utilizes the Net Promoter Score System ("NPS") which is a proven methodology for measuring customer loyalty through surveys that provide first-hand feedback.

Q. PLEASE PROVIDE A NARRATIVE OF HOW CUSTOMER SATISFACTION IS MEASURED THROUGH THE NPS.

A. NPS is a widely used survey tool designed to numerically measure customer satisfaction. The NPS numerical score is the percentage of "promoters" or customers recording a favorable experience, minus the percentage of "detractors" or customers who report a negative experience. The NPS survey poses questions that fall into two types. In the first question the customer provides a 0–10 rating, which establishes a standardized quantitative benchmark that can be tracked over time. Respondents give a rating between 0 (not at all likely) and 10 (extremely likely) that they would recommend us to friends or family and, depending on their response, are placed into one of 3 categories to establish an NPS score:

- Promoters respond with a score of 9 or 10 and are typically loyal and enthusiastic customers.
- Passives respond with a score of 7 or 8. These customers are satisfied with the service received, but not so much as to be considered promoters.

- Detractors respond with a score of 0 to 6. These customers are unhappy with the service they received and may even discourage others from taking service from the Company.

The second type of questions posed in the NPS survey are free-form, follow-up questions, which ask that the customer provide context and explanation for their various numerical ratings, and is intended to remove the sort of bias that a targeted survey question might otherwise impart. Such questions also afford the Company a great opportunity for customer follow-up. A customer that is willing to recommend (promote) Summit is also more likely to maintain service for the long haul. However, a customer that rates the company poorly is more likely to detract from the business by churning or spreading negative word of mouth. The survey helps Summit identify both types of customers so we can make continuous improvements to meet our customer needs, and if the customer requests, allows for specific follow up to resolve any issues.

Q. WHAT IS SUMMIT'S NPS SCORE FOR THE YEAR 2021?

A. Summit's NPS score for 2021 is 44. For context, the vendor retained by Summit to implement the NPS program also provides historical, industry-specific benchmarks: the past utility industry NPS scores range from a low of 5, average 27 to a high of 41. Summit's 2021 NPS score of 44 which places it in the 100th percentile of the utilities industry.

Q. ARE THERE OTHER METRICS CAPTURED BY SUMMIT TO MEASURE CUSTOMER SATISFACTION?

A. Yes. Summit tracks industry standard call center metrics internally, including service level, abandoned call rate and average speed of answer.

Q. HOW DOES SUI'S CALL CENTER PERFORMANCE COMPARE TO INDUSTRY STANDARDS?

A. The current industry standard for service level is 80 percent of all calls answered within 30 seconds, an abandoned call rate of 5percent and average speed of answer rate at 28 seconds. For years 2018-2020, the SUI contact center achieved an average service level of 85 percent of all calls answered within 30 seconds, an abandoned call rate of 2 percent and average speed of answer of 17 seconds. These results are well above industry standards.

Q. PLEASE PROVIDE AN OVERVIEW OF THE CUSTOMER SERVICE AND BILLING OPERATIONS THAT WILL SUPPORT SUMMIT'S OPERATIONS IN MAINE.

A. Summit is a part of the SUI customer service operation under the same leadership as the other Summit-affiliated operating companies. This includes a well-trained call center and customer billing staff led by management with an average tenure of 20 years. The call center is located in Ft. Smith, AR and has a normal operating staff of 20 call center representatives. Customers can reach the call center between the hours of 8am and 5pm eastern standard time. Emergency assistance is available 24 hours a day, seven days a week. Customers may also contact the Company through email at customerservice@summitnaturalgas.com. All call center representatives are trained to address billing and other customer service questions that are specific to Maine.

Q. WHAT CHALLENGES DOES SUMMIT ANTICIPATE REGARDING CUSTOMER SERVICE AND BILLING OPERATIONS?

A. Summit is always focused on process improvements to maintain and increase customer satisfaction based on their current and future needs. It is our customers themselves who provide the most direct feedback. Data captured from the surveys and other customer interactions are used to guide the evaluation of process and system improvements.

V. FUTURE CUSTOMER SERVICE INITIATIVES

Q. WHAT ARE SOME OF THE MEASURES SUMMIT IS EXPLORING FOR FUTURE IMPLEMENTATION TO IMPROVE CUSTOMER SATISFACTION?

A. Summit is exploring technologies in the following areas:

- Customer communication channel expansion.
  - Text Messaging.
    - Customer communication preference. Customers would have the option to select text notification preferences for multiple actions. Example pre and post payment confirmation, payment due date reminders, late payment notification and more.
    - Safety or emergency notification. In addition to other forms of communications Summit can leverage text messaging to provide greater ability to reach customers.
  - Two-way Chat.
    - Provide digital real-time communications with customers that prefer chat to a phone call.
  - Social Media.
    - Expand timely and valuable customer information postings and provide real-time responses to customer inquiries.

- Customer information system and Intelligent Natural Language Interactive Voice Response integration. This enables the customer to interact in a conversational manner without being constrained by keypad responses. The technology increases self-serve and agent information access capabilities and increases efficiency and streamlines the customer experience. Additionally, this provides customer self-service options outside of normal business hours.

Summit's investment in modern technologies will only improve the high level of customer satisfaction achieved as shown by the Company's above-benchmark NPS score. Innovation and expansion of existing practices and technology will continue to put the company at the forefront of customer service in the industry.

VI. CONCLUSION

Q. DO YOU HAVE A CONCLUDING STATEMENTS?

A. The Company works diligently to offer the best customer support in the industry. This is a critical component to maintaining and expanding our footprint in the state.

Q. DOES THIS CONCLUDE YOUR TESTIMONY?

A. Yes.

BEFORE THE
MAINE PUBLIC UTILITIES COMMISSION

DIRECT TESTIMONY

OF

MATTHEW JACOBSON

DIRECTOR OF SALES AND MARKETING

ON BEHALF OF

SUMMIT NATURAL GAS OF MAINE, INC.

DOCKET 2022-00025

MARCH 31, 2022

TABLE OF CONTENTS

I. INTRODUCTION AND BACKGROUND

Q. **STATE YOUR NAME AND BUSINESS ADDRESS**

A. My name is Matthew Jacobson. My business address is 2 Delorme Drive, Yarmouth, Maine 04096.

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

A. I am employed by Summit Utilities, Inc. as Director of Sales and Marketing with responsibility for all activities intended to expand and maintain the customer base of Summit Natural Gas of Maine, Inc. ("Summit" or "Company").

Q. ON WHOSE BEHALF ARE YOU TESTIFYING?

A. I am testifying on behalf of Summit.

II. STATEMENT OF QUALIFICATIONS

Q. PLEASE DESCRIBE YOUR EDUCATIONAL AND BUSINESS BACKGROUND.

A. I graduated with a Bachelor of Science degree from the United States Naval Academy in 1984. I took my commission in the US Air Force and served as a C-130 Aircraft Commander and Instructor Pilot from 1984 until 1995 with tours in West Germany and at the US Air Force Academy in Colorado Springs. While on Active duty in the Air Force, I earned a Master of Business Administration degree from Chapman University in 1992. I have held a variety of sales and market positions at several companies, including Executive Director of the Maine Lobster Marketing Collaborative and Executive Vice President of

Channel and Strategic Data Center Sales at Oxford Networks. I joined Summit Utilities, Inc. in 2019 as Director of Sales and Marketing. My duties support the Company's mission to deliver clean, safe, affordable, and reliable energy solutions to its customers through exceptional service delivered to existing customers and by overseeing all sales and marketing activities related to new business development in Summit's service territory. This includes efforts to add new residential and commercial customers whose premises are located adjacent to an existing service line as well as the evaluation and execution of opportunities to add new customers by expanding infrastructure.

Q. HAVE YOU PREVIOUSLY TESTIFIED BEFORE THIS COMMISSION?

A. No.

III. PURPOSE AND SUMMARY OF TESTIMONY

Q. PLEASE SUMMARIZE YOUR TESTIMONY.

A. My testimony provides an overview of Summit's strategy of responsible growth, and our efforts to both grow and retain Summit's customer base in an increasingly competitive environment in which customers have alternative choices to satisfy their heating needs through the use of heating oil, propane and the installation of heating appliances that run on electricity. I also describe the reasons why customers often choose to switch from the use of oil and propane to cleaner, more efficient, and more cost-effective natural gas, and I summarize the incentives available to do so. Finally, I provide an overview of Summit's plans for future growth in Maine.

IV. BUSINESS DEVELOPMENT

Q. HOW MANY CUSTOMERS DOES SNGME CURRENTLY HAVE?

A. The table below shows the total customer count by class as of June 30, 2021, the conclusion of the test year in this proceeding.

Customer Count as of June 30, 2021

Customer Class	Total Customers
Residential	3,603
Small Commercial	925
Large Commercial	92
Transportation	8

Q. HAS THE COMPANY ACHIEVED METER GROWTH IN RECENT YEARS?

A. Yes. The Company has met its growth goals for the last three years. Below is table of year end meter counts from 2014 through 2021.

Year End Meter Counts

	2014	2015	2016	2017	2018	2019	2020	2021
Residential	535	1,866	2,342	2,645	2,932	3,247	3,516	3,876
Small Commercial	177	358	521	609	681	826	907	997
Large Commercial	49	77	75	92	88	86	91	96
Transportation	4	4	3	5	8	8	8	8
Total	765	2,305	2,941	3,351	3,709	4,167	4,522	4,977
Year over Year Customer Change		1,540	636	410	358	458	355	455
Year over Year Percent Change		201%	28%	14%	11%	12%	9%	10%

Q. HAS THE COMPANY CONTINUED TO ADD CUSTOMERS SINCE THE TEST YEAR?

A. Yes. Since July 1, 2021, the Company has added approximately 317 Residential meters, 119 Small Commercial meters, 7 Large Commercial meters and 2 Transportation meters.

Q. HOW DOES SUMMIT MAINTAIN RELATIONSHIPS WITH CUSTOMERS IN ITS SERVICE COMMUNITIES?

A. The Company has local teams that develop personal relationships with our customers in all customer classes. These teams get to know our customers' needs and challenges, whether that's conversion, understanding and managing a new fuel, or support with contractors. Summit offers a safe, reliable, and cost-effective energy alternative that can make a big difference in the lives and businesses of our customers.

Q. PLEASE DESCRIBE HOW SUMMIT MARKETS TO POTENTIAL CUSTOMERS.

A. The opportunity to switch from fuel oil or propane to natural gas has several intrinsic benefits to customers. These include lower energy costs, practical considerations such as eliminating the need to mount and refill external storage tanks, and environmental benefits such as decreasing a customer's carbon footprint. Rebates also play a role in motivating customers to switch to natural gas and help to offset the cost of conversion. In addition, Summit purchases gas in bulk and passes that pricing, which is regulated by the Commission, on to its customers.

Summit offers conversion incentive rebates to both residential and commercial customers. Beginning in 2022, the total rebate for residential customers will be $3,300 and $10,000 for commercial customers. These rebates help to defray the cost of converting from heating oil or other alternative fuels to natural gas.

Q. PLEASE EXPLAIN THE RELATIONSHIP WITH EMT.

A. In June 2020, the Commission approved Summit's request that it be permitted to self-administer its residential natural gas conversion and conservation incentive program – a measure designed to reduce processing time for customers by eliminating often duplicative inspection and verification activities, and delays in the issuance of rebate payment to customers that were an artifact of the previous, dual-administration of the program with EMT. See *Summit Natural Gas of Maine, Inc.; Request for Approval of Revision for the Processing of Conversion Incentive Rebates,* Docket No. 2020-00120, Order (Jun. 29, 2020). As required by the June 29 Order, Summit continues to work with EMT cooperatively to develop a plan for reporting and the sharing of information regarding its administration of its residential conversion incentive rebate program and for the payment by Summit of its share of a statewide assessment of residential building characterizations as may be undertaken by the EMT.

Q. HOW DO EXISTING CUSTOMERS INTERACT WITH SUMMIT?

A. Customers can interact with Summit in a variety of ways. Summit's website provides a comprehensive description of its services and programs available to customers, with links to both internal and external web pages that provide detailed information. The website includes a list of Frequently Asked Questions ("FAQs"), and a method to contact customer service by e-mail. In addition, a customer may obtain the Company's PUC-approved tariff in its most current form. Customers may also contact Customer Service via telephone. Summit also has active Facebook pages where the Company provides relevant information to customers about a variety of topics including safety, energy conservation, community efforts and rebates. Summit witness Mr. Fred Kirkwood provides a summary and statistics related to our contact with customers, as well as Company measures of customer satisfaction through the Net Promoter Score system ("NPS").

V. GROWTH PLAN

Q. WHAT ARE THE TYPES OF CUSTOMERS THAT MAY JOIN THE SUMMIT SYSTEM?

A. Summit customer classes include Residential, Small Commercial, Large Commercial, and Firm Transportation. For growth purposes, Summit categorizes potential customers as falling within one of two classes. "Infill customers" are those whose premises are located along the existing main-line pipe of Summit's distribution system and who therefore require only a new service line in order to obtain gas service. "Demand-Driven" customers are those who would take gas service if Summit were to construct a new main-line, or extend an existing main-line.

Q. WHAT ARE THE AREAS SUMMIT IS CONSIDERING FOR DEMAND-DRIVEN GROWTH OPPORTUNITIES?

A. The Company takes an active yet disciplined approach to finding viable opportunities to expand main-line service to unserved or underserved locations. Most recently, the Company expanded into West Falmouth, Farmingdale, First Park, and the Gardiner Business Park area. Summit focuses on areas that have both demand and density, or a large anchor customer that can support the necessary capital investment, to meet our strategy of responsible growth.

Q. WHAT IS THE POTENTIAL FOR INFILL AND DEMAND-DRIVEN GROWTH IN THESE AREAS IN TERMS OF NUMBERS OF CUSTOMERS?

A. The Company is constantly assessing opportunities for Infill growth; while the specific opportunities are always subject to change, the Infill opportunity is substantial, and Summit currently has identified the following Infill opportunities:

Residential: 6,229 meters

Small Commercial: 1,052 meters

Large Commercial: 5 meters

These potential customers are all directly located in close proximity to existing main-line pipe, and we are always looking for further growth adjacent to our facilities. We also see many viable Demand-Driven opportunities to expand our service area and are actively recruiting potential customers in those areas.

Q. WHAT IS SUMMIT'S GROWTH EXPECTATION FOR THE NEXT FIVE YEARS?

A. The Company has set goals to continue to grow for the next five years by continuing to add over 1,500 RMEs per year, consistent with our recent history.

Q. WHAT MOTIVATES CUSTOMERS TO SWITCH TO NATURAL GAS?

A. For most Summit customers, convenience is the most influential factor in switching to natural gas from an alternative fuel source. In the case of new construction, the higher cost to install a heating oil system is a driving reason for the customer to consider natural gas. Customers appreciate not having to shovel a path and arrange for a truck to pull up every month to deliver oil or propane, and not having to pay for a full tank all at once. Furthermore, many chefs and home cooks prefer to cook with natural gas rather than heat from an alternate source. Lastly, many customers understand the benefit of reduced emissions from natural gas, which is less carbon-intensive than heating oil. EPA statistics show that replacing an old oil boiler with a new efficient natural gas boiler can reduce emissions by up to 38%.[1]

VI. COMPETITION

Q. WHAT ARE THE PRIMARY SOURCES OF COMPETITION TO NATURAL GAS IN SUMMIT'S SERVICE TERRITORY BY CUSTOMER TYPE?

A. With respect to residential customers, Summit primarily competes with heating oil and propane. Lately we have seen some customer interest in heat pumps, but most installations require another heat source in conjunction with a heat pump to ensure adequate heating.

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[1] Based on internal modeling derived from data from the U.S. Department of Energy and the U.S. Energy Information Administration. For data sources, please visit: https://www.eia.gov/state/data.php?sid=ME#ConsumptionExpenditures , https://www.eia.gov/environment/emissions/co2_vol_mass.php , https://www.efficiencymaine.com/at-home/high-efficiency-boilers-furnaces/ , https://www.aga.org/globalassets/2019-natural-gas-factsts-updated.pdf , https://www.eia.gov/dnav/ng/ng_cons_num_a_EPG0_VN3_Count_a.htm , **https://www.aga.org/research/reports/a-comparison-of-energy-use-operating-costs-and-carbon-dioxide-emissions-of-home-appliances–2018-update/

For Small Commercial customers, the competition is primarily heating oil. For Large Commercial customers, competition may come from many different sources, such as heating oil, propane, coal, waste and other fuels.

VII. CONCLUSION

Q. DO YOU HAVE ANY CONCLUDING STATEMENTS?

A. Yes. The Summit system continues to grow to serve the people of Maine, whose interest in being able to choose natural gas service remains robust. Safe, reliable, and clean fuel is popular across our customer types in Maine, and the Summit sales team has taken a robust and disciplined approach to reaching as many of those potential customers as possible. In light of uncertainty relating to availability and price of oil, natural gas is an important option for Maine families, businesses, and municipal governments. Recently we have seen a marked increase in interest from institutional users. Schools and municipal facilities, institutional settings like hospitals and retirement communities are all searching for the value Summit offers; clean, safe, reliable, and cost-effective fuel for today and the future.

Q. DOES THIS CONCLUDE YOUR TESTIMONY?

A. Yes.

BEFORE THE
MAINE PUBLIC UTILITIES COMMISSION

DIRECT TESTIMONY

OF

JASON WEEKLEY

SENIOR VICE PRESIDENT AND CHIEF OPERATIONS OFFICER

ON BEHALF OF

SUMMIT NATURAL GAS OF MAINE, INC.

DOCKET NO. 2022-00025

MARCH 31, 2022

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I. INTRODUCTION AND BACKGROUND

Q. **STATE YOUR NAME AND BUSINESS ADDRESS**

A. My name is Jason Weekley. My business address is 10825 E. Geddes Avenue, Suite 410, Centennial, CO 80112.

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

A. I am employed by Summit Utilities, Inc. ("SUI") as Senior Vice President and Chief Operations Officer. In this capacity, I oversee daily operations for SUI's six operating companies that serve customers in six states, including Summit Natural Gas of Maine, Inc. I am responsible for the functional areas of operations, construction, engineering, gas control, measurement, pipeline safety, and safety and training.

Q. ON WHOSE BEHALF ARE YOU TESTIFYING?

A. I am testifying on behalf of Summit Natural Gas of Maine, Inc. ("Summit" or the "Company").

II. STATEMENT OF QUALIFICATIONS

Q. PLEASE DESCRIBE YOUR EDUCATIONAL AND BUSINESS BACKGROUND.

A. I have over 25 years of experience leading successful operations, engineering, and project management teams. Prior to joining Summit, I served as the Vice President of Operations for SAFEbuilt, a municipal services company operating in 10 states. Prior to SAFEbuilt, I served as the Vice President of Operations for SourceGas, now part of Black Hills Energy, a natural gas utility serving 425,000 customers in Arkansas, Colorado, Nebraska, and Wyoming. Prior to that role, I served as Sr. Director of Operations for SourceGas Arkansas, headquartered in Fayetteville, Arkansas. I also served for 12 years as an officer in the Army National Guard which included a tour of duty in Iraq. I received my Bachelor of Science in Electrical Engineering from Louisiana State University, and I am a National Association of Corrosion Engineers ("NACE") Certified Cathodic Protection Specialist. Additionally, I am active in industry associations including the Southern Gas Association Board of Directors (member), Southern Gas Association Executive Council (former chair), and American Gas Association Operations Managing Committee (member).

Q. HAVE YOU PREVIOUSLY TESTIFIED BEFORE THIS COMMISSION?

A. No.

III. PURPOSE AND SUMMARY OF TESTIMONY

Q. PLEASE SUMMARIZE YOUR TESTIMONY.

A. My testimony provides an overview of the build out of Summit's operations and personnel in Maine and the development and improvement of critical policies, procedures, and operations and technical leadership. I also discuss our current safety and damage prevention metrics which demonstrate the Company's exceptional performance during the past three years. Summit has strived, and I believe succeeded, to become a company that has diligently performed and improved its essential operational practices to provide safe and reliable natural gas service to its customers.

IV. SNGME BUILD OUT

Q. HAVE THERE BEEN SIGNIFICANT CHANGES TO THE COMPANY'S OPERATIONS SINCE IT BEGAN DOING BUSINESS IN MAINE?

A. Yes. The Company has matured significantly since it commenced operations in 2013. Summit has not only grown its assets and customer base, but, even more importantly, it has improved the capabilities of its workforce in the areas of construction supervision, operation of the distribution and transmission systems, governance and leadership, and overall compliance with the Maine Public Utility Commission's ("Commission") gas safety rules.

Q. HOW HAS THE COMPANY GROWN ITS INFRASTRUCTURE?

A. Since starting from scratch in 2013, Summit now operates 312 miles of pipeline including approximately 68 miles of transmission piping and 182 miles of distribution piping, serving over 5,000 customers including nearly 4,000 residential customers and 1,103 small and large commercial customers. The Company provides natural gas to 13 communities in Maine in both the Kennebec Valley and the Cumberland, Falmouth, and Yarmouth areas. The Company intends to continue growing its customer count and to provide service to additional communities.

Q. HAS THE COMPANY ALSO ADDED PERSONNEL IN THE STATE?

A. Yes. Summit now has two field operations offices in the state, one in Portland and one in Winslow, in addition to corporate offices in Yarmouth and Augusta. We continue to hire and train for both field and office personnel. We are training technicians in-house and have stringent oversight of our contractors. Currently, we employ approximately 60 team members in the state of Maine that are proud to live and work in our service territories. In 2021, the Company was named one of the Best Places to Work in Maine for the third year in a row.[1] In addition to competitive compensation and benefits, we believe that this

[1] https://summitnaturalgasmaine.com/Article/197/summit-utilities-inc-named-2021-best-places-to-work-in-maine.

success is attributable in no small part to the Company's culture of safety and team member engagement.

Q. HAS THE COMPANY ALSO MADE STRIDES TOWARD DECARBONIZATION IN THE STATE OF MAINE?

A. Yes. Summit is a forward-looking company with a goal of reducing the carbon intensity of the gas we deliver to our customers. In the spring of 2019, Summit launched a Renewable Natural Gas ("RNG") program to further the Company's commitment to building a sustainable energy future. As part of that program, Summit matched five percent of our residential gas demand for one year with RNG attributes at no cost to our customers to help reduce our carbon footprint. In addition, Summit began giving customers a renewable choice when it came to their home heating needs by allowing them to match 10 to 100 percent of their average annual gas usage with voluntary RNG attributes. This program was started with the goal of helping jumpstart the renewable market and spur investment in new technologies that mitigate the impacts of climate change.

Q. HOW HAS THE COMPANY INCREASED ITS GOVERNANCE AND INDUSTRY AFFILIATIONS SINCE THE BEGINNING?

A. Since 2013, Summit has grown and matured into a company that is proud of our partnership with the Commission's Gas Safety team. The Company has adopted crucial policies and procedures and has brought on key operations leadership that understands the natural gas industry and is focused on pipeline safety and operational excellence. These policies and procedures have been put into place as the Company has grown and learned through our collective experience. To date, the Company has established several internal operations governance committees, including the Operations Standards Committee, the Materials Standards Committee, the Welding Committee, and the DIMP Committee. These committees are integral to the way we do business and make decisions. In addition, the Company has established a Risk Management Committee, which provides oversight and review of major risk exposure, including the review and approval of key capital projects, special rate agreements, contracts, parent guarantees, gas supply strategies, and insurance strategies. Summit also updated its records and retention policy in 2018.

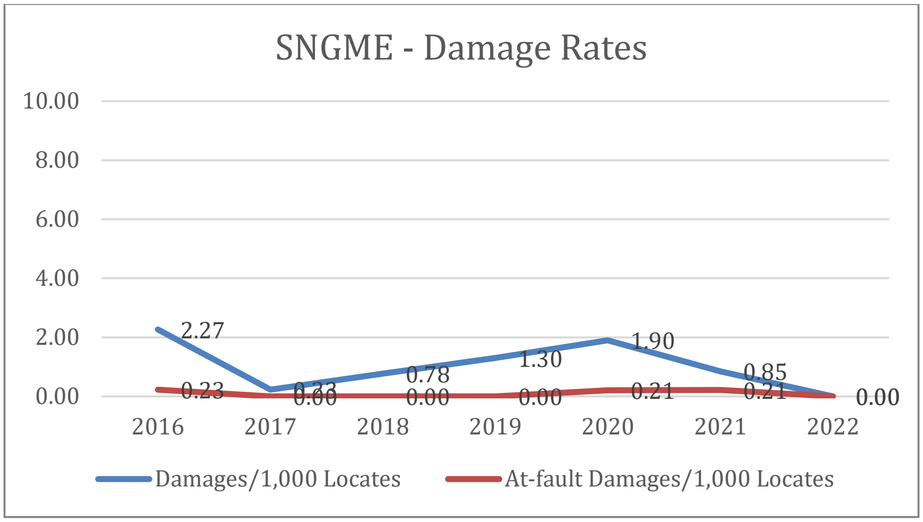
Summit also recognizes the importance of participation in industry committees, and Summit team members participate in various committees across the spectrum to gain and share information regarding operational best practices. Summit and SUI are involved in industry organizations such as the American Gas Association, the Southern Gas Association, the Northeast Gas Association, the Midwest Energy Association, the Common Ground Alliance, to name a few.

V. OPERATIONS RECORD

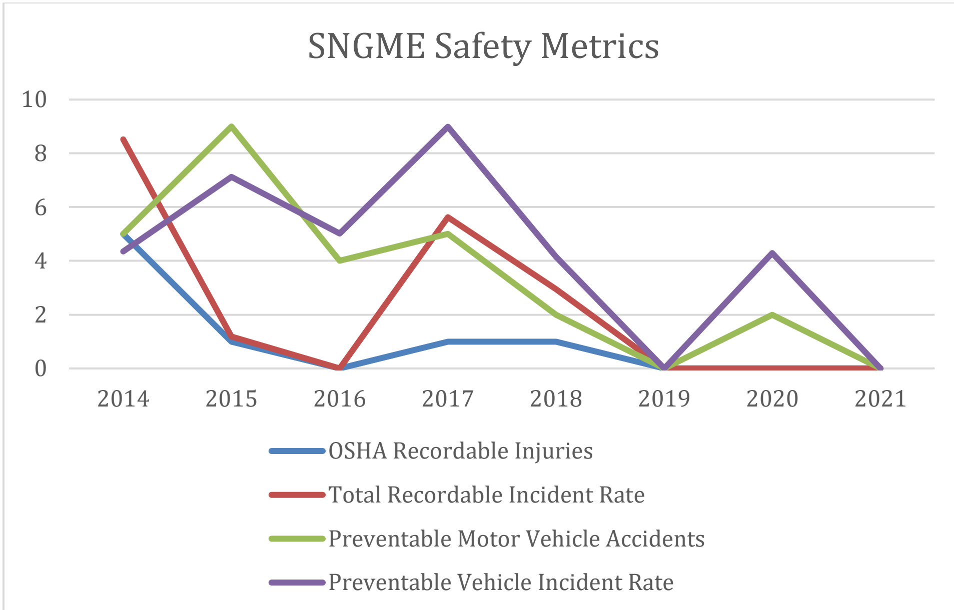
Q. HOW HAS THE COMPANY PERFORMED IN RECENT YEARS WITH RESPECT TO SAFETY AND OPERATIONS RECORDS?

A. Since 2013, Summit has placed significant focus on our operations, and now has an excellent safety record as shown in our damage prevention and leak statistics.

The Company conducts leak surveys annually and has had zero leaks found in the last three years. From a damage prevention standpoint, the Company has been working diligently to educate our contractors and the public about safe digging practices.



Summit has spent the last five years on a mission to eliminate recordable injuries in the workplace. This Drive to Zero cultural campaign has resulted in fewer injuries and motor vehicle accidents. In fact, Summit has celebrated 3 years without a recordable injury. The Company has continued to educate employees and has experienced general downward trends in all categories, including OSHA Recordable Injuries, Total Recordable Incident Rate ("TRIR"), Preventable Motor Vehicle Accidents, and Preventable Vehicle Incident Rate ("PVIR"), including achieving a zero in all categories in 2021.



VI. <u>REMEDIATION</u>

Q. HAS THE COMPANY COMPLETED REMEDIATION ON ITS SYSTEM?

A. Yes. The Company experienced challenges with a contractor in the 2013 and 2014 construction seasons that led to the improper installation of butt fusions, electrofusion tees, and improper cover depth. The Company took steps to address these issues. Beginning with the 2015 construction season, Summit instituted new processes that ensured all contractors were properly qualified and supervised. To ensure the continual safety of the system, the Company conducted additional system assessments, including accelerated leak surveys of mains, visual inspections, and numerous records reviews. The activities ultimately mitigated the areas of concern.

Q. WERE ANY OF THESE COSTS PASSED ON TO RATEPAYERS?

A. No.

Q. WHERE THERE ANY PROCEEDINGS BEFORE THIS COMMISSION THAT ADDRESSED THESE CONCERNS?

Yes. There were multiple proceedings that addressed these concerns,[2] and all were addressed to the satisfaction of the Gas Safety Manager of the Commission under the Consent Agreement filed on August 5, 2016, in Docket No. 2014-00219. An Order was issued on August 10, 2016, approving the Consent Agreement.

VII. CONCLUSION

Q. DO YOU HAVE ANY CONCLUDING STATEMENTS?

A. Yes. Summit has matured into a utility with an excellent employee and pipeline safety record that works closely with the Commission Gas Safety Staff and the communities we serve. The Company provides safe, reliable service to our customers, while offering great jobs and community support. The Company looks forward to our continued growth and safe, reliable operations in the State of Maine.

Q. DOES THIS CONCLUDE YOUR TESTIMONY?

A. Yes.

[2] The Dockets included in the Consent Agreement in Docket 2014-00219 were Docket No. 2014-00221, Docket No. 2015-00342, Docket No. 2015-00343, Docket No. 2016-00015, and Docket No. 2016-00039.

BEFORE THE
MAINE PUBLIC UTILITIES COMMISSION

SUMMIT NATURAL GAS OF MAINE, INC.
REQUEST FOR APPROVAL OF AN ALTENRNATIVE
RATE PLAN (35-A M.R.S § 4706)

DOCKET NO. 2022-00025

DIRECT TESTIMONY

OF

RONALD J. AMEN

MANAGING PARTNER – ATRIUM ECONOMICS

ON BEHALF OF

SUMMIT NATURAL GAS MAINE, INC.

MARCH 31, 2022

TABLE OF CONTENTS

I. INTRODUCTION AND BACKGROUND

Q. STATE YOUR NAME AND BUSINESS ADDRESS

A. My name is Ronald J. Amen and my business address is 10 Hospital Center Commons, Suite 400, Hilton Head Island, SC 29926.

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

A. I am employed by Atrium Economics, LLC ("Atrium") as a Managing Partner. Atrium is a management consulting and financial advisory firm focused on the North American energy industry.

Q. ON WHOSE BEHALF ARE YOU TESTIFYING?

A. I am testifying on behalf of Summit Natural Gas of Maine, Inc. ("Summit" or the "Company").

II. STATEMENT OF QUALIFICATIONS

Q. PLEASE DESCRIBE YOUR EDUCATIONAL AND BUSINESS BACKGROUND.

A. I have over 40 years of experience in the utility industry, the last 25 years of which have been in the field of utility management and economic consulting. I have advised and assisted utility management, industry trade organizations, and large energy users in matters pertaining to costing and pricing; competitive market analysis; regulatory planning and policy development; resource planning and acquisition; strategic business planning; merger and acquisition analysis; organizational restructuring; new product and service development; and load research studies. I have prepared and presented expert testimony before numerous utility regulatory bodies across North America and have spoken on utility industry issues and activities dealing with the pricing and marketing of gas utility services, gas and electric resource planning and evaluation, and utility infrastructure replacement.

Further background information summarizing my work experience, presentation of expert testimony, and other industry-related activities is included as Exhibit RJA-1 to my testimony.

Q. HAVE YOU PREVIOUSLY TESTIFIED BEFORE THIS COMMISSION?

A. No.

III. PURPOSE AND SUMMARY OF TESTIMONY

Q. PLEASE SUMMARIZE YOUR TESTIMONY.

A. The purpose of my testimony is to describe and support the revenue requirement, allocated cost of service study, and rate design put forth in the Company's Petition for rates in this proceeding. The results of the Company's revenue requirement including pro forma adjustments, and the proposed 8.15 percent return on rate base, exceeds the pro forma operating revenues at present rates by $40.1 million. However, the Company is only seeking a revenue increase of $2,846,969 for the first year of its multi-year rate plan.

First, I will present the determination of normal weather for purposes of normalizing test year billing determinants, which is a critical input to the development of the revenue requirement. This is followed by my discussion of the weather normalization process of determining a representative level of gas throughput for the Company's test year ended June 30, 2021, under the predefined level of normal weather conditions. Next, I present the development of Summit's revenue requirement and allocated cost of service study, including a comprehensive overview of the schedules created in support of them. Finally, I present the Company's proposed rates and the resulting customer bill impacts based on the Company's requested revenue increase.

Q. ARE YOU SPONSORING ANY EXHIBITS TO YOUR DIRECT TESTIMONY?

A. Yes. I am sponsoring the following 22 Exhibits, all of which were prepared by me or under my supervision and direction.:

- Exhibit RJA-01 – Resume of Ronald J. Amen
- Exhibit RJA-02 – Heating Degree Day History
- Exhibit RJA-03 – Heating Degree Day Analysis Summary
- Exhibit RJA-04 – Proposed Normal Weather
- Exhibit RJA-05 – Summary of Statistical Results from Heating Degree Day Regression Analysis
- Exhibit RJA-06 – Weather Normalized Usage
- Exhibit RJA-07 – Weather Normalization and Customer Annualization
- Exhibit RJA-08 – Gross Plant
- Exhibit RJA-09 – Reserve for Depreciation
- Exhibit RJA-10 – Other Rate Base
- Exhibit RJA-11 – Rate Base Summary
- Exhibit RJA-12 – Operating Revenue
- Exhibit RJA-13 – Operations and Maintenance Expense
- Exhibit RJA-14 – Depreciation and Amortization Expense
- Exhibit RJA-15 – Property Taxes
- Exhibit RJA-16 – Rate of Return
- Exhibit RJA-17 – Revenue Requirement
- Exhibit RJA-18 – Customer Component of Mains Analysis
- Exhibit RJA-19 – Summary of Allocated Cost of Service Study Results

- Exhibit RJA-20 – Proposed Rate Design
- Exhibit RJA-21 – Customer Bill Impacts
- Exhibit RJA-22 – Residential Customer Bill Impacts

IV. <u>NORMAL WEATHER DETERMINATION</u>

Q. WHAT IS THE PURPOSE OF DETERMINING NORMAL WEATHER?

A. Determining normal weather is the necessary first step to establishing annual natural gas consumption volumes and distribution rates that reasonably reflect expected weather conditions during the future period that the Company's rates will be in effect. Natural gas distribution companies' sales volumes are heavily dependent on weather conditions, primarily the temperature during the winter period. To recognize the impact on gas sales volumes due to variations in weather conditions, base year sales and revenues are adjusted to reflect the load during the test period had weather conditions been "normal."

Q. WHAT IS THE COMPANY PROPOSING AS THE BASIS UPON WHICH ITS CUSTOMER DEMANDS ARE NORMALIZED FOR WEATHER?

A. The Company is proposing to use a rolling 10-year Heating Degree Day ("HDD") average to normalize its annual gas volumes for rate setting purposes.

Q. Please define an HDD.

A. An HDD is defined as 65 degrees less average daily temperature, where average daily temperature equals the average of the high and low temperatures on each day. If the average daily temperature exceeds 65 degrees, the HDD for that day is set equal to zero. A particular month's HDDs equal the sum of the daily HDDs for that month.

Q. PLEASE EXPLAIN THE METHOD FOR DETERMINING THE MOST CONSISTENT WEATHER PREDICTOR TO NORMALIZE SUMMIT'S ANNUAL CUSTOMER DEMANDS FOR WEATHER.

A. The method began by examining the Company's annual HDD over the period from 1950 to 2020, for the Portland Jetport and Augusta Airport weather stations. The goal of the analysis was to determine the best predictor of future HDD levels for purposes of "normalizing" actual natural gas consumption during the test year and for the upcoming timeframe when the Company's new rates are expected to be in effect. A common forecasting technique was used that estimates the average annual HDD for a given timeframe and then uses those results to predict weather in the forecast year. In this case, the Company's "forecast year" is based on the first year in which the Company's new base rates will be in effect (which is assumed to be 2023). For this analysis, four alternative means of forecasting HDDs were tested: (1) a 30-year rolling average of annual HDD data ended in 2020; (2) a 20-year rolling average of annual HDD data ended in 2020; (3) a 10-year rolling average of annual HDD data ended in 2020; and (4) a 5-year rolling average of annual HDD data ended in 2020. The predictive capability of these four timeframes were then compared to determine which one was most appropriate.

Q. PLEASE DESCRIBE THE TYPE AND SOURCE OF THE DATA YOU USED TO ANALYZE THE CHOICE OF WEATHER NORMAL FOR SUMMIT.

A. First, the Company adopted the standard NOAA definition of a heating degree day; that is, the difference between the average daily temperature (based on maximum and minimum daily temperatures) and 65 degrees Fahrenheit (or zero, if the average temperature is above 65 degrees Fahrenheit). All data used in the Company's weather analysis was sourced from NOAA data files that presented daily temperature and HDD data. The NOAA weather stations that were used to construct the 71-year data series of HDDs applicable to the Company's temperature zones included Portland Jetport (Cumberland, Falmouth, Yarmouth Service Area), and Augusta State Airport (Kennebec Valley Service Area). Exhibit RJA–02 presents in graphic form the HDD data series for the weather stations located in Summit's two temperature zones and depicts the level of year-to-year weather variability in each of the temperature zones.

Q. PLEASE DESCRIBE HOW YOU ANALYZED THE HDD DATA.

A. First, the average annual HDD were calculated for the four alternatives being tested, starting in the first year of available temperature data from each weather station, so it was possible to calculate 30-year, 20-year, 10-year, and 5-year rolling averages for the range of years through 2020. Each of the four alternative averages for each year were compared to the actual HDD observed two years later. For example, the four averages for 2017 were compared with the actual HDD for 2019, recording the difference (or error) between the actual and forecasted values for each of the four averages being tested. This analysis was replicated from the first year of data available up to 2020 – the most recent year for which actual HDD data existed. This analysis is consistent with the process generally followed within the context of a rate case.

Q. HOW DID YOU COMPARE THE PREDICTIVE CAPABILITIES OF THE VARIOUS AVERAGES BEING TESTED?

A. A standard statistical measure called the "root mean squared error" or "RMSE" was used to compare the predictive capabilities of the four selected averages. The RMSE is a number representing the degree to which the forecasted values fail to correspond to the actual data.

It is a widely used measure to assess the accuracy of point forecasts. While there are other statistical measures used to convey information about a forecast's performance, such as the mean error or mean absolute error, these measures tend to de-emphasize the consistency of the forecasting technique, while the RMSE tends to emphasize this element of the forecast's predictive capabilities. The smaller the RMSE, the smaller the overall difference between the actual and forecasted HDD. The formula for the RMSE is:

$$\text{RMSE} = \sqrt{\frac{1}{n}\sum_{i=1}^{n}(HDD_i - HDD_i^F)^2}$$

Where:

n = the number of years

i = year of the observation

HDD_i = actual observed values

HDD_i^F = forecasted values

All RMSE values are stated in HDD.

Q. PLEASE DESCRIBE THE RESULTS OF THIS ANALYSIS.

A. For the Company's two temperature zones, Exhibit RJA-03 summarizes annual HDD data for the four sets of weather averages tested, the forecast error, and RMSE resulting from each average. As demonstrated in Exhibit RJA-03, over the respective data set periods, the 10-year rolling average outperforms the other periods in predicting weather two years into the future in three of the four weather averages tested. For the Portland Jetport, the 10-year rolling average has the lowest RMSE for the 40, 30, and 20-year bands as shown in Exhibit RJA-03, column d, lines 4, 8, and 12. For the Augusta Airport, the 10-year rolling average has the lowest RMSE for the 40, 20, and 10-year bands as shown in Exhibit RJA-03, column h, lines 4, 12, and 16. Based on the RMSE test, therefore, the 10-year rolling average provides a better basis for forecasting HDD during the time when the Company's approved rates in this case are anticipated to go into effect. A summary of the proposed monthly normal HDD by Summit's temperature zones is presented in Exhibit RJA-04.

Q. HOW WAS THIS NORMAL WEATHER DETERMINATION USED IN THE DEVELOPMENT OF THE COMPANY'S REVENUE REQUREMENT?

A. The normal HDDs were used to calculate weather normalized volumes that serve as the basis for the Company's Test Year pro forma revenue. The weather normalization is discussed in the next section of my testimony.

V. WEATHER NORMALIZATION

Q. PLEASE DEFINE WEATHER NORMALIZATION WITHIN THE CONTEXT OF SUMMIT'S RATE CASE FILING.

A. Weather normalization is the process of determining a representative level of gas throughput for the Company's test year ended June 30, 2021, under a predefined level of normal weather conditions, which is represented by a historical average level HDDs. Over the long term, using normal weather conditions eliminates a bias which could be introduced by using volume levels in the historical test year that are higher or lower than what would normally be expected. Thus, it is usually necessary to apply an adjustment to actual sales to recognize what volumes would have been if conditions were normal.

Q. HOW DO THE TEST YEAR HDDS COMPARE TO THE 10-YEAR NORMAL HDDS?

A. The test year HDDs were 3.9 percent warmer than normal for the Cumberland, Falmouth, Yarmouth ("CFY") service area, and 6.5 percent warmer than normal for the Kennebec Valley ("KV") service area. Table 1 presents the comparison of actual test year HDDs and 10-year normal HDDs.

Table 1 – Comparison of Test Year and Normal HDDs

Service Area	Test Year HDDs	Normal HDDs	Difference From Normal
CFY	6,382	6,638	-3.9%
KV	6,649	7,115	-6.5%

Q. PLEASE DESCRIBE THE WEATHER NORMALIZATION METHOD YOU USED TO DETERMINE THE RELATIONSHIP BETWEEN SALES VOLUMES AND WEATHER.

A. I used multiple linear regression analysis to predict sales or use per customer (dependent variable), using multiple variables that represent weather conditions, specifically HDDs (independent variables).

Multiple linear regression yields an equation of the form:

$$Y = B + A_1X_1 + A_2X_2 + ... + A_KX_K$$

Where:

Y = the dependent variable

$X_1...X_K$ = the independent variables

B = the y-intercept (or constant)

$A_1...A_K$ = the regression coefficients

The dependent variable "Y" is monthly use per customer. I calculated the dependent variable by dividing the class monthly volumes by monthly number of customers in each class, for each service area. The reason the dependent variable is the monthly use per customer, not the total monthly volumes, is because the per-customer basis reduces the effect of growth or decline in volumes due to changes in number of customers. Independent variables "$X_1...X_K$" are weather variables such as HDDs. The intercept "B" is a monthly constant derived from the regression analysis and represents use per customer that is not affected by the independent variables. This non-weather sensitive use is generally referred to as "base use". The coefficients "$A_1...A_K$" are developed from the regression analysis based on a least squares the best fit.

Several statistics can be calculated with a regression analysis to assist in the evaluation of an analysis' significance (the degree to which the independent variables in an analysis explain the dependent variable). In my analysis, I focus on the coefficient of determination (R-squared) and the F-statistic to evaluate of the significance of alternative regression analysis results.

Q. WHAT DATA DO YOU USE IN PERFORMING THE MULTIPLE LINEAR REGRESSION ANALYSIS DESCRIBED ABOVE?

A. My analysis is based on regressing Test Year actual monthly use per customer versus Test Year actual monthly HDDs. This regression analysis provides coefficients that I use to determine use per customer per HDD that I will apply to normal weather.

Q. PLEASE EXPLAIN THE VARIABLES YOU USED FOR YOUR REGRESSION ANALYSIS.

A. The correlation between HDDs and sales to space heating customers is quite high. HDDs are typically used as a basis to predict a customer's natural gas space heating requirement. The results of my analyses in this case confirm this fact.

I include the current and previous month's HDDs as independent variables in my regression analyses to account for cycle billing. Monthly sales are based on the reading from a customer's meter, which is used to compute the customer's actual usage over the period since the prior meter reading. Meter reads are performed on a regular billing cycle that does not necessarily correspond to a calendar month. Therefore, most of customers' bills are for a 30-day period that spans over portions of two calendar months. For this reason, HDDs for the previous month are also included as an independent variable.

Q. WHAT SALES AND CUSTOMER DATA DID YOU USE?

A. I used monthly sales and the numbers of customers for each rate schedule and service area for the period 2016 through June 2021. My goal is to use a sufficiently long period of time such that the average HDDs over that period are approximately equal to normal.

Q. PLEASE DESCRIBE YOUR REGRESSION RESULTS.

A. To identify anomalies in usage patterns over the period for which I have sales data, I performed regression analyses in decreasing blocks of time (full data, 5-years, 4-years, 3-years, etc.) for each customer class. Exhibit RJA-05 summarizes the results of each of the regression analyses. I evaluated the results of each of these time periods using five criteria to determine which period should be used to calculate my proposed adjustment. These five criteria are:

1. Consistency of predicted normal use per customer.

2. Proximity of average actual annual HDDs for the period compared to normal HDDs.

3. R-squared – values in the high 90th percentile range are common for residential and small commercial customer classes.

4. F-statistic – higher values equate to a higher level of significance.

5. Obvious changes in the database as reflected in coefficients and statistics.

Based on these criteria, I used the five-year period July 2016 through June 2021 shown in column c of Exhibit RJA-05 to compute my weather normalization adjustment.

Q. WHY DID YOU USE THE FIVE-YEAR TIME PERIOD?

A. As discussed earlier, I wanted to balance using a long enough period to capture normal conditions with using a shorter period to capture current usage characteristics. The average actual HDDs during the five-year period of July 2016 through June 2021 for the two weather stations were very close to the 10-year normal HDDs. For the CFY weather station there was a 0.0 percent difference, and the KV weather station averaged 0.04 percent warmer than normal. This meets my desire to use a period where the weather conditions were nearly normal. Additionally, the five-year regression analyses have generally better statistics than the time periods shorter than five years. I believe that the five-year analyses represent the best balance and are the most appropriate for determining the weather normalization adjustment.

Q. HOW DID YOU DETERMINE THE WEATHER NORMALIZED THERM ADJUSTMENT?

A. I multiply the base load per customer and heating coefficients per HDD by class from the 5-year regression analysis by the actual monthly customers and normal HDDs, respectively, to calculate test year normal therms. This calculation is summarized in Exhibit RJA-06. The monthly weather normalized therm adjustment resulted from the difference between the calculated normal and test year actual monthly therms for each rate class in each service area. In some months, actual weather was warmer than normal while in other months the weather was colder than normal. In total, the weather for the test year ended June 30, 2021, was warmer than normal, resulting in a positive net weather adjustment to throughput of approximately 700,000 therms. Special Contract customers were not weather normalized.

Q. PLEASE SUMMARIZE YOUR RECOMMENDED WEATHER NORMALIZATION ADJUSTMENT.

A. My recommended weather normalization adjustment is summarized in Exhibit RJA-07. I recommend an increase to test year throughput of 172,380 therms for the Residential class, 320,380 therms for the Small Commercial class, and 209,142 therms for the Large Commercial class as shown in column (q) of Exhibit RJA-07, labeled "WN Therm Adjustment." This adjustment reflects that weather conditions in Summit's service territory were warmer than normal during the Test Year.

Q. PLEASE DESCRIBE THE NET REVENUE ADJUSTMENT FOR EACH CUSTOMER CLASS RESULTING FROM YOUR WEATHER NORMALIZATION PROCESS.

A. The weather adjustment therms were multiplied by the current distribution charge in each rate schedule to derive the weather normalized revenue impact for each class. As shown in column (r) of Exhibit RJA-07, labeled "WN Revenue Adjustment," the weather normalization revenue adjustment is $169,795 for the Residential class, $278,410 for the Small Commercial class, and $133,642 for the Large Commercial class.

VI. PRO FORMA BILLING DETERMINANTS

Q. PLEASE DESCRIBE THE DEVELOPMENT OF THE PROFORMA BILLING DETERMINANTS AND REVENUES AT CURRENT RATES.

A. First, an annualization adjustment was made to reflect a change in the rates made June 1, 2021. This adjustment is shown in column s of Exhibit RJA-07. This adjustment is calculated as the difference between the current rates in column c and the rates in effect prior to June 1, 2021, in column (b) times the full rate billing determinants in columns (e) and (h).

Second, a revenue adjustment was made to impute the full tariff rate onto the Small Commercial and Large Commercial customers who have special rate agreements. This adjustment is shown in column (t) of Exhibit RJA-07. The imputed revenue is calculated as the current rates in column (c) times the special rate billing determinants in columns (f) and (i) less the per books special rate revenue in column (m). Company Witness Mr. Porter addresses these special rate agreements.

Lastly, a Customer Annualization Adjustment, as shown in Exhibit RJA-07, was performed using the test year-end number of customers by class to determine the Year-End Customer Adjustment in column (u), and Annualization Therm Adjustment in column (w), by class. The respective numerical adjustments were priced at the corresponding current customer charges and volumetric block rates to determine the Customer Revenue Adjustment in column (v), and the Therm Revenue Adjustment in column (x).

The Annualization Revenue Adjustment by class in column (y) is the sum these adjustments.

Q. HAVE THE PRO FORMA BILLING DETERMINANTS BEEN REFLECTED THE REVENUE REQUIREMENT?

A. Yes. The preceding weather normalization and annualization adjustments are the basis for the pro forma billing determinants and revenues used to develop the Company's revenue requirement.

VII. REVENUE REQUIREMENT

Q. WHAT IS MEANT BY THE TERM "REVENUE REQUIREMENT"?

A. A utility's revenue requirement is the sum of its operations and maintenance ("O&M") expenses, depreciation and amortization expenses, income, and other taxes, and typically includes a fair and reasonable return on a utility's rate base. A utility's revenue requirement is based on the revenues and expenses experienced during a test year. When the revenue requirement exceeds a utility's test year revenues, a revenue deficiency exists, and a rate increase is usually required.

Q. WHAT IS THE PURPOSE OF YOUR TESTIMONY RELATED TO REVENUE REQUIREMENT IN THIS PROCEEDING?

A. My revenue requirement testimony presents the results of Summit's natural gas operations for the period beginning July 1, 2020 and ending June 30, 2021 (the "Test Year"), adjusted on a pro forma basis for the normalization and annualization of certain amounts included during this period. As noted above, the revenue requirement determines the level of revenues required to pay operating expenses, to provide for depreciation and taxes, and to permit an opportunity to earn a fair and reasonable return on its investment. Retail gas revenues at current rates do not and will not produce a level of net operating income sufficient to provide a fair return on the net original cost of Summit's property, plant, and equipment. This data is then used as the starting point for the Company's class cost of service study, which I discuss later in my testimony.

Q. **PLEASE SUMMARIZE YOUR CONCLUSION WITH RESPECT TO THE COMPANY'S REVENUE REQUIREMENT**.

A. Based on the proforma adjustments to the Company's Test Year results of operations, I conclude that Summit experienced a revenue deficiency of $40.1 million over adjusted (i.e., weather normalized) Test Year revenues. This revenue deficiency is based on a weighted average return on rate base of 8.15 percent, including a cost of equity component of 11.10 percent.

Q. DOES SUMMIT SEEK AN ORDER FROM THE COMMISSION IN THIS PROCEEDING AUTHORIZING THE COMPANY TO INCREASE ITS DISTRIBUTION RATES TO FULLY RECOVER THIS REVENUE DEFICIENCY?

A. No. As stated in the Direct Testimony of Mr. Tyson Porter, the Company is not proposing to increase distribution rates to recover its full revenue deficiency. As Mr. Porter explains, the Company is instead proposing a new multi-year rate plan designed in the first year to increase current rate schedule revenue by 30 percent, which produces additional revenue of $2.8 million in the first year of the rate plan. The revenue requirement I developed is being submitted in support of the Company's proposed rate plan, notwithstanding that the rate plan is intended to recover far less than the Company's revenue deficiency.

Q. IS THE INFORMATION CONTAINED IN YOUR REVENUE REQUIREMENT EXHIBITS OBTAINED OR DERIVED FROM THE BOOKS AND RECORDS OF THE COMPANY?

A. Yes, the information included in the revenue requirement exhibits was obtained from the books and records of the Company. The Company's trial balance as of June 30, 2021 was used as the basis for the analysis.

Q. PLEASE SUMMARIZE EXHIBIT RJA-08 THROUGH EXHIBIT RJA-11 SUPPORTING THE RATE BASE CALCULATIONS.

A. Exhibit RJA-08 through Exhibit RJA-11 present Summit's calculation of rate base. The rate base amounts for gross plant and accumulated depreciation are based on Test Year amounts as of June 30, 2021. Other rate base items shown in Exhibit RJA-10 were calculated using a thirteen-month average ended June 30, 2021, for materials and supplies, inventory overhead, prepaid expenses, customer deposits, deferred taxes and the regulatory asset associated with excess deferred income taxes that resulted from the Tax Cuts Job Act of 2017 ("TCJA"). As summarized in Exhibit RJA-11 the Company's rate base through June 30, 2021, is $351,367,268.

Q. PLEASE EXPLAIN WHY THE COMPANY HAS A NET DEFERRED TAX ASSET AS A COMPONENT OF RATE BASE?

A. Over the course of the last decade, the Company has generated significant net operating losses that are carried on the balance sheet in the form of deferred tax assets. For the Test Year, the deferred tax assets exceeded the accumulated deferred income tax liability by $15,447,838 on a 13-month average basis (see Exhibit RJA-10.1, p. 5 of 6). As such, this amount was included as a component of Other Rate Base in Exhibit RJA-10.

Q. HAS THE COMPANY INCLUDED ANY CONSTRUCTION WORK IN PROGRESS IN THE DETERMINATION OF RATE BASE?

A. No.

Q. **PLEASE SUMMARIZE EXHIBIT RJA-12 THROUGH EXHIBIT RJA-15 SUPPORTING THE REVENUE AND EXPENSE CALCULATIONS FOR THE TEST YEAR.**

A. Exhibits RJA-12 through Exhibit RJA-15 present the Company's Test Year revenues and expenses as adjusted for normal weather and other pro forma adjustments.

Q. HOW DID YOU CALCULATE PRO FORMA OPERATING REVENUE?

A. Exhibit RJA-12 summarizes test year revenue, the pro forma adjustments, and the pro forma revenue of $14,563,363. The pro forma revenues were calculated by multiplying the current rates times pro forma billing determinants (previously discussed in Section VI) for each customer class as shown in Exhibit RJA-12.1.

Q. PLEASE DESCRIBE EXHIBIT RJA-13.

A. Exhibit RJA-13 shows the Operations and Maintenance expenses ("O&M") for the Test Year period ended June 30, 2021, with pro forma adjustments. Exhibit RJA-13.1 shows the O&M detail by FERC account.

Q. WHAT PRO FORMA ADJUSTMENTS WERE MADE TO THE TEST YEAR O&M?

A. The first adjustment was to reallocate FERC Account 922 – "Administrative Expenses Transferred" to the FERC 900 series expense accounts. FERC Account 922 contains contra allocation amounts for Summit's General & Administrative costs ("G&A"). FERC Account 922 is credited with G&A costs that are originally coded to FERC 900 series accounts. The G&A costs are then transferred to burden Summit's capital and expense workorders; however, the original charges remain in the FERC 900 series accounts for tracking purposes. FERC Account 922 is used to credit the transferred amounts. While this adjustment does not change the total O&M expense, it was done so that the expenses could be properly placed in the allocated cost of service study. Additional detail related to this adjustment is provided in Exhibit RJA-13.1

The second adjustment removes civil and political expenses from the Test Year O&M.

The Company's pro forma O&M expense included in the revenue requirement calculation is $8,057,791.

Q. PLEASE DESCRIBE EXHIBIT RJA-14.

A. Exhibit RJA-14 calculates the Company's pro forma depreciation and amortization expense as of June 30, 2021. As discussed in Mr. Porter's Direct Testimony, the Company has extended the depreciation periods for certain capitalized assets, which had the effect of lowering depreciation rates and depreciation expense. Exhibit RJA-14.1 shows the calculation of depreciation expense by multiplying the updated depreciation rates by the pro forma gross plant balances from Exhibit RJA-08.1. The reduction in depreciation expense from the Test Year is shown in Exhibit RJA-14 ($1,220,365). There has been no adjustment to the Test Year amortization expense. The pro forma depreciation and amortization expenses the Company has included in its revenue requirement calculations is $7,777,746.

Q. HAS SUMMIT INCLUDED ANY RATE CASE EXPENSES IN ITS REVENUE REQUIREMENT CALCULATIONS?

A. No. The Company budgeted approximately $550,000 for rate cases expenses for this proceeding but is not seeking recovery at this time given that it is not seeking to recover its full cost of service.

Q. PLEASE DESCRIBE HOW PROPERTY TAXES WERE CALCULATED.

A. The Company started with the Test Year booked amount for property taxes through June 30, 2021 and adjusted the balance to tie to the actual 2021 property tax bills, which are detailed in Exhibit RJA-15.1. The property tax amount as shown in Exhibit RJA-15 is $2,594,832.

Q. PLEASE DESCRIBE EXHIBIT RJA-16.

A. Exhibit RJA-16 presents the weighted average cost of capital ("WACC") used in the calculation of the revenue requirement. As discussed in detail in the Direct Testimony of Mr. Dylan D'Ascendis, the Company's WACC is 8.15 percent.

Q. PLEASE DESCRIBE EXHIBIT RJA-17.

A. Exhibit RJA-17 is the Revenue Sufficiency Study that solves for the revenue deficiency based on Test Year determinants updated with pro forma adjustments through June 30, 2021, at both the full rate of return in column (d), and at the 30 percent rate schedule revenue increase requested in the first year of the rate plan in column (f). The revenue deficiency at the first year of the rate plan ($2,846,969) is used in my allocated cost of service study.

Q. HOW WERE INCOME TAXES CALCULATED?

A. Income taxes were calculated using a composite rate for state and federal income taxes of 28.05 percent. As shown in Exhibit RJA 17.1, Line No. 15, the composite rate was applied to net income before tax for the full revenue requirement and the first year of the rate plan scenarios.

Q. PLEASE SUMMARIZE THE REVENUE DEFICIENCY.

A As shown in Exhibit RJA-17, the calculated Test Year revenue deficiency is $40.1 million. As noted above, and as discussed in greater detail in Mr. Porter's testimony, Summit is not seeking to recover the full amount of its revenue deficiency in this proceeding. Rather, the Company is requesting Commission approval of a multi-year rate plan designed to ease customers into contributing toward a greater share of Summit's cost of providing service during the term of the plan. For the first year of the rate plan, Summit seeks to adjust its rates to produce additional annual revenue of $2,846,969, which results in total annual revenue of $17,410,333 as shown in Exhibit RJA-17.1 Column (i), Line No. 6. I use this total value as the basis of the class cost of service analysis discussed in Section IX of my testimony.

VIII. PURPOSE AND PRINCIPLES OF COST ALLOCATION

Q. WHY DO UTILITIES CONDUCT COST ALLOCATION STUDIES AS PART OF THE REGULATORY PROCESS?

A. There are many purposes for utilities conducting cost allocation studies, ranging from designing appropriate price signals in rates to determining the share of costs or revenue requirements borne by the utility's various rate or customer classes. In this case, an embedded Allocated Cost of Service Study ("ACOSS") is a useful tool for determining the allocation of Summit's revenue requirement among its customer classes. It is also a useful tool for rate design because it can identify the important cost drivers associated with serving customers and satisfying their design day demands.

Q. WHAT IS THE PURPOSE OF AN ACOSS?

A. The purpose of an ACOSS is to determine what costs are incurred to serve the various classes of customers of the utility. When these costs are all tabulated, the rate of return that is provided by each class of service of the utility can be determined. This resulting rate of return will be impacted by the cost allocation resulting from the methodology employed. The ACOSS is a tool that the analyst uses to assist in determining revenue responsibility by rate class and rate design. The results of the ACOSS will provide the analyst with the data necessary to design cost-based rates.

Q. WHAT IS THE GUIDING PRINCIPLE THAT SHOULD BE FOLLOWED WHEN PERFORMING AN ACOSS?

A. *Cost causation* is the fundamental principle applicable to all cost studies for purposes of allocating costs to customer groups. Cost causation addresses the question: which customer or group of customers causes the utility to incur particular types of costs? In order to answer this question, it is necessary to establish a relationship between a utility's customers and the particular costs incurred by the utility in serving those customers.

Q. WHAT IS THE GENERAL FRAMEWORK OF AN ACOSS

A. As I indicated above, the ACOSS analysis is intended to establish cost responsibility among the various customer classes the utility serves. The analysis should result in an appropriate allocation of the utility's total revenue requirement among the various customer classes. The most important theoretical principle underlying an ACOSS is that cost incurrence should follow cost causation. In other words, the costs that customers become responsible to pay should be those costs that the particular customers caused the utility to incur because of the characteristics of the customers' usage of utility service.

Q. PLEASE DESCRIBE THE PROCESS OF PERFORMING AN ACOSS ANALYSIS?

A. In order to establish the cost responsibility of each customer class, initially a three-step analysis of the utility's total operating costs must be undertaken: (1) functionalization; (2) classification; and (3) allocation.

The first step, cost functionalization, identifies and separates plant and expenses into specific categories based on the various characteristics of utility operation. Summit's primary functional cost categories associated with gas service include transmission, distribution, onsite, and customer accounts and services. Indirect costs that support these functions, such as intangible plant, general plant, and administrative and general expenses, are allocated to functions using allocation factors related to plant and/or labor ratios, i.e., internal allocation factors.

Classification of costs, the second step, further separates the functionalized plant and expenses into the three cost defining characteristics previously discussed: (1) customer, (2) demand or capacity, and (3) commodity. The final step is the allocation of each functionalized and classified cost element to the individual customer class. Costs typically are allocated on customer, demand, commodity, or revenue allocation factors.

From a cost of service perspective, the best approach is a direct assignment of costs where costs are incurred by a customer or class of customers and can be so identified. Where costs cannot be directly assigned, the development of allocation factors by rate class uses principles of both economics and engineering. This results in appropriate allocation factors for different elements of costs based on cost causation. For example, we know from the way customers are billed that each customer requires a meter. Meters differ in size and type depending on the customer's load characteristics and have different costs based on size and type. Therefore, differences in the cost of meters are reflected by using a different average meter cost for each class of service.

Q. ARE THERE FACTORS THAT CAN INFLUENCE THE OVERALL COST ALLOCATION FRAMEWORK UTILIZED BY A GAS UTILITY WHEN PERFORMING AN ACOSS?

A. Yes. The factors which can influence the cost allocation used to perform an ACOSS include: (1) the physical configuration of the utility's gas system; (2) the availability of data within the utility; and (3) the state regulatory policies and requirements applicable to the utility.

Q. WHY ARE THESE CONSIDERATIONS RELEVANT TO CONDUCTING SUMMIT'S ACOSS?

A. It is important to understand these considerations because they influence the overall context within which a utility's cost study was conducted. In particular, they provide an indication of where efforts should be focused for purposes of conducting a more detailed analysis of the utility's gas system design and operations and understanding the regulatory environment in the state the utility operates in as it pertains to cost of service studies and gas ratemaking issues.

Q. PLEASE EXPLAIN WHY THE PHYSICAL CONFIGURATION OF THE SYSTEM IS AN IMPORTANT CONSIDERATION.

A. The particulars of the physical configuration of the transmission and distribution system are important. The specific characteristics of the system configuration, such as whether the distribution system is a centralized or a dispersed one, should be identified. Other such characteristics are whether the utility has a single city-gate or a multiple city-gate configuration, whether the utility has an integrated transmission and distribution system or a distribution only operation, and whether the system is a multiple pressure-based or a single pressure-based operation.

Q. WHAT ARE THE SPECIFIC PHYSICAL CHARACTERISTICS OF THE SUMMIT SYSTEM?

A. The physical configuration of the Summit system is a dispersed / multiple city-gate, integrated transmission / distribution and multiple-pressure based system.

Q. HOW DOES THE AVAILABILITY OF DATA INFLUENCE AN ACOSS?

A. The structure of the utility's books and records can influence the cost study framework. This structure relates to attributes such as the level of detail, segregation of data by operating unit or geographic region, and the types of load data available.

Q. HOW DO STATE REGULATORY POLICIES AFFECT A UTILITY'S ACOSS?

A. State regulatory policies and requirements prescribe whether there are any historical precedents used to establish utility rates in the state. Specifically, state regulations and past precedents set forth the methodological preferences or guidelines for performing cost studies or designing rates which can influence the proposed cost allocation method utilized by the utility.

Q. HOW IS THE CONCEPT OF COST CAUSATION, DISCUSSED EARLIER, APPLIED TO THE EVALUATION OF THE UTILITY'S TRANSMISSION AND DISTRIBUTION SYSTEM?

A. There are three basic components in gas utility operations which govern cost behavior. These are: (1) extending distribution services to all customers entitled to be attached to the system; (2) meeting the aggregate design day capacity requirements of all customers entitled to service on the peak day; and (3) delivering volumes of natural gas to all customers either on a sales or transportation basis. These operational components have been identified for purposes of the ACOSS as Customer Costs, Demand Costs and Commodity Costs, respectively.

Q. PLEASE PROVIDE ADDITIONAL DETAILS REGARDING THESE THREE COST CLASSIFICATION COMPONENTS OF GAS UTILITY COST OF SERVICE STUDY.

A. *Customer Costs* are incurred to extend service to and attach a customer to the distribution system, meter any gas usage and maintain the customer's account. Customer Costs are largely a function of the number and density of customers served and continue to be incurred whether or not the customer uses any gas. They may include capital costs associated with minimum size distribution mains, services, meters, regulators and customer billing and accounting expenses.

Demand Costs are capacity related costs associated with a plant that is designed, installed, and operated to meet maximum hourly or daily gas flow requirements, such as transmission and distribution mains or more localized distribution facilities which are designed to satisfy individual customer maximum demands. Capacity related costs are also a component of gas supply contracts which are incurred to meet the utility's requirements for serving daily peak demands and the winter peaking season.

Commodity Costs are those costs that vary with the throughput sold to, or transported for, customers. However, when as is the case with Summit, a gas utility's cost of gas is not recovered through its base rates, very little of its remaining delivery service cost structure is commodity related.

Q. HOW DOES ONE ESTABLISH THE COST AND UTILITY SERVICE RELATIONSHIPS YOU PREVIOUSLY DISCUSSED?

A. To establish these relationships, the Company must analyze its gas system design and operations, its accounting records as well as its system and customer load data (e.g., annual and peak period gas consumption levels). From the results of those analyses, methods of direct assignment and common cost allocation methodologies can be chosen for all of the utility's plant and expense elements.

Q. PLEASE EXPLAIN WHAT YOU MEAN BY THE TERM "DIRECT ASSIGNMENT."

A. The term direct assignment relates to a specific identification and isolation of plant and/or expense incurred exclusively to serve a specific customer or group of customers. Direct assignments best reflect the cost causation characteristics of serving individual customers or groups of customers. Therefore, in performing an ACOSS, the analyst seeks to maximize the amount of plant and expense directly assigned to a particular customer group to avoid the need to rely upon other more generalized allocation methods. An alternative to direct assignment is an allocation methodology supported by a special study as is done with costs associated with meters and services.

Q. WHAT PROMPTS THE ANALYST TO ELECT TO PERFORM A SPECIAL STUDY?

A. When direct assignment is not readily apparent from the description of the costs recorded in the various utility plant and expense accounts, then further analysis may be conducted to derive an appropriate basis for cost allocation. For example, in evaluating the costs charged to certain operating or administrative expense accounts, it is customary to assess the underlying activities, the related services provided, and for whose benefit the services were performed.

Q. HOW DO YOU DETERMINE WHETHER TO DIRECTLY ASSIGN COSTS TO A PARTICULAR CUSTOMER OR CUSTOMER CLASS?

A. Direct assignments of plant and expenses to specific customers or classes of customers are made on the basis of special studies wherever the necessary data are available. These assignments are developed by detailed analyses of the utility's maps and records, work order descriptions, property records, and customer accounting records. Within time and budgetary constraints, the greater the magnitude of cost responsibility based upon direct assignments, the less reliance need be placed on common plant allocation methodologies associated with joint use plant.

Q. IS IT REALISTIC TO ASSUME THAT A LARGE PORTION OF THE PLANT AND EXPENSES OF A UTILITY CAN BE DIRECTLY ASSIGNED?

A. No. The nature of utility operations is characterized by the existence of common or joint use facilities, as mentioned earlier. Out of necessity, then, to the extent a utility's plant and expense cannot be directly assigned to customer groups, common allocation methods must be derived to assign or allocate the remaining costs to the rate classes. The analyses discussed above facilitate the derivation of reasonable allocation factors for cost allocation purposes.

IX. <u>SUMMIT'S ALLOCATED COST OF SERVICE STUDY</u>

Q. WHAT WAS THE SOURCE OF THE COST DATA ANALYZED IN ACOSS?

A. All cost of service data was extracted from the Company's total cost of service (i.e., total revenue requirement) and Exhibits contained in this filing. Where more detailed information was required to perform various analyses related to certain plant and expense elements, the data were derived from the historical books and records of the Company and information provided by Company personnel.

Q. HOW ARE THE SUMMIT RATE CLASSES STRUCTURED FOR PURPOSES OF CONDUCTING ITS ACOSS?

A. For Summit's ACOSS, three rate classes were included:

- Residential Gas Service (Schedule RG)
- Small Commercial Gas Service (Schedule SC)
- Large Commercial Gas Service (Schedule LC)

Q. HOW WERE THE COMPANY'S EIGHT SPECIAL CONTRACT TRANSPORTATION CUSTOMERS REPRESENTED IN THE ACOSS?

A. The Test Year revenues provided by the Special Contract Transportation Customers were allocated to the three customer classes on the basis of their respective class revenue requirement before the revenue credit is applied.

Q. HOW DID THE ACOSS CLASSIFY AND ALLOCATE INVESTMENT IN TRANSMISSION MAINS?

A. Summit books all system mains in the FERC Account 376 – Distribution Mains; however, the vast majority of Summit's steel main is designated as transmission main in the U.S. Department of Transportation Pipeline and Hazardous Materials Safety Administration ("PHMSA") annual report submissions (99.3 percent by milage). Therefore, for the purposes of the ACOSS, I have functionalized steel mains to the Transmission function and plastic mains to the Distribution function. Transmission mains are classified as demand-related and allocated to the rate classes based on class contribution to system design day peak.

Q. HOW DID THE ACOSS CLASSIFY AND ALLOCATE INVESTMENT IN DISTRIBUTION MAINS?

A. The ACOSS classified 44.7 percent of the investment in distribution mains as customer related and 55.3 percent of the investment as demand related. This customer-demand split, shown in Exhibit RJA-18, is discussed later in my testimony and. The customer related portion of the distribution mains investment was then allocated based on the number of customers on Summit's system. The demand related investment was allocated to the customer classes based on their respective contribution to peak day demand under system design weather conditions, in other words, on a "design day" basis.

Q. PLEASE EXPLAIN THE BASIS FOR THE CHOICE OF CLASSIFICATION AND ALLOCATION METHODS.

A. It is widely accepted that distribution mains are installed to meet both system peak period load requirements and to connect customers to the utility's gas system. Therefore, to ensure that the rate classes that cause the Company to incur this plant investment or expense are charged with its cost, distribution mains should be allocated to the rate classes in proportion to their peak period load requirements and number of customers.

There are two cost factors that influence the level of distribution mains facilities installed by a utility in expanding its gas distribution system. First, the size of the distribution main (i.e., the diameter of the main) is directly influenced by the sum of the peak period gas demands placed on the gas distribution system by its customers. Secondly, the total installed footage of distribution mains is influenced by the need to expand the distribution system to connect new customers to the system. Therefore, to recognize that these two cost factors influence the level of investment in distribution mains, it is appropriate to allocate such investment based on both peak period demands and the number of customers served by the utility.

Q. IS THIS METHOD USED TO DETERMINE A CUSTOMER COST COMPONENT OF DISTRIBUTION MAINS A GENERALLY ACCEPTED TECHNIQUE FOR DETERMINING CUSTOMER COSTS?

A. Yes. The two most commonly used methods for determining the customer cost component of distribution mains facilities consist of the following: (1) the zero-intercept approach and 2) the most commonly installed, minimum-sized unit of plant investment. Under the zero-intercept approach, a customer cost component is developed through regression analyses to determine the unit cost associated with a zero-inch diameter distribution main. The method regresses unit costs associated with the various sized distribution mains installed on the LDC's gas system against the size (diameter) of the various distribution mains installed. The zero-intercept method seeks to identify that portion of plant representing the smallest size pipe required merely to connect any customer to the LDC's distribution system, regardless of the customer’s peak or annual gas consumption.

The most commonly installed, minimum-sized unit approach is intended to reflect the engineering considerations associated with installing distribution mains to serve gas customers. That is, the method utilizes actual installed investment units to determine the minimum distribution system rather than a statistical analysis based upon investment characteristics of the entire distribution system. For purposes of determining the customer component of distribution mains to be used in Summit's ACOSS, the minimum system method was employed.

Two of the more commonly accepted literary references relied upon when preparing embedded cost of service studies, Electric Utility Cost Allocation Manual, by John J. Doran et al, National Association of Regulatory Utility Commissioners ("NARUC"), and Gas Rate Fundamentals, American Gas Association, both describe minimum system concepts and methods as an appropriate technique for determining the customer component of utility distribution facilities.

Clearly, the existence and utilization of a customer component of distribution facilities, specifically for distribution mains, is a fully supportable and commonly used approach in the gas industry.

Q. WITH RESPECT TO SUMMIT'S SPECIFIC OPERATING EXPERIENCE, IS THERE DEMONSTRABLE EVIDENCE TO SUPPORT THE USE OF A CUSTOMER COMPONENT OF DISTRIBUTION MAINS?

A. Yes. The most commonly installed, minimum-sized distribution mains analysis focused on 2-inch diameter plastic pipe. The dominant pipe size for new distribution main installations by far is 2-inch plastic, with over 654,000 feet installed of the total 1.15 million feet of distribution main. The 2-inch plastic pipe analysis, adjusted downward to account for its load carrying capacity, yielded a minimum system result of 44.7 percent. The results are provided in Exhibit RJA-18 – Customer Component of Mains Analysis.

Q. WOULD ONE EXPECT THERE TO BE A STRONG CORRELATION BETWEEN THE NUMBER OF CUSTOMERS SERVED BY SUMMIT AND THE LENGTH OF ITS SYSTEM OF DISTRIBUTION MAINS?

A. Yes. Development of the Company's distribution grid over time is a dynamic process. Customers are added to the distribution system on a continuous basis under a variety of installation conditions. Accordingly, this process cannot be viewed as a static situation where a particular customer being added to the system at any one point in time can serve as a representative example for all customers. Rather, it is more appropriate to understand and appreciate that for every situation where a customer can be added with little or no additional footage of mains installed, there are contrasting situations where a customer can be added only by extending the distribution mains to the customer's "off-system" location.

Recognizing that the goal is to more reasonably classify and allocate the total cost of Summit's distribution mains facilities, it is appropriate to analyze the cost causation factors that relate to these facilities based on the total number of customers serviced from such facilities. Accordingly, the concept of using a minimum system approach for classifying distribution mains simply reflects the fact that the average customer serviced by the Company requires a minimum amount of mains investment to receive such service. Thus, it is entirely appropriate to conclude that the number of customers served by Summit represents a primary causal factor in determining the amount of distribution mains cost that should be assessed to any particular group of customers. One can readily conclude that a customer component of distribution mains is a distinct and separate cost category that has much support from an engineering and operating standpoint.

Q. HOW DID THE ACOSS ALLOCATE O&M EXPENSES?

A. In general, these expenses are allocated based on the cost allocation methods used for the Company's corresponding plant accounts. A utility's O&M expenses generally are thought to support the utility's corresponding plant in service accounts. Put differently, the existence of plant facilities necessitates the incurrence of cost, i.e., expenses by the utility to operate and maintain those facilities. As a result, the allocation basis used to allocate a particular plant account will be the same basis as used to allocate the corresponding expense account. For example, Account No. 887, Maintenance of Mains, is allocated on the same basis as its corresponding plant account, Mains – Account No. 376. With the detailed analyses supporting the assignment or allocation of major plant in service components; where feasible, it was deemed appropriate to rely upon those results in allocating related expenses in view of the overall conceptual acceptability of such an approach.

Q. PLEASE DESCRIBE THE CLASSIFICATION AND ALLOCATION OF CUSTOMER ACCOUNTS AND CUSTOMER SERVICE EXPENSES IN THE ACOSS.

A. Customer accounts and services expenses were classified as customer-related costs and allocated based on the average number of distribution customers by class.

Q. HOW WERE ADMINISTRATIVE AND GENERAL ("A&G") EXPENSES AND TAXES ALLOCATED TO EACH RATE CLASS?

A. A&G expenses were allocated on an account-by-account basis. Items related to labor costs, such as employee pensions and benefits, were allocated based on O&M labor costs. Items related to plant, such as maintenance of general plant and property taxes, were allocated based on plant. Regulatory Commission expense was allocated on rate base.

Q. PLEASE DESCRIBE THE METHOD USED TO ALLOCATE THE RESERVE FOR DEPRECIATION AS WELL AS DEPRECIATION EXPENSES.

A. These items were allocated by function in proportion to their associated plant accounts. For example, the depreciation reserve on depreciation expense associated with Account 376 – Mains was allocated on the same basis as the plant Account 376 – Mains.

Q. HOW WERE INCOME TAXES ALLOCATED TO EACH RATE CLASS?

A. Current income taxes were allocated based on each class's allocation of rate base. Income taxes for the total revenue requirement were allocated to each class based on the allocation of rate base to each class. Income taxes at proposed revenues by class were allocated to each class based on the proposed margin revenue for each class.

X. SUMMARY OF THE ALLOCATED COST OF SERVICE STUDY

Q. PLEASE DESCRIBE THE RESULTS OF YOUR ACOSS WITH RESPECT TO RATE OF RETURN UNDER THE COMPANY'S RATE CLASSES.

A. Exhibit RJA-19, Page 1, presents the summary results of the ACOSS at present rates under the Company's rate classes. As shown on Line 18 of this exhibit, at present rates the ACOSS shows the variation in the rates of return by rate schedule. The system total rate of return at current rates is -0.06 percent. The Residential (Schedule RG) service class rate of return is -1.28 percent, the Small Commercial (Schedule SC) service class rate of return is 0.90 percent, and the Large Commercial (Schedule LC) service class rate of return is 1.36 percent.

Q. WHAT CONCLUSIONS DO YOU DRAW FROM THESE RATE OF RETURN RESULTS?

A. The Company is not earning a positive rate of return on its investment. I also conclude that the customer classes' individual rates of return are within a narrow band, from -1.28

percent to 1.36 percent. This result informs the revenue apportionment and rate design discussed in the following sections of my testimony.

Q. PLEASE DESCRIBE THE RESULTS OF YOUR ACOSS WITH RESPECT TO CLASSIFIED COSTS.

A. The ACOSS summarized the costs allocated to the rate schedules on a classified basis, i.e., by demand, customer, and commodity basis. Of particular interest, are the customer and demand related costs. Exhibit RJA-19, Page 4, provides a summary of the functionalized and classified costs by rate class at equalized rates of return after the revenue credit. Page 5 shows the costs on a unit rate basis. As discussed in more detail later in my testimony, these results were used as a guide in developing the monthly customer and demand charges proposed for the various rate schedules.

Q. PLEASE DISCUSS THE SIGNIFICANCE OF THE UNIT CLASSIFIED COST RESULTS FROM THE SUMMIT ACOSS.

A. The unit cost section of Exhibit RJA-19, Page 5, shows the disparities between the classified unit costs and the corresponding rate components of each respective rate class's rate schedule. For example, the total unit customer cost per month for the Residential class is $133.98. By comparison, the current monthly Residential Service and Facilities charge is $21.91. The total unit customer related cost for the Residential class is sub-divided into the following components:

- Distribution $33.55
- Onsite (Service and Meter costs) $18.28
- Customer Accounts and Services $82.15

The Onsite costs most closely correspond to the actual number of customers currently receiving service on Summit's distribution system and are completely recovered by the current Service and Facilities charge. However, the Distribution costs reflect the minimum system component of distribution mains that represents the customer related construction and expenses of extending the distribution pipeline system throughout Summit's service territory. The capital investment costs to extend the distribution system are lumpy, in the sense that pipelines can't be economically constructed one customer at a time. As Summit's customer base grows within the service territory (i.e., customer density increases), this component of fixed distribution costs will more closely reflect the unit customer-related distribution cost. Similarly, the Customer Accounts and Services costs comprise the fixed costs of infrastructure, technology, and labor costs of providing customer service and administrative functions. This subcategory of customer related costs will better reflect the economies of scale inherent in the provision of customer service and administrative functions as the customer base grows. Therefore, as the unit customer related costs decline with the growth of customers on the Summit distribution system, and the Service and Facilities charges gradually increase, the remaining cost and revenue disparities will be reduced.

XI. PRINCIPLES OF SOUND RATE DESIGN

Q. PLEASE IDENTIFY THE PRINCIPLES OF RATE DESIGN THAT PROVIDE GUIDANCE TO THE DEVELOPMENT OF SOUND RATE DESIGN PROPOSALS FOR SUMMIT.

A. Several rate design principles find broad acceptance in the recognized literature on utility ratemaking and regulatory policy. These principles include:

(1) Cost of Service,

(2) Efficiency,

(3) Value of Service,

(4) Stability/Gradualism,

(5) Non-Discrimination,

(6) Administrative Simplicity, and

(7) Balanced Budget.

These rate design principles draw heavily upon the "Attributes of a Sound Rate Structure" developed by James Bonbright in Principles of Public Utility Rates.[1]

Q. PLEASE DISCUSS THE PRINCIPLE OF EFFICIENCY.

A. The principle of efficiency broadly incorporates both economic and technical efficiency. As such, this principle has both a pricing dimension and an engineering dimension. Economically efficient pricing promotes good decision-making by gas producers and consumers, fosters efficient expansion of delivery capacity, results in efficient capital investment in customer facilities, and facilitates the efficient use of existing gas pipeline, storage, transmission, and distribution resources. The efficiency principle benefits stakeholders by creating outcomes for regulation consistent with the long-run benefits of competition while permitting the economies of scale consistent with the best cost of service. Technical efficiency means that the development of the gas utility system is

[1] Principles of Public Utility Rates, Second Edition, Page 111-113 James C. Bonbright, Albert L. Danielson, David R. Kamerschen, Public Utility Reports, Inc., 1988.

designed and constructed to meet the design day requirements of customers using the most economic equipment and technology consistent with design standards.

Q. PLEASE DISCUSS THE COST OF SERVICE AND VALUE OF SERVICE PRINCIPLES.

A. These principles each relate to designing rates that recover the utility's total revenue requirement without causing inefficient choices by consumers. The cost of service principle contrasts with the value of service principle when certain transactions do not occur at price levels determined by the embedded cost of service. In essence, the value of service acts as a ceiling on prices. Where prices are set at levels higher than the value of service, consumers will not purchase the service.

Q. PLEASE DISCUSS THE PRINCIPLE OF STABILITY.

A. The principle of stability typically applies to customer rates. This principle suggests that reasonably stable and predictable prices are important objectives of a proper rate design.

Q. PLEASE DISCUSS THE CONCEPT OF NON-DISCRIMINATION.

A. The concept of non-discrimination requires prices designed to promote fairness and avoid undue discrimination. Fairness requires no undue subsidization either between customers within the same class or across different classes of customers.

This principle recognizes that the ratemaking process requires discrimination where there are factors at work that cause the discrimination to be useful in accomplishing other objectives. For example, considerations such as the location, type of meter and service, demand characteristics, size, and a variety of other factors are often recognized in the design of utility rates to properly distribute the total cost of service to and within customer classes. This concept is also directly related to the concepts of vertical and horizontal equity. The principle of horizontal equity requires that "equals should be treated equally" and vertical equity requires that "unequals should be treated unequally." Specifically, these principles of equity require that where cost of service is equal – rates should be equal and, where costs are different – rates should be different.

Q. PLEASE DISCUSS THE PRINCIPLE OF ADMINISTRATIVE SIMPLICITY.

A. The principle of administrative simplicity as it relates to rate design requires that prices be reasonably simple to administer and understand. This concept includes price transparency within the constraints of the ratemaking process. Prices are transparent when customers are able to reasonably calculate and predict bill levels and interpret details about the charges resulting from the application of the tariff.

Q. PLEASE DISCUSS THE PRINCIPLE OF THE BALANCED BUDGET.

A. This principle permits the utility a reasonable opportunity to recover its allowed revenue requirement based on the cost of service. Proper design of utility rates is a necessary condition to enable an effective opportunity to recover the cost of providing service included in the revenue authorized by the regulatory authority. This principle is very similar to the stability objective that was previously discussed from the perspective of customer rates.

Q. CAN THE OBJECTIVES INHERENT IN THESE PRINCIPLES COMPETE WITH EACH OTHER AT TIMES?

A. Yes, like most principles that have broad application, these principles can compete with each other. This competition or tension requires further judgment to strike the right balance between the principles. Detailed evaluation of rate design alternatives and rate design recommendations must recognize the potential and actual competition between these principles. Indeed, Bonbright discusses this tension in detail. Rate design recommendations must deal effectively with such tension. As noted above, there are tensions between cost and value of service principles. There are potential conflicts between simplicity and non-discrimination and between value of service and non-discrimination. Other potential conflicts arise where utilities face unique circumstances that must be considered as part of the rate design process.

Q. HOW ARE THESE PRINCIPLES TRANSLATED INTO THE DESIGN OF RATES?

A. The overall rate design process, which includes both the apportionment of the revenues to be recovered among rate classes and the determination of rate structures within rate classes, consists of finding a reasonable balance between the above-described criteria or guidelines that relate to the design of utility rates. Economic, regulatory, historical, and social factors all enter the process. In other words, both quantitative and qualitative information is evaluated before reaching a final rate design determination. Out of necessity then, the rate design process must be, in part, influenced by judgmental evaluations.

Q. HAVE YOU RELIED UPON THESE PRINCIPALS IN MAKING YOUR REVENUE ALLOCATION AND RATE DESIGN PROPOSALS?

A. Yes. Due to the Company's current operating results, negative system rate of return, and very narrow differences between the class rates of return, these circumstances present unique circumstances. Therefore, the foregoing principles were given consideration and limited application in determining the proposed class revenue apportionment and increases to the respective rate components of the tariff service schedules.

XII. <u>DETERMINATION OF PROPOSED CLASS REVENUES</u>

Q. WHAT IS THE COMPANY'S PROPOSAL FOR THE APPORTIONMENT OF THE REQUESTED SYSTEM MARGIN REVENUE INCREASE TO THE RESPECTIVE RATE CLASSES?

A. Based on the results of the ACOSS and the narrow differences in the relative rates of return shown for the respective rate classes, the Company is proposing an apportionment of the system revenue increase to the three rate classes on an equal percentage of margin revenue basis. This will also provide a guide for future margin revenue increases under the Company's multi-year rate plan.

XIII. RATE DESIGN

Q. PLEASE SUMMARIZE THE PROPOSED RATE DESIGN CHANGES.

A. In consultation with Summit, Atrium is proposing changes to monthly service and facilities charges for the first year of the Company's proposed rate plan. We are recommending an increase to the Residential class (Schedule RG) from $21.91 to $28.48, to the Small Commercial class (Schedule SC) from $36.13 to $46.97 per month, and to the Large Commercial class (Schedule LC) class from $312.17 to $405.82 per month. These increases are the same percentage (30 percent) as the overall rate schedule margin revenue increase.

Q. HAVE YOU PROVIDED AN EXHIBIT DETAILING THE PROPOSED RATES AND CORRESPONDING REVENUES?

A. Yes. Exhibit RJA-20 – Proposed Rate Design, presents summaries by customer class of the proposed revenue increases. This Exhibit displays the revenues calculated under the present and proposed rates for each customer rate schedule for the first year of the rate plan. The proposed revenue increase by class and corresponding percentages are also shown.

XIV. CUSTOMER BILL IMPACTS

Q. WHAT ARE THE CORRESPONDING BILL COMPARISONS FOR SUMMIT'S CUSTOMERS SERVED UNDER ITS VARIOUS RATE SCHEDULES?

A. A presentation of the bill impacts, including gas costs, at various ranges of annual consumption levels is provided for all rate schedules in Exhibit RJA-21 – Customer Bill Impacts.

Q. HAVE YOU PREPARED ADDITIONAL BILL COMPARISONS FOR ITS RESIDENTIAL CUSTOMERS?

A. Yes. The monthly bill impacts for the average Residential customer using 839.72 therms per year are provided in Exhibit RJA-22 – Residential Customer Bill Impacts. The monthly bill impacts in Exhibit RJA-22 include the current cost of gas adjustment rate. Exhibit RJA-22 shows that the average Residential customer will experience a total bill increase of approximately $327 per year, or about $27 per month on average, during the first year of the rate plan.

XV. CONCLUSION

Q. DO YOU HAVE A CONCLUDING STATEMENTS?

A. My direct testimony presents the following:

1. I have presented an analysis of historical HDDs which resulted in a proposed 10-year normal weather period for the purpose of weather normalizing actual customer usage during the historical test year.
2. I have presented the adjustment to Test Year actual therms to account for the difference between the HDDs experienced during the Test Year and the 10-year normal HDDs. Additionally, I adjusted per book sales to Test Year-end customer counts and imputed

revenues for Small Commercial and Large Commercial customers on special rate agreements.

3. I have presented the results of the Company's revenue requirement, including pro forma adjustments. The Company's revenue requirement, including the proposed 8.15 percent return on rate base, exceeds the pro forma operating revenues at present rates by $40.1 million. However, the Company is only seeking a revenue increase of $2,846,969 for the first year of its multi-year rate plan.
4. I have presented the Company's allocated class cost of service study results and a corresponding class revenue increase allocation on an equal percent of margin basis.
5. Finally, I have presented the Company's recommended rate design for the first year of the multi-year rate plan, consisting of an equal percentage increase to the Service and Facilities charge and Delivery charge components of each rate schedule.

Q. DOES THIS CONCLUDE YOUR TESTIMONY?

A. Yes.

BEFORE THE

MAINE PUBLIC UTILITIES COMMISSION

DIRECT TESTIMONY

OF

DYLAN W. D'ASCENDIS, CRRA, CVA

ON BEHALF OF

SUMMIT NATURAL GAS OF MAINE, INC.

DOCKET NO. 2022-00025

March 31, 2022

TABLE OF CONTENTS

I. INTRODUCTION AND BACKGROUND

Q. PLEASE STATE YOUR NAME AND BUSINESS ADDRESS.

A. My name is Dylan W. D'Ascendis. My business address is 3000 Atrium Way, Suite 241, Mount Laurel, NJ 08054.

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

A. I am a Partner at ScottMadden, Inc.

Q. PLEASE SUMMARIZE YOUR PROFESSIONAL EXPERIENCE AND EDUCATIONAL BACKGROUND.

A. I have offered expert testimony on behalf of investor-owned utilities before over 30 state regulatory commissions in the United States, the Federal Energy Regulatory Commission, the Alberta Utility Commission, and one American Arbitration Association panel on issues including, but not limited to, common equity cost rate, rate of return, valuation, capital structure, class cost of service, and rate design.

On behalf of the American Gas Association ("AGA"), I calculate the AGA Gas Index, which serves as the benchmark against which the performance of the American Gas Index Fund ("AGIF") is measured on a monthly basis. The AGA Gas Index and AGIF are a market capitalization weighted index and mutual fund, respectively, comprised of the common stocks of the publicly traded corporate members of the AGA.

I am a member of the Society of Utility and Regulatory Financial Analysts ("SURFA"). In 2011, I was awarded the professional designation "Certified Rate of Return Analyst" by SURFA, which is based on education, experience, and the successful completion of a comprehensive written examination.

I am also a member of the National Association of Certified Valuation Analysts ("NACVA") and was awarded the professional designation "Certified Valuation Analyst" by the NACVA in 2015.

I am a graduate of the University of Pennsylvania, where I received a Bachelor of Arts degree in Economic History. I have also received a Master of Business Administration with high honors and concentrations in Finance and International Business from Rutgers University.

The details of my educational background and expert witness appearances are shown in Appendix A.

II. PURPOSE AND SUMMARY

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

A. The purpose of my testimony is to present evidence on behalf of Summit Natural Gas of Maine, Inc. ("Summit" or the "Company") about the appropriate capital structure and corresponding cost rates the Company should be given the opportunity to earn on its jurisdictional rate base.

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

A. Yes. I have prepared Schedules DWD-1 through DWD-8, which were prepared by me or under my direction.

Q. WHAT IS YOUR RECOMMENDED COST OF CAPITAL FOR SUMMIT?

A. I recommend the Maine Public Utilities Commission (the "Commission") authorize the Company the opportunity to earn a weighted average cost of capital ("WACC") of 8.15% based on a hypothetical capital structure. The ratemaking capital structure consists of 50.00% long-term debt at an embedded cost rate of 5.20% and 50.00% common equity at my recommended common equity cost rate of 11.10%. The overall rate of return is summarized on page 1 of Schedule DWD-1 and in Table 1 below:

Table 1: Summary of Overall Rate of Return

Type of Capital	Ratios	Cost Rate	Weighted Cost Rate
Long-Term Debt	50.00%	5.20%	2.60%
Common Equity	50.00%	11.10%	5.55%
Total	100.00%		8.15%

Q. PLEASE SUMMARIZE YOUR RECOMMENDED COMMON EQUITY COST RATE.

A. My recommended common equity cost rate of 11.10% is summarized on page 2 of Schedule DWD-1. I have assessed the market-based common equity cost rates of companies of relatively similar, but not necessarily identical, risk to Summit. Using companies of relatively comparable risk as proxies is consistent with the principles of fair rate of return established in the *Hope*[1] and *Bluefield*[2] decisions. No proxy group can be identical in risk to any single company. Consequently, there must be an evaluation of relative risk between the company and the proxy group to determine if it is appropriate to adjust the proxy group's indicated rate of return.

My recommendation results from applying several cost of common equity models, specifically the Discounted Cash Flow ("DCF") model, the Risk Premium Model ("RPM"), and the Capital Asset Pricing Model ("CAPM"), to the market data of a proxy group of six natural gas distribution utilities ("Utility Proxy Group") whose selection criteria will be discussed below. In addition, I applied the DCF model, RPM, and CAPM to a proxy group of 46 domestic, non-price regulated companies comparable in total risk

1 *Federal Power Comm'n v. Hope Natural Gas Co.*, 320 U.S. 591 (1944).
2 *Bluefield Water Works Improvement Co. v. Public Serv. Comm'n*, 262 U.S. 679 (1922).

to the Utility Proxy Group ("Non-Price Regulated Proxy Group"). The results derived from each are as follows:

Table 2: Summary of Common Equity Cost Rates

Discounted Cash Flow Model	10.08%
Risk Premium Model	10.95%
Capital Asset Pricing Model	12.32%
Cost of Equity Models Applied to Comparable Risk, Non-Price Regulated Companies	13.14%
Indicated Range	10.08% - 13.14%
Size Adjustment	1.00%
Recommended Range	11.08% - 14.14%
Recommended Cost of Common Equity	11.10%

The indicated range of common equity cost rates applicable to the Utility Proxy Group is between 10.08% and 13.14% before any Company-specific adjustments. My Company-specific indicated range of common equity cost rates, adjusted for Company size, is between 11.08% and 14.14%. From this range of results, I recommend the Commission find that a common equity cost rate of 11.10% is appropriate for the purpose of establishing a revenue requirement that would allow the Company an opportunity to earn a return on its jurisdictional rate base.

III. GENERAL PRINCIPLES

Q. WHAT GENERAL PRINCIPLES HAVE YOU CONSIDERED IN ARRIVING AT YOUR RECOMMENDED COMMON EQUITY COST RATE OF 11.10%?

A. In unregulated industries, marketplace competition is the principal determinant of the price of products or services. For regulated public utilities, regulation must act as a substitute for marketplace competition. Assuring that the utility can fulfill its obligations to the public, while providing safe and reliable service at all times, requires a level of earnings sufficient to maintain the integrity of presently invested capital. Sufficient earnings also permit the attraction of needed new capital at a reasonable cost, for which the utility must compete with other firms of comparable risk, consistent with the fair rate of return standards established by the U.S. Supreme Court in the previously cited *Hope* and *Bluefield* cases. However, in this case the Company is using the common equity cost rate of 11.10% to set the standard of what rates would be reasonable and are seeking less than what would be allowed under this construct, as discussed further in Mr. Tyson Porter's Direct Testimony.

The U.S. Supreme Court affirmed the fair rate of return standards in *Hope*, when it stated:

> The rate-making process under the Act, *i.e.,* the fixing of 'just and reasonable' rates, involves a balancing of the investor and the consumer interests. Thus we stated in the Natural Gas Pipeline Co. case that 'regulation does not insure that the business shall produce net revenues.' 315 U.S. at page 590, 62 S.Ct. at page 745. But such considerations aside, the investor interest has a legitimate concern with the financial integrity of the company whose rates are being regulated. From the investor or company point of view it is important that there be enough revenue not only for operating expenses but also for the capital costs of the business. These include service on the debt and dividends on the stock. Cf. Chicago & Grand Trunk R. Co. v. Wellman, 143 U.S. 339, 345, 346 12 S.Ct. 400,402. By that standard the return to the equity owner should be commensurate with returns on investments in other enterprises having corresponding risks. That return, moreover, should be sufficient to assure confidence in the financial integrity of the enterprise, so as to maintain its credit and to attract capital.[3]

In summary, the U.S. Supreme Court has found a return that is adequate to attract capital at reasonable terms enables the utility to provide service while maintaining its financial integrity. As discussed above, and in keeping with established regulatory standards, that return should be commensurate with the returns expected elsewhere for investments of equivalent risk. The Commission's decision in this proceeding, therefore,

[3] *Hope*, 320 U.S. 591 (1944), at 603.

should provide the Company opportunity to earn a return that is: (1) adequate to attract capital at reasonable cost and terms; (2) sufficient to ensure its financial integrity; and (3) commensurate with returns on investments in enterprises having corresponding risks, even if the Company determines that an alternative request is appropriate due to market conditions..

Lastly, the required return for a regulated public utility is established on a stand-alone basis, i.e., for the utility operating company at issue in a rate case. Parent entities, like other investors, have capital constraints and must look at the attractiveness of the expected risk-adjusted return of each investment alternative in their capital budgeting process. That is, utility holding companies that own many utility operating companies have choices as to where they will invest their capital within the holding company family. Therefore, the opportunity cost concept applies regardless of the source of the funding, public funding or corporate funding.

When funding is provided by a parent entity, the return still must be sufficient to provide an incentive to allocate equity capital to the subsidiary or business unit rather than other internal or external investment opportunities. That is, the regulated subsidiary must compete for capital with all the parent company's affiliates, and with other, similarly situated companies. In that regard, investors value corporate entities on a sum-of-the-parts basis and expect each division within the parent company to provide an appropriate risk-adjusted return.

It therefore is important that the authorized ROE reflects the risks and prospects of the utility's operations and supports the utility's financial integrity from a stand-alone perspective as measured by their combined business and financial risks. Consequently, the ROE authorized in this proceeding should be sufficient to support the operational (*i.e.,* business risk) and financing (*i.e.,* financial risk) of the Company's Maine utility operations on a stand-alone basis.

Q. WITHIN THAT BROAD FRAMEWORK, HOW IS THE COST OF CAPITAL ESTIMATED IN REGULATORY PROCEEDINGS?

A. Regulated utilities primarily use common stock and long-term debt to finance their permanent property, plant, and equipment (*i.e.*, rate base). The fair rate of return for a regulated utility is based on its weighted average cost of capital, in which, as noted earlier, the costs of the individual sources of capital are weighted by their respective book values.

The cost of capital is the return investors require to make an investment in a firm. Investors will provide funds to a firm only if the return that they *expect* is equal to, or greater than, the return that they *require* to accept the risk of providing funds to the firm.

The cost of capital (that is, the combination of the costs of debt and equity) is based on the economic principle of "opportunity costs." Investing in any asset (whether debt or equity securities) represents a forgone opportunity to invest in alternative assets. For any investment to be sensible, its expected return must be at least equal to the return expected on alternative, comparable risk investment opportunities. Because investments with like risks should offer similar returns, the opportunity cost of an investment should equal the return available on an investment of comparable risk.

Whereas the cost of debt is contractually defined and can be directly observed as the interest rate or yield on debt securities, the cost of common equity must be estimated based on market data and various financial models. Because the cost of common equity is premised on opportunity costs, the models used to determine it are typically applied to a group of "comparable" or "proxy" companies.

In the end, the estimated cost of capital should reflect the return that investors require in light of the subject company's business and financial risks, and the returns available on comparable investments.

Q. IS THE AUTHORIZED RETURN SET IN REGULATORY PROCEEDINGS GUARANTEED?

A. No, it is not. Consistent with the *Hope* and *Bluefield* standards, the rate-setting process should provide the utility a reasonable opportunity to recover its return of, and return on, its prudently incurred investments, but it does not guarantee that return. While a utility may have control over some factors that affect the ability to earn its authorized return (*e.g.*, management performance, operating and maintenance expenses, etc.), there are several factors beyond a utility's control that affect its ability to earn its authorized return. Those may include factors such as weather, the economy, and the prevalence and magnitude of regulatory lag.

<u>Business Risk</u>

Q. PLEASE DEFINE BUSINESS RISK AND EXPLAIN WHY IT IS IMPORTANT FOR DETERMINING A FAIR RATE OF RETURN.

A. The investor-required return on common equity reflects investors' assessment of the total investment risk of the subject firm. Total investment risk is often discussed in the context of business and financial risk.

Business risk reflects the uncertainty associated with owning a company's common stock without the company's use of debt and/or preferred stock financing. One way of considering the distinction between business and financial risk is to view the former as the uncertainty of the expected earned return on common equity, assuming the firm is financed with no debt.

Examples of business risks generally faced by utilities include, but are not limited to, the regulatory environment, mandatory environmental compliance requirements, customer mix and concentration of customers, service territory economic growth, market demand, risks and uncertainties of supply, operations, capital intensity, size, and the like, all of which have a direct bearing on earnings. Although analysts, including rating agencies, may categorize business risks individually, as a practical matter, such risks are interrelated and not wholly distinct from one another. Therefore, it is difficult to quantify the effect of any individual risk specifically and numerically on investors' required return, *i.e.*, the cost of capital. For determining an appropriate return on common equity, the relevant issue is where investors see the subject company as falling within a spectrum of risk. To the extent investors view a company as being exposed to high risk, the required return will increase, and vice versa.

For regulated utilities, business risks are both long-term and near-term in nature. Whereas near-term business risks are reflected in year-to-year variability in earnings and cash flow brought about by economic or regulatory factors, long-term business risks reflect the prospect of an impaired ability of investors to obtain both a fair rate of return on, and return of, their capital. Moreover, because utilities accept the obligation to provide safe, adequate, and reliable service at all times (in exchange for a reasonable opportunity to earn a fair return on their investment), they generally do not have the option to delay, defer, or reject capital investments. Because those investments are capital-intensive, utilities generally do not have the option to avoid raising external funds during periods of capital market distress, if necessary.

Because utilities invest in long-lived assets, long-term business risks are of paramount concern to equity investors. That is, the risk of not recovering the return on their investment extends far into the future. The timing and nature of events that may lead to losses, however, also are uncertain and, consequently, those risks and their implications for the required return on equity tend to be difficult to quantify. Regulatory commissions (like investors who commit their capital) must review a variety of quantitative and qualitative data and apply their reasoned judgment to determine how long-term risks weigh in their assessment of the market-required return on common equity.

Financial Risk

Q. PLEASE DEFINE FINANCIAL RISK AND EXPLAIN WHY IT IS IMPORTANT IN DETERMINING A FAIR RATE OF RETURN.

A. Financial risk is the additional risk created by the introduction of debt and preferred stock into the capital structure. The higher the proportion of debt and preferred stock in the capital structure, the higher the financial risk to common equity owners (*i.e.,* failure to receive dividends due to default or other covenants). Therefore, consistent with the basic financial principle of risk and return, common equity investors demand higher returns as compensation for bearing higher financial risk.

Q. CAN BOND AND CREDIT RATINGS BE A PROXY FOR A FIRM'S COMBINED BUSINESS AND FINANCIAL RISKS TO EQUITY OWNERS (*I.E.*, INVESTMENT RISK)?

A. Yes, similar bond ratings/issuer credit ratings reflect, and are representative of, similar combined business and financial risks (*i.e.*, total risk) faced by bond investors.[4] Although specific business or financial risks may differ between companies, the same bond/credit rating indicates that the combined risks are roughly similar from a debtholder perspective.

[4] Risk distinctions within S&P's bond rating categories are recognized by a plus or minus, e.g., within the A category, an S&P rating can by at A+, A, or A-. Similarly, risk distinction for Moody's ratings are distinguished by numerical rating gradations, e.g., within the A category, a Moody's rating can be A1, A2 and A3.

The caveat is that these debtholder risk measures do not translate directly to risks for common equity.

Q. DO RATING AGENCIES ACCOUNT FOR COMPANY SIZE IN THEIR BOND RATINGS?

A. No. Neither Standard & Poor's ("S&P") nor Moody's Investor Service ("Moody's") have minimum company size requirements for any given rating level. This means, all else equal, a relative size analysis must be conducted for equity investments in companies with similar bond ratings.

IV. SUMMIT'S OPERATIONS AND THE UTILITY PROXY GROUP

Q. ARE YOU FAMILIAR WITH SUMMIT'S OPERATIONS?

A. Yes. Summit provides natural gas distribution services to 4,628 customers throughout Maine. The Company is a wholly owned subsidiary of Summit Utilities, Inc.

Q. WHY IS IT NECESSARY TO DEVELOP A PROXY GROUP WHEN ESTIMATING THE ROE FOR THE COMPANY?

A. It is necessary to develop groups of publicly traded, comparable companies to serve as "proxies" for Summit because the Company is not publicly traded and does not have publicly traded equity securities. In addition to the analytical necessity of doing so, the use of proxy companies is consistent with the *Hope* and *Bluefield* comparable risk standards, as discussed above. I have selected two proxy groups that, in my view, are fundamentally risk-comparable to the Company: a Utility Proxy Group and a Non-Price Regulated Proxy Group, which is comparable in total risk to the Utility Proxy Group.[5]

Even when proxy groups are carefully selected, it is common for analytical results to vary from company to company. Despite the care taken to ensure comparability, because

[5] The development of the Non-Price Regulated Proxy Group is explained in more detail below.

no two companies are identical, market expectations regarding future risks and prospects will vary within the proxy group. It therefore is common for analytical results to reflect a seemingly wide range, even for a group of similarly situated companies. At issue is how to estimate the ROE from within that range. That determination will be best informed by employing a variety of sound analyses that necessarily must consider the sort of quantitative and qualitative information discussed throughout my Direct Testimony. Additionally, a relative risk analysis between the Company and the Utility Proxy Group must be made to determine whether or not explicit Company-specific adjustments need to be made to the Utility Proxy Group indicated results.

Q. PLEASE EXPLAIN HOW YOU CHOSE THE COMPANIES IN THE UTILITY PROXY GROUP.

A. The companies selected for the Utility Proxy Group met the following criteria:

(i) They were included in the Natural Gas Utility Group of *Value Line's Standard Edition* ("*Value Line*") (November 26, 2021);

(ii) They have 70% or greater of fiscal year 2020 total operating income derived from, and 70% or greater of fiscal year 2020 total assets attributable to, regulated gas distribution operations;

(iii) At the time of preparation of this testimony, they had not publicly announced that they were involved in any major merger or acquisition activity (*i.e.*, one publicly-traded utility merging with or acquiring another);

(iv) They have not cut or omitted their common dividends during the five years ended 2020 or through the time of preparation of this testimony;

(v) They have *Value Line* and Bloomberg Professional Services ("Bloomberg") adjusted Betas;

(vi) They have positive *Value Line* five-year dividends per share ("DPS") growth rate projections; and

(vii) They have *Value Line*, Zacks, Yahoo! Finance, or Bloomberg consensus five-year earnings per share ("EPS") growth rate projections.

The following six companies met these criteria: Atmos Energy Corporation, New Jersey Resources Corp., Northwest Natural Gas Company, ONE Gas, Inc., South Jersey Industries, Inc., and Spire, Inc.

Q. PLEASE DESCRIBE SCHEDULE DWD-2, PAGE 1.

A. Page 1 of Schedule DWD-2 contains comparative capitalization and financial statistics for the Utility Proxy Group for the years 2016 to 2020. During the five-year period ending 2020, the historically achieved average earnings rate on book common equity for the Utility Proxy Group averaged 8.36%. The average common equity ratio based on total capital (excluding short-term debt) was 51.86%, and the average dividend payout ratio was 76.58%. Total debt to earnings before interest, taxes, depreciation, and amortization ("EBITDA") for the years 2016 to 2020 ranges between 4.21 and 8.44 times, with an average of 5.95 times. Funds from operations to total debt range from 49.76% to 54.34%, with an average of 52.23%.

V. CAPITAL STRUCTURE

Q. WHAT CAPITAL STRUCTURE RATIOS DO YOU RECOMMEND BE EMPLOYED IN DEVELOPING AN OVERALL FAIR RATE OF RETURN APPROPRIATE FOR THE COMPANY?

A. I recommend the use of a hypothetical capital structure, which consists of 50.00% long-term debt and 50.00% common equity as shown on page 1 of Schedule DWD-1. This hypothetical capital structure is consistent with the average 2020 capital structure ratios maintained by the Utility Proxy Group, as shown on page 2 of Schedule DWD-2.

Q. WHY ARE YOU RECOMMENDING A HYPOTHETICAL CAPITAL STRUCTURE IN THIS PROCEEDING?

A. Summit's estimated capital structure ratios at test-year end June 30, 2021 consists of 35.00% long-term debt and 65.00% common equity.[6] Although the estimated capital structure and related ratios represent the capital structure which finances the Summit stand-alone Maine jurisdictional rate base, a common equity ratio of 65.00% is inappropriate at this time for ratemaking purposes because it contains a higher than necessary common equity ratio, which results in, all else equal, a higher revenue cost of capital which must be paid for by ratepayers.

Q. WHAT LONG-TERM DEBT COST RATE IS MOST APPROPRIATE FOR SUMMIT IN THIS PROCEEDING?

A. Summit's actual expected long-term debt cost rate of 5.20% is reasonable and appropriate as Summit's cost of long-term debt in this proceeding.

VI. COMMON EQUITY COST RATE MODELS

Q. IS IT IMPORTANT THAT COST OF COMMON EQUITY MODELS BE MARKET BASED?

A. Yes. A public utility must compete for equity in capital markets along with all other companies of comparable risk, which includes non-utilities. The cost of common equity is thus determined based on equity market expectations for the returns of those comparable risk companies. When individual investors choose to invest capital among companies of

[6] Company provided.

comparable risk, they will choose a company which provides a higher return over a company providing a lower return.

Q. ARE YOUR COST OF COMMON EQUITY MODELS MARKET BASED?

A. Yes. The DCF model uses market prices in developing the model's dividend yield component. Regarding the RPM, the Predictive Risk Premium Model ("PRPM") uses monthly market returns in addition to expectations of the risk-free rate and the total market risk premium approach uses bond ratings and expected bond yields that reflect the market's assessment of bond/credit risk. In addition, Beta coefficients ("β"), which reflect the market/systematic risk component of equity risk premium, are derived from regression analyses of market prices. The CAPM is market based for many of the same reasons that the RPM is market based (*i.e.*, the use of expected bond yields and Betas). Selection criteria for comparable risk non-price regulated companies are based on regression analyses of market prices and reflect the market's assessment of total risk.

Q. WHAT ANALYTICAL APPROACHES DID YOU USE TO DETERMINE THE COMPANY'S ROE?

A. As discussed earlier, I have relied on the DCF model, the RPM, and the CAPM, which I apply to the Utility Proxy Group described above. I also applied these same models to a Non-Price Regulated Proxy Group described later in this section.

I rely on these models because reasonable investors use a variety of tools and do not rely exclusively on a single source of information or single model. Moreover, the models on which I rely focus on different aspects of return requirements, and provide different insights to investors' views of risk and return. The DCF model, for example, estimates the investor-required return assuming a constant expected dividend yield and growth rate in perpetuity, while Risk Premium-based methods (*i.e.,* the RPM and CAPM approaches) provide the ability to reflect investors' views of risk, future market returns, and the relationship between interest rates and the cost of common equity. Just as the use of market data for the Utility Proxy Group adds the reliability necessary to inform expert judgment in arriving at a recommended common equity cost rate, the use of multiple generally accepted common equity cost rate models also adds reliability and accuracy when arriving at a recommended common equity cost rate.

<u>Discounted Cash Flow Model</u>

Q. WHAT IS THE THEORETICAL BASIS OF THE DCF MODEL?

A. The theory underlying the DCF model is that the present value of an expected future stream of net cash flows during the investment holding period can be determined by discounting those cash flows at the cost of capital, or the investors' capitalization rate. DCF theory indicates that an investor buys a stock for an expected total return rate, which is derived from the cash flows received from dividends and market price appreciation. Mathematically, the dividend yield on market price plus a growth rate equals the capitalization rate; *i.e.*, the total common equity return rate expected by investors as shown below:

$$K_e = (D_0\ (1+g))/P + g$$

where:

K_e = the required Return on Common Equity;
D_0 = the annualized Dividend Per Share;
P = the current stock price; and
g = the growth rate.

Q. WHICH VERSION OF THE DCF MODEL DID YOU USE?

A. I used the single-stage constant growth DCF model in my analyses.

Q. PLEASE DESCRIBE THE DIVIDEND YIELD YOU USED IN APPLYING THE CONSTANT GROWTH DCF MODEL.

A. The unadjusted dividend yields are based on the proxy companies' dividends as of December 31, 2021, divided by the average closing market price for the 60 trading days ended December 31, 2021.[7]

Q. PLEASE EXPLAIN YOUR ADJUSTMENT TO THE DIVIDEND YIELD.

A. Because dividends are paid periodically (*e.g.* quarterly), as opposed to continuously (e.g. daily), an adjustment must be made to the dividend yield. This is often referred to as the discrete, or the Gordon Periodic, version of the DCF model.

DCF theory calls for using the full growth rate, or D_1, in calculating the model's dividend yield component. Since the companies in the Utility Proxy Group increase their quarterly dividends at various times during the year, a reasonable assumption is to reflect one-half the annual dividend growth rate in the dividend yield component, or $D_{1/2}$. Because the dividend should be representative of the next 12-month period, this adjustment is a conservative approach that does not overstate the dividend yield. Therefore, the actual average dividend yields in Column 1, page 1 of Schedule DWD-3 have been adjusted upward to reflect one-half the average projected growth rate shown in Column 5.

Q. PLEASE EXPLAIN THE BASIS FOR THE GROWTH RATES YOU APPLY TO THE UTILITY PROXY GROUP IN YOUR CONSTANT GROWTH DCF MODEL.

A. Investors with more limited resources than institutional investors are likely to rely on widely available financial information services, such as *Value Line*, Zacks, and Yahoo! Finance. Investors realize that analysts have significant insight into the dynamics of the industries and individual companies they analyze, as well as companies' ability to

[7] *See*, column 1, page 1 of Schedule DWD-3.

effectively manage the effects of changing laws and regulations, and ever-changing economic and market conditions. For these reasons, I used analysts' five-year forecasts of EPS growth in my DCF analysis.

Over the long run, there can be no growth in DPS without growth in EPS. Security analysts' earnings expectations have a more significant influence on market prices than dividend expectations. Thus, using earnings growth rates in a DCF analysis provides a better match between investors' market price appreciation expectations and the growth rate component of the DCF.

Q. PLEASE SUMMARIZE THE CONSTANT GROWTH DCF MODEL RESULTS.

A. As shown on page 1 of Schedule DWD-3, for the Utility Proxy Group, the mean result of applying the single-stage DCF model is 10.26%, the median result is 9.90%, and the average of the two is 10.08%. In arriving at a conclusion for the constant growth DCF-indicated common equity cost rate for the Utility Proxy Group, I relied on an average of the mean and the median results of the DCF. This approach considers all the proxy utilities' results, while mitigating the high and low outliers of those individual results.

The Risk Premium Model

Q. PLEASE DESCRIBE THE THEORETICAL BASIS OF THE RPM.

A. The RPM is based on the fundamental financial principle of risk and return; namely, that investors require greater returns for bearing greater risk. The RPM recognizes that common equity capital has greater investment risk than debt capital, as common equity shareholders are behind debt holders in any claim on a company's assets and earnings. As a result, investors require higher returns from common stocks than from bonds to compensate them for bearing the additional risk.

While it is possible to directly observe bond returns and yields, investors' required common equity returns cannot be directly determined or observed. According to RPM theory, one can estimate a common equity risk premium over bonds (either historically or prospectively) and use that premium to derive a cost rate of common equity. The cost of common equity equals the expected cost rate for long-term debt capital, plus a risk premium over that cost rate, to compensate common shareholders for the added risk of being unsecured and last-in-line for any claim on the corporation's assets and earnings upon liquidation.

Q. PLEASE EXPLAIN HOW YOU DERIVED YOUR INDICATED COST OF COMMON EQUITY BASED ON THE RPM.

A. To derive my indicated cost of common equity under the RPM, I used two risk premium methods. The first method was the PRPM and the second method was a risk premium model using a total market approach. The PRPM estimates the risk-return relationship directly, while the total market approach indirectly derives a risk premium by using known metrics as a proxy for risk.

Q. PLEASE EXPLAIN THE PRPM.

A. The PRPM, published in the *Journal of Regulatory Economics,*[8] was developed from the work of Robert F. Engle, who shared the Nobel Prize in Economics in 2003 "for methods of analyzing economic time series with time-varying volatility ("ARCH")".[9] Engle found that volatility changes over time and is related from one period to the next, especially in financial markets. Engle discovered that volatility of prices and returns clusters over time and is therefore highly predictable and can be used to predict future levels of risk and risk

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[8] Autoregressive conditional heteroscedasticity. See "A New Approach for Estimating the Equity Risk Premium for Public Utilities", Pauline M. Ahern, Frank J. Hanley and Richard A. Michelfelder, Ph.D. *The Journal of Regulatory Economics* (December 2011), 40:261-278.

[9] www.nobelprize.org.

premiums.

The PRPM estimates the risk-return relationship directly, as the predicted equity risk premium is generated by predicting volatility or risk. The PRPM is not based on an estimate of investor behavior, but rather on an evaluation of the results of that behavior (*i.e.*, the variance of historical equity risk premiums).

The inputs to the model are the historical returns on the common shares of each Utility Proxy Group company minus the historical monthly yield on long-term U.S. Treasury securities through December 2021. Using a generalized form of ARCH, known as GARCH, I calculated each Utility Proxy Group company's projected equity risk premium using Eviews© statistical software. When the GARCH model is applied to the historical return data, it produces a predicted GARCH variance series[10] and a GARCH coefficient.[11] Multiplying the predicted monthly variance by the GARCH coefficient and then annualizing it[12] produces the predicted annual equity risk premium. I then added the forecasted 30-year U.S. Treasury bond yield of 2.74%[13] to each company's PRPM-derived equity risk premium to arrive at an indicated cost of common equity. The 30-year U.S. Treasury bond yield is a consensus forecast derived from *Blue Chip Financial Forecasts* ("*Blue Chip*").[14] The mean PRPM indicated common equity cost rate for the Utility Proxy Group is 10.87%, the median is 11.73 %, and the average of the two is 11.30%. Consistent with my reliance on the average of the median and mean results of the DCF models, I relied on the average of the mean and median results of the Utility Proxy Group PRPM to calculate a cost of common equity rate of 11.30%.

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10 Illustrated on Columns 1 and 2, page 2 of Schedule DWD-4.
11 Illustrated on Column 4, page 2 of Schedule DWD-4.
12 Annualized Return = (1 + Monthly Return) ^12 - 1.
13 See Column 6, page 2 of Schedule DWD-4.
14 *Blue Chip Financial Forecasts*, December 1, 2021 at page 14 and January 1, 2022 at 2.

Q. HAS THE COMMISSION COMMENTED ON THE USE OF THE PRPM IN THE PAST?

A. Yes. In its 2014 Order Re: Maine Water Company-Camden & Rockland Division, the Commission stated: "We are not convinced that we should accept results based on a newly derived analytical model that has not yet been rigorously vetted."[15]

Q. WOULD YOU LIKE TO RESPOND TO THE COMMISSION'S COMMENTS?

A. Yes, I would. The PRPM is based on the research of Dr. Robert F. Engle, dating back to the early 1980s. Dr. Engle discovered that the volatility of market prices, returns, and risk premiums clusters over time, making prices, returns, and risk premiums highly predictable. In 2003, he shared the Nobel Prize in Economics for this work, characterized as "methods of analyzing economic time series with time-varying volatility ("ARCH").[16] Dr. Engle[17] noted that relative to volatility, "the standard tools have become the ARCH/GARCH[18] models." Hence, the methodology is not new.

In addition, the GARCH methodology has been well tested by academia since Engle's, *et al*. research was originally published in 1982, 38 years ago. I use the well-established GARCH methodology to estimate the PRPM model using a standard commercial and relatively inexpensive statistical package, Eviews,©[19] to develop a means by which to estimate a predicted ERP which, when added to a bond yield, results in a cost of common equity.

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15 State of Maine Public Utilities Commission, Docket No. 2013-00362, Order Approving Stipulation and Setting Return on Equity, March 25, 2014.

16 www.nobelprize.org.

17 Robert Engle, "GARCH 101: The Use of ARCH/GARCH Models in Applied Econometrics", *Journal of Economic Perspectives*, Volume 15, No. 4, Fall 2001, at 157-168.

18 Autoregressive Conditional Heteroskedasticity/Generalized Autoregressive Conditional Heteroskedasticity.

19 In addition to Eviews,® the GARCH methodology can be applied and the PRPM derived using other standard statistical software packages such as SAS, RATS, S-Plus and JMulti, which are not cost-prohibitive. The software that I used in this proceeding, Eviews,® currently costs $600 - $700 for a single user commercial license. In addition, JMulti is a free downloadable software with GARCH estimation applications.

Also, the PRPM is in the public domain, having been published six times in academically peer-reviewed journals: *Journal of Economics and Business* (June 2011 and April 2015),[20] *The Journal of Regulatory Economics* (December 2011),[21] *The Electricity Journal* (May 2013 and March 2020),[22] and *Energy Policy* (April 2019).[23] Notably, none of these articles have been rebutted in the academic literature.

Finally, the PRPM has also been presented to a number of utility industry/regulatory/academic groups including the following: The Edison Electric Institute Cost of Capital Working Group; The NARUC Staff Subcommittee on Accounting and Finance; The National Association of Electric Companies Finance/Accounting/Taxation and Rates and Regulations Committees; the NARUC Electric Committee; The Wall Street Utility Group; the Indiana Utility Regulatory Commission Cost of Capital Task Force; the Financial Research Institute of the University of Missouri Hot Topic Hotline Webinar; and the Center for Research and Regulated Industries Annual Eastern Conference on two occasions.

Q. HAS THE PRPM BEEN ACCEPTED BY OTHER REGULATORY COMMISSIONS?

A. Yes. In Docket No. 2017-292-WS, the Public Service Commission of South Carolina ("PSC SC") accepted Blue Granite Water Company's entire requested ROE, which

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20 Eugene A. Pilotte and Richard A. Michelfelder, "Treasury Bond Risk and Return, the Implications for the Hedging of Consumption and Lessons for Asset Pricing", *Journal of Economics and Business*, June 2011, 582-604. and Richard A. Michelfelder, "Empirical Analysis of the Generalized Consumption Asset Pricing Model: Estimating the Cost of Capital", *Journal of Economics and Business*, April 2015, 37-50.

21 Pauline M. Ahern, Frank J. Hanley, and Richard A. Michelfelder, "New Approach to Estimating the Equity Risk Premium for Public Utilities", *The Journal of Regulatory Economics*, December 2011, at 40:261-278.

22 Richard A. Michelfelder, Pauline M. Ahern, Dylan W. D'Ascendis, and Frank J. Hanley, "Comparative Evaluation of the Predictive Risk Premium Model, the Discounted Cash Flow Model and the Capital Asset Pricing Model for Estimating the Cost of Common Equity", *The Electricity Journal*, April 2013, at 84-89; and Richard A. Michelfelder, Pauline M. Ahern, and Dylan W. D'Ascendis, "Decoupling, Risk Impacts and the Cost of Capital", *The Electricity Journal,* January 2020.

23 Richard A. Michelfelder, Pauline M. Ahern, and Dylan W. D'Ascendis, "Decoupling Impact and Public Utility Conservation Investment", *Energy Policy*, April 2019, 311-319.

included the PRPM, therefore implicitly approving use of the PRPM. The relevant portion states:

> The Commission finds Mr. D'Ascendis' arguments persuasive. He provided more indicia of market returns, by using more analytical methods and proxy group calculations. Mr. D'Ascendis' use of analysts' estimates for his DCF analysis is supported by consensus, as is his use of the arithmetic mean. The Commission also finds that Mr. D'Ascendis' non-price regulated proxy group more accurately reflects the total risk faced [by] price regulated utilities and CWS. Furthermore, there is no dispute that CWS is significantly smaller than its proxy group counterparts, and, therefore, it may present a higher risk. An appropriate ROE for CWS is 10.45% to 10.95%. The Company used an ROE of 10.5% in computing its Application, a return on the low end of Mr. D'Ascendis' range, and the Commission finds that ROE is supported by the evidence.[24]

Likewise, in Docket No. W-354, Subs 363, 364 and 365, the State of North Carolina Utilities Commission ("NCUC") approved my RPM and CAPM analyses, which also used PRPM analyses as presented in this proceeding. The relevant portion of the order states:

> In doing so the Commission finds that the DCF (8.81%), Risk Premium (10.00%) and CAPM (9.29%) model results provided by witness D'Ascendis, as updated to use current rates in D'Ascendis Late-Filed Exhibit No. 1, as well as the risk premium (9.57%) analysis of witness Hinton, are credible, probative, and are entitled to substantial weight as set forth below.[25]

Q. PLEASE EXPLAIN THE TOTAL MARKET APPROACH RPM.

A. The total market approach RPM adds a prospective public utility bond yield to an average of: 1) an equity risk premium that is derived from a Beta-adjusted total market equity risk premium, 2) an equity risk premium based on the S&P Utilities Index, and 3) an equity risk premium based on authorized ROEs for gas distribution utilities.

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[24] PSC SC Docket No. 2017-292-WS - Order No. 2018-345, at 14 (May 17, 2018).

[25] NCUC Docket No. W-354, Sub 363, 364, 365, *Order Granting Partial Rate Increase and Requiring Customer Notice*, at PDF 72 (March 31, 2020).

Q. PLEASE EXPLAIN THE BASIS OF THE EXPECTED BOND YIELD OF 4.03% APPLICABLE TO THE UTILITY PROXY GROUP.

A. The first step in the total market approach RPM analysis is to determine the expected bond yield. Because both ratemaking and the cost of capital, including common equity cost rate, are prospective in nature, a prospective yield on similarly-rated long-term debt is essential. I relied on a consensus forecast of about 50 economists of the expected yield on Aaa-rated corporate bonds for the six calendar quarters ending with the second calendar quarter of 2023, and *Blue Chip's* long-term projections for 2023 to 2027, and 2028 to 2032. As shown on line 1, page 3 of Schedule DWD-4, the average expected yield on Moody's Aaa-rated corporate bonds is 3.63%. To derive an expected yield on Moody's A2-rated public utility bonds, I made an upward adjustment of 0.40%, which represents a recent spread between Aaa-rated corporate bonds and A2-rated public utility bonds, in order to adjust the expected Aaa-rated corporate bond yield to an equivalent A2-rated public utility bond yield.[26] Adding that recent 0.40% spread to the expected Aaa-rated corporate bond yield of 3.63% results in an expected A2-rated public utility bond yield of 4.03%.

I then reviewed the average credit rating for the Utility Proxy Group from Moody's to determine if an adjustment to the estimated A2-rated public utility bond was necessary. Since the Utility Proxy Group's average Moody's long-term issuer rating is A2, no other adjustment needed to make the A2 prospective bond yield applicable to the A2-rated public utility bond. The results are a 4.03% expected bond yield applicable to the Utility Proxy Group.

[26] As shown on line 2 and explained in note 2, page 3 of Schedule DWD-4.

Table 3: Summary of the Calculation of the Utility Proxy Group Projected Bond Yield[27]

Prospective Yield on Moody's Aaa-Rated Corporate Bonds (*Blue Chip)*	3.63%
Adjustment to Reflect Yield Spread Between Moody's Aaa-Rated Corporate Bonds and Moody's A2-Rated Utility Bonds	0.40%
Prospective Bond Yield Applicable to the Utility Proxy Group	4.03%

To develop the indicated ROE using the total market approach RPM, this prospective bond yield is then added to the average of the three different equity risk premiums described below.

Q. PLEASE EXPLAIN HOW THE BETA-DERIVED EQUITY RISK PREMIUM IS DETERMINED.

A. The components of the Beta-derived risk premium model are: 1) an expected market equity risk premium over corporate bonds, and 2) the Beta coefficient. The derivation of the Beta-derived equity risk premium that I applied to the Utility Proxy Group is shown on lines 1 through 9, page 8 of Schedule DWD-4. The total Beta-derived equity risk premium I applied is based on an average of three historical market data-based equity risk premiums, two *Value Line*-based equity risk premiums, and a Bloomberg-based equity risk premium. Each of these is described below.

Q. HOW DID YOU DERIVE A MARKET EQUITY RISK PREMIUM BASED ON LONG-TERM HISTORICAL DATA?

A. To derive a historical market equity risk premium, I used the most recent holding period returns for the large company common stocks from the Stocks, Bonds, Bills, and Inflation ("SBBI") Yearbook 2020 ("SBBI - 2021")[28] less the average historical yield on Moody's Aaa/Aa-rated corporate bonds for the period 1928 to 2020. Using holding period returns

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27 As shown on page 3 of Schedule DWD-4.

28 SBBI Appendix A Tables: Morningstar Stocks, Bonds, Bills, & Inflation 1926-2020.

over a very long time is appropriate because it is consistent with the long-term investment horizon presumed by investing in a going concern, *i.e.*, a company expected to operate in perpetuity.

SBBI's long-term arithmetic mean monthly total return rate on large company common stocks was 11.94%, and the long-term arithmetic mean monthly yield on Moody's Aaa/Aa-rated corporate bonds was 6.02%.[29] As shown on line 1, page 8 of Schedule DWD-4, subtracting the mean monthly bond yield from the total return on large company stocks results in a long-term historical equity risk premium of 5.92%.

I used the arithmetic mean monthly total return rates for the large company stocks and yields (income returns) for the Moody's Aaa/Aa corporate bonds, because they are appropriate for the purpose of estimating the cost of capital as noted in <u>SBBI - 2021.</u>[30] Using the arithmetic mean return rates and yields is appropriate because historical total returns and equity risk premiums provide insight into the variance and standard deviation of returns needed by investors in estimating future risk when making a current investment. If investors relied on the geometric mean of historical equity risk premiums, they would have no insight into the potential variance of future returns, because the geometric mean relates the change over many periods to a <u>constant</u> rate of change, thereby obviating the year-to-year fluctuations, or variance, which is critical to risk analysis.

Q. PLEASE EXPLAIN THE DERIVATION OF THE REGRESSION-BASED MARKET EQUITY RISK PREMIUM.

A. To derive the regression-based market equity risk premium of 8.61% shown on line 2, page 8 of Schedule DWD-4, I used the same monthly annualized total returns on large company common stocks relative to the monthly annualized yields on Moody's Aaa/Aa-rated

29 As explained in note 1, page 9 of Schedule DWD-4.

30 <u>SBBI - 2021</u>, at 10-22.

corporate bonds as mentioned above. I modeled the relationship between interest rates and the market equity risk premium using the observed monthly market equity risk premium as the dependent variable, and the monthly yield on Moody's Aaa/Aa-rated corporate bonds as the independent variable. I then used a linear Ordinary Least Squares ("OLS") regression, in which the market equity risk premium is expressed as a function of the Moody's Aaa/Aa-rated corporate bonds yield:

$$RP = \alpha + \beta\ (R_{Aaa/Aa})$$

Q. PLEASE EXPLAIN THE DERIVATION OF THE PRPM EQUITY RISK PREMIUM.

A. I used the same PRPM approach described above as applied to the Utility Proxy Group to the historical equity risk premium. The inputs to the model are the historical monthly returns on large company common stocks minus the monthly yields on Moody's Aaa/Aa-rated corporate bonds during the period from January 1928 through December 2021.[31] Using the previously discussed generalized form of ARCH, known as GARCH, the projected equity risk premium is determined using Eviews© statistical software. The resulting PRPM predicted a market equity risk premium of 8.02%.[32]

Q. PLEASE EXPLAIN THE DERIVATION OF A PROJECTED EQUITY RISK PREMIUM BASED ON *VALUE LINE* DATA FOR YOUR RPM ANALYSIS.

A. As noted above, because both ratemaking and the cost of capital are prospective, a prospective market equity risk premium is needed. The derivation of the forecasted or prospective market equity risk premium can be found in note 4, page 9 of Schedule DWD-4. Consistent with my calculation of the dividend yield component in my DCF analysis,

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31 Data from January 1928 to December 2020 is from SBBI - 2021. Data from January 2021 to December 2021 is from Bloomberg.

32 Shown on line 3, page 8 of Schedule DWD-4.

this prospective market equity risk premium is derived from an average of the three- to five-year median market price appreciation potential by *Value Line* for the 13 weeks ended December 31, 2021, plus an average of the median estimated dividend yield for the common stocks of the 1,700 firms covered in *Value Line*'s Standard Edition.[33]

The average median expected price appreciation is 37%, which translates to a 8.19% annual appreciation, and, when added to the average of *Value Line's* median expected dividend yields of 1.77%, equates to a forecasted annual total return rate on the market of 9.96%. The forecasted Moody's Aaa-rated corporate bond yield of 3.63% is deducted from the total market return of 9.96%, resulting in an equity risk premium of 6.33%, as shown on line 4, page 8 of Schedule DWD-4.

Q. PLEASE EXPLAIN THE DERIVATION OF AN EQUITY RISK PREMIUM BASED ON THE S&P 500 COMPANIES.

A. Using data from *Value Line*, I calculated an expected total return on the S&P 500 companies using expected dividend yields and long-term growth estimates as a proxy for capital appreciation. The expected total return for the S&P 500 is 16.33%. Subtracting the prospective yield on Moody's Aaa-rated corporate bonds of 3.63% results in an 12.70% projected equity risk premium.

Q. PLEASE EXPLAIN THE DERIVATION OF AN EQUITY RISK PREMIUM BASED ON BLOOMBERG DATA.

A. Using data from Bloomberg, I calculated an expected total return on the S&P 500 using expected dividend yields and long-term growth estimates as a proxy for capital appreciation, identical to the method described above. The expected total return for the

[33] As explained in detail in note 1, page 2 of Schedule DWD-5.

S&P 500 is 18.28%. Subtracting the prospective yield on Moody's Aaa-rated corporate bonds of 3.63% results in a 14.65% projected equity risk premium.

Q. WHAT IS YOUR CONCLUSION OF A BETA-DERIVED EQUITY RISK PREMIUM FOR USE IN YOUR RPM ANALYSIS?

A. I gave equal weight to all six equity risk premiums based on each source - historical, *Value Line*, and Bloomberg - in arriving at a 9.37% equity risk premium.

Table 4: Summary of the Calculation of the Equity Risk Premium Using Total Market Returns[34]

Historical Spread Between Total Returns of Large Stocks and Aaa and Aa2-Rated Corporate Bond Yields (1928 – 2020)	5.92%
Regression Analysis on Historical Data	8.61%
PRPM Analysis on Historical Data	8.02%
Prospective Equity Risk Premium using Total Market Returns from *Value Line* Summary & Index less Projected Aaa Corporate Bond Yields	6.33%
Prospective Equity Risk Premium using Measures of Capital Appreciation and Income Returns from *Value Line* for the S&P 500 less Projected Aaa Corporate Bond Yields	12.70%
Prospective Equity Risk Premium using Measures of Capital Appreciation and Income Returns from Bloomberg Professional Services for the S&P 500 less Projected Aaa Corporate Bond Yields	14.65%
Average	9.37%

After calculating the average market equity risk premium of 9.37%, I adjusted it by the Beta coefficient to account for the risk of the Utility Proxy Group. As discussed below, the Beta coefficient is a meaningful measure of prospective relative risk to the market as a whole, and is a logical way to allocate a company's, or proxy group's, share of the market's total equity risk premium relative to corporate bond yields. As shown on page 1 of Schedule DWD-5, the average of the mean and median Beta coefficient for the Utility Proxy Group is 0.92. Multiplying the 0.92 average by the market equity risk premium of 9.37% results in a Beta-adjusted equity risk premium for the Utility Proxy Group of 8.62%.

34 As shown on page 8 of Schedule DWD-4.

Q. HOW DID YOU DERIVE THE EQUITY RISK PREMIUM BASED ON THE S&P UTILITY INDEX AND MOODY'S A-RATED PUBLIC UTILITY BONDS?

A. I estimated three equity risk premiums based on S&P Utility Index holding period returns, and two equity risk premiums based on the expected returns of the S&P Utilities Index, using *Value Line* and Bloomberg data, respectively. Turning first to the S&P Utility Index holding period returns, I derived a long-term monthly arithmetic mean equity risk premium between the S&P Utility Index total returns of 10.65%, and monthly Moody's A-rated public utility bond yields of 6.49% from 1928 to 2020, to arrive at an equity risk premium of 4.16%.[35] I then used the same historical data to derive an equity risk premium of 6.31% based on a regression of the monthly equity risk premiums. The final S&P Utility Index holding period equity risk premium involved applying the PRPM using the historical monthly equity risk premiums from January 1928 to December 2021 to arrive at a PRPM-derived equity risk premium of 4.84% for the S&P Utility Index.

I then derived expected total returns on the S&P Utilities Index of 10.91% and 9.10% using data from *Value Line* and Bloomberg, respectively, and subtracted the prospective Moody's A2-rated public utility bond yield of 4.03%[36], which resulted in equity risk premiums of 6.88% and 5.07%, respectively. As with the market equity risk premiums, I averaged each risk premium based on each source (*i.e.*, historical, *Value Line*, and Bloomberg) to arrive at my utility-specific equity risk premium of 5.45%.

[35] As shown on line 1, page 12 of Schedule DWD-4.
[36] Derived on line 3, page 3 of Schedule DWD-4.

Table 5: Summary of the Calculation of the Equity Risk Premium Using S&P Utility Index Holding Returns[37]

Historical Spread Between Total Returns of the S&P Utilities Index and A2-Rated Utility Bond Yields (1928 – 2020)	4.16%
Regression Analysis on Historical Data	6.31%
PRPM Analysis on Historical Data	4.84%
Prospective Equity Risk Premium using Measures of Capital Appreciation and Income Returns from *Value Line* for the S&P Utilities Index less Projected A2 Utility Bond Yields	6.88%
Prospective Equity Risk Premium using Measures of Capital Appreciation and Income Returns from Bloomberg Professional Services for the S&P Utilities Index less Projected A2 Utility Bond Yields	5.07%
Average	5.45%

Q. HOW DID YOU DERIVE AN EQUITY RISK PREMIUM OF 5.63% BASED ON AUTHORIZED ROES FOR GAS DISTRIBUTION UTILITIES?

A. The equity risk premium of 5.63% shown on line 3, page 7 of Schedule DWD-4 is the result of a regression analysis based on regulatory awarded ROEs related to the yields on Moody's A-rated public utility bonds. That analysis is shown on page 13 of Schedule DWD-4. Page 13 of Schedule DWD-4 contains the graphical results of a regression analysis of 809 rate cases for gas distribution utilities which were fully litigated during the period from January 1, 1980 through December 31, 2021. It shows the implicit equity risk premium relative to the yields on A-rated public utility bonds immediately prior to the issuance of each regulatory decision. It is readily discernible that there is an inverse relationship between the yield on A-rated public utility bonds and equity risk premiums. In other words, as interest rates decline, the equity risk premium rises and vice versa, a result consistent with financial literature on the subject.[38] I used the regression results to estimate the equity risk premium applicable to the projected yield on Moody's A2-rated

[37] As shown on page 12 of Schedule DWD-4.

[38] *See*, *e.g.*, Robert S. Harris and Felicia C. Marston, *The Market Risk Premium: Expectational Estimates Using Analysts' Forecasts*, Journal of Applied Finance, Vol. 11, No. 1, 2001, at 11 to 12; Eugene F. Brigham, Dilip K. Shome, and Steve R. Vinson, *The Risk Premium Approach to Measuring a Utility's Cost of Equity*, Financial Management, Spring 1985, at 33 to 45.

public utility bonds of 4.03%. Given the expected A-rated utility bond yield of 4.03%, it can be calculated that the indicated equity risk premium applicable to that bond yield is 5.63%, which is shown on line 3, page 7 of Schedule DWD-4.

Q. WHAT IS YOUR CONCLUSION OF AN EQUITY RISK PREMIUM FOR USE IN YOUR TOTAL MARKET APPROACH RPM ANALYSIS?

A. The equity risk premium I apply to the Utility Proxy Group is 6.57%, which is the average of the Beta-adjusted equity risk premium for the Utility Proxy Group, the S&P Utilities Index, and the authorized return utility equity risk premiums of 8.62%, 5.45%, and 5.63%, respectively.[39]

Q. WHAT IS THE INDICATED RPM COMMON EQUITY COST RATE BASED ON THE TOTAL MARKET APPROACH?

A. As shown on line 6, page 3 of Schedule DWD-4, I calculated a common equity cost rate of 10.60% for the Utility Proxy Group based on the total market approach RPM.

Table 6: Summary of the Total Market Return Risk Premium Model[40]

Prospective Moody's A2-Rated Utility Bond Applicable to the Utility Proxy Group	4.03%
Prospective Equity Risk Premium	6.57%
Indicated Cost of Common Equity	10.60%

Q. WHAT ARE THE RESULTS OF YOUR APPLICATION OF THE PRPM AND THE TOTAL MARKET APPROACH RPM?

A. As shown on page 1 of Schedule DWD-4, the indicated RPM-derived common equity cost rate is 10.95%, which gives equal weight to the PRPM (11.30%) and the adjusted-market approach results (10.60%).

39 As shown on page 7 of Schedule DWD-4.
40 As shown on page 3 of Schedule DWD-4.

The Capital Asset Pricing Model

Q. PLEASE EXPLAIN THE THEORETICAL BASIS OF THE CAPM.

A. CAPM theory defines risk as the co-variability of a security's returns with the market's returns as measured by the Beta coefficient (β). A Beta coefficient less than 1.0 indicates lower variability than the market as a whole, while a Beta coefficient greater than 1.0 indicates greater variability than the market.

The CAPM assumes that all non-market or unsystematic risk can be eliminated through diversification. The risk that cannot be eliminated through diversification is called market, or systematic, risk. In addition, the CAPM presumes that investors only require compensation for systematic risk, which is the result of macroeconomic and other events that affect the returns on all assets. The model is applied by adding a risk-free rate of return to a market risk premium, which is adjusted proportionately to reflect the systematic risk of the individual security relative to the total market as measured by the Beta coefficient. The traditional CAPM model is expressed as:

$$R_s = R_f + \beta (R_m - R_f)$$

Where:
R_s = Return rate on the common stock
R_f = Risk-free rate of return
R_m = Return rate on the market as a whole
β = Adjusted Beta coefficient (volatility of the security relative to the market as a whole)

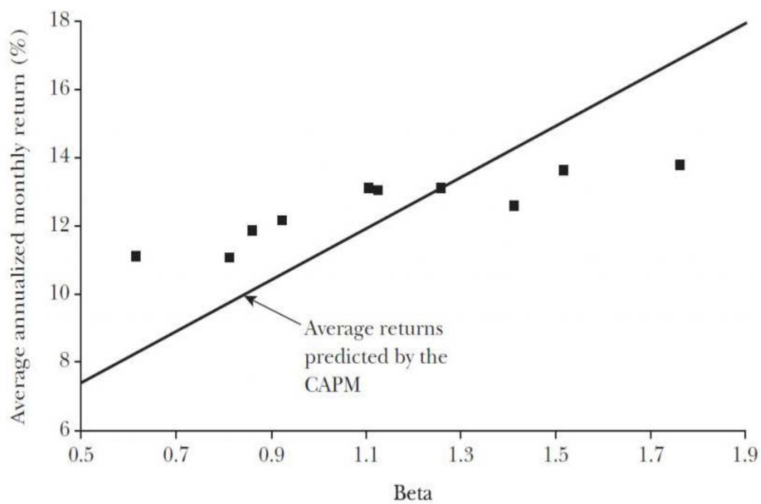
Numerous tests of the CAPM have measured the extent to which security returns and Beta coefficients are related as predicted by the CAPM, confirming its validity. The empirical CAPM ("ECAPM") reflects the reality that while the results of these tests support the notion that the Beta coefficient is related to security returns, the empirical Security

Market Line ("SML") described by the CAPM formula is not as steeply sloped as the predicted SML.[41]

The ECAPM reflects this empirical reality. Fama and French clearly state regarding Figure 2, below, that "[t]he returns on the low beta portfolios are too high, and the returns on the high beta portfolios are too low." [42]

Figure 2 http://pubs.aeaweb.org/doi/pdfplus/10.1257/0895330042162430

Average Annualized Monthly Return versus Beta for Value Weight Portfolios Formed on Prior Beta, 1928–2003



In addition, Morin observes that while the results of these tests support the notion that Beta is related to security returns, the empirical SML described by the CAPM formula is not as steeply sloped as the predicted SML. Morin states:

> With few exceptions, the empirical studies agree that … low-beta securities earn returns somewhat higher than the CAPM would predict, and high-beta securities earn less than predicted.[43]
>
> * * *
>
> Therefore, the empirical evidence suggests that the expected return on a security is related to its risk by the following approximation:

$$K = R_F + x\,\beta(R_M - R_F) + (1-x)\,\beta(R_M - R_F)$$

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[41] Roger A. Morin, New Regulatory Finance (Public Utility Reports, Inc., 2006), at 175. ("Morin")

[42] Eugene F. Fama and Kenneth R. French, "The Capital Asset Pricing Model: Theory and Evidence", *Journal of Economic Perspectives*, Vol. 18, No. 3, Summer 2004 at 33. ("Fama & French")

[43] Morin, at 175.

> where x is a fraction to be determined empirically. The value of x that best explains the observed relationship [is] Return = 0.0829 + 0.0520 β is between 0.25 and 0.30. If x = 0.25, the equation becomes:
>
> $$K = R_F + 0.25(R_M - R_F) + 0.75\ \beta(R_M - R_F)$$[44]

Fama and French provide similar support for the ECAPM when they state:

> The early tests firmly reject the Sharpe-Lintner version of the CAPM. There is a positive relation between beta and average return, but it is too 'flat.'… The regressions consistently find that the intercept is greater than the average risk-free rate… and the coefficient on beta is less than the average excess market return… This is true in the early tests… as well as in more recent cross-section regressions tests, like Fama and French (1992).[45]

Finally, Fama and French further note:

> Confirming earlier evidence, the relation between beta and average return for the ten portfolios is much flatter than the Sharpe-Linter CAPM predicts. The returns on low beta portfolios are too high, and the returns on the high beta portfolios are too low. For example, the predicted return on the portfolio with the lowest beta is 8.3 percent per year; the actual return as 11.1 percent. The predicted return on the portfolio with the t beta is 16.8 percent per year; the actual is 13.7 percent.[46]

Clearly, the justification from Morin, Fama, and French, along with their reviews of other academic research on the CAPM, validate the use of the ECAPM. In view of theory and practical research, I have applied both the traditional CAPM and the ECAPM to the companies in the Utility Proxy Group and averaged the results.

Q. WHAT BETA COEFFICIENTS DID YOU USE IN YOUR CAPM ANALYSIS?

A. For the Beta coefficients in my CAPM analysis, I considered two sources: *Value Line* and Bloomberg Professional Services. While both of those services adjust their calculated (or "raw") Beta coefficients to reflect the tendency of the Beta coefficient to regress to the market mean of 1.00, *Value Line* calculates the Beta coefficient over a five-year period, while Bloomberg calculates it over a two-year period.

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44 Morin, at 190.
45 Fama & French, at 32.
46 *Ibid.,* at 33.

Q. PLEASE DESCRIBE YOUR SELECTION OF A RISK-FREE RATE OF RETURN.

A. As shown in Schedules DWD-4 and DWD-5, the risk-free rate adopted for applications of the RPM and CAPM is 2.74%. This risk-free rate is based on the average of the *Blue Chip* consensus forecast of the expected yields on 30-year U.S. Treasury bonds for the six quarters ending with the second calendar quarter of 2023, and long-term projections for the years 2023 to 2027 and 2028 to 2032.

Q. WHY DO YOU USE THE PROJECTED 30-YEAR TREASURY YIELD IN YOUR ANALYSES?

A. The yield on long-term U.S. Treasury bonds is almost risk-free and its term is consistent with the long-term cost of capital to public utilities measured by the yields on Moody's A2-rated public utility bonds; the long-term investment horizon inherent in utilities' common stocks; and the long-term life of the jurisdictional rate base to which the allowed fair rate of return (*i.e.*, cost of capital) will be applied. In contrast, short-term U.S. Treasury yields are more volatile and largely a function of Federal Reserve monetary policy.

Q. PLEASE EXPLAIN THE ESTIMATION OF THE EXPECTED RISK PREMIUM FOR THE MARKET USED IN YOUR CAPM ANALYSES.

A. The basis of the market risk premium is explained in detail in note 1 on Schedule DWD-5. As discussed above, the market risk premium is derived from an average of three historical data-based market risk premiums, two *Value Line* data-based market risk premiums, and one Bloomberg data-based market risk premium.

The long-term income return on U.S. Government securities of 5.05% was deducted from the SBBI - 2021 monthly historical total market return of 12.20%, which results in an historical market equity risk premium of 7.15%.[47] I applied a linear OLS

[47] SBBI - 2021, at Appendix A-1 (1) through A-1 (3) and Appendix A-7 (19) through A-7 (21).

regression to the monthly annualized historical returns on the S&P 500 relative to historical yields on long-term U.S. Government securities from <u>SBBI -2021</u>. That regression analysis yielded a market equity risk premium of 9.53%. The PRPM market equity risk premium is 8.95% and is derived using the PRPM relative to the yields on long-term U.S. Treasury securities from January 1926 through December 2021.

The *Value Line*-derived forecasted total market equity risk premium is derived by deducting the forecasted risk-free rate of 2.74%, discussed above, from the *Value Line* projected total annual market return of 9.96%, resulting in a forecasted total market equity risk premium of 7.22%. The S&P 500 projected market equity risk premium using *Value Line* data is derived by subtracting the projected risk-free rate of 2.74% from the projected total return of the S&P 500 of 16.33%. The resulting market equity risk premium is 13.59%.

The S&P 500 projected market equity risk premium using Bloomberg data is derived by subtracting the projected risk-free rate of 2.74% from the projected total return of the S&P 500 of 18.28%. The resulting market equity risk premium is 15.54%. These six measures, when averaged, result in an average total market equity risk premium of 10.33%.

Table 7: Summary of the Calculation of the Market Risk Premium for Use in the CAPM[48]

Historical Spread Between Total Returns of Large Stocks and Long-Term Government Bond Yields (1926 – 2020)	7.15%
Regression Analysis on Historical Data	9.53%
PRPM Analysis on Historical Data	8.95%
Prospective Equity Risk Premium using Total Market Returns from *Value Line* Summary & Index less Projected 30-Year Treasury Bond Yields	7.22%
Prospective Equity Risk Premium using Measures of Capital Appreciation and Income Returns from *Value Line* for the S&P 500 less Projected 30-Year Treasury Bond Yields	13.59%
Prospective Equity Risk Premium using Measures of Capital Appreciation and Income Returns from Bloomberg Professional Services for the S&P 500 less Projected 30-Year Treasury Bond Yields	15.54%
Average	10.33%

Q. WHAT ARE THE RESULTS OF YOUR APPLICATION OF THE TRADITIONAL AND EMPIRICAL CAPM TO THE UTILITY PROXY GROUP?

A. As shown on page 1 of Schedule DWD-5, the mean result of my CAPM/ECAPM analyses is 12.38%, the median is 12.26%, and the average of the two is 12.32%. Consistent with my reliance on the average of mean and median DCF results discussed above, the indicated common equity cost rate using the CAPM/ECAPM is 12.32%.

Common Equity Cost Rates for a Proxy Group of Domestic, Non-Price Regulated Companies Based on the DCF, RPM, and CAPM

Q. WHY DO YOU ALSO CONSIDER A PROXY GROUP OF DOMESTIC, NON-PRICE REGULATED COMPANIES?

A. In the *Hope* and *Bluefield* cases, the U.S. Supreme Court did not specify that comparable risk companies had to be utilities. Since the purpose of rate regulation is to be a substitute for marketplace competition, non-price regulated firms operating in the competitive marketplace make an excellent proxy group if they are comparable in total risk to the Utility

48 As shown on page 2 of Schedule DWD-5.

Proxy Group being used to estimate the cost of common equity. The selection of such domestic, non-price regulated competitive firms theoretically and empirically results in a proxy group which is comparable in total risk to the Utility Proxy Group, since all of these companies compete for capital in the exact same markets.

Q. HOW DID YOU SELECT NON-PRICE REGULATED COMPANIES THAT ARE COMPARABLE IN TOTAL RISK TO THE UTILITY PROXY GROUP?

A. In order to select a proxy group of domestic, non-price regulated companies similar in total risk to the Utility Proxy Group, I relied on the Beta coefficients and related statistics derived from *Value Line* regression analyses of weekly market prices over the most recent 260 weeks (*i.e.*, five years). These selection criteria resulted in a proxy group of 46 domestic, non-price regulated firms comparable in total risk to the Utility Proxy Group. Total risk is the sum of non-diversifiable market risk and diversifiable company-specific risks. The criteria used in selecting the domestic, non-price regulated firms was:

(i) They must be covered by *Value Line* (Standard Edition);

(ii) They must be domestic, non-price regulated companies, *i.e.*, not utilities;

(iii) Their Beta coefficients must lie within plus or minus two standard deviations of the average unadjusted Beta coefficients of the Utility Proxy Group; and

(iv) The residual standard errors of the *Value Line* regressions which gave rise to the unadjusted Beta coefficients must lie within plus or minus two standard deviations of the average residual standard error of the Utility Proxy Group.

Beta coefficients measure market, or systematic, risk, which is not diversifiable. The residual standard errors of the regressions measure each firm's company-specific, diversifiable risk. Companies that have similar Beta coefficients <u>and</u> similar residual standard errors resulting from the same regression analyses have similar total investment risk.

Q. HAVE YOU PREPARED A SCHEDULE WHICH SHOWS THE DATA FROM WHICH YOU SELECTED THE 46 DOMESTIC, NON-PRICE REGULATED COMPANIES THAT ARE COMPARABLE IN TOTAL RISK TO THE UTILITY PROXY GROUP?

A. Yes, the basis of my selection and both proxy groups' regression statistics are shown in Schedule DWD-6.

Q. DID YOU CALCULATE COMMON EQUITY COST RATES USING THE DCF MODEL, RPM, AND CAPM FOR THE NON-PRICE REGULATED PROXY GROUP?

A. Yes. Because the DCF model, RPM, and CAPM have been applied in an identical manner as described above, I will not repeat the details of the rationale and application of each model. One exception is in the application of the RPM, where I did not use public utility-specific equity risk premiums, nor did I apply the PRPM to the individual non-price regulated companies.

Page 2 of Schedule DWD-7 derives the constant growth DCF model common equity cost rate. As shown, the indicated common equity cost rate, using the constant growth DCF for the Non-Price Regulated Proxy Group comparable in total risk to the Utility Proxy Group, is 14.03%.

Pages 3 through 5 of Schedule DWD-7 contain the data and calculations that support the 13.10% RPM common equity cost rate. As shown on line 1, page 3 of Schedule DWD-7, the consensus prospective yield on Moody's Baa-rated corporate bonds for the six quarters ending in the second quarter of 2023, and for the years 2022 to 2027 and 2028 to 2032, is 4.44%.[49] Since the Non-Price Regulated Proxy Group has an average Moody's

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49 *Blue Chip Financial Forecasts*, December 1, 2021, at 14 and January 1, 2022, at 2.

long-term issuer rating of Baa1/Baa2, a downward adjustment of 0.06%[50] to the projected Baa corporate bond yield is necessary to reflect the difference in ratings, which results in a projected Baa2 corporate bond yield of 4.39%.

When the Beta-adjusted risk premium of 8.71%[51] relative to the Non-Price Regulated Proxy Group is added to the adjusted prospective Baa2-rated corporate bond yield of 4.39%, the indicated RPM common equity cost rate is 13.10%.

Page 6 of Schedule DWD-7 contains the inputs and calculations that support my indicated CAPM/ECAPM common equity cost rate of 12.39%.

Q. HOW IS THE COST RATE OF COMMON EQUITY BASED ON THE NON-PRICE REGULATED PROXY GROUP COMPARABLE IN TOTAL RISK TO THE UTILITY PROXY GROUP?

A. As shown on page 1 of Schedule DWD-7, the results of the common equity models applied to the Non-Price Regulated Proxy Group -- which group is comparable in total risk to the Utility Proxy Group -- are as follows: 14.03% (DCF), 13.10% (RPM), and 12.39% (CAPM). The average of the mean and median of these models is 13.14%, which I used as the indicated common equity cost rates for the Non-Price Regulated Proxy Group.

VII. CONCLUSION OF COMMON EQUITY COST RATE BEFORE ADJUSTMENTS

Q. WHAT ARE THE INDICATED COMMON EQUITY COST RATES BEFORE ADJUSTMENTS?

A. By applying multiple cost of common equity models to the Utility Proxy Group and the Non-Price Regulated Proxy Group, the indicated range of common equity cost rates before any relative risk adjustment is between 10.08% and 13.14%. I used multiple cost of common equity models as primary tools in arriving at my recommended common equity

50 As demonstrated in line 2 and described in note 2 of page 3 of Schedule DWD-7.
51 Derived on page 5 of Schedule DWD-7.

cost rate, because no single model is so inherently precise that it can be relied on to the exclusion of other theoretically sound models. Using multiple models adds reliability to the estimated common equity cost rate, with the prudence of using multiple cost of common equity models supported in both the financial literature and regulatory precedent.

Based on these common equity cost rate results, I conclude that a common equity cost rate between 10.08% and 13.14% is reasonable and appropriate before any adjustments for relative risk differences between Summit and the Utility Proxy Group are made.[52]

VIII. ADJUSTMENTS TO THE COMMON EQUITY COST RATE

Size Adjustment

Q. DOES A COMPANY'S SIZE RELATIVE TO THE UTILITY PROXY GROUP COMPANIES IMPACT ITS BUSINESS RISK?

A. Yes. A smaller size relative to the Utility Proxy Group companies indicates greater relative business risk for a utility because, all else being equal, size has a material bearing on risk.

Size affects business risk because smaller companies generally are less able to cope with significant events that affect sales, revenues and earnings. For example, smaller companies face more risk exposure to business cycles and economic conditions, both nationally and locally. Additionally, the loss of revenues from a few larger customers would have a greater effect on a small company than on a bigger company with a larger, more diverse, customer base.

As further evidence that smaller firms are riskier, investors generally demand greater returns from smaller firms to compensate for less marketability and liquidity of their securities. Duff & Phelps' 2020 Valuation Handbook – U.S. Guide to Cost of Capital

[52] The 10.08% low end of the range represents the lowest model result. The 13.14% high end of the range is the highest model result.

("D&P - 2020") discusses the nature of the small-size phenomenon, providing an indication of the magnitude of the size premium based on several measures of size. In discussing "Size as a Predictor of Equity Premiums," D&P - 2020 states:

> The size effect is based on the empirical observation that companies of smaller size are associated with greater risk and, therefore, have greater cost of capital [sic]. The "size" of a company is one of the most important risk elements to consider when developing cost of equity capital estimates for use in valuing a business simply because size has been shown to be a *predictor* of equity returns. In other words, there is a significant (negative) relationship between size and historical equity returns - as size *decreases*, returns tend to *increase*, and vice versa. (footnote omitted) (emphasis in original)[53]

Furthermore, in "The Capital Asset Pricing Model: Theory and Evidence," Fama and French note size is indeed a risk factor which must be reflected when estimating the cost of common equity. On page 38, they note:

> **. . .** the higher average returns on small stocks and high book-to-market stocks reflect unidentified state variables that produce undiversifiable risks (covariances) in returns not captured in the market return and are priced separately from market betas.[54]

Based on this evidence, Fama and French proposed their three-factor model which includes a size variable in recognition of the effect size has on the cost of common equity.

Also, it is a basic financial principle that the use of funds invested, and not the source of funds, is what gives rise to the risk of any investment.[55] Eugene Brigham, a well-known authority, states:

> A number of researchers have observed that portfolios of small-firms (sic) have earned consistently higher average returns than those of large-firm stocks; this is called the "small-firm effect." On the surface, it would seem to be advantageous to the small firms to provide average returns in a stock market that are higher than those of larger firms. In reality, it is bad news for the small firm; **what the small-firm effect means is that the capital**

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53 Duff & Phelps 2020 Valuation Handbook – U.S. Guide to Cost of Capital, Wiley 2018, at 4-1.

54 Fama & French, at 25-43.

55 Richard A. Brealey and Stewart C. Myers, Principles of Corporate Finance (McGraw-Hill Book Company, 1996), at 204-205, 229.

market demands higher returns on stocks of small firms than on otherwise similar stocks of the large firms. (emphasis added)[56]

Consistent with the financial principle of risk and return discussed above, increased relative risk due to small size must be considered in the allowed rate of return on common equity. Therefore, the Commission's authorization of a cost rate of common equity in this proceeding must appropriately reflect the unique risks of Summit, including its small size, which is justified and supported above by evidence in the financial literature.

Q. SHOULD THE COMMISSION CONSIDER SUMMIT AS A STAND-ALONE COMPANY?

A. Yes, it should. Because it is Summit's rate base to which the overall rates of return set forth in this proceeding will be applied for the purpose of establishing an allowed revenue requirement, they should be evaluated as a stand-alone entity. To do otherwise would be discriminatory, confiscatory, and inaccurate. It is also a basic financial precept that the use of the funds invested give rise to the risk of the investment. As Brealey and Myers state:

> *The true cost of capital depends on the use to which the capital is put.*
>
> ***
>
> ***Each project should be evaluated at its own opportunity cost of capital; the true cost of capital depends on the use to which the capital is put.*** (italics and bold in original) [57]

Morin confirms Brealey and Myers when he states:

> Financial theory clearly establishes that the cost of equity is the risk-adjusted opportunity cost of the investors and not the cost of the specific capital sources employed by the investors. The true cost of capital depends on the use to which the capital is put and not on its source. The Hope and Bluefield doctrines have made clear that the relevant considerations in calculating a company's cost of capital are the alternatives available to

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56 Eugene F. Brigham, Fundamentals of Financial Management, Fifth Edition (The Dryden Press, 1989), at 623.

57 Richard A. Brealey and Stewart C. Myers, Principles of Corporate Finance, McGraw-Hill, Third Edition, 1988, at 173, 198.

> investors and the returns and risks associated with those alternatives.[58]

Additionally, Levy and Sarnat state:

> The firm's cost of capital is the discount rate employed to discount the firm's average cash flow, hence obtaining the value of the firm. It is also the weighted average cost of capital, as we shall see below. The weighted average cost of capital should be employed for project evaluation… only in cases where the risk profile of the new projects is a "carbon copy" of the risk profile of the firm.[59]

Although Levy and Sarnat discuss a project's cost of capital relative to a firm's cost of capital, these principles apply equally to the use of a proxy group-based cost of capital. Each company must be viewed on its own merits, regardless of the source of its equity capital. As *Bluefield* clearly states:

> A public utility is entitled to such rates as will permit it to earn a return on the value of the property which it employs for the convenience of the public equal to that generally being made at the same time and in the same general part of the country on investments in other business undertakings which are attended by corresponding risks and uncertainties; [60]

In other words, it is the "risks and uncertainties" surrounding the property employed for the "convenience of the public" which determines the appropriate level of rates. In this proceeding, the property employed "for the convenience of the public" is the rate base of Summit. Thus, it is only the risk of investment in Summit that is relevant to the determination of the cost of common equity to be applied to the common equity-financed portion of that rate base.

In addition, in the Fama and French article previously cited, the authors[61] proposed that their three-factor model include the SMB (Small Minus Big) factor, which indicates that small capitalization firms are more risky than large capitalization firms, confirming

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58 Morin, at 523.

59 Haim Levy & Marshall Sarnat, Capital Investment and Financial Decisions, Prentice/Hall International, 1986, at 465.

60 *Bluefield*, at 6.

61 Fama & French, at 39.

that size is a risk factor which must be taken into account in estimating the cost of common equity.

Consistent with the financial principle of risk and return discussed previously, and the stand-alone nature of ratemaking, an upward adjustment must be applied to the indicated cost of common equity derived from the cost of equity models of the proxy groups used in this proceeding.

Q. IS THERE A WAY TO QUANTIFY A RELATIVE RISK ADJUSTMENT DUE TO SUMMIT'S SMALL SIZE RELATIVE TO THE UTILITY PROXY GROUP?

A. Yes. The Company has greater relative risk than the average company in the Utility Proxy Group because of its smaller size compared with the group, as measured by an estimated market capitalization of common equity for Summit (whose common stock is not publicly traded).

Table 8: Size as Measured by Market Capitalization for Summit and the Utility Proxy Group

	Market Capitalization*	Times Greater than The Company
	($ Millions)	
Summit	$305.410	
Utility Proxy Group Median	$4,789.883	15.7x
*From page 1 of Schedule DWD-8.		

Summit's estimated market capitalization for was $305.410 million as of December 31, 2021,[62] compared with the median market capitalization of the Utility Proxy Group of

[62] $305.410M = $343.930M (requested rate base) * 50.00% (requested equity ratio) * 177.6% (market-to-book ratio of the Utility Proxy Group) as demonstrated on page 2 of Schedule DWD-8.

$4.8 <u>billion</u> as of December 31, 2021. The Utility Proxy Group's market capitalization is 15.7 times the size of Summit's estimated market capitalization.

As a result, it is necessary to upwardly adjust the indicated range of common equity cost rates to reflect Summit's greater risk due to its smaller relative size. The determination is based on the size premiums for portfolios of New York Stock Exchange, American Stock Exchange, and NASDAQ listed companies ranked by deciles for the 1926 to 2020 period. The average size premium for the Utility Proxy Group with a market capitalization of $4.8 billion falls in the fourth decile, while Summit's market capitalization of $305.410 million places the Company in the ninth decile. The size premium spread between the fourth decile and the ninth decile is 1.54%. Even though a 1.54% upward size adjustment is indicated, I applied a size premium of 1.00% to Summit's indicated range of common equity cost rates.

Q. WHAT IS THE INDICATED COST OF COMMON EQUITY AFTER YOUR COMPANY-SPECIFIC ADJUSTMENTS?

A. Applying the 1.00% size adjustment to the indicated cost of common equity range of 10.08% to 13.14% results in a Company-specific cost of common equity rate range of 11.08% to 14.14%, which is my recommended common equity cost rate range. Based on that range I recommend a Company-specific cost of common equity rate of 11.10%.

IX. <u>CONCLUSION</u>

Q. WHAT IS YOUR RECOMMENDED OVERALL ROE FOR SUMMIT?

A. Given the indicated ROE range applicable to the Utility Proxy Group of 10.08% to 13.14%, and the Company-specific ROE range of 11.08% to 14.14%, I conclude that an appropriate ROE for the purpose of determining an allowed revenue requirement for the Company is 11.10%.

Q. IN YOUR OPINION, WOULD APPLICATION OF AN ROE OF 11.10% FOR THE PURPOSE OF ESTABLISHING AN ALLOWED REVENUE REQUIREMENT BE FAIR AND REASONABLE TO SUMMIT AND ITS CUSTOMERS?

A. Yes, it is.

Q. IN YOUR OPINION, IS SUMMIT'S PROPOSED CAPITAL STRUCTURE CONSISTING OF 50.00% LONG-TERM DEBT AND 50.00% COMMON EQUITY FAIR AND REASONABLE?

A. Yes, it is.

Q. IN YOUR OPINION, IS SUMMIT'S PROPOSED COST OF LONG-TERM DEBT OF 5.20% FAIR AND REASONABLE?

A. Yes, it is.

Q. DOES THIS CONCLUDE YOUR DIRECT TESTIMONY?

A. Yes, it does.

Resume & Testimony Listing of:
Dylan W. D'Ascendis, CRRA, CVA
Partner

Summary

Dylan is an experienced consultant and a Certified Rate of Return Analyst (CRRA) and Certified Valuation Analyst (CVA). Dylan joined ScottMadden in 2016 and has become a leading expert witness with respect to cost of capital and capital structure. He has served as a consultant for investor-owned and municipal utilities and authorities for 13 years. Dylan has testified as an expert witness on over 100 occasions regarding rate of return, cost of service, rate design, and valuation before more than 30 regulatory jurisdictions in the United States and Canada, an American Arbitration Association panel, and the Superior Court of Rhode Island. He also maintains the benchmark index against which the Hennessy Gas Utility Mutual Fund performance is measured. Dylan holds a B.A. in economic history from the University of Pennsylvania and an M.B.A. with concentrations in finance and international business from Rutgers University.

Areas of Specialization

- Regulation and Rates
- Rate of Return
- Valuation
- Mutual Fund Benchmarking
- Capital Market Risk
- Regulatory Strategy
- Cost of Service

Recent Expert Testimony Submission/Appearance

- Regulatory Commission of Alaska – Capital Structure
- Federal Energy Regulatory Commission – Rate of Return
- Public Utility Commission of Texas – Return on Equity
- Hawaii Public Utilities Commission – Cost of Service / Rate Design
- Pennsylvania Public Utility Commission - Valuation

Recent Assignments

- Provided expert testimony on the cost of capital for ratemaking purposes before numerous state utility regulatory agencies
- Sponsored valuation testimony for a large municipal water company in front of an American Arbitration Association Board to justify the reasonability of their lease payments to the City
- Co-authored a valuation report on behalf of a large investor-owned utility company in response to a new state regulation which allowed the appraised value of acquired assets into rate base

Recent Articles and Speeches

- Co-Author of: "Decoupling, Risk Impacts and the Cost of Capital", co-authored with Richard A. Michelfelder, Ph.D., Rutgers University and Pauline M. Ahern. The Electricity Journal, March, 2020
- Co-Author of: "Decoupling Impact and Public Utility Conservation Investment", co-authored with Richard A. Michelfelder, Ph.D., Rutgers University and Pauline M. Ahern. Energy Policy Journal, 130 (2019), 311-319
- "Establishing Alternative Proxy Groups", before the Society of Utility and Regulatory Financial Analysts: 51st Financial Forum, April 4, 2019, New Orleans, LA
- "Past is Prologue: Future Test Year", Presentation before the National Association of Water Companies 2017 Southeast Water Infrastructure Summit, May 2, 2017, Savannah, GA.
- Co-author of: "Comparative Evaluation of the Predictive Risk Premium Model™, the Discounted Cash Flow Model and the Capital Asset Pricing Model", co-authored with Richard A. Michelfelder, Ph.D., Rutgers University, Pauline M. Ahern, and Frank J. Hanley, The Electricity Journal, May, 2013
- "Decoupling: Impact on the Risk and Cost of Common Equity of Public Utility Stocks", before the Society of Utility and Regulatory Financial Analysts: 45th Financial Forum, April 17-18, 2013, Indianapolis, IN

Sponsor	Date	Case/Applicant	Docket No.	Subject
Regulatory Commission of Alaska				
Cook Inlet Natural Gas Storage Alaska, LLC	07/21	Cook Inlet Natural Gas Storage Alaska, LLC	Docket No. TA45-733	Capital Structure
Alaska Power Company	09/20	Alaska Power Company; Goat Lake Hydro, Inc.; BBL Hydro, Inc.	Tariff Nos. TA886-2; TA6-521; TA4-573	Capital Structure
Alaska Power Company	07/16	Alaska Power Company	Docket No. TA857-2	Rate of Return
Alberta Utilities Commission				
AltaLink, L.P., and EPCOR Distribution & Transmission, Inc.	01/20	AltaLink, L.P., and EPCOR Distribution & Transmission, Inc.	2021 Generic Cost of Capital, Proceeding ID. 24110	Rate of Return
Arizona Corporation Commission				
EPCOR Water Arizona, Inc.	06/20	EPCOR Water Arizona, Inc.	Docket No. WS-01303A-20-0177	Rate of Return
Arizona Water Company	12/19	Arizona Water Company – Western Group	Docket No. W-01445A-19-0278	Rate of Return
Arizona Water Company	08/18	Arizona Water Company – Northern Group	Docket No. W-01445A-18-0164	Rate of Return
Arkansas Public Service Commission				
Southwestern Electric Power Co.	07/21	Southwestern Electric Power Co.	Docket No. 21-070-U	Return on Equity
CenterPoint Energy Resources Corp.	05/21	CenterPoint Arkansas Gas	Docket No. 21-004-U	Return on Equity
Colorado Public Utilities Commission				
Summit Utilities, Inc.	04/18	Colorado Natural Gas Company	Docket No. 18AL-0305G	Rate of Return
Atmos Energy Corporation	06/17	Atmos Energy Corporation	Docket No. 17AL-0429G	Rate of Return
Delaware Public Service Commission				
Delmarva Power & Light Co.	01/22	Delmarva Power & Light Co.	Docket No. 22-002 (Gas)	Return on Equity
Delmarva Power & Light Co.	11/20	Delmarva Power & Light Co.	Docket No. 20-0149 (Electric)	Return on Equity
Delmarva Power & Light Co.	10/20	Delmarva Power & Light Co.	Docket No. 20-0150 (Gas)	Return on Equity
Tidewater Utilities, Inc.	11/13	Tidewater Utilities, Inc.	Docket No. 13-466	Capital Structure
Public Service Commission of the District of Columbia				
Washington Gas Light Company	09/20	Washington Gas Light Company	Formal Case No. 1162	Rate of Return
Federal Energy Regulatory Commission				
LS Power Grid California, LLC	10/20	LS Power Grid California, LLC	Docket No. ER21-195-000	Rate of Return
Florida Public Service Commission				
Tampa Electric Company	04/21	Tampa Electric Company	Docket No. 20210034-EI	Return on Equity
Peoples Gas System	09/20	Peoples Gas System	Docket No. 20200051-GU	Rate of Return
Utilities, Inc. of Florida	06/20	Utilities, Inc. of Florida	Docket No. 20200139-WS	Rate of Return
Hawaii Public Utilities Commission				
Launiupoko Irrigation Company, Inc.	12/20	Launiupoko Irrigation Company, Inc.	Docket No. 2020-0217 / Transferred to 2020-0089	Capital Structure
Lanai Water Company, Inc.	12/19	Lanai Water Company, Inc.	Docket No. 2019-0386	Cost of Service / Rate Design
Manele Water Resources, LLC	08/19	Manele Water Resources, LLC	Docket No. 2019-0311	Cost of Service / Rate Design
Kaupulehu Water Company	02/18	Kaupulehu Water Company	Docket No. 2016-0363	Rate of Return
Aqua Engineers, LLC	05/17	Puhi Sewer & Water Company	Docket No. 2017-0118	Cost of Service / Rate Design

Sponsor	Date	Case/Applicant	Docket No.	Subject
Hawaii Resources, Inc.	09/16	Laie Water Company	Docket No. 2016-0229	Cost of Service / Rate Design
Illinois Commerce Commission				
Utility Services of Illinois, Inc.	02/21	Utility Services of Illinois, Inc.	Docket No. 21-0198	Rate of Return
Ameren Illinois Company d/b/a Ameren Illinois	07/20	Ameren Illinois Company d/b/a Ameren Illinois	Docket No. 20-0308	Return on Equity
Utility Services of Illinois, Inc.	11/17	Utility Services of Illinois, Inc.	Docket No. 17-1106	Cost of Service / Rate Design
Aqua Illinois, Inc.	04/17	Aqua Illinois, Inc.	Docket No. 17-0259	Rate of Return
Utility Services of Illinois, Inc.	04/15	Utility Services of Illinois, Inc.	Docket No. 14-0741	Rate of Return
Indiana Utility Regulatory Commission				
Aqua Indiana, Inc.	03/16	Aqua Indiana, Inc. Aboite Wastewater Division	Docket No. 44752	Rate of Return
Twin Lakes, Utilities, Inc.	08/13	Twin Lakes, Utilities, Inc.	Docket No. 44388	Rate of Return
Kansas Corporation Commission				
Atmos Energy	07/19	Atmos Energy	19-ATMG-525-RTS	Rate of Return
Kentucky Public Service Commission				
Atmos Energy Corporation	07/21	Atmos Energy Corporation	2021-00304	PRP Rider Rate
Atmos Energy Corporation	06/21	Atmos Energy Corporation	2021-00214	Rate of Return
Duke Energy Kentucky, Inc.	06/21	Duke Energy Kentucky, Inc.	2021-00190	Return on Equity
Bluegrass Water Utility Operating Company	10/20	Bluegrass Water Utility Operating Company	2020-00290	Return on Equity
Louisiana Public Service Commission				
Utilities, Inc. of Louisiana	05/21	Utilities, Inc. of Louisiana	Docket No. U-36003	Rate of Return
Southwestern Electric Power Company	12/20	Southwestern Electric Power Company	Docket No. U-35441	Return on Equity
Atmos Energy	04/20	Atmos Energy	Docket No. U-35535	Rate of Return
Louisiana Water Service, Inc.	06/13	Louisiana Water Service, Inc.	Docket No. U-32848	Rate of Return
Maine Public Utilities Commission				
The Maine Water Company	09/21	The Maine Water Company	Docket No. 2021-00053	Rate of Return
Maryland Public Service Commission				
Washington Gas Light Company	08/20	Washington Gas Light Company	Case No. 9651	Rate of Return
FirstEnergy, Inc.	08/18	Potomac Edison Company	Case No. 9490	Rate of Return
Massachusetts Department of Public Utilities				
Unitil Corporation	12/19	Fitchburg Gas & Electric Co. (Elec.)	D.P.U. 19-130	Rate of Return
Unitil Corporation	12/19	Fitchburg Gas & Electric Co. (Gas)	D.P.U. 19-131	Rate of Return
Liberty Utilities	07/15	Liberty Utilities d/b/a New England Natural Gas Company	Docket No. 15-75	Rate of Return
Minnesota Public Utilities Commission				
Northern States Power Company	11/01	Northern States Power Company	Docket No. G002/GR-21-678	Return on Equity
Northern States Power Company	10/21	Northern States Power Company	Docket No. E002/GR-21-630	Return on Equity
Northern States Power Company	11/20	Northern States Power Company	Docket No. E002/GR-20-723	Return on Equity
Mississippi Public Service Commission				
Atmos Energy	03/19	Atmos Energy	Docket No. 2015-UN-049	Capital Structure

Sponsor	Date	Case/Applicant	Docket No.	Subject
Atmos Energy	07/18	Atmos Energy	Docket No. 2015-UN-049	Capital Structure
Missouri Public Service Commission				
Spire Missouri, Inc.	12/20	Spire Missouri, Inc.	Case No. GR-2021-0108	Return on Equity
Indian Hills Utility Operating Company, Inc.	10/17	Indian Hills Utility Operating Company, Inc.	Case No. SR-2017-0259	Rate of Return
Raccoon Creek Utility Operating Company, Inc.	09/16	Raccoon Creek Utility Operating Company, Inc.	Case No. SR-2016-0202	Rate of Return
Public Utilities Commission of Nevada				
Southwest Gas Corporation	09/21	Southwest Gas Corporation	Docket No. 21-09001	Return on Equity
Southwest Gas Corporation	08/20	Southwest Gas Corporation	Docket No. 20-02023	Return on Equity
New Hampshire Public Utilities Commission				
Aquarion Water Company of New Hampshire, Inc.	12/20	Aquarion Water Company of New Hampshire, Inc.	Docket No. DW 20-184	Rate of Return
New Jersey Board of Public Utilities				
Middlesex Water Company	05/21	Middlesex Water Company	Docket No. WR21050813	Rate of Return
Atlantic City Electric Company	12/20	Atlantic City Electric Company	Docket No. ER20120746	Return on Equity
FirstEnergy	02/20	Jersey Central Power & Light Co.	Docket No. ER20020146	Rate of Return
Aqua New Jersey, Inc.	12/18	Aqua New Jersey, Inc.	Docket No. WR18121351	Rate of Return
Middlesex Water Company	10/17	Middlesex Water Company	Docket No. WR17101049	Rate of Return
Middlesex Water Company	03/15	Middlesex Water Company	Docket No. WR15030391	Rate of Return
The Atlantic City Sewerage Company	10/14	The Atlantic City Sewerage Company	Docket No. WR14101263	Cost of Service / Rate Design
Middlesex Water Company	11/13	Middlesex Water Company	Docket No. WR1311059	Capital Structure
New Mexico Public Regulation Commission				
Southwestern Public Service Company	01/21	Southwestern Public Service Company	Case No. 20-00238-UT	Return on Equity
North Carolina Utilities Commission				
Carolina Water Service, Inc.	07/21	Carolina Water Service, Inc.	Docket No. W-354 Sub 384	Rate of Return
Piedmont Natural Gas Co., Inc.	03/21	Piedmont Natural Gas Co., Inc.	Docket No. G-9, Sub 781	Return on Equity
Duke Energy Carolinas, LLC	07/20	Duke Energy Carolinas, LLC	Docket No. E-7, Sub 1214	Return on Equity
Duke Energy Progress, LLC	07/20	Duke Energy Progress, LLC	Docket No. E-2, Sub 1219	Return on Equity
Aqua North Carolina, Inc.	12/19	Aqua North Carolina, Inc.	Docket No. W-218 Sub 526	Rate of Return
Carolina Water Service, Inc.	06/19	Carolina Water Service, Inc.	Docket No. W-354 Sub 364	Rate of Return
Carolina Water Service, Inc.	09/18	Carolina Water Service, Inc.	Docket No. W-354 Sub 360	Rate of Return
Aqua North Carolina, Inc.	07/18	Aqua North Carolina, Inc.	Docket No. W-218 Sub 497	Rate of Return
North Dakota Public Service Commission				
Northern States Power Company	09/21	Northern States Power Company	Case No. PU-21-381	Rate of Return
Northern States Power Company	11/20	Northern States Power Company	Case No. PU-20-441	Rate of Return
Public Utilities Commission of Ohio				
Duke Energy Ohio, Inc.	10/21	Duke Energy Ohio, Inc.	Case No. 21-887-EL-AIR	Return on Equity
Aqua Ohio, Inc.	07/21	Aqua Ohio, Inc.	Case No. 21-0595-WW-AIR	Rate of Return
Aqua Ohio, Inc.	05/16	Aqua Ohio, Inc.	Case No. 16-0907-WW-AIR	Rate of Return
Pennsylvania Public Utility Commission				
Community Utilities of Pennsylvania, Inc.	04/21	Community Utilities of Pennsylvania, Inc.	Docket No. R-2021-3025207	Rate of Return
Vicinity Energy Philadelphia, Inc.	04/21	Vicinity Energy Philadelphia, Inc.	Docket No. R-2021-3024060	Rate of Return

Sponsor	Date	Case/Applicant	Docket No.	Subject
Delaware County Regional Water Control Authority	02/20	Delaware County Regional Water Control Authority	Docket No. A-2019-3015173	Valuation
Valley Energy, Inc.	07/19	C&T Enterprises	Docket No. R-2019-3008209	Rate of Return
Wellsboro Electric Company	07/19	C&T Enterprises	Docket No. R-2019-3008208	Rate of Return
Citizens' Electric Company of Lewisburg	07/19	C&T Enterprises	Docket No. R-2019-3008212	Rate of Return
Steelton Borough Authority	01/19	Steelton Borough Authority	Docket No. A-2019-3006880	Valuation
Mahoning Township, PA	08/18	Mahoning Township, PA	Docket No. A-2018-3003519	Valuation
SUEZ Water Pennsylvania Inc.	04/18	SUEZ Water Pennsylvania Inc.	Docket No. R-2018-000834	Rate of Return
Columbia Water Company	09/17	Columbia Water Company	Docket No. R-2017-2598203	Rate of Return
Veolia Energy Philadelphia, Inc.	06/17	Veolia Energy Philadelphia, Inc.	Docket No. R-2017-2593142	Rate of Return
Emporium Water Company	07/14	Emporium Water Company	Docket No. R-2014-2402324	Rate of Return
Columbia Water Company	07/13	Columbia Water Company	Docket No. R-2013-2360798	Rate of Return
Penn Estates Utilities, Inc.	12/11	Penn Estates, Utilities, Inc.	Docket No. R-2011-2255159	Capital Structure / Long-Term Debt Cost Rate
South Carolina Public Service Commission				
Blue Granite Water Co.	12/19	Blue Granite Water Company	Docket No. 2019-292-WS	Rate of Return
Carolina Water Service, Inc.	02/18	Carolina Water Service, Inc.	Docket No. 2017-292-WS	Rate of Return
Carolina Water Service, Inc.	06/15	Carolina Water Service, Inc.	Docket No. 2015-199-WS	Rate of Return
Carolina Water Service, Inc.	11/13	Carolina Water Service, Inc.	Docket No. 2013-275-WS	Rate of Return
United Utility Companies, Inc.	09/13	United Utility Companies, Inc.	Docket No. 2013-199-WS	Rate of Return
Utility Services of South Carolina, Inc.	09/13	Utility Services of South Carolina, Inc.	Docket No. 2013-201-WS	Rate of Return
Tega Cay Water Services, Inc.	11/12	Tega Cay Water Services, Inc.	Docket No. 2012-177-WS	Capital Structure
Tennessee Public Utility Commission				
Piedmont Natural Gas Company	07/20	Piedmont Natural Gas Company	Docket No. 20-00086	Return on Equity
Public Utility Commission of Texas				
Southwestern Public Service Company	02/21	Southwestern Public Service Company	Docket No. 51802	Return on Equity
Southwestern Electric Power Company	10/20	Southwestern Electric Power Company	Docket No. 51415	Rate of Return
Virginia State Corporation Commission				
Virginia Natural Gas, Inc.	04/21	Virginia Natural Gas, Inc.	PUR-2020-00095	Return on Equity
Massanutten Public Service Corporation	12/20	Massanutten Public Service Corporation	PUE-2020-00039	Return on Equity
Aqua Virginia, Inc.	07/20	Aqua Virginia, Inc.	PUR-2020-00106	Rate of Return
WGL Holdings, Inc.	07/18	Washington Gas Light Company	PUR-2018-00080	Rate of Return
Atmos Energy Corporation	05/18	Atmos Energy Corporation	PUR-2018-00014	Rate of Return
Aqua Virginia, Inc.	07/17	Aqua Virginia, Inc.	PUR-2017-00082	Rate of Return
Massanutten Public Service Corp.	08/14	Massanutten Public Service Corp.	PUE-2014-00035	Rate of Return / Rate Design
Public Service Commission of West Virginia				
Monongahela Power Company and The Potomac Edison Company	11/21	Monongahela Power Company and The Potomac Edison Company	Case No. 21-0813-E-P (Solar)	Return on Equity

ATRIUM ECONOMICS
CENTERED ON ENERGY

Ronald J. Amen

Managing Partner

Mr. Amen has over 40 years of combined experience in utility management and consulting in the areas of regulatory support, resource planning, organizational development, distribution operations and customer service, marketing, and systems administration.

He has advised gas, electric and water utility clients in the following areas: regulatory policy, strategy and analysis; cost of service studies (embedded and marginal cost analyses); rate design and pricing issues including time- of-use rates, revenue decoupling, weather normalization and other cost tracking mechanisms; resource strategy, planning and financial analysis; and business process design, evaluation and organizational structures. Mr. Amen has provided expert testimony in numerous state and provincial regulatory agencies, and the Federal Energy Regulatory Commission. Prior to establishing Atrium Economics in 2020, Mr. Amen's consulting experience included Director Advisory & Planning at Black & Veatch Management Consulting, LLC, Vice President of Concentric Energy Advisors, Inc. and Director with Navigant Consulting, Inc. His prior utility experience includes leadership of State and Federal Regulatory Affairs at two electric and gas utilities, and management positions in Regulatory Affairs, Information Systems and Distribution Operations.

EDUCATION

University of Nebraska,
Bachelor of Science with Distinction, Business Administration, Finance and Economics

YEARS EXPERIENCE

42

PROFESSIONAL ASSOCIATIONS

American Gas Association
Southern Gas Association

RELEVANT EXPERTISE

Financial Analysis; Litigation Support; Regulatory Support; Strategy; Utility Operations

REPRESENTATIVE PROJECT EXPERIENCE

Regulatory Policy, Strategy and Analysis

Western Export Group (2019)

In a Nova Gas Transmission, LTD. (NGTL) Rate Design and Service Application before the Canada Energy Regulator (CER), Mr. Amen led a consulting team supporting the interests of the Western Export Group, a group of nine utility companies located in the Western U.S. and British Columbia who are export shippers on the NGTL system. The case resulted in a settlement with all parties.

Regulatory Commission of Alaska (2019 – 2020)

Part of a multi-functional team that assisted the Regulatory Commission of Alaska (RCA) in its evaluation of the Chugach Electric Association, Inc's acquisition of the Municipal of Anchorage d/b/a Municipal Light & Power Department. Assisted the RCA with its evaluation of the long-term benefits of the transaction to ML&P and Chugach customers, the implication of terms and assumptions in various agreements, and the careful balance of the fiscal and regulatory implications for the customers of the combined entity.

CPS Energy (2017 – 2018)
Provided an overall review of the client's Strategic Roadmap to prioritize its multi-year regulatory initiatives. (e.g., changes in product and service offerings, restructuring of current rate classes, introduction of new rate structures, rate levels, and tariff provisions). Current pricing processes and platforms assessed to identify recommended enhancements to enable the development and implementation of dynamic pricing concepts. Assisted client with preparation of next rate case (e.g., costing and pricing analyses, load forecasting, internal communications, and stakeholder engagement).

FortisBC Energy, Inc. (2016 – 2018, 2021)
Performed an overall review of the client's Transportation Service Model. Analyzed the client's various midstream transportation and storage capacity resources used in providing balancing of transportation customers' loads. Review included the physical diversity, functionality and flexibility provided by the various capacity resources, and the cost impact caused by transportation customers' imbalance levels. Conducted an industry-wide benchmarking study of current industry-wide best practices, by regulatory jurisdiction, related to transportation balancing tariff provisions. Participated in stakeholder workshops and testified before the BCUC. Retained in 2021 to update quantitative analysis of the operation of the transportation balancing rules for reporting requirements of the BCUC in 2022.

McDowell Rackner & Gibson Law Firm (2015 – 2016)
Provided due diligence services to the law firm in connection with a state utility commission investigation into the law firm client's gas storage and optimization activities. Provided an independent opinion as to the likely outcome of the Commission's ongoing investigation.

Gulfport Energy Corporation (2016)
Provided regulatory analysis and support to Gulfport Energy Corporation in the ANR Pipeline Company Natural Gas Act §4 rate proceeding before the Federal Energy Regulatory Commission (FERC). Analyzed as-filed cost of service and rate design to identify key cost of service, cost allocation, rate design and service related/tariff issues. Developed an integrated cost of service and rate design model to prepare studies on client issues. Prepared best/worst case litigation outcomes, discovery and evaluations of discovery of other parties. Analyzed FERC staff top sheets and settlement offers; and assisted in the preparation of settlement positions.

Confidential Financial / Energy Partners (2015)
Provided regulatory due diligence support for client related to a proposed merger with a multijurisdictional gas/electric company including an evaluation of the regulatory landscape in the various applicable state jurisdictions, recent regulatory decisions, and current regulatory issues.

Confidential International Energy Company (2014)
Provided regulatory due diligence support for client related to a proposed merger with a multijurisdictional gas company including an evaluation of the regulatory landscape in the various applicable state jurisdictions, recent regulatory decisions, and current regulatory issues.

Pacific Gas & Electric Company (2014)
Developed an extensive industrywide benchmarking study to determine the cost allocation and ratemaking treatment utilized by Local Distribution Companies (LDCs) in the United States for recovery of gas transmission costs. Benchmarked cost allocation and rate design utilized by Interstate/Intrastate Pipelines. Benchmarked how Industrial & Electric Generation customers are served with natural gas.

Public Service Company of New Mexico (2009-2010)
Provided case management, revenue requirement, cost of service and rate design support for general rate cases in the utility's two state regulatory jurisdictions. Issue management and policy development included an electric fuel and purchased power cost mechanism, recovery of environmental remediation costs for a coal fired power plant, and the valuation of renewable energy credits related to a wind power facility.

Confidential International Energy Company (2009)
Provided due diligence on behalf of client related to the purchase of a gas/electric utility, including a review of the regulatory and market-related assumptions underlying the client's valuation model, resulting in the validation of the model and identification of key business risks and opportunities.

Resource Planning, Strategy and Financial Analysis

Great Plains Natural Gas (2021)
Retained to review the gas supply procurement practices and objectives of Great Plains, the interstate pipeline, storage and supply contracts, and other information available to Great Plains leading up to and throughout the severe weather event that occurred from February 13-17, 2021, and the actions by Great Plains personnel in response to the weather event, as part of a state-wide investigation by the Minnesota Public Utilities Commission. Expert testimony filed on behalf of Great Plains.

Fortis BC Energy, Inc. (2011, 2021)
Retained to help develop a gas supply incentive mechanism in cooperation with the British Columbia Utilities Commission staff and the company's other stakeholders. Provided an independent analysis of the utility's management of pipeline and storage capacity and supply. Part of this work entailed a review of the major markets in which the utility transacted, reviewing the size of trading activity at the major market hubs and reviewing the price indices for these markets. In 2021, retained to refresh all quantitative analysis of the operation of the GSMIP for reporting requirements of the BCUC in 2022.

Black Hills Colorado Electric Utility (2009)

Engaged as a member of a consultant team that served as the independent evaluator in a competitive solicitation for non-intermittent generation resources. Jointly recommended by the utility client, the staff of the utility commission and the state attorney general, the consulting team acted as an agent of the public utility commission monitoring and overseeing the solicitation, which included reviewing the request for proposals and solicitation process, including provisions of the power purchase agreement, preliminary review (economic and contractual) of bids received from the request for proposals, initial modeling of bids for screening, selection of bidders with whom to conduct negotiations and oversight of the negotiation process, and the ultimate selection of the winning bid. Provided due diligence review of all input data, preliminary and final model output, and output summaries. The team produced biweekly confidential reports to the commission regarding the process and its results.

NW Natural (2007-2008)

Assisted with the development of its long-term Integrated Resource Plan (IRP) for its Oregon and Washington service territories. The IRP included the evaluation of incremental inter- and intra-state pipeline capacity, underground storage, and two proposed LNG plants under development in the region.

Puget Sound Energy (2007)

Engaged to assist the client with the development of a natural gas resource efficiency and direct end-use strategy, an interdepartmental initiative focused on preparing a natural gas resource efficiency plan that optimizes customers' end-use energy consumption while furthering corporate customer, financial, environmental, and social responsibilities.

Puget Sound Energy (2002 – 2003)

Provided resource planning strategy and analysis for the company's Least Cost Plan, including a review of the company's underlying 20-year electric and gas demand forecasts. As a member of a consulting team, served as the client's financial advisor for the acquisition of new electric power supply resources. Conducted a multitrack solicitation process for evaluation of generation assets and purchase power agreements. Provided regulatory support for the acquisition.

Cost Allocation, Pricing Issues and Rate Design

Until Electric System and Northern Utilities, Inc. (2021)

Mr. Amen provided allocated cost of service, marginal cost of service, class revenue apportionment, rate design, and expert witness support for the utility's separate electric and gas general rate cases before the New Hampshire Public Utilities Commission. Cases are currently pending before the NHPUC.

Manitoba Hydro – Centra Gas Manitoba (2021)

Retained to review and assist in the regulatory approval process of the Cost of Service Study for Centra Gas Manitoba's natural gas operations. Prepared a report assessing Centra's current COSS method in conformance with the regulatory requirements of the Manitoba Public Utilities Board.

Focusing on the trends of Canadian gas distribution utilities, the COSS method utilized in the current COSS was reviewed against the: (1) cost causative factors identified for each plant and expense element of Centra's total cost of service; and (2) the current range of regulatory practices observed in the North American gas utility market. The case is currently pending before the MPUB.

Montana-Dakota Utilities and Great Plains Natural Gas (2020 – 2021)
Mr. Amen provided cost of service, class revenue apportionment, rate design, and expert witness support for the gas utilities' general rate cases before the Montana Public Service Commission and North Dakota Public Service Commission. Testimony included theoretical principals and practical application of cost allocation, and rate design principles or objectives that have broad acceptance in utility regulatory and policy literature. Supported the Straight Fixed-Variable Rate Design (SFV) in North Dakota with analysis showing low-income residential customers would experience lower annual bills under the SFV rate design than a volumetric weighted rate design. Provided a presentation at a public input hearing and oral testimony at Commission hearings in both jurisdictions. SFV rate design was approved by the North Dakota PSC.

Chesapeake Utilities Corporation (2020 – 2021)
Reviewed and evaluated Chesapeake's Swing Service Rider (SSR), which recovers intrastate pipeline capacity costs directly from all transportation customers, and the application of the current cost allocation methodology underlying the service for its Florida gas utilities, Central Florida Gas and Florida Public Utilities. Supported Chesapeake through three primary tasks; (1) Assessment of the factors influencing the current cost allocation method, its impact on various customer groups, and data collection, (2) Assessment of the appropriateness of alternative cost allocation methods and model the application to and impact on the SSR charges, and (3) Provided a report of the evaluation, modelling results and recommendations in a report and conducted a review session with Chesapeake management personnel.

Kansas City, KS Board of Public Utilities (2019 – 2020)
Provided expert witness testimony supporting the basis for a Green Energy Program, its objectives and overall benefits. Provide an assessment of how the program is aligned with best practices in design of Green Energy tariff programs nationally. Testimony also provided an assessment of how the program mitigates potential risks the to the Board of Public Utilities and protects against subsidization of other rate classes.

NW Natural (2018 – 2019)
Provided cost of service, class revenue apportionment, rate design, and expert witness support for the gas utility's general rate case before the Washington Utility and Transportation Commission (WUTC), filed in December 2018. Testimony included theoretical principals and practical application of cost allocation, and rate design principles or objectives that have broad acceptance in utility regulatory and policy literature.

Chesapeake Utilities Corporation (2018 – 2019)

Developed a Weather Normalization Adjustment (WNA) mechanism applicable to the monthly billings of Chesapeake's residential and general service customers. Sponsored the WNA mechanism through expert testimony filed with the Delaware Public Service Commission in January 2019. The testimony included a description of the WNA calculations; back-casting performance analyses, with bill impacts; a WNA tariff; and conceptual and evidentiary support for this ratemaking mechanism.

Louisville Gas & Electric Company and Kentucky Utilities Company (2018)

Engaged by LG&E and KU to a conduct a study in support of a joint utility and stakeholder collaborative concerning economical deployment of electric bus infrastructure by the transit authorities in the Louisville and Lexington KY areas, as well as possible cost-based rate structures related to charging stations and other infrastructure needed for electric buses.

Summit Utilities – Colorado Natural Gas, Inc. (2018)

Engaged by Summit Utilities to develop and support with expert testimony an appropriate normal weather period for the client's five Colorado temperature zones, resulting normalized billing determinants, and a Weather Normalization Adjustment ("WNA") proposal in conjunction with the filing of a general rate case for its Colorado Natural Gas , Inc. subsidiary.

Westar Energy (2018)

Provided cost of service and expert witness support for the electric utility's general rate case filing before the Kansas Corporation Commission (KCC). The cost of service study determined the cost components for a new Residential Distributed Generation (DG) customer class that provided the basis for recommendations for establishing components of a sound, modern three-part rate design for this new Residential DG (roof-top solar) service, which was approved by the KCC.

Florida Public Utilities (Chesapeake Utilities) (2017 – 2018)

Provided a rate stratification study of the utility's commercial and industrial customer classes to facilitate the reconfiguration of the classes by size of service facilities, annual volume, and load factor. Reviewed the cost allocation bases and recommended alternatives for recovery of capital investments related to the utility's Gas Reliability Investment Program (GRIP).

Tacoma Power (2016 – 2018)

Provided cost of service and rate design support for the electric utility's general rate case filings, including support for recovery of fixed costs through fixed charges and impacts on low income customers. Provided recommendations as to specifications in the client's cost of service analysis (COSA) model for deriving Open Access Transmission Tariff rates, using FERC approved standards to guide the evaluation. Conducted an electric utility costing and pricing workshop for the PUB in October 2017; and participated with Tacoma Utilities staff in a comprehensive electric and water Rates and Financial Planning workshop in February 2018. Engagement was extended for the 2019 – 2020 rate filing, which incorporated the Black & Veatch municipal COSA model for costing and ratemaking purposes. Future project work involves working on the re-design of the general service and industrial rate schedules, economic development rate strategies, demand response rates, and other innovative rate programs.

Tacoma Power (2017)

Engaged to review and assess current rates for 3rd Party Pole Attachments (PA), and more specifically, to determine and recommend if any rate adjustments were needed. Performed several tasks:

- Performed a market survey of rates charged by comparable utilities
- Reviewed current regulations on rate setting and practice for 3rd Party Pole Attachments as set forth by the Federal Communications Commission (FCC) and the State of Washington (WA), and the interpretation of such regulations in court decisions
- Reviewed industry best practices under the FCC, WA, and the American Public Power Association (APPA)
- Collected and reviewed data for cost-based fees including:
  - Application Fees
  - Non-Compliance Fees
- Reviewed cost data supplied by the City of Tacoma as relates to determining pole costs, and
- Performed modeling of rates under the FCC Model, the APPA model and the State of Washington shared model (50 % FCC Rate/ 50% APPA Rate).

BC Hydro (2016)

Provided research and analysis of the line extension policies of a select group of peer utilities in Canada with similar regulatory regimes as well as U.S. utilities based on their geographic relationship to the client. Conducted interviews with peer utilities to gather comparative information regarding their line extension policies and related internal procedures. Performed a comparative analysis of the various line extension policies from the selected peer group.

Cascade Natural Gas Corporation (2015 – 2019)

Provided cost of service and rate design support for several of the company's general rate case filings in its two state jurisdictions, 3 in Oregon and 2 in Washington. Conducted Long-run Incremental Cost Studies in the Oregon jurisdiction and embedded class allocated cost of service studies in the Washington jurisdiction. Performed benchmark analyses to compare each of the client's administrative and general (A&G) and operations and management (O&M) expenses, on a per-customer basis, to various peer groups. Analyses were performed for natural gas utilities and combination utilities with both electric and gas operations. Various iterations of the analyses were prepared to make the peer group of utilities more comparable to the characteristics of the client's utility operations. Represented the client's interests in a Washington generic rulemaking proceeding on the subject of electric and gas cost of service methodologies and minimum filing requirements.

Chesapeake Utilities (2015 – 2016)
For its Delaware jurisdiction, provided cost of service and rate design support in the client's general rate case proceeding, including expert witness testimony in support of the utility's proposed gas revenue decoupling mechanism.

Homer Electric Association / Alaska Electric and Energy Cooperatives (2015)
Represented clients in an ENSTAR gas general rate proceeding. Testimony discussed accepted industry principles of revenue allocation and rate design, including the applicability to and alignment with ENSTAR's revenue allocation and rate design proposals for large power and industrial customers. Provided a critique of certain methodological aspects of ENSTAR's Cost of Service study, proposed revenue allocation, and rate design relating to the various large power and industrial customers.

Arkansas Oklahoma Gas Corporation (2002, 2003, 2004, 2007, 2012, 2013)
Provided cost of service and rate design support for several of the company's general rate case filings in its two state jurisdictions and in support of Section 311 transportation filings (2007, 2010) before the Federal Energy Regulatory Commission. Provided related research, design and expert witness testimony in support of a Revenue Decoupling mechanism in one jurisdiction and a Weather Normalization Adjustment mechanism in the other jurisdiction, along with a significant increase in fixed charges and the introduction of demand charges for the company's largest customer classes. Conducted a pre-filing "decoupling" workshop for the utility commission staff.

Northern Indiana Public Service Company (NiSource) (2009 – 2010, 2013, 2017, 2021)
Conducted class allocated cost of service studies for the client's natural gas (including two other affiliate gas utilities) and electric operations. Work included reconfiguring the Company's commercial and industrial customer classes according to size of load and customer-related facilities. Rate design was modernized to recover a greater portion of fixed costs via fixed monthly customer and demand-based charges, a transition to a "Straight-Fixed Variable" form of rate design. Industry research was provided on alternative rate designs for the electric service, including Time-of-Use rates and Critical Peak Pricing. Served as an expert witness on behalf of the client in five general rate cases before the Indiana Utility Regulatory Commission. The 2021 rate case is currently pending before the IURC.

Southwestern Public Service Company (Xcel) (2012)
Retained to conduct a study to estimate the conservation effect of replacing its existing electric residential rate design with an alternative rate design such as an inverted block rate design. Reviewed inclining block rate structures that have actively been employed in other jurisdictions and also reviewed technical and academic literature to assess the elasticity of electricity demand for residential customers in the southwestern U.S. Analyzed 2009-2011 residential data to determine what sort of conservation effect the company may expect by implementing an inclining block rate structure. Provided an overview of alternative rate structures which may also promote conservation effects, such as seasonal rates, three-part rates and time-of-use (TOU) rates, and considered the competing incentives of promoting conservation and cost recovery, without specific rate mechanisms to address this conflict.

Atlantic Wallboard LP and Flakeboard Company Limited (JD Irving) (2012)

Represented clients in an Enbridge Gas New Brunswick Limited Partnership ("EGNB") general rate proceeding. Testimony responded to the 2012 allocated cost of service study and rate design that was submitted to the New Brunswick Energy and Utilities Board by EGNB. Testimony also provided benchmark information regarding EGNB's distribution pipeline infrastructure in New Brunswick. CA.

Western Massachusetts Electric Company (Northeast Utilities) (2010 – 2011)

Supported utility in its decoupling proposal for the company's general rate case. Work included: 1) research on the financial implications of decoupling; 2) identification of decoupling mechanism details to address company and regulatory requirements and objectives; 3) identification of rate adjustment mechanisms that would work together with the company's proposed decoupling mechanism; and 4) preparing pre-filed testimony and testifying at hearings in support of the company's decoupling and rate adjustment proposals. The proposed rate adjustment mechanisms included an inflation adjustment mechanism based on a statistical analysis, and a capital spending mechanism to recover the costs associated with capital plant investment targeted to improving service reliability.

Interstate Power & Light (Alliant Energy) (2010 – 2011)

Conducted class allocated cost of service studies for a Midwestern electric utility's Minnesota electric system. Work included reconfiguring the company's customer classes for cost of service purposes to collapse end-use based classes with the classes to which they would be eligible. Cost of service studies were performed on a before-and-after basis for the existing and proposed classes. The cost of service studies included a fixed/variable study for production costs, and a primary/secondary study for poles, transformers and conductors. Performed a TOU analysis to determine the appropriate rate differentials for its peak and off-peak rates. Served as an expert witness on behalf of the client in a general rate case before the Minnesota Public Service Commission.

National Grid (2010)

Conducted class allocated cost of service studies for the client's Massachusetts natural gas operations. This task included combined gas cost of service studies for the consolidation of four gas service territories into two gas utility subsidiaries. During interrogatories, performed four separate allocated cost of service studies for each gas service territory. Work included reconfiguring the company's commercial and industrial customer classes according to size of load and customer-related facilities. Served as an expert witness on behalf of the client in consolidated general rate cases before the Massachusetts Department of Public Utilities.

Puget Sound Energy (2001 – 2002, 2006 – 2007, 2019 – 2020)

In three Washington general rate proceedings, provided cost of service and rate design support, including expert witness testimony in support of the utility's proposed revenue decoupling mechanism. Conducted research on accelerated cost recovery mechanisms for infrastructure replacement, and electric power cost adjustment mechanisms. In the latest general rate case, Mr.

Amen is sponsoring expert testimony on a proposed revenue attrition adjustment to the client's revenue requirement.

Utility System Operations and Organizational Development

Philadelphia Gas Works (2017, 2020)
Engaged to provide an independent consulting engineer's report to be included as an appendix to the official statement prepared in connection with the issuance of the City of Philadelphia, Pennsylvania Gas Works Revenue Bonds. The evaluation of the PGW system included a discussion of organization, management, and staffing; system service area; supply facilities; distribution facilities; and the utility's Capital Improvement Plan (CIP). Our report also contained: (a) financial feasibility information, including analyses of gas rates and rate methodology; (b) projection of future operation and maintenance expenses; (c) CIP financing plans; (d) projection of revenue requirements as a determinant of future revenues; (e) an assessment of PGW's ability to satisfy the covenants in the General Gas Works Revenue Bond Ordinance of 1998 authorizing the issuance of the Bonds; and (f) information regarding potential liquefied natural gas ("LNG") expansion opportunities.

Puget Sound Energy (2013 – 2014)
Engaged to perform a review of its project management and capital spending authorization processes (CSA). The overall project objectives were to educate project management (PM) staff as to the importance and relevance of regulatory prudence standards, evaluate existing PM processes along with newly introduced corporate CSA processes, and propose PM and corporate process and documentation efficiencies. This task was accomplished through 1) a situational assessment and risk review; 2) analysis of project management practices; and 3) development of common documentation for the CSA and PM processes.

Puget Sound Energy (2012 – 2013)
Engaged to perform a review of how the company compares to similarly-situated utilities in the areas of the underlying capitalized costs related to new customer additions ("new business investment") and the management policies and practices that influence the new business capital investment. Examined the interrelationships of our client's management policies and practices in the functional areas related to new business investment and developed an understanding of the nature of the costs captured by the new business investment process. Benchmarked those costs relative to peers' cost factors and management capital expenditure practices and performed targeted peer group interviews on our client's behalf. The review identified certain trends and/or interrelationships between management policies and practices, as well as other exogenous factors, and the resulting impact on new business investment.

Puget Sound Energy (2011 – 2012)
Engaged to perform a review of its electric transmission planning and project prioritization process. The emphasis of the review was to determine if the process implemented by the client could be expected to meet the regulatory standard of prudence, as adopted by the state regulatory commission. Reviewed the prudence standard adopted by the commission in several recent

regulatory proceedings, supplemented by our knowledge of the prudence standard adopted at a national level and in other states. The engagement included two phases: 1) an initial situation assessment of the existing process employed by the client, and 2) a review of the historic implementation of that process by reviewing a sampling of transmission projects. Compiled and provided examples of capital planning documents and procedures, viewed as "best practices," from other electric utilities and other relevant transmission entities.

Alliant Energy (2011 – 2012)
Provided audit support for one of the company's gas and electric utilities, Interstate Power & Light, during a management audit ordered by one of its two regulatory jurisdictions. Conducted a pre-audit of distribution operations and resource planning processes to provide the client with potential audit issues. Assisted the client throughout the audit process in responding to information requests, preparing company executives and management personnel for audit interviews, and management of preliminary audit issues and findings by the independent audit firm.

Ameren Illinois Utilities (2009 – 2010)
Performed a number of benchmark analyses to compare each of the client's A&G and O&M expenses, on a per-customer basis, to various peer groups conducted for the client's natural gas and electric operations. Analyses were performed for natural gas, electric and combination utilities with both electric and gas operations. Various iterations of the analyses were prepared to make the peer group of utilities more comparable to the characteristics of the client's utility operations. Served as an expert witness on behalf of the client in a consolidated general rate case proceeding of its three utility subsidiaries before the Illinois Commerce Commission.

EXPERT WITNESS TESTIMONY PRESENTATION

- Alaska Regulatory Commission
- Arkansas Public Service Commission
- British Columbia Utility Commission (Canada)
- Colorado Public Utility Commission
- Connecticut Department of Public Utility Control
- Delaware Public Service Commission
- Illinois Commerce Commission
- Indiana Utility Regulatory Commission
- Kansas Corporation Commission
- Manitoba Public Utilities Board (Canada)
- Massachusetts Department of Utilities
- Minnesota Public Utilities Commission
- Missouri Public Service Commission
- Montana Public Service Commission
- New Brunswick Energy and Utilities Board (Canada)
- New Hampshire Public Utilities Commission
- North Dakota Public Service Commission
- Oklahoma Corporation Commission
- Oregon Public Utility Commission
- Pennsylvania Public Utility Commission
- Washington Utilities and Transportation Commission
- Federal Energy Regulatory Commission

SELECTED PUBLICATIONS / PRESENTATIONS

"Enhancing the Profitability of Growth," American Gas Association, Rate and Regulatory Issues Seminar, April 4 - 7, 2004

"Regulatory Treatment of New Generation Resource Acquisition: Key Aspects of Resource Policy, Procurement and New Resource Acquisition," Law Seminars International, Managing the Modern Utility Rate Case, February 17 - 18, 2005

"Managing Regulatory Risk – The Risk Associated with Uncertain Regulatory Outcomes," Western Energy Institute, Spring Energy Management Meeting, May 18 - 20, 2005

"Capital Asset Optimization – An Integrated Approach to Optimizing Utilization and Return on Utility Assets," Southern Gas Association, July 18 - 20, 2005

"Resource Planning as a Cost Recovery Tool," Law Seminars International, Utility Rate Case Issues & Strategies, February 22 - 23, 2007

"Natural Gas Infrastructure Development and Regulatory Challenges," Southeastern Association of Regulatory Utility Commissioners, Annual Conference, June 4 – 6, 2007

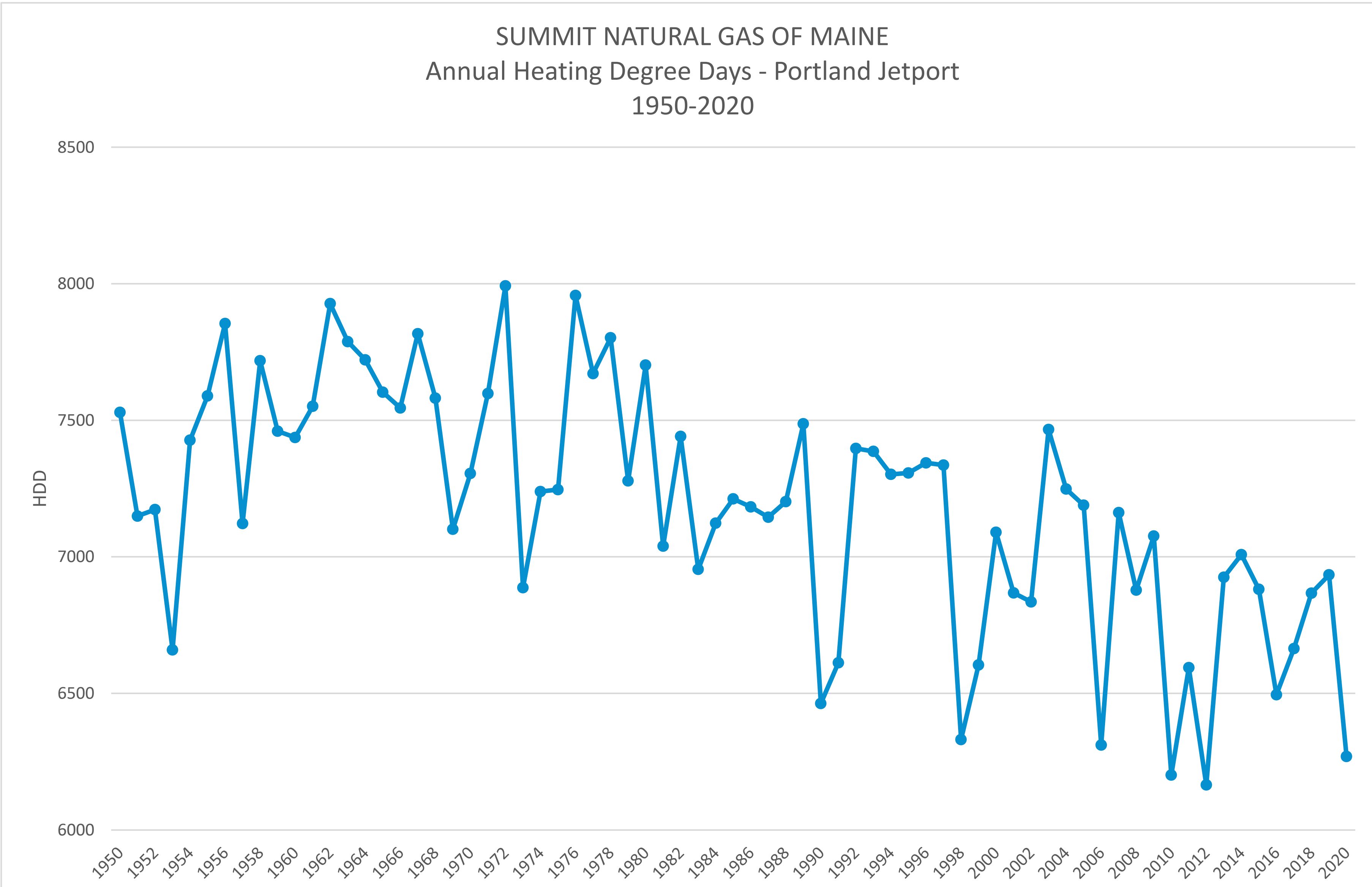
"Resource Planning in a Changing Regulatory Environment," Law Seminars International, Utility Rate Cases – Current Issues & Strategies, February 7 - 8, 2008

"Natural Gas Distribution Infrastructure Replacement," American Gas Association, Rate Committee Meeting and Regulatory Issues Seminar, April 11 – 13, 2010

"Building a T&D Investment Program to Satisfy Customers, Regulators and Shareholders," SNL Webinar, March 27, 2014

"Utility Infrastructure Replacement; Trends in Aging Infrastructure, Replacement Programs and Rate Treatment," Large Public Power Council, Rates Committee Meeting, August 14, 2014

"Natural Gas in the Decarbonization Era, Gas Resource Planning for Electric Generation," EUCI, January 22-23, 2020


SUMMIT NATURAL GAS OF MAINE
Annual Heating Degree Days - Portland Jetport
1950-2020
HDD
8500
8000
7500
7000
6500
6000
1950
1952
1954
1956
1958
1960
1962
1964
1966
1968
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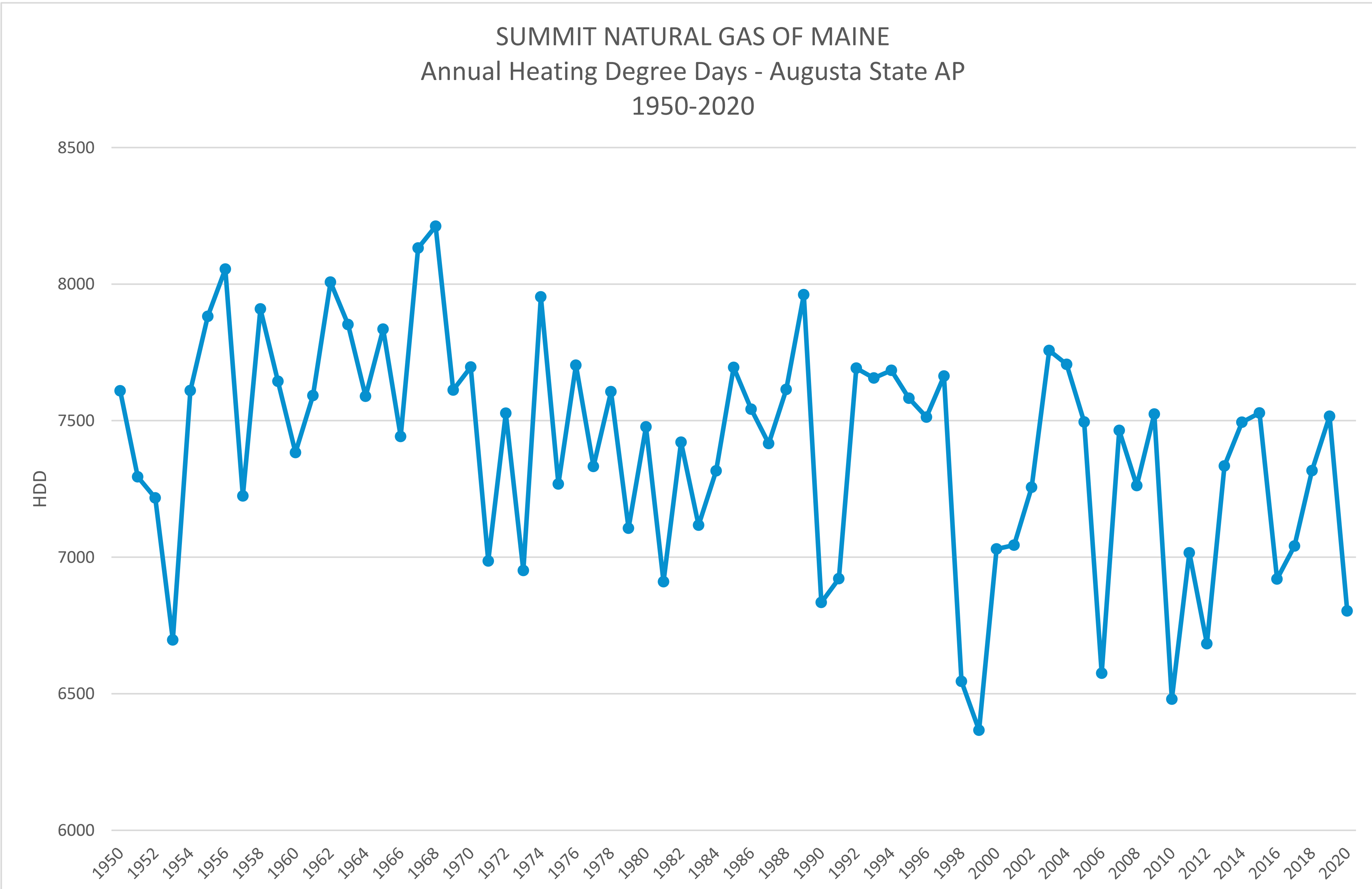
SUMMIT NATURAL GAS OF MAINE
Annual Heating Degree Days - Augusta State AP
1950-2020
HDD
8500
8000
7500
7000
6500
6000
1950
1952
1954
1956
1958
1960
1962
1964
1966
1968
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2008
2010
2012
2014
2016
2018
2020

	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)
		Weather Station: Portland Jetport				**Weather Station: Augusta State AP**			
Line	**Forecast Error Squared**	30-Year Average (Rolling)	20-Year Average (Rolling)	10-Year Average (Rolling)	5-Year Average (Rolling)	30-Year Average (Rolling)	20-Year Average (Rolling)	10-Year Average (Rolling)	5-Year Average (Rolling)
1	**40-year Band**								
2	Sum	8,056,860	6,768,021	5,734,237	6,837,812	6,997,997	6,845,688	6,815,257	9,151,606
3	Mean	201,421	169,201	143,356	170,945	174,950	171,142	170,381	228,790
4	Root Mean Squared Error (RMSE)	448.80	411.34	378.62	413.46	418.27	413.69	412.77	478.32
5	**30-year Band**								
6	Sum	6,060,765	4,928,200	4,320,832	5,423,867	5,605,777	5,442,740	5,637,686	7,738,550
7	Mean	202,025	164,273	144,028	180,796	186,859	181,425	187,923	257,952
8	Root Mean Squared Error (RMSE)	449.47	405.31	379.51	425.20	432.27	425.94	433.50	507.89
9	**20-year Band**								
10	Sum	3,829,792	3,069,871	2,556,162	2,954,948	2,856,684	2,806,898	2,730,904	4,042,481
11	Mean	191,490	153,494	127,808	147,747	142,834	140,345	136,545	202,124
12	Root Mean Squared Error (RMSE)	437.60	391.78	357.50	384.38	377.93	374.63	369.52	449.58
13	**10-year Band**								
14	Sum	1,781,093	1,413,291	1,114,827	1,030,068	1,054,595	995,723	986,471	1,084,421
15	Mean	178,109	141,329	111,483	103,007	105,460	99,572	98,647	108,442
16	Root Mean Squared Error (RMSE)	422.03	375.94	333.89	320.95	324.75	315.55	314.08	329.31

	Cumberland/Falmouth/Yarmouth (Portland Jetport)	Kennebec Valley (Agusta State Airport)
January	1,218.6	1,322.8
February	1,081.8	1,164.0
March	954.9	1,026.6
April	613.9	632.2
May	308.4	292.2
June	85.9	86.7
July	4.4	7.1
August	9.0	10.8
September	125.5	140.5
October	414.8	452.9
November	758.4	819.2
December	1,062.2	1,159.6
	6,637.8	7,114.6

Summit Natural Gas of Maine, Inc.
Summary of Statistical Results from Heating Degree Day Regression Analysis

Line	[a] Description		[b] All Data	[c] 5-Years	[d] 4-Years	[e] 3-Years	[f] 2-Years	[g] 1-Year
1	**RESIDENTIAL**							
2	Weather Station - Portland Jetport (CFY)							
3	Constant		0.44100	0.48712	0.49256	0.50632	0.55736	0.54078
4	Current Month's HDD		0.00097	0.00067	0.00091	0.00120	0.00129	0.00139
5	Previous Month's HDD		0.00990	0.01021	0.01006	0.00985	0.00964	0.00946
6	Adjusted R Squared		0.96974	0.97288	0.97312	0.97042	0.96784	0.96154
7	F		1,042.61	1,059.27	851.76	575.08	347.05	138.51
8	10-Year Normal HDD	6,638						
9	Predicted Normal UPC (dth)		77.43	78.10	78.74	79.39	79.30	78.51
10	Load Factor		21.4%	21.5%	21.5%	21.5%	21.7%	21.6%
11	Weather Station - Augusta State Airport (KV)							
12	Constant		0.09844	0.13248	0.09601	0.12988	0.23256	(0.09815)
13	Current Month's HDD		0.00397	0.00378	0.00388	0.00411	0.00433	0.00439
14	Previous Month's HDD		0.00900	0.00908	0.00899	0.00855	0.00801	0.00846
15	Adjusted R Squared		0.97616	0.97678	0.97472	0.97588	0.97584	0.97998
16	F		1,331.59	1,242.21	906.96	709.05	465.59	270.16
17	10-Year Normal HDD	7,115						
18	Predicted Normal UPC (dth)		93.50	93.08	92.73	91.62	90.56	90.28
19	Load Factor		22.4%	22.4%	22.4%	22.4%	22.7%	21.9%
20	**SMALL COMMERCIAL**							
21	Weather Station - Portland Jetport (CFY)							
22	Constant		4.09175	4.20238	4.08867	3.71512	3.79639	3.35315
23	Current Month's HDD		0.00284	0.00226	0.00372	0.00538	0.00617	0.00440
24	Previous Month's HDD		0.02920	0.02902	0.02692	0.02511	0.02223	0.02372
25	Adjusted R Squared		0.93411	0.93870	0.94100	0.93488	0.94142	0.94531
26	F		461.77	452.73	375.83	252.22	185.83	96.06
27	10-Year Normal HDD	6,638						
28	Predicted Normal UPC (dth)		261.81	258.03	252.45	246.94	234.08	226.89
29	Load Factor		23.8%	23.9%	23.9%	23.6%	23.9%	23.5%
30	Weather Station - Augusta State Airport (KV)							
31	Constant		4.86995	4.93159	4.77587	5.52028	5.95371	5.06643
32	Current Month's HDD		0.01306	0.01271	0.01337	0.01473	0.01582	0.01475
33	Previous Month's HDD		0.03837	0.03707	0.03682	0.03424	0.03105	0.03329
34	Adjusted R Squared		0.95278	0.97166	0.97261	0.97274	0.97641	0.97925
35	F		656.82	1,012.45	835.50	625.36	477.01	260.57
36	10-Year Normal HDD	7,115						
37	Predicted Normal UPC (dth)		424.35	413.38	414.39	414.65	404.92	402.61
38	Load Factor		24.8%	24.9%	24.8%	25.3%	25.7%	25.1%

Line	[a] Description		[b] All Data	[c] 5-Years	[d] 4-Years	[e] 3-Years	[f] 2-Years	[g] 1-Year
39	**LARGE COMMERCIAL**							
40	Weather Station - Portland Jetport (CFY)							
41	Constant		48.79955	50.01800	53.75135	56.08811	54.63617	67.16268
42	Current Month's HDD		0.06862	0.05347	0.06641	0.07970	0.11387	0.08051
43	Previous Month's HDD		0.39477	0.42345	0.40409	0.39737	0.35936	0.38271
44	Adjusted R Squared		0.95003	0.97457	0.97477	0.97327	0.96727	0.97759
45	F		618.84	1,131.52	908.78	638.19	340.83	240.91
46	10-Year Normal HDD	6,638						
47	Predicted Normal UPC (dth)		3,661.50	3,765.92	3,768.15	3,839.73	3,796.86	3,880.68
48	Load Factor		23.2%	23.2%	23.4%	23.5%	23.4%	24.2%
49	Weather Station - Augusta State Airport (KV)							
50	Constant		21.86919	21.44124	19.55433	13.09606	20.36832	18.26331
51	Current Month's HDD		0.11780	0.10903	0.12076	0.12381	0.14356	0.15982
52	Previous Month's HDD		0.28461	0.30182	0.30139	0.31445	0.26768	0.24108
53	Adjusted R Squared		0.94765	0.95699	0.95948	0.96194	0.96651	0.98285
54	F		589.32	657.33	557.51	443.27	332.89	316.28
55	10-Year Normal HDD	7,115						
56	Predicted Normal UPC (dth)		3,125.46	3,180.33	3,238.05	3,275.25	3,170.25	3,071.46
57	Load Factor		23.7%	23.6%	23.5%	23.0%	23.6%	23.5%
58	Peak HDD used to calculate load factor:							
59	Portland Jetport Peak HDD	90						
60	Augusta State Airport Peak HDD	88						

Summit Natural Gas of Maine, Inc.
Weather Normalized Usage

[a]	[b]	[c]	[d]	[e]	[f]	[g]	[h]	[i]	[j]	[k]	[l]	[m]	[n]	[o]	[p]	[q]	[r]	[s]	[t]
	Heating Degree Days - Portland				Cumberland/Falmouth/Yarmouth (CFY)														
	Test Year Actual		10-Year Normal		Residential					Small Commercial					Large Commercial				
Month	Current	Prior Month	Current	Prior Month	Customers	Usage (dth)	UPC	Normal UPC	Normal Use (dth)	Cust.	Usage (dth)	UPC	Normal UPC	Normal Use (dth)	Cust.	Usage (dth)	UPC	Normal UPC	Normal Use (dth)
Jul-20	1.0	58.0	4.4	85.9	2,031	3,544.4	1.7	1.4	2,777.4	304	1,951.6	6.4	6.7	2,038.3	19	1,787.1	94.1	86.6	1,645.9
Aug-20	14.0	1.0	9.0	4.4	2,038	2,588.9	1.3	0.5	1,096.7	311	1,636.9	5.3	4.4	1,353.0	19	1,507.2	79.3	52.4	994.9
Sep-20	101.0	14.0	125.5	9.0	2,058	2,631.4	1.3	0.7	1,365.0	309	1,815.8	5.9	4.7	1,466.9	20	1,564.2	78.2	60.5	1,210.8
Oct-20	471.0	101.0	414.8	125.5	2,091	4,569.5	2.2	2.0	4,281.3	320	2,805.1	8.8	8.8	2,810.0	20	2,778.2	138.9	125.3	2,506.8
Nov-20	680.0	471.0	758.4	414.8	2,123	11,170.8	5.3	5.2	11,110.2	332	4,891.8	14.7	18.0	5,960.1	20	6,436.5	321.8	266.2	5,324.4
Dec-20	1,040.0	680.0	1,062.2	758.4	2,138	15,320.4	7.2	8.9	19,128.6	336	6,802.4	20.2	28.6	9,612.6	20	7,503.2	375.2	428.0	8,559.2
Jan-21	1,147.0	1,040.0	1,218.6	1,062.2	2,167	29,618.7	13.7	12.2	26,340.2	348	13,110.1	37.7	37.8	13,146.6	21	13,077.4	622.7	565.0	11,864.3
Feb-21	1,096.0	1,147.0	1,081.8	1,218.6	2,182	27,539.0	12.6	13.7	29,808.1	346	11,948.8	34.5	42.0	14,534.3	21	11,671.8	555.8	623.9	13,101.5
Mar-21	927.0	1,096.0	954.9	1,081.8	2,185	27,436.0	12.6	12.2	26,609.7	349	12,255.8	35.1	37.8	13,174.9	21	11,493.1	547.3	559.2	11,742.5
Apr-21	570.0	927.0	613.9	954.9	2,198	22,518.0	10.2	10.7	23,415.8	348	9,992.8	28.7	33.3	11,587.6	21	10,083.1	480.1	487.2	10,231.1
May-21	291.0	570.0	308.4	613.9	2,194	11,572.1	5.3	7.0	15,281.1	340	4,877.3	14.3	22.7	7,722.3	20	6,216.3	310.8	326.5	6,529.3
Jun-21	44.0	291.0	85.9	308.4	2,208	5,729.5	2.6	3.7	8,158.6	337	2,810.8	8.3	13.3	4,497.3	20	3,265.4	163.3	185.2	3,704.1
Total	6,382	6,396	6,638	6,638		164,238.7	75.9	78.1	169,372.6		74,899.1	220.0	258.0	87,903.8		77,383.5	3,767.5	3,765.9	77,414.6

CFY Regression Coefficients:

Constant	0.4871	4.2024	50.0180
Current HDD	0.0007	0.0023	0.0535
Prior HDD	0.0102	0.0290	0.4234

[a]	[b]	[c]	[d]	[e]	[f]	[g]	[h]	[i]	[j]	[k]	[l]	[m]	[n]	[o]	[p]	[q]	[r]	[s]	[t]
	Heating Degree Days - Augusta				Kennebec Valley (KV)														
	Test Year Actual		10-Year Normal		Residential					Small Commercial					Large Commercial				
Month	Current	Prior Month	Current	Prior Month	Customers	Usage (dth)	UPC	Normal UPC	Normal Use (dth)	Cust.	Usage (dth)	UPC	Normal UPC	Normal Use (dth)	Cust.	Usage (dth)	UPC	Normal UPC	Normal Use (dth)
Jul-20	9.0	66.0	7.1	86.7	1,256	1,607.9	1.3	0.9	1,188.8	544	5,441.4	10.0	8.2	4,480.3	68	3,721.1	54.7	48.4	3,290.0
Aug-20	30.0	9.0	10.8	7.1	1,267	1,209.2	1.0	0.2	301.3	547	4,341.5	7.9	5.3	2,916.7	69	2,844.2	41.2	24.8	1,708.6
Sep-20	138.0	30.0	140.5	10.8	1,276	1,418.6	1.1	0.8	971.9	543	4,911.1	9.0	7.1	3,865.3	69	3,130.5	45.4	40.0	2,761.4
Oct-20	517.0	138.0	452.9	140.5	1,326	3,647.8	2.8	3.1	4,137.5	551	9,010.7	16.4	15.9	8,760.1	69	7,529.5	109.1	113.2	7,812.7
Nov-20	706.0	517.0	819.2	452.9	1,352	8,842.6	6.5	7.3	9,925.7	561	17,033.2	30.4	32.1	18,028.8	70	17,842.4	254.9	247.5	17,321.8
Dec-20	1,052.0	706.0	1,159.6	819.2	1,378	13,504.1	9.8	12.0	16,472.9	571	22,915.5	40.1	50.0	28,575.1	71	25,744.4	362.6	395.1	28,053.9
Jan-21	1,224.0	1,052.0	1,322.8	1,159.6	1,389	21,632.2	15.6	15.7	21,754.3	582	37,423.0	64.3	64.7	37,677.4	73	36,773.7	503.7	515.7	37,643.0
Feb-21	1,140.0	1,224.0	1,164.0	1,322.8	1,405	21,407.4	15.2	16.5	23,243.3	587	35,893.5	61.1	68.8	40,367.1	72	34,118.0	473.9	547.6	39,427.2
Mar-21	969.0	1,140.0	1,026.6	1,164.0	1,419	19,946.2	14.1	14.6	20,691.9	588	34,458.4	58.6	61.1	35,947.2	72	30,560.4	424.4	484.7	34,897.7
Apr-21	549.0	969.0	632.2	1,026.6	1,415	14,593.8	10.3	11.8	16,758.5	588	26,545.0	45.1	51.0	30,003.6	72	26,448.2	367.3	400.2	28,815.7
May-21	276.0	549.0	292.2	632.2	1,408	6,904.4	4.9	7.0	9,823.9	590	14,439.9	24.5	32.1	18,928.9	72	12,823.9	178.1	244.1	17,575.9
Jun-21	39.0	276.0	86.7	292.2	1,395	2,794.9	2.0	3.1	4,343.0	588	8,021.3	13.6	16.9	9,917.2	72	5,462.9	75.9	119.1	8,574.2
Total	6,649	6,676	7,115	7,115		117,509.1	84.5	93.1	129,613.1		220,434.3	381.1	413.4	239,467.6		206,999.1	2,891.3	3,180.3	227,882.2

KV Regression Coefficients:

Constant	0.1325	4.9316	21.4412
Current HDD	0.0038	0.0127	0.1090
Prior HDD	0.0091	0.0371	0.3018

Summit Natural Gas of Maine, Inc.
Weather Normalization and Customer Annualization
12 Months Ended June 30, 2021

Docket No. 2022-00025
Exhibit RJA-07

					Per Books									
Line No.	Description	Rates: July 2020 - May 2021	Current Rates: June 2021 -	Month	Full Rate Test Year Customers	Special Rate Test Year Customers	Total Test Year Customers	Full Rate Test Year Therms	Special Rate Test Year Therms	Total Test Year Therms	Test Year UPC	Calculated Full Rate Revenue	Special Rate Revenue	Total Revenue
	[a]	[b]	[c]	[d]	[e]	[f]	[g]	[h]	[i]	[j]	[k]	[l]	[m]	[n]
1	**Residential - Schedule RG**													
2	Service and Facilities Charge	$21.70 /month	$21.91 /month											
3	Distribution Charge	$0.9470 /therm	$0.9850 /therm											
4				July	3,287	-	3,287	51,523	-	51,523	15.67	$ 120,121	$ -	$ 120,121
5				August	3,305	-	3,305	37,981	-	37,981	11.49	$ 107,687	$ -	$ 107,687
6				September	3,334	-	3,334	40,500	-	40,500	12.15	$ 110,701	$ -	$ 110,701
7				October	3,417	-	3,417	82,173	-	82,173	24.05	$ 151,967	$ -	$ 151,967
8				November	3,475	-	3,475	200,134	-	200,134	57.59	$ 264,934	$ -	$ 264,934
9				December	3,516	-	3,516	288,245	-	288,245	81.98	$ 349,265	$ -	$ 349,265
10				January	3,556	-	3,556	512,509	-	512,509	144.13	$ 562,511	$ -	$ 562,511
11				February	3,587	-	3,587	489,463	-	489,463	136.45	$ 541,360	$ -	$ 541,360
12				March	3,604	-	3,604	473,822	-	473,822	131.47	$ 526,916	$ -	$ 526,916
13				April	3,613	-	3,613	371,118	-	371,118	102.72	$ 429,851	$ -	$ 429,851
14				May	3,602	-	3,602	184,766	-	184,766	51.30	$ 253,136	$ -	$ 253,136
15				June	3,603	-	3,603	85,244	-	85,244	23.66	$ 162,907	$ -	$ 162,907
16										2,817,477	792.66	$ 3,581,355	$ -	$ 3,581,355
17	**Small Commercial - Schedule SC**													
18	Service and Facilities Charge	$35.79 /month	$36.13 /month											
19	Distribution Charge	$0.8360 /therm	$0.8690 /therm											
20				July	818	30	848	49,102	24,828	73,929	87.18	$ 70,325	$ 9,035	$ 79,360
21				August	828	30	858	40,567	19,217	59,784	69.68	$ 63,548	$ 7,270	$ 70,818
22				September	822	30	852	45,771	21,497	67,268	78.95	$ 67,684	$ 8,063	$ 75,747
23				October	841	30	871	82,444	35,714	118,158	135.66	$ 99,023	$ 13,593	$ 112,615
24				November	863	30	893	164,291	54,958	219,250	245.52	$ 168,234	$ 20,946	$ 189,180
25				December	877	30	907	235,665	61,514	297,179	327.65	$ 228,404	$ 24,128	$ 252,532
26				January	900	30	930	406,768	98,563	505,331	543.37	$ 372,269	$ 38,184	$ 410,453
27				February	903	30	933	390,053	88,370	478,422	512.78	$ 358,402	$ 34,892	$ 393,294
28				March	907	30	937	378,290	88,852	467,142	498.55	$ 348,712	$ 35,006	$ 383,718
29				April	906	30	936	284,582	80,795	365,378	390.36	$ 270,336	$ 31,101	$ 301,437
30				May	900	30	930	146,858	46,314	193,172	207.71	$ 154,984	$ 16,338	$ 171,322
31				June	895	30	925	75,097	33,224	108,321	117.10	$ 97,596	$ 13,007	$ 110,602
32								2,299,488	653,846	2,953,334	3,214.51	$ 2,299,518	$ 251,561	$ 2,551,079

					Per Books									
Line No.	Description	Rates: July 2020 - May 2021	Current Rates: June 2021 -	Month	Full Rate Test Year Customers	Special Rate Test Year Customers	Total Test Year Customers	Full Rate Test Year Therms	Special Rate Test Year Therms	Total Test Year Therms	Test Year UPC	Calculated Full Rate Revenue	Special Rate Revenue	Total Revenue
	[a]	[b]	[c]	[d]	[e]	[f]	[g]	[h]	[i]	[j]	[k]	[l]	[m]	[n]
33	**Large Commercial - Schedule LC**													
34	Service and Facilities Charge	$309.19 /month	$312.17 /month											
35	Distribution Charge	$0.6140 /therm	$0.6390 /therm											
36				July	61	26	87	43,261	11,821	55,082	633.13	$ 45,423	$ 5,337	$ 50,759
37				August	62	26	88	34,378	9,136	43,514	494.48	$ 40,278	$ 4,630	$ 44,908
38				September	63	26	89	36,742	10,205	46,947	527.49	$ 42,038	$ 5,103	$ 47,141
39				October	63	26	89	83,826	19,250	103,076	1,158.16	$ 70,948	$ 11,060	$ 82,008
40				November	64	26	90	166,966	75,823	242,789	2,697.66	$ 122,305	$ 38,336	$ 160,641
41				December	65	26	91	212,896	119,580	332,475	3,653.58	$ 150,815	$ 60,160	$ 210,976
42				January	68	26	94	322,938	175,573	498,511	5,303.31	$ 219,309	$ 83,146	$ 302,454
43				February	67	26	93	304,341	153,557	457,898	4,923.63	$ 207,581	$ 74,502	$ 282,083
44				March	67	26	93	286,143	134,392	420,535	4,521.88	$ 196,408	$ 64,460	$ 260,868
45				April	67	26	93	232,624	132,690	365,314	3,928.11	$ 163,547	$ 55,190	$ 218,737
46				May	66	26	92	138,509	51,893	190,402	2,069.58	$ 105,451	$ 24,514	$ 129,965
47				June	66	26	92	63,721	23,562	87,282	948.72	$ 61,321	$ 12,921	$ 74,242
48								1,926,344	917,481	2,843,826	30,859.73	$ 1,425,424	$ 439,358	$ 1,864,783

Summit Natural Gas of Maine, Inc.
Weather Normalization and Customer Annualization
12 Months Ended June 30, 2021

					Weather Normalization			
Line No.	Description	Rates: July 2020 - May 2021	Current Rates: June 2021 -	Month	Normal UPC	Test Year Normal Therms	WN Therm Adjustment	WN Revenue Adjustment
	[a]	[b]	[c]	[d]	[o]	[p]	[q]	[r]
1	**Residential - Schedule RG**							
2	Service and Facilities Charge	$21.70 /month	$21.91 /month					
3	Distribution Charge	$0.9470 /therm	$0.9850 /therm					
4				July	12.07	39,662	(11,861)	$ (11,683)
5				August	4.23	13,979	(24,002)	$ (23,642)
6				September	7.01	23,370	(17,130)	$ (16,873)
7				October	24.64	84,188	2,015	$ 1,985
8				November	60.54	210,359	10,226	$ 10,072
9				December	101.26	356,015	67,770	$ 66,753
10				January	135.25	480,945	(31,564)	$ (31,090)
11				February	147.90	530,514	41,051	$ 40,435
12				March	131.25	473,016	(806)	$ (794)
13				April	111.19	401,743	30,625	$ 30,166
14				May	69.70	251,050	66,284	$ 65,290
15				June	34.70	125,016	39,772	$ 39,175
16					839.72	2,989,857	172,380	$ 169,795
17	**Small Commercial - Schedule SC**							
18	Service and Facilities Charge	$35.79 /month	$36.13 /month					
19	Distribution Charge	$0.8360 /therm	$0.8690 /therm					
20				July	76.87	65,186	(8,744)	$ (7,598)
21				August	49.76	42,696	(17,087)	$ (14,849)
22				September	62.58	53,321	(13,947)	$ (12,120)
23				October	132.84	115,701	(2,457)	$ (2,135)
24				November	268.63	239,889	20,639	$ 17,936
25				December	421.03	381,877	84,697	$ 73,602
26				January	546.49	508,240	2,909	$ 2,528
27				February	588.44	549,014	70,592	$ 61,344
28				March	524.25	491,221	24,079	$ 20,924
29				April	444.35	415,911	50,534	$ 43,914
30				May	286.57	266,512	73,340	$ 63,732
31				June	155.83	144,145	35,825	$ 31,132
32					3,557.66	3,273,714	320,380	$ 278,410

					Weather Normalization			
Line No.	Description	Rates: July 2020 - May 2021	Current Rates: June 2021 -	Month	Normal UPC	Test Year Normal Therms	WN Therm Adjustment	WN Revenue Adjustment
	[a]	[b]	[c]	[d]	[o]	[p]	[q]	[r]
33	**Large Commercial - Schedule LC**							
34	Service and Facilities Charge	$309.19 /month	$312.17 /month					
35	Distribution Charge	$0.6140 /therm	$0.6390 /therm					
36				July	567.35	49,360	(5,722)	$ (3,657)
37				August	307.21	27,034	(16,479)	$ (10,530)
38				September	446.31	39,722	(7,225)	$ (4,617)
39				October	1,159.50	103,195	119	$ 76
40				November	2,516.24	226,461	(16,328)	$ (10,433)
41				December	4,023.41	366,131	33,655	$ 21,506
42				January	5,266.74	495,073	(3,438)	$ (2,197)
43				February	5,648.25	525,287	67,389	$ 43,062
44				March	5,015.08	466,402	45,867	$ 29,309
45				April	4,198.58	390,468	25,154	$ 16,074
46				May	2,620.13	241,052	50,650	$ 32,366
47				June	1,334.59	122,782	35,500	$ 22,684
48					33,103.39	3,052,968	209,142	$ 133,642

Summit Natural Gas of Maine, Inc.
Weather Normalization and Customer Annualization
12 Months Ended June 30, 2021

					Annualization Adjustments						
Line No.	Description	Rates: July 2020 - May 2021	Current Rates: June 2021 -	Month	Rate Change Annualization	Special Rate Imputed	Year End Customer Adjustment	Customer Revenue Adjustment	Annualized Therm Adjustment	Therm Revenue Adjustment	Annualization Revenue Adjustment
	[a]	[b]	[c]	[d]	[s]	[t]	[u]	[v]	[w]	[x]	[y]
1	**Residential - Schedule RG**										
2	Service and Facilities Charge	$21.70 /month	$21.91 /month								
3	Distribution Charge	$0.9470 /therm	$0.9850 /therm								
4				July	$ 2,648		316	$ 6,924	3,813	$ 3,756	$ 13,328
5				August	$ 2,137		298	$ 6,529	1,260	$ 1,242	$ 9,908
6				September	$ 2,239		269	$ 5,894	1,886	$ 1,857	$ 9,990
7				October	$ 3,840		186	$ 4,075	4,583	$ 4,514	$ 12,429
8				November	$ 8,335		128	$ 2,804	7,748	$ 7,632	$ 18,772
9				December	$ 11,692		87	$ 1,906	8,809	$ 8,677	$ 22,275
10				January	$ 20,222		47	$ 1,030	6,357	$ 6,261	$ 27,513
11				February	$ 19,353		16	$ 351	2,366	$ 2,331	$ 22,034
12				March	$ 18,762		(1)	$ (22)	(131)	$ (129)	$ 18,611
13				April	$ 14,861		(10)	$ (219)	(1,112)	$ (1,095)	$ 13,547
14				May	$ 7,778		1	$ 22	70	$ 69	$ 7,868
15				June	$ -		-	$ -	-	$ -	$ -
16					$ 111,867	$ -		$ 29,294	35,649	$ 35,114	$ 176,275
17	**Small Commercial - Schedule SC**										
18	Service and Facilities Charge	$35.79 /month	$36.13 /month								
19	Distribution Charge	$0.8360 /therm	$0.8690 /therm								
20				July	$ 1,898	$ 13,625	77	$ 2,782	5,919	$ 5,144	$ 23,449
21				August	$ 1,620	$ 10,513	67	$ 2,421	3,334	$ 2,897	$ 17,452
22				September	$ 1,790	$ 11,702	73	$ 2,637	4,569	$ 3,970	$ 20,100
23				October	$ 3,007	$ 18,526	54	$ 1,951	7,173	$ 6,234	$ 29,717
24				November	$ 5,715	$ 27,897	32	$ 1,156	8,596	$ 7,470	$ 42,238
25				December	$ 8,075	$ 30,412	18	$ 650	7,579	$ 6,586	$ 45,723
26				January	$ 13,729	$ 48,551	(5)	$ (181)	(2,732)	$ (2,375)	$ 59,725
27				February	$ 13,179	$ 42,986	(8)	$ (289)	(4,708)	$ (4,091)	$ 51,784
28				March	$ 12,792	$ 43,290	(12)	$ (434)	(6,291)	$ (5,467)	$ 50,182
29				April	$ 9,699	$ 40,194	(11)	$ (397)	(4,888)	$ (4,248)	$ 45,248
30				May	$ 5,152	$ 24,993	(5)	$ (181)	(1,433)	$ (1,245)	$ 28,719
31				June	$ -	$ 16,949	-	$ -	-	$ -	$ 16,949
32					$ 76,657	$ 329,638		$ 10,116	17,118	$ 14,876	$ 431,287

Summit Natural Gas of Maine, Inc.
Weather Normalization and Customer Annualization
12 Months Ended June 30, 2021

					Annualization Adjustments						
Line No.	Description	Rates: July 2020 - May 2021	Current Rates: June 2021 -	Month	Rate Change Annualization	Special Rate Imputed	Year End Customer Adjustment	Customer Revenue Adjustment	Annualized Therm Adjustment	Therm Revenue Adjustment	Annualization Revenue Adjustment
	[a]	[b]	[c]	[d]	[s]	[t]	[u]	[v]	[w]	[x]	[y]
33	**Large Commercial - Schedule LC**										
34	Service and Facilities Charge	$309.19 /month	$312.17 /month								
35	Distribution Charge	$0.6140 /therm	$0.6390 /therm								
36				July	$ 1,263	$ 10,333	5	$ 1,561	2,837	$ 1,813	$ 14,970
37				August	$ 1,044	$ 9,324	4	$ 1,249	1,229	$ 785	$ 12,402
38				September	$ 1,106	$ 9,535	3	$ 937	1,339	$ 856	$ 12,433
39				October	$ 2,283	$ 9,357	3	$ 937	3,478	$ 2,223	$ 14,800
40				November	$ 4,365	$ 18,231	2	$ 624	5,032	$ 3,216	$ 26,436
41				December	$ 5,516	$ 24,368	1	$ 312	4,023	$ 2,571	$ 32,767
42				January	$ 8,276	$ 37,162	(2)	$ (624)	(10,533)	$ (6,731)	$ 38,083
43				February	$ 7,808	$ 31,737	(1)	$ (312)	(5,648)	$ (3,609)	$ 35,624
44				March	$ 7,353	$ 29,533	(1)	$ (312)	(5,015)	$ (3,205)	$ 33,369
45				April	$ 6,015	$ 37,716	(1)	$ (312)	(4,199)	$ (2,683)	$ 40,736
46				May	$ 3,659	$ 16,762	-	$ -	-	$ -	$ 20,422
47				June	$ -	$ 10,251	-	$ -	-	$ -	$ 10,251
48					$ 48,690	$ 244,309		$ 4,058	(7,456)	$ (4,765)	$ 292,293

Summit Natural Gas of Maine, Inc.
Weather Normalization and Customer Annualization
12 Months Ended June 30, 2021

Line No.	Description	Rates: July 2020 - May 2021	Current Rates: June 2021 -	Month	ProForma at Current Rates: Test Year Adjusted Customers	Test Year Adjusted Therms	Test Year Adjusted Revenue at Current Rates
	[a]	[b]	[c]	[d]	[z]	[aa]	[ab]
1	**Residential - Schedule RG**						
2	Service and Facilities Charge	$21.70 /month	$21.91 /month				
3	Distribution Charge	$0.9470 /therm	$0.9850 /therm				
4				July	3,603	43,475	$ 121,765
5				August	3,603	15,240	$ 93,953
6				September	3,603	25,255	$ 103,818
7				October	3,603	88,771	$ 166,381
8				November	3,603	218,108	$ 293,778
9				December	3,603	364,824	$ 438,293
10				January	3,603	487,302	$ 558,934
11				February	3,603	532,880	$ 603,829
12				March	3,603	472,885	$ 544,733
13				April	3,603	400,631	$ 473,563
14				May	3,603	251,119	$ 326,294
15				June	3,603	125,016	$ 202,082
16					43,236	3,025,506	$ 3,927,424
17	**Small Commercial - Schedule SC**						
18	Service and Facilities Charge	$35.79 /month	$36.13 /month				
19	Distribution Charge	$0.8360 /therm	$0.8690 /therm				
20				July	925	71,105	$ 95,210
21				August	925	46,030	$ 73,421
22				September	925	57,890	$ 83,727
23				October	925	122,874	$ 140,198
24				November	925	248,485	$ 249,354
25				December	925	389,455	$ 371,857
26				January	925	505,507	$ 472,706
27				February	925	544,307	$ 506,423
28				March	925	484,930	$ 454,824
29				April	925	411,024	$ 390,600
30				May	925	265,079	$ 263,774
31				June	925	144,145	$ 158,682
32					11,100	3,290,832	$ 3,260,776

Summit Natural Gas of Maine, Inc.
Weather Normalization and Customer Annualization
12 Months Ended June 30, 2021

					ProForma at Current Rates			
Line No.	Description	Rates: July 2020 - May 2021	Current Rates: June 2021 -	Month	Test Year Adjusted Customers	Test Year Adjusted Therms		Test Year Adjusted Revenue at Current Rates
	[a]	[b]	[c]	[d]	[z]	[aa]		[ab]
33	**Large Commercial - Schedule LC**							
34	Service and Facilities Charge	$309.19 /month	$312.17 /month					
35	Distribution Charge	$0.6140 /therm	$0.6390 /therm					
36				July	92	52,196	$	62,073
37				August	92	28,263	$	46,780
38				September	92	41,061	$	54,957
39				October	92	106,674	$	96,884
40				November	92	231,494	$	176,644
41				December	92	370,154	$	265,248
42				January	92	484,540	$	338,341
43				February	92	519,639	$	360,769
44				March	92	461,387	$	323,546
45				April	92	386,270	$	275,546
46				May	92	241,052	$	182,752
47				June	92	122,782	$	107,178
48					1,104	3,045,512	$	2,290,718

Summit Natural Gas of Maine, Inc.
Docket No. 2022-00025
Gross Plant
RJA-08

Line No	Description (a)	Reference (b)	Test Year End June 2021 (c)	Adjustment 1 (d)	Adjusted Total (e)
1	Gross Plant	RJA-08.1	$ 377,794,581	$ -	$ 377,794,581

Notes: (1) There are no adjustments to plant being made.

Summit Natural Gas of Maine, Inc.
Docket No. 2022-00025
Gross Plant Detail
RJA-08.1

Line No	FERC	Test Year End June 2021	Adjustment 1	Adjusted Total
	(a)	(b)	(c)	(d)
1	302 - Franchises and consents	$ 115,838	$ -	$ 115,838
2	303 - Miscellaneous Intangible Plant	2,650,000	-	2,650,000
3	374 - Land and land rights	2,554,277	-	2,554,277
4	376 - Mains, Distribution	298,470,686	-	298,470,686
5	378 - Meas. and reg. stat. eq.-Gen	21,602,202	-	21,602,202
6	380 - Services	24,970,019	-	24,970,019
7	380.1 - Services Non-Res	5,366,870	-	5,366,870
8	381 - Meters	3,180,937	-	3,180,937
9	381.1 - Meters - Electronic	21,973	-	21,973
10	381.2 - Meters - ERTS	238,574	-	238,574
11	382 - Meter installations	2,212,327	-	2,212,327
12	382.1 - Meter Installs Non-Res	282,409	-	282,409
13	383 - House regulators	456,505	-	456,505
14	386 - Other property-cust premises	4,989,192	-	4,989,192
15	390.1 - Structures and improvements	1,097,842	-	1,097,842
16	391 - Office furniture, equipment	640,807	-	640,807
17	391.1 - Software	3,223,855	-	3,223,855
18	391.2 - Computer Equipment	245,714	-	245,714
19	392 - Transportation equipment	2,764,201	-	2,764,201
20	394 - Tools, shop, garage equipment	737,207	-	737,207
21	396 - Power operated equipment	1,841,672	-	1,841,672
22	397 - Communication equipment	131,471	-	131,471
23	**Gross Plant**	$ 377,794,581	$ -	$ 377,794,581

Notes: (1) There are no adjustments to plant being made.

Summit Natural Gas of Maine, Inc.
Docket No. 2022-00025
Reserve for Depreciation
RJA-09

Line No	Description (a)	Reference (b)	Test Year End June 2021 (c)	Adjustment 1 (d)	Adjusted Total (e)
1	Reserve for Depreciation	RJA-09.1	$ (52,015,921)	$ -	$ (52,015,921)

Notes: (1) There are no adjustments to depreciation reserve being made.

Summit Natural Gas of Maine, Inc.
Docket No. 2022-00025
Reserve for Depreciation Detail
RJA-09.1

Line No	Account Description	Test Year End June 2021	Adjustment 1	Adjusted Total
	(a)	(b)	(c)	(d)
1	302 - Franchises and consents	$ (14,083)	$ -	$ (14,083)
2	303 - Miscellaneous Intangible Plant	(1,146,167)	-	(1,146,167)
3	374 - Land and land rights	(4,257)	-	(4,257)
4	376 - Mains, Distribution	(37,080,779)	-	(37,080,779)
5	378 - Meas. and reg. stat. eq.-Gen	(2,765,182)	-	(2,765,182)
6	380 - Services	(2,306,793)	-	(2,306,793)
7	380.1 - Services Non-Res	(523,479)	-	(523,479)
8	381 - Meters	(331,462)	-	(331,462)
9	381.1 - Meters - Electronic	(256)	-	(256)
10	381.2 - Meters - ERTS	(7,610)	-	(7,610)
11	382 - Meter installations	(139,706)	-	(139,706)
12	382.1 - Meter Installs Non-Res	(19,342)	-	(19,342)
13	383 - House regulators	(6,314)	-	(6,314)
14	386 - Other property-cust premises	(386,326)	-	(386,326)
15	390.1 - Structures and improvements	(248,793)	-	(248,793)
16	391 - Office furniture, equipment	(412,678)	-	(412,678)
17	391.1 - Software	(3,156,627)	-	(3,156,627)
18	391.2 - Computer Equipment	(120,009)	-	(120,009)
19	392 - Transportation equipment	(2,557,186)	-	(2,557,186)
20	394 - Tools, shop, garage equipment	(292,724)	-	(292,724)
21	396 - Power operated equipment	(409,865)	-	(409,865)
22	397 - Communication equipment	(86,282)	-	(86,282)
23	**Reserve for Depreciation Total**	$ (52,015,921)	$ -	$ (52,015,921)

Notes: (1) There are no adjustments to depreciation reserve being made.

Summit Natural Gas of Maine, Inc.
Docket No. 2022-00025
Other Rate Base
RJA-10

Line No	Description	Reference	Test Year End June 2021
	(a)	(b)	(c)
1	Materials & Supplies	RJA-10.1	$ 2,502,307
2	Inventory Overhead	RJA-10.1	28,120
3	Prepaids	RJA-10.1	186,551
4	Customer Deposits	RJA-10.1	(13,266)
5	Net Deferred Tax Asset	RJA-10.1	15,447,838
6	Other Regulatory Asset	RJA-10.1	7,437,058
7	**Total**	Sum of Totals Above	**$ 25,588,608**

Summit Natural Gas of Maine, Inc.
Docket No. 2022-00025
MATERIALS & SUPPLIES
Other Rate Base Detail
RJA-10.1

Line No	Month (a)	Reference (b)	Balance (c)
1	JUN-20	TB by Month	$ 2,502,927
2	JUL-20	TB by Month	2,505,116
3	AUG-20	TB by Month	2,506,237
4	SEP-20	TB by Month	2,453,476
5	OCT-20	TB by Month	2,433,582
6	NOV-20	TB by Month	2,423,818
7	DEC-20	TB by Month	2,415,301
8	JAN-21	TB by Month	2,453,687
9	FEB-21	TB by Month	2,450,188
10	MAR-21	TB by Month	2,586,180
11	APR-21	TB by Month	2,912,511
12	MAY-21	TB by Month	2,474,139
13	JUN-21	TB by Month	2,412,831
14			$ 32,529,993
15			
16	**13 month Average**		**$ 2,502,307**

Summit Natural Gas of Maine, Inc.
Docket No. 2022-00025
INVENTORY OVERHEAD
Other Rate Base Detail
RJA-10.1

Line No	Month (a)	Reference (b)	Balance (c)
1	JUN-20	TB by Month	$ 12,840
2	JUL-20	TB by Month	7,654
3	AUG-20	TB by Month	11,619
4	SEP-20	TB by Month	(5,322)
5	OCT-20	TB by Month	4,724
6	NOV-20	TB by Month	10,085
7	DEC-20	TB by Month	-
8	JAN-21	TB by Month	11,367
9	FEB-21	TB by Month	30,517
10	MAR-21	TB by Month	57,422
11	APR-21	TB by Month	82,758
12	MAY-21	TB by Month	98,114
13	JUN-21	TB by Month	43,776
14			$ 365,554
15			
16	**13 month Average**	**13 month Average**	**$ 28,120**

Summit Natural Gas of Maine, Inc.
Docket No. 2022-00025
PREPAIDS
Other Rate Base Detail
RJA-10.1

Line No	Month	Reference	Balance
	(a)	(b)	(c)
1	JUN-20	TB by Month	$ 497,880
2	JUL-20	TB by Month	459,059
3	AUG-20	TB by Month	187,369
4	SEP-20	TB by Month	173,738
5	OCT-20	TB by Month	146,599
6	NOV-20	TB by Month	128,033
7	DEC-20	TB by Month	114,919
8	JAN-21	TB by Month	94,892
9	FEB-21	TB by Month	74,843
10	MAR-21	TB by Month	56,277
11	APR-21	TB by Month	61,721
12	MAY-21	TB by Month	224,065
13	JUN-21	TB by Month	205,776
14			$ 2,425,169
15			
16	**13 month Average**	13 month Average	**$ 186,551**

Summit Natural Gas of Maine, Inc.
Docket No. 2022-00025
CUSTOMER DEPOSITS
Other Rate Base Detail
RJA-10.1

Line No	Month (a)	Reference (b)	Balance (c)
1	JUN-20	TB by Month	$ (13,766)
2	JUL-20	TB by Month	(13,731)
3	AUG-20	TB by Month	(14,509)
4	SEP-20	TB by Month	(15,479)
5	OCT-20	TB by Month	(15,688)
6	NOV-20	TB by Month	(15,723)
7	DEC-20	TB by Month	(15,460)
8	JAN-21	TB by Month	(14,768)
9	FEB-21	TB by Month	(13,866)
10	MAR-21	TB by Month	(12,941)
11	APR-21	TB by Month	(9,930)
12	MAY-21	TB by Month	(7,981)
13	JUN-21	TB by Month	(8,615)
14			$ (172,457)
15			
16	**13 month Average**	13 month Average	**$ (13,266)**

Summit Natural Gas of Maine, Inc.
Docket No. 2022-00025
NET DEFERRED TAX ASSET
Other Rate Base Detail
RJA-10.1

Line No	Month	Reference	Balance
	(a)	(b)	(c)
1	JUN-20	TB by Month	$ 15,020,534
2	JUL-20	TB by Month	15,368,534
3	AUG-20	TB by Month	15,657,534
4	SEP-20	TB by Month	16,051,534
5	OCT-20	TB by Month	16,349,534
6	NOV-20	TB by Month	15,878,910
7	DEC-20	TB by Month	14,501,473
8	JAN-21	TB by Month	14,644,473
9	FEB-21	TB by Month	14,905,473
10	MAR-21	TB by Month	15,109,473
11	APR-21	TB by Month	15,386,473
12	MAY-21	TB by Month	15,777,473
13	JUN-21	TB by Month	16,170,473
14			$ 200,821,892
15			
16	**13 month Average**	13 month Average	**$ 15,447,838**

Summit Natural Gas of Maine, Inc.
Docket No. 2022-00025
OTHER REGULATORY ASSET
Other Rate Base Detail
RJA-10.1

Line No	Month	Reference	Balance
	(a)	(b)	(c)
1	JUN-20	TB by Month	$ 7,437,058
2	JUL-20	TB by Month	7,437,058
3	AUG-20	TB by Month	7,437,058
4	SEP-20	TB by Month	7,437,058
5	OCT-20	TB by Month	7,437,058
6	NOV-20	TB by Month	7,437,058
7	DEC-20	TB by Month	7,437,058
8	JAN-21	TB by Month	7,437,058
9	FEB-21	TB by Month	7,437,058
10	MAR-21	TB by Month	7,437,058
11	APR-21	TB by Month	7,437,058
12	MAY-21	TB by Month	7,437,058
13	JUN-21	TB by Month	7,437,058
14			$ 96,681,757
15			
16	**13 month Average**	13 month Average	**$ 7,437,058**

Summit Natural Gas of Maine, Inc.
Docket No. 2022-00025
Rate Base Summary
RJA-11

Line No	Description	Reference	Test Year End June 2021	Adjustment	Pro Forma
	(a)	(b)	(c)	(d)	(e)
1	Gross Plant in Service	RJA-08	$ 377,794,581	$ -	$ 377,794,581
2	Less: Accumulated Depreciation	RJA-09	$ (52,015,921)	$ -	$ (52,015,921)
3	Net Plant in Service	Line 1 + Line 2	$ 325,778,660	$ -	$ 325,778,660
4	Other Rate Base				
5	Materials & Supplies	RJA-10	$ 2,502,307	$ -	$ 2,502,307
6	Prepaids	RJA-10	186,551	-	186,551
7	Inventory Overhead	RJA-10	28,120	-	28,120
8	Customer Deposits	RJA-10	(13,266)	-	(13,266)
9	Subtotal	Sum of Lines 5-8	$ 2,703,712	$ -	$ 2,703,712
10	Net Deferred Tax Asset	RJA-10	$ 15,447,838	$ -	$ 15,447,838
11	Other Regulatory Asset	RJA-10	$ 7,437,058	$ -	$ 7,437,058
12	Total Other Rate Base	Sum of Lines 9-11	$ 25,588,608	$ -	$ 25,588,608
13	Total Rate Base	Line 3 + Line 12	$ 351,367,268	$ -	$ 351,367,268

Notes: (1) There are no adjustments being made.

Summit Natural Gas of Maine, Inc.
Docket No. 2022-00025
Operating Revenue
RJA-12

Line No	Description	Reference	Total Test Year Revenue	Adjustments	Pro Forma Revenue
	(a)	(b)	(c)	(d)	(e)
1	Service and Facilities Revenue	SF-12, RJA-12.1	$ 4,263,114	$ 124,549	$ 4,387,664
2	Distribution Revenue	SF-12, RJA-12.1	8,858,617	1,309,632	10,168,249
3	Cost of Gas Adjustment	SF-12	4,482,848	(4,482,848)	-
4	Miscellaneous Revenue	SF-12	7,451	-	7,451
5	Total	Sum of Lines 1-4	$ 17,612,030	$ (3,048,667)	$ 14,563,363

Notes: (1) Adjustments include weather normalization, annualization adjustment, and discounted rate customers.

Summit Natural Gas of Maine, Inc.
Docket No. 2022-00025
Pro Forma Revenue
RJA-12.1

			Distribution Revenue			Service and Facilities Revenue			Total Revenue
Line No	**Customer Class**	**Reference**	**Charge per therm**	**Annual Volume (therms)**	**Annual Revenue**	**Monthly Charge**	**Meter Counts**	**Annual Revenue**	**Annual Revenue**
	(a)	**(b)**	**(c)**	**(d)**	**(e)**	**(f)**	**(g)**	**(h)**	**(i)**
1	Residential	SF-12.1 & SF-12.2	$ 0.9850	3,025,506	$ 2,980,124	$ 21.91	3,603	$ 947,301	$ 3,927,424
2	Small Commercial	SF-12.1 & SF-12.2	0.8690	3,290,832	2,859,733	36.13	925	401,043	3,260,776
3	Large Commercial	SF-12.1 & SF-12.2	0.6390	3,045,512	1,946,082	312.17	92	344,636	2,290,718
4	Transportation	SF-12.1 & SF-12.2	Negotiated	30,523,980	2,382,310	Negotiated	8	2,694,684	5,076,994
5	Total	Sum of Lines 1-4		39,885,830	$ 10,168,249		4,628	$ 4,387,664	$ 14,555,912

Summit Natural Gas of Maine, Inc.
Docket No. 2022-00025
Operations and Maintenance Expense
RJA-13

Line No	Description	Reference	Test Year End June 2021	Adjustment 1	Adjustment 2	Pro Forma
	(a)	(b)	(c)	(d)	(e)	(f)
1	Operations & Maintenance Expense	RJA-13.1	$ 8,171,073	$ (0)	$ (113,282)	$ 8,057,791

Notes:
(1) Adjustment 1 represents realocation of Administrative expenses transferred contra account.
(2) Adjustment 2 represents Civic/Political Expense being removed from O&M, since these amounts pertain to lobbying expenses

Summit Natural Gas of Maine, Inc.
Docket No. 2022-00025
Operations and Maintenance Detail
RJA-13.1

Line No	Account Description	Reference	Account Number	O&M incl Allocations	Adjustment 1	Adjustment 2	Pro Forma
	(a)	(b)	(c)	(d)	(e)	(f)	(g)
1	Transmission operation of mains	TB by Month	8560	$ 5,988	$ -	$ -	$ 5,988
2	Transmission pipeline integrity	TB by Month	8561	9,253	-	-	9,253
3	Transmission measuring & reg station - general	TB by Month	8570	56,084	-	-	56,084
4	Transmission measuring & reg station - industrial	TB by Month	8571	5,744	-	-	5,744
5	Transmission other exp (limited use-maps & records)	TB by Month	8590	3,571	-	-	3,571
6	Transmission rents (rights-of-way, etc)	TB by Month	8600	1,599	-	-	1,599
7	Maintenance of transmission mains (367)	TB by Month	8630	102,813	-	-	102,813
8	Maint of transmission measuring & reg stations (369)	TB by Month	8650	69,731	-	-	69,731
9	Maint of transmission communication equip (370)	TB by Month	8660	2,132	-	-	2,132
10	Distribution load dispatching	TB by Month	8710	(55)	-	-	(55)
11	Distribution compressor station labor & expenses	TB by Month	8720	-	-	-	-
12	Distribution mains & services (locates & leak surveys)	TB by Month	8740	410,881	-	-	410,881
13	Distribution measuring & reg station exp-general	TB by Month	8750	127,692	-	-	127,692
14	Distribution measuring & reg station exp-Industrial	TB by Month	8760	54,192	-	-	54,192
15	Meter & house regulator exp (meter switch-outs)	TB by Month	8780	399,855	-	-	399,855
16	Customer installation expenses	TB by Month	8790	13,816	-	-	13,816
17	Distribution other exp (limited use-maps & records)	TB by Month	8800	86,640	-	-	86,640
18	Distribution rents (rights-of-way, etc)	TB by Month, SF-13.1	8810	3,568	(260)	-	3,308
19	Maintenance supervision & engineering	TB by Month	8850	57,647	-	-	57,647
20	Maintenance of mains (UPIS 376)	TB by Month	8870	18,890	-	-	18,890
21	Maintenance of measuring & reg equip-general (378)	TB by Month	8890	-	-	-	-
22	Maintenance of services (UPIS 380)	TB by Month	8920	23,909	-	-	23,909
23	Maintenance of other equipment	TB by Month	8940	1,172	-	-	1,172
24	Meter reading expenses (labor & materials)	TB by Month	9020	16,805	-	-	16,805
25	Customer records & collection exp (labor & materials)	TB by Month	9030	329,863	-	-	329,863
26	Uncollectible accounts	TB by Month	9040	85,702	-	-	85,702
27	Customer assistance expenses (informational)	TB by Month	9080	984,748	-	-	984,748
28	Informational & instructional advertising expenses	TB by Month	9090	25,155	-	-	25,155
29	Demonstrating & selling expenses	TB by Month, SF-13.1	9120	2,199,967	(4,686)	-	2,195,281
30	Advertising expenses	TB by Month	9130	4,093	-	-	4,093
31	Administrative & general salaries	TB by Month, SF-13.1	9200	1,665,334	(551,246)	-	1,114,088
32	Office supplies & general expenses (non-labor)	TB by Month, SF-13.1	9210	652,927	(303,611)	-	349,316
33	Administrative expenses transferred (contra alloc)	TB by Month, SF-13.1	9220	(4,363,310)	4,363,310	-	-
34	Outside services employed	TB by Month, SF-13.1	9230	764,641	(28,595)	-	736,046
35	Property insurance (not insurance recoveries)	TB by Month, SF-13.1	9240	380,835	(339,538)	-	41,297
36	Employee pensions & benefits	TB by Month, SF-13.1	9260	19,932	(17,855)	-	2,077
37	Regulatory commission expenses	TB by Month	9280	225,337	-	-	225,337
38	Miscellaneous general expenses	TB by Month, SF-13.1	9302	3,221,442	(2,901,673)	-	319,769
39	Rents	TB by Month, SF-13.1	9310	291,837	(208,488)	-	83,349
40	Maintenance of general plant (390, 391, 397, 398)	TB by Month, SF-13.1	9320	97,362	(7,357)	-	90,005
41	Donations/Sponsors	TB by Month	0000	7,542	-	(7,542)	-
42	Civic/Political Expense	TB by Month	0000	105,740	-	(105,740)	-
43		Sum of Lines 1-42		$ 8,171,073	$ (0)	$ (113,282)	$ 8,057,791

Notes: (1) Adjustment 1 represents realocation of Administrative expenses transferred contra account.
(2) Adjustment 2 represents Civic/Political Expense being removed from O&M, since these amounts pertain to lobbying expenses.

Summit Natural Gas of Maine, Inc.
Docket No. 2022-00025
Depreciation and Amortization
RJA-14

Line No	Description	Reference	Test Year End June 2021	Adjustment 1	Pro Forma
	(a)	(b)	(c)	(d)	(e)
1	Depreciation Expense	TB by Month, RJA-14.1	$ 8,821,436	$ (1,220,365)	$ 7,601,071
2	Amortization Expense	TB by Month	176,676	-	176,676
3	Total		$ 8,998,111	$ (1,220,365)	$ 7,777,746

Notes: (1) Adjustment 1 represents Depreciation Expense adjustment as a result of a change to depreciation rates

Summit Natural Gas of Maine, Inc.
Docket No. 2022-00025
Pro Forma Depreciation Expense
RJA-14.1

Line No	FERC Description	Reference	Plant Balance Test Year End June 2021	Adjustment 1	Adjusted Total	Depr. Rate	Pro Forma Depreciation Expense
	(a)	(b)	(c)	(d)	(e)	(f)	(g)
1	302 - Franchises and consents	RJA-08.1, SF-14.1	$ 115,838	$ -	$ 115,838	2.00%	$ 2,317
2	303 - Miscellaneous Intangible Plant	RJA-08.1, SF-14.1	2,650,000	-	2,650,000	6.67%	176,667
3	374 - Land and land rights	RJA-08.1, SF-14.1	2,554,277	-	2,554,277	0.00%	-
4	376 - Mains, Distribution	RJA-08.1, SF-14.1	298,470,686	-	298,470,686	1.43%	4,263,867
5	378 - Meas. and reg. stat. eq.-Gen	RJA-08.1, SF-14.1	21,602,202	-	21,602,202	2.00%	432,044
6	380 - Services	RJA-08.1, SF-14.1	24,970,019	-	24,970,019	1.54%	384,154
7	380.1 - Services Non-Res	RJA-08.1, SF-14.1	5,366,870	-	5,366,870	1.54%	82,567
8	381 - Meters	RJA-08.1, SF-14.1	3,180,937	-	3,180,937	2.00%	63,619
9	381.1 - Meters - Electronic	RJA-08.1, SF-14.1	21,973	-	21,973	2.00%	439
10	381.2 - Meters - ERTS	RJA-08.1, SF-14.1	238,574	-	238,574	2.00%	4,771
11	382 - Meter installations	RJA-08.1, SF-14.1	2,212,327	-	2,212,327	2.00%	44,247
12	382.1 - Meter Installs Non-Res	RJA-08.1, SF-14.1	282,409	-	282,409	2.00%	5,648
13	383 - House regulators	RJA-08.1, SF-14.1	456,505	-	456,505	2.00%	9,130
14	386 - Other property-cust premises	RJA-08.1, SF-14.1	4,989,192	-	4,989,192	2.00%	99,784
15	390.1 - Structures and improvements	RJA-08.1, SF-14.1	1,097,842	-	1,097,842	5.00%	54,892
16	391 - Office furniture, equipment	RJA-08.1, SF-14.1	640,807	-	640,807	10.00%	64,081
17	391.1 - Software	RJA-08.1, SF-14.1	3,223,855	-	3,223,855	33.33%	1,074,618
18	391.2 - Computer Equipment	RJA-08.1, SF-14.1	245,714	-	245,714	33.33%	81,905
19	392 - Transportation equipment	RJA-08.1, SF-14.1	2,764,201	-	2,764,201	20.00%	552,840
20	394 - Tools, shop, garage equipment	RJA-08.1, SF-14.1	737,207	-	737,207	5.00%	36,860
21	396 - Power operated equipment	RJA-08.1, SF-14.1	1,841,672	-	1,841,672	8.33%	153,473
22	397 - Communication equipment	RJA-08.1, SF-14.1	131,471	-	131,471	10.00%	13,147
23	**Total**	Sum of Lines 1-22	$ 377,794,581	$ -	$ 377,794,581		$ 7,601,071

Notes: (1) There are no adjustments to plant being made.

Summit Natural Gas of Maine, Inc.
Docket No. 2022-00025
Property Tax (Taxes Other than Income)
RJA-15

Line No	Description	Reference	Property Tax	Adjustment 1	Pro Forma
	(a)	(b)	(c)	(d)	(e)
1	Taxes Other than Income	TB by Month, RJA-15.1	$ 2,723,911	$ (129,078)	$ 2,594,832

Notes: (1) Adjustment 1 reconciles the test year property tax expense to the 2021 calendar year property tax expense

Summit Natural Gas of Maine, Inc.
Docket No. 2022-00025
Property Tax (Taxes Other than Income) Detail
RJA-15.1

Line No	County	Town	2021 Property Tax	
	(a)	(b)	(c)	
1	Kennebec	Augusta	$	457,859
2	Kennebec	Augusta		570
3	Kennebec	Augusta		14,587
4	Kennebec	Chelsea		91,495
5	Kennebec	Farmingdale		8,011
6	Kennebec	Gardiner		78,782
7	Kennebec	Hallowell		60,933
8	Kennebec	Oakland		97,457
9	Kennebec	Pittston		90,072
10	Kennebec	Randolph		53,763
11	Kennebec	Sidney		16,685
12	Kennebec	Vassalboro		112,614
13	Kennebec	Vassalboro		153
14	Kennebec	Waterville		348,134
15	Kennebec	Winslow		36,340
16	Kennebec	Winslow		6,854
17	Kennebec	Winslow		1,000
18	Kennebec	Winslow		8,225
19	Somerset	Fairfield		309,236
20	Somerset	Fairfield		469
21	Somerset	Madison		87,829
22	Somerset	Norridgewock		143,751
23	Somerset	Skowhegan		95,870
24	Cumberland	Cumberland		158,204
25	Cumberland	Cumberland		154,055
26	Cumberland	Cumberland		5,135
27	Cumberland	Falmouth		93,930
28	Cumberland	Portland		410
29	Cumberland	Yarmouth		62,410
30	**Total**		**$**	**2,594,832**

Summit Natural Gas of Maine, Inc.
Docket No. 2022-00025
Rate of Return at June 30, 2021
RJA-16

Line No	Description	Reference	Amount	Calculated Capital Ratio	Hypothetical Capital Ratio	Cost of Capital	Weighted Cost of Capital (c) * (d)
	(a)	(b)	(c)	(d)	(e)	(f)	(g)
1	Total Long Term Debt	RJA-16.2	$ 125,000,000	35.00%	50.00%	5.20%	2.60%
2	Common Equity	RJA-16.1	$ 232,094,507	65.00%	50.00%	11.10%	5.55%
3	Total	Line 1 + Line 2	$ 357,094,507	100.00%	100.00%		8.15%

Notes: (1) Debt = $125M of shareholder promissory notes
(2) The hypothetical capital ratio is addressed by witness D'Ascendis

Summit Natural Gas of Maine, Inc.
Docket No. 2022-00025
Equity
RJA-16.1

Line No	Description (a)	Reference (b)	Amount (c)
1	Common Stock	TB by Month	$ 1,920,131
2	Contributed Capital	TB by Month	296,667,908
3	Accumulated Deficit	TB by Month	(56,521,710)
4	Accumulated Deficit - Current Year	TB by Month	(9,971,823)
5	Common Equity	Sum of Lines 1-4	$ 232,094,507

Summit Natural Gas of Maine, Inc.
Docket No. 2022-00025
Debt
RJA-16.2

Line No	Issue (a)	Reference (b)	Principal Amount (c)	Interest Rate (d)	Annual Cost (e)
1	Total Long Term Debt	TB by Month	$ 125,000,000	5.20%	$ 6,500,000

Notes: (1) Debt = $125M of shareholder promissory notes

Summit Natural Gas of Maine, Inc.
Docket No. 2022-00025
Revenue Requirement
RJA-17

Line No	Reference	Pro Forma Revenue	Revenue Requirement	Revenue Excess/Deficiency	Revenue Requirement Adjustment	Revised Revenue Deficiency
	(a)	(b)	(c)	(d)	(e)	(f)
1	RJA-17.1	$ 14,555,912	$ 54,663,620	$ (40,107,707)	$ (37,260,738)	$ (2,846,969)

Summit Natural Gas of Maine, Inc.
Docket No. 2022-00025
Revenue Sufficiency
RJA-17.1

						Results at 11.1% ROE		Results at Requested Increase	
Line No	Description	Reference	Test Year Revenue Ending June 2021	Adjustments	Pro Forma Revenue	Revenue Increase	Adjusted Test Year Revenue	Revenue Increase	Adjusted Test Year Revenue
	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)
1	Service and Facilities Revenue	RJA-12, RJA-12.1	$ 4,263,114	$ 124,549	$ 4,387,664	$ -	$ 4,387,664	$ -	$ 4,387,664
2	Distribution Revenue	RJA-12, RJA-12.1	8,858,617	1,309,632	10,168,249	-	10,168,249	-	10,168,249
3	Cost of Gas Adjustment	RJA-12, RJA-12.1	4,482,848	(4,482,848)	-	-	-	-	-
4	Miscellaneous Revenue	RJA-12, RJA-12.1	7,451	-	7,451	-	7,451	-	7,451
5	Base Rate Revenue Change		-	-	-	40,107,707	40,107,707	2,846,969	2,846,969
6	Total Operating Revenue	Sum of Lines 1-5	$ 17,612,030	$ (3,048,667)	$ 14,563,363	$ 40,107,707	$ 54,671,071	$ 2,846,969	$ 17,410,333
7	Natural gas purchase costs (PGA)	Line 3	$ 4,482,848	$ (4,482,848)	$ -	$ -	$ -	$ -	$ -
8	Operations & Maintenance	RJA-13	8,171,073	(113,282)	8,057,791	-	8,057,791	-	8,057,791
9	Depreciation and Amortization	RJA-14	8,998,111	(1,220,365)	7,777,746	-	7,777,746	-	7,777,746
10	Taxes Other Than Income	RJA-15	2,723,911	(129,078)	2,594,832	-	2,594,832	-	2,594,832
11	Total Operating Expenses	Sum of Lines 7-10	$ 24,375,943	$ (5,945,573)	$ 18,430,369	$ -	$ 18,430,369	$ -	$ 18,430,369
12	Income Before Interest and Income Taxes	Line 6 - Line 11	$ (6,763,913)	$ 2,896,907	$ (3,867,006)	$ 40,107,707	$ 36,240,702	$ 2,846,969	$ (1,020,037)
13	Assigned Interest (Rate Base * Component Cost of Debt)	Line 18 * RJA-16	(9,135,549)	-	(9,135,549)	-	(9,135,549)	-	(9,135,549)
14	Net Income Before Income Taxes	Line 12 + Line 13	$ (15,899,462)	$ 2,896,907	$ (13,002,555)	$ 40,107,707	$ 27,105,153	$ 2,846,969	$ (10,155,585)
15	Income Taxes at 28.05%	Line 14 * SF-17.1	$ (4,460,546)		$ (3,647,828)	$ 11,252,097	$ 7,604,269	$ 798,709	$ (2,849,119)
16	Net Income	Line 14 - Line 15	$ (11,438,915)		$ (9,354,727)	$ 28,855,610	$ 19,500,883	$ 2,048,261	$ (7,306,466)
17	Rate of Return on Rate Base	(Line 16 - Line 13)/ Line 18	-0.66%		-0.06%		8.15%		0.52%
18	Rate Base	RJA-11	$ 351,367,268		$ 351,367,268		$ 351,367,268		$ 351,367,268

Summit Natural Gas of Maine, Inc.
Case No. 2022-00025
Customer Component of Mains Analysis

Line	(a) Description	(b) Diameter	(c) Original Cost	(d) Cost $2021	(e) Feet	(f) Unit Cost $2021	(g)
1	Plastic	0.75	$ 3,178	$ 3,308	-		
2	Plastic	1	$ 70,026	$ 76,819	817	$ 94.03	
3	Plastic	2	$ 56,599,324	$ 65,015,408	654,213	$ 99.38	
4	Plastic	4	$ 20,460,108	$ 23,613,588	125,586	$ 188.03	
5	Plastic	6	$ 10,812,272	$ 12,307,713	62,932	$ 195.57	
6	Plastic	8	$ 68,611,661	$ 78,995,713	269,097	$ 293.56	
7	Plastic	12	$ 15,390,018	$ 17,764,365	32,418	$ 547.98	
8	Plastic		$ 171,946,588	$ 197,776,914	1,145,063		
9	Steel		$ 126,304,140	$ 178,648,035	379,450		
10	Non-unitized		$ 219,958	$ 219,958	15		
11	**TOTAL**		$ 298,470,686	$ 376,644,907	1,524,528		

12 **MINIMUM SYSTEM CALCULATION**

Line	Material	Minimum Size Unit Cost	Cost $2021	Feet	Customer Component	Percent
14	Plastic	$ 99.38	$ 197,776,914	1,145,063	$ 113,795,871	**57.5%**

Line	ADJUSTED MINIMUM SYSTEM CALCULATION	Amount	Reference
16	Minimum System Cost	$ 113,795,871	Line 14, Customer Component
17	Minimum System Serving Design Day Demand (%)	22.31%	Line 39
18	Minimum System Serving Design Day Demand	$ 25,392,833	Line 16 * Line 17
19	Remaining Customer Portion	$ 88,403,038	Line 16 - Line 18
20	Total Cost	$ 197,776,914	Line 14, Cost $2021
21	**Adjusted Minimum System**	**44.7%**	Line 19 / Line 20

22 **Derrivation of the Load Carrying Capability of 2-inch Main as a Percent of Design Day Peak**

Line	Description	Amount	Reference
24	Minimum System Main Diameter (inches)	2	
25	Pipe Diameter Squared	4	Line 24 squared
26	Constant	0.3720	pipeline capacity constant
27	System Operating Pressure (PSIG)	60	
28	Cubic Feet of Capacity per Thousand Feet of Main	89.28	Line 25 * Line 26 * Line 27
29	Thousands of Feet in Mile	5.28	
30	Cubic Feet of Capacity per Mile	471.40	Line 28 * Line 29
31	Hours in Day	24	
32	**Ccf of Capacity per Mile per Day**	**113.14**	Line 30 x Line 31 / 100
33	Total Design Day (in Ccf)	109,954	
34	Total Customers	4,620	
35	Ccf Per Customer on Design Day	23.80	Line 33 / Line 34
36	Miles of Distribution Main	216.87	Line 14 / 5,280 ft per mile
37	Customers Per Mile	21.30	Line 34 / Line 36
38	**Capacity (Ccf) Required on Design Day per Mile**	**507.01**	Line 35 * Line 37
39	**Portion of Required Capacity Met by 2-Inch Main Capacity**	**22.31%**	Line 32 / Line 38

NOTES: 68.2 miles of coated and protected steel transmission mains per 2020 PHMSA Transmission Annual Report
0.45 miles of coated and protected steel distribution mains per 2020 PHMSA Distribution Annual Report
99.3% of Steel mains are Transmission, therefore excluded Steel from Minimum System

Summit Natural Gas of Maine, Inc.
12 Months Ending June 30, 2021
Docket No. 2022-00025
Summary of Cost of Service Study Results

	(a)	(b)	(c)	(d)	(e)
Line No.	**Revenue Requirement Summary**	**Account Balance**	**Residential**	**Small Commercial**	**Large Commercial**
1	**Rate Base**				
2	Plant in Service	$ 377,794,581	$ 185,580,191	$ 107,669,622	$ 84,544,768
3	Accumulated Reserve for Depreciation	(52,015,921)	(26,063,389)	(14,763,849)	(11,188,683)
4	Other Rate Base Items	25,588,608	12,556,294	7,296,256	5,736,059
5	**Total Rate Base**	$ 351,367,268	$ 172,073,095	$ 100,202,029	$ 79,092,144
6	**Revenue at Current Rates**				
7	Rate Schedule Revenue	$ 9,478,918	$ 3,927,424	$ 3,260,776	$ 2,290,718
8	Special Contracts (Revenue Credit)	5,076,994	3,055,383	1,278,660	742,951
9	Miscellaneous Revenues	7,451	4,484	1,877	1,090
10	**Total Revenue at Current Rates**	$ 14,563,363	$ 6,987,291	$ 4,541,313	$ 3,034,759
11	**Expenses at Current Rates**				
12	O&M and A&G Expenses	$ 8,057,791	$ 5,462,491	$ 1,889,983	$ 705,316
13	Depreciation and Amortization Expense	7,777,746	4,249,195	2,043,863	1,484,688
14	Taxes Other Than Income	2,594,832	1,265,551	741,904	587,377
15	Income Taxes	(3,647,828)	(1,786,430)	(1,040,278)	(821,120)
16	**Total Expenses at Current Rates**	$ 14,782,541	$ 9,190,808	$ 3,635,472	$ 1,956,261
17	**Operating Income at Current Rates**	$ (219,178)	$ (2,203,517)	$ 905,841	$ 1,078,498
18	**Current Rate of Return**	-0.06%	-1.28%	0.90%	1.36%

	(a)	(b)	(c)	(d)	(e)
Line No.	**Revenue Requirement Summary**	**Account Balance**	**Residential**	**Small Commercial**	**Large Commercial**
19	**Revenue Requirement at Equal Rates of Return**				
20	Required Return	0.52%	0.52%	0.52%	0.52%
21	Required Operating Income	$ 1,829,083	$ 895,746	$ 521,613	$ 411,723
22	**Operating Income (Deficiency)/Surplus**	**$ (2,048,261)**	**$ (3,099,263)**	**$ 384,228**	**$ 666,774**
23	**Expenses at Required Return**				
24	O&M and A&G Expenses	$ 8,057,791	$ 5,462,491	$ 1,889,983	$ 705,316
25	Depreciation and Amortization Expense	7,777,746	4,249,195	2,043,863	1,484,688
26	Taxes Other Than Income	2,594,832	1,265,551	741,904	587,377
27	Income Taxes	(3,647,828)	(1,786,430)	(1,040,278)	(821,120)
28	Gross Up - Income Taxes	798,709	391,147	227,774	179,788
29	**Total Expenses at Required Return**	$ 15,581,250	$ 9,581,955	$ 3,863,246	$ 2,136,049
30	**Rate Margin at Equal Rates of Return**				
31	Total Revenue Requirement at Equal Rates of Return	$ 17,410,333	$ 10,477,701	$ 4,384,859	$ 2,547,772
32	LESS				
33	Current Special Contracts (Revenue Credit)	5,076,994	3,055,383	1,278,660	742,951
34	Current Miscellaneous Revenues	7,451	4,484	1,877	1,090
35	**Total Rate Margin at Equal Rates of Return**	$ 12,325,887	$ 7,417,835	$ 3,104,322	$ 1,803,731
36	**Rate Margin (Deficiency)/Surplus**	**$ (2,846,969)**	**$ (3,490,410)**	**$ 156,454**	**$ 486,987**
37	**Proposed Margin Revenue**				
38	Proposed Rate Margin Increase (Decrease)	**$ 2,846,969**	**$ 1,179,592**	**$ 979,366**	**$ 688,011**
39	Current Rate Schedule Revenue	9,478,918	3,927,424	3,260,776	2,290,718
40	Special Contracts Revenue	5,076,994	3,055,383	1,278,660	742,951
41	Miscellaneous Revenue	7,451	4,484	1,877	1,090
42	**Total Proposed Margin Revenue**	**$ 17,410,333**	**$ 8,166,883**	**$ 5,520,679**	**$ 3,722,770**
43	Percent Margin Revenue Change	20%	17%	22%	23%
44	Percent Rate Increase	30%	30%	30%	30%
45	**Operating Income at Proposed Rates**				
46	Income Prior to Taxes	$ (1,020,037)	$ (2,810,355)	$ 844,929	$ 945,389
47	**Proposed Return Prior to Income Taxes**	**-0.29%**	**-1.63%**	**0.84%**	**1.20%**
48	Income Taxes	(2,849,119)	(1,336,472)	(903,433)	(609,214)
49	**Operating Income**	$ 1,829,083	$ (1,473,883)	$ 1,748,362	$ 1,554,603
50	**Proposed Return**	**0.52%**	**-0.86%**	**1.74%**	**1.97%**

Summit Natural Gas of Maine, Inc.
12 Months Ending June 30, 2021
Docket No. 2022-00025
Functionalized and Classified Rate Base and Revenue Requirement, and Unit Costs by Customer Class

	(a)	(b)	(c)	(d)	(e)
Line	**Description**	**TOTAL**	**Residential**	**Small Commercial**	**Large Commercial**
1	**Functional Rate Base**				
2	**Transmission**				
3	Demand	$ 122,058,400	$ 41,999,096	$ 40,703,373	$ 39,355,930
4	Commodity	$ -	$ -	$ -	$ -
5	Customer	$ -	$ -	$ -	$ -
6	Subtotal	$ 122,058,400	$ 41,999,096	$ 40,703,373	$ 39,355,930
7	**Distribution**				
8	Demand	$ 112,596,021	$ 38,743,185	$ 37,547,911	$ 36,304,926
9	Commodity	$ -	$ -	$ -	$ -
10	Customer	$ 74,622,896	$ 58,151,649	$ 14,960,812	$ 1,510,435
11	Subtotal	$ 187,218,917	$ 96,894,834	$ 52,508,722	$ 37,815,361
12	**Onsite**				
13	Demand	$ -	$ -	$ -	$ -
14	Commodity	$ -	$ -	$ -	$ -
15	Customer	$ 41,415,347	$ 32,653,061	$ 6,854,866	$ 1,907,420
16	Subtotal	$ 41,415,347	$ 32,653,061	$ 6,854,866	$ 1,907,420
17	**Customer Accounts & Services**				
18	Demand	$ -	$ -	$ -	$ -
19	Commodity	$ -	$ -	$ -	$ -
20	Customer	$ 674,604	$ 526,104	$ 135,067	$ 13,434
21	Subtotal	$ 674,604	$ 526,104	$ 135,067	$ 13,434
22	**Total**				
23	Demand	$ 234,654,421	$ 80,742,281	$ 78,251,284	$ 75,660,856
24	Commodity	$ -	$ -	$ -	$ -
25	Customer	$ 116,712,847	$ 91,330,814	$ 21,950,745	$ 3,431,288
26	**TOTAL RATE BASE**	$ 351,367,268	$ 172,073,095	$ 100,202,029	$ 79,092,144

Summit Natural Gas of Maine, Inc.
12 Months Ending June 30, 2021
Docket No. 2022-00025
Functionalized and Classified Rate Base and Revenue Requirement, and Unit Costs by Customer Class

	(a)	(b)	(c)	(d)	(e)
Line	**Description**	**TOTAL**	**Residential**	**Small Commercial**	**Large Commercial**
27	**Functional Revenue Requirement After Revenue Credit**				
28	**Transmission**				
29	Demand	$ 2,239,566	$ 770,613	$ 746,838	$ 722,115
30	Commodity	$ -	$ -	$ -	$ -
31	Customer	$ -	$ -	$ -	$ -
32	Subtotal	$ 2,239,566	$ 770,613	$ 746,838	$ 722,115
33	**Distribution**				
34	Demand	$ 2,496,802	$ 859,125	$ 832,620	$ 805,057
35	Commodity	$ -	$ -	$ -	$ -
36	Customer	$ 2,149,155	$ 1,450,451	$ 532,061	$ 166,644
37	Subtotal	$ 4,645,957	$ 2,309,575	$ 1,364,681	$ 971,701
38	**Onsite**				
39	Demand	$ -	$ -	$ -	$ -
40	Commodity	$ -	$ -	$ -	$ -
41	Customer	$ 893,343	$ 790,234	$ 82,799	$ 20,310
42	Subtotal	$ 893,343	$ 790,234	$ 82,799	$ 20,310
43	**Customer Accounts & Services**				
44	Demand	$ -	$ -	$ -	$ -
45	Commodity	$ -	$ -	$ -	$ -
46	Customer	$ 4,554,472	$ 3,551,897	$ 911,880	$ 90,695
47	Subtotal	$ 4,554,472	$ 3,551,897	$ 911,880	$ 90,695
48	**Total**				
49	Demand	$ 4,736,368	$ 1,629,738	$ 1,579,458	$ 1,527,172
50	Commodity	$ -	$ -	$ -	$ -
51	Customer	$ 7,596,971	$ 5,792,581	$ 1,526,740	$ 277,650
52	**TOTAL REVENUE REQUIREMENT AFTER REVENUE CREDIT AT EQUAL RATES OF RETURN**	$ 12,333,339	$ 7,422,319	$ 3,106,198	$ 1,804,821
53	Demand	38.40%	21.96%	50.85%	84.62%
54	Energy	0.00%	0.00%	0.00%	0.00%
55	Customer	61.60%	78.04%	49.15%	15.38%

Summit Natural Gas of Maine, Inc.
12 Months Ending June 30, 2021
Docket No. 2022-00025
Functionalized and Classified Rate Base and Revenue Requirement, and Unit Costs by Customer Class

	(a)	(b)	(c)	(d)	(e)
Line	**Description**	**TOTAL**	**Residential**	**Small Commercial**	**Large Commercial**
56	**Functional Unit Costs**				
57	**Transmission**				
58	Demand	$ 0.14	$ 1.70	$ 1.70	$ 1.70
59	Commodity	$ -	$ -	$ -	$ -
60	Customer	$ -	$ -	$ -	$ -
61	**Distribution**				
62	Demand	$ 1.89	$ 1.89	$ 1.89	$ 1.89
63	Commodity	$ -	$ -	$ -	$ -
64	Customer	$ 38.77	$ 33.55	$ 47.93	$ 150.95
65	**Onsite**				
66	Demand	$ -	$ -	$ -	$ -
67	Commodity	$ -	$ -	$ -	$ -
68	Customer	$ 16.11	$ 18.28	$ 7.46	$ 18.40
69	**Customer Accounts & Services**				
70	Demand	$ -	$ -	$ -	$ -
71	Commodity	$ -	$ -	$ -	$ -
72	Customer	$ 82.15	$ 82.15	$ 82.15	$ 82.15
73	**Total**				
74	Demand (per month)	$ 3.59	$ 3.59	$ 3.59	$ 3.59
75	Commodity	$ -	$ -	$ -	$ -
76	Customer (per cust month)	$ 137.03	$ 133.98	$ 137.54	$ 251.49
77	Customer (Onsite & Customer Accounts)	$ 98.27	$ 100.43	$ 89.61	$ 100.55
78	Demand & Customer (per cust month)	$ 222.46	$ 171.67	$ 279.84	$ 1,634.80
79	**BILLING DETERMINANTS**				
80	Demand (Peak Day Demand * 12)	1,319,445	454,008	440,001	425,436
81	Commodity	9,361,850	3,025,506	3,290,832	3,045,512
82	Customers (Number of Bills)	55,440	43,236	11,100	1,104

Summit Natural Gas of Maine, Inc.
Case No. 2022-00025
Proposed Rate Design

Line No.	Rate Description	Current Rates	Pro Forma Test Year Billing Determinants (bills or therms)	Pro Forma Revenue at Current Rates	Proposed Rates	Revenue at Proposed Rates	Change in Revenue	Percent Change
	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)
				(b) * (c)		(e) * (c)	(f) - (d)	(g) / (d)
1	RG - Residential							
2	Service and Facility Charge	$21.91	43,236	$ 947,301	$28.48	$ 1,231,361	$ 284,061	30%
3	Distribution Charge	$0.985	3,025,506	$ 2,980,124	$1.281	$ 3,875,674	$ 895,550	30%
4	Total Residential			$ 3,927,424		$ 5,107,035	$ 1,179,610	
5	SC - Small Commercial							
6	Service and Facility Charge	$36.13	11,100	$ 401,043	$46.97	$ 521,367	$ 120,324	30%
7	Distribution Charge	$0.869	3,290,832	$ 2,859,733	$1.130	$ 3,718,640	$ 858,907	30%
8	Total Small Commercial			$ 3,260,776		$ 4,240,007	$ 979,231	
9	LC - Large Commercial							
10	Service and Facility Charge	$312.17	1,104	$ 344,636	$405.82	$ 448,025	$ 103,390	30%
11	Distribution Charge	$0.639	3,045,512	$ 1,946,082	$0.831	$ 2,530,820	$ 584,738	30%
12	Total Large Commercial			$ 2,290,718		$ 2,978,845	$ 688,128	
13	Total Rate Schedule Revenue			$ 9,478,918		$ 12,325,887	$ 2,846,969	

Summit Natural Gas of Maine, Inc.
Case No. 2022-00025
Customer Bill Impacts

Bill Impacts for Rate Schedule RG - Residential

Line No.	(a)	(b)	(c)	(d)	(e)
1	Rate Component	Current Rates	Proposed Rates		
2	Service and Facility Charge	$21.91	$28.48		
3	Low Income Program Charge	$0.19	$0.19		
4	Distribution Charge	$0.985	$1.281		
5	CGA Rate	$1.100	$1.100		
6	Annual Consumption (therms)	Revenue at Current Rates	Revenue at Proposed Rates	Change in Revenue	Percent Change
7	100	$474	$582	$108	23%
8	200	$682	$820	$138	20%
9	300	$891	$1,058	$168	19%
10	400	$1,099	$1,296	$197	18%
11	500	$1,308	$1,535	$227	17%
12	600	$1,516	$1,773	$256	17%
13	700	$1,725	$2,011	$286	17%
14	800	$1,933	$2,249	$316	16%
15	900	$2,142	$2,487	$345	16%
16	1,000	$2,350	$2,725	$375	16%
17	1,100	$2,559	$2,963	$404	16%
18	1,200	$2,767	$3,201	$434	16%
19	1,300	$2,976	$3,439	$464	16%
20	1,400	$3,184	$3,677	$493	15%
21	1,500	$3,393	$3,916	$523	15%
22	1,600	$3,601	$4,154	$552	15%
23	1,700	$3,810	$4,392	$582	15%
24	1,800	$4,018	$4,630	$612	15%
25	1,900	$4,227	$4,868	$641	15%
26	2,000	$4,435	$5,106	$671	15%
27	2,100	$4,644	$5,344	$700	15%
28	2,200	$4,852	$5,582	$730	15%
29	2,300	$5,061	$5,820	$760	15%
30	2,400	$5,269	$6,058	$789	15%
31	2,500	$5,478	$6,297	$819	15%

Bill Impacts for Rate Schedule SC - Small Commercial

Line No.	(a)	(b)	(c)
33	Rate Component	Current Rates	Proposed Rates
34	Service and Facility Charge	$36.13	$46.97
35	Low Income Program Charge	$0.19	$0.19
36	Distribution Charge	$0.869	$1.130
37	CGA Rate	$1.100	$1.100

Line No.	(a) Annual Consumption (therms)	(b) Revenue at Current Rates	(c) Revenue at Proposed Rates	(d) Change in Revenue	(e) Percent Change
38					
39	500	$1,420	$1,681	$261	18%
40	1,000	$2,405	$2,796	$391	16%
41	1,500	$3,389	$3,911	$522	15%
42	2,000	$4,374	$5,026	$652	15%
43	2,500	$5,358	$6,141	$783	15%
44	3,000	$6,343	$7,256	$913	14%
45	3,500	$7,327	$8,371	$1,044	14%
46	4,000	$8,312	$9,486	$1,174	14%
47	4,500	$9,296	$10,601	$1,305	14%
48	5,000	$10,281	$11,716	$1,435	14%
49	5,500	$11,265	$12,831	$1,566	14%
50	6,000	$12,250	$13,946	$1,696	14%
51	6,500	$13,234	$15,061	$1,827	14%
52	7,000	$14,219	$16,176	$1,957	14%
53	7,500	$15,203	$17,291	$2,088	14%
54	8,000	$16,188	$18,406	$2,218	14%
55	8,500	$17,172	$19,521	$2,349	14%
56	9,000	$18,157	$20,636	$2,479	14%
57	9,500	$19,141	$21,751	$2,610	14%
58	10,000	$20,126	$22,866	$2,740	14%
59	10,500	$21,110	$23,981	$2,871	14%
60	11,000	$22,095	$25,096	$3,001	14%
61	11,500	$23,079	$26,211	$3,132	14%
62	12,000	$24,064	$27,326	$3,262	14%
63	12,500	$25,048	$28,441	$3,393	14%

Bill Impacts for Rate Schedule LC - Large Commercial

Line No.	(a)	(b)	(c)	(d)	(e)
65	Rate Component	Current Rates	Proposed Rates		
66	Service and Facility Charge	$312.17	$405.82		
67	Low Income Program Charge	$0.19	$0.19		
68	Distribution Charge	$0.639	$0.831		
69	CGA Rate	$1.100	$1.100		
70	Annual Consumption (therms)	Revenue at Current Rates	Revenue at Proposed Rates	Change in Revenue	Percent Change
71	5,000	$12,443	$14,527	$2,084	17%
72	10,000	$21,138	$24,182	$3,044	14%
73	15,000	$29,833	$33,837	$4,004	13%
74	20,000	$38,528	$43,492	$4,964	13%
75	25,000	$47,223	$53,147	$5,924	13%
76	30,000	$55,918	$62,802	$6,884	12%
77	35,000	$64,613	$72,457	$7,844	12%
78	40,000	$73,308	$82,112	$8,804	12%
79	45,000	$82,003	$91,767	$9,764	12%
80	50,000	$90,698	$101,422	$10,724	12%
81	55,000	$99,393	$111,077	$11,684	12%
82	60,000	$108,088	$120,732	$12,644	12%
83	65,000	$116,783	$130,387	$13,604	12%
84	70,000	$125,478	$140,042	$14,564	12%
85	75,000	$134,173	$149,697	$15,524	12%
86	80,000	$142,868	$159,352	$16,484	12%
87	85,000	$151,563	$169,007	$17,444	12%
88	90,000	$160,258	$178,662	$18,404	11%
89	95,000	$168,953	$188,317	$19,364	11%
90	100,000	$177,648	$197,972	$20,324	11%
91	105,000	$186,343	$207,627	$21,284	11%
92	110,000	$195,038	$217,282	$22,244	11%
93	115,000	$203,733	$226,937	$23,204	11%
94	120,000	$212,428	$236,592	$24,164	11%
95	125,000	$221,123	$246,247	$25,124	11%

Summit Natural Gas of Maine, Inc.
Case No. 2022-00025
Residential Customer Bill Impacts

Bill Impacts for Rate Schedule RG - Residential

Line No.	(a)	(b)	(c)	(d)	(e)	(f)
1	Rate Component		Current Rates	Proposed Rates		
2	Service and Facility Charge		$21.91	$28.48		
3	Low Income Program Charge		$0.19	$0.19		
4	Distribution Charge		$0.985	$1.281		
5	CGA Rate		$1.100	$1.100		

Line No.	Month	Average thems Per Customer	Revenue at Current Rates	Revenue at Proposed Rates	Change in Revenue	Percent Change
7	January	135.25	$ 304.09	$ 350.70	$ 46.60	15%
8	February	147.90	330.47	380.82	50.35	15%
9	March	131.25	295.75	341.17	45.42	15%
10	April	111.19	253.94	293.42	39.48	16%
11	May	69.70	167.42	194.62	27.20	16%
12	June	34.70	94.44	111.29	16.84	18%
13	July	12.07	47.26	57.40	10.14	21%
14	August	4.23	30.92	38.74	7.82	25%
15	September	7.01	36.71	45.36	8.64	24%
16	October	24.64	73.47	87.33	13.86	19%
17	November	60.54	148.32	172.80	24.49	17%
18	December	101.26	233.22	269.76	36.54	16%
19	**TOTAL**	839.72	$ 2,016.01	$ 2,343.41	$ 327.40	16%
20	Monthly Average		$ 168.00	$ 195.28	$ 27.28	16%

Summit Natural Gas of Maine
Table of Contents
Supporting Exhibits Accompanying the Direct Testimony
of Dylan W. D'Ascendis, CRRA, CVA

Summit Natural Gas of Maine
Recommended Capital Structure and Cost Rates
for Ratemaking Purposes

Type Of Capital	Ratios (1)	Cost Rate	Weighted Cost Rate
Long-Term Debt	50.00%	5.20% (2)	2.60%
Common Equity	50.00%	11.10% (3)	5.55%
Total	100.00%		8.15%

Notes:

(1) Hypothetical Capital Structure based on the average capital structure maintained by the Utility Proxy Group as shown on Schedule DWD-2.
(2) Company-provided.
(3) From page 2 of this Schedule.

Summit Natural Gas of Maine
Brief Summary of Common Equity Cost Rate

Line No.	Principal Methods	Proxy Group of Six Natural Gas Distribution Companies
1.	Discounted Cash Flow Model (DCF) (1)	10.08%
2.	Risk Premium Model (RPM) (2)	10.95%
3.	Capital Asset Pricing Model (CAPM) (3)	12.32%
4.	Market Models Applied to Comparable Risk, Non-Price Regulated Companies (4)	13.14%
5.	Indicated Range of Common Equity Cost Rates before Adjustment for Size Risk	10.08% - 13.14%
6.	Size Adjustment (5)	1.00%
7.	Recommended Range of Common Equity Cost Rates after Adjustment for Size Risk	11.08% - 14.14%
8.	Recommended Cost of Common Equity Cost Rate	11.10%

Notes:
(1) From page 1 of Schedule DWD-3.
(2) From page 1 of Schedule DWD-4.
(3) From page 1 of Schedule DWD-5.
(4) From page 1 of Schedule DWD-7.
(5) Adjustment to reflect the Company's greater business risk due to its smaller size relative to the Utility Proxy Group as detailed in Mr. D'Ascendis' Direct Testimony.

Summit Natural Gas of Maine
CAPITALIZATION AND FINANCIAL STATISTICS (1) FOR THE
Proxy Group of Six Natural Gas Distribution Companies
2016 - 2020, Inclusive

	2020	2019	2018	2017	2016	5 YEAR AVERAGE
			(MILLIONS OF DOLLARS)			
Capitalization Statistics						
Amount of Capital Employed						
Total Permanent Capital	$5,120.937	$4,363.314	$3,944.927	$3,417.743	$3,170.840	
Short-Term Debt	$348.750	$457.978	$344.825	$324.810	$307.435	
Total Capital Employed	$5,469.687	$4,821.292	$4,289.752	$3,742.553	$3,478.275	
Indicated Average Capital Cost Rates (2)						
Total Debt	3.22 %	3.54 %	3.57 %	3.70 %	3.39 %	
Preferred Stock	6.12 %	2.81 %	NA %	NA %	NA %	
Capital Structure Ratios						
Based on Total Permanent Capital:						
Long-Term Debt	50.37 %	47.63 %	48.32 %	47.12 %	45.62 %	47.81 %
Preferred Stock	0.81	0.87	-	-	-	0.33
Common Equity	48.83	51.51	51.69	52.89	54.39	51.86
Total	100.00 %	100.00 %	100.00 %	100.00 %	100.00 %	100.00 %
Based on Total Capital:						
Total Debt, Including Short-Term Debt	54.34 %	52.51 %	52.76 %	51.78 %	49.76 %	52.23 %
Preferred Stock	0.71	0.75	-	-	-	0.29
Common Equity	44.95	46.74	47.24	48.22	50.24	47.48
Total	100.00 %	100.00 %	100.00 %	100.00 %	100.00 %	100.00 %
Financial Statistics						
Financial Ratios - Market Based						
Earnings / Price Ratio	4.62 %	3.78 %	4.55 %	2.46 %	4.72 %	4.02 %
Market / Average Book Ratio	185.55	223.45	216.10	217.96	196.56	207.92
Dividend Yield	3.32	2.76	2.87	2.77	2.98	2.94
Dividend Payout Ratio	81.51	77.25	134.41	26.31	63.44	76.58
Rate of Return on Average Book Common Equity	8.69 %	8.54 %	10.03 %	5.26 %	9.28 %	8.36 %
Total Debt / EBITDA (3)	5.75 x	5.59 x	5.76 x	8.44 x	4.21 x	5.95 x
Funds from Operations / Total Debt (4)	12.42 %	12.55 %	23.82 %	17.54 %	18.39 %	16.94 %
Total Debt / Total Capital	54.34 %	52.51 %	52.76 %	51.78 %	49.76 %	52.23 %

Notes:
(1) All capitalization and financial statistics for the group are the arithmetic average of the achieved results for each individual company in the group, and are based upon financial statements as originally reported in each year.
(2) Computed by relating actual total debt interest or preferred stock dividends booked to average of beginning and ending total debt or preferred stock reported to be outstanding.
(3) Total debt relative to EBITDA (Earnings before Interest, Income Taxes, Depreciation and Amortization).
(4) Funds from operations (sum of net income, depreciation, amortization, net deferred income tax and investment tax credits, less total AFUDC) plus interest charges as a percentage of total debt.

Source of Information: Company Annual Forms 10-K

Capital Structure Based upon Total Permanent Capital for the
Proxy Group of Six Natural Gas Distribution Companies
2016 - 2020, Inclusive

	2020	2019	2018	2017	2016	5 YEAR AVERAGE
Atmos Energy Corporation						
Long-Term Debt	40.02 %	38.03 %	39.15 %	44.03 %	41.32 %	40.51 %
Preferred Stock	0.00	0.00	0.00	0.00	0.00	0.00
Common Equity	59.98	61.97	60.85	55.97	58.68	59.49
Total Capital	100.00 %	100.00 %	100.00 %	100.00 %	100.00 %	100.00 %
New Jersey Resources Corporation						
Long-Term Debt	55.35 %	50.11 %	47.89 %	48.45 %	49.09 %	50.18 %
Preferred Stock	0.00	0.00	0.00	0.00	0.00	0.00
Common Equity	44.65	49.89	52.11	51.55	50.91	49.82
Total Capital	100.00 %	100.00 %	100.00 %	100.00 %	100.00 %	100.00 %
Northwest Natural Holding Company						
Long-Term Debt	51.81 %	50.43 %	49.12 %	51.22 %	45.82 %	49.68 %
Preferred Stock	0.00	0.00	0.00	0.00	0.00	0.00
Common Equity	48.19	49.57	50.88	48.78	54.18	50.32
Total Capital	100.00 %	100.00 %	100.00 %	100.00 %	100.00 %	100.00 %
ONE Gas, Inc.						
Long-Term Debt	41.76 %	37.65 %	38.62 %	37.84 %	38.71 %	38.92 %
Preferred Stock	0.00	0.00	0.00	0.00	0.00	0.00
Common Equity	58.24	62.35	61.38	62.16	61.29	61.08
Total Capital	100.00 %	100.00 %	100.00 %	100.00 %	100.00 %	100.00 %
South Jersey Industries, Inc.						
Long-Term Debt	63.65 %	64.06 %	69.16 %	49.88 %	44.65 %	58.28 %
Preferred Stock	0.00	0.00	0.00	0.00	0.00	0.00
Common Equity	36.35	35.94	30.84	50.12	55.35	41.72
Total Capital	100.00 %	100.00 %	100.00 %	100.00 %	100.00 %	100.00 %
Spire Inc.						
Long-Term Debt	49.62 %	45.49 %	45.95 %	51.27 %	54.10 %	49.29 %
Preferred Stock	4.83	5.19	0.00	0.00	0.00	2.00
Common Equity	45.55	49.32	54.05	48.73	45.90	48.71
Total Capital	100.00 %	100.00 %	100.00 %	100.00 %	100.00 %	100.00 %
Proxy Group of Six Natural Gas Distribution Companies						
Long-Term Debt	50.37 %	47.63 %	48.32 %	47.12 %	45.62 %	47.81 %
Preferred Stock	0.81	0.87	0.00	0.00	0.00	0.33
Common Equity	48.83	51.51	51.69	52.89	54.39	51.86
Total Capital	100.00 %	100.00 %	100.00 %	100.00 %	100.00 %	100.00 %

Source of Information:
Annual Forms 10-K

Summit Natural Gas of Maine
Indicated Common Equity Cost Rate Using the Discounted Cash Flow Model for the
Proxy Group of Six Natural Gas Distribution Companies

	[1]	[2]	[3]	[4]	[5]	[6]	[7]
Proxy Group of Six Natural Gas Distribution Companies	Average Dividend Yield (1)	Value Line Projected Five Year Growth in EPS (2)	Zack's Five Year Projected Growth Rate in EPS	Yahoo! Finance Projected Five Year Growth in EPS	Average Projected Five Year Growth in EPS (3)	Adjusted Dividend Yield (4)	Indicated Common Equity Cost Rate (5)
Atmos Energy Corporation	2.86 %	7.00 %	7.30 %	7.20 %	7.17 %	2.96 %	10.13 %
New Jersey Resources Corporation	3.74	1.50	7.10	6.00	4.87	3.83	8.70
Northwest Natural Holding Company	4.15	5.50	5.00	5.70	5.40	4.26	9.66
ONE Gas, Inc.	3.32	6.50	5.00	2.90	4.80	3.40	8.20
South Jersey Industries, Inc.	5.19	11.50	5.60	5.20	7.43	5.38	12.81
Spire Inc.	4.33	10.00	5.30	7.31	7.54	4.49	12.03
						Average	10.26 %
						Median	9.90 %
						Average of Mean and Median	10.08 %

NA= Not Available
NMF= Not Meaningful Figure

Notes:

(1) Indicated dividend at 12/31/2021 divided by the average closing price of the last 60 trading days ending 12/31/2021 for each company.
(2) From pages 2 through 7 of this Schedule.
(3) Average of columns 2 through 4 excluding negative growth rates.
(4) This reflects a growth rate component equal to one-half the conclusion of growth rate (from column 5) x column 1 to reflect the periodic payment of dividends (Gordon Model) as opposed to the continuous payment. Thus, for Atmos Energy Corporation, 2.86% x (1+(1/2 x 7.17%)) = 2.96%.
(5) Column 5 + column 6.

Source of Information:

Value Line Investment Survey
www.zacks.com Downloaded on 12/31/2021
www.yahoo.com Downloaded on 12/31/2021

ATMOS ENERGY CORP. NYSE-ATO

RECENT PRICE	96.21	P/E RATIO	18.1 (Trailing: 18.8; Median: 19.0)	RELATIVE P/E RATIO	0.96	DIV'D YLD	2.9%	VALUE LINE

TIMELINESS 4 Lowered 8/20/21
SAFETY 1 Raised 6/6/14
TECHNICAL 5 Lowered 11/26/21
BETA .80 (1.00 = Market)

18-Month Target Price Range

Low-High	Midpoint (% to Mid)
$81-$136	$109 (15%)

2024-26 PROJECTIONS

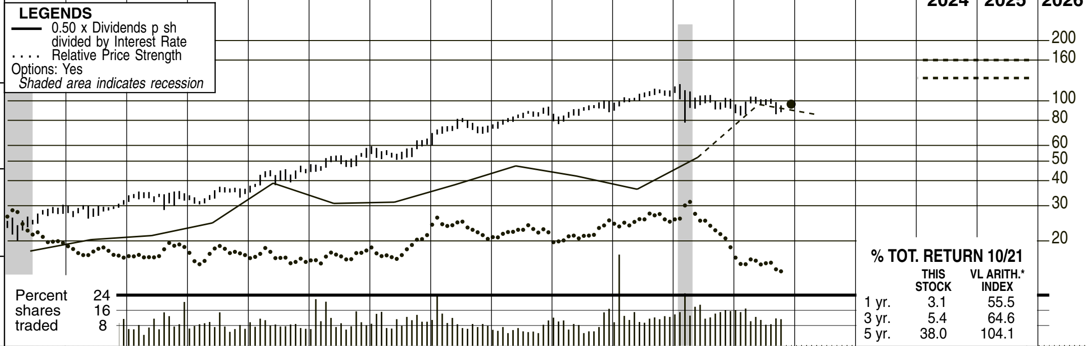
	Price	Gain	Ann'l Total Return
High	160	(+65%)	*16%*
Low	130	(+35%)	*10%*

Institutional Decisions

	4Q2020	1Q2021	2Q2021
to Buy	280	256	247
to Sell	228	258	223
Hld's(000)	107949	107920	109549

	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021
High:	32.0	35.6	37.3	47.4	58.2	64.8	82.0	93.6	100.8	115.2	121.1	105.0
Low:	25.9	28.5	30.4	34.9	44.2	50.8	60.0	72.5	76.5	89.2	77.9	84.6

Target Price Range 2024 | 2025 | 2026



% TOT. RETURN 10/21

	THIS STOCK	VL ARITH.* INDEX
1 yr.	3.1	55.5
3 yr.	5.4	64.6
5 yr.	38.0	104.1

2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	© VALUE LINE PUB. LLC	24-26
61.75	75.27	66.03	79.52	53.69	53.12	48.15	38.10	42.88	49.22	40.82	32.23	26.01	28.00	24.32	22.41	*26.00*	*26.40*	Revenues per sh A	*35.50*
3.90	4.26	4.14	4.19	4.29	4.64	4.72	4.76	5.14	5.42	5.81	6.19	6.62	7.24	7.57	8.03	*8.75*	*9.40*	"Cash Flow" per sh	*11.00*
1.72	2.00	1.94	2.00	1.97	2.16	2.26	2.10	2.50	2.96	3.09	3.38	3.60	4.00	4.35	4.72	5.12	*5.45*	Earnings per sh AB	*6.50*
1.24	1.26	1.28	1.30	1.32	1.34	1.36	1.38	1.40	1.48	1.56	1.68	1.80	1.94	2.10	2.30	2.50	*2.72*	Div'ds Decl'd per sh C■	*3.30*
4.14	5.20	4.39	5.20	5.51	6.02	6.90	8.12	9.32	8.32	9.61	10.46	10.72	13.19	14.19	15.38	*15.05*	*18.15*	Cap'l Spending per sh	*15.15*
19.90	20.16	22.01	22.60	23.52	24.16	24.98	26.14	28.47	30.74	31.48	33.32	36.74	42.87	48.18	53.95	*60.25*	*64.00*	Book Value per sh	*87.85*
80.54	81.74	89.33	90.81	92.55	90.16	90.30	90.24	90.64	100.39	101.48	103.93	106.10	111.27	119.34	125.88	*131.00*	*135.00*	Common Shs Outst'g D	*155.00*
16.1	13.5	15.9	13.6	12.5	13.2	14.4	15.9	15.9	16.1	17.5	20.8	22.0	21.7	23.2	22.3	18.8		Avg Ann'l P/E Ratio	*22.5*
.86	.73	.84	.82	.83	.84	.90	1.01	.89	.85	.88	1.09	1.11	1.17	1.24	1.13	.99		Relative P/E Ratio	*1.25*
4.5%	4.7%	4.2%	4.8%	5.3%	4.7%	4.2%	4.1%	3.5%	3.1%	2.9%	2.4%	2.3%	2.2%	2.1%	2.2%	2.6%		Avg Ann'l Div'd Yield	*2.3%*

CAPITAL STRUCTURE as of 6/30/21
Total Debt $7328.9 mill. **Due in 5 Yrs** $410.0 mill.
LT Debt $7128.5 mill. **LT Interest** $370.0 mill.
(LT interest earned: 9.5x; total interest coverage: 9.5x)
Leases, Uncapitalized Annual rentals $20.4 mill.

Pfd Stock None

Pension Assets-9/20 $528.9 mill.
Oblig. $604.2 mill.
Common Stock 130,790,813 shs.
as of 7/30/21

MARKET CAP: $12.6 billion (Large Cap)

2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022		24-26
4347.6	3438.5	3886.3	4940.9	4142.1	3349.9	2759.7	3115.5	2901.8	2821.1	3407.5	*3565*	Revenues ($mill) A	*5500*
199.3	192.2	230.7	289.8	315.1	350.1	382.7	444.3	511.4	580.5	665.6	*735*	Net Profit ($mill)	*1000*
36.4%	33.8%	38.2%	39.2%	38.3%	36.4%	36.6%	27.0%	21.4%	19.5%	18.8%	*20.0%*	Income Tax Rate	*25.0%*
4.6%	5.6%	5.9%	5.9%	7.6%	10.5%	13.9%	14.3%	17.6%	20.6%	19.5%	*20.6%*	Net Profit Margin	*18.2%*
49.4%	45.3%	48.8%	44.3%	43.5%	38.7%	44.0%	34.3%	38.0%	40.0%	*38.5%*	*40.0%*	Long-Term Debt Ratio	*40.0%*
50.6%	54.7%	51.2%	55.7%	56.5%	61.3%	56.0%	65.7%	62.0%	60.0%	*61.5%*	*60.0%*	Common Equity Ratio	*60.0%*
4461.5	4315.5	5036.1	5542.2	5650.2	5651.8	6965.7	7263.6	9279.7	11323	*12835*	*14400*	Total Capital ($mill)	*22700*
5147.9	5475.6	6030.7	6725.9	7430.6	8280.5	9259.2	10371	11788	13355	*15065*	*16350*	Net Plant ($mill)	*19600*
6.1%	6.1%	5.9%	6.4%	6.6%	7.2%	6.4%	6.9%	6.1%	5.5%	*6.5%*	*6.5%*	Return on Total Cap'l	*5.5%*
8.8%	8.1%	8.9%	9.4%	9.9%	10.1%	9.8%	9.3%	8.9%	8.6%	*8.5%*	*8.5%*	Return on Shr. Equity	*7.5%*
8.8%	8.1%	8.9%	9.4%	9.9%	10.1%	9.8%	9.3%	8.9%	8.6%	*8.5%*	*8.5%*	Return on Com Equity	*7.5%*
3.3%	2.8%	4.0%	4.7%	4.9%	5.1%	4.9%	4.8%	4.6%	4.4%	*4.5%*	*4.5%*	Retained to Com Eq	*3.5%*
62%	65%	56%	50%	51%	50%	50%	48%	48%	49%	*49%*	*50%*	All Div'ds to Net Prof	*51%*

CURRENT POSITION ($MILL.)	2019	2020	6/30/21
Cash Assets	24.5	20.8	524.6
Other	433.5	450.5	590.8
Current Assets	458.0	471.3	1115.4
Accts Payable	265.0	235.8	280.4
Debt Due	464.9	.2	200.4
Other	479.5	546.4	581.7
Current Liab.	1209.4	782.4	1062.5
Fix. Chg. Cov.	990%	1306%	1315%

ANNUAL RATES of change (per sh)	Past 10 Yrs.	Past 5 Yrs.	Est'd '18-'20 to '24-'26
Revenues	-8.5%	-11.0%	*6.0%*
"Cash Flow"	5.5%	7.0%	*6.5%*
Earnings	8.0%	9.0%	*7.0%*
Dividends	5.0%	7.5%	*7.5%*
Book Value	7.5%	10.0%	*10.5%*

Fiscal Year Ends	QUARTERLY REVENUES ($ mill.) A Dec.31	Mar.31	Jun.30	Sep.30	Full Fiscal Year
2018	889.2	1219.4	562.2	444.7	3115.5
2019	877.8	1094.6	485.7	443.7	2901.8
2020	875.6	977.6	493.0	474.9	2821.1
2021	914.5	1319.1	605.6	568.3	3407.5
2022	*960*	*1385*	*630*	*590*	*3565*

Fiscal Year Ends	EARNINGS PER SHARE A B E Dec.31	Mar.31	Jun.30	Sep.30	Full Fiscal Year
2018	1.40	1.57	.64	.41	4.00
2019	1.38	1.82	.68	.49	4.35
2020	1.47	1.95	.79	.53	4.72
2021	1.71	2.30	.78	.37	5.12
2022	*1.84*	*2.29*	*.82*	*.50*	*5.45*

Cal-endar	QUARTERLY DIVIDENDS PAID C■ Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2017	.45	.45	.45	.485	1.84
2018	.485	.485	.485	.525	1.98
2019	.525	.525	.525	.575	2.15
2020	.575	.575	.575	.625	2.35
2021	.625	.625	.625	.68	

BUSINESS: Atmos Energy Corporation is engaged primarily in the distribution and sale of natural gas to over three million customers through six regulated natural gas utility operations: Louisiana Division, West Texas Division, Mid-Tex Division, Mississippi Division, Colorado-Kansas Division, and Kentucky/Mid-States Division. Gas sales breakdown for fiscal 2020: 68.6%, residential; 26.2%, commercial; 3.6%, industrial; and 1.6% other. The company sold Atmos Energy Marketing, 1/17. Officers and directors own approximately 1.2% of common stock (12/20 Proxy). President and Chief Executive Officer: Kevin Akers. Incorporated: Texas. Address: Three Lincoln Centre, Suite 1800, 5430 LBJ Freeway, Dallas, Texas 75240. Telephone: 972-934-9227. Internet: www.atmosenergy.com.

Atmos Energy's earnings stand to rise, once again, in fiscal 2022. (The year began on October 1st.) The natural gas distribution unit, which generates the lion's share of total revenues, may enjoy increased consumption levels, if temperatures across the service territories are generally favorable. An expanded customer base ought to help, too. Moreover, we anticipate a respectable performance from the pipeline and storage division. Although uncertainties concerning COVID-19 persist, full-year profits might advance around 6%, to $5.45 a share, versus fiscal 2021's $5.12 figure. Turning to the following year, share net stands to increase at a similar percentage rate, to $5.80, as operating margins widen further.

Capital spending for the year that ended recently totaled about $1.97 billion. Approximately 88% of the expenditures were used to enhance the safety and reliability of Atmos Energy's natural gas distribution and transmission systems. Regarding the new fiscal year, the budget is expected to be $2.4 billion—$2.5 billion. It's also worth mentioning that management projects total capital spending from fiscal 2022 through fiscal 2026 to lie between $13 billion and $14 billion. A substantial portion of the funds will continue to be allocated to where they were last year. Supported by healthy corporate finances, it appears that these objectives are quite achievable.

The quarterly common stock dividend was increased almost 9%, to $0.68 a share. Moreover, we anticipate further steady hikes out to the 2024-2026 period. The payout ratio over that span ought to be in the neighborhood of 50%, which seems reasonable. However, the dividend yield is not spectacular compared to the average of *Value Line's* Natural Gas Utility Industry group.

Atmos Energy shares hold decent, risk-adjusted total return potential. Long-term capital appreciation possibilities are appealing, at the recent quotation. Dividend growth prospects look promising, as well. Meanwhile, the equity is pegged to underperform the broader market averages during the next six to 12 months (Timeliness rank 4: Below Average).

Frederick L. Harris, III November 26, 2021

(A) Fiscal year ends Sept. 30th. (B) Diluted shrs. Excl. nonrec. gains (loss): '10, 5¢; '11, (1¢); '18, $1.43; '20, 17¢. Excludes discontinued operations: '11, 10¢; '12, 27¢; '13, 14¢; '17, 13¢. Next egs. rpt. due early Feb.
(C) Dividends historically paid in early March, June, Sept., and Dec. ■ Div. reinvestment plan. Direct stock purchase plan avail.
(D) In millions.
(E) Qtrs may not add due to change in shrs outstanding.

Company's Financial Strength	A+
Stock's Price Stability	95
Price Growth Persistence	70
Earnings Predictability	100

NEW JERSEY RES. NYSE-NJR

RECENT PRICE 39.18 | P/E RATIO 17.3 (Trailing: 14.8 / Median: 17.0) | RELATIVE P/E RATIO 0.92 | DIV'D YLD 3.7% | VALUE LINE

TIMELINESS 4 Lowered 8/20/21
SAFETY 2 Lowered 4/17/20
TECHNICAL 3 Raised 11/19/21
BETA 1.00 (1.00 = Market)

High:	22.0	25.2	25.1	23.8	32.1	34.1	38.9	45.4	51.8	51.2	44.7	44.4
Low:	16.7	19.8	19.3	19.5	21.9	26.8	30.5	33.7	35.6	40.3	21.1	33.3

Target Price Range 2024 | 2025 | 2026

LEGENDS
—— 0.40 x Dividends p sh divided by Interest Rate
. . . . Relative Price Strength
3-for-2 split 3/08
2-for-1 split 3/15
Options: Yes
Shaded area indicates recession

18-Month Target Price Range
Low-High Midpoint (% to Mid)
$20-$44 $32 (-20%)

2024-26 PROJECTIONS

	Price	Gain	Ann'l Total Return
High	50	(+30%)	10%
Low	35	(-10%)	2%

Institutional Decisions

	4Q2020	1Q2021	2Q2021
to Buy	132	105	102
to Sell	118	139	130
Hld's(000)	71013	68468	68609

% TOT. RETURN 10/21

	THIS STOCK	VL ARITH.* INDEX
1 yr.	34.2	55.5
3 yr.	-7.3	64.6
5 yr.	29.8	104.1

2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	© VALUE LINE PUB. LLC	24-26
38.10	39.81	36.31	45.37	31.17	32.05	36.30	27.08	38.38	44.40	32.09	21.90	26.28	33.24	29.01	20.39	**20.90**	**22.95**	Revenues per sh A	**24.60**
1.31	1.37	1.22	1.81	1.58	1.63	1.70	1.86	1.93	2.73	2.52	2.46	2.68	3.72	2.99	3.30	**3.50**	**3.55**	"Cash Flow" per sh	**3.90**
.88	.93	.78	1.35	1.20	1.23	1.29	1.36	1.37	2.08	1.78	1.61	1.73	2.72	1.96	2.07	**2.20**	**2.30**	Earnings per sh B	**2.45**
.45	.48	.51	.56	.62	.68	.72	.77	.81	.86	.93	.98	1.04	1.11	1.19	1.27	**1.36**	**1.45**	Div'ds Decl'd per sh C■	**1.65**
.64	.64	.73	.86	.90	1.05	1.13	1.26	1.33	1.52	3.76	4.15	3.80	4.39	5.83	4.65	**4.10**	**4.10**	Cap'l Spending per sh	**4.00**
5.30	7.50	7.75	8.64	8.29	8.81	9.36	9.80	10.65	11.48	12.99	13.58	14.33	16.18	17.37	19.26	**20.35**	**21.40**	Book Value per sh D	**24.15**
82.64	82.88	83.22	84.12	83.17	82.35	82.89	83.05	83.32	84.20	85.19	85.88	86.32	87.69	89.34	95.80	**97.00**	**98.00**	Common Shs Outst'g E	**100.00**
16.8	16.1	21.6	12.3	14.9	15.0	16.8	16.8	16.0	11.7	16.6	21.3	22.4	15.6	24.3	17.7	*Bold figures are*	*Value Line*	Avg Ann'l P/E Ratio	**17.0**
.89	.87	1.15	.74	.99	.95	1.05	1.07	.90	.62	.84	1.12	1.13	.84	1.29	.91	*estimates*		Relative P/E Ratio	**.95**
3.1%	3.2%	3.0%	3.3%	3.5%	3.7%	3.3%	3.4%	3.7%	3.5%	3.1%	2.9%	2.7%	2.6%	2.5%	3.5%			Avg Ann'l Div'd Yield	**3.7%**

2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022		24-26
3009.2	2248.9	3198.1	3738.1	2734.0	1880.9	2268.6	2915.1	2592.0	1953.7	**2025**	**2250**	Revenues ($mill) A	**2460**
106.5	112.4	113.7	176.9	153.7	138.1	149.4	240.5	175.0	196.2	**215**	**225**	Net Profit ($mill)	**245**
30.2%	7.1%	25.4%	30.2%	26.3%	15.5%	17.2%	- -	NMF	5.0%	**5.0%**	**5.0%**	Income Tax Rate	**5.0%**
3.5%	5.0%	3.6%	4.7%	5.6%	7.3%	6.6%	8.2%	6.7%	10.0%	**10.6%**	**10.1%**	Net Profit Margin	**10.0%**
35.5%	39.2%	36.6%	38.2%	43.2%	47.7%	44.6%	45.4%	49.8%	55.1%	**54.0%**	**54.5%**	Long-Term Debt Ratio	**53.5%**
64.5%	60.8%	63.4%	61.8%	56.8%	52.3%	55.4%	54.6%	50.2%	44.9%	**46.0%**	**45.5%**	Common Equity Ratio	**46.5%**
1203.1	1339.0	1400.3	1564.4	1950.6	2230.1	2233.7	2599.6	3088.9	4104.2	**4270**	**4595**	Total Capital ($mill)	**5215**
1295.9	1484.9	1643.1	1884.1	2128.3	2407.7	2609.7	2651.0	3041.2	3983.0	**4065**	**4145**	Net Plant ($mill)	**4395**
9.7%	9.2%	9.0%	12.1%	8.6%	6.9%	7.7%	10.1%	6.4%	5.6%	**6.0%**	**6.0%**	Return on Total Cap'l	**6.0%**
13.7%	13.8%	12.8%	18.3%	13.9%	11.8%	12.1%	16.9%	11.3%	10.6%	**11.0%**	**11.0%**	Return on Shr. Equity	**10.0%**
13.7%	13.8%	12.8%	18.3%	13.9%	11.8%	12.1%	16.9%	11.3%	10.6%	**11.0%**	**11.0%**	Return on Com Equity	**10.0%**
6.2%	6.2%	5.2%	11.0%	7.0%	4.8%	5.0%	10.2%	4.6%	4.3%	**4.0%**	**4.0%**	Retained to Com Eq	**3.0%**
55%	55%	59%	40%	50%	60%	59%	40%	59%	60%	**62%**	**63%**	All Div'ds to Net Prof	**67%**

CAPITAL STRUCTURE as of 6/30/21
Total Debt $2420.9 mill. **Due in 5 Yrs** $420.5 mill.
LT Debt $2221.6 mill. **LT Interest** $47.1 mill.
Incl. $54.9 mill. capitalized leases.
(LT interest earned: 5.0x; total interest coverage: 5.0x)
Pension Assets-9/20 $404.4 mill. **Oblig.** $643.0 mill.
Pfd Stock None

Common Stock 96,433,901 shs. **as of 8/2/21**
MARKET CAP: $3.8 billion (Mid Cap)

CURRENT POSITION ($MILL.)	2019	2020	6/30/21
Cash Assets	2.7	117.0	4.7
Other	508.9	505.3	513.6
Current Assets	511.6	622.3	518.3
Accts Payable	295.9	270.1	310.8
Debt Due	46.9	152.6	199.3
Other	103.6	111.0	103.5
Current Liab.	446.4	533.7	613.6
Fix. Chg. Cov.	545%	545%	550%

ANNUAL RATES of change (per sh)	Past 10 Yrs.	Past 5 Yrs.	Est'd '18-'20 to '24-'26
Revenues	-2.5%	-6.5%	-2.0%
"Cash Flow"	7.0%	7.0%	2.5%
Earnings	6.0%	5.5%	1.5%
Dividends	7.0%	6.5%	5.5%
Book Value	7.5%	8.5%	5.5%

Fiscal Year Ends	QUARTERLY REVENUES ($ mill.) A Dec.31	Mar.31	Jun.30	Sep.30	Full Fiscal Year
2018	705.3	1019.1	543.4	647.3	2915.1
2019	811.8	866.2	434.9	479.1	2592.0
2020	615.0	639.6	299.0	400.1	1953.7
2021	454.3	802.2	367.6	*400.9*	*2025*
2022	*510*	*855*	*430*	*455*	*2250*

Fiscal Year Ends	EARNINGS PER SHARE A B Dec.31	Mar.31	Jun.30	Sep.30	Full Fiscal Year
2018	1.53	1.61	d.09	d.33	2.72
2019	.61	1.27	d.20	.29	1.96
2020	.44	1.12	d.06	.57	2.07
2021	.46	1.77	d.15	*.12*	*2.20*
2022	*.48*	*1.80*	*d.13*	*.15*	*2.30*

Cal-endar	QUARTERLY DIVIDENDS PAID C ■ Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2017	.255	.255	.255	.273	1.04
2018	.273	.273	.273	.2925	1.11
2019	.2925	.2925	.2925	.3125	1.19
2020	.3125	.3125	.3125	.3325	1.27
2021	.3325	.3325	.3325	.3625	

BUSINESS: New Jersey Resources Corp. is a holding company providing retail/wholesale energy svcs. to customers in NJ, and in states from the Gulf Coast to New England, and Canada. New Jersey Natural Gas had 558,000 cust. at 9/30/20. Fiscal 2020 volume: 215 bill. cu. ft. (14% interruptible, 21% res., 10% commercial & elec. utility, 55% capacity release programs). N.J. Natural Energy subsidiary provides unregulated retail/wholesale natural gas and related energy svcs. 2020 dep. rate: 2.8%. Has 1,156 empls. Off./dir. own 1.3% of common; BlackRock, 14.3%; Vanguard, 10.6% (12/20 Proxy). CEO, President & Director: Steven D. Westhoven. Incorporated: New Jersey. Address: 1415 Wyckoff Road, Wall, NJ 07719. Telephone: 732-938-1480. Web: www.njresources.com.

We look for New Jersey Resources to post decent financial results for fiscal 2021 (ended September 30th). (Note: The company was expected to issue its annual earnings release shortly after this report went to press.) The provider of retail and wholesale energy services appeared well positioned to post modest top-line growth of about 3.5%, to roughly $2.0 billion. One primary driver this year was the incremental contributions from the nonutility operations, particularly the Energy Services segment, which performed quite well over the past 12 months. At the same time, the New Jersey Natural Gas regulated utility business continues to add new customer accounts, albeit at a slower pace than last year, owing to the resurgance of COVID-19 cases in recent months. Some uncertainty does come from an uptick in bad-debt accounts. Elsewhere, the company brought numerous capital expansion projects into service over the past year. On balance, these factors likely drove the bottom line about 6.5% higher, to $2.20 a share.

We look for this steady momentum to continue into fiscal 2022. New Jersey Resources appears well positioned for revenue growth of about 11%, to $2.25 billion thanks to new customer accounts, capital growth projects, and rate cases. To that point, the company plans to add 28,000-30,000 new customers from 2021-2023. And the NJNG division has a pending base-rate increase of $165 million that is awaiting approval. In sum, we look for NJR's bottom line to rise about 5% this year, to $2.30 a share.

The balance sheet is in decent shape. Cash reserves fell substantially from 2020's elevated levels, to $4.7 million at the end of June, the last period for which financial information is available. This was still in line with historical levels. Meanwhile, long-term debt has been steadily creeping higher, but it is on par with industry standards. Finally, the board recently authorized a 9% increase in the quarterly payout, to $0.3625.

These good-quality shares are ranked to lag the broader market averages, and are trading inside our 3- to 5-year Target Price Range, suggesting limited upside potential.

Bryan J. Fong *November 26, 2021*

(A) Fiscal year ends Sept. 30th.
(B) Diluted earnings. Qtly. revenues and egs. may not sum to total due to rounding and change in shares outstanding. Next earnings report due early Feb.
(C) Dividends historically paid in early Jan., April, July, and October. ■ Dividend reinvestment plan available.
(D) Includes regulatory assets in 2020: $527.5 million, $5.51/share.
(E) In millions, adjusted for splits.

Company's Financial Strength	A+
Stock's Price Stability	80
Price Growth Persistence	50
Earnings Predictability	55

N.W. NATURAL NYSE-NWN

RECENT PRICE 46.87 | P/E RATIO 18.4 (Trailing: 17.0 Median: 24.0) | RELATIVE P/E RATIO 0.97 | DIV'D YLD 4.1% | VALUE LINE

TIMELINESS 5 Lowered 11/19/21
SAFETY 3 Lowered 3/19/21
TECHNICAL 3 Raised 11/19/21
BETA .85 (1.00 = Market)

High:	50.9	49.0	50.8	46.6	52.6	52.3	66.2	69.5	71.8	74.1	77.3	56.8
Low:	41.1	39.6	41.0	40.0	40.1	42.0	48.9	56.5	51.5	57.2	42.3	41.7

18-Month Target Price Range
Low-High: $38-$65 | Midpoint (% to Mid): $52 (10%)

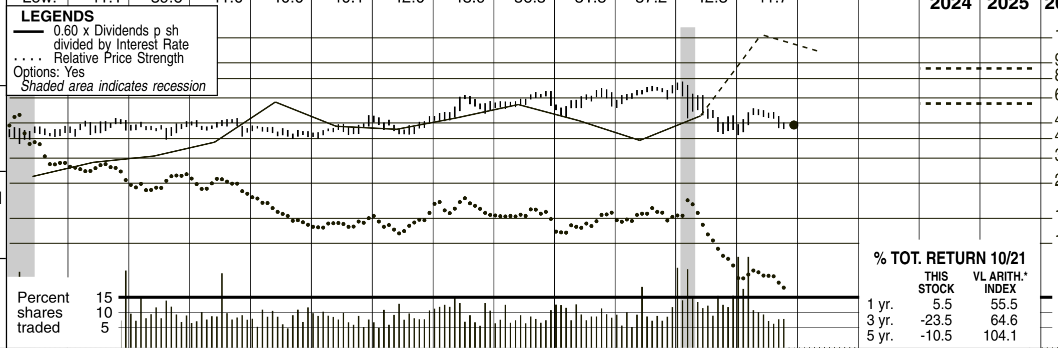
Target Price Range
2024 | 2025 | 2026

2024-26 PROJECTIONS

	Price	Gain	Ann'l Total Return
High	90	(+90%)	20%
Low	60	(+30%)	10%

Institutional Decisions

	4Q2020	1Q2021	2Q2021
to Buy	99	103	114
to Sell	85	89	81
Hld's(000)	22201	21451	21444



% TOT. RETURN 10/21

	THIS STOCK	VL ARITH.* INDEX
1 yr.	5.5	55.5
3 yr.	-23.5	64.6
5 yr.	-10.5	104.1

2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	© VALUE LINE PUB. LLC	24-26
33.01	37.20	39.13	39.16	38.17	30.56	31.72	27.14	28.02	27.64	26.39	23.61	26.52	24.45	24.49	25.29	*26.75*	*27.75*	Revenues per sh	*31.10*
4.34	4.76	5.41	5.31	5.20	5.18	5.00	4.94	5.04	5.05	4.91	4.93	1.04	5.28	5.15	5.69	*5.75*	*6.10*	"Cash Flow" per sh	*6.85*
2.11	2.35	2.76	2.57	2.83	2.73	2.39	2.22	2.24	2.16	1.96	2.12	d1.94	2.33	2.19	2.30	*2.50*	*2.70*	Earnings per sh A	*3.10*
1.32	1.39	1.44	1.52	1.60	1.68	1.75	1.79	1.83	1.85	1.86	1.87	1.88	1.89	1.90	1.91	*1.92*	*1.93*	Div'ds Decl'd per sh B■	*1.96*
3.48	3.56	4.48	3.92	5.09	9.35	3.76	4.91	5.13	4.40	4.37	4.87	7.43	7.43	7.95	9.18	*8.40*	*8.70*	Cap'l Spending per sh	*9.40*
21.28	22.01	22.52	23.71	24.88	26.08	26.70	27.23	27.77	28.12	28.47	29.71	25.85	26.41	28.42	29.05	*33.85*	*37.10*	Book Value per sh D	*45.30*
27.58	27.24	26.41	26.50	26.53	26.58	26.76	26.92	27.08	27.28	27.43	28.63	28.74	28.88	30.47	30.59	*31.00*	*31.00*	Common Shs Outst'g C	*32.00*
17.0	15.9	16.7	18.1	15.2	17.0	19.0	21.1	19.4	20.7	23.7	26.9	- -	26.6	30.9	25.0	*Bold figures are*	*Value Line*	Avg Ann'l P/E Ratio	*24.0*
.91	.86	.89	1.09	1.01	1.08	1.19	1.34	1.09	1.09	1.19	1.41	- -	1.44	1.65	1.30	*estimates*		Relative P/E Ratio	*1.35*
3.7%	3.7%	3.1%	3.3%	3.7%	3.6%	3.9%	3.8%	4.2%	4.1%	4.0%	3.3%	3.0%	3.0%	2.8%	3.3%			Avg Ann'l Div'd Yield	*2.6%*

2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022		24-26
848.8	730.6	758.5	754.0	723.8	676.0	762.2	706.1	746.4	773.7	*830*	*860*	Revenues ($mill)	*995*
63.9	59.9	60.5	58.7	53.7	58.9	d55.6	67.3	65.3	70.3	*75.0*	*85.0*	Net Profit ($mill)	*100*
40.4%	42.4%	40.8%	41.5%	40.0%	40.9%	- -	26.4%	16.2%	23.1%	*21.0%*	*21.0%*	Income Tax Rate	*21.0%*
7.5%	8.2%	8.0%	7.8%	7.4%	8.7%	NMF	9.5%	8.8%	9.1%	*9.0%*	*9.9%*	Net Profit Margin	*10.1%*
47.3%	48.5%	47.6%	44.8%	42.5%	44.4%	47.9%	48.1%	48.2%	49.2%	*49.0%*	*46.5%*	Long-Term Debt Ratio	*43.0%*
52.7%	51.5%	52.4%	55.2%	57.5%	55.6%	52.1%	51.9%	51.8%	50.8%	*51.0%*	*53.5%*	Common Equity Ratio	*57.0%*
1356.2	1424.7	1433.6	1389.0	1357.7	1529.8	1426.0	1468.9	1672.0	1748.8	*2050*	*2150*	Total Capital ($mill)	*2550*
1893.9	1973.6	2062.9	2121.6	2182.7	2260.9	2255.0	2421.4	2438.9	2654.8	*2640*	*2750*	Net Plant ($mill)	*3105*
6.2%	5.7%	5.8%	5.8%	5.5%	5.1%	NMF	5.8%	5.2%	5.2%	*4.0%*	*4.0%*	Return on Total Cap'l	*4.0%*
8.9%	8.2%	8.1%	7.6%	6.9%	6.9%	NMF	8.8%	7.5%	7.9%	*7.5%*	*7.5%*	Return on Shr. Equity	*7.0%*
8.9%	8.2%	8.1%	7.6%	6.9%	6.9%	NMF	8.8%	7.5%	7.9%	*7.5%*	*7.5%*	Return on Com Equity	*7.0%*
2.4%	1.6%	1.5%	1.1%	.6%	.9%	NMF	2.1%	1.4%	1.7%	*1.5%*	*2.0%*	Retained to Com Eq	*2.5%*
73%	80%	81%	85%	92%	87%	NMF	76%	82%	79%	*77%*	*72%*	All Div'ds to Net Prof	*63%*

CAPITAL STRUCTURE as of 9/30/21
Total Debt $1315.8 mill. **Due in 5 Yrs** $360.2 mill.
LT Debt $916.0 mill. **LT Interest** $43.1 mill.

(Total interest coverage: 3.1x)

Pension Assets-12/20 $373.9 mill.
Oblig. $595.2 mill.

Pfd Stock None

Common Stock 30,730,274 shares
as of 10/27/21

MARKET CAP $1.4 billion (Mid Cap)

CURRENT POSITION ($MILL.)	2019	2020	9/30/21
Cash Assets	9.6	30.2	19.5
Other	284.1	293.0	338.7
Current Assets	293.7	323.2	358.2
Accts Payable	113.4	97.9	97.9
Debt Due	224.2	399.9	399.8
Other	144.6	129.3	237.2
Current Liab.	482.2	627.1	734.9
Fix. Chg. Cov.	336%	335%	312%

ANNUAL RATES of change (per sh)	Past 10 Yrs.	Past 5 Yrs.	Est'd '18-'20 to '24-'26
Revenues	-3.5%	-2.0%	*4.0%*
"Cash Flow"	.5%	1.5%	*4.0%*
Earnings	-1.5%	1.5%	*5.5%*
Dividends	1.5%	.5%	*.5%*
Book Value	1.0%	- -	*8.5%*

Cal-endar	QUARTERLY REVENUES ($ mill.) Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2018	264.7	124.6	91.2	226.7	706.1
2019	285.4	123.4	90.3	247.3	746.4
2020	285.2	135.0	93.3	260.2	773.7
2021	315.9	148.9	101.4	*263.8*	*830*
2022	*320*	*150*	*110*	*280*	*860*

Cal-endar	EARNINGS PER SHARE A Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2018	1.46	d.01	d.39	1.27	2.33
2019	1.50	.07	d.61	1.26	2.19
2020	1.58	d.17	d.61	1.50	2.30
2021	1.94	d.02	d.67	*1.25*	*2.50*
2022	*1.96*	*.01*	*d.57*	*1.30*	*2.70*

Cal-endar	QUARTERLY DIVIDENDS PAID B ■ Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2017	.47	.47	.47	.4725	1.88
2018	.4725	.4725	.4725	.475	1.89
2019	.475	.475	.475	.4775	1.90
2020	.4775	.4775	.4775	.48	1.91
2021	.48	.48	.48	.483	

BUSINESS: Northwest Natural Holding Co. distributes natural gas to 1000 communities, 775,000 customers, in Oregon (89% of customers) and in southwest Washington state. Principal cities served: Portland and Eugene, OR; Vancouver, WA. Service area population: 3.7 mill. (77% in OR). Company buys gas supply from Canadian and U.S. producers; has transportation rights on Northwest Pipeline system. Owns local underground storage. Rev. breakdown: residential, 37%; commercial, 22%; industrial, gas transportation, 41%. Employs 1,167. BlackRock Inc. owns 16.4% of shares; State Street, 15.4%; Off./Dir., 1.03% (4/21 proxy). CEO: David H. Anderson. Inc.: Oregon. Address: 220 NW 2nd Ave., Portland, OR 97209. Tel.: 503-226-4211. Internet: www.nwnatural.com.

Since our August review, shares of Northwest Natural Holding Co. have staged a correction. In fact, the stock's price has lost nearly 12% of its value, likely a reflection of the challenging operating environment over the past year.

Meanwhile, the regional distributor of natural gas posted lower-than-expected September-period financial results. Revenues advanced 8.7%, to $101.4 million, bolstered by new customer accounts and recently implemented rate case increases in Oregon. In fact, the company has added almost 12,000 natural gas meters over the last year. That said, the top line was still fairly below our outlook of $110 million. On the profitability front, overall expenses increased 180 basis points when viewed as a percentage of revenues. The primary driver here was higher operating and maintenance items. All told, these factors drove bottom-line losses nearly 10% deeper into the red, to a deficit of $0.67 a share.

Consequently, we have shaved a dime off our 2021 share-net estimate, bringing that figure to $2.50. Our revised outlook would still represent a healthy year-over-year advance of almost 9%. This ought to be driven by top-line growth of about 7.5%, to $830 million. A good portion of these solid results will likely come in the fourth quarter, owing to the seasonal nature of NWN's business. What's more, the rate cases in Oregon and Washington have set increases that come in over time, which augurs well for prospects and should allow the company to focus on geographic expansion and system upgrades.

The financial position is in good shape. Although cash reserves fell about 35% so far this year, that cushion still sits at $19.5 million. Meanwhile, the long-term debt load ticked 6.5% higher, to $916 million, or 51% of the capital structure, which is actually on the lower side for this industry. Finally, the board recently approved a modest increase in the quarterly dividend of just under 1%, to $0.483 per share.

These shares are ranked to lag the broader market averages in the coming year. That said, recent volatility in this space and the downturn in the stock's price leaves NWN with sizable recovery potential and a solid dividend yield.

Bryan J. Fong *November 26, 2021*

(A) Diluted earnings per share. Excludes nonrecurring items: '06, ($0.06); '08, ($0.03); '09, $0.06; May not sum due to rounding. Next earnings report due in early Feb.
(B) Dividends historically paid in mid-February, May, August, and November.
■ Dividend reinvestment plan available.
(C) In millions.
(D) Includes intangibles. In 2020: $69.2 million, $2.26/share.

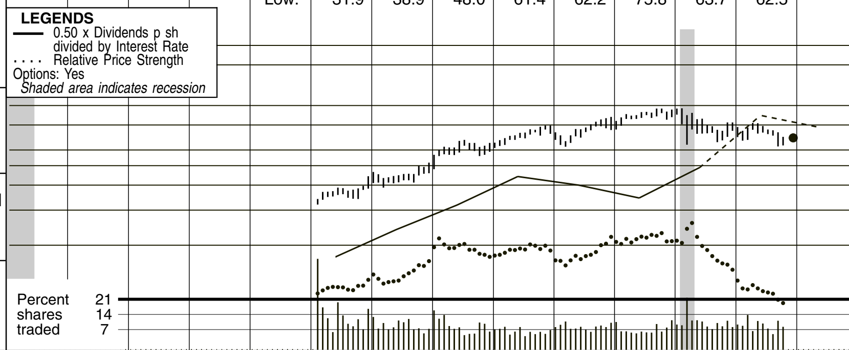
Company's Financial Strength	A
Stock's Price Stability	85
Price Growth Persistence	35
Earnings Predictability	10

ONE GAS, INC. NYSE-OGS

RECENT PRICE **68.97** | P/E RATIO **17.4** (Trailing: 18.1 / Median: NMF) | RELATIVE P/E RATIO **0.92** | DIV'D YLD **3.6%** | **VALUE LINE**

TIMELINESS 4 Lowered 6/11/21
SAFETY 2 New 6/2/17
TECHNICAL 4 Raised 11/26/21
BETA .80 (1.00 = Market)

High:	44.3	51.8	67.4	79.5	87.8	96.7	97.0	81.9	
Low:	31.9	38.9	48.0	61.4	62.2	75.8	63.7	62.5	



Target Price Range
2024 | 2025 | 2026
200
160
100
80
60
50
40
30
20

% TOT. RETURN 10/21

	THIS STOCK	VL ARITH.* INDEX
1 yr.	0.5	55.5
3 yr.	-8.2	64.6
5 yr.	24.1	104.1

18-Month Target Price Range

Low-High	Midpoint (% to Mid)
$59-$103	$81 (15%)

2024-26 PROJECTIONS

	Price	Gain	Ann'l Total Return
High	145	(+110%)	23%
Low	105	(+50%)	14%

Institutional Decisions

	4Q2020	1Q2021	2Q2021
to Buy	123	127	111
to Sell	163	144	140
Hld's(000)	42726	42395	43179

The shares of ONE Gas, Inc. began trading "regular-way" on the New York Stock Exchange on February 3, 2014. That happened as a result of the separation of ONEOK's natural gas distribution operation. Regarding the details of the spinoff, on January 31, 2014, ONEOK distributed one share of OGS common stock for every four shares of ONEOK common stock held by ONEOK shareholders of record as of the close of business on January 21. It should be mentioned that ONEOK did not retain any ownership interest in the new company.

2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	© VALUE LINE PUB. LLC	24-26
--	--	--	34.92	29.62	27.30	29.43	31.08	31.32	28.78	*32.05*	*34.20*	Revenues per sh	*43.00*
--	--	--	4.52	4.82	5.43	5.96	6.32	6.96	7.36	*7.75*	*8.20*	"Cash Flow" per sh	*9.75*
--	--	--	2.07	2.24	2.65	3.02	3.25	3.51	3.68	*3.85*	*4.05*	Earnings per sh A	*5.00*
--	--	--	.84	1.20	1.40	1.68	1.84	2.00	2.16	*2.32*	*2.48*	Div'ds Decl'd per sh B■	*2.95*
--	--	--	5.70	5.63	5.91	6.81	7.50	7.91	8.87	*9.00*	*9.20*	Cap'l Spending per sh	*9.75*
--	--	--	34.45	35.24	36.12	37.47	38.86	40.35	42.01	*46.05*	*49.50*	Book Value per sh	*74.40*
--	--	--	52.08	52.26	52.28	52.31	52.57	52.77	53.17	*53.50*	*53.50*	Common Shs Outst'g C	*57.00*
--	--	--	17.8	19.8	22.7	23.5	23.1	25.3	21.7	*Bold figures are*		Avg Ann'l P/E Ratio	*25.0*
--	--	--	.94	1.00	1.19	1.18	1.25	1.35	1.11	*Value Line*		Relative P/E Ratio	*1.40*
--	--	--	2.3%	2.7%	2.3%	2.4%	2.5%	2.3%	2.7%	*estimates*		Avg Ann'l Div'd Yield	*2.4%*
--	--	--	1818.9	1547.7	1427.2	1539.6	1633.7	1652.7	1530.3	*1715*	*1830*	Revenues ($mill)	*2450*
--	--	--	109.8	119.0	140.1	159.9	172.2	186.7	196.4	*205*	*215*	Net Profit ($mill)	*285*
--	--	--	38.4%	38.0%	37.8%	36.4%	23.7%	18.7%	17.5%	*17.0%*	*17.5%*	Income Tax Rate	*22.0%*
--	--	--	6.0%	7.7%	9.8%	10.4%	10.5%	11.3%	12.8%	*12.0%*	*11.7%*	Net Profit Margin	*11.6%*
--	--	--	40.1%	39.5%	38.7%	37.8%	38.6%	37.7%	41.5%	*61.5%*	*60.0%*	Long-Term Debt Ratio	*47.0%*
--	--	--	59.9%	60.5%	61.3%	62.2%	61.4%	62.3%	58.5%	*38.5%*	*40.0%*	Common Equity Ratio	*53.0%*
--	--	--	2995.3	3042.9	3080.7	3153.5	3328.1	3415.5	3815.7	*6400*	*6620*	Total Capital ($mill)	*8000*
--	--	--	3293.7	3511.9	3731.6	4007.6	4283.7	4565.2	4867.1	*5150*	*5380*	Net Plant ($mill)	*6000*
--	--	--	4.4%	4.7%	5.2%	5.8%	5.9%	6.4%	6.0%	*5.0%*	*5.0%*	Return on Total Cap'l	*5.0%*
--	--	--	6.1%	6.5%	7.4%	8.2%	8.4%	8.8%	8.8%	*8.5%*	*8.0%*	Return on Shr. Equity	*6.5%*
--	--	--	6.1%	6.5%	7.4%	8.2%	8.4%	8.8%	8.8%	*8.5%*	*8.0%*	Return on Com Equity	*6.5%*
--	--	--	3.7%	3.1%	3.5%	3.7%	3.7%	3.8%	3.7%	*3.5%*	*3.0%*	Retained to Com Eq	*3.0%*
--	--	--	40%	53%	52%	55%	56%	56%	58%	*61%*	*62%*	All Div'ds to Net Prof	*59%*

CAPITAL STRUCTURE as of 9/30/21
Total Debt $4019.1 mill. **Due in 5 Yrs** $1020.0 mill.
LT Debt $3683.1 mill. **LT Interest** $150.0 mill.
(LT interest earned: 4.8x; total interest coverage: 4.8x)
Leases, Uncapitalized Annual rentals $7.9 mill.
Pfd Stock None
Pension Assets-12/20 $987.6 mill.
Oblig. $1077.6 mill.
Common Stock 53,587,508 shs.
as of 10/25/21
MARKET CAP: $3.7 billion (Mid Cap)

CURRENT POSITION ($MILL.)	2019	2020	9/30/21
Cash Assets	17.9	8.0	6.5
Other	488.3	531.9	746.4
Current Assets	506.2	539.9	752.9
Accts Payable	120.5	152.3	127.5
Debt Due	516.5	418.2	336.0
Other	235.7	226.6	256.6
Current Liab.	872.7	797.1	720.1
Fix. Chg. Cov.	567%	587%	600%

ANNUAL RATES of change (per sh)	Past 10 Yrs.	Past 5 Yrs.	Est'd '18-'20 to '24-'26
Revenues	--	-1.0%	*6.0%*
"Cash Flow"	--	8.0%	*6.0%*
Earnings	--	10.0%	*6.5%*
Dividends	--	14.5%	*7.0%*
Book Value	--	3.0%	*10.5%*

Cal-endar	QUARTERLY REVENUES ($ mill.) Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2018	638.5	292.5	238.3	464.4	1633.7
2019	661.0	290.6	248.6	452.5	1652.7
2020	528.2	273.3	244.6	484.2	1530.3
2021	625.3	315.6	273.9	*500.2*	*1715*
2022	*650*	*355*	*310*	*515*	*1830*

Cal-endar	EARNINGS PER SHARE A Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2018	1.72	.39	.31	.83	3.25
2019	1.76	.46	.33	.96	3.51
2020	1.72	.48	.39	1.09	3.68
2021	1.79	.56	.38	*1.12*	*3.85*
2022	*1.85*	*.62*	*.45*	*1.13*	*4.05*

Cal-endar	QUARTERLY DIVIDENDS PAID B■ Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2017	.42	.42	.42	.42	1.68
2018	.46	.46	.46	.46	1.84
2019	.50	.50	.50	.50	2.00
2020	.54	.54	.54	.54	2.16
2021	.58	.58	.58	.58	

BUSINESS: ONE Gas, Inc. provides natural gas distribution services to more than two million customers. There are three divisions: Oklahoma Natural Gas, Kansas Gas Service, and Texas Gas Service. The company purchased 153 Bcf of natural gas supply in 2020, compared to 174 Bcf in 2019. Total volumes delivered by customer (fiscal 2020): transportation, 58.3%; residential, 31.7%; commercial & industrial, 9.4%; other, .6%. ONE Gas has around 3,600 employees. BlackRock owns 11.9% of common stock; The Vanguard Group, 9.7%; American Century Investment, 7.6%; officers and directors, 1.9% (4/21 Proxy). CEO: Robert S. McAnnally. Incorporated: Oklahoma. Address: 15 East Fifth Street, Tulsa, Oklahoma 74103. Tel.: 918-947-7000. Internet: www.onegas.com.

ONE Gas appears on track to register higher earnings in 2021. During the first nine months, share net of $2.73 was 5.4% higher than the year-earlier total of $2.59. This was brought about partially by benefits from new rates, primarily in Texas and Oklahoma. Another positive was customer growth in Oklahoma and Texas. The effective income tax rate was lower, as well. If there are no major pandemic-related disruptions in the fourth quarter, we expect full-year profits to increase almost 5%, to $3.85 a share, compared to the 2020 tally of $3.68. Assuming further widening of operating margins in 2022, share net might advance at a similar percentage rate, to $4.05.

The Financial Strength rating is B++. When the third quarter concluded, cash and equivalents were $6.5 million, and cash flows were decent. Furthermore, there was $664 million available (out of $1 billion) under a commercial paper program. ONE Gas also possesses a $1 billion revolving credit facility maturing in March, 2026. However, at the end of the September period, long-term debt was on the heavy side (61.4% of total capital). Nevertheless, we believe that the company will be able to handily meet its various obligations for some time.

This year's capital expenditures, including asset removal costs, are anticipated to be approximately $540 million. (That would be about 5% above the 2020 figure of $512.2 million.) Around 70% of the budget is devoted to system integrity and pipeline replacement projects. Notably, the energy company projects total spending to be $3 billion ($540 million—$640 million annually) between 2021 and 2025, with roughly the same percentage of capital allocated to where it is presently.

These good-quality shares should be of interest to total return-focused investors with a long-term bent. Capital appreciation potential out to 2024-2026 looks appealing, when stacked against the *Value Line* median. Consider, also, the healthy dividend growth prospects. But, right now, the equity is pegged to underperform the broader market averages in the next six to 12 months (Timeliness rank 4: Below Average).

Frederick L. Harris, III November 26, 2021

(A) Diluted EPS. Excludes nonrecurring gain: 2017, $0.06. Next earnings report due early Feb. Quarterly EPS for 2018 don't add up due to rounding.
(B) Dividends historically paid in early March, June, Sept., and Dec. ■ Dividend reinvestment plan. Direct stock purchase plan.
(C) In millions.

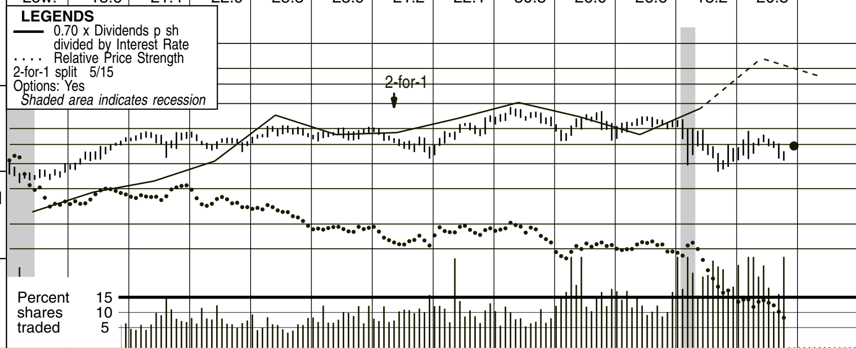
Company's Financial Strength	B++
Stock's Price Stability	95
Price Growth Persistence	60
Earnings Predictability	100

SOUTH JERSEY INDS. NYSE-SJI

RECENT PRICE 24.54 | P/E RATIO 14.5 (Trailing: 14.2 Median: 19.0) | RELATIVE P/E RATIO 0.77 | DIV'D YLD 5.3% | VALUE LINE

TIMELINESS 3 Raised 10/29/21
SAFETY 3 Lowered 8/28/20
TECHNICAL 5 Lowered 11/12/21
BETA 1.05 (1.00 = Market)

High:	27.1	29.0	29.0	31.1	30.6	30.4	34.8	38.4	36.7	34.5	33.4	29.2
Low:	18.6	21.4	22.9	25.3	25.9	21.2	22.1	30.8	26.0	26.6	18.2	20.8



18-Month Target Price Range
Low-High Midpoint (% to Mid)
$9-$34 $22 (-10%)

2024-26 PROJECTIONS

	Price	Gain	Ann'l Total Return
High	50	(+105%)	22%
Low	35	(+45%)	13%

Institutional Decisions

	4Q2020	1Q2021	2Q2021
to Buy	110	141	132
to Sell	91	89	106
Hld's(000)	110377	102245	105367

Target Price Range 2024 | 2025 | 2026
80, 60, 50, 40, 30, 25, 20, 15, 10, 7.5

% TOT. RETURN 10/21

	THIS STOCK	VL ARITH.* INDEX
1 yr.	23.9	55.5
3 yr.	-13.6	64.6
5 yr.	-7.9	104.1

2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	© VALUE LINE PUB. LLC	24-26
15.89	15.88	16.15	16.18	14.19	15.48	13.71	11.16	11.18	12.98	13.52	13.04	15.63	19.20	17.63	15.32	*16.65*	*17.40*	Revenues per sh	*20.85*
1.25	1.75	1.60	1.74	1.86	2.10	2.23	2.34	2.48	2.67	2.42	2.67	2.79	2.91	2.56	3.32	*2.75*	*2.95*	"Cash Flow" per sh	*4.15*
.86	1.23	1.05	1.14	1.19	1.35	1.45	1.52	1.52	1.57	1.44	1.34	1.23	1.38	1.12	1.68	*1.65*	*1.80*	Earnings per sh A	*2.70*
.43	.46	.51	.56	.61	.68	.75	.83	.90	.96	1.02	1.06	1.10	1.13	1.16	1.19	*1.25*	*1.32*	Div'ds Decl'd per sh B ■	*1.50*
1.60	1.26	.94	1.04	1.83	2.79	3.20	4.01	4.84	5.01	4.87	3.50	3.43	3.99	5.46	4.84	*4.90*	*5.65*	Cap'l Spending per sh	*7.50*
6.75	7.55	8.12	8.67	9.12	9.54	10.33	11.63	12.64	13.65	14.62	16.22	14.99	14.82	15.41	16.51	*16.20*	*16.95*	Book Value per sh C	*20.20*
57.96	58.65	59.22	59.46	59.59	59.75	60.43	63.31	65.43	68.33	70.97	79.48	79.55	85.51	92.39	100.59	*112.50*	*115.00*	Common Shs Outst'g D	*120.00*
16.6	11.9	17.2	15.9	15.0	16.8	18.4	16.9	18.9	18.0	17.9	21.7	27.9	22.6	28.3	14.9	*Bold figures are*		Avg Ann'l P/E Ratio	*16.0*
.88	.64	.91	.96	1.00	1.07	1.15	1.08	1.06	.95	.90	1.14	1.40	1.22	1.51	.77	*Value Line*		Relative P/E Ratio	*.90*
3.0%	3.2%	2.8%	3.1%	3.4%	3.0%	2.8%	3.2%	3.1%	3.4%	3.9%	3.6%	3.2%	3.6%	3.7%	4.8%	*estimates*		Avg Ann'l Div'd Yield	*3.5%*

CAPITAL STRUCTURE as of 9/30/21
Total Debt $3404.4 mill. **Due in 5 Yrs** $380.1 mill.
LT Debt $3195.9 mill. **LT Interest** $112.0 mill.

Leases, Uncapitalized Annual rentals $1.2 mill.
Pension Assets-12/20 $331 mill. **Oblig.** $481.8 mill.

Pfd Stock None

Common Stock 112,448,495 shs. **as of 11/1/21**

MARKET CAP: $2.8 billion (Mid Cap)

2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022		24-26
828.6	706.3	731.4	887.0	959.6	1036.5	1243.1	1641.3	1628.6	1541.4	*1875*	*2000*	Revenues ($mill)	*2500*
87.0	93.3	97.1	104.0	99.0	102.8	98.1	116.2	103.0	163.0	*185*	*200*	Net Profit ($mill)	*320*
22.4%	10.8%	- -	- -	5.9%	42.0%	- -	- -	- -	9.9%	*22.0%*	*21.0%*	Income Tax Rate	*21.0%*
10.5%	13.2%	13.3%	11.7%	10.3%	9.9%	7.9%	7.1%	6.3%	10.6%	*9.9%*	*10.0%*	Net Profit Margin	*12.8%*
40.5%	45.0%	45.1%	48.0%	49.2%	38.5%	48.5%	62.4%	59.2%	62.6%	*64.0%*	*64.0%*	Long-Term Debt Ratio	*62.5%*
59.5%	55.0%	54.9%	52.0%	50.8%	61.5%	51.5%	37.6%	40.8%	37.4%	*36.0%*	*36.0%*	Common Equity Ratio	*37.5%*
1048.3	1337.6	1507.4	1791.9	2043.9	2097.2	2315.4	3373.9	3493.9	4437.3	*5075*	*5400*	Total Capital ($mill)	*6425*
1352.4	1578.0	1859.1	2134.1	2448.1	2623.8	2700.2	3653.5	4073.5	4464.2	*4850*	*5200*	Net Plant ($mill)	*6000*
8.9%	7.4%	6.8%	6.4%	5.4%	5.4%	5.1%	4.4%	4.0%	4.8%	*5.0%*	*5.0%*	Return on Total Cap'l	*6.0%*
13.9%	12.7%	11.7%	11.2%	9.5%	8.0%	8.2%	9.2%	7.2%	9.8%	*10.0%*	*10.5%*	Return on Shr. Equity	*13.0%*
13.9%	12.7%	11.7%	11.2%	9.5%	8.0%	8.2%	9.2%	7.2%	9.8%	*10.0%*	*10.5%*	Return on Com Equity	*13.0%*
6.7%	5.8%	4.8%	4.3%	2.8%	1.6%	.9%	1.7%	NMF	2.9%	*2.5%*	*2.5%*	Retained to Com Eq	*6.0%*
52%	55%	59%	61%	71%	80%	89%	82%	104%	70%	*76%*	*76%*	All Div'ds to Net Prof	*56%*

CURRENT POSITION ($MILL.)	2019	2020	9/30/21
Cash Assets	6.4	34.0	25.4
Other	646.1	472.8	546.3
Current Assets	652.5	506.8	571.7
Accts Payable	232.2	256.6	301.0
Debt Due	1316.6	739.2	208.6
Other	183.1	167.8	309.2
Current Liab.	1731.9	1163.6	818.8
Fix. Chg. Cov.	176%	238%	246%

ANNUAL RATES of change (per sh)	Past 10 Yrs.	Past 5 Yrs.	Est'd '18-'20 to '24-'26
Revenues	1.5%	6.5%	*3.0%*
"Cash Flow"	4.5%	3.0%	*6.0%*
Earnings	1.5%	-1.5%	*11.5%*
Dividends	6.5%	4.0%	*4.5%*
Book Value	5.5%	2.5%	*4.5%*

Cal-endar	QUARTERLY REVENUES ($ mill.) Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2018	521.9	227.3	302.5	589.6	1641.3
2019	637.3	266.9	261.2	463.2	1628.6
2020	534.1	260.0	261.5	485.8	1541.4
2021	674.3	311.8	365.6	*523.3*	*1875*
2022	*700*	*335*	*380*	*585*	*2000*

Cal-endar	EARNINGS PER SHARE A Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2018	1.19	.07	d.27	.39	1.38
2019	1.09	d.13	d.30	.46	1.12
2020	1.15	d.01	d.06	.62	1.68
2021	1.26	.02	d.17	*.54*	*1.65*
2022	*1.30*	*.02*	*d.10*	*.58*	*1.80*

Cal-endar	QUARTERLY DIVIDENDS PAID B■ Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2017	- -	.273	.273	.553	1.10
2018	- -	.280	.280	.567	1.13
2019	- -	.287	.287	.582	1.16
2020	- -	.295	.295	.598	1.19
2021	- -	.303	.303	.303	

BUSINESS: South Jersey Industries, Inc. is a holding company. The company distributes natural gas in New Jersey and Maryland. South Jersey Gas rev. mix '20: residential, 48%; commercial, 23%; cogen. and electric gen., 9%; industrial, 20%. Acq. Elizabethtown Gas and Elkton Gas, 7/18. Nonutil. oper. incl. South Jersey Energy, South Jersey Resources Group, South Jersey Exploration, Marina Energy, South Jersey Energy Service Plus, and SJI Midstream. Has about 1,130 empl. Off./dir. own less than 1% of common; BlackRock, 14.4%; State Street Corporation, 13.9%; The Vanguard Group, 10.8% (3/21 proxy). Pres. & CEO: Michael J. Renna. Chairman: Joseph M. Rigby. Inc.: NJ. Addr.: 1 South Jersey Plaza, Folsom, NJ 08037. Tel.: 609-561-9000. Web: www.sjindustries.com.

South Jersey Industries reported mixed results for the September period. The top line increased considerably on a year-to-year basis, due mostly to greater revenue at the nonutility line. Sales growth at the utility segment was much more modest. Regardless, operating expenses also advanced dramatically, and the company posted an adjusted share deficit of $0.17 for the recent period, which was significantly wider than the year-ago level. We expect a difficult bottom-line comparison for the fourth quarter, and share net for full-year 2021 will probably come in shy of the impressive figure generated in the previous year.

Earnings growth ought to resume next year and continue thereafter. The company's utility business should further benefit from customer growth, rate relief, and infrastructure investments. We expect solid results from the nonutility side, too. Efforts by the company to control operating expenses ought to bear fruit, as well.

South Jersey has announced plans to build a $12 million renewable natural gas facility. It will be located at Oakridge Dairy, the largest dairy farm in Connecticut. The anaerobic digester is expected to be operational by September of next year. It will capture raw methane and other greenhouse gases produced by the farm. The project will also include equipment to transform the collected biogas into commercial-grade, pipeline-quality renewable natural gas that will be integrated into the distribution system of subsidiary Elizabethtown Gas. In addition to Oakridge, South Jersey has partnered with Rev LNG, a full-service supplier of liquefied natural gas, compressed natural gas, and renewable natural gas. South Jersey and Rev LNG plan to build similar plants at other sites in the year ahead.

These shares are neutrally ranked for year-ahead performance. Looking further out, we anticipate solid growth in revenues and earnings for the company in the years ahead. From the recent quotation, this stock offers worthwhile total return potential for the pull to mid-decade. This is supported by a generous dividend yield. All things considered, patient, income-oriented subscribers may want to take a closer look.

Michael Napoli, CFA *November 26, 2021*

(A) Based on economic egs. from 2007. GAAP EPS: '10, $1.11; '11, $1.49; '12, $1.49; '13, $1.28; '14, $1.46; '15, $1.52; '16, $1.56; '17, ($0.04); '18, $0.21; '19, $0.84; '20, $1.62. Excl. nonrecur. gain (loss): '10, ($0.24); '11, $0.04; '12, ($0.03); '13, ($0.24); '14, ($0.11); '15, $0.08; '16, $0.22; '17, ($1.27); '18, ($1.17); '19, ($0.28); '20, ($0.06). Next egs. rpt. due early February. (B) Div'ds paid early April, July, Oct., and late Dec. ■ Div. reinvest. plan avail. (C) Incl. reg. assets. In 2020: $674.0 mill., $6.70 per shr. (D) In mill., adj. for split.

Company's Financial Strength	B++
Stock's Price Stability	65
Price Growth Persistence	15
Earnings Predictability	65

SPIRE INC. NYSE-SR

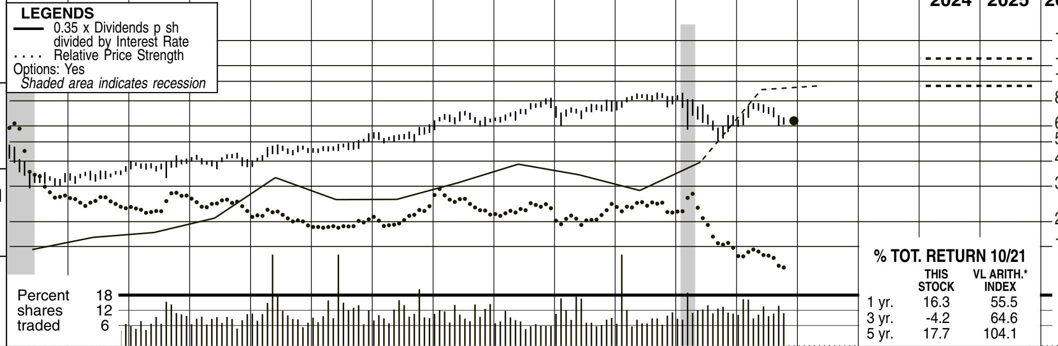
RECENT PRICE **63.61** | P/E RATIO **15.7** (Trailing: 13.3; Median: 19.0) | RELATIVE P/E RATIO **0.83** | DIV'D YLD **4.3%** | VALUE LINE

TIMELINESS **4** Lowered 8/20/21
SAFETY **2** Raised 6/20/03
TECHNICAL **4** Raised 11/19/21
BETA .85 (1.00 = Market)

High:	37.8	42.8	44.0	48.5	55.2	61.0	71.2	82.9	81.1	88.0	88.0	77.9
Low:	30.8	32.9	36.5	37.4	44.0	49.1	57.1	62.3	60.1	71.7	50.6	59.3

Target Price Range 2024 | 2025 | 2026

LEGENDS
— 0.35 x Dividends p sh divided by Interest Rate
.... Relative Price Strength
Options: Yes
Shaded area indicates recession



18-Month Target Price Range

Low-High	Midpoint (% to Mid)
$45-$74	$60 (-5%)

2024-26 PROJECTIONS

	Price	Gain	Ann'l Total Return
High	130	(+105%)	22%
Low	95	(+50%)	14%

Institutional Decisions

	4Q2020	1Q2021	2Q2021
to Buy	131	124	112
to Sell	148	139	126
Hld's(000)	41028	42475	42992

Percent shares traded 18 / 12 / 6

% TOT. RETURN 10/21

	THIS STOCK	VL ARITH.* INDEX
1 yr.	16.3	55.5
3 yr.	-4.2	64.6
5 yr.	17.7	104.1

2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	© VALUE LINE PUB. LLC	24-26
75.43	93.51	93.40	100.44	85.49	77.83	71.48	49.90	31.10	37.68	45.59	33.68	36.07	38.78	38.30	35.96	*42.30*	*37.75*	Revenues per sh A	*58.20*
2.98	3.81	3.87	4.22	4.56	4.11	4.62	4.58	3.12	3.87	6.15	6.16	6.54	7.55	7.12	5.25	*8.75*	*8.10*	"Cash Flow" per sh	*10.50*
1.90	2.37	2.31	2.64	2.92	2.43	2.86	2.79	2.02	2.35	3.16	3.24	3.43	4.33	3.52	1.44	*4.70*	*4.00*	Earnings per sh A B	*5.50*
1.37	1.40	1.45	1.49	1.53	1.57	1.61	1.66	1.70	1.76	1.84	1.96	2.10	2.25	2.37	2.49	2.60	*2.74*	Div'ds Decl'd per sh C■	*3.10*
2.84	2.97	2.72	2.57	2.36	2.56	3.02	4.83	4.00	3.96	6.68	6.42	9.08	9.86	16.15	12.37	*11.35*	*10.95*	Cap'l Spending per sh	*11.45*
17.31	18.85	19.79	22.12	23.32	24.02	25.56	26.67	32.00	34.93	36.30	38.73	41.26	44.51	45.14	44.19	*47.95*	*50.90*	Book Value per sh D	*70.60*
21.17	21.36	21.65	21.99	22.17	22.29	22.43	22.55	32.70	43.18	43.36	45.65	48.26	50.67	50.97	51.60	*52.00*	*53.00*	Common Shs Outst'g E	*55.00*
16.2	13.6	14.2	14.3	13.4	13.7	13.0	14.5	21.3	19.8	16.5	19.6	19.8	16.7	22.8	NMF	*14.4*		Avg Ann'l P/E Ratio	*20.5*
.86	.73	.75	.86	.89	.87	.82	.92	1.20	1.04	.83	1.03	1.00	.90	1.21	NMF	*.76*		Relative P/E Ratio	*1.15*
4.4%	4.3%	4.4%	3.9%	3.9%	4.7%	4.3%	4.1%	4.0%	3.8%	3.5%	3.1%	3.1%	3.1%	3.0%	3.4%	3.8%		Avg Ann'l Div'd Yield	*2.8%*

2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022		24-26
1603.3	1125.5	1017.0	1627.2	1976.4	1537.3	1740.7	1965.0	1952.4	1855.4	*2200*	*2000*	Revenues ($mill) A	*3200*
63.8	62.6	52.8	84.6	136.9	144.2	161.6	214.2	184.6	88.6	*245*	*210*	Net Profit ($mill)	*300*
31.4%	29.6%	25.0%	27.6%	31.2%	32.5%	32.4%	32.4%	15.7%	12.3%	*20.0%*	*21.0%*	Income Tax Rate	*23.5%*
4.0%	5.6%	5.2%	5.2%	6.9%	9.4%	9.3%	10.9%	9.5%	4.8%	*11.1%*	*10.5%*	Net Profit Margin	*9.4%*
38.9%	36.1%	46.6%	55.1%	53.0%	50.9%	50.0%	45.7%	45.0%	49.0%	*52.0%*	*51.0%*	Long-Term Debt Ratio	*45.0%*
61.1%	63.9%	53.4%	44.9%	47.0%	49.1%	50.0%	54.3%	55.0%	51.0%	*48.0%*	*49.0%*	Common Equity Ratio	*55.0%*
937.7	941.0	1959.0	3359.4	3345.1	3601.9	3986.3	4155.5	4625.6	4946.0	*5700*	*6000*	Total Capital ($mill)	*7500*
928.7	1019.3	1776.6	2759.7	2941.2	3300.9	3665.2	3970.5	4352.0	4680.1	*5050*	*5350*	Net Plant ($mill)	*6800*
8.1%	7.9%	3.3%	3.1%	5.1%	4.9%	5.0%	6.3%	5.1%	2.9%	*6.0%*	*5.0%*	Return on Total Cap'l	*5.5%*
11.1%	10.4%	5.0%	5.6%	8.7%	8.2%	8.1%	9.5%	7.3%	3.5%	*9.0%*	*7.0%*	Return on Shr. Equity	*7.5%*
11.1%	10.4%	5.0%	5.6%	8.7%	8.2%	8.1%	9.5%	7.9%	3.2%	*9.0%*	*7.0%*	Return on Com Equity	*7.5%*
4.9%	4.3%	1.0%	1.5%	3.7%	3.3%	3.3%	4.7%	2.7%	NMF	*3.5%*	*2.0%*	Retained to Com Eq	*3.0%*
56%	59%	81%	73%	58%	59%	60%	51%	66%	NMF	*61%*	*69%*	All Div'ds to Net Prof	*62%*

CAPITAL STRUCTURE as of 6/30/21
Total Debt $3510.8 mill. **Due in 5 Yrs** $1720.0 mill.
LT Debt $2939.0 mill. **LT Interest** $135.0 mill.
(Total interest coverage: 2.0x)

Leases, Uncapitalized Annual rentals $8.8 mill.
Pension Assets-9/20 $897.9 mill. **Oblig.** $1401.3 mill.
Pfd Stock $242.0 mill. **Pfd Div'd** $14.8 mill.
Common Stock 51,684,120 shs. **as of 7/31/21**

MARKET CAP: $3.3 billion (Mid Cap)

CURRENT POSITION ($MILL.)	2019	2020	6/30/21
Cash Assets	5.8	4.1	23.9
Other	608.7	586.5	874.4
Current Assets	614.5	590.6	898.3
Accts Payable	301.5	243.3	352.1
Debt Due	783.2	708.4	571.8
Other	384.1	497.5	367.9
Current Liab.	1468.8	1449.2	1291.8
Fix. Chg. Cov.	272%	373%	385%

ANNUAL RATES of change (per sh)	Past 10 Yrs.	Past 5 Yrs.	Est'd '18-'20 to '24-'26
Revenues	-8.0%	- -	*7.5%*
"Cash Flow"	4.5%	8.5%	*8.0%*
Earnings	1.5%	4.5%	*10.0%*
Dividends	4.5%	6.0%	*4.5%*
Book Value	7.0%	5.5%	*7.5%*

Fiscal Year Ends	QUARTERLY REVENUES ($ mill.)A Dec.31	Mar.31	Jun.30	Sep.30	Full Fiscal Year
2018	561.8	813.4	350.6	239.2	1965.0
2019	602.0	803.5	321.3	225.6	1952.4
2020	566.9	715.5	321.1	251.9	1855.4
2021	512.6	1104.9	327.8	*254.7*	*2200*
2022	*530*	*892*	*325*	*253*	*2000*

Fiscal Year Ends	EARNINGS PER SHARE A B F Dec.31	Mar.31	Jun.30	Sep.30	Full Fiscal Year
2018	2.39	2.03	.52	d.51	4.33
2019	1.32	3.04	d.09	d.74	3.52
2020	1.24	2.54	d1.87	d.45	1.44
2021	1.65	3.55	.03	*d.53*	*4.70*
2022	*1.75*	*2.78*	*.05*	*d.58*	*4.00*

Cal-endar	QUARTERLY DIVIDENDS PAID C ■ Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2017	.525	.525	.525	.525	2.10
2018	.5625	.5625	.5625	.5625	2.25
2019	.5925	.5925	.5925	.5925	2.37
2020	.6225	.6225	.6225	.6225	2.49
2021	.65	.65	.65	.65	

BUSINESS: Spire Inc., formerly known as the Laclede Group, Inc., is a holding company for natural gas utilities, which distributes natural gas across Missouri, including the cities of St. Louis and Kansas City, Alabama, and Mississippi. Has roughly 1.7 million customers. Acquired Missouri Gas 9/13, Alabama Gas Co 9/14. Utility therms sold and transported in fiscal 2020: 3.3 bill. Revenue mix for regulated operations: residential, 68%; commercial and industrial, 22%; transportation, 6%; other, 4%. Has about 3,583 employees. Officers and directors own 3.0% of common shares; BlackRock, 12.0% (1/21 proxy). Chairman: Edward Glotzbach; CEO: Suzanne Sitherwood. Inc.: Missouri. Address: 700 Market Street, St. Louis, Missouri 63101. Tel.: 314-342-0500. Internet: www.spireenergy.com.

Spire Inc. probably closed the book on a prosperous fiscal 2021, which ended on September 30th. (Please be aware that fourth-quarter numbers were not available when this report went to press.) Through the first nine months, earnings per share were $5.23, some 2.7 times higher than the year-ago tally of $1.91 (squeezed by the impact of COVID-19). That was brought about partially by the Gas Utility division, helped by increased Infrastructure System Replacement Surcharge (ISRS) revenues for the Missouri operations, the effects of colder weather, plus rate adjustments at Spire Alabama. Moreover, favorable market conditions, especially in February when Winter Storm Uri struck parts of the United States, lifted the performance of the Gas Marketing operation. If there were no major stumbling blocks during the fourth quarter, full-year earnings might have soared more than threefold, to $4.70 a share, relative to the fiscal 2020 tally of $1.44. Regarding fiscal 2022, we look for the company to register lower, though still respectable, share net of $4.00, since fiscal 2021's second-quarter figure will be a challenge to beat.

It appears that capital expenditures for the year that just concluded were around $590 million. (This is 7.5% lower than the fiscal 2020 amount of approximately $638 million.) Funds were deployed to such segments as infrastructure upgrades at the utilities and new business development initiatives. The fiscal 2022 budget is estimated to be roughly $580 million. Management adds that it expects total spending from fiscal 2021 through fiscal 2025 to be in the vicinity of $3 billion. Assuming that finances remain healthy, Spire ought to have minimal difficulty accomplishing these goals.

There are some things to like about the equity. Capital appreciation potential over the 3- to 5-year horizon is considerable, reflecting recent stock-price weakness. Consider, too, the healthy dividend yield and good prospects for further steady hikes in the payout. Other pluses include the 2 (Above Average) Safety rank and below-market Beta coefficient. But these shares possess a 4 (Below Average) rank for Timeliness.

Frederick L. Harris, III November 26, 2021

(A) Fiscal year ends Sept. 30th. (B) Based on diluted shares outstanding. Excludes nonrecurring loss: '06, 7¢. Excludes gain from discontinued operations: '08, 94¢. Next earnings report due late Jan. (C) Dividends paid in early January, April, July, and October. ■ Dividend reinvestment plan available. (D) Incl. deferred charges. In '20: $1,171.6 mill., $22.71/sh. (E) In millions. (F) Qtly. egs. may not sum due to rounding or change in shares outstanding.

Company's Financial Strength	B++
Stock's Price Stability	95
Price Growth Persistence	50
Earnings Predictability	45

Summit Natural Gas of Maine
Summary of Risk Premium Models for the
Proxy Group of Six Natural Gas Distribution Companies

	Proxy Group of Six Natural Gas Distribution Companies	
Predictive Risk Premium Model (PRPM) (1)	11.30	%
Risk Premium Using an Adjusted Total Market Approach (2)	10.60	%
Average	10.95	%

Notes:
(1) From page 2 of this Schedule.
(2) From page 3 of this Schedule.

Summit Natural Gas of Maine
Indicated ROE
Derived by the Predictive Risk Premium Model (1)

	[1]	[2]	[3]	[4]	[5]	[6]	[7]
Proxy Group of Six Natural Gas Distribution Companies	LT Average Predicted Variance	Spot Predicted Variance	Recommended Variance (2)	GARCH Coefficient	Predicted Risk Premium (3)	Risk-Free Rate (4)	Indicated ROE (5)
Atmos Energy Corporation	0.34%	0.35%	0.35%	2.2687	9.81%	2.74%	12.55%
New Jersey Resources Corporation	0.38%	0.35%	0.37%	2.0469	9.41%	2.74%	12.15%
Northwest Natural Holding Company	0.33%	0.32%	0.32%	1.5116	6.00%	2.74%	8.74%
ONE Gas, Inc.	0.34%	0.49%	0.41%	3.9551	NMF	2.74%	NMF
South Jersey Industries, Inc.	0.39%	0.50%	0.44%	1.6227	8.99%	2.74%	11.73%
Spire Inc.	0.71%	0.40%	0.55%	0.9382	6.42%	2.74%	9.16%
						Average	10.87%
						Median	11.73%
					Average of Mean and Median		11.30%

Notes:

(1) The Predictive Risk Premium Model uses historical data to generate a predicted variance and a GARCH coefficient. The historical data used are the equity risk premiums for the first available trading month as reported by Bloomberg Professional Service.

(2) Average of the long-term average and spot predicted variance.

(3) (1+(Column [3] * Column [4])$^{\wedge 12}$) - 1.

(4) From note 2 on page 2 of Schedule DWD-5

(5) Column [5] + Column [6].

Summit Natural Gas of Maine
Indicated Common Equity Cost Rate
Through Use of a Risk Premium Model
Using an Adjusted Total Market Approach

Line No.		Proxy Group of Six Natural Gas Distribution Companies	
1.	Prospective Yield on Aaa Rated Corporate Bonds (1)	3.63	%
2.	Adjustment to Reflect Yield Spread Between Aaa Rated Corporate Bonds and A2 Rated Public Utility Bonds	0.40	(2)
3.	Adjusted Prospective Yield on A2 Rated Public Utility Bonds	4.03	%
5.	Equity Risk Premium (4)	6.57	
6.	Risk Premium Derived Common Equity Cost Rate	10.60	%

Notes:
(1) Consensus forecast of Moody's Aaa Rated Corporate bonds from Blue Chip Financial Forecasts (see pages 10 and 11 of this Schedule).
(2) The average yield spread of A2 rated public utility bonds over Aaa rated corporate bonds of 0.40% from page 4 of this Schedule.
(3) Source of Information: Bloomberg Professional Services.
(4) From page 7 of this Schedule.

Summit Natural Gas of Maine
Interest Rates and Bond Spreads for
Moody's Corporate and Public Utility Bonds

Selected Bond Yields - Moody's

	[1]	[2]	[3]
	Aaa Rated Corporate Bond	A2 Rated Public Utility Bond	Baa2 Rated Public Utility Bond
Dec-2021	2.64 %	3.04 %	3.27 %
Nov-2021	2.62	3.02	3.25
Oct-2021	2.68	3.09	3.32
Average	2.65 %	3.05 %	3.28 %

Selected Bond Spreads

A2 Rated Public Utility Bonds Over Aaa Rated Corporate Bonds:
0.40 % (1)

Baa2 Rated Public Utility Bonds Over A2 Rated Public Utility Bonds:
0.23 % (2)

Notes:
(1) Column [2] - Column [1].
(2) Column [3] - Column [2].

Source of Information:
Bloomberg Professional Service

Summit Natural Gas of Maine
Comparison of Long-Term Issuer Ratings for
Proxy Group of Six Natural Gas Distribution Companies

	Moody's Long-Term Issuer Rating December 2021		Standard & Poor's Long-Term Issuer Rating December 2021	
Proxy Group of Six Natural Gas Distribution Companies	Long-Term Issuer Rating (1)	Numerical Weighting (2)	Long-Term Issuer Rating (1)	Numerical Weighting (2)
Atmos Energy Corporation	A1	5.0	A-	7.0
New Jersey Resources Corporation	A1	5.0	NR	- -
Northwest Natural Holding Company	Baa1	8.0	A+	5.0
ONE Gas, Inc.	A3	7.0	BBB+	8.0
South Jersey Industries, Inc.	A3	7.0	BBB	9.0
Spire Inc.	A1/A2	5.5	A-	7.0
Average	A2	6.3	A-	7.2

Notes:

(1) Ratings are that of the average of each company's utility operating subsidiaries.
(2) From page 6 of this Schedule.

Source Information: Moody's Investors Service
Standard & Poor's Global Utilities Rating Service

Numerical Assignment for
Moody's and Standard & Poor's Bond Ratings

Moody's Bond Rating	Numerical Bond Weighting	Standard & Poor's Bond Rating
Aaa	1	AAA
Aa1	2	AA+
Aa2	3	AA
Aa3	4	AA-
A1	5	A+
A2	6	A
A3	7	A-
Baa1	8	BBB+
Baa2	9	BBB
Baa3	10	BBB-
Ba1	11	BB+
Ba2	12	BB
Ba3	13	BB-
B1	14	B+
B2	15	B
B3	16	B-

Summit Natural Gas of Maine
Judgment of Equity Risk Premium for
Proxy Group of Six Natural Gas Distribution Companies

Line No.		Proxy Group of Six Natural Gas Distribution Companies
1.	Calculated equity risk premium based on the total market using the beta approach (1)	8.62 %
2.	Mean equity risk premium based on a study using the holding period returns of public utilities with A rated bonds (2)	5.45
3.	Predicted Equity Risk Premium Based on Regression Analysis of 809 Fully-Litigated Natural Gas Utility Rate Cases (3)	5.63
4.	Average equity risk premium	6.57 %

Notes: (1) From page 8 of this Schedule.
(2) From page 12 of this Schedule.
(3) From page 13 of this Schedule.

Summit Natural Gas of Maine
Derivation of Equity Risk Premium Based on the Total Market Approach
Using the Beta for the
Proxy Group of Six Natural Gas Distribution Companies

Line No.	Equity Risk Premium Measure	Proxy Group of Six Natural Gas Distribution Companies
	Ibbotson-Based Equity Risk Premiums:	
1.	Ibbotson Equity Risk Premium (1)	5.92 %
2.	Regression on Ibbotson Risk Premium Data (2)	8.61
3.	Ibbotson Equity Risk Premium based on PRPM (3)	8.02
4.	Equity Risk Premium Based on Value Line Summary and Index (4)	6.33
5.	Equity Risk Premium Based on Value Line S&P 500 Companies (5)	12.70
6.	Equity Risk Premium Based on Bloomberg S&P 500 Companies (6)	14.65
7.	Conclusion of Equity Risk Premium	9.37 %
8.	Adjusted Beta (7)	0.92
9.	Forecasted Equity Risk Premium	8.62 %

Notes provided on page 9 of this Schedule.

Summit Natural Gas of Maine
Derivation of Equity Risk Premium Based on the Total Market Approach
Using the Beta for the
Proxy Group of Six Natural Gas Distribution Companies

Notes:

(1) Based on the arithmetic mean historical monthly returns on large company common stocks from Ibbotson® SBBI® 2021 Market Report minus the arithmetic mean monthly yield of Moody's average Aaa and Aa corporate bonds from 1928-2020.

(2) This equity risk premium is based on a regression of the monthly equity risk premiums of large company common stocks relative to Moody's average Aaa and Aa2 rated corporate bond yields from 1928-2020 referenced in Note 1 above. Using the equation generated from the regression, an expected equity risk premium is calculated using the average consensus forecast of Aaa corporate bonds of 3.63% (from page 3 of this Schedule).

(3) The Predictive Risk Premium Model (PRPM) is discussed in the accompanying direct testimony. The Ibbotson equity risk premium based on the PRPM is derived by applying the PRPM to the monthly risk premiums between Ibbotson large company common stock monthly returns and average Aaa and Aa corporate monthly bond yields, from January 1928 through December 2021.

(4) The equity risk premium based on the Value Line Summary and Index is derived by subtracting the average consensus forecast of Aaa corporate bonds of 3.63% (from page 3 of this Schedule) from the projected 3-5 year total annual market return of 9.96% (described fully in note 1 on page 2 of Schedule DWD-5).

(5) Using data from Value Line for the S&P 500, an expected total return of 16.33% was derived based upon expected dividend yields and long-term earnings growth estimates as a proxy for capital appreciation. Subtracting the average consensus forecast of Aaa corporate bonds of 3.63% results in an expected equity risk premium of 12.70%.

(6) Using data from the Bloomberg Professional Service for the S&P 500, an expected total return of 18.28% was derived based upon expected dividend yields and long-term earnings growth estimates as a proxy for capital appreciation. Subtracting the average consensus forecast of Aaa corporate bonds of 3.63% results in an expected equity risk premium of 14.65%.

(7) Average of mean and median beta from Schedule DWD-5

Sources of Information:

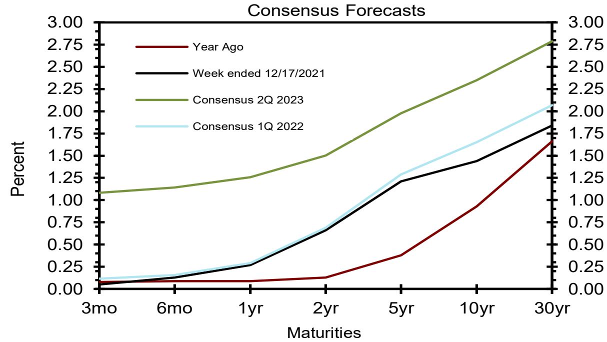
Stocks, Bonds, Bills, and Inflation - 2021 SBBI Yearbook, John Wiley & Sons, Inc.
Industrial Manual and Mergent Bond Record Monthly Update.
Value Line Summary and Index
Blue Chip Financial Forecasts, December 1, 2021 and January 1, 2022
Bloomberg Professional Service

Consensus Forecasts of U.S. Interest Rates and Key Assumptions

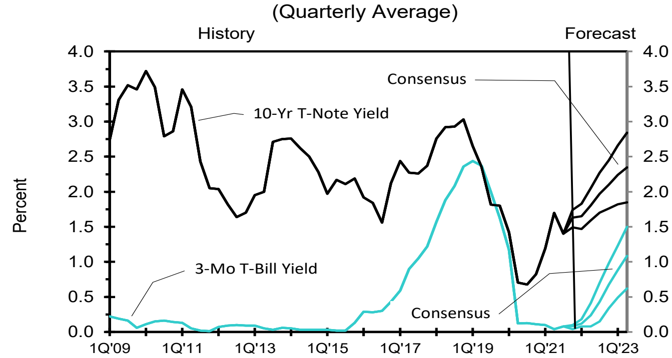
	History								Consensus Forecasts-Quarterly Avg.					
	Average For Week Ending				Average For Month			*Latest Qtr*	1Q	2Q	3Q	4Q	1Q	2Q
Interest Rates	Dec 17	Dec 10	Dec 3	Nov 26	Nov	Oct	Sep	4Q 2021*	**2022**	**2022**	**2022**	**2022**	**2023**	**2023**
Federal Funds Rate	0.08	0.08	0.08	0.08	0.08	0.08	0.08	0.08	**0.1**	**0.3**	**0.5**	**0.7**	**0.9**	**1.1**
Prime Rate	3.25	3.25	3.25	3.25	3.25	3.25	3.25	3.25	**3.3**	**3.4**	**3.6**	**3.8**	**4.0**	**4.2**
SOFR	0.05	0.05	0.05	0.05	0.05	0.05	0.05	0.05	**0.1**	**0.2**	**0.4**	**0.6**	**0.8**	**1.0**
Commercial Paper, 1-mo.	0.06	0.09	0.07	0.05	0.06	0.05	0.05	0.06	**0.1**	**0.2**	**0.4**	**0.6**	**0.9**	**1.1**
Treasury bill, 3-mo.	0.05	0.06	0.06	0.06	0.05	0.05	0.04	0.05	**0.1**	**0.2**	**0.4**	**0.7**	**0.9**	**1.1**
Treasury bill, 6-mo.	0.13	0.13	0.10	0.09	0.07	0.06	0.05	0.09	**0.2**	**0.3**	**0.5**	**0.7**	**0.9**	**1.1**
Treasury bill, 1 yr.	0.27	0.29	0.25	0.21	0.18	0.11	0.08	0.19	**0.3**	**0.4**	**0.6**	**0.9**	**1.1**	**1.3**
Treasury note, 2 yr.	0.66	0.68	0.56	0.59	0.51	0.39	0.24	0.51	**0.7**	**0.8**	**1.0**	**1.2**	**1.3**	**1.5**
Treasury note, 5 yr.	1.21	1.25	1.16	1.29	1.20	1.11	0.86	1.17	**1.3**	**1.4**	**1.6**	**1.7**	**1.8**	**2.0**
Treasury note, 10 yr.	1.44	1.48	1.43	1.61	1.56	1.58	1.37	1.54	**1.7**	**1.8**	**2.0**	**2.1**	**2.2**	**2.3**
Treasury note, 30 yr.	1.84	1.83	1.77	1.95	1.94	2.06	1.94	1.95	**2.1**	**2.2**	**2.4**	**2.5**	**2.7**	**2.8**
Corporate Aaa bond	2.78	2.77	2.74	2.84	2.79	2.85	2.72	2.81	**2.8**	**3.0**	**3.2**	**3.4**	**3.6**	**3.7**
Corporate Baa bond	3.24	3.24	3.22	3.31	3.25	3.31	3.16	3.27	**3.6**	**3.8**	**4.0**	**4.2**	**4.4**	**4.6**
State & Local bonds	2.57	2.58	2.57	2.56	2.57	2.59	2.67	2.58	**2.5**	**2.7**	**2.8**	**2.9**	**3.2**	**3.3**
Home mortgage rate	3.12	3.10	3.11	3.10	3.07	3.07	2.90	3.08	**3.2**	**3.4**	**3.6**	**3.7**	**3.9**	**4.0**
	History								Consensus Forecasts-Quarterly					
	1Q	2Q	3Q	4Q	1Q	2Q	3Q	4Q	1Q	2Q	3Q	4Q	1Q	2Q
Key Assumptions	2020	2020	2020	2020	2021	2021	2021	2021**	**2022**	**2022**	**2022**	**2022**	**2023**	**2023**
Fed's AFE $ Index	111.4	112.4	107.3	105.2	103.4	102.9	105.0	106.9	**108.3**	**108.3**	**108.3**	**107.9**	**107.7**	**107.4**
Real GDP	-5.1	-31.2	33.8	4.5	6.3	6.7	2.3	5.1	**3.7**	**3.9**	**3.3**	**2.7**	**2.5**	**2.3**
GDP Price Index	1.6	-1.5	3.6	2.2	4.3	6.1	6.0	4.6	**3.7**	**3.1**	**2.8**	**2.6**	**2.5**	**2.5**
Consumer Price Index	1.0	-3.1	4.7	2.4	3.7	8.4	6.6	5.6	**3.7**	**3.1**	**2.8**	**2.6**	**2.5**	**2.4**
PCE Price Index	1.3	-1.6	3.7	1.5	3.8	6.5	5.3	4.5	**3.4**	**2.8**	**2.6**	**2.4**	**2.4**	**2.3**

Forecasts for interest rates and the Federal Reserve's Major Currency Index represent averages for the quarter. Forecasts for Real GDP, GDP Price Index, PCE Price Index and Consumer Price Index are seasonally-adjusted annual rates of change (saar). Individual panel members' forecasts are on pages 4 through 9. Historical data: Treasury rates from the Federal Reserve Board's H.15; AAA-AA and A-BBB corporate bond yields from Bank of America-Merrill Lynch and are 15+ years, yield to maturity; State and local bond yields from Bank of America-Merrill Lynch, A-rated, yield to maturity; Mortgage rates from Freddie Mac, 30-year, fixed; SOFR from the New York Fed. *Interest rate data for 4Q 2021 are based on historical data through the week ended December 17. **Data for 4Q 2021 for the Fed's AFE $ Index are based on data through the week ended December 17. Figures for 4Q 2021 Real GDP, GDP Chained Price Index, Consumer Price Index, and PCE Price Index are consensus forecasts from the December 2021 survey.

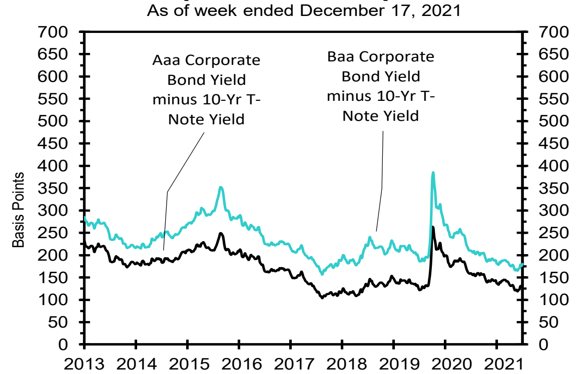
U.S. Treasury Yield Curve
Week ended December 17, 2021 & Year Ago vs.
1Q 2022 & 2Q 2023
Consensus Forecasts



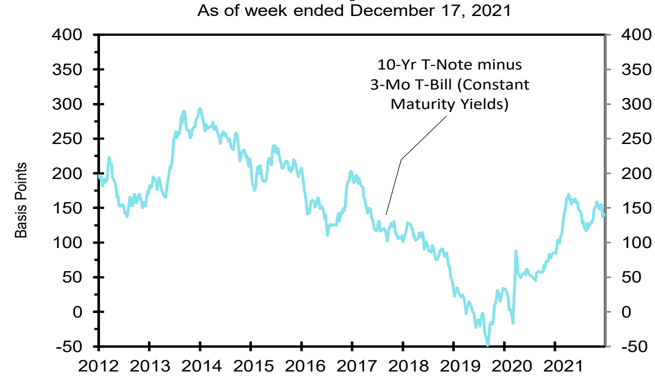
US 3-Mo T-Bills & 10-Yr T-Note Yield
(Quarterly Average)



Corporate Bond Spreads
As of week ended December 17, 2021



U.S. Treasury Yield Curve
As of week ended December 17, 2021



Long-Range Survey:

The table below contains the results of our twice-annual long-range CONSENSUS survey. There are also Top 10 and Bottom 10 averages for each variable. Shown are consensus estimates for the years 2023 through 2027 and averages for the five-year periods 2023-2027 and 2028-2032. Apply these projections cautiously. Few if any economic, demographic and political forces can be evaluated accurately over such long time spans.

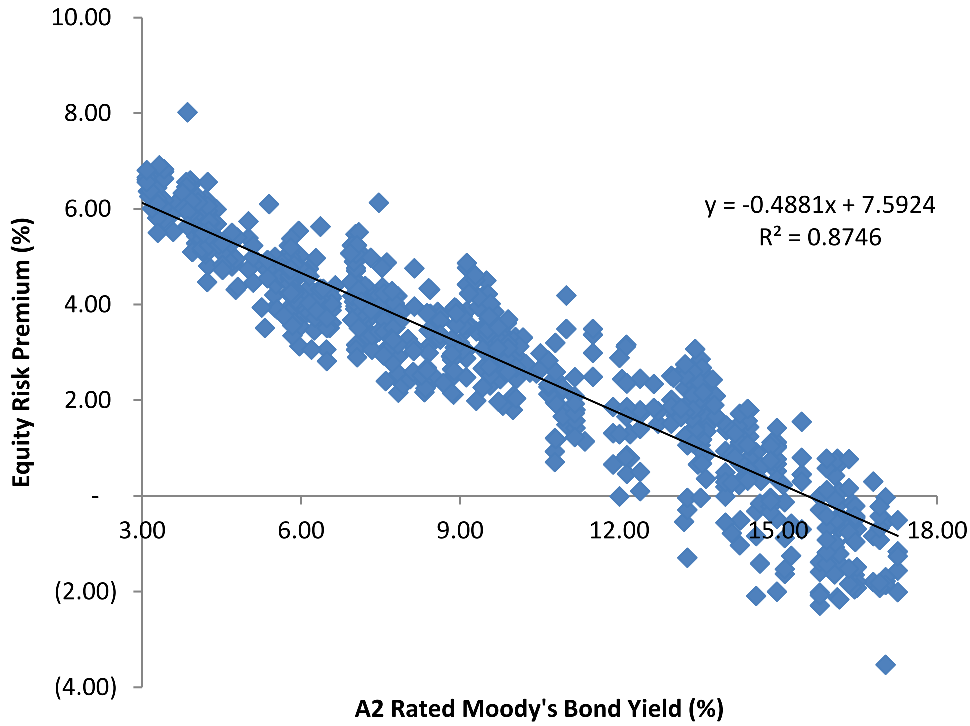
		Average For The Year					Five-Year Averages	
		2023	2024	2025	2026	2027	2023-2027	2028-2032
1. Federal Funds Rate	CONSENSUS	**0.8**	**1.6**	**2.0**	**2.2**	**2.3**	**1.8**	**2.2**
	Top 10 Average	1.2	2.2	2.7	2.7	2.8	2.3	2.9
	Bottom 10 Average	0.4	1.0	1.4	1.7	1.8	1.2	1.5
2. Prime Rate	CONSENSUS	**4.0**	**4.7**	**5.1**	**5.3**	**5.4**	**4.9**	**5.3**
	Top 10 Average	4.3	5.3	5.8	5.8	5.9	5.4	6.0
	Bottom 10 Average	3.6	4.1	4.5	4.9	5.0	4.4	4.6
3. LIBOR, 3-Mo.	CONSENSUS	**1.0**	**1.7**	**2.2**	**2.4**	**2.5**	**1.9**	**2.4**
	Top 10 Average	1.3	2.1	2.7	2.9	3.0	2.4	3.1
	Bottom 10 Average	0.7	1.2	1.6	1.9	2.0	1.5	1.8
4. Commercial Paper, 1-Mo	CONSENSUS	**0.9**	**1.6**	**2.1**	**2.3**	**2.4**	**1.9**	**2.4**
	Top 10 Average	1.2	2.0	2.6	2.8	2.9	2.3	2.9
	Bottom 10 Average	0.6	1.2	1.6	1.9	2.0	1.5	1.8
5. Treasury Bill Yield, 3-Mo	CONSENSUS	**0.8**	**1.4**	**1.8**	**2.0**	**2.3**	**1.7**	**2.2**
	Top 10 Average	1.2	1.9	2.5	2.6	2.8	2.2	2.9
	Bottom 10 Average	0.4	0.8	1.2	1.5	1.8	1.1	1.6
6. Treasury Bill Yield, 6-Mo	CONSENSUS	**0.8**	**1.4**	**1.9**	**2.1**	**2.4**	**1.7**	**2.3**
	Top 10 Average	1.2	2.0	2.6	2.7	2.9	2.3	3.0
	Bottom 10 Average	0.4	0.9	1.2	1.6	1.9	1.2	1.7
7. Treasury Bill Yield, 1-Yr	CONSENSUS	**1.0**	**1.6**	**2.1**	**2.4**	**2.5**	**1.9**	**2.4**
	Top 10 Average	1.4	2.1	2.7	2.8	3.0	2.4	3.1
	Bottom 10 Average	0.6	1.2	1.5	1.9	2.0	1.4	1.8
8. Treasury Note Yield, 2-Yr	CONSENSUS	**1.3**	**1.9**	**2.4**	**2.6**	**2.6**	**2.2**	**2.6**
	Top 10 Average	1.7	2.5	3.0	3.1	3.2	2.7	3.4
	Bottom 10 Average	0.8	1.4	1.8	2.0	2.1	1.6	1.9
9. Treasury Note Yield, 5-Yr	CONSENSUS	**1.9**	**2.4**	**2.8**	**2.9**	**2.9**	**2.6**	**3.0**
	Top 10 Average	2.3	3.0	3.4	3.5	3.6	3.1	3.8
	Bottom 10 Average	1.5	1.9	2.1	2.3	2.3	2.0	2.2
10. Treasury Note Yield, 10-Yr	CONSENSUS	**2.4**	**2.8**	**3.1**	**3.2**	**3.2**	**2.9**	**3.3**
	Top 10 Average	2.8	3.3	3.7	3.8	3.9	3.5	4.2
	Bottom 10 Average	2.0	2.3	2.4	2.5	2.5	2.3	2.4
11. Treasury Bond Yield, 30-Yr	CONSENSUS	**2.9**	**3.3**	**3.6**	**3.7**	**3.7**	**3.4**	**3.8**
	Top 10 Average	3.4	3.9	4.3	4.4	4.4	4.1	4.6
	Bottom 10 Average	2.4	2.8	2.9	3.0	3.0	2.8	3.0
12. Corporate Aaa Bond Yield	CONSENSUS	**3.7**	**4.2**	**4.5**	**4.6**	**4.8**	**4.4**	**4.9**
	Top 10 Average	4.3	4.7	5.1	5.2	5.4	4.9	5.6
	Bottom 10 Average	3.2	3.7	3.9	4.1	4.2	3.8	4.2
13. Corporate Baa Bond Yield	CONSENSUS	**4.6**	**5.0**	**5.3**	**5.5**	**5.6**	**5.2**	**5.7**
	Top 10 Average	5.1	5.5	5.9	6.1	6.2	5.7	6.5
	Bottom 10 Average	4.0	4.5	4.8	4.9	5.0	4.7	5.0
14. State & Local Bonds Yield	CONSENSUS	**3.2**	**3.7**	**3.9**	**4.1**	**4.2**	**3.8**	**4.3**
	Top 10 Average	3.8	4.3	4.5	4.7	4.8	4.4	5.0
	Bottom 10 Average	2.7	3.2	3.4	3.5	3.6	3.3	3.6
15. Home Mortgage Rate	CONSENSUS	**4.0**	**4.4**	**4.7**	**4.8**	**4.8**	**4.5**	**4.9**
	Top 10 Average	4.5	5.0	5.3	5.4	5.4	5.1	5.7
	Bottom 10 Average	3.6	3.9	4.1	4.1	4.2	4.0	4.1
A. Fed's AFE Nominal $ Index	CONSENSUS	**106.2**	**106.0**	**106.1**	**106.2**	**106.4**	**106.2**	**106.5**
	Top 10 Average	108.1	108.4	108.9	109.0	109.2	108.7	110.1
	Bottom 10 Average	104.4	104.0	103.7	103.7	103.9	103.9	103.1
		Year-Over-Year, % Change					Five-Year Averages	
		2023	2024	2025	2026	2027	2023-2027	2028-2032
B. Real GDP	CONSENSUS	**2.6**	**2.2**	**2.1**	**2.0**	**2.0**	**2.2**	**2.0**
	Top 10 Average	3.1	2.6	2.5	2.4	2.3	2.6	2.4
	Bottom 10 Average	2.2	1.7	1.7	1.7	1.7	1.8	1.7
C. GDP Chained Price Index	CONSENSUS	**2.5**	**2.2**	**2.2**	**2.1**	**2.1**	**2.2**	**2.1**
	Top 10 Average	3.0	2.7	2.5	2.4	2.4	2.6	2.4
	Bottom 10 Average	2.0	1.9	1.9	1.9	1.9	1.9	1.8
D. Consumer Price Index	CONSENSUS	**2.6**	**2.3**	**2.3**	**2.2**	**2.2**	**2.3**	**2.2**
	Top 10 Average	3.2	2.8	2.6	2.5	2.5	2.7	2.5
	Bottom 10 Average	2.1	2.0	2.0	2.0	2.0	2.0	1.9
E. PCE Price Index	CONSENSUS	**2.5**	**2.2**	**2.1**	**2.1**	**2.1**	**2.2**	**2.1**
	Top 10 Average	3.0	2.6	2.4	2.4	2.3	2.6	2.4
	Bottom 10 Average	2.0	1.9	1.9	1.9	1.9	1.9	1.9

Summit Natural Gas of Maine
Derivation of Mean Equity Risk Premium Based Studies
Using Holding Period Returns and
Projected Market Appreciation of the S&P Utility Index

Line No.		Implied Equity Risk Premium
	Equity Risk Premium based on S&P Utility Index Holding Period Returns (1):	
1.	Historical Equity Risk Premium	4.16 %
2.	Regression of Historical Equity Risk Premium (2)	6.31
3.	Forecasted Equity Risk Premium Based on PRPM (3)	4.84
4.	Forecasted Equity Risk Premium based on Projected Total Return on the S&P Utilities Index (Value Line Data) (4)	6.88
5.	Forecasted Equity Risk Premium based on Projected Total Return on the S&P Utilities Index (Bloomberg Data) (5)	5.07
6.	Average Equity Risk Premium (6)	5.45 %

Notes:
(1) Based on S&P Public Utility Index monthly total returns and Moody's Public Utility Bond average monthly yields from 1928-2020. Holding period returns are calculated based upon income received (dividends and interest) plus the relative change in the market value of a security over a one-year holding period.
(2) This equity risk premium is based on a regression of the monthly equity risk premiums of the S&P Utility Index relative to Moody's A2 rated public utility bond yields from 1928 - 2020 referenced in note 1 above. Using the equation generated from the regression, an expected equity risk premium is calculated using the prospective A2 rated public utility bond yield of 4.03% (from line 3, page 3 of this Schedule).
(3) The Predictive Risk Premium Model (PRPM) is applied to the risk premium of the monthly total returns of the S&P Utility Index and the monthly yields on Moody's A2 rated public utility bonds from January 1928 - December 2021.
(4) Using data from Value Line for the S&P Utilities Index, an expected return of 10.91% was derived based on expected dividend yields and long-term growth estimates as a proxy for market appreciation. Subtracting the expected A2 rated public utility bond yield of 4.03%, calculated on line 3 of page 3 of this Schedule results in an equity risk premium of 6.88%. (10.91% - 4.03% = 6.88%)
(5) Using data from Bloomberg Professional Service for the S&P Utilities Index, an expected return of 9.10% was derived based on expected dividend yields and long-term growth estimates as a proxy for market appreciation. Subtracting the expected A2 rated public utility bond yield of 4.03%, calculated on line 3 of page 3 of this Schedule results in an equity risk premium of 5.07%. (9.10% - 4.03% = 5.07%)
(6) Average of lines 1 through 5.

Summit Natural Gas of Maine
Prediction of Equity Risk Premiums Relative to
Moody's A2 Rated Utility Bond Yields



Constant	Slope	Prospective A2 Rated Utility Bond (1)	Prospective Equity Risk Premium
7.5924 %	-0.4881	4.03 %	5.63 %

Notes:
(1) From line 3 of page 3 of this Schedule.

Source of Information: Regulatory Research Associates

Summit Natural Gas of Maine
Indicated Common Equity Cost Rate Through Use
of the Traditional Capital Asset Pricing Model (CAPM) and Empirical Capital Asset Pricing Model (ECAPM)

	[1]	[2]	[3]	[4]	[5]	[6]	[7]	[8]
Proxy Group of Six Natural Gas Distribution Companies	Value Line Adjusted Beta	Bloomberg Adjusted Beta	Average Beta	Market Risk Premium (1)	Risk-Free Rate (2)	Traditional CAPM Cost Rate	ECAPM Cost Rate	Indicated Common Equity Cost Rate (3)
Atmos Energy Corporation	0.80	0.92	0.86	10.33 %	2.74 %	11.62 %	11.99 %	11.80 %
New Jersey Resources Corporation	1.00	0.96	0.98	10.33	2.74	12.86	12.91	12.89
Northwest Natural Holding Company	0.85	0.86	0.86	10.33	2.74	11.62	11.99	11.80
ONE Gas, Inc.	0.80	1.01	0.91	10.33	2.74	12.14	12.37	12.26
South Jersey Industries, Inc.	1.05	0.98	1.02	10.33	2.74	13.28	13.22	13.25
Spire Inc.	0.85	0.96	0.91	10.33	2.74	12.14	12.37	12.26
Mean			0.92			12.28 %	12.48 %	12.38 %
Median			0.91			12.14 %	12.37 %	12.26 %
Average of Mean and Median			0.92			12.21 %	12.43 %	12.32 %

Notes on page 2 of this Schedule.

Summit Natural Gas of Maine
Notes to Accompany the Application of the CAPM and ECAPM

Notes:

(1) The market risk premium (MRP) is derived by using six different measures from three sources: Ibbotson, Value Line, and Bloomberg as illustrated below:

Historical Data MRP Estimates:

Measure 1: Ibbotson Arithmetic Mean MRP (1926-2020)

Arithmetic Mean Monthly Returns for Large Stocks 1926-2020:	12.20	%
Arithmetic Mean Income Returns on Long-Term Government Bonds:	5.05	
MRP based on Ibbotson Historical Data:	7.15	%

Measure 2: Application of a Regression Analysis to Ibbotson Historical Data (1926-2020)	9.53	%

Measure 3: Application of the PRPM to Ibbotson Historical Data: (January 1926 - December 2021)	8.95	%

Value Line MRP Estimates:

Measure 4: Value Line Projected MRP (Thirteen weeks ending December 31, 2021)

Total projected return on the market 3-5 years hence*:	9.96	%
Projected Risk-Free Rate (see note 2):	2.74	
MRP based on Value Line Summary & Index:	7.22	%

*Forcasted 3-5 year capital appreciation plus expected dividend yield

Measure 5: Value Line Projected Return on the Market based on the S&P 500

Total return on the Market based on the S&P 500:	16.33	%
Projected Risk-Free Rate (see note 2):	2.74	
MRP based on Value Line data	13.59	%

Measure 6: Bloomberg Projected MRP

Total return on the Market based on the S&P 500:	18.28	%
Projected Risk-Free Rate (see note 2):	2.74	
MRP based on Bloomberg data	15.54	%
Average of Value Line, Ibbotson, and Bloomberg MRP:	10.33	%

(2) For reasons explained in the Direct Testimony, the appropriate risk-free rate for cost of capital purposes is the average forecast of 30 year Treasury Bonds per the consensus of nearly 50 economists reported in Blue Chip Financial Forecasts. (See pages 10 and 11 of Schedule DWD-4.) The projection of the risk-free rate is illustrated below:

First Quarter 2022	2.10	%
Second Quarter 2022	2.20	
Third Quarter 2022	2.40	
Fourth Quarter 2022	2.50	
First Quarter 2023	2.70	
Second Quarter 2023	2.80	
2023-2027	3.40	
2028-2032	3.80	
	2.74	%

(3) Average of Column 6 and Column 7.

Sources of Information:

Value Line Summary and Index
Blue Chip Financial Forecasts, December 1, 2021 and January 1, 2022
Stocks, Bonds, Bills, and Inflation - 2021 SBBI Yearbook, John Wiley & Sons, Inc.
Bloomberg Professional Services

Summit Natural Gas of Maine
Basis of Selection of the Group of Non-Price Regulated Companies
Comparable in Total Risk to the Utility Proxy Group

The criteria for selection of the proxy group of twenty-five non-price regulated companies was that the non-price regulated companies be domestic and reported in Value Line Investment Survey (Standard Edition).

The Non-Price Regulated Proxy Group were then selected based on the unadjusted beta range of 0.63 – 0.93 and residual standard error of the regression range of 2.6713 – 3.1861 of the Utility Proxy Group.

These ranges are based upon plus or minus two standard deviations of the unadjusted beta and standard error of the regression. Plus or minus two standard deviations captures 95.50% of the distribution of unadjusted betas and residual standard errors of the regression.

The standard deviation of the Utility Proxy Group's residual standard error of the regression is 0.1287. The standard deviation of the standard error of the regression is calculated as follows:

$$\text{Standard Deviation of the Std. Err. of the Regr.} = \frac{\text{Standard Error of the Regression}}{\sqrt{2N}}$$

where: N = number of observations. Since Value Line betas are derived from weekly price change observations over a period of five years, N = 259

$$\text{Thus, } 0.1287 = \frac{2.9287}{\sqrt{518}} = \frac{2.9287}{22.7596}$$

Source of Information: Value Line, Inc., December 2021
Value Line Investment Survey (Standard Edition)

Summit Natural Gas of Maine
Basis of Selection of Comparable Risk
Domestic Non-Price Regulated Companies

	[1]	[2]	[3]	[4]
Proxy Group of Six Natural Gas Distribution Companies	Value Line Adjusted Beta	Unadjusted Beta	Residual Standard Error of the Regression	Standard Deviation of Beta
Atmos Energy Corporation	0.80	0.69	2.6472	0.0666
New Jersey Resources Corporation	0.95	0.90	2.9292	0.0736
Northwest Natural Holding Company	0.80	0.69	3.0008	0.0754
ONE Gas, Inc.	0.80	0.68	2.7404	0.0689
South Jersey Industries, Inc.	1.05	1.01	3.4547	0.0869
Spire Inc.	0.85	0.71	2.7999	0.0704
Average	0.88	0.78	2.9287	0.0736

Beta Range (+/- 2 std. Devs. of Beta)	0.63	0.93
2 std. Devs. of Beta	0.15	
Residual Std. Err. Range (+/- 2 std. Devs. of the Residual Std. Err.)	2.6713	3.1861
Std. dev. of the Res. Std. Err.	0.1287	
2 std. devs. of the Res. Std. Err.	0.2574	

Source of Information: Valueline Proprietary Database, December 2021

Summit Natural Gas of Maine
Proxy Group of Non-Price Regulated Companies
Comparable in Total Risk to the
Proxy Group of Six Natural Gas Distribution Companies

	[1]	[2]	[3]	[4]
Proxy Group of Forty-Six Non-Price Regulated Companies	Value Line Adjusted Beta	Unadjusted Beta	Residual Standard Error of the Regression	Standard Deviation of Beta
Apple Inc.	0.90	0.82	3.1532	0.0793
Abbott Labs.	0.95	0.91	2.7460	0.0690
Analog Devices	0.95	0.86	2.6778	0.0673
Assurant Inc.	0.95	0.85	2.9139	0.0733
ANSYS, Inc.	0.85	0.76	2.8279	0.0711
Smith (A.O.)	0.90	0.83	2.7524	0.0692
Booz Allen Hamilton	0.90	0.82	3.0724	0.0772
Becton, Dickinson	0.80	0.67	2.8794	0.0724
Brown-Forman 'B'	0.85	0.76	2.6920	0.0677
Broadridge Fin'l	0.85	0.72	2.7392	0.0689
Brady Corp.	1.00	0.93	3.1533	0.0793
Cadence Design Sys.	0.90	0.82	2.9867	0.0751
Cerner Corp.	0.95	0.87	2.7913	0.0702
Cooper Cos.	0.95	0.92	2.7038	0.0680
CSW Industrials	0.85	0.76	2.7444	0.0690
Lauder (Estee)	0.90	0.83	2.7514	0.0692
Exponent, Inc.	0.85	0.76	2.9154	0.0733
FirstCash Holdings	0.85	0.72	3.1426	0.0790
Gentex Corp.	0.95	0.91	2.7484	0.0691
Hershey Co.	0.85	0.72	2.7087	0.0681
Int'l Flavors & Frag	0.90	0.81	3.1117	0.0782
Ingredion Inc.	0.90	0.78	2.9266	0.0736
Iron Mountain	0.95	0.87	3.0310	0.0762
Hunt (J.B.)	0.95	0.88	2.8114	0.0707
J&J Snack Foods	0.90	0.82	2.8400	0.0714
Henry (Jack) & Assoc	0.85	0.70	2.7540	0.0692
St. Joe Corp.	0.90	0.84	3.0735	0.0773
ManTech Int'l 'A'	0.85	0.72	3.0697	0.0772
McCormick & Co.	0.85	0.70	2.7595	0.0694
Altria Group	0.90	0.79	2.8916	0.0727
MSCI Inc.	0.95	0.86	2.9256	0.0735
Motorola Solutions	0.90	0.82	2.8041	0.0705
Vail Resorts	0.90	0.81	3.1566	0.0794
Northrop Grumman	0.85	0.71	2.8969	0.0728
PerkinElmer Inc.	0.95	0.92	2.6809	0.0674
Philip Morris Int'l	0.95	0.87	3.1795	0.0799
Pool Corp.	0.90	0.82	2.9389	0.0739
Post Holdings	0.95	0.88	2.9687	0.0746
Rollins, Inc.	0.85	0.76	2.8807	0.0724
Selective Ins. Group	0.85	0.74	2.9102	0.0732
Bio-Techne Corp.	0.80	0.63	3.1829	0.0800
Tetra Tech	0.90	0.83	2.9490	0.0741
AMERCO	0.95	0.87	2.6739	0.0672
United Parcel Serv.	0.80	0.64	2.9674	0.0746
Waters Corp.	0.95	0.87	2.7355	0.0688
Western Union	0.80	0.68	2.7006	0.0679
Average	0.89	0.80	2.8896	0.0726
Proxy Group of Six Natural Gas Distribution Companies	0.88	0.78	2.9287	0.0736

Source of Information: Valueline Proprietary Database, December 2021

Summit Natural Gas of Maine
Summary of Cost of Equity Models Applied to
Proxy Group of Forty-Six Non-Price Regulated Companies
Comparable in Total Risk to the
Proxy Group of Six Natural Gas Distribution Companies

Principal Methods		Proxy Group of Forty-Six Non-Price Regulated Companies	
Discounted Cash Flow Model (DCF) (1)		14.03	%
Risk Premium Model (RPM) (2)		13.10	
Capital Asset Pricing Model (CAPM) (3)		12.39	
	Mean	13.17	%
	Median	13.10	%
	Average of Mean and Median	13.14	%

Notes:
(1) From page 2 of this Schedule.
(2) From page 3 of this Schedule.
(3) From page 6 of this Schedule.

Summit Natural Gas of Maine
DCF Results for the Proxy Group of Non-Price-Regulated Companies Comparable in Total Risk to the
Proxy Group of Six Natural Gas Distribution Companies

	[1]	[2]	[3]	[5]	[6]	[7]	[8]
Proxy Group of Forty-Six Non-Price Regulated Companies	Average Dividend Yield	Value Line Projected Five Year Growth in EPS	Zack's Five Year Projected Growth Rate in EPS	Yahoo! Finance Projected Five Year Growth in EPS	Average Projected Five Year Growth Rate in EPS	Adjusted Dividend Yield	Indicated Common Equity Cost Rate (1)
Apple Inc.	0.55 %	13.00 %	12.50 %	15.68 %	13.73 %	0.59 %	14.32 %
Abbott Labs.	1.46	11.50	12.00	13.12	12.21	1.55	13.76
Analog Devices	1.55	11.00	12.30	14.78	12.69	1.65	14.34
Assurant Inc.	1.72	15.50	17.20	17.20	16.63	1.86	18.49
ANSYS, Inc.	-	8.00	11.90	11.18	10.36	-	NA
Smith (A.O.)	1.45	10.00	9.00	8.00	9.00	1.52	10.52
Booz Allen Hamilton	1.75	9.50	8.30	9.00	8.93	1.83	10.76
Becton, Dickinson	1.42	7.50	7.30	9.10	7.97	1.48	9.45
Brown-Forman 'B'	1.06	13.00	NA	10.59	11.80	1.12	12.92
Broadridge Fin'l	1.45	9.50	NA	11.80	10.65	1.53	12.18
Brady Corp.	1.72	7.50	7.00	7.00	7.17	1.78	8.95
Cadence Design Sys.	-	12.00	18.20	18.20	16.13	-	NA
Cerner Corp.	1.41	11.00	13.30	13.52	12.61	1.50	14.11
Cooper Cos.	0.01	19.00	11.00	10.00	13.33	0.01	13.34
CSW Industrials	0.46	11.50	NA	12.00	11.75	0.49	12.24
Lauder (Estee)	0.70	11.50	12.20	14.71	12.80	0.74	13.54
Exponent, Inc.	0.68	12.50	NA	15.00	13.75	0.73	14.48
FirstCash Holdings	1.58	10.00	NA	23.00	16.50	1.71	18.21
Gentex Corp.	1.35	10.50	15.30	15.80	13.87	1.44	15.31
Hershey Co.	1.99	6.00	7.70	9.13	7.61	2.07	9.68
Int'l Flavors & Frag	2.16	7.00	8.00	4.49	6.50	2.23	8.73
Ingredion Inc.	2.70	7.50	NA	10.80	9.15	2.82	11.97
Iron Mountain	5.21	8.50	NA	6.44	7.47	5.40	12.87
Hunt (J.B.)	0.62	10.00	15.00	23.00	16.00	0.67	16.67
J&J Snack Foods	1.69	8.50	NA	6.00	7.25	1.75	9.00
Henry (Jack) & Assoc	1.14	10.50	14.00	14.00	12.83	1.21	14.04
St. Joe Corp.	0.66	20.00	NA	(28.10)	20.00	0.73	20.73
ManTech Int'l 'A'	2.00	9.00	3.80	5.38	6.06	2.06	8.12
McCormick & Co.	1.73	6.00	6.30	6.80	6.37	1.79	8.16
Altria Group	7.86	6.00	4.00	5.17	5.06	8.06	13.12
MSCI Inc.	0.66	16.00	NA	19.50	17.75	0.72	18.47
Motorola Solutions	1.25	7.00	9.00	14.14	10.05	1.31	11.36
Vail Resorts	1.03	17.50	NA	64.78	41.14	1.24	42.38
Northrop Grumman	1.68	8.50	9.00	6.00	7.83	1.75	9.58
PerkinElmer Inc.	0.15	12.00	44.20	37.90	31.37	0.17	31.54
Philip Morris Int'l	5.36	7.00	7.80	11.03	8.61	5.59	14.20
Pool Corp.	0.60	17.00	NA	17.00	17.00	0.65	17.65
Post Holdings	-	10.00	NA	26.90	18.45	-	NA
Rollins, Inc.	1.14	11.50	NA	8.20	9.85	1.20	11.05
Selective Ins. Group	1.41	12.00	13.40	13.40	12.93	1.50	14.43
Bio-Techne Corp.	0.26	13.00	21.00	15.00	16.33	0.28	16.61
Tetra Tech	0.46	17.50	NA	15.00	16.25	0.50	16.75
AMERCO	-	10.50	NA	15.00	12.75	-	NA
United Parcel Serv.	1.99	11.50	12.10	17.48	13.69	2.13	15.82
Waters Corp.	-	6.00	10.00	10.60	8.87	-	NA
Western Union	5.14	8.00	NA	8.48	8.24	5.35	13.59
						Mean	14.47 %
						Median	13.59 %
						Average of Mean and Median	14.03 %

NA= Not Available
NMF= Not Meaningful Figure

(1) The application of the DCF model to the domestic, non-price regulated comparable risk companies is identical to the application of the DCF to the Utility Proxy Group. The dividend yield is derived by using the 60 day average price and the spot indicated dividend as of December 31, 2021. The dividend yield is then adjusted by 1/2 the average projected growth rate in EPS, which is calculated by averaging the 5 year projected growth in EPS provided by Value Line, www.zacks.com, and www.yahoo.com (excluding any negative growth rates) and then adding that growth rate to the adjusted dividend yield.

Source of Information: Value Line Investment Survey
www.zacks.com Downloaded on 12/31/2021
www.yahoo.com Downloaded on 12/31/2021

Summit Natural Gas of Maine
Indicated Common Equity Cost Rate
Through Use of a Risk Premium Model
Using an Adjusted Total Market Approach

Line No.		Proxy Group of Forty-Six Non-Price Regulated Companies	
1.	Prospective Yield on Baa2 Rated Corporate Bonds (1)	4.44	%
2.	Adjustment to Reflect Bond rating Difference of Non-Price Regulated Companies (2)	(0.06)	
3.	Adjusted Prospective Bond Yield	4.39	
4.	Equity Risk Premium (3)	8.71	
5.	Risk Premium Derived Common Equity Cost Rate	13.10	%

Notes: (1) Average forecast of Baa corporate bonds based upon the consensus of nearly 50 economists reported in Blue Chip Financial Forecasts dated December 1, 2021 and January 1, 2022 (see pages 10 and 11 of Schedule DWD-4). The estimates are detailed below.

First Quarter 2022	3.60	%
Second Quarter 2022	3.80	
Third Quarter 2022	4.00	
Fourth Quarter 2022	4.20	
First Quarter 2023	4.40	
Second Quarter 2023	4.60	
2023-2027	5.20	
2028-2032	5.70	
Average	4.44	%

(2) The average yield spread of Baa rated corporate bonds over A corporate bonds for the three months ending December 2021 . To reflect the Baa1/Baa2 average rating of the non-utility proxy group, the prosepctive yield on Baa corporate bonds must be adjusted by 1/6 of the spread between A and Baa corporate bond yields as shown below:

	A Corp. Bond Yield		Baa Corp. Bond Yield		Spread	
Dec-21	2.97	%	3.30	%	0.33	%
Nov-21	2.95		3.28		0.33	
Oct-21	3.02		3.35		0.33	
	Average yield spread				0.33	
	1/6 of spread				0.06	

(3) From page 5 of this Schedule.

Summit Natural Gas of Maine
Comparison of Long-Term Issuer Ratings for the
Proxy Group of Forty-Six Non-Price Regulated Companies of Comparable risk to the
Proxy Group of Six Natural Gas Distribution Companies

	Moody's Long-Term Issuer Rating December 2021		Standard & Poor's Long-Term Issuer Rating December 2021	
Proxy Group of Forty-Six Non-Price Regulated Companies	Long-Term Issuer Rating	Numerical Weighting (1)	Long-Term Issuer Rating	Numerical Weighting (1)
Apple Inc.	Aaa	1.0	AA+	2.0
Abbott Labs.	A2	6.0	A+	5.0
Analog Devices	A3	7.0	A-	7.0
Assurant Inc.	Baa3	10.0	BBB	9.0
ANSYS, Inc.	NA	--	NA	--
Smith (A.O.)	NA	--	NA	--
Booz Allen Hamilton	NA	--	NA	--
Becton, Dickinson	Baa3	10.0	BBB	9.0
Brown-Forman 'B'	A1	5.0	A-	7.0
Broadridge Fin'l	Baa1	8.0	BBB+	8.0
Brady Corp.	NA	--	NA	--
Cadence Design Sys.	A3	7.0	BBB+	8.0
Cerner Corp.	NA	--	NA	--
Cooper Cos.	WR	--	NR	--
CSW Industrials	NA	--	NA	--
Lauder (Estee)	A1	5.0	A+	5.0
Exponent, Inc.	NA	--	NA	--
FirstCash Holdings	Ba2	12.0	BB	12.0
Gentex Corp.	NA	--	NA	--
Hershey Co.	A1	5.0	A	6.0
Int'l Flavors & Frag	Baa3	10.0	BBB	9.0
Ingredion Inc.	Baa1	8.0	BBB	9.0
Iron Mountain	Ba3	13.0	BB-	13.0
Hunt (J.B.)	Baa1	8.0	BBB+	8.0
J&J Snack Foods	NA	--	NA	--
Henry (Jack) & Assoc	NA	--	NA	--
St. Joe Corp.	NA	--	NA	--
ManTech Int'l 'A'	WR	--	BB+	11.0
McCormick & Co.	Baa2	9.0	BBB	9.0
Altria Group	A3	7.0	BBB	9.0
MSCI Inc.	Ba1	11.0	BB+	11.0
Motorola Solutions	Baa3	10.0	BBB-	10.0
Vail Resorts	B2	15.0	BB	12.0
Northrop Grumman	Baa1	8.0	BBB+	8.0
PerkinElmer Inc.	Baa3	10.0	BBB	9.0
Philip Morris Int'l	A2	6.0	A	6.0
Pool Corp.	NA	--	NA	--
Post Holdings	B2	15.0	B+	14.0
Rollins, Inc.	NA	--	NA	--
Selective Ins. Group	Baa2	9.0	BBB	9.0
Bio-Techne Corp.	NA	--	NA	--
Tetra Tech	NA	--	NA	--
AMERCO	WR	--	NR	--
United Parcel Serv.	A2	6.0	A-	7.0
Waters Corp.	NA	--	NA	--
Western Union	Baa2	9.0	BBB	9.0
Average	Baa1/Baa2	8.5	BBB	8.6

Notes:
(1) From page 6 of Schedule DWD-4.

Source of Information:
Bloomberg Professional Services

Summit Natural Gas of Maine
Derivation of Equity Risk Premium Based on the Total Market Approach
Using the Beta for
Proxy Group of Forty-Six Non-Price Regulated Companies of Comparable risk to the
Proxy Group of Six Natural Gas Distribution Companies

Line No.	Equity Risk Premium Measure	Proxy Group of Forty-Six Non-Price Regulated Companies
1.	Ibbotson Equity Risk Premium (1)	5.92 %
2.	Regression on Ibbotson Risk Premium Data (2)	8.61
3.	Ibbotson Equity Risk Premium based on PRPM (3)	8.02
4.	Equity Risk Premium Based on Value Line Summary and Index (4)	6.33
5	Equity Risk Premium Based on Value Line S&P 500 Companies (5)	12.70
6.	Equity Risk Premium Based on Bloomberg S&P 500 Companies (6)	14.65
7.	Conclusion of Equity Risk Premium	9.37 %
8.	Adjusted Beta (7)	0.93
9.	Forecasted Equity Risk Premium	8.71 %

Notes:
(1) From note 1 of page 9 of Schedule DWD-4.
(2) From note 2 of page 9 of Schedule DWD-4.
(3) From note 3 of page 9 of Schedule DWD-4.
(4) From note 4 of page 9 of Schedule DWD-4.
(5) From note 5 of page 9 of Schedule DWD-4.
(6) From note 6 of page 9 of Schedule DWD-4.
(7) Average of mean and median beta from page 6 of this Schedule.

Sources of Information:
Stocks, Bonds, Bills, and Inflation - 2021 SBBI Yearbook, John Wiley & Sons, Inc.
Value Line Summary and Index
Blue Chip Financial Forecasts, December 1, 2021 and January 1, 2022
Bloomberg Professional Services

Summit Natural Gas of Maine
Traditional CAPM and ECAPM Results for the Proxy Group of Non-Price-Regulated Companies Comparable in Total Risk to the
Proxy Group of Six Natural Gas Distribution Companies

	[1]	[2]	[3]	[4]	[5]	[6]	[7]	[8]
Proxy Group of Forty-Six Non-Price Regulated Companies	Value Line Adjusted Beta	Bloomberg Beta	Average Beta	Market Risk Premium (1)	Risk-Free Rate (2)	Traditional CAPM Cost Rate	ECAPM Cost Rate	Indicated Common Equity Cost Rate (3)
Apple Inc.	0.95	1.02	0.98	10.33 %	2.74 %	12.86 %	12.91 %	12.89 %
Abbott Labs.	0.90	0.83	0.87	10.33	2.74	11.73	12.06	11.89
Analog Devices	0.95	1.02	0.99	10.33	2.74	12.97	12.99	12.98
Assurant Inc.	0.90	1.01	0.95	10.33	2.74	12.55	12.68	12.62
ANSYS, Inc.	0.85	0.98	0.91	10.33	2.74	12.14	12.37	12.26
Smith (A.O.)	0.85	1.01	0.93	10.33	2.74	12.35	12.53	12.44
Booz Allen Hamilton	0.90	0.90	0.90	10.33	2.74	12.04	12.29	12.17
Becton, Dickinson	0.75	0.55	0.65	10.33	2.74	9.45	10.36	9.91
Brown-Forman 'B'	0.90	0.95	0.92	10.33	2.74	12.24	12.45	12.35
Broadridge Fin'l	0.85	0.84	0.84	10.33	2.74	11.42	11.83	11.62
Brady Corp.	0.95	1.05	1.00	10.33	2.74	13.07	13.07	13.07
Cadence Design Sys.	0.90	0.99	0.94	10.33	2.74	12.45	12.60	12.53
Cerner Corp.	0.90	0.86	0.88	10.33	2.74	11.83	12.14	11.99
Cooper Cos.	0.95	0.95	0.95	10.33	2.74	12.55	12.68	12.62
CSW Industrials	0.90	1.02	0.96	10.33	2.74	12.66	12.76	12.71
Lauder (Estee)	0.95	1.04	1.00	10.33	2.74	13.07	13.07	13.07
Exponent, Inc.	0.90	0.96	0.93	10.33	2.74	12.35	12.53	12.44
FirstCash Holdings	0.90	0.94	0.92	10.33	2.74	12.24	12.45	12.35
Gentex Corp.	0.95	1.05	1.00	10.33	2.74	13.07	13.07	13.07
Hershey Co.	0.85	0.85	0.85	10.33	2.74	11.52	11.91	11.71
Int'l Flavors & Frag	0.95	1.05	1.00	10.33	2.74	13.07	13.07	13.07
Ingredion Inc.	0.95	0.91	0.93	10.33	2.74	12.35	12.53	12.44
Iron Mountain	0.90	1.04	0.97	10.33	2.74	12.76	12.84	12.80
Hunt (J.B.)	0.95	0.95	0.95	10.33	2.74	12.55	12.68	12.62
J&J Snack Foods	0.95	0.80	0.88	10.33	2.74	11.83	12.14	11.99
Henry (Jack) & Assoc	0.85	0.87	0.86	10.33	2.74	11.62	11.99	11.80
St. Joe Corp.	0.95	1.03	0.99	10.33	2.74	12.97	12.99	12.98
ManTech Int'l 'A'	0.85	1.09	0.97	10.33	2.74	12.76	12.84	12.80
McCormick & Co.	0.80	0.69	0.75	10.33	2.74	10.49	11.13	10.81
Altria Group	0.95	0.88	0.92	10.33	2.74	12.24	12.45	12.35
MSCI Inc.	0.95	0.95	0.95	10.33	2.74	12.55	12.68	12.62
Motorola Solutions	0.90	0.97	0.94	10.33	2.74	12.45	12.60	12.53
Vail Resorts	0.95	1.14	1.04	10.33	2.74	13.48	13.38	13.43
Northrop Grumman	0.85	0.78	0.82	10.33	2.74	11.21	11.68	11.44
PerkinElmer Inc.	0.90	0.79	0.85	10.33	2.74	11.52	11.91	11.71
Philip Morris Int'l	0.95	0.93	0.94	10.33	2.74	12.45	12.60	12.53
Pool Corp.	0.85	0.98	0.91	10.33	2.74	12.14	12.37	12.26
Post Holdings	0.95	0.88	0.91	10.33	2.74	12.14	12.37	12.26
Rollins, Inc.	0.85	0.69	0.77	10.33	2.74	10.69	11.29	10.99
Selective Ins. Group	0.90	1.00	0.95	10.33	2.74	12.55	12.68	12.62
Bio-Techne Corp.	0.85	0.92	0.89	10.33	2.74	11.93	12.22	12.08
Tetra Tech	0.95	1.05	1.00	10.33	2.74	13.07	13.07	13.07
AMERCO	0.95	1.06	1.01	10.33	2.74	13.17	13.15	13.16
United Parcel Serv.	0.80	0.84	0.82	10.33	2.74	11.21	11.68	11.44
Waters Corp.	0.95	0.85	0.90	10.33	2.74	12.04	12.29	12.17
Western Union	0.80	1.05	0.92	10.33	2.74	12.24	12.45	12.35
Mean			0.92			12.22 %	12.43 %	12.33 %
Median			0.93			12.35 %	12.53 %	12.44 %
Average of Mean and Median			0.93			12.29 %	12.48 %	12.39 %

Notes:
(1) From Schedule DWD-5, note 1.
(2) From Schedule DWD-5, note 2.
(3) Average of CAPM and ECAPM cost rates.

Summit Natural Gas of Maine
Derivation of Investment Risk Adjustment Based upon
Ibbotson Associates' Size Premia for the Decile Portfolios of the NYSE/AMEX/NASDAQ

Line No.		[1] Market Capitalization on December 31, 2021 (1) (millions)	[1] (times larger)	[2] Applicable Decile of the NYSE/AMEX/ NASDAQ (2)	[3] Applicable Size Premium (3)	[4] Spread from Applicable Size Premium (4)
1.	Summit Natural Gas of Maine	$ 305.410		9	2.29%	
2.	Proxy Group of Six Natural Gas Distribution Companies	$ 4,789.883	15.7 x	4	0.75%	1.54%

	[A] Decile	[B] Market Capitalization of Smallest Company (millions)	[C] Market Capitalization of Largest Company (millions)	[D] Size Premium (Return in Excess of CAPM)*
Largest	1	$ 29,025.803	$ 1,966,078.882	-0.22%
	2	13,178.743	28,808.073	0.49%
	3	6,743.361	13,177.828	0.71%
	4	3,861.858	6,710.676	0.75%
	5	2,445.693	3,836.536	1.09%
	6	1,591.865	2,444.745	1.37%
	7	911.586	1,591.765	1.54%
	8	451.955	911.103	1.46%
	9	190.019	451.800	2.29%
Smallest	10	2.194	189.831	5.01%

*From 2021 Duff & Phelps Cost of Capital Navigator

Notes:

(1) From page 2 of this Schedule.
(2) Gleaned from Columns [B] and [C] on the bottom of this page. The appropriate decile (Column [A]) corresponds to the market capitalization of the proxy group, which is found in Column [1].
(3) Corresponding risk premium to the decile is provided in Column [D] on the bottom of this page.
(4) Line No. 1 Column [3] – Line No. 2 Column [3]. For example, the 1.54% in Column [4], Line No. 2 is derived as follows 1.54% = 2.29% - 0.75%.

Summit Natural Gas of Maine
Market Capitalization of Summit Natural Gas of Maine and the
Proxy Group of Six Natural Gas Distribution Companies

Company	Exchange	[1] Common Stock Shares Outstanding at Fiscal Year End 2020 (millions)	[2] Book Value per Share at Fiscal Year End 2020 (1)	[3] Total Common Equity at Fiscal Year End 2020 (millions)	[4] Closing Stock Market Price on December 31, 2021	[5] Market-to-Book Ratio on December 31, 2021 (2)	[6] Market Capitalization on December 31, 2021 (3) (millions)
Summit Natural Gas of Maine		NA	NA	171.965 (4)	NA		
Based upon Proxy Group of Six Natural Gas Distribution Companies						177.6 (5)	$ 305.410 (6)
Proxy Group of Six Natural Gas Distribution Companies							
Atmos Energy Corporation	NYSE	125.882	$ 53.949	$ 6,791.203	$ 104.770	194.2 %	$ 13,188.707
New Jersey Resources Corporation	NYSE	95.949	19.226	1,844.692	41.060	213.6	3,939.673
Northwest Natural Holding Company	NYSE	30.589	29.054	888.733	48.780	167.9	1,492.131
ONE Gas, Inc.	NYSE	53.167	42.006	2,233.311	77.590	184.7	4,125.207
South Jersey Industries, Inc.	NYSE	100.592	16.571	1,666.876	26.120	157.6	2,627.461
Spire Inc.	NYSE	51.612	44.182	2,280.300	65.220	147.6	3,366.121
Average		76.299	$ 34.165	$ 2,617.519	$ 60.590	177.6 %	$ 4,789.883

NA= Not Available

Notes:
(1) Column 3 / Column 1.
(2) Column 4 / Column 2.
(3) Column 1 * Column 4.
(4) Requested rate base multiplied by the requested common equity ratio.
(5) The market-to-book ratio of Summit Natural Gas of Maine on December 31, 2021 is assumed to be equal to the market-to-book ratio of Proxy Group of Six Natural Gas Distribution Companies on December 31, 2021 as appropriate.
(6) Column [3] multiplied by Column [5].

Source of Information: 2020 Annual Forms 10K
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