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December 28, 2021

ELECTRONICALLY FILED

Aida Camacho-Welch, Secretary
NJ Board of Public Utilities
44 South Clinton Avenue
P.O. Box 350
Trenton, NJ 08625-0350

Re: In the Matter of the Petition of Elizabethtown Gas Company for Approval of Increased Base Tariff Rates and Charges for Gas Service, Changes to Depreciation Rates and Other Tariff Revisions

BPU Docket No.____________

Dear Secretary Camacho-Welch,

Enclosed is the Petition of Elizabethtown Gas Company for Approval of Increased Base Tariff Rates and Charges for Gas Service, Changes to Depreciation Rates and Other Tariff Revisions, which has been filed electronically today consistent with the Board's e-Filing rules.

Due to the pandemic, and in accordance with the New Jersey Board of Public Utilities ("BPU") March 19, 2020 and May 20, 2020 Orders issued in BPU Docket No. EO20030254, hard copies are not being submitted at this time, but can be provided at a later time, if needed.

Respectfully,

Deborah M. Franco

Enclosures

cc: Service List (Electronic Mail)

IN THE MATTER OF THE PETITION OF ELIZABETHTOWN GAS COMPANY FOR APPROVAL OF INCREASED BASE TARIFF RATES AND CHARGES FOR GAS SERVICE, CHANGES TO DEPRECIATION RATES AND OTHER TARIFF REVISIONS

BPU DOCKET NO. GR________

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IN THE MATTER OF THE PETITION OF ELIZABETHTOWN GAS COMPANY FOR APPROVAL OF INCREASED BASE TARIFF RATES AND CHARGES FOR GAS SERVICE, CHANGES TO DEPRECIATION RATES AND OTHER TARIFF REVISIONS

BPU DOCKET NO. GR________

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IN THE MATTER OF THE PETITION OF ELIZABETHTOWN GAS COMPANY FOR APPROVAL OF INCREASED BASE TARIFF RATES AND CHARGES FOR GAS SERVICE, CHANGES TO DEPRECIATION RATES AND OTHER TARIFF REVISIONS

BPU DOCKET NO. GR________

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STATE OF NEW JERSEY
BOARD OF PUBLIC UTILITIES

IN THE MATTER OF THE PETITION OF ELIZABETHTOWN GAS COMPANY FOR APPROVAL OF INCREASED BASE TARIFF RATES AND CHARGES FOR GAS SERVICE, CHANGES TO DEPRECIATION RATES AND OTHER TARIFF REVISIONS	: : : : :	**CASE SUMMARY** **BPU DOCKET NO.**

By this Petition, Elizabethtown Gas Company ("Elizabethtown" or the "Company") proposes to increase its base tariff rates, modify its depreciation rates, establish certain regulatory assets and implement certain other tariff revisions as detailed further in its Petition and supporting Exhibits.

This filing is predominantly driven by the significant capital investments that the Company has made since its last base rate proceeding. Since the Company's last base rate case, excluding Infrastructure Investment Program ("IIP") spending, Elizabethtown has invested approximately $214.8 million of plant additions net of retirements that are not currently reflected in rates, and projects that an additional $175.2 million of capital investment, net of retirements and excluding IIP, will be added to the UPIS balance by September 30, 2022. These capital investments have been and will continue to be made to ensure the safety, reliability and resiliency of Elizabethtown's distribution system, support customer needs, and maintain the Company's best in class customer service. Overall, these system investments will continue to support safe, reliable and clean natural gas service for Elizabethtown's customers.

With these investments, the Company must be given the opportunity to earn a fair return on and return of its investments to ensure it can continue to attract the necessary capital to support further investments that enable it to provide ongoing safe and reliable service to its customers. Without rate relief in this proceeding, Elizabethtown will fall substantially below the 9.6 percent return on equity authorized by the Board in the Company's last rate case. Absent Board approval of the rate relief requested in this filing, such under-earnings could negatively impact Elizabethtown's ability to attract capital at reasonable rates, which will in turn negatively impact ratepayers.

As demonstrated in this filing, Elizabethtown's projected operating revenues for the twelve-month period ending March 31, 2022 (utilizing six months of actual data and six months of estimated data) total $367,042,213. Inclusive of post-test year *pro forma* adjustments, the rates proposed in this filing would yield additional total operating revenues of $76,618,396, representing an increase of approximately 19% above adjusted post-test year revenues. The Company's proposed revenue requirement provides for the recovery of Elizabethtown's capital investments, an increased cost of capital and increased depreciation expense.

The impact of this Petition on the bill of an average residential customer using 100 therms per month would be $19.42 or 17.2%. The actual percentage increase applicable to specific customers will vary according to the applicable rate schedule and the level of each customer's usage.

STATE OF NEW JERSEY
BOARD OF PUBLIC UTILITIES

IN THE MATTER OF THE PETITION OF ELIZABETHTOWN GAS COMPANY FOR APPROVAL OF INCREASED BASE TARIFF RATES AND CHARGES FOR GAS SERVICE, CHANGES TO DEPRECIATION RATES AND OTHER TARIFF REVISIONS	**: : : : :**	**PETITION** **BPU DOCKET NO.**

TO: THE HONORABLE COMMISSIONERS OF THE BOARD OF PUBLIC UTILITIES

Elizabethtown Gas Company (hereinafter referred to as "Elizabethtown," "Petitioner" or the "Company"), a public utility corporation of the State of New Jersey, with its principal office at 520 Green Lane, Union, New Jersey, hereby petitions this Honorable Board (hereinafter referred to as the "Board") for authority pursuant to N.J.S.A. 48:2-21 and N.J.S.A. 48:2-21.1 and N.J.A.C. 14:1-5.12 to increase its base tariff rates and charges for gas service, and to implement certain other tariff revisions. The Company also proposes to modify its existing depreciation rates pursuant to N.J.S.A. 48:2-18 and N.J.A.C. 14:1-5.7 and seeks such other relief as more fully described herein. In support thereof, Petitioner states as follows:

I. BACKGROUND

1. Petitioner is engaged in the transmission, distribution, transportation and sale of natural gas within its service territory within the State of New Jersey. The Company's service territory includes all or portions of the following counties: Hunterdon, Mercer, Middlesex, Morris, Sussex, Union and Warren. Within its service territory, Elizabethtown provides natural gas service to approximately 303,000 customers.

2. Petitioner is a wholly owned subsidiary of SJI Utilities, Inc., which in turn is a wholly owned subsidiary of South Jersey Industries, Inc. ("SJI").

3. The rate schedules and other tariff provisions that Elizabethtown proposes to increase and modify by virtue of this filing are those currently effective rate schedules and tariff provisions now on file with the Board, designated "Tariff for Gas Service, B.P.U. No. 17 – Gas" (the "Existing Tariff"). The Existing Tariff was issued pursuant to Board Orders in Docket Nos. GX01050304, effective January 6, 2003; GR19040486, effective November 15, 2019; GR20050327, effective October 1, 2020; QO19010040 and GO20090619, effective July 1, 2021; GE21020618, effective September 1, 2021; GR21040747 and GR21071007, effective October 1, 2021; and GR21060876 and GR21071018, effective December 1, 2021.

4. The proposed rate schedules and other tariff provisions that Petitioner seeks to make effective as a result of this filing are those contained in the tariff sheets, which are redlined against the Existing Tariff to reflect proposed changes (the "Proposed Tariff"), a copy of which is attached to the Direct Testimony of Thomas Kaufmann as Schedule TK-25 and incorporated herein by reference. A clean copy of the Proposed Tariff is attached to the Direct Testimony of Mr. Kaufmann as Schedule TK-24 and is also incorporated herein by reference. It is requested that the Proposed Tariff be made effective January 28, 2022, a date which is no less than thirty (30) days from the date of this filing.

II. <u>BASE RATES</u>

5. Petitioner's projected operating revenues for the twelve-month test year period ending March 31, 2022 (utilizing six months' actual data and six months' estimated data) total $367,042,213. Inclusive of post-test year *pro forma* adjustments, the rates proposed in this Petition would yield additional operating revenues of $76,618,396, or approximately 19 percent above adjusted post-test year revenues.

6. The impact of this Petition on the bill of an average residential heat customer using 100 therms per month would be $19.42 or 17.2 percent. The actual percentage increase applicable to specific customers will vary according to the applicable rate schedule and the level of each customer's usage.

7. In accordance with N.J.A.C. 14:1-5.12(a)(4), the amount of operating revenue derived from intrastate service during the twelve months ended December 31, 2020 was $349,392,098.

8. The Company proposes to include a Cash Working Capital allowance in rate base of $31,959,285. This is based, in part, on a lead-lag study addressed in the Direct Testimony of Timothy S. Lyons, attached to the Petition and marked as Exhibit P-8.

9. Petitioner's filing proposes a return on equity of 10.75 percent applied to a capital structure that consists of 54.89 percent common equity and 45.11 percent long-term debt, which results in an overall after tax weighted average cost of capital of 7.63 percent. Petitioner's proposed capital costs and cost of capital are discussed in the Testimony and schedules of Paul R. Moul, attached to the Petition and marked as Exhibit P-7.

10. Further, the Company has calculated a consolidated tax adjustment, as required by N.J.A.C. 14:1-5.12(a)(11) and determined that no adjustment should be applied in this case as discussed in the Direct Testimony of Alan D. Felsenthal. After the execution of an Agreement of Non-Disclosure, a proposed version of which is included with this filing as Schedule C, a consolidated tax savings schedule calculated in accordance with N.J.A.C. 14:1-5.12(a)(11) will be provided to the parties.

11. Petitioner's test year ends March 31, 2022. Petitioner is proposing to reflect changes in certain capital expenditures through September 30, 2022 and changes in certain revenues and expenses through December 31, 2022.

12. Petitioner's filing in this case is based on six months of actual data and six months of estimated data. During the processing of this case, Elizabethtown will update its Direct Testimony and Exhibits, as appropriate to reflect actual results. It is anticipated that by the conclusion of this case, the entire test year ending March 31, 2022 will reflect actual results.

13. Petitioner is currently implementing an Infrastructure Investment Program ("IIP") in accordance with the Board's June 12, 2019 Order in BPU Docket No. GR18101197. Under the terms of that Order, Petitioner is required to submit a base rate case filing no later than June 30, 2024. Petitioner's filing herein fulfills that obligation. As discussed by Company witness Thomas Kaufmann, IIP investment costs through June 30, 2021 were previously included in rates on a provisional basis in BPU Docket Nos. GR20050327 and GR21040747, respectively. Petitioner is proposing to roll these IIP Investment costs into the rates to be established in this proceeding on a final basis. Company witness Michael P. Scacifero discusses the prudence of Petitioner's capital expenditures under the IIP.

III. <u>NEED FOR RATE RELIEF</u>

14. Since the conclusion of Elizabethtown's last base case -- the 2019 Base Rate Case[1] -- the Company has managed its business responsibly and effectively and continues to provide a high quality of service to its customers at reasonable rates. In order to maintain and enhance this

[1] *In the Matter of the Petition of Elizabethtown Gas Company for Approval of Increased Base Tariff Rates and Charges for Gas Service, Changes to Depreciation Rates, and Other Tariff Revisions*, Docket No. GR19040486, "Decision and Order Approving Initial Decision and Stipulation" (November 13, 2019) ("2019 Base Rate Case").

high level of service, the Company made significant prudent investments to its transmission and distribution systems, all the while experiencing cost increases that impact its cost of service.

15. The 2019 Base Rate Case was resolved by the Board in BPU Docket No. GR19040486 by order dated November 13, 2019 in which the Board authorized Petitioner to increase its base rates by approximately 11.26%. In that proceeding, Petitioner's test year end utility plant balance at August 31, 2019 was $1.474 billion. Since the Company's last base rate case, excluding Infrastructure Investment Program ("IIP") spending, Elizabethtown has invested approximately $214.8 million of plant additions net of retirements that are not currently reflected in rates, and projects that an additional $175.2 million of capital investment net of retirements, and excluding IIP, will be added to the UPIS balance by September 30, 2022, to ensure that the Company's customers continue to receive safe and reliable natural gas service.[2] In making these needed investments, the Company follows a number of practices to ensure that its capital expenditures are reasonable, including competitive bidding, contractor quality assurance, and cost tracking, which includes budget variance analysis.

16. The primary driver of the proposed rate increase in this case is to provide the Company a reasonable opportunity to earn a fair return on the investments made, so that it can continue to attract capital at reasonable rates and invest in the infrastructure necessary to continue providing safe and reliable service to its customers. Elizabethtown's request for rate relief is also driven by a need to recover an increased cost of capital and greater depreciation expense, as well as increases to the operations and maintenance ("O&M") costs incurred by the Company since the 2019 Base Rate Case. Without rate relief in this proceeding, allowing a reasonable return of and

[2] By Order dated June 12, 2019 the Board approved a stipulation that permitted Elizabethtown to implement an IIP to invest up to $300 million over a five-year period beginning July 1, 2019 and ending June 30, 2024. Schedule MPS-2 to Elizabethtown witness Michael P. Scacifero's testimony reflects the actual IIP expenditures through June 30, 2021 and approved for inclusion in rates in BPU Docket No. GR21040747.

return on these investments, Elizabethtown would earn a 5.77 percent return on equity ("ROE") for the test year ended March 31, 2022. This represents a significant under-earning relative to the 9.60 percent ROE authorized by the Board in the Company's last rate case, which could negatively impact Elizabethtown's ability to continue to attract capital at reasonable rates.

17. As a result of the Company's investments, customers are receiving benefits through increased safety and overall system reliability.

18. The Company plans to engage in ongoing, necessary transmission and distribution system construction projects over the test year and post-test year period as further detailed in the Direct Testimony of Michael P. Scacifero, attached hereto as Exhibit P-4. These major projects are necessary to improve Elizabethtown's transmission and distribution infrastructure and maintain safety and reliability. The Company is also investing in upgrades to its liquefied natural gas ("LNG") plant, which will allow the Company to address gas supply issues and increase reliability on the Company's distribution system, as discussed in the Direct Testimony of Leonard Willey and James Madden, attached hereto as Exhibit P-6. Elizabethtown is also planning significant clean energy projects, including a renewable natural gas project and solar panels for the Company's facilities, which will help achieve New Jersey's statewide clean energy and emission reductions goals, as discussed in the Direct Testimony of Christie McMullen, attached hereto as Exhibit P-2.

19. Elizabethtown recognizes that this filing is being made during an unprecedented period in which the State of New Jersey and its economy are only beginning to emerge from the devastating health impacts and economic dislocation caused by the COVID-19 pandemic. Ms. McMullen's testimony highlights the Company's efforts to address the impact of the pandemic on the Company's customers and employees and the State as whole, However, despite the Company's

efforts to effectively manage costs while continuing to provide customers with safe and reliable service during the pandemic, ongoing infrastructure investments and related capital expenditures, combined with an increase in the cost of capital and other expenses, have necessitated this filing for rate relief. Elizabethtown intends to maintain its excellent quality of service while also having an opportunity to earn a reasonable return for its shareholders.

20. The Company also proposes certain tariff changes as discussed in the Direct Testimony of Thomas Kaufmann. The changes proposed by Mr. Kaufmann streamline and clarify the tariff, roll the Company's IIP in Rider "F" into base rates, and separate heating and non-heating residential customers in determining Base Use per Customer for the Conservation Incentive Program ("CIP").

IV. OTHER REQUESTED RELIEF

21. As more fully discussed in the Direct Testimony of Dane A. Watson, attached hereto as Exhibit P-9, Petitioner proposes to modify its depreciation rates. Petitioner's proposed depreciation rates have been determined in a manner consistent with Board precedent. Petitioner's proposed depreciation rates are set forth in Exhibit P-9, Schedule DAW-1, Appendices A & B. A comparison of Petitioner's current and proposed depreciation rates is set forth in Schedule DAW-1, Appendix B to Exhibit P-9. The effect of the proposed depreciation rates on Petitioner's proposed revenue requirement is discussed in the Direct Testimonies of Dane Watson and John Houseman. Petitioner requests that its revised depreciation rates take effect simultaneously with the effective date of the new rates resulting from this proceeding which Petitioner anticipates will be later than ninety days after the filing of this Petition.

22. Petitioner proposes to retain its existing authority to establish a regulatory asset in which the incremental costs associated with a transmission integrity management program

incurred between rate cases will be tracked and deferred for later review and recovery in rates, as authorized in the 2019 Base Rate Case. These costs relate to certain Federal pipeline safety regulations that are currently pending, may significantly impact gas distribution operating costs, and are not reflected in the Company's test year or post-test year O&M expenses.

23. As discussed in the Direct Testimony of Mr. Houseman, Petitioner is also proposing to establish a regulatory asset defer any costs which would otherwise be expensed related to the Transportation Security Administration ("TSA") Security Directives. The Company anticipates that a portion of the costs related to evaluating, studying vulnerabilities and generating an action plan to comply with the TSA Security Directives will be allocated to capital projects that are recommended by these evaluations. The Company proposes to defer costs that are not eligible for capitalization under Generally Accepted Accounting Principles.

24. As discussed in the Direct Testimony of Mr. Houseman and the Direct Testimony of Mr. Madden and Mr. Willey, the Company also proposes to establish a regulatory asset to defer and recover the remaining undepreciated costs of the liquefaction equipment at the Erie Street LNG Facility that were not reimbursed by the vendor/manufacturer and are not properly considered costs for the new liquefaction facility. The liquefaction equipment at the Erie Street Facility was prudently constructed and placed in service to allow the Company to address gas supply issues on the Company's system. However, after being put into service, the liquefaction equipment at the Erie Street Facility became inoperable and could not be put back into service by the manufacturer. The Company proposes to amortize its unrecovered investment in its previous liquefaction equipment over an extended period.

25. The Company also proposes to establish a regulatory asset to enable Elizabethtown to defer for future recovery the difference between the costs incurred to establish an in-house gas

supply function at the Company and the costs that are ultimately included in the rates established in this proceeding for that purpose, as discussed in the Direct Testimony of Mr. Madden and Mr. Willey, the Direct Testimony of Mr. Houseman and the Direct Testimony of Mr. Kaufmann. In BPU Docket No. GR21040723 Elizabethtown has requested Board approval of an Asset Management Agreement that would obviate the need for Elizabethtown to bring its gas supply function in-house and incur the incremental costs of doing so. If that petition is not approved, Elizabethtown will likely incur incremental costs to bring its gas supply function in-house. As discussed by Mr. Kaufmann and Mr. Scacifero, Elizabethtown's proposed revenue requirement in this case includes both capital and operations and maintenance costs associated with bringing the gas supply function in-house.

26. As explained in the Direct Testimony of Mr. Kaufmann, Elizabethtown is proposing to amortize expenses related to this filing, including the projected costs of legal and consultant expenses, newspaper notices, court reporting, and other miscellaneous expenses, over a three-year period in accordance with Board precedent.

V. PROPOSED PROCEDURAL SCHEDULE

27. Elizabethtown respectfully proposes the following Procedural Schedule for the conduct of this proceeding:

December 28, 2021	Petition filed (6 Months Actuals/6 Months Pro Forma)
January 28, 2022	Discovery served by Rate Counsel/Staff
February 15, 2022	Company responses to discovery due on or before
February 18, 2022	Petitioner issues 9-3 Update
February 25, 2022	Discovery Conference
Week of March 7, 2022	Public Hearings
March 8, 2022	All second-round discovery served on or before

March 23, 2022	Company responses to second-round discovery due on or before
March 30, 2022	Initial Settlement Meeting
April 7, 2022	Rate Counsel and Intervenor Direct Testimony due on or before
April 11-15, 2022	Settlement Meetings
April 18, 2022	Discovery on Rate Counsel and Intervenor Direct Testimony due on or before
April 19-20, 2022	Settlement Meetings (if required)
May 2, 2022	Rate Counsel and Intervenor responses to discovery due on or before
May 2, 2022	Petitioner issues 12-0 Update
May 9, 2022	Petitioner and Intervenor Rebuttal Testimony due
May 16, 2022	Serve discovery on Rebuttal Testimony on or before
May 30, 2022	Responses to discovery on Rebuttal Testimony due on or before

Week of June 6, 2022	Evidentiary Hearings
4 weeks from conclusion of Evidentiary Hearings	Initial Briefs due
2 weeks from filing of Initial Briefs	Reply Briefs due on or before

VI. MISCELLANEOUS

28. Elizabethtown submits herewith, and incorporates as part hereof, all documents and exhibits required to accompany this Petition pursuant to N.J.A.C. 14:1-5.12, 14:1-4.1 and 14:1-5.1. A list of information required to be submitted with this Petition under the Board's regulations is set forth in Schedule D to this Petition. Likewise, attached hereto and incorporated herein by reference, are the Direct Testimony (Exhibits) and Schedules submitted on behalf of the following witnesses:

a. Christie McMullen, President and Chief Operating Officer, Elizabethtown Gas Company, whose testimony includes an overview of the Company and the primary issues driving the Company's filing in this case (Exhibit P-2);

b. Thomas Kaufmann, Manager of Rates and Tariffs, Elizabethtown Gas Company, whose testimony presents the Company's revenue requirement, revenue forecast and sponsors the Company's revised tariff (Exhibit P-3);

c. Michael P. Scacifero, Director, Engineering Services, Elizabethtown Gas Company, whose testimony addresses the capital expenditures made by the Company (Exhibit P-4);

d. John L. Houseman, Director of Accounting, South Jersey Industries, whose testimony sponsors certain accounting and related information (Exhibit P-5);

e. James Madden, Manager of Gas Production, South Jersey Industries, and Leonard Willey, Manager, Gas Supply, Elizabethtown Gas Company, whose testimony supports certain gas supply-related expenditures included in this filing including the costs of installing new LNG liquefaction equipment at the Company's Erie Street LNG facility (Exhibit P-6);

f. Paul Moul of P. Moul & Associates, whose testimony discusses the cost of capital for the Company (Exhibit P-7);

g. Timothy S. Lyons of Scott Madden, Inc., whose testimony supports the Company's cash working capital request using a lead lag study methodology (Exhibit P-8);

h. Dane A. Watson of Alliance Consulting Group whose testimony presents the Company's depreciation proposals (Exhibit P-9);

i. Alan D. Felsenthal of PricewaterhouseCoopers LLP whose testimony addresses certain tax issues (Exhibit P-10).

j. Daniel P. Yardley, Principal, Yardley & Associates, whose testimony includes a cost of service study and rate design based on the Company's revenue requirement (Exhibit P-11); and

29. Communications and correspondence concerning this Petition should be sent as follows:

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30. Petitioner is serving notice and a copy of this Petition, together with a copy of the exhibits and schedules annexed hereto on the Director, Division of Rate Counsel via electronic mail in lieu of providing hard copies. Due to the pandemic, and in accordance with the BPU's March 19, 2020 and May 20, 2020 Orders issued in BPU Docket No. EO20030254, hard copies cannot be provided at this time, but can be provided at a later time, as needed.

31. Similarly, Petitioner is also serving this notice and a copy of this Petition on the Department of Law and Public Safety via electronic mail in lieu of providing hard copies, but hard copies can be provided at a later time, as needed.

32. Notice of this filing, and the effect thereof will be served by mail or email upon the clerks of the respective municipalities and counties within Petitioner's service area at least twenty (20) days prior to the date set for the initial hearing, which notice shall include and specify the time and place of said hearing. A list of said municipalities and counties is contained in Schedule

TK-24 of Mr. Kaufmann's Direct Testimony. A copy of the form of notice is included herewith as Schedule B.

33. Customers will be notified of this filing and the effect thereof as well as the time and place of the initial hearing, by publication, at least twenty (20) days prior to the date set for the initial hearing, in newspapers of general circulation within the Petitioner's service territory. A copy of the form of notice is included herewith as Schedule A.

34. The reasons for the proposed rate increase and other relief requested by Petitioner in this Petition are as follows:

a. To be allowed a reasonable opportunity to earn its requested return on and return of investments made in facilities required to provide safe, adequate and proper service to existing and new customers of the Petitioner, and placed in service before September 30, 2022, the end of the six month post-test year period for capital reflected in this filing.

b. To recover revenue and expense adjustments through December 31, 2022, the end of the nine month post-test year period for these items.

c. To recover increased costs, not previously recovered in rates.

d. To permit Elizabethtown to earn an adequate rate of return on its current net investment in used and useful utility property.

e. To establish rates which are sufficient to enable Elizabethtown, under efficient and economical operation, to maintain and support its financial integrity and to raise and maintain such additional capital as may be necessary at a reasonable cost for the proper discharge of its public duty.

f. To offset such increases as are projected to occur in operating expenses and to maintain adequate levels of cash flow. and

g. To enable Petitioner to continue to furnish safe, adequate and proper service, to maintain existing facilities, and to provide such additional facilities as may be necessary to discharge its public duties.

35. Petitioner respectfully submits that the rates, tariff modifications and other relief requested by it are in all respects just and reasonable.

WHEREFORE, Petitioner respectfully requests the Board find and determine as follows:

a. that the proposed rates, including the proposed depreciation rates, and tariff revisions sought herein are just and reasonable and should be made effective; and

b. that Petitioner have such other and further relief as the Board may deem just, reasonable and proper under the circumstances presented to it in this case.

Respectfully submitted,

ELIZABETHTOWN GAS COMPANY

By:__________________________________
Deborah M. Franco
VP, Rates, Regulatory & Sustainability
SJI Utilities, Inc.

Dated: December 28, 2021

VERIFICATION

I, Deborah M. Franco, of full age, being duly sworn according to law, upon my oath, depose and say:

1. I am the Vice President, Rates, Regulatory and Sustainability of SJI Utilities, Inc. the parent company to Elizabethtown Gas Company ("Company") and I am authorized to make this verification on behalf of the Company.

2. I have reviewed the within petition and the information contained therein is true according to the best of my knowledge, information, and belief.

Deborah M. Franco
VP, Rates, Regulatory & Sustainability

Sworn to and subscribed
before me this 28th day
of December, 2021

CAROLYN A. JACOBS
NOTARY PUBLIC OF NEW JERSEY
My Commission Expires October 28, 2023

Exhibit P-1
Schedule A

Elizabethtown Gas Company

Notice of Public Hearings Regarding Proposed Gas Base Rate Increases, Changes in Depreciation Rates and Other Tariff Revisions

On December 28, 2021, Elizabethtown Gas Company ("Elizabethtown" or "Company") filed a Petition with the New Jersey Board of Public Utilities ("Board") in Docket No. _________ for approval of a request to increase base tariff rates and charges for gas service and implement other rate design and tariff revisions. The Company is also proposing to change its depreciation rates. The Company is proposing that these changes become effective January 28, 2022, or such other date as the Board may determine. The new base rates proposed herein would increase annual revenues by approximately $76.6 million. The proposed increase is predominantly the result of capital expenditures made or to be made by the Company related to system improvements and reliability since the Company's last base rate case. The $76.6 million increase would increase annual revenues by approximately 19%.

Set forth below are the current versus proposed rates, all of which are inclusive of taxes, that will permit customers to determine the effect upon them of the proposed increased rates. Any assistance required by customers in this regard will be furnished by the Company upon request.

	Current Base Tariff Rates			Proposed Base Tariff Rates		
	Service	**Demand**	**Distribution ***	**Service**	**Demand**	**Distribution ****
Residential Delivery Service	$10.00	-	$0.4809	$13.27	-	$0.6424
Small General Service	$27.01	-	$0.4278	$36.79	-	$0.5596
General Delivery Service	$37.50	$0.960	$0.2581	$61.84	$1.162	$0.3682
Public Station, per therm	-	-	$1.1126	$0.00	-	$0.0000
Large Volume Demand	$325.00	$1.333	$0.0561	$405.18	$1.866	$0.0655
Electric Generation Firm	$75.00	$0.640	$0.0509	$101.29	$0.800	$0.0421
Unmetered Gas Light, per mantle	-	-	$8.4300	$0.00	-	$11.31
Interruptible Cogeneration Srv.	$130.78	-	$0.0320	$175.58	-	$0.0320
Interruptible Service	$628.55	$0.098	$0.0843	$735.71	$0.269	$0.0843
Interruptible Transportation Srv.	$628.55	$0.427	$0.0987	$735.71	$0.533	$0.1391

* The sum of the current distribution rate and Rider F (Infrastructure Investment Program or "IIP")
** Rider F (IIP) rates are embedded in the proposed distribution rates and Rider F rates will be set to zero upon the effectiveness of the proposed distribution rates.

The Effect of The Proposed Increase On Typical Residential Monthly Bills (RDS Customers)

Consumption in Therms	Present Bill	Proposed Bill	Proposed Change	Percent Change
10	$20.27	$25.15	$4.88	24.1%
50	$61.33	$72.67	$11.34	18.5%
100	$112.65	$132.07	$19.42	17.2%
250	$266.63	$310.27	$43.64	16.4%

The Board has the statutory authority to establish Elizabethtown's rates at levels it finds just and reasonable as well as to establish the effective date of such rates. Therefore, the Board may establish the rates at levels and/or an effective date other than those proposed by Elizabethtown.

PLEASE TAKE FURTHER NOTICE that due to the COVID-19 Pandemic, a telephonic public hearing will be conducted on the following dates and times so that members of the public may present their views on the Company's Petition:

Dates:

Hearing Times: 4:30 p.m. and 5:30 p.m.

Exhibit P-1
Schedule A

Members of the public may present their views on the Petition during the public hearing by dialing the toll-free telephone number listed below, followed by entering the listed passcode when prompted.

Dial In:

Conference ID: followed by #

Copies of Elizabethtown's Petition can be reviewed on the Company's website at www.elizabethtowngas.com/rates-and-tariff under regulatory information.

Representatives of the Company, Board Staff and Rate Counsel will participate in the telephonic public hearing. Members of the public are invited to participate by utilizing the Dial–In and Conference ID information set forth above and may express their views on this filing. Such comments will be made part of the final record of the proceeding to be considered by the Board. The Board is also accepting written and emailed comments. Although both will be given equal consideration, the preferred method of transmittal is via email to ensure timely receipt while the Board continues to work remotely due to the COVID-19 Pandemic. Email comments should be submitted to: board.secretary@bpu.nj.gov, or through the Board's External Access Portal after obtaining a MyNewJersey Portal ID. Once an account is established, you will need an authorization code, which can be obtained upon request by emailing the Board's IT Helpdesk at ITHELPDESK@bpu.nj.gov. Detailed instructions for e-Filing can be found on the Board's home page at https://www.nj.gov/bpu/agenda/efiling. Written comments may be submitted to the Board Secretary, Aida Camacho-Welch, at the Board of Public Utilities, 44 South Clinton Avenue, Post Office Box 350, Trenton, NJ 08625-0350. Please include the name of the petition and the docket number when submitting comments.

Elizabethtown Gas Company
Christie McMullen – President and Chief Operating Officer

(add date)

To: County Clerk, Municipal Clerk and County Administrator

IN THE MATTER OF THE PETITION OF ELIZABETHTOWN GAS COMPANY FOR APPROVAL OF INCREASED BASE TARIFF RATES AND CHARGES FOR GAS SERVICE, CHANGES TO DEPRECIATION RATES AND OTHER TARIFF REVISIONS	: : : : : :	**BPU DOCKET NO. ______**

Pursuant to law, Elizabethtown Gas Company ("Elizabethtown" or the "Company") is providing you with notice of a filing made on December 28, 2021 with the New Jersey Board of Public Utilities for an increase in base rates, changes in the Board approved depreciation rates and changes to the Elizabethtown tariff. You may download the filing from the Company's website at www.elizabethtowngas.com/rates-and-tariff under regulatory information.

A public hearing related to this request has been scheduled for **(add date)** and Elizabethtown hereby serves upon you the notice of that hearing related to the above referenced matter. As noted on the attached copy of the public notice, the subject hearings are scheduled for **(add date)** in (**add location**), New Jersey and for **(add date)** in (**add location**), New Jersey.

Respectfully,

Deborah M. Franco
Vice President, Regulatory, Rates & Sustainability

Enclosure

Exhibit P-1
Schedule C

STATE OF NEW JERSEY
BOARD OF PUBLIC UTILITIES

IN THE MATTER OF THE PETITION OF ELIZABETHTOWN GAS COMPANY FOR APPROVAL OF INCREASED BASE TARIFF RATES AND CHARGES FOR GAS SERVICE, CHANGES TO DEPRECIATION RATES AND OTHER TARIFF REVISIONS	: : : : :	**BPU DOCKET NO.** **AGREEMENT OF NON-DISCLOSURE OF INFORMATION CLAIMED TO BE CONFIDENTIAL**

It is hereby AGREED, as of the day of 2022, by and among Elizabethtown Gas Company ("Elizabethtown" or "Petitioner"), the Staff of the New Jersey Board of Public Utilities ("Board Staff") and Division of Rate Counsel ("Rate Counsel") (collectively, the "Parties"), who have agreed to execute this Agreement of Non-Disclosure of Information Claimed to be Confidential ("Agreement") and to be bound thereby, that:

WHEREAS, in connection with the above-captioned proceeding before the Board of Public Utilities (the "Board"), Petitioner and/or another party ("Producing Party") may be requested or required to provide petitions, pre-filed testimony, other documents, analyses and/or other data or information regarding the subject matter of this proceeding that the Producing Party may claim constitutes or contains confidential, proprietary or trade secret information, or which otherwise may be claimed by the Producing Party to be of a market-sensitive, competitive, confidential or proprietary nature (hereinafter sometimes referred to as "Confidential Information" or "Information Claimed to be Confidential"); and

WHEREAS, the Parties wish to enter into this Agreement to facilitate the exchange of information while recognizing that under Board regulations at N.J.A.C. 14:1-12.1 et seq., a request for confidential treatment shall be submitted to the Custodian who is to rule on requests made pursuant to the Open Public Records Act ("OPRA"), N.J.S.A. 47:1A-1 et seq., unless such information is to be kept confidential pursuant to court or administrative order (including, but not limited to, an Order by an Administrative Law Judge sealing the record or a portion thereof pursuant to N.J.A.C. 1:1-14.1, and the parties acknowledge that an Order by an Administrative Law Judge to seal the record is subject to modification by the Board), and also recognizing that a request may be made to designate any such purportedly confidential information as public through the course of this administrative proceeding; and

WHEREAS, the Parties acknowledge that, despite each Party's best efforts to conduct a thorough pre-production review of all documents and electronically stored information WHEREAS, the Parties acknowledge that unfiled discovery materials are not subject to public access under OPRA; and ("ESI"), some work product material and/or privileged material ("Protected Material") may be inadvertently disclosed to another Party during the course of this proceeding; and

WHEREAS, the undersigned Parties desire to establish a mechanism to avoid waiver of privilege or any other applicable protective evidentiary doctrine as a result of the inadvertent disclosure of Protected Material;

NOW, THEREFORE, the Parties hereto, intending to be legally bound thereby, DO HEREBY AGREE as follows:

1. The inadvertent disclosure of any document or ESI which is subject to a legitimate claim that the document or ESI should have been withheld from disclosure as Protected Material shall not waive any privilege or other applicable protective doctrine for that document or ESI or for the subject matter of the inadvertently disclosed document or ESI if the Producing Party, upon becoming aware of the disclosure, promptly requests its return and takes reasonable precautions to avoid such inadvertent disclosure.

2. Except in the event that the receiving party or parties disputes the claim, any documents or ESI which the Producing Party deems to contain inadvertently disclosed Protected Material shall be, upon written request, promptly returned to the Producing Party or destroyed at the Producing Party's option. This includes all copies, electronic or otherwise, of any such documents or ESI. In the event that the Producing Party requests destruction, the receiving party shall provide written confirmation of compliance within thirty (30) days of such written request. In the event that the receiving party disputes the Producing Party's claim as to the protected nature of the inadvertently disclosed material, a single set of copies may be sequestered and retained by and under the control of the receiving party until such time as the Producing Party has received final determination of the issue by the Board of Public Utilities or an Administrative Law Judge, provided that the Board has not modified or rejected an order by the Administrative Law Judge.

3. Any such Protected Material inadvertently disclosed by the Producing Party to the receiving party pursuant to this Agreement shall be and remain the property of the Producing Party.

4. Any Information Claimed to be Confidential that the Producing Party produces to any of the other Parties in connection with the above-captioned proceeding and pursuant to the terms of this Agreement shall be specifically identified and marked by the Producing Party as Confidential Information when provided hereunder. If only portions of a document are claimed to be confidential, the producing party shall specifically identify which portions of that document are claimed to be confidential. Additionally, any such Information Claimed to be Confidential shall be provided in the form and manner prescribed by the Board's regulations at <u>N.J.A.C.</u> 14:1-12.1 <u>et seq.</u>, unless such information is to be kept confidential

pursuant to court or administrative order. However, nothing in this Agreement shall require the Producing Party to file a request with the Board's Custodian of Records for a confidentiality determination under N.J.A.C. 14:1-12.1 et seq. with respect to any Information Claimed to be Confidential that is provided in discovery and not filed with the Board.

5. With respect to documents identified and marked as Confidential Information, if the Producing Party's intention is that not all of the information contained therein should be given protected status, the Producing Party shall indicate which portions of such documents contain the Confidential Information in accordance with the Board's regulations at N.J.A.C. 14:1-12.2 and 12.3. Additionally, the Producing Party shall provide to all signatories of this Agreement full and complete copies of both the proposed public version and the proposed confidential version of any information for which confidential status is sought.

6. With respect to all Information Claimed to be Confidential, it is further agreed that:

(a) Access to the documents designated as Confidential Information, and to the information contained therein, shall be limited to the Party signatories to this Agreement and their identified attorneys, employees, and consultants whose examination of the Information Claimed to be Confidential is required for the conduct of this particular proceeding.

(b) Recipients of Confidential Information shall not disclose the contents of the documents produced pursuant to this Agreement to any person(s) other than their identified employees and any identified experts and consultants whom they may retain in connection with this proceeding, irrespective of whether any such expert is retained specially and is not expected to testify or is called to testify in this proceeding. All consultants or experts of any Party to this Agreement who are to receive copies of documents produced pursuant to this

Agreement shall have previously executed a copy of the Acknowledgement of Agreement attached hereto as "Attachment 1," which executed Acknowledgement of Agreement shall be forthwith provided to counsel for the Producing Party, with copies to counsel for Board Staff and the Rate Counsel.

(c) No other disclosure of Information Claimed to be Confidential shall be made to any person or entity except with the express written consent of the Producing Party or their counsel, or upon further determination by the Custodian, or order of the Board, the Government Records Council or of any court of competent jurisdiction that may review these matters.

7. The undersigned Parties have executed this Agreement for the exchange of Information Claimed to be Confidential only to the extent that it does not contradict or in any way restrict any applicable Agency Custodian, the Government Records Council, an Administrative Law Judge of the State of New Jersey, the Board, or any court of competent jurisdiction from conducting appropriate analysis and making a determination as to the confidential nature of said information, where a request is made pursuant to OPRA, N.J.S.A. 47:1A-1 et seq. Absent a determination by any applicable Custodian, Government Records Council, an Administrative Law Judge, the Board, or any court of competent jurisdiction that a document(s) is to be made public, the treatment of the documents exchanged during the course of this proceeding and any subsequent appeals is to be governed by the terms of this Agreement.

8. In the absence of a decision by the Custodian, Government Records Council, an Administrative Law Judge, or any court of competent jurisdiction, the acceptance by the undersigned Parties of information which the Producing Party has identified and marked as Confidential Information shall not serve to create a presumption that the material is in fact entitled

to any special status in these or any other proceedings. Likewise, the affidavit(s) submitted pursuant to N.J.A.C. 14:1-12.8 shall not alone be presumed to constitute adequate proof that the Producing Party is entitled to a protective order for any of the information provided hereunder.

9. In the event that any Party seeks to use the Information Claimed to be Confidential in the course of any hearings or as part of the record of this proceeding, the Parties shall seek a determination by the trier of fact as to whether the portion of the record containing the Information Claimed to be Confidential should be placed under seal. Furthermore, if any Party wishes to challenge the Producing Party's designation of the material as Confidential Information, such Party shall provide reasonable notice to all other Parties of such challenge and the Producing Party may make a motion seeking a protective order. In the event of such challenge to the designation of material as Confidential Information, the Producing Party, as the provider of the Information Claimed to be Confidential, shall have the burden of proving that the material is entitled to protected status. However, all Parties shall continue to treat the material as Confidential Information in accordance with the terms of this Agreement, pending resolution of the dispute as to its status by the trier of fact.

10. Confidential Information that is placed on the record of this proceeding under seal pursuant to a protective order issued by the Board, an Administrative Law Judge, provided that the Board has not modified or rejected an order by the Administrative Law Judge, or any court of competent jurisdiction shall remain with the Board under seal after the conclusion of this proceeding. If such Confidential Information is provided to appellate courts for the purposes of an appeal(s) from this proceeding, such information shall be provided, and shall continue to remain, under seal.

11. This Agreement shall not:

(a) Operate as an admission for any purpose that any documents or information produced pursuant to this Agreement are admissible or inadmissible in any proceeding.

(b) Prejudice in any way the right of the Parties, at any time, on notice given in accordance with the rules of the Board, to seek appropriate relief in the exercise of discretion by the Board for violations of any provision of this Agreement.

12. Within forty-five (45) days of the final Board Order resolving the above-referenced proceeding, all documents, materials, and other information designated as "Confidential Information," regardless of format, shall be destroyed or returned to counsel for the Producing Party. In the event that such Board Order is appealed, the documents and materials designated as "Confidential Information" shall be returned to counsel for the Producing Party or destroyed within forty-five (45) days of the conclusion of the appeal.

Notwithstanding the above return requirement, Board Staff and Rate Counsel may maintain in their files copies of all pleadings, briefs, transcripts, discovery and other documents, materials and information designated as "Confidential Information," regardless of format, exchanged or otherwise produced during these proceedings, provided that all such information and/or materials that contain Information Claimed to be Confidential shall remain subject to the terms of this Agreement. The Producing Party may request consultants who received Confidential Information who have not returned such material to counsel for the Producing Party as required above to certify in writing to counsel for the Producing Party that the terms of this Agreement have been met upon resolution of the proceeding.

13. The execution of this Agreement shall not prejudice the rights of any Party to seek relief from discovery under any applicable law providing relief from discovery.

14. The Parties agree that one original of this Agreement shall be created for each of the signatory parties for the convenience of all. The signature pages of each original shall be executed by the recipient and transmitted to counsel of record for the Petitioner, who shall send a copy of the fully executed document to all counsel of record. The multiple signature pages shall be regarded as, and given the same effect as, a single page executed by all Parties.

IN WITNESS THEREOF, the undersigned Parties do HEREBY AGREE to the form and execution of this Agreement.

ELIZABETHTOWN GAS COMPANY

By: _______________________________
Deborah M. Franco
VP, Rates, Regulatory & Sustainability

ANDREW J. BRUCK
ACTING ATTORNEY GENERAL OF
THE STATE OF NEW JERSEY
Attorney for the Staff of the
New Jersey Board of Public Utilities

By: _______________________________

Deputy Attorney General

BRIAN O. LIPMAN, ESQ.
DIRECTOR
NEW JERSEY
DIVISION OF RATE COUNSEL

By: _______________________________

Assistant Deputy Rate Counsel

Exhibit P-1
Schedule C

STATE OF NEW JERSEY
BOARD OF PUBLIC UTILITIES

IN THE MATTER OF THE PETITION OF ELIZABETHTOWN GAS COMPANY FOR APPROVAL OF INCREASED BASE TARIFF RATES AND CHARGES FOR GAS SERVICE AND OTHER TARIFF REVISIONS	: : : : :	**PETITION** **DOCKET NO.**

ACKNOWLEDGMENT OF AGREEMENT

The undersigned is an attorney, employee, consultant and/or expert witness for the Division of Rate Counsel or an intervenor who has received, or is expected to receive, Confidential Information provided by Elizabethtown or by another party ("Producing Party") which has been identified and marked by the Producing Party as "Confidential Information." The undersigned acknowledges receipt of the Agreement of Non-Disclosure of Information Claimed to be Confidential and agrees to be bound by the terms of the Agreement.

Dated: By: ________________________________

(Name, Title and Affiliation)

Index of Minimum Filing Requirements Pursuant to BPU Regulations

Requirement	Location in Filing
***N.J.A.C.* 14:1-5.7**	
The existing and proposed rates of depreciation. *N.J.A.C.* 14:1-5.7(a)(1)	Schedule DAW-1
The existing and proposed methods of calculating or determining the rates of depreciation. *N.J.A.C.* 14:1-5.7(a)(2)	Schedule DAW-1
The calculations or studies supporting the proposed change in depreciation rates. *N.J.A.C.* 14:1-5.7(a)(3)	Schedule DAW-1
The effect of the proposed changes on operating revenue deductions and operating income. *N.J.A.C.* 14:1-5.7(a)(4)	Schedules TK-2, TK-3, and JLH-5
A statement as to the date when it is proposed to make the changes in depreciation rates effective, which date shall not be earlier than 90 days after the filing of a petition under this rule. *N.J.A.C.* 14:1-5.7(a)(5)	Petition, ¶ 21
***N.J.A.C.* 14:1-5.11**	
Four copies of the proposed tariff or revision, change or alteration thereof, together with an explanation of the manner in which the tariff or change differs from the existing or prior tariff, and the effect, if any, upon revenue *N.J.A.C.* 14:1-5.11(a)(1)	Schedules TK-24 and TK-25
A statement of the reasons why the tariff or change is proposed to be filed. *N.J.A.C.* 14:1-5.11(a)(2)	Petition, § III
A statement of notices given, if any, together with a copy of the text of each said notices. *N.J.A.C.* 14:1-5.11(a)(3)	Petition, Schedules A and B

Requirement	Location in Filing
A statement as to the date on which it is proposed to make the tariff or change effective, which date shall not be earlier than 30 days after the filing unless otherwise permitted by the Board. *N.J.A.C.* 14:1-5.11(a)(4)	Petition, ¶ 4
***N.J.A.C.* 14:1-5.12**	
A comparative balance sheet for the most recent three-year period (calendar year or fiscal year). *N.J.A.C.* 14:1-5.12(a)(1)	Schedule JLH-1
A comparative income statement for the most recent three-year period (calendar year or fiscal year). *N.J.A.C.* 14:1-5.12(a)(2)	Schedule JLH-2
A balance sheet at the most recent date available *N.J.A.C.* 14:1-5.12(a)(3)	Schedule JLH-1
A statement of the amount of revenue derived in the calendar year last preceding the institution of the proceedings from the intrastate sales of the product supplied, or intrastate service rendered, the rates, tolls, fares or charges for which are the subject matter of the filing. *N.J.A.C.* 14:1-5.12(a)(4)	Schedule JLH-3
A *pro forma* income statement reflecting operating income at present and proposed rates and an explanation of all adjustments thereon, as well as a calculation showing the indicated rate of return on the average net investment for the same period as that covered by the pro forma income statement, that is, investment in plant facilities plus supplies and working capital to the extent claimed, less the reserve for depreciation and advances and contributions for facilities. *N.J.A.C.* 14:1-5.12(a)(5)	Schedules TK-3 and TK-4
An itemized schedule showing all payments or accruals to affiliated companies or organizations and to those who own in excess of five percent of the utility's capital stock regardless of the form or manner in which such charges are paid or accrued and an explanation of the service performed for such charges. *N.J.A.C.* 14:1-5.12(a)(9)	Schedule JLH-4

Requirement	**Location in Filing**
A copy of the form of notice to customers. *N.J.A.C.* 14:1-5.12(a)(10)	Petition, Schedules A and B
If a company is part of a family of companies that files a consolidated Federal income tax return, that company shall include in its petition a consolidated tax adjustment (CTA) calculation using the rate base method, which allows the parent company to keep certain tax savings, while requiring the petitioner to reflect the savings by reducing the rate base upon which the utility's return is determined. The CTA calculation must include all supporting information and documents necessary for the Board to determine and implement an appropriate CTA calculation pursuant to this section. A CTA provides a mechanism that the Board will utilize in rate cases, so that ratepayers should share a specified portion of the tax savings achieved from the filing of a consolidated tax return. Required information and supporting documents include, but are not limited to, a schedule showing each affiliate company's taxable income/loss by year, an indication whether the affiliate is a regulated utility company or not, the statutory Federal income tax requirement for each year, if any, and the alternative minimum tax requirement for each year, if any. The review period for the CTA calculation shall be for five consecutive tax years, including the complete tax year within the utility's proposed test year. The calculated CTA shall be allocated, so that the rate base may be reduced by up to 25 percent of the full CTA. The transmission portion of an electric distribution company's income shall not be included in the calculation of CTA. *N.J.A.C.* 14:1-5.12(a)(11)	Schedule ADF-2 (Confidential)

IN THE MATTER OF THE PETITION OF ELIZABETHTOWN GAS COMPANY FOR APPROVAL OF INCREASED BASE TARIFF RATES AND CHARGES FOR GAS SERVICE, CHANGES TO DEPRECIATION RATES AND OTHER TARIFF REVISIONS

BPU DOCKET NO. GR21__________

DIRECT TESTIMONY

OF

CHRISTIE MCMULLEN

President and Chief Operations Officer

On Behalf Of
Elizabethtown Gas Company

Exhibit P-2

December 28, 2021

TABLE OF CONTENTS

Exhibit P-2

ELIZABETHTOWN GAS COMPANY
DIRECT TESTIMONY OF
CHRISTIE MCMULLEN

I. INTRODUCTION

Q. PLEASE STATE YOUR NAME AND BUSINESS ADDRESS.

A. My name is Christie McMullen. My business address is 520 Green Lane, Union, New Jersey 07083.

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

A. I am President and Chief Operations Officer ("COO") of Elizabethtown Gas Company ("Elizabethtown" or the "Company").

Q. PLEASE DESCRIBE YOUR PROFESSIONAL RESPONSIBILITIES.

A. As President and COO of Elizabethtown, I oversee all aspects of Elizabethtown's operations. I am responsible for its day-to-day operations including promoting and ensuring safety, reliability, compliance, operational excellence and financial integrity.

Q. PLEASE BRIEFLY SUMMARIZE YOUR EDUCATIONAL BACKGROUND AND INDUSTRY-RELATED EXPERIENCE.

A. I am a graduate of the University of Maryland at College Park with a Bachelor of Science degree in electrical engineering. I also have a Masters of Business Administration from Loyola University Maryland. Prior to assuming my present responsibilities in December 2018, I was employed by Baltimore Gas & Electric Company ("BGE") where I served as Vice President of Gas Distribution from 2015-2018. I also served as the Vice President of Support Services and Chief Safety Officer (2011-2015) and Vice President of Business Transformation (2009-2011). I am a Six Sigma Master Black Belt with significant experience leading process improvement and business transformation programs. An active member of the American Gas Association ("AGA"), I serve on the Leadership Council and Operations Section Managing Committee. I also serve on the Board of Directors for the Northeast Gas Association.

Q. HAVE YOU PREVIOUSLY TESTIFIED OR SUBMITTED TESTIMONY BEFORE THE NEW JERSEY BOARD OF PUBLIC UTILITIES ("BOARD" OR "BPU") OR OTHER REGULATORY COMMISSION?

A. Yes. I submitted testimony before the Board in BPU Docket No. GR19040486, Elizabethtown's most recent base rate case ("2019 Rate Case"). I have also previously testified before the Maryland Public Service Commission regarding BGE's strategic infrastructure development and enhancement ("STRIDE") program.

II. <u>PURPOSE OF TESTIMONY</u>

Q. WHAT IS THE PURPOSE OF YOUR DIRECT TESTIMONY?

A. The purpose of my direct testimony in this proceeding is to provide an overview of Elizabethtown's filing with the Board seeking authority to increase the Company's base rates, modify its existing depreciation rates, and implement other tariff changes. Specifically, I will

(i) discuss how Elizabethtown and South Jersey Industries ("SJI") responded to the COVID-19 pandemic and the efforts we undertook to mitigate impacts to employees and customers;

(ii) provide a general summary of the Company's base rate filing and explain why Elizabethtown is seeking to increase base rates at this time;

(iii) describe the corporate structure and mission of Elizabethtown and its direct parent, SJI Utilities, Inc. ("SJIU"), within the SJI family of companies;

(iv) explain SJI's philosophy for managing utility operations to enable us to ensure that Elizabethtown provides safe, reliable and clean natural gas service at just and reasonable rates;

(v) discuss Elizabethtown's operational focus, our commitment to safety, the Company's recent safety performance and related safety initiatives and the indicators that drive our excellent customer service performance;

(vi) discuss actions taken by Elizabethtown to promote New Jersey's clean energy future set forth in the New Jersey Clean Energy Act of 2018 ("CEA") and the Energy Master Plan ("EMP"), including Elizabethtown's commitment to energy efficiency, sustainable energy sources, and emissions reductions;

(vii) discuss the ongoing demand for natural gas in Elizabethtown's service territory and the investments made by the Company to ensure we have continued access to reliable gas supply for our customers;

(viii) describe Elizabethtown's commitment to the local communities it serves,; and

(ix) introduce the other witnesses who are sponsoring testimony in this proceeding.

We recognize that this filing is being made during an unprecedented period in which our State and its economy are only beginning to emerge from the devastating health and economic impacts caused by the COVID-19 pandemic. In recognition of these circumstances, I will first address how the Company has responded to the COVID-19 pandemic. I will then highlight the important issues in this case and explain how the rate relief sought in the Company's filing furthers the objectives of the Company to provide safe, reliable, affordable and clean natural gas service to the benefit of its customers, the Board and the State of New Jersey.

III. <u>DISCUSSION</u>

Q. PLEASE DESCRIBE HOW ELIZABETHTOWN AND SJI RESPONDED TO THE COVID-19 PANDEMIC.

A. As providers of essential energy services, SJI and Elizabethtown are keenly aware of the impacts that the COVID-19 pandemic has had and continues to have on our customers, our employees and the State as a whole. SJI and Elizabethtown have remained committed to protecting the safety of customers and employees during the pandemic without compromising on Elizabethtown's obligation to deliver safe and reliable natural gas and exceptional customer service. I am proud of the work ethic displayed by our employees throughout the pandemic, many of whom, at times, were isolated or quarantined during this period. While certain non-critical work was suspended during the March 2020-May 2020 period to comply with the BPU Order issued in BPU Docket No. EO200300254 requiring public utilities to cease in-house or business visits absent health or safety needs, we reallocated our contractor resources to other work, such as work related to main replacements to ensure ongoing productivity, retention of critical resources for when restrictions were lifted and the continued provision of safe and reliable service.

Q. HAS ELIZABETHTOWN MADE ANY ADJUSTMENTS TO ITS OPERATIONS AS A RESULT OF THE COVID-19 PANDEMIC?

A. Yes. Elizabethtown made numerous adjustments to its operations to effectively respond to employee and customer needs during the pandemic, including implementing a moratorium on terminations as required by the Governor's Executive Orders, advising customers of assistance programs available to ease the burden of utility bills, and adapting to a work-from-home model for employees where possible. Beginning in mid-March 2021, the

Company re-opened its customer service centers in Elizabeth and Perth Amboy via a contactless format by altering the façade of the building to provide in-person service to customers three days per week; these centers are now open five days a week. We also completed renovations to our call center in June and to our administrative offices located at Green Lane in Union, New Jersey in October, creating a more efficient and inviting atmosphere which will help inspire and retain our employees who have begun to return to the workplace. In addition, we upgraded our automated outbound collections function in March 2021 to help facilitate bill collections and reduce our uncollectibles balance.

Q. PLEASE DESCRIBE SOME OF THE ASSISTANCE PROVIDED TO CUSTOMERS TO OFFSET IMPACTS FROM THE PANDEMIC.

A. The Company has worked with community partners to administer the COVID-19 Emergency Rental/Utility Assistance Program Phase II, which provides temporary rental or utility assistance to low and moderate-income households affected by the COVID-19 pandemic. Energy assistance has become a spotlight in customer communications; due to this effort, 12,640 customers received over 33,000 payments totaling $7.7 million in utility assistance during program year 2020-2021 – the highest it has been in the past six years.

Q. DID ELIZABETHTOWN EMPLOY ITS ENERGY EFFICIENCY PROGRAMS TO HELP CUSTOMERS DURING THE COVID-19 PANDEMIC?

A. Yes. Through the summer of 2020, the Company promoted energy saving tips to help customers save energy while spending more time at home through an email and social media campaign. Elizabethtown continued to promote Heating, Ventilation and Air Conditioning ("HVAC") rebates and home energy assessment programs through direct mail, email, and social media. Elizabethtown coordinated with its contractor, GreenLife, to promote the home weatherization program to income qualified customers through a combination of outreach events, direct mail, email, and social media from April 2020 to June 2021. For the new energy efficiency programs that started in July 2021, the Company promoted the new programs through its website, customer newsletter and social media. In October 2021, Elizabethtown launched a residential campaign featuring appliance rebates, HVAC rebates and financing, quick home energy checkups ("QHEC") and home weatherization for income-qualified customers through email and social media. Elizabethtown ran a campaign in October and November 2021 highlighting the direct install program and held a customer informational webinar

Q. WHY IS ELIZABETHTOWN SEEKING TO INCREASE ITS BASE RATES AT THIS TIME?

A. This filing is primarily driven by the significant capital investments that the Company has made and will continue to make since its last base rate proceeding. Since the Company's last base rate case in 2019, excluding the Company's Infrastructure Investment Program ("IIP") investments approved by the Board in BPU Docket No. GR18101197, the Company has invested $214.8 million of plant additions net of retirements that are not currently reflected in rates. The Company projects that an additional $175.2 million of capital investments net of retirements, excluding IIP, will be added to its plant in service balance by September 30, 2022. These capital investments have been and will be made to enhance the safety, reliability and resiliency of Elizabethtown's distribution system, support customer needs, and enhance customer service. Our continuing investments play a significant role in contributing to maintaining employment, job creation and growth in the economy of the State. The Company seeks to establish rates that will afford it a reasonable opportunity to earn a fair return on and return of the investments it makes to ensure it can continue to attract the necessary capital to support further investments that enable it to provide safe and reliable service to its customers.

Q. DOES THE COMPANY HAVE A REGULATORY OBLIGATION TO FILE A BASE RATE CASE?

A. Yes. The Board's order approving Elizabethtown's IIP program requires the Company to file a base rate case on or before June 30, 2024. That requirement was established in the Board's June 12, 2019 Order in BPU Docket No. GR18101197.[1] Although Elizabethtown is not obligated to file a base rate case until June 2024, the decision to file now was based on the significant capital investments made to support the Company's natural gas distribution system and the need to earn a fair and reasonable return on and return of those investments so that the Company can continue to attract capital at appropriate rates.

Q. PLEASE BRIEFLY DESCRIBE ELIZABETHTOWN'S FILING IN THIS PROCEEDING.

A. Elizabethtown is seeking to increase its base delivery rates by approximately $77 million annually or approximately 19 percent above adjusted post-test year revenues. This request is based on a proposed after tax return on invested capital of 7.63 percent, with a capital structure that includes a common equity component of 54.89 percent and a return on common equity of 10.75 percent. The proposed base rate increase will provide the Company with the opportunity to recover its reasonable cost of service and earn a fair return on and return of the capital invested in Elizabethtown's distribution system.

[1] *In the Matter of the Petition of Elizabethtown Gas Company to Implement an Infrastructure Investment Program ("IIP") and Associated Cost Recovery Mechanism Pursuant to N.J.S.A. 48:2-21 and N.J.A.C. 14:3-2A*, Docket No. 18101197, "Final Decision and Order Approving Stipulation" (June 12, 2019) at 6-7.

Elizabethtown and its parent companies, SJI and SJIU, are fully committed to continued investment in Elizabethtown's utility operations in a manner and at a level that will allow the Company to continue to provide its customers with safe and reliable service. At the same time, as reflected in the testimony of Company witness Thomas Kaufmann, the 100 therm residential bill that we are proposing is lower than the equivalent bills charged to customers during calendar years 2006 through 2009.

Q. PLEASE PROVIDE A BRIEF OVERVIEW OF THE COMPANY, ITS MISSION, AND ITS CORPORATE STRUCTURE.

A. Elizabethtown provides natural gas distribution service to approximately 303,000 residential, commercial and industrial customers in New Jersey in parts of Union, Middlesex, Sussex, Warren, Hunterdon, Morris and Mercer counties. Elizabethtown's service territory covers approximately 1,500 square miles and its distribution system consists of over 3,200 miles of mains. Elizabethtown provides a vital service to its customers and is committed to performing this service in a safe, reliable and environmentally supportive manner at a reasonable price.

Elizabethtown is a wholly owned subsidiary of SJIU, which in turn is a wholly owned subsidiary of SJI. SJI is a publicly traded energy services holding company. SJIU is the direct parent of Elizabethtown as well as Elizabethtown's sister utility, South Jersey Gas Company.

Q. HAVE THERE BEEN ANY RECENT CHANGES TO UNION MEMBERSHIP AMONG ELIZABETHTOWN EMPLOYEES?

A. Yes. On October 20, 2021 Elizabethtown's Customer Experience team members voted in favor of having the Utility Workers Union of America ("UWUA"), an AFL-CIO labor union, represent the employees as their exclusive collective bargaining representative. Elizabethtown is working with the Customer Experience team members and the UWUA to negotiate a first-time contract for these team members.

All Elizabethtown employees—union and non-union—are valued members of our team. The Company has a long history working alongside the unions that represent different portions of the company's work force, and we will work with the customer experience team, the UWUA, and all the Company's employees to continue to provide award-winning service to our customers.

Q. PLEASE DESCRIBE SJI'S PHILOSOPHY FOR MANAGING ITS UTILITY OPERATIONS, INCLUDING THOSE OF ELIZABETHTOWN.

A. SJI is committed to providing its customers with superior, reliable utility service while contributing to New Jersey's social and environmental needs, including those established in the CEA and EMP. In managing its utility businesses, SJI acts to ensure that its individual utilities are focused on three core values: (1) the consistent provision of safe and reliable service at just and reasonable rates; (2) robust investment in utility infrastructure that ensures safety, reliability and resiliency while facilitating the State's clean energy and energy efficiency goals; and (3) an overriding commitment to excellent customer service. Despite the challenging events of 2020 and 2021, like the devastation wrought by Hurricane Ida and the ongoing response to the COVID-19 pandemic, it is these core values that have allowed us to continue to offer our award-winning customer service and fulfill our obligation to provide safe, reliable and affordable natural gas service.

Q. WHAT IS ELIZABETHTOWN'S OPERATIONAL FOCUS?

A. The three core values I just mentioned guide Elizabethtown's operational focus. Consistent with this focus, over the past several years, Elizabethtown has undertaken a number of accelerated infrastructure replacement projects approved by the Board to ensure the continued safe and reliable operation of the Company's distribution system. The Company intends to continue these efforts through both the investments discussed in this filing as well as through the continued implementation of its approved IIP under which the Company is authorized to invest up to $300 million to replace the Company's vintage, at-risk infrastructure over the five year period ending June 30, 2024.

Q. PLEASE DESCRIBE SOME OF THE SAFETY INITIATIVES UNDERTAKEN BY ELIZABETHTOWN DURING THE TEST YEAR.

A. Safety is ingrained in who we are as a company. Because safety is a core Company value, it is a guiding principle behind everything we do. We expect our system to operate safely and reliably for our customers and for our employees to get home to their families safely every day. Beyond our infrastructure replacement projects which are vital to ensuring the continued safety and reliability of our gas distribution system, we undertook important safety initiatives to further support our customers and employees. For example, we recently constructed two new training facilities: Leak Town and a Virtual Reality Training Center. These facilities enhance our capabilities for training employees, giving them the knowledge and practices needed to respond to calls safely. Leak Town is an outdoor training center we constructed at Green Lane this year to enhance our capabilities for training our employees, allowing new hires to obtain hands-on experience and helping existing employees to maintain proficiency throughout the year by practicing in a controlled environment. The Virtual Reality Training Room is another tool we have added to the Elizabethtown Training Center at Green Lane to teach and train our field staff on a range of tasks that we routinely perform. The training places employees in a three-dimensional/360-degree virtual setting either in the field or inside a premise while they perform a set of procedures such as leak investigation and gas activation while allowing the instructor to evaluate the steps taken and provide feedback.

Q. WHAT ARE THE COMPANY'S OTHER RECENT SAFETY-RELATED ACCOMPLISHMENTS?

A. I am proud to say that we achieved zero OSHA Recordable incidents for the first nine months of the year. Additionally, the AGA recognized Elizabethtown with the Industry Leader Accident Prevention Award for 2019 and 2020 (awarded in 2020 and 2021) and we are on track to win the award for a third consecutive year with our 2021 safety performance (award to be issued in 2022). Our safety culture was further strengthened through additional training for both employees and our communities. For example, we provided *Natural Gas for Emergency Responders* training to multiple towns in our service territory, including training for over 100 emergency responders from Woodbridge Township. These training sessions cover a variety of topics related to the safety, incident detection, and response, including natural gas safety basics, investigation methods for indoor and outdoor leaks, first responder safety and fire department "do's and don'ts," natural gas fires, and evidence preservation. These sessions also serve as an important opportunity for Company personnel and first responders to meet in-person and develop relationships and discuss facilities and equipment specific to a county or municipality that are important to effectively respond to incidents. The trainings are often followed up with a response exercise designed to test and reinforce Company response procedures with a focus on incident management, communications and information sharing.

Q. CAN YOU PROVIDE EXAMPLES OF HOW ELIZABETHTOWN WORKS TO MAINTAIN ITS LEVEL OF OPERATIONAL EXCELLENCE?

A. Elizabethtown's parent, SJIU, participates in the AGA Best Practices Benchmarking Program which provides a means for gas utilities to survey other members on specific operational issues and evaluate themselves internally. SJIU also participates in the AGA Peer Review Program, which is a voluntary peer-to-peer safety and operational practices review program that allows local natural gas utilities throughout the nation to observe their peers, share best practices and identify opportunities to better serve their customers and communities. As part of the Peer Review Program, subject matter experts from peer companies evaluate other participating companies with the objective of gaining an understanding of the utility's practices, procedures and standards in an effort to identify strengths and leading indicators, as well as to identify areas that could be improved where appropriate.

Q. HAS ELIZABETHTOWN BEEN RECOGNIZED AS A LEADER IN THE NATURAL GAS INDUSTRY FOR OPERATIONAL PERFORMANCE AND CUSTOMER SERVICE?

A. Yes, several organizations have recognized Elizabethtown as an industry leader in delivering operational excellence and customer satisfaction. Elizabethtown has been ranked first in customer satisfaction by JD Power and Associates for gas utilities in the East Region Midsize Segment for seven consecutive years. In addition, as noted earlier, the AGA named Elizabethtown – along with its sister utility South Jersey Gas Company – as a 2020 Industry Leader in Accident Prevention. Elizabethtown was also recognized as an industry leader in several categories of the 2021 Cogent Syndicated Utility Trusted Brand & Customer Engagement, Residential Study performed by Escalent, a leading consumer research firm. Recognitions include "Easiest to do Business With," "Most Trusted Utility Brand," "Environmental Champion," and "Utility Customer Champion."

Q. WHAT ARE SOME INDICATORS OF ELIZABETHTOWN'S CUSTOMER SERVICE PERFORMANCE?

A. Elizabethtown has consistently performed well in the metrics set for Customer Service Standards in the 2019 Rate Case. Elizabethtown has consistently performed well in the area of reading meters in a timely manner and has averaged only 3.3 rebills per 1000 customers from December 2019 through September 2021, exceeding benchmarks of 95 percent meters read and ≤20 rebills per 1000. The Company has responded to 97.9 percent of leak calls within 60 minutes from December 2019 to September 2021, and has met or exceeded the 95 percent benchmark in all months except for September 2021, which was impacted by Hurricane Ida. The Company has also performed well in meeting customer appointments, with 97.1 percent of appointments met since the last rate case. The Company's field representatives also continually receive high marks in the quarterly customer satisfaction surveys conducted by the Company for both courtesy (93.1 percent) and knowledge (91.4 percent). Overall customer service agent quality scores, which are based on 19 customer service and functional expertise criteria, have also been at high levels and continue to improve.

Q. DOES THE COMPANY'S OPERATIONAL FOCUS ALIGN WITH THE CLEAN ENERGY GOALS OF NEW JERSEY?

A. Yes. SJI is positioning the organization, including Elizabethtown, to be a leader in achieving the climate goals of New Jersey by committing to making investments that will ensure that our infrastructure is part of the clean energy future. SJI is pursuing aggressive decarbonization goals, with commitments to (1) achieve a 70 percent carbon reduction of operational emissions and consumption by the year 2030, (2) realize 100 percent carbon reduction by 2040 and (3) dedicate at least 25 percent of annual capital expenditures on sustainability projects. We look forward to being part of the solution towards a clean energy future by investing in projects that facilitate the environmental goals of the State, including infrastructure enhancements and clean energy projects that will help decarbonize our gas supply while continuing to allow us to achieve our core mission of providing safe, reliable, affordable, clean energy for the customers and communities we serve.

Q. CAN YOU DESCRIBE SOME OF THE INVESTMENTS THAT FACILITATE THE STATE'S AND THE COMPANY'S ENVIRONMENTAL GOALS?

A. As an initial matter, replacement of leak prone pipe through Elizabethtown's IIP and base capital spending will greatly reduce methane emissions on the Company's system. Further, as discussed below, Elizabethtown is working to interconnect and incorporate renewable natural gas ("RNG") into its gas supply system. In addition, the Company is installing solar panels at its facilities in Union, Flemington, and Stewartsville, which not only promotes sustainability, but is also expected to produce electric costs savings that are reflected in the rates proposed in this proceeding. We also received BPU approval to invest approximately $76 million in a variety of energy efficiency programs including rebates, financing, an efficient products marketplace, a residential weatherization program for low-to-moderate income customers and home energy audits, as well as solutions for commercial customers. These investments will help our customers lower their energy bills and make better-informed decisions about their energy usage.

Q. PLEASE DESCRIBE ELIZABETHTOWN'S PLANNED RNG PROJECT.

A. The Company plans to purchase RNG from a Connecticut producer that is generated from raw organic material. The Company will receive truckloads – one truck every other day – of compressed RNG that will be injected into its distribution system in northwest New Jersey. The RNG will be used as supply for a portion of the Company's service territory that currently has only one pipeline supplier. Thus, the RNG not only supports the State's environmental goals, but enhances reliability and supply diversity in an isolated part of the Company's service territory. Elizabethtown plans for this project to be placed in-service during the post-test year. This RNG project is discussed in greater detail in the Direct Testimony of James Madden and Leonard Willey. This investment represents a commitment to providing our customers with clean natural gas service consistent with the environmental goals of the State and our decarbonization promise.

Q. PLEASE DESCRIBE THE COMPANY'S PLANS TO INSTALL SOLAR PANELS.

A. Elizabethtown will install solar panels at its facilities in Union (Green Lane), Flemington, and Stewartsville. These investments will allow the Company to reduce its carbon footprint and aid in achieving New Jersey's statewide emissions reductions goals. In addition to the environmental benefits, the Company will recognize an estimated annual net savings of $50,000 on its electric bills, reducing the level of operations and maintenance expenses reflected in this filing.

Q. PLEASE DESCRIBE THE DEMAND FOR NATURAL GAS SERVICE IN THE ELIZABETHTOWN SERVICE AREA.

A. Natural gas remains in strong demand. We achieved the 300,000 customer milestone in 2021 after installing more than 4700 new meters throughout our service territory. We expanded our customer base with the installation of 18 miles of infrastructure in the Northwest Division, driven by new businesses in Byram Township and the completion of main installation throughout the Lake Mohawk community.

Q. HAS THE COMPANY MADE ANY INVESTMENTS TO CONTINUE TO ENSURE RELIABLE GAS SUPPLY FOR ITS CUSTOMERS?

A. Yes. Elizabethtown is investing in new liquefaction equipment at its Erie Street Liquefied Natural Gas ("LNG") Facility. This project provides a non-pipeline redundancy solution that promotes system reliability, protects customers from potential gas supply disruption on our upstream pipeline supplies systems, and helps to ensure that Elizabethtown can meet peak day demand for our customers under adverse conditions. The Board has acknowledged the threat of pipeline service disruptions and expressed concern about its potential impact on New Jersey customers. A number of pipeline incidents have occurred in recent years that have threatened gas supply in New Jersey and other eastern states, including the April 2016 incident involving Texas Eastern Transmission Company, LLC – one of Elizabethtown's largest pipeline suppliers. These incidents, as well as ongoing cybersecurity threats, underscore the need for utilities to build in non-pipeline redundancies and supply sources that will protect their customers and their systems against these threats. Elizabethtown's investment in liquefaction equipment at the Erie Street LNG Facility will allow the Company to address the risk of supply loss and promote safety and reliability for our customers.

Q. HOW DOES ELIZABETHTOWN PLAY AN ACTIVE ROLE IN THE COMMUNITIES IT SERVES?

A. A culture based on safety, reliability, customer service and giving back to the community is woven throughout Elizabethtown and the rest of the SJI family of companies. This culture is exemplified by the substantial investments that have and will be made to modernize and improve the safety, reliability and resiliency of Elizabethtown's natural gas distribution system. This culture is further exemplified by SJI's and Elizabethtown's continued involvement in, and financial contributions to, the communities we serve. Elizabethtown recognizes that, as a local natural gas utility, it has a unique responsibility to its customers, employees, communities and the public. Elizabethtown believes in commitment to the community and has provided significant financial support to local nonprofit, civic, and business and commerce organizations. To make the most meaningful impact in our communities, Elizabethtown focuses its charitable giving on four distinct areas: energy assistance; education; environmental stewardship; and community enrichment. An example of these charitable giving pillars in practice is Elizabethtown's continued support of the Elizabeth Coalition to House the Homeless, an organization which serves the immediate needs of the homeless and near-homeless. In 2021 Elizabethtown donated $5,000 towards the organization's school supply drive. Elizabethtown has also continued its partnership with Union County College and it's "Fueling the Future" scholarship program, awarding $1,000 scholarships to 10 full-time students pursuing degrees in science, technology, engineering, or mathematics related disciplines. In addition, in recognition of the essential efforts of the many first responders in our territory, in 2021 we established a First Responders Grant Program that provided financial support to various fire and police departments of many municipalities in the communities we serve. These are just some examples of the donations we make in connection with our charitable contributions of almost $200,000 per year.

Q. DOES ELIZABETHTOWN PROVIDE SUPPORT TO LOW INCOME CUSTOMERS?

A. Yes, providing customers in need with energy assistance became a spotlight in customer communications (newsletters, payment reminder notices, joint utility summit and employee training). As noted earlier, due to this effort, 12,640 customers received $7.7M in utility assistance during program year 2020-2021, which again, is the highest it has been in the past six years. Elizabethtown partners with providers to promote financial assistance to those in need through low income assistance programs, including the Low-Income Home Energy Assistance Program ("LIHEAP"), Payment Assistance for Gas and Electric ("PAGE"), Lifeline, Comfort Partners and NJ SHARES, as well as other grants and relief funds administered by our State and Federal agency partners.

Elizabethtown offers energy assistance training to all customer-facing employees. The Company also promotes energy assistance, along with money saving efficiency measures, through its website, customer newsletters, bill inserts, press releases and social media accounts, as well as external events. Through these efforts, Elizabethtown made over 4 million contacts in our communities in 2020. These critically important efforts offer a path to utility bill relief for our customers and neighbors in need – keeping them connected to the natural gas service that supports their heating, hot water and cooking needs.

Q. PLEASE INTRODUCE THE OTHER WITNESSES PROVIDING TESTIMONY IN SUPPORT OF ELIZABETHTOWN'S FILING IN THIS PROCEEDING.

A. The other witnesses and the subjects addressed in their testimony are as follows:

- Thomas Kaufmann, Manager of Rates and Tariffs, Elizabethtown Gas Company, whose testimony presents the Company's proposed revenue requirement, revenue forecast, and sponsors the Company's revised tariff;
- Michael P. Scacifero, Director, Engineering Services, Elizabethtown Gas Company, addresses capital expenditures;
- John L. Houseman, Director of Accounting, South Jersey Industries, whose testimony sponsors certain accounting and related information;
- James Madden, Manager of Gas Production, South Jersey Industries, and Leonard Willey, Manager, Gas Supply, Elizabethtown Gas Company, whose testimony provides an overview of project and gas supply requirements for the Company;
- Paul Moul of P. Moul & Associates, whose testimony discusses the cost of capital;
- Timothy S. Lyons of ScottMadden, Inc. sponsors the Company's lead/lag study;
- Dane A. Watson of Alliance Consulting Group presents the Company's depreciation proposals;
- Alan D. Felsenthal of PricewaterhouseCoopers LLP addresses certain tax issues; and
- Daniel P. Yardley of Yardley and Associates presents the Company's embedded cost of service study and proposed rate design.

IV. CONCLUSION

Q. DO YOU HAVE ANY CONCLUDING REMARKS?

A. Yes. Despite the challenges of the COVID-19 pandemic, Elizabethtown has managed and continues to manage its operations responsibly and effectively to uphold its commitment to provide superior service to our customers at reasonable rates. We recognize that our proposed increase is significant; however, it is driven predominantly by the cost of prudent and necessary investments and we must be afforded the opportunity to earn a reasonable return on and return of investments made since the Company's last base rate case proceeding that are not reflected in rates. I respectfully request that the Board provide Elizabethtown with the opportunity to earn a fair return on its investments and grant our requested rate relief at this time.

Q. DOES THIS CONCLUDE YOUR TESTIMONY?

A. Yes. It does.

IN THE MATTER OF THE PETITION OF ELIZABETHTOWN GAS COMPANY FOR APPROVAL OF INCREASED BASE TARIFF RATES AND CHARGES FOR GAS SERVICE, CHANGES TO DEPRECIATION RATES AND OTHER TARIFF REVISIONS

BPU DOCKET NO. ___________

DIRECT TESTIMONY

OF

THOMAS KAUFMANN

Manager, Rates and Tariffs
Elizabethtown Gas Company

On Behalf of
Elizabethtown Gas Company

Exhibit P-3

December 28, 2021

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Exhibit P-3

ELIZABETHTOWN GAS COMPANY
DIRECT TESTIMONY OF
THOMAS KAUFMANN

I. <u>INTRODUCTION</u>

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

A. My name is Thomas Kaufmann. I am employed by Elizabethtown Gas Company ("Elizabethtown" or "Company") as Manager, Rates and Tariffs. My business address is 520 Green Lane, Union, New Jersey 07083.

Q. PLEASE DESCRIBE YOUR PROFESSIONAL RESPONSIBILITIES.

A. I am responsible for designing and developing rates and rate schedules for regulatory filings with the New Jersey Board of Public Utilities ("Board" or "BPU") and internal management purposes. I also oversee daily rate department functions, including tariff administration, monthly parity pricing, competitive analyses and preparation of management reports.

Q. PLEASE SUMMARIZE YOUR EDUCATIONAL BACKGROUND AND INDUSTRY RELATED EXPERIENCE.

A. In June 1977, I graduated from Rutgers University, Newark, N.J., with a Bachelor of Arts degree in Business Administration, majoring in accounting and economics. In July 1979, I graduated from Fairleigh Dickinson University, Madison, N.J., with a Master of Business Administration, majoring in finance.

My professional responsibilities have encompassed financial analysis, accounting, planning, and pricing in manufacturing and energy services companies in both regulated and unregulated industries. In 1977, I was employed by Allied Chemical Corp. as a staff accountant. In 1980, I was employed by Celanese Corp. as a financial analyst. In 1981, I was employed by Suburban Propane as a Strategic Planning Analyst, promoted to Manager of Rates and Pricing in 1986 and to Director of Acquisitions and Business Analysis in 1990. In 1993, I was employed by Concurrent Computer as a Manager, Pricing Administration. In 1996, I joined NUI Utilities Inc., now part of South Jersey Industries, Inc. ("SJI"), as a Rate Analyst, was promoted to Manager of Regulatory Support in August 1997, Manager of Regulatory Affairs in February 1998, and named Manager of Rates and Tariffs in July 1998.

II. <u>PURPOSE OF TESTIMONY</u>

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

A. The purpose of my testimony is to support Elizabethtown's revenue requirement calculation in this case, which is based on a test year ending March 31, 2022, including *pro forma* adjustments to the test year Income Statement and Statement of Rate Base to derive post-test year amounts. In support of the revenue requirement, I explain *pro forma* adjustments to test year revenues, cost of gas and operations and maintenance ("O&M") expense, as well as the rate base calculation. I will also address Elizabethtown's compliance with certain requirements from the Board Order approving SJI's acquisition of the assets of Elizabethtown that are relevant to this rate proceeding. In addition, I will present the Company's revenue determinants forecast and tariff revisions, and will provide bill comparisons between present and proposed rates.

Q. DO YOU SPONSOR ANY SCHEDULES IN YOUR DIRECT TESTIMONY?

A. Yes. I am sponsoring the following Schedules, supporting the Company's calculation of its revenue requirement and rate base:

- Schedule TK-1 – Revenue Requirement;

- Schedule TK-2 – Statement of Rate Base;
- Schedule TK-3 – Operating Income Statement;
- Schedule TK-4 – Summary of *Pro Forma* Adjustments to Operating Income excluding annualization and normalization adjustments;
- Schedule TK-5 – Post Test Year Annualization and Normalization Adjustments to Revenue and Cost of Gas;
- Schedule TK-6 – Derivation of Revenue Expansion Factor;
- Schedule TK-7 – Rider Adjustment;
- Schedule TK-8 – Proposed Infrastructure Investment Program ("IIP") Revenue Roll-In to Base Rates from IIP Rider F;
- Schedule TK-9 – Payroll Expense;
- Schedule TK-10 – Employee Benefits Expense;
- Schedule TK-11 – Allocated Service Company Expense;
- Schedule TK-12 – Rate Case Expense;
- Schedule TK-13 – Other O&M Expense;
- Schedule TK-14 – Inflation Adjustment;
- Schedule TK-15 – Revenue Taxes;
- Schedule TK-16 – Customer Deposits;
- Schedule TK-17.1 – Cash Working Capital (Test Year);
- Schedule TK-17.2 – Cash Working Capital (Post-Test Year);
- Schedule TK-18 – Inventories;
- Schedule TK-19 – Billing Determinants, consisting of Post-Test Year Forecast of Customers, Demand and Therm Usage;

- Schedule TK-20 – Test Year and Post-Test Year Customer Counts and Therms;
- Schedule TK-21 – Conservation Incentive Program ("CIP") Base Use per Customer ("BUC");
- Schedule TK-22 – Test Year and Post-Test Year Newark Airport Monthly Normal Degree Days;
- Schedule TK-23 – Bill Comparisons for Residential and Commercial Customers;
- Schedule TK-24 – Complete proposed tariff; and
- Schedule TK-25 – Complete proposed tariff in redline form.

III. <u>TEST YEAR</u>

Q. WHAT TEST YEAR PERIOD IS ELIZABETHTOWN USING TO DETERMINE THE REVENUE REQUIREMENT IN THIS PROCEEDING?

A. Elizabethtown's test year is the twelve months ending March 31, 2022. This filing utilizes six months of actual data ending September 30, 2021 and six months of estimated data through March 31, 2022. The actual data has been obtained from the Company's books and records. Generally, the estimated data has been extracted from the Company's operating and capital budgets and forecasts. The estimated data will be replaced with actual data as the case progresses, ultimately containing all actual results in the 12-month update.

Q. HAS ELIZABETHTOWN INCLUDED ANY POST-TEST YEAR ADJUSTMENTS IN THE DETERMINATION OF THE PROPOSED REVENUE REQUIREMENT?

A. Yes. Elizabethtown is proposing to reflect changes in certain capital expenditures through September 30, 2022 and changes in certain revenues and expenses through December 31, 2022, as described later in my testimony as well as in the Direct Testimony of Mr. Michael P. Scacifero (Exhibit P-4). Including these post-test year adjustments is consistent with standards previously adopted by the Board and provides for an annualization and/or adjustment of revenues, expenses and capital expenditures through the time period in which rates are expected to be in effect. Specifically, the Board's policy concerning post-test year adjustments, as set forth in its Order in *Re Elizabethtown Water Company*, Docket No. WR8504330, is that utilities are afforded an opportunity to make a record concerning known and measurable changes to expenses and revenues that are nine months beyond the test year and for changes in rate base items that are six months beyond the test year. The post-test year adjustments included in this case are within these parameters. The post-test year adjustments to rate base and operating income are provided in Schedules TK-2 and TK-3, respectively.

Q. PLEASE DESCRIBE THE CORPORATE RELATIONSHIP BETWEEN ELIZABETHTOWN AND SJI.

A. Elizabethtown is a wholly-owned subsidiary of SJI Utilities, Inc. ("SJIU"), which in turn is a wholly-owned subsidiary of SJI. SJIU owns and operates two utilities, Elizabethtown and South Jersey Gas Company. SJIU and SJI provide a variety of shared administrative services to Elizabethtown and other affiliates. Elizabethtown was authorized by the Board to enter into services agreements with SJIU and SJI when the Board approved SJI's acquisition of Elizabethtown's assets. Shared services costs are assessed to Elizabethtown by SJIU and SJI in accordance with the cost assignment methodologies set forth in the services agreements.

Q. WERE THE COSTS INCURRED FROM SJIU AND SJI THAT ARE INCLUDED IN ELIZABETHTOWN'S REVENUE REQUIREMENT PROJECTED IN A MANNER CONSISTENT WITH THE PROJECTIONS FOR ELIZABETHTOWN?

A. Yes. All affiliate costs reflected in Elizabethtown's filing are based on six months of actual financial information for the period ending September 30, 2021 and six months of estimated data through March 31, 2022. The Company also included post-test year adjustments for known and measurable changes in costs by applying the same criteria used to determine such adjustments for Elizabethtown itself.

IV. REVENUE REQUIREMENT

Q. HOW HAVE YOU CALCULATED THE REVENUE REQUIREMENT AND THE ASSOCIATED REVENUE DEFICIENCY?

A. Schedule TK-1, attached hereto, reflects the calculation of Elizabethtown's requested additional operating revenue of $76,618,396, as supported by Company witnesses in this case. The calculation of this amount is as follows and discussed below:

REVENUE REQUIREMENT		
Adjusted Rate Base	$1,392,067,037	TK-2
Rate of Return	7.6300%	
Required Operating Income	106,214,715	
Adjusted Net Operating Income	51,648,105	TK-3
Income Deficiency	54,566,610	
Revenue Factor	1.404126	TK-6
Operating Revenue Adjustment to Base Rates	$76,618,396	

The adjusted rate base is calculated on Schedule TK-2. Schedule TK-2 reflects the adjustments made to specific rate base elements and provides a reference to the Schedules sponsored by each witness supporting the adjustment. The proposed rate of return on rate base is sponsored by Mr. Paul R. Moul (Exhibit P-7). The required operating income calculated on Schedule TK-1 is the adjusted rate base times the rate of return. The income deficiency is the required operating income less the adjusted net operating income. The revenue factor is derived on Schedule TK-6 consisting of percentages for uncollectibles, assessments and taxes. The operating revenue adjustment to base rates is the revenue factor times the income deficiency.

The Adjusted Net Operating Income includes the Company's proposal to roll the Board approved amounts of IIP operating revenues from the IIP Rider F into base rates in this case as shown on Schedule TK-5 and detailed on Schedule TK-8, as discussed further below. After adjusting operating revenues for the roll-in of IIP and other net income, the Company's revenue deficiency is $76,618,396 as shown in Schedule TK-1.

Q. HOW IS THE REVENUE EXPANSION FACTOR CALCULATED?

A. Schedule TK-6 depicts the derivation of the revenue expansion factor used to convert the income deficiency into the net operating revenue requirement. The revenue factor includes adjustments for BPU and Division of Rate Counsel ("RC") Assessments, uncollectibles, State Income Tax, and Federal Income Tax. The adjustments for BPU and RC Assessments and State and Federal Income Tax are based on current statutory rates. The adjustment for uncollectibles is based on the Company's five-year average, excluding increased uncollectible costs associated with the impact of the COVID-19 pandemic, which have been deferred and will be recovered through a regulatory asset approved by the Board in Docket No. AO20060471. Each of the components of the revenue factor must be reflected in this factor in order for the Company to recover each incremental dollar of income from the required revenue increase.

Q. PLEASE EXPLAIN WHY COSTS ASSOCIATED WITH THE COMPANY'S IIP ARE UNDER REVIEW IN THIS CASE.

A. The IIP was approved by a Board Order dated June 12, 2019 in BPU Docket No. GR18101197 ("IIP Order"). Pursuant to Paragraph 14 of the Stipulation of Settlement approved by the Board in the IIP Order, "The prudency of the IIP Projects will be reviewed by the Board in the Company's subsequent base rate proceedings. The Company will file a base rate case no later than June 30, 2024." This filing meets these requirements of the IIP Order and provides for a prudence review of the IIP to date. The prudence of the Company's IIP expenditures is discussed in the Direct Testimony of Company witness Michael P. Scacifero.

Q. WHY IS THE COMPANY PROPOSING TO ROLL THE COSTS RECOVERED THROUGH THE IIP TARIFF RIDER F INTO BASE RATES IN THIS CASE?

A. The IIP expenditures are for mains and services which are included in the Company's Utility Plant In-Service ("UPIS"), as well as the associated depreciation and deferred taxes, which are components of rate base. Though not expressly stated in the IIP Order, it was contemplated that IIP expenditures, to a date certain, would be included in the derivation of base rates at the time of a subsequent rate case.

Q. PLEASE EXPLAIN THE COMPANY'S PROPOSAL TO ROLL THE IIP INTO BASE RATES IN THIS CASE.

A. For base ratemaking purposes, the Company proposes to include the IIP operating revenues in the base rates proposed in this case and to include the IIP mains and services which have previously been reflected in the Company's IIP cost recovery filings in the Company's rate base. The IIP in-service capital and revenue requirements being rolled into base rates are detailed in Schedule TK-8. The amounts detailed on Schedule TK-8 are actual amounts approved in the respective BPU orders in Docket Nos. GR20050237 and GR21040747. In addition, please see Schedule DPY-2 by Company witness Mr. Yardley in Exhibit P-11, which reflects the roll-in to base rate revenues.

Q. WHAT WILL HAPPEN TO THE CURRENTLY APPROVED IIP RIDER F TARIFF RATES WHEN BASE RATES BECOME EFFECTIVE?

A. When base rates, including this adjustment, become effective, the approved IIP amount will be removed from the computation in resetting the Rider F IIP rates, which may be zero if this case settles before year three IIP rates go into effect.

V. <u>OPERATING INCOME</u>

Q. PLEASE OUTLINE AND EXPLAIN THE REVENUE AND EXPENSE ADJUSTMENTS, SHOWN ON SCHEDULE TK-3, THAT THE COMPANY IS PROPOSING TO MAKE IN THIS FILING.

A. *Pro Forma* and Annualization and Normalization adjustments of the revenue and cost of sales reflected on Schedule TK-3 (Operating Income Statement) are as follows:

	Pro Forma Adjustments	Annualization & Normalization Adjustments	Total Adjustments
Operating Revenues	($33,375,184)	$72,595,627	$39,220,443
Cost of Sales-Rider Revenue Offsets	($19,021,805)	$0	($19,021,805)
Cost of Sales Purchased Gas	$0	$50,177,004	$50,177,004
Operating Margin Revenues	($14,353,379)	$22,418,623	$8,065,244

The adjustments to the 12-month test year ending March 31, 2022 shown on Schedule TK-3 are from Schedules TK-4 and TK-5. Schedule TK-4 summarizes the *pro forma* revenue and cost of sales adjustments from rider adjustments, which are discussed below. Schedule

TK-5 presents the annualization and normalization adjustments, which are also discussed below. The adjustments shown on these Schedules are supported by various witnesses in this case and include a reference to the adjustments sponsored by each witness.

<u>Pro Forma Adjustments</u>: Schedule TK-4 adjustments for Tariff Rider revenues and cost of sales are detailed on Schedule TK-7. These adjustments to revenues and costs for the Company's Tariff Riders include the On-system Margin Credit ("OSMC"), Energy Efficiency Program ("EEP"), Remediation Adjustment Clause ("RAC"), Clean Energy Program ("CEP"), and IIP amounts currently being booked as revenue. These programs and the associated riders are designed to be adjusted outside of a base rate case. As such, the Company has removed the revenue and cost associated with these riders from the *pro forma* income statement in this case. The proposal to roll the IIP Rider F into base rates, based on previously approved in-service capital amounts, was discussed earlier in my testimony. This is accomplished by replacing these removed IIP booked revenue amounts shown on Schedule TK-7 with those approved as shown on Schedules TK-5 and TK-8.

<u>Annualization and Normalization Adjustment:</u> Schedule TK-5 details the derivation of the annualization and normalization adjustments made in the Company's Operating Income Statement, Schedule TK-3. The methodology to derive the adjustments is based on adding an annualization to the normalized forecasted post-test year therms. The annualization component is calculated by applying the monthly normalized forecasted use-per-customer during the twelve-month post-test year period to the difference between the monthly forecasted customer count and the customer count at the end of the post-test year, December 31, 2022. These annualization and normalization calculations result in the billing determinants shown on Schedule TK-19 which, when applied to current rates, compute the operating margin revenues shown in the schedules of Company witness Mr. Daniel P. Yardley (Exhibit P-11) and summarized on Schedule TK-5. This calculation using annualized and normalized therms results in the operating margin revenues, inclusive of the proposed IIP roll-in. This amount plus the gas cost adjustment, estimated by the Company using forecasted sales therms, results in the operating revenue adjustments shown on Schedule TK-5. These adjustments and the rider adjustments are summarized on Schedule TK-3. The annualization and tariff class normalized forecast is discussed in detail later in my testimony.

Q. PLEASE OUTLINE AND EXPLAIN THE *PRO FORMA* O&M ADJUSTMENTS, SHOWN ON SCHEDULE TK-3, THAT THE COMPANY IS PROPOSING TO MAKE IN THIS FILING.

A. The *Pro Forma* O&M Expense Adjustments reflected on Schedule TK-3 (Operating Income Statement) are as follows***:***

	Schedule	Pro Forma Adjustments
Payroll Expense	TK-9	$1,700,773
Employee Benefits Expense	TK-10	$172,974
Service Company Expense	TK-11	$1,309,307
Rate Case Expenses	TK-12	$470,488
Other O&M Expenses	TK-13	($31,322)
Inflation Adjustment	TK-14	$1,121,960
Remove Charitable & Civic Contributions Expenses	TK-4	($472,243)
		$4,271,937

Schedule TK-4 provides a summary of these *pro forma* O&M expense adjustments, as well as the associated Schedule references supporting these adjustments, which are discussed below.

Payroll Expense: Schedule TK-9 identifies the Company's *pro forma* adjustments for employee payroll changes and employee annualization. The resulting increase to fixed compensation expense is based on anticipated additions and separations during the test year period, as well as projected post-test year wage increases. The payroll expense for all non-union and union employees of Elizabethtown is expected to increase by 3 percent effective March 1, 2022. The FICA Payroll Tax adjustment reflected on Schedule TK-9 is included in Taxes Other Than Income Taxes shown on Schedule TK-3.

Employee Benefits Expense: Schedule TK-10 reflects the *pro forma* adjustment to annualize healthcare benefits based on the anticipated net additions and separations identified in the payroll expense adjustment discussed above.

Allocated Service Company Salaries and Benefit Expense: Schedule TK-11 identifies the Company's *pro forma* adjustment to annualize salaries and benefits allocated directly from its affiliated service companies, SJI and SJIU. The increase to allocated expense is based on anticipated additions and separations during the test year period, as well as projected post-test year wage increases. The payroll expense for all employees of SJI and SJIU contain a 3 percent increase.

Rate Case Expenses: Schedule TK-12 reflects the *pro forma* adjustment made for projected expenses related to this proceeding. This adjustment includes the projected costs of legal and consultant expenses, newspaper notices, court reporting, and other miscellaneous expenses. This schedule shows the total anticipated expenses in this case; however, consistent with Board policy, the Company proposes to amortize these expenses over a three-year period, which results in the expense amount reflected on Schedule TK-12.

<u>Other O&M Expenses</u>: Schedule TK-13 reflects *pro forma* adjustments for an increase in costs related to the expense associated with bringing the Elizabethtown asset management component of gas supply in-house. This adjustment is discussed in the testimony of Company witnesses Mr. Madden and Mr. Willey. The Company is also requesting authority to establish a regulatory asset to defer and recover the remaining undepreciated costs of the liquefaction equipment at the Erie Street LNG Facility that were not reimbursed by the vendor/manufacturer and are not serviceable for the new liquefaction facility as shown on Schedule TK-13. Please also see the testimonies of Company witness Mr. Houseman as well Company witnesses Mr. Madden and Mr. Willey. Schedule TK-13 also reflects an estimated annual net savings of $49,790 in the Company's electric bills due to the installation of solar panels, further discussed in the testimony of Company witness Ms. McMullen, as well as certain management fee expense adjustments for expenses that are excluded from the determination of the revenue requirement.

<u>Inflation Adjustment:</u> Schedule TK-14 reflects a *pro forma* adjustment for inflation on residual O&M expenses presented on this schedule. The residual amount of O&M expense is calculated as the total post-test year O&M expense, less expenses that are subsequently adjusted for known and measurable items or that otherwise are not subject to inflation, such as uncollectibles expense. The resulting residual O&M expense was multiplied by the inflation factor shown on this schedule to develop the known and measurable inflation allowance. The inflation factor was developed based on the Energy Information Administration's average projected Gross Domestic Product-Price Index ("GDP-PI") for the end of the post-test year period compared to the GDP-PI at the mid-point of the test year.

<u>Remove Charitable & Civic Contributions Expense:</u> Schedule TK-4, line 3(g), reflects the removal of Charitable & Civic Contributions Expense which are considered shareholder expenses. They are being removed as an expense item consistent with Board policy.

Q. PLEASE EXPLAIN THE ANNUALIZATION AND NORMALIZATION O&M ADJUSTMENTS IN THIS FILING SHOWN ON SCHEDULE TK-3.

A. The annualization and normalization adjustment for O&M expenses, shown on line 7 of Schedule TK-3, is for uncollectible expenses and is calculated by applying the proposed uncollectible adjustment percentage factor calculated in Schedule TK-6 to the annualization and normalization operating revenue adjustments shown in Schedule TK-3.

Q. PLEASE DESCRIBE THE DEPRECIATION AND AMORTIZATION ADJUSTMENTS THE COMPANY IS PROPOSING TO MAKE IN THIS FILING.

A. The *pro forma* adjustments to accumulated depreciation and amortization Schedule TK-2 line 2, and depreciation and amortization expense, Schedule TK-3 line 8, are set forth on Schedule JLH-5 and discussed in further detail in the Direct Testimony of Mr. John L. Houseman (Exhibit P-5). The changes to depreciation rates reflected in the proposed depreciation expense are based on the results of a study prepared by Company witness Mr. Dane A. Watson (Exhibit P-9).

Q. PLEASE OUTLINE AND EXPLAIN THE TAXES OTHER THAN INCOME TAXES ADJUSTMENT THE COMPANY IS PROPOSING TO MAKE IN THIS FILING.

A. The Taxes Other Than Income Taxes adjustment, reflected on Schedule TK-3, line 9, is described in more detail below:

	Schedule	*Pro Forma* Adjustments
Payroll Taxes	TK-9	$153,070
Revenue Taxes	TK-15	($35,450)
		$117,620

Payroll Taxes: As discussed above, Schedule TK-9 calculates the projected increase in FICA payroll taxes based on anticipated employee payroll changes and employee annualization.

Revenue Taxes: Schedule TK-15 reflects the Public Utility Assessment ("PUA") tax adjustment related to certain pro forma revenue adjustments. The PUA is the sum of the BPU and RC assessment factors. The amount of Taxes Other Than Income Taxes on Schedule TK-3 is for PUA taxes related to the annualization and normalization revenue adjustment, which is calculated by applying the PUA percentage factor shown on Schedule TK-6 to the operating revenue adjustment.

Q. PLEASE EXPLAIN THE FEDERAL AND STATE INCOME TAX ADJUSTMENTS REFLECTED ON SCHEDULE TK-3.

A. The *pro forma* adjustment to Federal and State Income Tax expense on Schedule TK-3, line 10, includes an interest synchronization adjustment as well as the income tax effect on all *pro forma* adjustments identified previously and reflected on Schedule TK-4. The interest synchronization adjustment is calculated on Schedule JLH-8 and discussed in further detail by Company witness Mr. Houseman. In addition, in a similar manner, the taxes for the annualization and normalization adjustment are computed on Schedule TK-3 by applying the Combined Net Tax Rate from Schedule TK-6 to the annualization and normalization adjustments to Net Operating Income excluding Federal and State Income

Tax expense and Excess Deferred Tax Amortization. Similarly, taxes are calculated on the Revenue Deficiency and adjusted accordingly.

Q. PLEASE EXPLAIN THE EXCESS DEFERRED TAX AMORTIZATION ADJUSTMENTS REFLECTED ON SCHEDULE TK-3.

A. The Excess Deferred Tax Amortization shown on Schedule TK-3, line 11, reflects the Company's refund of excess deferred taxes resulting from the 2017 Tax Cuts and Jobs Act. The excess deferred tax balance and related amortizations are discussed in further detail by Company witness Mr. Alan Felsenthal (Exhibit P-10).

Q. PLEASE EXPLAIN THE RATEMAKING ADJUSTMENT FOR INTEREST ON CUSTOMER DEPOSITS.

A. The adjustment for interest on customer deposits is shown on Schedule TK-3, line 16 and detailed on Schedule TK-16. Interest expense, in accordance with Generally Accepted Accounting Principles, is booked below the line, but interest on customer deposits has been moved above the line for ratemaking purposes. This adjustment is appropriate when customer deposits are used to reduce rate base as a customer supplied source of capital, as we have done in this case. The projected test year interest to be paid to customers is based on the monthly interest rates shown on Schedule TK-16. The calculation of these rates is described in the current Board regulations *N.J.A.C.* 14:3-3.5(d). The post-test year interest expense shown on Schedule TK-3 is based on applying the interest rate issued by the BPU on October 18, 2021 and effective January 1, 2022 to the projected post-test year customer deposit balance on Schedule TK-16. This amount, when compared to the March 31, 2022 test year interest expense on Schedule TK-3, results in the *pro forma* post-test year adjustment shown on Schedule TK-3.

VI. RATE BASE

Q. PLEASE OUTLINE AND EXPLAIN THE RATE BASE ADJUSTMENTS THE COMPANY IS PROPOSING TO MAKE IN THIS FILING.

A. Schedule TK-2 summarizes the *pro forma* rate base adjustments supported by all witnesses in this case and provides a reference to the schedules sponsored by each witness.

Utility Plant In-Service: The balance for UPIS was calculated starting with the actual balance as of September 30, 2021. Those amounts include approved actual IIP investments through June 30, 2021, but were adjusted to remove year three IIP in-service amounts from July 2021 through September 2021. This adjustment is required to remove IIP amounts from UPIS that have not yet been filed for and approved by the Board, and a similar updated adjustment from July 2021 forward will also be made in the Company's 9+3 and 12+0 filing updates. As shown on Schedules MPS-2 and MPS-3 to Company witness Michael P. Scacifero's testimony there are no forecasted IIP amounts in this filing. Forecasted plant additions (other than those recovered through the IIP) for the period October 2021 through March 2022 were added and estimates for plant retirements for the same time period were deducted to develop the estimated test year ending balance as of March 31, 2022. The Company also included forecasted plant additions, reduced for plant retirements, for the six-month post-test year period ending September 30, 2022. The forecasted plant additions are discussed in further detail by Company witness Mr. Scacifero (Exhibit P-4).

Accumulated Depreciation & Amortization: The balance for accumulated depreciation and amortization was calculated using the actual balance as of September 30, 2021, adjusted for an acquisition adjustment discussed more fully by Company witness Mr. Houseman. The balance was further adjusted by adding estimated depreciation expense and subtracting estimated plant retirements and cost of removal for the period October 2021 through March 2022 to develop the estimated test year ending balance as of March 31, 2022. The Company also included a post-test year period adjustment to reflect estimated depreciation expense, less projected plant retirements and cost of removal related to the post-test year capital expenditures included in UPIS for the period April 2022 through September 2022. The *pro forma* post-test year accumulated depreciation adjustment is calculated on Schedule JLH-5 and discussed in further detail by Company witness Mr. Houseman.

Pension and Other Post-Employment Benefits ("OPEB"): The balance reflected on TK-2, line 4, reflects the accrued pension and OPEB balances, as well as the unamortized pension and OPEB regulatory asset acquired from the Southern Company. This regulatory asset was established in Elizabethtown's 2016 rate case in Docket No. GR16090826 and reaffirmed by the Board's Order dated November 13, 2019 in the Company's last rate case in Docket No. GR19040486. The pension and OPEB adjustment is calculated on Schedule JLH-9 and discussed in further detail by Company witness Mr. Houseman.

Cash Working Capital: The test year and post-test year cash working capital balances are calculated on Schedules TK-17.1 and TK-17.2, respectively, based on the lead-lag study days sponsored by Company witness Mr. Timothy Lyons (Exhibit P-8) applied to the test year and post year amounts on these schedules.

Inventory Working Capital: The test year and post-test year cash working capital balances are calculated on Schedule TK-18 utilizing 13-month averages. Utilizing a 13-month average for inventories allows the Company to include a full year of activity and appropriately reflect seasonal fluctuations in the account balance.

<u>Customer Deposits and Customer Advances</u>: Customer Deposits set forth on Schedule TK-16 and summarized on lines 11-13 reflect the Company's projected 13-month average customer deposits for test year and post-test year periods. Projected customer deposits are the product of the average deposit per customer and the number of customers with deposits. Customer Advances is a 13-month average of actual balance sheet amounts.

<u>Deferred Income Taxes:</u> The test year deferred income tax balances were estimated starting with the actual balances as of September 30, 2021 and then projecting changes to the components of the deferred income tax balances through March 31, 2022. Schedules JLH-6 and JLH-7, sponsored by Company witness Mr. Houseman, reflect the post-test year rate base adjustment to capture the increase in Federal and State deferred taxes for the period through September 31, 2022. The Company has also included the Excess Deferred Income Tax balance reflected on its books through September 30, 2022, as described by Company witness Mr. Felsenthal. Deferred income tax adjustments are discussed in further detail by Company witness Mr. Houseman.

<u>Consolidated Tax Adjustment ("CTA"):</u> The Company's proposed statement of rate base reflects a CTA of $0 as described in further detail in the Direct Testimony of Mr. Felsenthal (Exhibit P-10).

VII. <u>JUNE 22, 2018 ORDER REQUIREMENTS</u>

Q. PLEASE DESCRIBE THE ACQUISITION TRANSACTION THAT OCCURRED IN 2018.

A. In July 2018, SJI, through its affiliate, acquired substantially all of the assets of Pivotal Utility Holdings, Inc. d/b/a Elizabethtown Gas. That transaction (the "Acquisition") was approved in the Board's June 22, 2018 Order in BPU Docket No. GM17121309 ("June 22 Order").

Q. DID THE JUNE 22 ORDER IMPOSE ANY CONDITIONS ON THE COMPANY'S FILING THAT YOU WILL BE ADDRESSING?

A. Yes. I will address the following conditions that were imposed by the June 22 Order:

i. Any net savings realized by Elizabethtown through the Acquisition integration process will be flowed through to the Company's customers through the normal base rate case process;

ii. In future rate proceedings, to ensure that Elizabethtown's customers will only pay costs to achieve to the extent that there are offsetting synergy savings, Elizabethtown will net the total costs to achieve synergy savings against the resulting total synergy savings and may recover those costs to achieve only up to the amount of the synergy savings generated;

iii. Elizabethtown will not seek recovery in rates of (a) any acquisition premium associated with the Acquisition or any previous acquisition, (b) any costs associated with goodwill arising from the Acquisition or any previous acquisition, or (c) any Transaction Costs incurred in connection with the Acquisition. Transaction Costs are defined as (i) consultant, investment banker, legal and regulatory support fees (internal as well as external), and printing and similar expenses, (ii) change in control payments or (iii) any severance or retention costs. Transaction Costs also include SJI flotation expense (such as Underwriters fees) associated with common stock issuances undertaken to finance the Acquisition;

iv. For a period of five (5) years following the Acquisition, the amount of costs assessed to Elizabethtown for services provided by an affiliate shall be no greater than they would have been had the Acquisition not occurred, regardless of whether such services are provided directly or indirectly by SJI, SJIU, or any other SJI affiliate.

Certain additional commitments are discussed in the Direct Testimony of Company witness Paul Moul (Exhibit P-7).

Q. IS ELIZABETHTOWN SEEKING TO RECOVER ANY ACQUISITION PREMIUM OR TRANSACTION COSTS IN THIS PROCEEDING?

A. No. In addition, as discussed in the Direct Testimony of Mr. Moul, Elizabethtown is not seeking to recover any costs associated with goodwill arising from the Acquisition.

Q. PLEASE DESCRIBE THE REQUIREMENT RELATED TO AFFILIATE COSTS ORDERED BY THE BOARD IN THE JUNE 22 ORDER.

A. Pursuant to the Stipulation approved by the June 22 Order, for a period five (5) years following the Acquisition, the amount of costs assessed to Elizabethtown for services provided by an affiliate shall be no greater than they would have been had the Acquisition not occurred.

Q. IS THE COMPANY IN COMPLIANCE WITH THIS COMMITMENT?

A. Yes. Under the June 22 Order an annual level of allocated costs of $19.7 million was established as the baseline for the Company's commitment. The affiliate costs reflected in Elizabethtown's proposed cost of service total $19.3 million for twelve months ending December 31, 2020. These amounts are set forth on Schedule JLH-4 to Mr. Houseman's testimony.

Q. IS ELIZABETHTOWN REQUESTING TO RECOVER ANY COSTS TO ACHIEVE SYNERGY SAVINGS IN ITS PROPOSED RATES?

A. No. Moreover, the Company has not identified any net savings realized by Elizabethtown as a result of the Acquisition integration process. The Company's proposed revenue requirement reasonably reflects the Company's cost of providing safe and adequate utility service at this time.

Q. PLEASE SUMMARIZE THE PRIMARY REASONS FOR ELIZABETHTOWN'S ANNUAL REVENUE DEFICIENCY.

A. Since the Company's last base rate case, excluding IIP spending, Elizabethtown has invested approximately $214.8 million of plant additions net of retirements that are not currently reflected in rates, and projects that an additional $175.2 million of capital investment net of retirements, excluding IIP, will be added to the UPIS balance by September 30, 2022, to ensure that our customers continue to receive safe and reliable natural gas service. Primary drivers for rate relief in this proceeding are the value of Elizabethtown's investments in infrastructure and the Company's need to earn a reasonable return on those investments based upon the current cost of capital. Additionally an increase in depreciation expense associated with a change in depreciation rates as recommended by Company witness Mr. Watson contributes to the incremental revenues requested herein. The Company's proposals in this case are just and reasonable and should be adopted by the Board. Doing so will send a proper signal to the financial community regarding New Jersey's regulatory environment and the financial health and stability of the Company. While the Company recognizes that its proposed revenue requirement increase is significant, the 100 therm residential bill that Elizabethtown is proposing in this case is lower than the equivalent bills that were charged to customers during calendar years 2006 through 2009 – a period in which commodity gas costs were much higher than they are today.

VIII. REVENUE FORECAST

Q. FOR WHAT PERIODS ARE ELIZABETHTOWN'S TEST YEAR AND POST-TEST YEAR FIRM DEMAND FORECAST?

A. Elizabethtown's forecast determinants reflect annualized and normalized firm demand for a test year ending March 31, 2022 and a post-test year period ending nine months later, on December 31, 2022, as shown on Schedule TK-19.

Q. PLEASE EXPLAIN HOW ELIZABETHTOWN DEVELOPED THE DEMAND FORECAST ON SCHEDULE TK-19.

A. The demand forecast is prepared on a class-by-class basis using different methods that are explained later in my testimony. The forecast amounts shown on Schedule TK-19 are based on post-test year projections of customers utilizing gas service inclusive of new customer growth projections through December 31, 2022. The forecasted customers and therms shown on Schedule TK-20 reflect a normalized level of monthly billing therms. This therm forecast is further adjusted to annualize the therm usage and revenues to the customer count at December 31, 2022 in accordance with the post-test year monthly normalized uses per customer class. The post-test year forecast results, inclusive of the annualization, are set forth on Schedule TK-19 and are the basis on which the proposed rates are developed in order to achieve the requested revenue increase.

Q. PLEASE EXPLAIN WHAT YOU MEAN BY "ANNUALIZED."

A. Annualizing is taking a set of conditions at a specific point in time and applying them for an entire period. The Company annualizes based upon two sets of conditions as specified at given points in time: (i) the number of customers and (ii) the forecasted normalized use per customer by class. The Company applies these two points to the difference in the customer counts from those on December 31, 2022, the end of the post-test year, and then uses the post-test year monthly therm usages per customer in computing the annualized therms attributable to that month's change in the customer count from those on December 31, 2022. Schedule TK-20 presents actuals and projections of the number of customers and therms billed for the test year and post-test year periods from April 2021 to December 2022. The post-test year reflects normalized and annualized therms on TK-19. In annualizing the number of customers, the Company accounts for the fact that even if the number of connected customers does not change, the monthly number of billed customers will vary over an annual period for reasons such as customers moving in and out of premises, accounts being turned on and off for payment of back bills and for non-payment, and for customers whose service is turned off and on seasonally. These normal monthly fluctuations are a real ongoing occurrence that affects the Company's revenue stream. Consequently, the Company annualizes the forecast to properly reflect the number of customers that the Company would expect to bill each month during these annual periods.

Q. PLEASE EXPLAIN HOW THE TEST YEAR AND POST-TEST YEAR CUSTOMER CONSUMPTION ARE NORMALIZED.

A. Normalization is a process that adjusts occurrences to reflect a normal or commonly expected set of conditions. In the context of the Company's demand forecast, the Company normalizes for those conditions that influence gas consumption and thus, revenues. Many conditions may affect customer consumption to some degree, and they can vary by class of customers. However, the primary factors that affect the total demands of residential and commercial customers are the number of customers and weather. Annualizing the number of customers effectively normalizes the customer count upon which rates will be established. Therefore, the remaining adjustment for normalization of residential and commercial customers is to utilize an average or normal weather pattern during the test year and post-test year periods.

In the case of large industrial accounts, which are not as weather sensitive as other categories of customers, consumption is normalized individually by adjusting for factors that may influence gas consumption. This was accomplished on an individual customer basis through a review of historical consumption for each account in consultation with the Company's Marketing representatives.

For temperature sensitive classes of customers, such as the residential and commercial classes, weather normalization is accomplished by applying a normal weather pattern to consumption equations derived for each class, as described more fully later in my testimony.

Q. WHY DO YOU ADJUST THE POST-TEST YEAR DEMAND AND REVENUES OUT TO DECEMBER 31, 2022?

A. Demand and revenue are calculated as of December 31, 2022 to match the outside date for which certain expenses are included in the Company's filing. If revenues were employed from a period ending prior to this date, then the base rates established for the Company would reflect certain costs but not offsetting revenues. Conversely, if revenues were employed from a point after this date, then the base rates established would not reflect costs that match revenues. Neither result provides a proper matching.

Q. PLEASE DISCUSS THE COMPANY'S APPROACH TO FORECASTING DEMAND AND REVENUE FOR THE TEST YEAR AND POST-TEST YEAR PERIODS.

A. The Company forecasts throughput and revenues for the various service classifications in its tariff. Because of the differences in customer classes, different approaches are used to forecast demand and revenues for (i) the Residential Delivery Service ("RDS"); (ii) sales and transportation customers served under the Small General Service ("SGS") and General Delivery Service ("GDS") service classes; and (iii) all other customers.

Q. PLEASE EXPLAIN THE APPROACH USED TO FORECAST DEMAND AND REVENUE.

A. The RDS, SGS and GDS customer classes were forecasted using a two stage weather normalization-econometric forecast model approach along with the selected Moody's independent variable that drove each forecast.

These rate classes are responsible for approximately 75 percent (based on actual 2020 booked therms) of total Company sales by class. The methodology employed consisted of the following four (4) steps:

1. Weather normalization of class-by-class monthly actual data for six years of gas use–per-customer for the period 2015-2020 using a set of non-linear multiple regression models that were estimated on a class-specific basis. These models relate monthly sales-by-class to billing cycle-adjusted, monthly average temperature data to arrive at the appropriate weather

corrections over the range of temperatures over the heating season. The Company applied a twenty-year (temperature data from January 1, 2001 through December 31, 2020) normal Newark Airport weather pattern, as set forth in Schedule TK-22, in the use-per-customer models.

This enhanced, class-specific, billing cycle-weighted weather normalization methodology has the effect of producing more accurate weather normalization adjustments to actual class use-per-customer and sales, particularly in the transitional months (e.g., April, May, October and November).

2. For customer classes that were forecasted using econometric models, the Company's forecast consultant developed class-by-class use per customer forecasts using dynamic multiple regression models that employed specific economic driver variables that demonstrated both significant economic and statistical relevance. Moody's Analytics provided both the historical databases and 2021 vintage forecasts of all variables tested.

3. For the class-by-class customer count forecasts, Company personnel (Gas Supply) provided customers-by-class forecasts based upon historical customer count information and their overall knowledge of the Company's service territory.

4. Finally, the class-by-class, use-per-customer forecasts were combined with the corresponding customer count forecasts to yield an overall volumetric forecast for the service territory for the test year and beyond.

In the preparation of these forecasts, the Company and its consultants used the most recent 72 month historical databases in order to capture the most recent effects of more efficient gas-consuming appliances, smart thermostats and Heating, Ventilation and Air Conditioning equipment that have affected use per customer for each class and also the most recent impacts of conservation efforts and programs. The contiguous April 2020 thru March 2021 timeframe contained the most relevant use-per-customer and customer growth/decline information, by class, from the beginning of the effects of COVID-19 pandemic through the beginning of the economic recovery from the pandemic during the winter of 2020-2021. Just as important, the Moody's-developed economic driver forecasts contained actual observed driver performance during the economic downturn at the start of the pandemic thru the period that began to show economic recovery.

For all other classes of customers, the Company begins by projecting the class's demand on a customer-by-customer basis. This process takes into account historical consumption for the individual customer and makes appropriate adjustments based upon the Company's marketing representatives' knowledge of the customer and its operations. Then, by applying the customer's projected demand along with other billing determinants including, but not limited to, the customer's contract demand quantities to the existing rate structure, forecast revenues for each customer are generated.

Q. HOW WERE THE REVENUES IN THE PROOF OF REVENUES FOR THE POST-TEST YEAR PERIOD DEVELOPED?

A. The Company developed the revenues for the post-test year proof of revenue, by applying the forecast of normalized and annualized consumption per the projected annualized number of customers, described above, to the existing rate structure and rates from the

Company's tariff. These revenues (margins) are those for the post-test year ended December 31, 2022 on TK-3, Line 4.

Q. DOES THE COMPANY PLAN TO MAKE UPDATES TO WEATHER NORMALIZATION CLAUSE ("WNC")?

A. Yes. Although the CIP Rider G supersedes the WNC, the CIP requires that the WNC be updated in order to estimate the weather related portion of the CIP. In order to estimate the weather impact, the Company has updated the Normal Degree Days, Base Number of Customers and Therms per Degree Day as well as the Margin Revenue Factor. The updated Normal Degree Days are set forth on Schedule TK-22.

IX. TARIFF CHANGES

Q. WHAT TARIFF CHANGES ARE BEING PROPOSED BY THE COMPANY IN THIS FILING?

A. The Company is proposing to make a limited number of changes to its tariff, which are reflected in the clean and redlined versions of the tariff in Schedules TK-24 and TK-25. Some of these proposed changes are as follows:

(i) roll-in the revenues associated with IIP Rider F per actual amounts through June 30, 2021, and reset the Rider F rates to remove these amounts;

(ii) a separation of residential CIP Base Use per Customer ("BUC") in Rider G to heating and non-heating averages; and

(iii) consolidation of summary sheets at the end of the tariff by listing multiple class information on each sheet.

Q. WHAT ARE THE PROPOSED CHANGES TO THE CIP TARIFF IN THIS CASE?

A. In addition to updating the BUC for the annualized and normalized customer usages shown on Schedule TK-21, the Company is proposing to break down the RDS BUC to heating and non-heating to more closely reflect the usages for measuring energy efficiency reductions within the RDS class than the current average BUC does. These BUC factors are based on the same data used to derive the billing determinants shown on Schedule TK-19, which are those used to derive the proposed rates in the proof of revenues sponsored by Company witness Mr. Yardley in Exhibit P-11. In addition, the earnings test percentage language will be revised to reflect that approved in this case by modifying the tariff language from "in excess of 9.6% for any twelve-month period ending June 30" to "in excess of a return on equity percentage, authorized by the Board in the Company's most recent base rate case, for any twelve-month period ending June 30."

X. BILL COMPARISONS

Q. HAVE YOU PREPARED A BILL COMPARISON FOR THE PRESENT AND PROPOSED RESIDENTIAL AND COMMERCIAL SERVICE CLASSES RATES?

A. Yes. Schedule TK-23 sets forth bill comparisons for the RDS, SGS and GDS service classifications for sales service. These classes comprise the majority of our customers.

Q. WHAT IS THE BILL IMPACT OF THE PROPOSED RATE CHANGES FOR A RESIDENTIAL CUSTOMER USING 100 THERMS.

A. The proposed rates for a residential customer using 100 therms would result in a bill increase of $19.42 or 17.2%.

Q. DOES THIS CONCLUDE YOUR PREPARED DIRECT TESTIMONY?

A. Yes, it does.

Schedule TK-1
6+6

ELIZABETHTOWN GAS COMPANY
REVENUE REQUIREMENT

Line			REFERENCE
1	Adjusted Rate Base	$1,392,067,037	TK-2
2	Rate of Return	7.63%	
3	Required Operating Income	106,214,715	
4	Adjusted Net Operating Income	51,648,105	TK-3
5	Income Deficiency	54,566,610	
6	Revenue Factor	1.404126	TK-6
7	Operating Revenue Adjustment to Base Rates	$76,618,396	

ELIZABETHTOWN GAS COMPANY
STATEMENT OF RATE BASE

Line No.		G/L Accounts	6 MONTHS ACTUAL BALANCES AS OF Sep-2021	TEST YEAR ADJUSTMENT	12 MONTH RATE BASE 3/31/2022	POST TEST YEAR ADJUSTMENT	ADJUSTED RATE BASE 9/30/2022	REFERENCE TO RATEMAKING ADJUSTMENTS
1	Utility Plant In Service	10100, 10110	$1,831,715,277	$27,903,262	$1,859,618,539	$131,341,559	$1,990,960,098	MPS-1
2	Accumulated Depreciation & Amortization	10800, 10810, 10820, 10830, 10850, 29110, Acq Adj.	($459,742,521)	($6,288,747)	($466,031,268)	($13,003,820)	($479,035,088)	JLH-5
3	Net Utility Plant		$1,371,972,756	$21,614,515	$1,393,587,271	$118,337,739	$1,511,925,010	
4	Pension/OPEB	Reg Asset: 16120 Accrued: 27510, 27500	$35,573,617	($99,822)	$35,473,795	($99,822)	$35,373,973	JLH-9
5	Cash Working Capital		$0	$18,267,997	$18,267,997	$13,691,288	$31,959,285	TK-17
6	Inventory Average Balances	14600, 14610	$0	$13,648,372	$13,648,372	$3,751,910	$17,400,282	TK-18
7	Customer Deposits (1)	22000	($4,420,559)	($38,630)	($4,459,189)	($17,849)	($4,477,038)	TK-16
8	Customer Advances (1)	29430	($1,781,688)	$0	($1,781,688)	$0	($1,781,688)	
9	Deferred Income Taxes:							
10	Excess Protected ADIT	28110 Reg Liability	($78,798,907)	$440,856	($78,358,051)	$452,692	($77,905,359)	ADF-3
11	Federal Income Tax	27000	($60,926,061)	($12,719,135)	($73,645,196)	($8,224,891)	($81,870,087)	JLH-6
12	NJ CBT	27000	($28,693,592)	($5,990,174)	($34,683,766)	($3,873,575)	($38,557,341)	JLH-7
13	Consolidated Tax Adjustment		$0	$0	$0	$0	$0	ADF-2
14	Total Rate Base		$1,232,925,566	$35,123,979	$1,268,049,545	$124,017,492	$1,392,067,037	

(1) Represents Thirteen Month Averages of Account Balances

ELIZABETHTOWN GAS COMPANY
OPERATING INCOME STATEMENT

Line No.		6 MONTHS ACTUAL Sep-2021	6 MONTHS PROJECTED DATA	TEST YEAR 12 MOS ENDED 3/31/2022	TEST & POST TEST YR. PRO FORMA ADJUSTMENTS	ANNUALIZATION & NORMALIZATION ADJUSTMENTS	POST TEST YEAR ENDED 12/31/2022	REVENUE DEFICIENCY	POST TEST YEAR 12 MOS ENDED 12/31/2022
1	**Operating Revenues**	$90,553,028	$276,489,185	$367,042,213	($33,375,184)	$72,595,627	$406,262,656	$76,618,396	$482,881,052
2	**Cost of Sales-Rider Revenue Offsets**	$6,621,023	$12,400,782	$19,021,805	($19,021,805)	$0	$0	$0	$0
3	**Cost of Sales Purchased Gas**	$23,406,957	$106,533,930	$129,940,887	$0	$50,177,004	$180,117,891	$0	$180,117,891
4	**Operating Margin Revenues**	$60,525,048	$157,554,473	$218,079,521	($14,353,379)	$22,418,623	$226,144,765	$76,618,396	$302,763,161
6	**Operating Expenses:**								
7	**Operation & Maintenance Exps.**	$38,229,030	$43,908,436	$82,137,466	$4,271,937	$482,616	$86,892,019	$509,359	$87,401,378
8	**Depreciation Expense**	$22,398,943	$24,526,956	$46,925,899	$13,906,104	$0	$60,832,003	$0	$60,832,003
9	**Taxes Other Than Income Taxes**	$2,355,356	$2,474,510	$4,829,866	$117,620	$195,210	$5,142,696	$206,027	$5,348,723
10	**Federal Income Taxes & NJ CBT**	($691,022)	$24,341,451	$23,650,429	($5,906,634)	$6,111,338	$23,855,133	$21,336,336	$45,191,469
11	**Excess Deferred Tax Amortization**	($795,780)	($807,618)	($1,603,398)	($624,496)	$0	($2,227,894)	$0	($2,227,894)
12	**Total Operating Expenses**	$61,496,527	$94,443,735	$155,940,262	$11,764,531	$6,789,164	$174,493,957	$22,051,722	$196,545,679
14	**Net Operating Income**	($971,479)	$63,110,738	$62,139,259	($26,117,910)	$15,629,459	$51,650,808	$54,566,674	$106,217,482
15	**Ratemaking Adjustment:**								
16	**Interest on Customer Deposits**	$15,544	$9,098	$24,642	($21,939)	$0	$2,703	$0	$2,703
17	**Adjusted Net Operating Income**	($987,023)	$63,101,640	$62,114,617	($26,095,971)	$15,629,459	$51,648,105	$54,566,674	$106,214,779
18	**Total Rate Base**			$1,268,049,545			$1,392,067,037		$1,392,067,037
19	**Return on Rate Base**			4.8984%			3.7102%		7.6300%
20	**Adjusted Net Income**			$40,177,360			$27,565,345		$82,132,019
21	**Return on Equity**			5.77%			3.61%		10.75%

ELIZABETHTOWN GAS COMPANY
PRO FORMA ADJUSTMENTS TO MARCH 31, 2022 OPERATING INCOME

		Test & Post Test Year Pro Forma Adjustments
1. Operating Revenues		
(a) Remove Rider Revenues (TK-7)	$	(33,375,184)
		(33,375,184)
2. Cost of Sales-Rider Revenue Offsets		
(a) Cost of Sales-Rider Revenue Offsets (TK-7)	$	(19,021,805)
		(19,021,805)
3. Operation and Maintenance expenses		
(a) Annualization of Payroll (TK-9)	$	1,700,773
(b) Annualization of Benefits (TK-10)	$	172,974
(c) Annualization of Allocated Service Company Salaries & Benefits (TK-11)	$	1,309,307
(d) Amortization of Rate Case expenses (TK-12)	$	470,488
(e) Other Operations and Maintenance Expenses (TK-13)	$	(31,322)
(f) Inflation Adjustment (TK-14)	$	1,121,960
(g) Remove Charitable & Civic Contribution Expense	$	(472,243)
		4,271,937
4. Depreciation and Amortization Expense (TK-5)		
(a) Annualize Test Year Depreciation Expense (JLH-5)	$	9,841,191
(b) Annualize Post Test Year Depreciation Expense (JLH-5)	$	4,064,913
		13,906,104
5. Taxes Other Than Income		
(a) FICA Payroll Tax Adjustment (TK-9)	$	153,070
(b) Adjustment for PUA (TK-15)	$	(35,450)
		117,620
6. Interest (TK-16)		
(a) Adjust Interest on Customer Deposits	$	(21,939)
		(21,939)
7. Excess Deferred Tax Amortization		
(a) Excess Deferred Tax Amortization	$	(624,496)
		(624,496)
8. Taxes - Income - Current		
(a) Interest Synchronization (JLH-8)	$	3,264,844
(b) Income Tax effect of adjustments 1 - 6 times tax rate	$	(9,171,478)
		(5,906,634)

Schedule TK-5
6+6

ELIZABETHTOWN GAS COMPANY
PRO FORMA ADJUSTMENTS TO MARCH 31, 2022 OPERATING INCOME
POST TEST YEAR REVENUE & COST OF GAS ADJUSTMENTS
ANNUALIZATION & NORMALIZATION ADJUSTMENTS

Line No.		Test Year	TK-7 Rider Adjustments	Annualization & Normalization Adjustments	Net of Adjustments	
1	Income Statement					
2	Operating Revenues	$367,042,213	($33,375,184)	$72,595,627	$406,262,656	
3	Cost of Sales-Rider Revenue Offsets	$19,021,805	($19,021,805)			
4	Cost of Sales Purchased Gas	$129,940,887		$50,177,004	$180,117,891	
5	**Operating Margin Revenues**	$218,079,521	($14,353,379)	$22,418,623	$226,144,765	
6		-	-	-	-	
7					Present	
8				Margin Details	Proof Revenues	
9	Test Year per Annulaized and Normalized Determinants at Current Rates plus IIP Roll-In:					
10	Total System Base Distribution Revenue including Other Revenues				$212,250,282	DPY-2 at Current Rates
11	IIP Revenue Requirement from Rider F to Base Rates				$13,894,483	TK-8 IIP
12					$226,144,765	DPY-3 Total
13	Net of Operating Margin Revenue Adjustments:					
14	On-System Margin Sharing Credit (“OSMC”) Revenue		($199,444)			
15	Removal of IIP Rider F Booked Revenues (TK-7)		($13,183,294)			
16	Net EEP Actual / Projected Allowed Revenue Requirement		($970,641)			
17			($14,353,379)			
18	IIP Approved Revenue Requirement from Rider F to Base Rates (TK-8)		-	$13,894,483		
19	Annualization Normalization			$8,524,140		
20	Gas Sales Revenue, Increase / (Decrease)			$50,177,004		
21	Operating Revenues			$72,595,627		
22	Purchase Gas Cost, Increase / (Decrease)			$50,177,004		
23				$22,418,623		

Schedule TK-6
6+6

ELIZABETHTOWN GAS COMPANY
DERIVATION OF REVENUE EXPANSION FACTOR

Line No.			
1	Additional Required Revenue Percentage		100.0000%
2	Percentage Adjustment for Uncollectibles		0.6648%
3	BPU Assessments		0.2154%
4	Rate Counsel Assessments		0.0535%
5	Percentage of Income Before State Income Tax		99.0663%
6	State Income Tax Percentage	9.00%	8.9160%
7	Percentage of Income Before Federal Income Tax		90.1503%
8	Federal Income Tax Percentage	21.00%	18.9316%
9	Revenue Expansion Factor - Percent		71.2187%
10	Revenue Expansion Factor - Whole Number		**1.404126**

Schedule TK-7
6+6

ELIZABETHTOWN GAS COMPANY
PRO FORMA ADJUSTMENTS TO MARCH 31, 2022 OPERATING INCOME
RIDER ADJUSTMENTS

Line No.		TOTAL
1	On-System Margin Sharing Credit ("OSMC") Revenue	$199,444
2	Energy Efficiency Program ("EEP") Revenue	$3,212,410
3	Remediation Adjustment Clause ("RAC") Revenue	$3,215,644
4	Clean Energy Program ("CEP") Revenue	$13,564,392
5	Infrastructure Investment Program ("IIP") Billed Revenue, moving from Rider to Base Rates	$13,183,294
6	**Total Revenue**	**$33,375,184**
7	EEP Rider Amortization	$2,241,769
8	RAC Rider Revenue Offset	$3,215,644
9	CEP Rider Revenue Offset	$13,564,392
10	**Cost of Sales Revenue Offsets**	**$19,021,805**
11	Net Margin Adjustment	**$14,353,379**

Schedule TK-8
6+6

ELIZABETHTOWN GAS COMPANY
INFRASTRUCTURE INVESTMENT PROGRAM ("IIP")

SUMMARY OF APPROVED AND PROPOSED REVENUE REQUIREMENTS
FROM RIDER "F" TO BASE RATES

	Filing Date		12 Months Ending	In-Service Capital *	Revenue Requirement **
Approved	07/15/20	Docket No. GR20050327, Dated: 9-30-20, Effective on: 10-1-20	06/30/20	$63,310,031	$6,830,571
Approved	07/15/21	Docket No. GR21040747, Dated: 9-14-21, Effective on: 10-1-21	06/30/21	$64,004,144	$7,063,912
IIP Revenue Requirement from Rider F to Base Rates				**$127,314,175**	**$13,894,483**

* In-Service Capital consists of Mains and Services, capped at a $1.2 M mile, Monitor, Methane Leak Survey in year 1 and applicable AFUDC amounts.

** When base rates inclusive of the previously approved Revenue Requirements become effective, this amount will be removed from the computation in resetting the Rider F IIP rates, which may be zero if this case settles before year 3 IIP rates go into effect.

Schedule TK-9
6+6

ELIZABETHTOWN GAS COMPANY
PRO FORMA ADJUSTMENTS TO MARCH 31, 2022 OPERATING INCOME
PAYROLL EXPENSE

Line No.		Test Year	Annualized Post Test Year *	Adjustment To Test Year
1	Payroll Expenses:			
2	Gross Expenses:			
3	Fixed Payroll	$38,035,374	$40,985,445	$2,950,071
4	Variable Compensation	$1,893,855	$1,893,855	$0
5	Total Compensation	$39,929,229	$42,879,300	$2,950,071
6	Capitalized Payroll Expenses			
7	Direct Payroll	($13,365,098)	($14,614,396)	($1,249,298)
8	Variable Compensation	($665,474)	($665,474)	$0
9	Capitalized Compensation	($14,030,572)	($15,279,870)	($1,249,298)
10	Net Compensation Expense	$25,898,657	$27,599,430	$1,700,773
11	Retention Bonus Adjustment	$0	$0	$0
12	**Pro Forma Payroll Adjustment (O&M)**	$25,898,657	$27,599,430	**$1,700,773**
13	State Income Tax Percentage			9.00%
14	**Pro Forma FICA Payroll Tax Adjustment - Sch. TK-3 Taxes Other than Income**			**$153,070**
15	**Lead Lag Test Year and Post Year:**			
16	Regular Payroll	**$24,670,276**	$26,371,049	**$1,700,773**
17	Variable Compensation	**$1,228,381**	$1,228,381	**$0**
18	Net Compensation Expense	$25,898,657	$27,599,430	$1,700,773

* Includes a 3% merit increase effective March 1, 2022.

Schedule TK-10
6+6

ELIZABETHTOWN GAS COMPANY
PRO FORMA ADJUSTMENTS TO MARCH 31, 2022 OPERATING INCOME
EMPLOYEE BENEFITS EXPENSE

Line No.		Test Year	Annualized Post Test Year	Adjustment To Test Year
	Employee Benefits Expenses:			
1	Employee Benefits Expense	$7,733,785	$8,058,960	$325,175
2	less: Capitalized Benefits	($3,619,875)	($3,772,076)	($152,201)
3	**Pro Forma Benefits Adjustment**	$4,113,910	$4,286,884	**$172,974**

Schedule TK-11
6+6

ELIZABETHTOWN GAS COMPANY
PRO FORMA ADJUSTMENTS TO MARCH 31, 2022 OPERATING INCOME
ALLOCATED SERVICE COMPANY SALARIES & BENEFITS EXPENSE

Line No.			
	Allocated Service Company Salaries & Benefits Expenses:		
1	Annualized Post Test Year Expenses	$4,610,427	
2	Less: Test Year Expenses	$3,301,120	
3	**Pro Forma Allocated Expense Adjustment**		**$1,309,307**

Schedule TK-12
6+6

ELIZABETHTOWN GAS COMPANY
PRO FORMA ADJUSTMENTS TO MARCH 31, 2022 OPERATING INCOME
RATE CASE EXPENSES

Line No.	Category		Expense
1	Legal Expenses		$950,000
2	Consultant Expenses		$210,000
3	Newspaper Notices		$835
4	Court Reporting		$630
5	Postage & Office Supplies		$0
6	Miscellaneous Expenses		$0
7	Contingency/Rebuttal Witnesses		$250,000
8	Total Rate Case Expenses		$1,411,465
9	**Pro Forma Adjustment per Amortization Period**	3	**$470,488**

Schedule TK-13
6+6

ELIZABETHTOWN GAS COMPANY
PRO FORMA ADJUSTMENTS TO MARCH 31, 2022 OPERATING INCOME
OTHER ANNUALIZED O&M EXPENSE

Line No.		Proposed In This Case	Adjustment to Test Year
1	**Bring Gas Supply Function In-House ***		
2	Salaries of 3 FTE's Annualized (in Sch TK-9)	$307,452	
3	Benefits Annualized (in Sch TK-10)	$62,532	
4	Licensing	$89,143	$89,143
5	Subscriptions, Platts	$6,534	$6,534
6	Travel	$6,429	$6,429
7	Other	$1,609	$1,609
8	Included in Proposed Expenses	$473,699	$103,715
9			
10	**Proposed Erie Street Regulatory Asset** **	Book Balance	
11	Retired Net Book Value	$6,751,219	
12	Amortization Years	37.2	$181,484
13			
14	**Solar Panel Electricity k/WH - Expense Adjustment *****		
15	Annual Electric Costs 12 Months		
16	Pre COVID Period LDC 12-31-19	$109,156	
17	Solar Annual	$59,366	($49,790)
18			
19	**Management Fee Expense, Adjustments per 12 Mos Dec 2020**		
20	Charitable Contributions	($184,883)	
21	Lobbying	($17,933)	
22	Meals & Entertainment	($15,067)	
23	Other	($48,848)	($266,731)
24			
25	**Total Pro Forma Adjustment - Other O&M Expense**		**($31,322)**

* See Testimony of J. Madden and L. Willey.
** See Testimony of J. Houseman.
*** See Testimony of C. McMullen.

Schedule TK-14
6+6

ELIZABETHTOWN GAS COMPANY
PRO FORMA ADJUSTMENTS TO MARCH 31, 2022 OPERATING INCOME
O&M INFLATION ADJUSTMENT

Line No.	Description	Index
1	Calculation of Inflation Rate	
2	GDPIPD Index Value at the Midpoint of the Test Year:	
3	September 1, 2021	119.5
4	October 1, 2021	119.9
5	Average	119.7
6	GDPIPD Index Value at the End of the Post-Test Year:	
7	December 1, 2022	122.9
8	January 1, 2023	122.9
9	Average (1/1/23=12/1/22, data N/A at time of filing)	122.9
10	Projected Inflation Rate	2.6734%
11	Calculation of O&M Inflation Adjustment	
12	Post-Test Year Total O&M Expenses	$86,892,019
13	Less: Normalizing Adjustments	
14	Annualization of Payroll (TK-9)	$27,599,430
15	Annualization of Benefits (TK-10)	$4,286,884
16	Annualization of Allocated Service Company Costs (TK-11)	$4,610,427
17	Amortization of Rate Case expenses (TK-12)	$470,488
18	Other Operations and Maintenance Expenses (TK-13)	($31,322)
19	Total Normalizing Adjustments	$36,935,907
20	Less: Items Not Subject to Inflation	
21	Pension / OBEP	$5,110,817
22	Uncollectibles	$2,877,768
23	Total Items Not Subject to Inflation	$7,988,585
24	Residual O&M Expenses	$41,967,527
25	Inflation Rate	2.6734%
26	Pro Forma Adjustment to O&M Expense	**$1,121,960**

Schedule TK-15
6+6

ELIZABETHTOWN GAS COMPANY
PRO FORMA ADJUSTMENTS TO MARCH 31, 2022 OPERATING INCOME
REVENUE TAXES - TAXES OTHER THAN INCOME

Line No.		
1	**PUA Adjustments**	
2	Removed IIP Rider Revenues (TK-7) *	($13,183,294)
3	Other	$0
4	Total Revenue Adjustment	($13,183,294)
5	PUA Tax Rate, sum of the BPU and RC Assessment Factors	0.2689%
6	**Pro Forma Adjustment to PUA**	**($35,450)**

* Removed PUA per its replacement with IIP amount on Schedule TK-8 with PUA applied on Schedule TK-3.

Schedule TK-16
6+6

ELIZABETHTOWN GAS COMPANY
PRO FORMA ADJUSTMENTS TO MARCH 31, 2022 OPERATING INCOME
CUSTOMER DEPOSITS

Line No.	Month	Actual and Projected Data	Number of Customers	Number of Customers with Deposits	Percentage of Customers with Deposits	Average Deposit Per Customer	Rate Base for Customer Deposits	Customer Deposit Rate	Monthly Interest	13 Month Avg. Rate Base for Customer Deposits
1	Sep-20	Actual	298,972	28,857	9.65%	$144	$4,165,541	2.33%	$7,752	
2	Oct-20	Actual	299,465	29,646	9.90%	$145	$4,286,271	2.33%	$8,253	
3	Nov-20	Actual	300,687	30,310	10.08%	$144	$4,350,311	2.33%	$8,281	
4	Dec-20	Actual	301,613	30,411	10.08%	$146	$4,437,685	2.33%	$8,578	
5	Jan-21	Actual	302,327	30,401	10.06%	$147	$4,464,489	0.75%	$2,457	
6	Feb-21	Actual	302,968	31,291	10.33%	$146	$4,557,562	0.75%	$2,799	
7	Mar-21	Actual	302,593	30,198	9.98%	$152	$4,575,909	0.75%	$2,369	
TY	Apr-21	Actual	302,007	29,680	9.83%	$145	$4,308,838	0.75%	$2,670	
2	May-21	Actual	302,349	29,723	9.83%	$146	$4,335,057	0.75%	$2,683	
3	Jun-21	Actual	302,478	30,108	9.95%	$146	$4,397,008	0.75%	$2,752	
4	Jul-21	Actual	302,358	30,474	10.08%	$147	$4,478,302	0.75%	$2,815	
5	Aug-21	Actual	302,287	30,628	10.13%	$148	$4,544,299	0.75%	$2,470	
6	Sep-21	Actual	302,028	30,491	10.10%	$150	$4,565,995	0.75%	$2,154	$4,420,559
7	Oct-21	Projected	294,842	29,779	10.10%	$150	$4,466,850	0.75%	$2,845	$4,443,737
8	Nov-21	Projected	294,677	29,762	10.10%	$150	$4,464,300	0.75%	$2,752	$4,457,431
9	Dec-21	Projected	294,447	29,739	10.10%	$150	$4,460,850	0.75%	$2,842	$4,465,934
10	Jan-22	Projected	294,186	29,713	10.10%	$150	$4,456,950	0.06%	$227	$4,467,416
11	Feb-22	Projected	294,160	29,710	10.10%	$150	$4,456,500	0.06%	$205	$4,466,802
12	Mar-22	Projected	294,295	29,724	10.10%	$150	$4,458,600	0.06%	$227	$4,459,189
PTY	Apr-22	Projected	293,373	29,631	10.10%	$150	$4,444,650	0.06%	$219	$4,449,092
2	May-22	Projected	294,115	29,706	10.10%	$150	$4,455,900	0.06%	$227	$4,460,405
3	Jun-22	Projected	295,232	29,818	10.10%	$150	$4,472,700	0.06%	$221	$4,470,993
4	Jul-22	Projected	296,394	29,936	10.10%	$150	$4,490,400	0.06%	$229	$4,478,177
5	Aug-22	Projected	297,056	30,003	10.10%	$150	$4,500,450	0.06%	$229	$4,479,880
6	Sep-22	Projected	297,516	30,049	10.10%	$150	$4,507,350	0.06%	$222	$4,477,038
7	Oct-22	Projected	297,881	30,086	10.10%	$150	$4,512,900	0.06%	$230	$4,472,954
8	Nov-22	Projected	297,783	30,076	10.10%	$150	$4,511,400	0.06%	$222	$4,476,381
9	Dec-22	Projected	297,351	30,032	10.10%	$150	$4,504,800	0.06%	$230	$4,479,496
	Post-Test Year Annualization of Interest									
10	Dec-22	Projected	297,351	30,032	10.10%	$150	$4,504,800	0.06%	$2,703	

Rate Base Test Year Adjustment

Line No.			*13 mo average*
11	Actual Ending	Sep-21	$4,420,559
12	TY ending	Mar-22	$4,459,189
13	Test Year Adjustment		$38,630

Rate Base PTY Pro-Forma Adjustment

		13 mo average
TY ending	Mar-22	$4,459,189
BS PTY Ending	Sep-22	$4,477,038
Pro-Forma PTY Adjustment		$17,849

Income Statement Interest Pro-Forma Adjustment

Actual	$15,544
Projected	$9,098
Test Year Interest	**$24,642**
Post Test Year Annualized Interest	**$2,703**
Pro-Forma Adjustment	**($21,939)**

Schedule TK-17.1
6+6

ELIZABETHTOWN GAS COMPANY
LEAD-LAG STUDY
WORKING CAPITAL REQUIREMENT
TEST YEAR

Line	Description		Test Year Expenses	Average Daily Expenses	Revenue Lag Days	Ref.	Expense Lead Days	Ref.	Net (Lead)/Lag Days	Working Capital Requirement
1	Gas Costs & Operations and Maintenance Expenses									
2	Purchased Gas Costs & Other Riders		$ 148,962,692	408,117	57.23	A	(40.24)	B	16.9900	$ 6,933,908
3	Regular Payroll		24,670,276	67,590	57.23	A	(9.77)	C	47.4600	3,207,821
4	Variable Compensation		1,228,381	3,365	57.23	A	(253.42)	C	(196.1900)	(660,179)
5	Pension/OPEB		5,110,817	14,002	57.23	A	-		57.2300	801,334
6	Retirement Savings Plan		985,309	2,699	57.23	A	(19.63)	C	37.6000	101,482
7	Group Insurance		3,984,236	10,916	57.23	A	(40.16)	C	17.0700	186,336
8	Uncollectible Expense		2,368,409	6,489	57.23	A	(990.73)	C	(933.5000)	(6,057,482)
9	Service Company Charges		22,873,964	62,668	57.23	A	(37.86)	C	19.3700	1,213,879
10	Other Third-Party O&M Expenses		20,916,074	57,304	57.23	A	(37.88)	C	19.3500	1,108,832
11	Total O&M Expenses		$ 231,100,158				.			$ 6,835,931
12	Income Taxes									
13	Excess Deferred Tax Amortization		$ (1,603,398)	(4,393)	57.23		-		57.2300	(251,411)
14	Federal Income Taxes	21%	16,078,255	44,050	57.23	A	(37.24)	D	19.9900	880,560
15	State Income Tax	9%	7,572,176	20,746	57.23	A	(37.24)	D	19.9900	414,713
16	Total Federal Income Taxes		$ 22,047,033							$ 1,043,862
17	Taxes Other Than Income Taxes		$ 4,829,866	13,233	57.23	A	(10.58)	E	46.6500	$ 617,319
18	Depreciation and Amortization Expense		$ 46,925,899	128,564	57.23	A	-		57.2300	$ 7,357,718
19	Interest Expense									
20	Interest on Long-Term Debt		$ 35,697,287	97,801	57.23	A	(90.00)	F	(32.7700)	$ (3,204,939)
21	Interest on Short-Term Debt		-	-	57.23	A	(3.94)	F	53.2900	-
22	Interest on Customer Deposits		24,642	68	57.23	A	(234.62)	F	(177.3900)	(12,063)
23	Total Interest Expense		$ 35,721,929							$ (3,217,002)
24	Return		$ 26,417,330	72,376	57.23	A	-		57.2300	$ 4,142,078
25	Other Adjustments									
26	Incidental collections									$ 1,985,982
27	Employee deductions									(497,891)
28	Total Other Adjustments		$ -	$ -						$ 1,488,091
29	Total		$ 367,042,215	$ 214,173						**$ 18,267,997**

Schedule TK-17.2
6+6

ELIZABETHTOWN GAS COMPANY
LEAD-LAG STUDY
WORKING CAPITAL REQUIREMENT
POST TEST YEAR

Line	Description		Adjustments to Test Year Expenses	Adjusted Test Year to Post Test Year Expenses	Average Daily Expenses	Revenue Lag Days	Ref.	Expense Lead Days	Ref.	Net (Lead)/Lag Days	Working Capital Requirement
1	Gas Costs & Operations and Maintenance Expenses										
2	Purchased Gas Costs & Riders		$50,177,004	$ 199,139,696	545,588	57.23	A	(40.24)	B	16.9900	$ 9,269,540
3	Regular Payroll		1,700,773	$ 26,371,049	72,249	57.23	A	(9.77)	C	47.4600	3,428,938
4	Variable Compensation		-	$ 1,228,381	3,365	57.23	A	(253.42)	C	(196.1900)	(660,179)
5	Pension/OPEB		0	$ 5,110,817	14,002	57.23	A	-		57.2300	801,334
6	Retirement Savings Plan		0	$ 985,309	2,699	57.23	A	(19.63)	C	37.6000	101,482
7	Group Insurance		172,974	$ 4,157,210	11,390	57.23	A	(40.16)	C	17.0700	194,427
8	Uncollectible Expense		509,359	$ 2,877,768	7,884	57.23	A	(990.73)	C	(933.5000)	(7,359,714)
9	Service Company Charges		1,309,307	$ 24,183,271	66,256	57.23	A	(37.86)	C	19.3700	1,283,379
10	Other Third-Party O&M Expenses		1,571,499	$ 22,487,573	61,610	57.23	A	(37.88)	C	19.3500	1,192,154
11	Total Gas and O&M Expenses		(19,021,805)	$ 286,541,074				.			$ 8,251,361
12	Income Taxes										
13	Excess Deferred Tax Amortization			$ (2,227,894)	(6,104)	57.23		-		57.2300	(349,332)
14	Federal Income Taxes	21.00%	review cells	20,270,701	55,536	57.23	A	(37.24)	D	19.9900	1,110,165
15	State Income Tax	9.00%		9,546,641	26,155	57.23	A	(37.24)	D	19.9900	522,838
16	Total Federal Income Taxes			$ 27,589,448							$ 1,283,671
17	Taxes Other Than Income Taxes			$ 5,348,723	14,654	57.23	A	(10.58)	E	46.6500	$ 683,609
18	Depreciation and Amortization Expense			$ 60,832,003	166,663	57.23	A	-		57.2300	$ 9,538,123
19	Interest Expense										
20	Interest on Long-Term Debt			$ 24,082,760	65,980	57.23	A	(90.00)	F	(32.7700)	$ (2,162,165)
21	Interest on Short-Term Debt			-	-	57.23	A	(3.94)	F	53.2900	-
22	Interest on Customer Deposits			2,703	7	57.23	A	(234.62)	F	(177.3900)	(1,242)
23	Total Interest Expense			$ 24,085,463							$ (2,163,407)
24	Return			$ 82,131,955	225,019	57.23	A	-		57.2300	$ 12,877,837
25	Other Adjustments										
26	Incidental collections										$ 1,985,982
27	Employee deductions										(497,891)
28	Total Other Adjustments			$ -	$ -						$ 1,488,091
29	Total			$ 486,528,666	$ 406,336						**$ 31,959,285**

Schedule TK-18
6+6

ELIZABETHTOWN GAS COMPANY
CASH WORKING CAPITAL
GAS INVENTORIES AND MATERIALS & SUPPLIES
TEST YEAR AND POST TEST YEAR 13 MONTH AVERAGES

Line		Test Year	Post Test Year
1	LNG & Gas Stored Underground	$12,450,002	$16,201,912
2	Materials and Supplies *	$1,198,370	$1,198,370
3	**Total**	**$13,648,372**	**$17,400,282**

* Based on 13 Mo. through: Sep-21

6+6 Schedule TK- 19

ELIZABETHTOWN GAS COMPANY
Revenue Proof Billing Determinants

		Number of Bills Test Year December 2022 *12	Daily Contract Quantity (DCQ) Monthly Therms	Annual Therms =Mo DCQ Thms*12	Therms Post Test Year	Customer Annualization to December 2022	Total Therms
RDSH	Residential Heating	3,011,856			242,746,042	1,744,888	244,490,930
RDSNH	Residential Non-Heating	409,740			7,908,489	43,766	7,952,255
RDS	Residential Delivery Service	3,421,596			250,654,531	1,788,654	252,443,185
SGS	Small General Service	207,744			23,789,576	(9,538)	23,780,038
GDS	General Delivery Service	78,876	1,861,359.4	22,336,313	110,348,992	995,285	111,344,277
GDSAC May-Oct	GDS - CIAC , May-Oct Discounted Rate	132	-	-	32,668	0	32,668
GDSEDS	GDS Economic Development	12	-	-	12,232	0	12,232
NGV	Public Station, per therm	12	-	-	47,552	0	47,552
LVD	Large Volume Demand	600	375,585.4	4,507,025	51,676,578	0	51,676,578
EGF	Electric Generation Firm	0	-	-	0	0	0
GLS	Unmetered Gas Light, per mantle	84	-	-	2,664	0	2,664
CSI	Interruptible Cogeneration Srv.	12	-	-	70	0	70
IS	Interruptible Service	12	787.0	9,444	21,741	0	21,741
ITS-IS	Interruptible Transportation Srv.	120	24,083.3	289,000	2,050,698	0	2,050,698
ITS-CSI	Interruptible Transportation Srv.	0	-	-	0	0	0
ITS-LVD	Int.Trans.Srv.	408	303,953.6	3,647,443	35,980,038	0	35,980,038
Proof Flex and Special Contracts:			-	-			
FTS-MSC		12	-	-	13,612,932	0	13,612,932
CS-4		12	-	-	675,217	0	675,217
S.B ITS -LVD Flex		12	52,498.5	629,982	437,592	0	437,592
D.NP All ITS-LVD		12	-	-	8,728,663	0	8,728,663
M.ULT. ITS-LVD		12	-	-	16,492,846	0	16,492,846
	Total	3,709,668	2,618,267.2	31,419,207	514,564,590	2,774,401	517,338,991

ELIZABETHTOWN GAS COMPANY
TEST YEAR AND POST TEST YEAR CUSTOMER COUNTS AND THERMS
TEST YEAR

Schedule TK- **20**
Consisting of 2 Pages

	Proof Rate Classes	Apr-21	May-21	Jun-21	Jul-21	Aug-21	Sep-21	Oct-21	Nov-21	Dec-21	Jan-22	Feb-22	Mar-22
		Actual	Actual	Actual	Actual	Actual	Actual	Projected	Projected	Projected	Projected	Projected	Projected
RDSH	Residential Heating	245,200	245,528	245,715	245,714	245,773	245,631	245,894	246,860	247,828	248,076	248,321	248,522
RDSNH	Residential Non-Heating	33,101	33,164	33,145	33,065	32,988	32,904	33,531	33,663	33,795	33,823	33,850	33,869
RDS	Residential Delivery Service	278,301	278,692	278,860	278,779	278,761	278,535	279,425	280,523	281,623	281,899	282,171	282,391
SGS	Small General Service	17,203	17,164	17,126	17,088	17,033	17,001	16,906	17,044	17,214	17,328	17,336	17,345
GDS	General Delivery Service	6,383	6,373	6,372	6,371	6,372	6,372	6,368	6,401	6,465	6,484	6,486	6,489
GDSAC	GDS - CIAC	11	11	11	11	11	11	11	11	11	11	11	11
GDSEDS	GDS Economic Development	1	1	1	1	1	1	1	1	1	1	1	1
NGV	Public Station, per therm	1	1	1	1	1	1	1	1	1	1	1	1
LVD	Large Volume Demand	48	48	48	48	49	48	50	50	50	50	50	50
EGF	Electric Generation Firm	-	-	-	-	-	-	-	-	-	-	-	-
GLS	Unmetered Gas Light, per mantle	7	7	7	7	7	7	7	7	7	7	7	7
CSI	Interruptible Cogeneration Srv.	1	1	1	1	1	1	1	1	1	1	1	1
IS	Interruptible Service	1	1	1	1	1	1	1	1	1	1	1	1
ITS-IS	Interruptible Transportation Srv.	10	10	10	10	10	10	10	10	10	10	10	10
ITS-CSI	Interruptible Transportation Srv.	-	-	-	-	-	-	-	-	-	-	-	-
ITS-LVD	Int.Trans.Srv.	34	34	34	34	34	34	34	34	34	34	34	34
Proof Flex and Special Contracts:													
FTS-MSC		1	1	1	1	1	1	1	1	1	1	1	1
CS-4		1	1	1	1	1	1	1	1	1	1	1	1
S.B ITS -LVD Flex		1	1	1	1	1	1	1	1	1	1	1	1
D.NP All ITS-LVD		2	2	2	2	2	2	1	1	1	1	1	1
M.ULT. ITS-LVD		1	1	1	1	1	1	1	1	1	1	1	1
	Total	302,007	302,349	302,478	302,358	302,287	302,028	302,820	304,089	305,423	305,832	306,114	306,346

		Apr-21	May-21	Jun-21	Jul-21	Aug-21	Sep-21	Oct-21	Nov-21	Dec-21	Jan-22	Feb-22	Mar-22
RDSH	Residential Heating	16,161,339	8,970,489	4,173,584	4,134,228	4,242,666	4,611,485	10,930,138	26,950,709	39,892,598	47,961,583	39,256,820	31,735,535
RDSNH	Residential Non-Heating	649,958	452,909	334,984	257,740	225,876	239,712	436,120	810,019	1,074,727	1,385,573	1,203,607	731,535
RDS	Residential Delivery Service	16,811,297	9,423,398	4,508,568	4,391,968	4,468,542	4,851,197	11,366,258	27,760,728	40,967,325	49,347,156	40,460,427	32,467,070
SGS	Small General Service	1,415,349	571,675	416,073	241,634	355,454	304,639	1,033,808	2,106,443	3,958,269	5,274,940	4,690,176	3,064,972
GDS	General Delivery Service	8,681,175	5,217,808	3,736,260	3,377,448	3,260,814	3,479,836	6,117,766	11,235,050	16,270,970	20,170,021	18,195,662	13,293,545
GDSAC	GDS CIAC	3,120	205	13,667	15,375	7,786	195	8,816	16,002	23,137	29,195	26,207	19,346
GDSEDS	Public Station, per therm	3,837	4,813	516	247	248	569	706	1,246	1,816	2,288	2,096	1,556
NGV	Public Station, per therm	1,462	4,016	6,460	5,552	7,500	5,279	4,498	4,191	2,804	2,775	3,127	4,054
LVD	Large Volume Demand	3,342,128	3,232,253	2,968,429	2,979,158	3,004,413	2,949,068	3,130,443	3,564,166	4,263,781	5,031,925	6,072,173	4,790,999
EGF	Electric Generation Firm	-	-	-	-	(1,176)	-	-	-	-	-	-	-
GLS	Unmetered Gas Light, per mantle	222	222	222	222	222	222	222	222	222	222	222	222
CSI	Interruptible Cogeneration Srv.	176	73	-	10	72	1,180	10	-	10	10	10	-
IS	Interruptible Service	2,043	-	10	-	-	-	383	1,260	5,248	5,998	5,086	1,713
ITS-IS	Interruptible Transportation Srv.	171,142	148,205	128,266	119,822	118,738	128,177	138,856	156,627	235,599	250,993	245,408	221,975
ITS-CSI	Interruptible Transportation Srv.	-	-	-	-	-	-	-	-	-	-	-	-
ITS-LVD	Int.Trans.Srv.	2,770,672	2,729,857	2,838,611	2,520,273	2,741,784	2,730,382	3,017,204	3,143,345	3,017,926	3,272,304	2,891,043	3,054,322
Proof Flex and Special Contracts:													
FTS-MSC		1,278,258	1,439,447	1,144,096	1,429,722	1,429,238	1,354,712	1,134,411	1,134,411	1,134,411	1,134,411	1,134,411	1,134,411
CS-4		2,840	-	2,106,070	1,082,760	2,790,500	584,170	-	77,000	-	-	-	-
S.B ITS -LVD Flex		28,881	7,193	42,890	803	7,314	207	45,140	18,520	76,880	103,003	93,021	50,779
D.NP All ITS-LVD		664,344	680,895	696,751	706,294	660,844	706,259	717,087	720,050	858,832	881,352	834,091	831,207
M.ULT. ITS-LVD		1,439,366	1,269,562	1,269,577	1,315,166	1,287,759	1,370,516	1,321,060	979,572	1,674,344	1,628,010	1,546,402	1,498,192
	Total	36,616,312	24,729,622	19,876,466	18,186,454	20,140,052	18,466,608	28,036,668	50,918,833	72,491,574	87,134,603	76,199,562	60,434,363

ELIZABETHTOWN GAS COMPANY
TEST YEAR AND POST TEST YEAR CUSTOMER COUNTS AND THERMS
POST TEST YEAR WITH ANNUALIZED AND NORMALIZED THERMS

Schedule TK- 20
Consisting of 2 Pages

	Proof Rate Classes	Jan-22 Projected	Feb-22	Mar-22	Apr-22	May-22	Jun-22	Jul-22	Aug-22	Sep-22	Oct-22	Nov-22	Dec-22	
RDSH	Residential Heating	248,076	248,321	248,522	248,659	248,784	248,947	249,124	249,328	249,572	250,094	250,604	250,988	
RDSNH	Residential Non-Heating	33,823	33,850	33,869	33,893	33,914	33,942	33,970	33,998	34,023	34,076	34,110	34,145	
RDS	Residential Delivery Service	281,899	282,171	282,391	282,552	282,698	282,889	283,094	283,326	283,595	284,170	284,714	285,133	
SGS	Small General Service	17,328	17,336	17,345	17,335	17,320	17,272	17,241	17,244	17,252	17,274	17,297	17,312	
GDS	General Delivery Service	6,484	6,486	6,489	6,498	6,500	6,508	6,516	6,522	6,525	6,536	6,555	6,573	
GDSAC	GDS - CIAC	11	11	11	11	11	11	11	11	11	11	11	11	
GDSEDS	GDS Economic Development	1	1	1	1	1	1	1	1	1	1	1	1	
NGV	Public Station, per therm	1	1	1	1	1	1	1	1	1	1	1	1	
LVD	Large Volume Demand	50	50	50	50	50	50	50	50	50	50	50	50	
EGF	Electric Generation Firm	-	-	-	-	-	-	-	-	-	-	-	-	
GLS	Unmetered Gas Light, per mantle	7	7	7	7	7	7	7	7	7	7	7	7	
CSI	Interruptible Cogeneration Srv.	1	1	1	1	1	1	1	1	1	1	1	1	
IS	Interruptible Service	1	1	1	1	1	1	1	1	1	1	1	1	
ITS-IS	Interruptible Transportation Srv.	10	10	10	10	10	10	10	10	10	10	10	10	
ITS-CSI	Interruptible Transportation Srv.	-	-	-	-	-	-	-	-	-	-	-	-	
ITS-LVD	Int.Trans.Srv.	34	34	34	34	34	34	34	34	34	34	34	34	
Proof Flex and Special Contracts:														
FTS-MSC		1	1	1	1	1	1	1	1	1	1	1	1	
CS-4		1	1	1	1	1	1	1	1	1	1	1	1	
S.B ITS -LVD Flex		1	1	1	1	1	1	1	1	1	1	1	1	
D.NP All ITS-LVD		1	1	1	1	1	1	1	1	1	1	1	1	
M.ULT. ITS-LVD		1	1	1	1	1	1	1	1	1	1	1	1	
	Total	305,832	306,114	306,346	306,506	306,639	306,790	306,972	307,213	307,493	308,101	308,687	309,139	
														Total Post Test Year
RDSH	Residential Heating	48,524,572	39,678,443	32,050,436	15,968,301	7,971,002	5,611,005	4,973,337	4,663,118	5,526,758	11,344,830	27,589,571	40,589,557	244,490,930
RDSNH	Residential Non-Heating	1,398,764	1,214,096	737,496	461,396	402,918	365,602	314,974	285,281	317,719	478,251	855,759	1,119,999	7,952,255
RDS	Residential Delivery Service	49,923,336	40,892,539	32,787,932	16,429,697	8,373,920	5,976,607	5,288,311	4,948,399	5,844,477	11,823,081	28,445,330	41,709,556	252,443,185
SGS	Small General Service	5,270,069	4,683,683	3,059,141	1,469,120	493,190	408,565	411,899	414,165	414,077	1,047,529	2,126,862	3,981,738	23,780,038
GDS	General Delivery Service	20,446,877	18,439,730	13,465,630	7,068,402	3,344,011	3,689,312	3,360,280	3,368,298	3,370,973	6,446,983	11,618,711	16,600,603	111,219,810
GDSAC	GDS CIAC	29,195	26,207	19,346	10,216	4,755	4,973	4,648	4,633	4,635	9,024	16,188	23,315	157,135
GDSEDS	Public Station, per therm	2,288	2,096	1,556	807	332	334	335	336	336	722	1,260	1,830	12,232
NGV	Public Station, per therm	2,775	3,127	4,054	4,718	3,646	3,684	4,434	4,671	4,950	4,498	4,191	2,804	47,552
LVD	Large Volume Demand	5,031,925	6,072,173	4,790,999	4,014,278	3,978,376	3,767,012	3,822,519	3,809,551	3,491,336	3,652,587	4,290,434	4,955,388	51,676,578
EGF	Electric Generation Firm	-	-	-	-	-	-	-	-	-	-	-	-	-
GLS	Unmetered Gas Light, per mantle	222	222	222	222	222	222	222	222	222	222	222	222	2,664
CSI	Interruptible Cogeneration Srv.	10	10	-	10	-	10	10	-	-	10	-	10	70
IS	Interruptible Service	5,998	5,086	1,713	2,043	-	10	-	-	-	383	1,260	5,248	21,741
ITS-IS	Interruptible Transportation Srv.	250,993	245,408	221,975	171,866	148,655	128,576	120,082	118,988	110,097	139,449	157,495	237,114	2,050,698
ITS-CSI	Interruptible Transportation Srv.	-	-	-	-	-	-	-	-	-	-	-	-	-
ITS-LVD	Int.Trans.Srv.	3,272,304	2,891,043	3,054,322	3,030,203	2,959,452	2,832,907	2,814,237	2,936,756	3,001,133	3,021,097	3,146,372	3,020,212	35,980,038
Proof Flex and Special Contracts:		-	-	-	-	-	-	-	-	-	-	-	-	
FTS-MSC		1,134,411	1,134,411	1,134,411	1,134,411	1,134,411	1,134,411	1,134,411	1,134,411	1,134,411	1,134,411	1,134,411	1,134,411	13,612,932
CS-4		-	-	-	284	-	210,607	108,276	279,050	-	-	77,000	-	675,217
S.B ITS -LVD Flex		103,003	93,021	50,779	23,104	5,755	34,312	643	5,851	8,692	36,112	14,816	61,504	437,592
D.NP All ITS-LVD		881,352	834,091	831,207	664,343	680,895	696,751	706,294	660,844	476,917	717,087	720,050	858,832	8,728,663
M.ULT. ITS-LVD		1,628,010	1,546,402	1,498,192	1,450,162	1,279,084	1,279,099	1,325,030	1,297,417	1,184,661	1,330,968	986,919	1,686,902	16,492,846
	Total	87,982,768	76,869,249	60,921,479	35,473,886	22,406,704	20,167,392	19,101,631	18,983,592	19,046,917	29,364,163	52,741,521	74,279,689	517,338,991

Exhibit P-3

ELIZABETHTOWN GAS COMPANY
Conservation Incentive Program ("CIP") - Baseline Use per Customer ("BUC")

6+6 Schedule TK- 21

		Post Test	Post Test	Post Test	Post Test	Post Test	Post Test	Post Test	Post Test	Post Test	Post Test	Post Test	End Of Post Test	
		Jan-22	Feb-22	Mar-22	Apr-22	May-22	Jun-22	Jul-22	Aug-22	Sep-22	Oct-22	Nov-22	Dec-22	Sum Of Bills
Customer Counts:														
RDSH	Residential Heating	248,076	248,321	248,522	248,659	248,784	248,947	249,124	249,328	249,572	250,094	250,604	250,988	2,991,019
RDSNH	Residential Non-Heating	33,823	33,850	33,869	33,893	33,914	33,942	33,970	33,998	34,023	34,076	34,110	34,145	407,613
RDS	Residential Delivery Service	281,899	282,171	282,391	282,552	282,698	282,889	283,094	283,326	283,595	284,170	284,714	285,133	3,398,632
SGS	Small General Service	17,328	17,336	17,345	17,335	17,320	17,272	17,241	17,244	17,252	17,274	17,297	17,312	207,556
GDS	General Delivery Service	6,496	6,498	6,501	6,510	6,512	6,520	6,528	6,534	6,537	6,548	6,567	6,585	78,336
	Total	305,723	306,005	306,237	306,397	306,530	306,681	306,863	307,104	307,384	307,992	308,578	309,030	3,684,524
Therms:	**Forecast Pre Annualization**													
RDSH	Residential Heating	47,961,583	39,256,820	31,735,535	15,820,126	7,901,006	5,565,377	4,936,402	4,632,277	5,495,578	11,304,421	27,547,360	40,589,557	242,746,042
RDSNH	Residential Non-Heating	1,385,573	1,203,607	731,535	457,991	400,192	363,428	313,360	284,053	316,584	477,285	854,882	1,119,999	7,908,489
RDS	Residential Delivery Service	49,347,156	40,460,427	32,467,070	16,278,117	8,301,198	5,928,805	5,249,762	4,916,330	5,812,162	11,781,706	28,402,242	41,709,556	250,654,531
SGS	Small General Service	5,274,940	4,690,176	3,064,972	1,471,072	493,418	407,621	410,210	412,538	412,642	1,045,230	2,125,019	3,981,738	23,789,576
GDS	General Delivery Service	20,201,504	18,223,965	13,314,447	6,998,772	3,311,959	3,658,136	3,336,123	3,347,132	3,351,327	6,420,438	11,604,341	16,625,748	110,393,892
	Total	74,823,600	63,374,568	48,846,489	24,747,961	12,106,575	9,994,562	8,996,095	8,676,000	9,576,131	19,247,374	42,131,602	62,317,042	384,837,999
Therms:	**Annualization Adjustments**													
RDSH	Residential Heating	562,989	421,623	314,901	148,175	69,996	45,628	36,935	30,841	31,180	40,409	42,211	0	1,744,888
RDSNH	Residential Non-Heating	13,191	10,489	5,961	3,405	2,726	2,174	1,614	1,228	1,135	966	877	0	43,766
RDS	Residential Delivery Service	576,180	432,112	320,862	151,580	72,722	47,802	38,549	32,069	32,315	41,375	43,088	0	1,788,654
SGS	Small General Service	(4,871)	(6,493)	(5,831)	(1,952)	(228)	944	1,689	1,627	1,435	2,299	1,843	0	(9,538)
GDS	General Delivery Service	276,856	244,068	172,085	80,653	37,139	36,483	29,140	26,135	24,617	36,291	31,818	0	995,285
	Total	848,165	669,687	487,116	230,281	109,633	85,229	69,378	59,831	58,367	79,965	76,749	0	2,774,401
Therms:	**Annualized**													
RDSH	Residential Heating	48,524,572	39,678,443	32,050,436	15,968,301	7,971,002	5,611,005	4,973,337	4,663,118	5,526,758	11,344,830	27,589,571	40,589,557	244,490,930
RDSNH	Residential Non-Heating	1,398,764	1,214,096	737,496	461,396	402,918	365,602	314,974	285,281	317,719	478,251	855,759	1,119,999	7,952,255
RDS	Residential Delivery Service	49,923,336	40,892,539	32,787,932	16,429,697	8,373,920	5,976,607	5,288,311	4,948,399	5,844,477	11,823,081	28,445,330	41,709,556	252,443,185
SGS	Small General Service	5,270,069	4,683,683	3,059,141	1,469,120	493,190	408,565	411,899	414,165	414,077	1,047,529	2,126,862	3,981,738	23,780,038
GDS	General Delivery Service	20,478,360	18,468,033	13,486,532	7,079,425	3,349,098	3,694,619	3,365,263	3,373,267	3,375,944	6,456,729	11,636,159	16,625,748	111,389,177
	Total	75,671,765	64,044,255	49,333,605	24,978,242	12,216,208	10,079,791	9,065,473	8,735,831	9,634,498	19,327,339	42,208,351	62,317,042	387,612,400
CIP-BUC	**Annualized Therms / End of PTY Customer Count:**													Sum of Months
RDSH	Residential Heating	193.3	158.1	127.7	63.6	31.8	22.4	19.8	18.6	22.0	45.2	109.9	161.7	974.1
RDSNH	Residential Non-Heating	41.0	35.6	21.6	13.5	11.8	10.7	9.2	8.4	9.3	14.0	25.1	32.8	233.0
SGS	Small General Service	304.4	270.5	176.7	84.9	28.5	23.6	23.8	23.9	23.9	60.5	122.9	230.0	1,373.6
GDS	General Delivery Service	3,109.8	2,804.6	2,048.1	1,075.1	508.6	561.1	511.0	512.3	512.7	980.5	1,767.1	2,524.8	16,915.7

6+6 Schedule TK- **22**

ELIZABETHTOWN GAS COMPANY
Test Year and Post Year
Newark Airport Monthly 20 Year Normal Degree Days

Based upon 24 point, 10am to 10am, hourly interval data
for the period January 1, 2001 through December 31, 2020

Test Year		Post Test Year	
Month	**Degree Days Base 65ºF**	**Month**	**Degree Days Base 65ºF**
Apr-21	340	Jan-22	992
May-21	52	Feb-22	834
Jun-21	0	Mar-22	693
Jul-21	0	Apr-22	340
Aug-21	0	May-22	52
Sep-21	0	Jun-22	0
Oct-21	212	Jul-22	0
Nov-21	516	Aug-22	0
Dec-21	818	Sep-22	0
Jan-22	992	Oct-22	212
Feb-22	834	Nov-22	516
Mar-22	693	Dec-22	818
Total	**4,457**	**Total**	**4,457**

ELIZABETHTOWN GAS COMPANY **6+6 Schedule TK-23**
2021 Rate Case

Proposed Bill Changes
To Current Rates at 12-1-2021

Residential Service	Class Avg Thms	From	Rate Change	To	$$$ Change	% Chg.
Customer Charge		$10.00	3.27	$13.27		
Distribution Charge		$0.4382	0.2042	$0.6424		
BGSS-P		$0.4798	-	$0.4798		
IIP		$0.0427	(0.0427)	$0.0000		
CAC, all other Riders		$0.0658	-	$0.0658		
100 Therm Bill	100	$112.65		$132.07	$19.42	17.2%
Ann 1,000 Therm Bill	1,000	$1,146.50		$1,347.24	$200.74	17.5%
Small General Service						
Customer Charge		$27.01	9.78	$36.79		
Distribution Charge		$0.3807	0.1789	$0.5596		
BGSS-P		$0.4798	-	$0.4798		
IIP		$0.0471	(0.0471)	$0.0000		
CAC, all other Riders		$0.0658	-	$0.0658		
Average Bill	115	$138.95		$163.89	$24.94	17.9%
Average Annual Bill	1,374	$1,661.57		$1,960.02	$298.45	18.0%
General Delivery Service						
Customer Charge		$37.50	24.34	$61.84		
Demand Charge	283	$0.960	0.202	$1.162		
Distribution Charge		$0.2301	0.1381	$0.3682		
BGSS-P *		$0.4798	-	$0.4798		
IIP		$0.0280	(0.0280)	$0.0000		
CAC, all other Riders		$0.0658	-	$0.0658		
Average Bill	1,410	$1,442.40		$1,679.14	$236.74	16.4%
Average Annual Bill	16,916	$16,867.07		$19,417.94	$2,550.87	15.1%

* Using BGSS-P as a Proxy for BGSS-M

ELIZABETHTOWN GAS COMPANY

TARIFF FOR GAS SERVICE
B.P.U. NO. 18

2021 Rate Case

ELIZABETHTOWN GAS COMPANY

TARIFF FOR GAS SERVICE

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SERVICE CLASSIFICATIONS LISTED BELOW ARE AVAILABLE IN
THE ENTIRE TERRITORY SERVED BY ELIZABETHTOWN GAS COMPANY

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SERVICE CLASSIFICATIONS LISTED BELOW ARE AVAILABLE IN
THE ENTIRE TERRITORY SERVED BY ELIZABETHTOWN GAS COMPANY

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(continued)

TERRITORY SERVED
WHOLLY WITHIN THE STATE OF NEW JERSEY

ELIZABETHTOWN DIVISION

Middlesex County

1. Carteret
2. Edison (part)
3. Metuchen
4. Perth Amboy
5. Woodbridge
   - Avenel
   - Colonia
   - Fords
   - Iselin
   - Keasbey
   - Port Reading
   - Sewaren

Union County

1. Clark
2. Cranford
3. Elizabeth
4. Fanwood
5. Garwood
6. Hillside
7. Kenilworth
8. Linden
9. Mountainside
10. Rahway
11. Roselle
12. Roselle Park
13. Scotch Plains
14. Union
15. Westfield
16. Winfield
17. Winfield Park

NORTHWEST DIVISION

Hunterdon County (Southern District)

1. Alexandria
2. Bethlehem
3. Bloomsbury
4. Califon
5. Clinton (Town)
6. Clinton (Twp.)/ Annandale
7. Delaware
8. East Amwell/ Ringoes
9. Flemington
10. Franklin
11. Frenchtown
12. Glen Gardner
13. Hampton
14. High Bridge
15. Holland
16. Kingwood (Twp.)
17. Lambertville
18. Lebanon (Bor.)
19. Lebanon (Twp.)/Stockton
20. Milford (Bor.)
21. Raritan
22. Readington (part)
23. Stockton
24. Union
25. West Amwell

Mercer County (Southern District)

1. Hopewell (Bor.)
2. Hopewell (Twp. Part)
3. Lawrence
4. Pennington

Morris County (Central District)

1. Mount Olive (Twp. Part) / Budd Lake
2. Washington (Twp. Part) / Long Valley

Sussex County
(Northern District)

1. Andover (Bor.)
2. Andover (Twp.)
3. Branchville
4. Byram (Twp.)
5. Frankford
6. Franklin (Bor.)
7. Fredon
8. Green
9. Hamburg
10. Hampton
11. Hardyston
12. Lafayette
13. Newton
14. Ogdensburg
15. Sparta
16. Sussex
17. Vernon
18. Wantage

Warren County
(Central District)

1. Allamuchy
2. Alpha
3. Belvidere
4. Franklin
5. Greenwich
6. Hackettstown
7. Harmony
8. Independence
9. Lopatcong
10. Mansfield
11. Oxford
12. Phillipsburg
13. Pohatcong
14. Washington (Bor.)
15. Washington (Twp.)
16. White

STANDARD TERMS AND CONDITIONS

1. GENERAL

1.01 - Applicability

These Standard Terms and Conditions, filed as part of the Tariff of Elizabethtown Gas Company (hereinafter referred to as “Gas Company” or “Company”), set forth the terms and conditions under which service is rendered and will be supplied. They govern all classes of service to the extent applicable and are made a part of all agreements for the supply of gas service unless specifically modified by the terms of a particular service classification or by special terms written in and made a part of a contract for service.

Failure by the Gas Company to enforce any provisions, terms, or conditions set forth in this Tariff shall not be deemed a waiver thereof.

Per the New Jersey Administrative Code (“N.J.A.C.”) 14:3 (“Chapter”) Section 14:3-1.3(i) Tariffs states: If there is any inconsistency with this Chapter and a tariff, these rules shall govern, except if the tariff provides for more favorable treatment of Customers than does this Chapter, in which case the tariff shall govern.

1.02 – Termination or Revision of Tariff

This Tariff is subject to the orders of the Board of Public Utilities of the State of New Jersey (hereinafter referred to as “Board” or “BPU”), effective as of this date or as may be promulgated and become legally effective in the future.

Gas Company reserves the right at all times and in any manner permitted by law and the applicable rules and regulations of the Board to terminate, change or modify by revision, amendment, supplement, or otherwise, this Tariff or any part thereof, or any revision, amendment or supplement thereto. All contracts for service are accepted subject to the above reservations.

1.03 – Agents

No representative or agent of Gas Company has the authority to modify, alter, or waive any provision contained in this Tariff or to bind Gas Company by any promise or representation thereto.

1.04 – Application of Tariff

Receipt of gas service from Gas Company makes the receiver a "Customer", as defined in Section 2.01 hereof. However, Gas Company will not be required to continue to render service unless, if upon request of Gas Company, (a) Customer makes, or has made, an application for service in accordance with the Standard Terms and Conditions set forth herein and (b) such application is accepted by Gas Company in accordance with the terms of said Standard Terms and Conditions.

Service furnished by Gas Company prior to its acceptance of Customer's application shall, nevertheless, be charged for at the rates contained in the applicable service classification. The applicable service classification, in a case where more than one service classification might apply and Customer has failed to make a selection, shall be that service classification which in the sole judgement of Gas Company is most advantageous to Customer. (See Section 2.03)

1.05 – Inspection of Tariff

The tariff is available to all Customers for public inspection in each office where applications for service may be made. The Tariff is also available for review or copying at the Company's website at www.Elizabethtowngas.com.

2. OBTAINING SERVICE

2.01 – Application for Service

An application for service may be made at any commercial office of Gas Company, either in person, by mail, by telephone, or by any other means made available by the Company. A written application form or agreement may be required from any person, firm, organization, partnership, corporation, or otherwise, applying for or using gas service (hereinafter referred to as "Customer"). If the Company requires a written application, the application may be subsequently submitted to the Customer for signature. There will be a $15.00 administration charge to establish service to a new Customer or re-establish service to an existing Customer.

Applicant(s) may be required by the Gas Company to supply proof of identity and prior address. Any such requirement to provide proof of identity or prior address shall be in accordance with the provisions of N.J.A.C. 14:3-3.2 as may be amended or superseded.

Separate application may be required in each case where gas service is applied to the same person, firm, organization, partnership, corporation, or otherwise, at two or more non-contiguous properties. For purposes of applying these rates, service at each non-contiguous location shall be considered as service to a separate Customer.

Customer shall state, at the time of making application for service, the conditions under which service will be required. Customer may be required to sign an agreement covering special circumstances necessary for the supply of service in accordance with Customer's requirements. In the case in which the Customer signs a main and/or service extension agreement and subsequently does not install any of the indicated equipment within a reasonable time, not to exceed one year, or purchase the requested quantities of gas, the Company reserves the right to charge the Customer for the full cost of providing the service and main, as applicable.

Gas Company reserves the right to place limitations on the amount and character of gas service it will supply; to refuse service to new Customers or to existing Customers for additional load, if unable to obtain the necessary equipment and facilities to supply such service; to reject applications for service or additional service where such service is not available or where such service might affect the supply of gas to other Customers; or for other good and sufficient reasons.

In accordance with the provisions in N.J.A.C. 14:3-3.2(g), within two business days of receipt of the Customer's application for utility service, or on a mutually agreed upon date, the utility shall initiate the service, except in those cases where the utility or Customer must install or contract to install an extension, as defined at N.J.A.C. 14:3-8.2, to the structure where said service shall be received.

2.02 – Form of Application

Standard applications or agreements to supply gas service shall be in accordance with the particular service classification. Agreements for longer term than that specified in the service classification may be required where large or special investment is necessary to supply service, where special facilities are required to serve a Customer, or where the hourly capacity of the Gas Company's facilities required to serve the Customer's demand, in the opinion of the Gas Company, may be out of proportion to the monthly or annual use of gas service for occasional, intermittent, or low load factor purposes. Gas Company reserves the right to require contributions towards the investment required for such service and to establish such minimum charges and facilities charges as may be equitable under the circumstances involved.

2.03 – Selection of Rate

Gas Company will assist in the selection of the available rate which is most desirable from the standpoint of Customer. However, the responsibility for making the selection shall, at all times, rest with Customer. Any advice given by Gas Company will be based on Customer's statements.

Customer may request Gas Company to change the service classification under which they are billed. However, Gas Company shall not be obligated to make such a change more than once in 12 calendar months even though Customer may qualify for service under more than one service classification.

2.04 – Deposit and Guarantee

Where an applicant's credit is not established, where the credit of a Customer with Gas Company has become impaired, or where Gas Company deems it necessary for other reasons, a deposit or other guarantee satisfactory to Gas Company may be required as security for the payment of future and final bills for gas service and other charges resulting from the rendering of gas service before Gas Company will commence or continue to render service. Service shall not be discontinued for failure to make such deposit, unless said deposit had been included on prior bills, or notices to the Customer. All requests for deposits shall be in accordance with N.J.A.C. 14:3-3.4.

All deposits shall bear simple interest at the rate equal to the average yield on new six-month Treasury Bills for the twelve month period ending each September 30 and shall be paid by the utility on all deposits held by it. Said rate shall become effective on January 1 of the following year. The Board shall perform the annual calculation to determine the applicable interest rate and shall notify the Gas Company of said rate.

Interest accrued from deposits for Residential Service accounts shall be credited to Customer's bill, unless the Customer requests a separate check, at least once during a 12-month period for such service rendered or to be rendered. Customers not purchasing gas under the Residential Service classification will be refunded interest accrued from their service deposit at the time that the deposit is refunded to the Customer. A deposit shall bear interest until it is returned or applied to an outstanding balance.

Gas Company shall review a residential Customer's account at least once every year and non-residential Customer's account at least once every two years and if such review indicates that a Customer has established good credit, the Gas Company will apply the deposit to the outstanding balance on the Customers' account, unless the Customer requests a separate check.

Gas Company reserves the right to apply a deposit, plus accrued interest on said deposit, against unpaid bills for service or other charges resulting from the rendering of gas service. If such action is taken and the Customer continues to receive gas service the Customer shall be required to restore the deposit to the original amount or such other reasonable amount as Gas Company may determine. If the account is closed only the remaining balance will be refunded.

Gas Company shall have a reasonable time in which to read meters and to ascertain that all the obligations of Customer have been fully performed before being required to refund any deposit, in accordance with N.J.A.C. 14:3-3.5.

2.05 – Gas Main Extensions and Service Connections

An extension deposit or contribution in aid of construction may be required from Customer for the extension of gas mains towards the cost of installing a service connection, as set forth in Sections 3 and 4 of these Standard Terms and Conditions.

The making of a deposit or contribution in aid of construction in connection with the extension of a main or service shall not under any circumstances give Customer any interest in the gas main or service or appurtenances thereto, the ownership being at all times vested in Gas Company.

2.06 – Permits

The Gas Company shall obtain or cause to be obtained all easements, licenses or permits necessary to enable the Gas Company or its agents access to connect its mains to the Customer's equipment. This shall be construed to mean all permits and certificates, municipal or otherwise, required by law or the Gas Company's rules. The Gas Company shall not be obliged to furnish service unless and until such permits, instruments, consents and certificates shall have been delivered to the Company. The Company reserves the right to require that Customer obtain or cause to be obtained all easements, licenses, or permits necessary to enable the Company or its agents access to connect its mains to the Customer's equipment.

The Customer may be responsible for payment of the amount by which such easements, licenses or permit fees exceeds $15.00. Payment shall be made prior to the Company filing for said documents.

By making application for service, Customer grants to Gas Company a right-of-way for its lines and other facilities, across, over, under or along the property owned or controlled by Customer, to the extent that the same is necessary to enable Gas Company to render service to premises.

2.07 – Temporary Service

Where service is to be used for a limited period, the use of the service shall be classified as temporary and Customer shall be required to assume the actual cost of the facilities required to furnish service and also their connection and removal, which shall not be less than twice the minimum charge per month for residential service. The minimum period for billing of gas consumption shall be one (1) month. Temporary service will be furnished only where Gas Company's facilities are suitable and quantity of gas is available without in any way interfering with other Customers of Gas Company.

2.08 – Authorization to Turn On Gas to the Meter

Only duly authorized employees or agents of Gas Company shall be permitted to turn on gas.

3. EXTENSIONS OF MAINS AND/OR SERVICE LINES

3.01 –General Provisions

The provisions and definitions within N.J.A.C. 14:3-8.1, *et seq.*, shall be applicable.

The construction of main extensions are subject to the regulations at N.J.A.C. 14:3-8.1, *et seq.* The Company may construct and will own and maintain distribution mains located on streets, highways, and right of way, used or usable as a part of its distribution system. The making of a deposit or contribution by the Customer shall not give the Customer any interest in the facilities, the ownership being vested exclusively in the Company.

The Company may require up-front contributions, or deposits, pursuant to N.J.A.C. 14:3-8.1, *et seq.* These charges shall be increased for any tax consequences to the Company. If the Company accepts an application for an extension, the Company may furnish and place, at no cost to the Customer, up to 200 feet of normal residential facilities.

Deposits that are received from Customers pursuant to the Extensions of Mains and Services shall be refunded without interest in accordance with the applicable formula contained in N.J.A.C. 14:3-8.10 and N.J.A.C. 14:3-8.11. In no event shall the Company refund more than the total deposit amount received from the Customer. Any deposit amount not refunded within ten (10) years from the date service was initiated, shall remain with the Company and shall constitute a contribution in aid of construction.

3.02 Main and Service Extensions Requested by Customers

1) Residential

The Company shall extend its gas mains and services to serve an individual residential Customer at no charge where the Extension Cost does not exceed ten (10) times the annual Distribution Revenue. The Distribution Revenue shall be the incremental initial or actual total annual billings, as determined by the Gas Company, derived from the Applicant's and/or existing Customer's applicable Service Classification, inclusive of Sales and Use Tax, minus the Basic Gas Supply Service, inclusive of Sales and Use Tax. The Company shall require a deposit equal to the Extension Cost in excess of ten (10) times the annual Distribution Revenue and shall include any tax consequences to the Company. The Company will waive the deposit requirement where the excess cost is $3,000 or less.

2) - Non-Residential

The Company will extend its gas mains and services to an individual firm commercial or industrial Customer and shall require a deposit equal to the Extension Costs, increased by any tax consequences to the Company. The Company will waive the deposit requirement where the excess cost is $3,000 or less. In lieu of a deposit for Extension Costs, the Company and the Customer may agree upon a satisfactory revenue guarantee.

3) - Extension of Service to New Developments

The Company shall require a deposit for an extension subject to this Section, in the amount of the Extension Cost required to serve the development. The deposit shall be increased by any tax consequences to the Company. The Company will waive the deposit requirement where the excess cost is $3,000 or less. In lieu of a deposit for Extension Costs, the Company and the Customer may agree upon a satisfactory revenue guarantee.

3.03 - Service Connection Location

Service connections will be measured at right angles from the nearest curb line to the Applicant's building, at the point of service entrance designated by the Company. Meters and regulators will be furnished and installed by the Company. The costs of meters and regulators (including the installation) may be waived by the Company.

The Applicant shall consult the Company as to the exact point at which the service pipe will enter the building before installing interior gas piping or starting any other work dependent upon the location of the service pipe. The Company will determine the location of the service pipe depending upon physical constraints in the street and other practical considerations.

4. SERVICE CONNECTIONS

4.01 – General

Subject to the provisions of the Extensions of Mains and/or Service Lines section of this tariff, gas service will normally be supplied to each premise through a single service pipe, except where, in the judgment of Gas Company, it is deemed desirable to install more than one service pipe. The Gas Company may also choose to install multiple meters on one service pipe providing service to several premises. If more than one service is installed for the convenience of the Customer, each location will be considered as a separate Customer. In addition, at its expense and option, the Company may include a "customer valve" on the premise side of the meter on new, existing and/or re-established existing services. The ownership of the valve will be transferred to the Customer upon gas flowing through the valve.

4.02 – Change in Existing Installations

Any change in the location of the existing service pipe or meter set requested by Customer and approved by Gas Company shall be made at the expense of Customer. The Gas Company reserves the right to change the location of an existing service pipe or meter set to a placement and location determined solely by the Gas Company upon giving the Customer ten (10) days notice, unless it is done as part of an unforeseen repair or an upgrade to the main. The Gas Company shall bear all costs related to such changes including re-connecting pipes to the premise side of the meter and appurtenances related to any meter reading devices.

A Customer who qualifies pursuant to 49 CFR Section 192 and/or has a service line that is 2" or less and has a system minimum pressure of ten (10) pounds per square inch gauge or more may request installation of an Excess Flow Valve (EFV). If a Customer does not qualify for an EFV the Company will offer to install a Curb Stop. The Customer will be required to pay all EFV or Curb Stop installation costs associated with such installation before the Company begins work if:

a) the Company has not scheduled the Customer's premises for a service line replacement or a new service line or,
b) the Customer requests the installation prior to the Company's scheduled installation time.

5. METERS AND ASSOCIATED EQUIPMENT

5.01 – General

Subject to the provisions of the Extensions of Mains and/or Service Lines section of this tariff, the Gas Company will furnish, install and maintain meters for each premise and/or service. In addition, where appropriate, when a Customer has two or more service classifications, the Customer will have separate meters.

Where more than one meter is installed in a premise, the readings of all such meters supplying a Customer under the same service classification may be combined for billing purposes. The Customer may be charged a monthly service charge for each meter even if said meters are combined for billing purposes.

5.02 - Customer's Responsibility

Customer shall provide and maintain, without charge to Gas Company, a suitable space for the metering and associated equipment. Such space shall be as near as practicable to the point of entrance of the service pipe, adequately ventilated, dry, free from corrosive vapors, not subject to extreme temperatures, free from appreciable vibrations or any other conditions that may impact the meter as well as being readily accessible to authorized employees or agents of Gas Company. In apartment houses, office buildings, townhouses or condominiums with multiple service, all meters shall, whenever possible, be grouped together. Adequate passageway, maintained free of obstacles and unsafe and hazardous conditions, shall be provided at all times.

Customer shall not tamper with or remove meters or other equipment or permit access thereto, except by authorized employees or agents of Gas Company.

With the exception of the "customer valve" on the premise side of the meter, when installed (see Section 4.01), all equipment furnished by the Gas Company shall remain its property and may be replaced whenever deemed necessary by the Gas Company or as required by the Board and may be removed by Gas Company at any time after discontinuance of service.

In case of loss or damage from the act or negligence of Customer or the Customer's agents, employees and or contractors, or of failure to return property supplied by Gas Company, Customer shall pay to Gas Company the value of such property.

5.03 – Automatic Meter Reading Equipment (AMR)

The Company in its sole discretion may install, at its expense, an AMR device to monitor a Customer's gas consumption. However, when gas is to be delivered at a pressure in excess of the Company's standard gauge pressure noted in Section 7.02, or such equipment is required by the service classification under which the Customer will receive service, the Company shall determine any necessary equipment inclusive of compensating and AMR devices to be installed at the Customer's expense. When such devices require attachment to telephone and/or electric utilities, the Customer shall provide and pay for suitable connections unless the Company elects to make such connections. When an AMR device is requested by the Customer, the AMR device and any necessary appurtenances shall be installed at the Customer's expense if the installation is deemed feasible by the Company. Where feasible, the Company will make data from the AMR device or other equipment available to the Customer upon the signing of a Service Agreement.

Payments made by the Customer shall not give the Customer ownership of the equipment. All equipment remains the sole property of the Company. Installation of an AMR does not relieve the Customer of the obligations of Sections 5.02 – Customer's Responsibility or Section 9 Access to Premises.

6. CUSTOMER'S INSTALLATION

6.01 – General

No material change in the size, total capacity, or method of operation of Customer's equipment shall be made without previous written notice to the Gas Company and subsequent approval by the Gas Company.

The Gas Company will assume no responsibility for the condition of Customer's gas installation or for accidents, fires, or failures which may occur as the result of the condition of such gas installation.

Neither by inspection or non-rejection, nor in any other way, does the Gas Company give any warranty, expressed or implied, as to the adequacy, safety, or other characteristics of any structure, equipment, wires, pipes, appliances, or devices used by the Customer.

Gas Company shall not be liable for damages to the Customer's equipment or injuries sustained by Customer due to the condition or character of Customer's facilities and equipment. The Gas Company will not be responsible for the use, care or handling of the gas delivered to Customer after same passes beyond the point at which the Company's service facilities connect to the Customer's facility. Gas Company also shall not be liable for any claim for damage resulting from the supply, use, care or handling of the gas or from the presence or operation of the Company's structures, equipment, pipes or devices except for direct damages resulting from the Gas Company's negligence, recklessness or willful misconduct. The Gas Company will not be liable for special or consequential damages.

6.02 – Equipment, Piping and Installation

Customer appliances, piping and installations shall be made and maintained in accordance with the standards and specifications set forth in American National Standard, National Fuel Gas Code, ANSI Z223.1, and such other regulations as may be promulgated from time to time by any governmental agency having jurisdiction over the Customer's installation.

6.03 – Back Pressure and Suction

When the nature of Customer's gas equipment is such that it may cause back pressure or suction in the piping system, meters, or other associated equipment of Gas Company, suitable protective devices, subject to inspection and approval by Gas Company, shall be furnished, installed, and maintained by Customer.

6.04 – Adequacy and Safety of Installation

Gas Company shall not be required to supply gas service until Customer's installation has been approved by the authorities, if any, having jurisdiction, and Gas Company further reserves the right to withhold its service or to discontinue its service whenever such installation, or part thereof, is deemed by Gas Company to be unsafe, inadequate or unsuitable for receiving service, to interfere with or impair the continuity or quality of service to Customer or others, or for other good and sufficient reason.

7. METER READINGS AND BILLING

7.01 – General

Gas Company will select the type and make of metering equipment and may, from time to time, change or alter such equipment. It shall be the obligation of Gas Company to supply meters that will accurately and adequately furnish records for billing purposes. Bills will be based upon registration of Gas Company meters, except as otherwise provided for herein.

At such time as Gas Company may deem proper or as the Board may require, Gas Company will test its meters in accordance with the standards and bases prescribed by the Board. The performance of a test outside of these standards is at the Company's option. Any Customer requesting such a meter test more than once in a twelve (12) month period shall be charged all related costs to test the equipment, inclusive but not limited to time and material costs with overhead factors for the second and subsequent tests. In the event of a dispute the Gas Company's meter will be presumed to be correct, subject to test results in accordance with N.J.A.C. 14:3-4.5 and 14:3-4.6.

7.02 – Correction for Pressure and/or Temperature

For purposes of measurement, a cubic foot of gas is that volume occupying one cubic foot (12" x 12" x 12") at the Company's standard gauge pressure of five (5) inches water column and at a temperature of 60°F.

In any case where Gas Company measures or the Customer has requested that the gas delivered is at a pressure greater than five (5) inches of water column or at temperatures other than 60° F, the cubic feet of gas registered by the meter shall be subject to correction for billing purposes by the application of proper correction factors or by the use of pressure and/or temperature compensating devices under Section 5.03 – Automatic Meter Reading Equipment (AMR).

7.03 – Therm Conversion Factor

Meter readings of Customers shall be converted from cubic feet to therms by applying a therm conversion factor. A therm is defined as a unit of heat energy equal to 100,000 British Thermal Units (B.T.U.'s). For billing purposes, the Customer's gas usage in cubic feet will be converted to therms using a therm conversion factor representing the actual weighted average BTU value per 100 cubic feet of gas that was delivered into the Company's system in the second preceding calendar month as adjusted to a dry basis as reported each month to the Board in accordance with N.J.A.C. 14:6-3.2. This therm conversion factor expressed to precision of at least three decimal places, shall be applied in calculating bills on a service rendered basis. The Gas Company may at its option, upon 30 day notice to Board and the New Jersey Division of Rate Counsel ("Rate Counsel or RC"), modify the calendar period used in determining the BTU factor, if it is modified toward or at a period closer to that of the Customer billing periods. In that event, the Company's reports to the Board concerning the BTU value of gas delivered into the Company's system shall contain sufficient detail to allow the Board to review the Company's calculation of therm conversion factors.

7.04 – Billing Period

Unless otherwise specified, the charges in this Tariff are stated on a "monthly" basis. The term "month" for billing purposes, shall mean a period of thirty (30) days.

Bills for service furnished will normally be rendered monthly. However, the Company reserves the right to bill bi-monthly. Gas Company also expressly reserves the right to render to any Customer bills based on meter reading periods which may be shorter than a month. Such bills will be prorated as provided in Section 7.05 hereof and are due as provided in Section 7.10 hereof.

7.05 – Proration of Monthly Charges

Except for temporary service accounts, the monthly charges for all initial bills, all final bills, and all bills for periods longer than five (5) days more, or shorter than five (5) days less, than the regular monthly billing period shall be prorated on the basis of a thirty-day month or the actual number of days in the billing period. For temporary service accounts, the minimum billing period for billing purposes shall be one month.

7.06 – Estimated Bills and Discontinuance of Service for Excessive Estimated Reads

Where Gas Company is unable for any reason to read the meter, Gas Company reserves the right to estimate the amount of gas supplied based upon past usage and other information available and submit a bill determined on that basis. Such a bill shall be marked as to the fact that it is an estimated bill. During the summer period (defined here as May 15th through September 15th) the Gas Company may suspend the reading of manually read meters when the Company determines such suspension is necessary to permit the Company to redirect its work force to higher priority projects, provided, however, that the Company may not suspend meter readings for any individual Customer for four (4) or more consecutive billing periods (monthly accounts) or two (2) or more consecutive billing periods (bimonthly and quarterly accounts). During such time the accounts will be billed based on estimated usage. Adjustment of Customer's estimated use to actual use shall be made when an actual reading is next obtained. Notwithstanding the above, the Gas Company reserves the right to discontinue gas service when a meter reading is not obtained in accordance with N.J.A.C. 14:3-7.2(e)(3) which states "When a utility estimates an account for four consecutive billing periods (monthly accounts), or two consecutive billing periods (bimonthly and quarterly accounts), the utility shall mail a notice marked "Important Notice" to the Customer on the fifth and seventh months, respectively, explaining that a meter reading must be obtained and said notice shall explain the penalty for failure to complete an actual meter reading. After all reasonable means to obtain a meter reading have been exhausted, including, but not limited to, offering to schedule meter readings for evenings and on weekends, the utility may discontinue service provided at least eight months have passed since the last meter reading was obtained, the Board has been so notified and the Customer has been properly notified by prior mailing. If service is discontinued and subsequently restored, the utility may charge a reconnection charge equal to the reconnection charge for restoring service after discontinuance for nonpayment."

7.07 – Billing Adjustments Due to Inaccurate Meter Recordings

When it is determined that the Gas Company's meter is inaccurate or defective, the use of gas service shall be determined by a test of the meter, or by registration of the meter set in its place during the period next following, or after due consideration of previous or subsequent properly measured deliveries. Whenever a meter is found to be registering fast by more than 2% an adjustment of charges shall be made in accordance with the provisions of N.J.A.C. 14:3-4.6.

If a meter is found to be registering less than 100% of the service provided, the Gas Company shall not adjust the charges retrospectively and/or require the Customer to repay the amount undercharged except if: 1) the meter was tampered with; 2) the meter failed to register at all; or 3) the circumstances are such that the Customer should reasonably have known that the bill did not reflect the actual usage. In rebilling a Customer under such conditions, the Gas Company may, per its determination, utilize previous or subsequent properly measured deliveries, perform a load analysis and/or a degree day analysis to estimate the usage. The Gas Company shall allow the Customer to make payment over a period of time equal to that during which the undercharges occurred, in accordance with N.J.A.C. 14:3-4.6(f).

Any adjustment to the Customer's account resulting from the terms in this section will be billed or applied to the account as the case may be. If the adjustment results in a credit, such amount may be refunded upon request by the Customer, in lieu of bill credit, in accordance with N.J.A.C. 14:3-4.6, as may be amended or superseded.

7.08 – Separate Billing for Each Installation

The service classifications are based upon the rendering of service through a single delivery and metering point. Service rendered to the same Customer at other points of delivery shall be separately metered and billed, except as provided in Section 5.01 hereof.

7.09 – Sale for Resale of Gas Service and Sub-Metering

1. General

Gas service supplied by the Company shall not be resold by Customer to others except where the Customer is another publicly regulated gas utility, where the gas is used for conversion to Compressed Natural Gas ("CNG"), or the Customer of record is sub-metering in accordance with the conditions set forth below.

2. Sub-Metering

a. Gas sub-metering is the practice in which a Customer of record of the Gas Company, through the use of direct metering devices, monitors, evaluates or measures the Customer of record's own utility consumption or the consumption of a tenant for accounting or conservation purposes.

Gas sub-meters are devices that measure the volume of gas being delivered to particular locations in a system after measurement by a Company owned meter.

b. If the Customer of record charges the tenant for the usage incurred by the tenant, the sum of such charge(s) to the tenant shall not exceed the cost incurred by the Customer of record for providing gas service, including reasonable administrative expenses. Further, the sum of such charge(s) to the tenant shall not exceed the amount the utility would have charged such tenant if the tenant had been served and billed by the Company directly. The reselling of sub-metering gas service for profit is prohibited.

c. Gas sub-metering, in accordance with the conditions described hereinabove, is permitted in new or existing buildings or premises where the basic characteristic of use is industrial or commercial. Gas sub-metering is not permitted in existing buildings or premises where the basic characteristic of use is residential except where such buildings or premises are publicly financed or government owned or are charitable in nature or are condominiums or cooperative housing.

d. The Customer of record shall contact the Company prior to the installation of any gas sub-metering device, in order to ascertain whether the affected premises is located within a low pressure portion of the Company's supply system and whether or not the installation of a gas check metering device will cause any significant pressure drop to the affected premises.

e. All gas consuming devices in any unit must be metered through a single gas sub- meter.

7.10 – Payment of Bills

At least 15 days' time for payment shall be allowed after the date a bill is mailed. Bills are payable at any commercial office at Gas Company or at any duly authorized collection agency or by mail or any other means made available by the Company. The Gas Company may discontinue service for nonpayment of bills provided the amount is greater than $100 and or more than three (3) months delinquent and it gives the Customer at least 10 days' written notice of its intention to discontinue service. The notice of discontinuance shall not be mailed until the expiration of the said initial 15-day period. However, in cases of fraud, illegal use, or when it is clearly indicated that the Customer is preparing to leave, immediate payment of accounts may be required. The Gas Company reserves the right to request wire transfer of funds for payment of bills when the Company reasonably determines that payment by wire transfer is required.

A late payment charge equal to one-twelfth of the lower of 18% or the highest rate allowed by law shall be applied to the monthly billing for all non-residential Customers. However, service to a governmental entity will not be subject to a late payment charge. Per Section 14:3-7.1(e) of the N.J.A.C., the utility shall not apply a late payment charge sooner than twenty five (25) days after a bill is rendered. Therefore, the Company may, beginning on the twenty-sixth (26th) day after rendering a bill, assess late payment charges. The charge will be applied to all amounts previously billed including late payment charges and accounts payable that are not received by Gas Company within the days specified above. The amount of the late payment charge to be added to the unpaid balance shall be calculated by multiplying the unpaid balance by the late charge rate. When payment is received by the Company from a Customer who has an unpaid balance which includes charges for late payment, the Customer's payment shall be applied first to such late payment charges and then the remainder to the unpaid balance.

7.11 – Reimbursement of Expense for Processing Uncollectible Checks

A charge of $15.00 will be made to reimburse the Company for the expense of processing Customer checks which are returned by the Company's bank as uncollectible. A charge of $8.00 will be made to reimburse the Company for the expense of processing Customer checks that are re-submitted and again returned by the Company's bank as uncollectible.

7.12 – Beginning and Ending Service

Any Customer starting the use of service without making application for service and enabling Gas Company to read the meter will be held liable for any amount due for service supplied to the premises from the last reading of the meter immediately preceding the Customer's occupancy, as shown by the records of Gas Company.

Customers shall give reasonable notice of intended removal from any premises wherein they are receiving gas service. Customer shall be liable for service taken after notice of termination has been received by the Company until such time as the meter is read and disconnected, not to exceed forty-eight (48) hours. Notice to discontinue service does not relieve a Customer from any minimum or guaranteed payment under any service classification or contract.

7.13 – Budget Plan

Heating Customers billed under Service Classification RDS have the option of paying for their use of total service in equal estimated monthly installments as set forth in the applicable Gas Company's House Heat Budget Plan. The Company may offer a budget plan to all classes of Customers.

8. LEAKAGE

Customer shall immediately give notice to Gas Company of any escape of gas in or about Customer's premises.

9. ACCESS TO PREMISES

Properly identified employees or agents of Gas Company shall have access to Customer's premises at all reasonable times for any and all necessary purposes in connection with the rendering of service or the removal of its property.

10. RIGHT TO SUSPEND, CURTAIL, OR DISCONTINUE SERVICE

Gas Company shall have, upon reasonable notice, when it can be reasonably given, the right to suspend, curtail or discontinue its service for any of the following reasons:

(1) For the purpose of making repairs, changes, replacements, or improvements in any part of its system.

(2) For compliance in good faith with any governmental order or directive, whether federal, state, municipal, or otherwise, notwithstanding such order or directive subsequently may be held to be invalid.

(3) For any of the following act(s) or omission(s) on the part of Customer:

a. Non-payment of a valid bill due for service furnished at the present or any previous locations. However, nonpayment for business service shall not be a reason for discontinuance of residential service.

b. Tampering with any facility of Gas Company.

c. Fraudulent representation in relation to the use of gas service.

d. Customer moving from the premises unless the Customer requests that service be continued.

e. Delivering gas service to others without written approval of Gas Company except as permitted under Section 7.09 – Sale for Resale of Gas Service and Sub-Metering.

f. Failure to make or increase an advance payment or deposit when requested by Gas Company.

g. Refusal to contract for service where such contract is required.

h. Connecting and operating equipment in such a manner as to produce disturbing effects on the gas system of Gas Company or on systems of other Customers.

i. Failure to comply with any of these Standard Terms and Conditions.

j. Where the conditions of Customer's installation or facilities presents a hazard to life or property.

k. Failure of Customer to repair any faulty facility of Customer.

l. Failure to provide access to the meter to obtain a reading as permitted under Section 7.06 – Estimated Bills and Discontinuance of Service for Excessive Estimated Reads.

(4) For refusal of reasonable access to Customer's premises for necessary purposes in connection with the rendering of service, including meter installation, reading or testing, or the maintenance or removal of the property of Gas Company.

Failure of Gas Company to exercise its rights to suspend, curtail or discontinue service, for any of the above reasons, shall not be deemed a waiver thereof.

Should gas service be terminated for any of the above reasons, the minimum charge for the unexpired portion of the term shall become due and payable immediately, provided, however, that if satisfactory arrangements are subsequently made by Customer for reconnection of the service, the immediate payment of the minimum charge for the unexpired portion of the contract term may be waived or modified as the circumstances indicate would be just and reasonable.

11. <u>RECONNECTION AND TAMPERING CHARGES</u>

<u>11.01 – Reconnection and Collection Charges</u>

A charge of $15.00 shall be made when the Company makes a collection visit to the customer or the premises and/or to restore service when service has been suspended or discontinued for any of the reasons cited in Sections 10.(3), excepting 10.(3)d, and 10.(4) of these Standard Terms and Conditions. Recurring reconnection charges in any 12-month period shall be charged at the approved regular rates for Customer service otherwise performed by Gas Company but not less than $30.00.

A charge of $200.00 may be made when service has been terminated for any of the reasons cited in Sections 10.(3), excepting 10.(3)d, and 10.(4), and which required the installation of a curb box for said termination.

<u>11.02 – Tampering Charge</u>

In the event it is established that a Company's meters or other equipment on the Customer's premises have been tampered with, and such tampering results in incorrect measurement of the service supplied as determined by the Company, the cost for such gas service, based upon the Company's estimate from available data and not registered by the Company's meter, shall be paid by the beneficiary of such service. The beneficiary shall be any person who benefits from such tampering. The actual cost of investigation, inspection and determination of such tampering, and other costs, such as but not limited to the installation of protective equipment, legal fees, and other costs relating to the administrative, civil or criminal proceedings, shall be billed to the beneficiary of such tampering in the case of non-residential accounts. In the case of residential accounts, all such costs shall be billed to the responsible party. The responsible party shall be the party who either tampered with or caused the tampering with a meter or other equipment or knowingly received the benefit to tampering by or caused by another. In the event a residential Customer unknowingly received the benefit of meter or equipment tampering, the Company shall only seek from the benefiting Customer the cost of the service provided but not the cost of investigation.

Under certain conditions, tampering with the Company's facilities may also be punishable by fine and/or imprisonment under New Jersey law.

11.03 – Diversion of Service

Diversion is an unauthorized connection to pipes and/or wiring by which the utility service registers on the tenant Customers' meter although such service is being used by other than the tenant-customer of record without the tenant-customer's knowledge or cooperation. Where a tenant-customer alleges or it is established that service has been diverted outside of such Customers' premises, that tenant-customer shall not be required to pay for such service without that tenant-customer's consent. The definitions, procedures, investigations and determination of N.J.A.C. 14:3-7.8 shall apply.

12. CONTINUITY OF SERVICE

Gas Company will use reasonable diligence to provide a regular and uninterrupted supply of service; but, should the supply be suspended, curtailed, or discontinued by Gas Company for any of the reasons set forth in Section 10 of these Standard Terms and Conditions or should the supply of service be interrupted, curtailed, deficient, defective, or fail, by reason of any act of God, accident, strike, legal process, governmental interference, acts of third parties, or by reason of compliance in good faith with any governmental order or directive, notwithstanding such order or directive subsequently may be held to be invalid, provided such reasons are not the product of the Company's negligence, or willful misconduct, Gas Company shall not be liable for any loss or damage, direct or consequential, resulting from any such suspension, discontinuance, interruption, curtailment, deficiency, defect, or failure.

Additionally, Gas Company may curtail or interrupt service to any Customer or Customers in the event of emergency threatening the integrity of its system or the systems to which it is directly or indirectly connected if, in its sole judgement, such action will prevent or alleviate the emergency condition.

13. LIMITATION OF SERVICE AVAILABILITY

Where the facilities of Gas Company and/or the quantity of gas available are restricted or limited, preference may be given by Gas Company in supplying service to Customers giving consideration to such factors as 1) annual gas use, 2) volume of gas, 3) load factor, 4) end use of gas, 5) capital investment costs, and 6) number of appliances.

14. CHARACTERISTICS OF SUPPLIED GAS

Type(s) of gas supplied:

1. Natural gas

2. Natural gas mixed with Propane-Air Gas and or Manufactured Gases and or Liquefied Natural Gas

3. In areas where natural gas service is not available, undiluted commercial grade propane gas distributed through Gas Company facilities and having a minimum heating value of 2,400 BTU per cubic foot.

15. GENERAL

15.01 – Inspection of Customer Facilities

Neither by inspection, approval nor non-rejection, nor in any other way does Gas Company give any guarantee or assume any responsibility, expressed or implied, as to the adequacy, safety, or characteristics of any structures, equipment, pipes, appliances, or devices owned, installed, or maintained by Customer or leased by Customer from third parties, except in those instances in which the above equipment or facilities are owned, or leased by Gas Company.

15.02 – Force Majeure

Neither Gas Company, TPS, or Customer shall be liable for damages to the other for any act, omission, or circumstance occasioned by or in consequence of any acts of God, strikes, lockouts, acts of the public enemy, wars, blockades, insurrections, riots, epidemics, landslides, lightning, earthquakes, fires, storms, floods, washouts, arrests and restraints of rulers and people, civil disturbances, explosions, breakage or accident to machinery or lines of pipe, temporary failure of gas supply, temporary failure of firm transportation arrangements, the binding order of any court or governmental authority which has been resisted in good faith by all reasonable legal means, acts of third parties, and any other cause, whether of the kind herein enumerated or otherwise, not within the control of the party claiming suspension and which by the exercise of due diligence such party is unable to prevent or overcome.

Such cause or contingencies affecting the performance by Gas Company, TPS or Customer, however, shall not relieve it of liability in the event of its concurrent negligence or in the event of its failure to use due diligence to remedy the situation and remove the cause in an adequate manner and with all reasonable dispatch, nor shall such causes or contingencies affecting performance relieve either party from its obligations to make payments of amounts then due hereunder in respect of gas theretofore delivered.

16. GAS CURTAILMENT PLAN

16.01- Purpose

The purpose of this plan is to preserve the ability to continue to provide essential gas services, as defined below, to the broadest base of Customers given limited gas supply and/or delivery capacity.

16.02 - Definition of Essential Gas Users

Essential Gas Users are defined as gas service to individual residential dwellings, multi-family residential dwellings, schools, hospitals, day care centers, nursing homes, dormitories, correctional facilities, twenty-four hour emergency facilities such as municipal police, fire or emergency medical departments and similar facilities which do not have installed alternate fuel equipment and an alternate fuel supply.

16.03 – Actions Required Before Implementation of the Gas Curtailment Plan

The Gas Curtailment Plan will be implemented only after the Company has:

1. Exercised all of its rights to interrupt service to interruptible service classifications – ITS, IS, CS, CSI, as provided for in the Company's Tariff;

2. Availed itself of all cogeneration firm recall gas;

3. Interrupted SIS service, if being provided.

Nothing in the Gas Curtailment Plan shall inhibit the Company from managing and scheduling interruptions in service as covered above in a manner that it determines is appropriate to meet the conditions on its system. However, the Gas Curtailment Plan Action Steps will not go into effect until such time as all options available above have been exercised.

16.04 – Curtailment Plan Action Steps

1. The Company shall request all transportation Customers and their TPS to maximize deliveries of gas into the Company's system and request excess deliveries be made available to the Company at a compensation price agreed to by the parties.

2. The Company shall reduce gas service to its own facilities to a minimum;

3. The Company shall appeal to firm large industrial and commercial Customers to voluntarily reduce gas consumption;

4. The Company shall appeal to its general population of Customers to reduce gas consumption by lowering thermostats 5^{o} F, closing off unused rooms, reducing non-essential uses of gas – i.e., gas lights, clothes drying;

5. The Company shall declare the existence of a gas curtailment emergency on its system and notify the BPU and other appropriate state agencies;

6. The Company shall seek emergency supplies from pipelines, suppliers and other gas companies;

7. The Company shall curtail service to all firm industrial services greater than 2,000 therms/day other than plant protection;

8. The Company shall curtail service to all firm industrial services less than 2,000 therms/but greater than 500 therms/day other than plant protection;

9. The Company shall curtail non-essential firm commercial usage 500 therms/day or greater;

10. The Company shall curtail remaining non-essential commercial and industrial usage;

11. The Company shall curtail service for industrial plant protection;

12. The Company shall systematically curtail essential uses employing the Company's emergency plan.

16.05 – Appropriation of End User Transportation Gas

When a gas curtailment emergency is declared (Step 5 in Section 16.04 above), any third-party transportation gas being delivered into the Company's system for end-use Customers shall be appropriated by the Company to serve the priority of service under this curtailment plan. Customers and TPSs whose gas is so appropriated shall be compensated for such gas at its replacement cost but not less than the equivalent price of #2 fuel oil and to the extent the Customer's actual delivered service is curtailed, that Customer shall receive curtailment credits equal to a proration of any fixed monthly service charge and demand charges to correspond to the amount of the curtailed service.

16.06 – Liability Exclusion

The declaration of a gas curtailment emergency shall constitute a force majeure condition under Section 15.02 of these Standard Terms and Conditions. Consequently, the Company shall not be liable for any damages, loss of product or other business losses suffered by Customers as a result of curtailed gas service.

17. UNAUTHORIZED GAS USE

Unauthorized Use includes, but is not limited to, any volume of gas taken by Customer in excess of its maximum daily requirement as set forth in its Service Agreement with Gas Company or the quantity of gas allowed by Gas Company on any day for any reason, including as a result of a curtailment or interruption notice issued by the Company in accordance with its tariff and/or the Board of Public Utilities of the State of New Jersey or any other governmental agency having jurisdiction. A "day" shall be a period of twenty-four (24) consecutive hours, beginning as near as practical to 8 a.m., or as otherwise agreed upon by Customer and Gas Company.

The Company reserves the right to physically curtail the gas service to any Customer if, in the Company's sole judgement, such action is necessary to protect the operation of its system.

If a Customer uses gas after having been notified that gas is not available under their Service Classification, and or if applicable, uses gas in excess of the maximum daily quantity or requirements as established in the Service Agreement then unauthorized gas charges shall apply.

Furthermore, if a TPS fails to deliver gas in the quantities and or imbalance ranges specified in the TPS Service Classification then unauthorized gas charges shall apply to the TPS.

In addition to the above, the following conditions have been ordered by the BPU specifically related to Interruptible Customers and their suppliers: A Customer who fails to discontinue natural gas use, consistent with the terms and conditions of the relevant interruptible service agreements, and suppliers who fail to deliver natural gas during a critical period/OFO notice, consistent with the terms and conditions of applicable service agreements and TPS Agreements, shall be charged a penalty equal to the charges for Unauthorized Gas Use.

All Unauthorized Usage shall be billed at the higher of $2.50 per therm or a rate equal to ten times the highest price of the daily ranges which are published in Gas Daily on the table “Daily Price Survey” for delivery in Transco Zone 6 or Texas Eastern Zone M-3. This rate shall not be lower than the maximum penalty charge for unauthorized daily overruns as provided for in the FERC-approved gas tariffs of the interstate pipelines which deliver gas into New Jersey. This is in addition to all applicable taxes and charges of the Customer’s service class.

Nothing herein shall be construed to prevent the Company from taking all lawful steps to stop the unauthorized use of gas by Customer, including disconnecting Customers service.

Such payment for unauthorized use shall not be deemed as giving Customer or TPS any rights to use such gas.

The Gas Company may, in its sole discretion, permanently discontinue service upon a finding by the Gas Company that the Customer has not complied with the conditions and provisions of the tariff.

TPSs that have subscribed to Standby for their Essential Use Customers are not subject to Unauthorized Use Charges for volumes that are within the limits of their Standby Service but will be billed the Standby Rate determined at month end. Any revenues from Unauthorized Gas Use penalty charges shall be credited to the BGSS.

All Unauthorized Use Charges applicable to transportation services will be billed to and payable by the TPS providing gas supply for such services. In the event a TPS fails to pay these charges, the Customers of that TPS shall be billed directly by the Company for either: 1) their proportionate share, based on the Allocation of Supplies as set forth in the TPS service classification; or 2) their direct share identified through their non-compliance to Company directives to ease or curtail gas use.

18. NEW JERSEY SALES AND USE TAX

In accordance with P.L. 1997, c. 162 (the "energy tax reform statute"), as amended by P.L. 2016, c. 57, provision for the New Jersey Sales and Use Tax ("SUT") has been included in all charges applicable under this tariff by multiplying the charges that would apply before application of the SUT by the factor 1.06625. The energy tax reform statute exempts the following customers from the SUT provision, and when billed to such Customers, the charges otherwise applicable under this tariff shall be reduced by the provision for the SUT included therein:

1. Franchised providers of utility services (gas, electricity, water, waste water and telecommunications services provided by local exchange carriers) within the State of New Jersey.

2. Cogenerators in operation, or which have filed an application for an operating permit or a construction permit and a certificate of operation in order to comply with air quality standards under P.L. 1954, c. 212 (C.26:2C-1 et seq.) with the New Jersey Department of Environmental Protection, on or before March 10, 1997.

3. Special contract Customers for which a Customer-specific tax classification was approved by a written Order of the BPU prior to January 1, 1998.

4. Agencies or instrumentalities of the federal government.

5. International organizations of which the United States of America is a member.

In accordance with P.L. 2004, c. 65 "The Business Retention and Relocation Assistance Act" and subsequent amendment (P.L. 2005, c.374) exempts the following Customers from the SUT provision, and when billed to such Customers, the charges otherwise applicable shall be reduced by the provision for the SUT included therein:

1. A qualified business that employs at least 250 people within an enterprise zone, at least 50 % of whom are directly employed in a manufacturing process, for the exclusive use or consumption of such business within an enterprise zone.

2. A group of two or more persons:

   a. Each of which is a qualified business that are all located within a single redevelopment area adopted pursuant to the "Local Redevelopment and Housing Law," P.L.1992, c.79 (C.40A:12A-1 et seq.);

b. That collectively employ at least 250 people within an enterprise zone, at least 50% of whom are directly employed in a manufacturing process;

c. Are each engaged in a vertically integrated business, evidenced by the manufacture and distribution of a product or family of products that, when taken together, are primarily used, packaged and sold as a single product; and

d. Collectively use the energy and utility service for the exclusive use or consumption of each of the persons that comprise a group within an enterprise zone.

3. A business facility located within a county that is designated for the 50% tax exemption under Section 1 of P.L.1993, c.373 (C.54:32B-8.45) provided that the business certifies that it employs at least 50 people at that facility, at least 50% of whom are directly employed in a manufacturing process, and provided that the energy and utility services are consumed exclusively at that facility.

A business that meets the requirements in (1), (2) or (3) above shall not be provided the exemption described in this section until it has complied with such requirements for obtaining the exemption as may be provided pursuant to P.L.1983, c.303 (C.52:27H-60 et seq.) and P.L.1966, c.30 (C.54:32B-1 et seq.) and the Company has received a sales tax exemption letter issued by the New Jersey Department of Treasury, Division of Taxation.

19. NEGOTIATED RATES, TERMS AND CONDITIONS

In accordance with the BPU’s Order dated August 18, 2011 in BPU Docket No. GR10100761 (“Order”) the Company has developed the following criteria for determining whether it will, in individual circumstances, negotiate rates, terms and conditions of service with Customers that otherwise would not take service under the terms of the service classifications set forth in this tariff. Any individually negotiated rates, terms or conditions agreed to pursuant to this tariff provision are subject to prior approval by the BPU. Negotiated rates, terms and conditions that may be made available are intended to address unique circumstances applicable at the time that the negotiated rates, terms and conditions are agreed to with individual Customers.

Negotiated rates, terms and conditions will be offered by the Company in circumstances in which it determines in its sole reasonable judgment, that such individual rates, terms and conditions are necessary to prevent (i) physical bypass of the Company’s distribution system, (ii) economic bypass of the Company’s distribution system or, (iii) the loss of load that could otherwise be served at rates that would exceed marginal costs.

Customers seeking negotiated rates, terms and conditions, and claiming that such rates, terms and conditions are necessary to prevent the Customer from physically bypassing the Company’s distribution system, must provide the Company with the following:

(i) a statement from an interstate pipeline involved in such bypass that the proposed interconnection between Customer and the pipeline is operationally viable, that sufficient capacity is available to serve such Customer, and that the pipeline would serve the Customer if requested;

(ii) maps or flow diagrams that identify the proposed route of the pipeline needed to serve the Customer from the interconnection with the pipeline and the Customer's site, the size of the connecting pipeline and any other appurtenant facilities required;

(iii) engineering studies related to the estimated costs to complete construction of facilities interconnecting the pipeline and the Customer;

(iv) information concerning the status of all reliability and environmental or other permits and approvals from local, state and federal agencies;

(v) a description of any other benefits that the Customer proposes to provide the Company under a service agreement between the Company and Customer; and

(vi) such other information as the Company may require.

Customers seeking negotiated rates, terms and conditions for reasons other than to avoid physical bypass must provide the Company (i) such information as the Customer deems relevant to its request, and (ii) such information as the Company may require given the particular circumstances.

In determining whether to offer individually negotiated rates, terms and conditions to a particular Customer, the Company will consider all relevant information provided by the Customer and make a judgment as to whether negotiated rates, terms and conditions are necessary to prevent physical or economic bypass or the loss of load that could otherwise be served at rates that exceed marginal costs. Customers may apply for negotiated rates, terms and conditions by contacting the Company in writing. The Company will respond to any request for negotiated rates, terms and conditions within sixty (60) days of receiving a Customer's written request and all required information.

SERVICE CLASSIFICATION – RESIDENTIAL DELIVERY SERVICE (RDS)

APPLICABLE TO USE OF SERVICE FOR:

All residential purposes in individual residences and in individual flats, individual apartments in multiple family buildings, only where each individual flat or individual apartment is served through its own separate meter and religious institutions where the total rated input capacity of all gas utilization equipment does not exceed 500,000 BTU per hour. The rate is not available for hotels, nor for recognized rooming or boarding houses where the number of rented bedrooms is more than twice the number of bedrooms used by Customer. This rate is not applicable for industrial or commercial use of gas. In residential premises, use for purposes other than residential will be permitted only where such use is incidental to Customer's own residential use. Service for heating and/or cooling of premises will be rendered at this rate. Service to detached outbuildings or outside appliances appurtenant to the residence will be included in this rate provided Customer installs the necessary piping so that the gas used in such facilities may be measured by the meter located at the residence.

Service will be provided if Gas Company's facilities are suitable.

CHARACTER OF SERVICE:

Continuous, however, Customers may either purchase gas supply from a Third Party Supplier ("TPS") or the Company's Rider "A", Basic Gas Supply Service ("BGSS")

*CHARGES PER MONTH:

	Gas Supply from BGSS	Gas Supply from TPS
Service Charge	$13.27	$13.27
Distribution Charge per Therm	$0.6424	$0.6424
Commodity Charge	Per Rider "A"	Per TPS Agreement

* The charges set forth in this Service Classification include sales and use tax and will be adjusted for all other applicable Riders of this Tariff and any additional taxes or similar charges that are lawfully imposed by the Company. A customer that receives gas supply from a TPS will be charged for commodity according to any agreement between the Customer and the TPS.

SERVICE CLASSIFICATION – RESIDENTIAL DELIVERY SERVICE (RDS)
(continued)

MINIMUM MONTHLY CHARGE:

Service Charge.

TERM OF PAYMENT:

All bills are due upon presentation.

TERM OF CONTRACT:

One year, and thereafter until terminated by five (5) days written notice.

STANDARD TERMS AND CONDITIONS:

This Service Classification is subject to the Standard Terms and Conditions of this Tariff.

SPECIAL PROVISIONS, APPLICABLE TO CUSTOMERS RECEIVING GAS SUPPLY FROM THIRD PARTY SUPPLIERS

1.
Utilizing a Third Party Supplier

A Customer choosing to contract with a TPS for supply service will be enrolled for this service with the Company by the TPS on their behalf. A Customer will receive a confirmation notice from the Company noting their choice of supplier and that the Customer will have seven (7) calendar days from the date of the confirmation notice to contact the Company and rescind its selection, after which, if not rescinded, the residential Customer's TPS enrollment shall be accepted by the Company. Customer agrees that as between the Company and Customer, the Company shall be entitled to rely upon information concerning deliveries of natural gas on behalf of Customer provided by the TPS.

2. Switching Suppliers

Customer may switch TPSs or return to the Company's BGSS service at any time subject to the conditions of Customer enrollment. A Customer electing to return to the BGSS service should contact their TPS who will carry out the necessary steps with the Company. The decision and steps necessary to switch TPSs are carried out between the newly selected TPS and the Customer. Customer will not be charged a fee to change its TPS or return to BGSS service.

SERVICE CLASSIFICATION – RESIDENTIAL DELIVERY SERVICE (RDS)
(continued)

SPECIAL PROVISIONS, APPLICABLE TO CUSTOMERS RECEIVING GAS SUPPLY FROM THIRD PARTY SUPPLIERS (continued)

3. Limitations on the Availability of Transportation Service

Customer's TPS must demonstrate that it possesses Comparable Capacity or Standby Balancing Service sufficient to provide their Customers' Unadjusted Average Daily Delivery Quantity, as defined under the TPS Service Classification, during the months of November through March. If at any time it is determined that TPS does not meet this provision, then TPS's Customers will be returned to BGSS gas supply service.

4. Load Balancing Charge

A Load Balancing Charge of $0.0552 per therm, which includes taxes, shall be billed to the TPS for all metered quantities of its RDS Customers.

5. Gas Commingling

Service under this Service Classification is provided by the Company within its service territory for the Customer. The gas transported under this Service Classification is not the property of the Company. However, the Company reserves the right to commingle such gas with other supplies. Moreover, the Company reserves the right to utilize Customer's gas, when necessary, in accordance with the applicable curtailment provisions of this Tariff.

6. Transportation to Gas Company Facilities

The Company is not responsible for making arrangements for Customers for transporting gas from its source to the Company's interconnection with delivering pipeline suppliers. All such responsibility rests with Customer's TPS. Company shall have no responsibility with respect to such gas before Customer delivers or has delivered on its behalf such gas to Company or after Company redelivers such gas to Customer at the meter at Customer's premises or on account of anything which may be done, happen or arise with respect to such gas before such delivery or after such redelivery. Customer agrees that as between the Company and Customer, the Company shall be entitled to rely upon information concerning deliveries of natural gas on behalf of Customer provided by TPS.

7. Gas Supply Obligation

In the event that Customer's TPS ceases operations, or for any other reason fails to deliver the Average Daily Delivery Quantity ("ADDQ"), the Company shall provide replacement gas supplies under the BGSS service.

SERVICE CLASSIFICATION – RESIDENTIAL DELIVERY SERVICE (RDS)
(continued)

SPECIAL PROVISIONS, APPLICABLE TO CUSTOMERS RECEIVING GAS SUPPLY FROM THIRD PARTY SUPPLIERS (continued)

8. Indemnification

As between Company and Customer, Customer warrants that it has clear title to any gas supplies delivered into the Company's system for redelivery to Customer and Customer shall be deemed to be in exclusive control and possession of gas prior to its delivery into the Company's system for redelivery to Customer. Customer agrees to indemnify, defend and hold harmless Company from any and all claims, suits or damage actions arising out of deliveries of gas into Company's system on behalf of Customer.

SERVICE CLASSIFICATION – SMALL GENERAL SERVICE (SGS)

APPLICABLE TO USE OF SERVICE FOR:

Small General Service is available to those Customers whose annual weather normalized usage as determined by the Company is less than 5,000 therms per year and where Gas Company's facilities are suitable and the quantity of gas is available for the service desired. In August of each year the Company shall review each Customer's eligibility based on their annual normalized usage and if in excess of 5,500 therms for two consecutive years will transfer the Customer to General Delivery Service.

CHARACTER OF SERVICE:

Continuous.

*CHARGES PER MONTH:

	Gas Supply from BGSS	Gas Supply from TPS
Service Charge	$36.79	$36.79
Distribution Charge per Therm	$0.5596	$0.5596
Commodity Charge	Per Rider "A"	Per TPS Agreement

* The charges set forth in this Service Classification include sales and use tax and will be adjusted for all other applicable Riders of this Tariff and any additional taxes or similar charges that are lawfully imposed by the Company. A Customer that receives gas supply from a TPS will be charged for commodity according to any agreement between the Customer and the TPS.

MINIMUM MONTHLY CHARGE:

The Service Charge.

TERM OF PAYMENT:

All bills are due upon presentation. Should the Customer fail to make payment in full, the Company may, within the time period specified in and in accordance with Section 7.10 of the Standard Terms and Conditions of this Tariff, assess late payment charges.

TERM OF CONTRACT:

One year, and thereafter until terminated by five (5) days written notice.

SERVICE CLASSIFICATION – SMALL GENERAL SERVICE (SGS)
(continued)

STANDARD TERMS AND CONDITIONS:

This Service Classification is subject to the Standard Terms and Conditions of this Tariff.

SPECIAL PROVISIONS, APPLICABLE TO CUSTOMERS RECEIVING GAS SUPPLY FROM THIRD PARTY SUPPLIERS (TPS)

1. Service Agreement

The signing of a Service Agreement and possession by the Customer of a fully executed contract to purchase gas from a TPS are conditions precedent to receiving gas supply from a TPS.

2. Balancing Charge

Customers will be charged a balancing charge of $0.0171 per therm, which includes sales tax, in the months of November through March to offset system supply costs utilized to absorb the differences between the TPS delivered Average Daily Delivery Quantities and the actual daily gas supply requirements of the Customers.

3. Commingling

Service under this Service Classification is provided by the Company within its service territory for the Customer. The gas transported under this Service Classification is not the property of the Company. However, the Company reserves the right to commingle such gas with other supplies. Moreover, the Company reserves the right to utilize Customer's gas, when necessary, in accordance with the applicable curtailment provisions of this Tariff.

4. Transportation to Gas Company Facilities

The Company is not responsible for making arrangements for transportation service Customers for transporting the gas from its source to the Company's interconnection with the delivering pipeline supplier.

5. Nominations for Service

The Customer's TPS shall nominate on behalf of its Customers the total monthly requirements for that billing month per an Average Daily Delivery Quantity ("ADDQ") determined as stated in the TPS section of this tariff.

SERVICE CLASSIFICATION – SMALL GENERAL SERVICE (SGS)
(continued)

6. Utilizing a Third Party Supplier

A Customer choosing to contract with a TPS for supply service will be enrolled for this service with the Company by the TPS on their behalf. A Customer will receive a confirmation notice from the Company notifying them of their enrollment by a TPS and that the Customer should contact the TPS noted on the letter within seven (7) calendar days if they seek to have it rescinded. Customer agrees that as between the Company and Customer, the Company shall be entitled to rely upon information concerning deliveries of natural gas on behalf of Customer provided by the TPS.

7. Imbalance Charges

To the extent that a TPS ceases operations or under delivers gas, Customers shall be ultimately responsible for payment of any charges not paid for by their TPS, including but not limited to daily and or monthly imbalance charges for gas supplies consumed by Customer but not delivered by TPS. In the event a TPS fails to pay these charges the Customers shall be billed directly by the Company for their direct portion, if by their non-compliance to Company directives to cease gas use, and/or a prorata share by applying the Allocation of Supply terms of the TPS Service Classification, except that essential service gas Customers will first be credited with standby gas purchased by the TPS on their behalf.

8. Unauthorized Use

This Service Classification is subject to Unauthorized Gas Use Section of the Standard Terms and Conditions.

9. Gas Supply Obligation

In the event that Customer's TPS fails to deliver, the Company may, in its sole discretion, provide replacement gas supplies. The Company shall have no obligation to provide natural gas supplies to Customers that contract for TPS Service, except for those whose TPS contracted for Standby Service, limited to Essential Gas User Customers. In the event that a Customer that is not covered by Standby Service seeks to purchase natural gas supplies from the Company, such sales may be made by the Company in its sole discretion under such terms and conditions as the Company may require.

SERVICE CLASSIFICATION – SMALL GENERAL SERVICE (SGS)
(continued)

10. Limitations on the Availability of TPS Transportation Service

TPS Service is not available to Customers who are defined as "Essential Gas Users" under the curtailment provision as set forth in Section 17 of the Standard Terms and Conditions of this Tariff unless such Customers' TPS, in an amount sufficient to meet such Customers' ADDQ and/or DCQ, agrees to contract and pay for Standby Service as defined in the TPS Service Classification or for such Customers' TPS demonstrates that it possesses Comparable Capacity as defined in the TPS Service Classification.

11. Indemnification

As between Company and Customer, Customer warrants that it has clear title to any gas supplies delivered into the Company's system for redelivery to Customer and Customer shall be deemed to be in exclusive control and possession of gas prior to its delivery into the Company's system for redelivery to Customer. Customer agrees to indemnify, defend and hold harmless Company from any and all claims, suits or damage actions arising out of deliveries of gas on behalf of transporting Customer.

12. SPECIAL PROVISIONS, APPLICABLE TO VETERANS' ORGANIZATIONS:

Veterans' Organization Service: Pursuant to N.J.S.A 48:2-21.41, when natural gas service is delivered to a Customer that is a Veterans' Organization, serving the needs of veterans of the armed forces, the Customer may apply and be eligible for billing under this Special Provision.

Each Customer shall be eligible for billing under this Special Provision upon submitting an Application for Veterans' Organization Service under this service classification and by qualifying as a "Veterans' Organization" as defined by N.J.S.A. 48:2-21.41 defines a Veterans' Organization that qualifies for this Special Provision as "an organization dedicated to serving the needs of veterans of the armed forces that: is chartered under federal law, qualifies as a tax exempt organization under paragraph (19) of subsection (c) of section 501 of the federal Internal Revenue Code of 1986, 26 U.S.C. s.501(c)(19), or that is organized as a corporation under the 'New Jersey Nonprofit Corporation Act,' N.J.S.15A:1-1 et seq." Under N.J.S.A. 48:2-21.41, a qualified Veterans' Organization shall be charged the residential rate for service delivered to the property where the Veterans' Organization primarily operates, if the residential rate is lower than the commercial rate for service at that property.

SERVICE CLASSIFICATION – SMALL GENERAL SERVICE (SGS)
(continued)

12. SPECIAL PROVISIONS, APPLICABLE TO VETERANS' ORGANIZATIONS (continued):

The Customer shall furnish satisfactory proof of eligibility of service under this Special Provision to the Company. Once proof of eligibility is determined by the Company, service under this Special Provision shall begin with the next billing cycle following receipt of the Application.

The Customer will continue to be billed on this service classification. At least once annually, the Company shall review eligible Customers' charges for service delivered, defined to include Service Charges and Distribution Charges, under this Special Provision for all relevant periods. If these comparable charges for service delivered under the Residential Delivery Service (RDS) classification are lower than the charges under this classification a credit in the amount of the difference shall be applied to the Customer's next bill.

SERVICE CLASSIFICATION – GENERAL DELIVERY SERVICE (GDS)

APPLICABLE TO USE OF SERVICE FOR:

General Delivery Service is available to those Customers whose annual weather normalized usage as determined by the Company is 5,000 or more therms per year and where Gas Company's facilities are suitable and the quantity of gas is available for the service desired. In August of each year the Company shall review Customer usages and those Customers whose weather normalized usage, as determined by the Company, is less than 4,500 therms for two consecutive years will be transferred to Small General Service.

CHARACTER OF SERVICE:

Continuous, however, customers may either purchase gas supply from a Third Party Supplier ("TPS") or the Company's Rider "A", Basic Gas Supply Service ("BGSS").

*CHARGES PER MONTH:

	Gas Supply from BGSS	Gas Supply from TPS
Service Charge	$61.84	$61.84
Demand Charge per DCQ	$1.162	$1.162
Distribution Charge per Therm	$0.3682	$0.3682
Commodity Charge	Per Rider "A"	Per TPS Agreement

* The charges set forth in this Service Classification include sales and use tax and will be adjusted for all other applicable Riders of this Tariff and any additional taxes or similar charges that are lawfully imposed by the Company. A Customer that receives gas supply from a TPS will be charged for commodity according to any agreement between the Customer and the TPS.

DETERMINATION OF THE DEMAND CHARGE QUANTITY (DCQ)
The DCQ will be determined by the Customer's maximum daily requirements in terms of therm units per day. The DCQ level shall be the highest actual daily metered consumption registered from an approved automatic meter reading device at Customer's premises within a period of not less than two years, but up to three years immediately preceding the Customer obtaining service or renewing a Service Agreement under this Service Classification if such information is available. Otherwise DCQ shall be set equal to the product of (1) the highest winter monthly consumption for the most recent winter (October through April), normalized for weather, divided by the applicable number of days in the respective billing month, and (2) 1.36, provided that DCQ shall not be less than the highest non-winter month consumption divided by the applicable number of days in the respective billing month. For process loads, the Company may base the DCQ on historical consumption. If historical consumption information is not available, then (a) the initial DCQ level shall be based upon the Customer's gas utilization equipment expressed in consumption per day, and (b) after twelve (12) months of actual consumption has been metered, the DCQ level shall be redetermined.

SERVICE CLASSIFICATION – GENERAL DELIVERY SERVICE (GDS)
(continued)

DETERMINATION OF THE DEMAND CHARGE QUANTITY (DCQ) (continued)

If the Customer's maximum daily usage exceeds the DCQ as stated in the Service Agreement more than three (3) times in twelve (12) months, the Company may increase the DCQ in the Service Agreement to the highest level experienced during the previous 12 months.

MINIMUM MONTHLY CHARGE:

The sum of the Service Charge and the Demand Charge.

TERM OF PAYMENT:

All bills are due upon presentation. Should the Customer fail to make payment in full, the Company may, within the time period specified in and in accordance with Section 7.10 of the Standard Terms and Conditions of this Tariff, assess late payment charges.

TERM OF CONTRACT:

One year, and thereafter until terminated by five (5) days written notice.

STANDARD TERMS AND CONDITIONS:

This Service Classification is subject to the Standard Terms and Conditions of this Tariff.

SERVICE CLASSIFICATION – GENERAL DELIVERY SERVICE (GDS)
(continued)

SPECIAL PROVISIONS SECTIONS I & II:

I. SPECIAL PROVISIONS, APPLICABLE TO ALL CUSTOMERS RECEIVING SERVICE UNDER THIS SERVICE CLASSIFICATION

1. Distributed Generation of 12 kW or More and Gas Cooling & Refrigeration of 10 Tons or More

Under separate application Customers who are using gas for distributive generation with a rated capacity of twelve (12) kW or more, and/or gas cooling equipment with a rated capacity of ten (10) tons or more, and where gas consumed is separately metered, will be billed at the above rates, except that the applicable Distribution Charges will be billed at a rate of $0.0647 per therm commencing with the first meter reading taken in the ordinary course of business in May and concluding with the meter reading taken in the ordinary course of business in October. During all other periods, the Distribution and Commodity Charge per therm stated in this service classification shall apply.

SERVICE CLASSIFICATION – GENERAL DELIVERY SERVICE (GDS)
(continued)

I. SPECIAL PROVISIONS, APPLICABLE TO ALL CUSTOMERS RECEIVING SERVICE UNDER THIS SERVICE CLASSIFICATION (continued)

2. Economic Development Service (EDS):

Any new Customer employing a minimum of ten (10) full time equivalent employees, who locates in or expands a new or vacant building within the Company's service territory and enters into a GDS service agreement and (2) any existing Customer who expands into a new or vacant building and adds a minimum of ten (10) full time equivalent employees at the facility within the Company's service territory and is a party to a GDS service agreement shall be eligible for an EDS discount. For new Customers, this building must be new or have been vacant for a minimum of three (3) months. For existing Customers, the space utilized for operations must expand by more than 5,000 square feet. Gas used subject to the EDS discount for existing Customers will be calculated by the Company and will be based solely on the Customer's incremental usage. This service is offered to any eligible Customer for a period of five (5) years, continuing to meet the above requirements, from the date of the initial Service Agreement under this service. The EDS Customers shall receive a fifty (50) percent pre tax discount in this Service Class's Distribution Charge during the period of eligibility.

3. Boiler Limitation

This service classification is not available for new or additional boiler equipment with a rated input in excess of 12.5 million BTU's per hour. The Gas Company may waive this limitation in cases where the Customer enters into a longer term contract or agrees to guarantee a monthly minimum revenue level as may be determined by the Gas Company.

SERVICE CLASSIFICATION – GENERAL DELIVERY SERVICE (GDS)
(continued)

II. SPECIAL PROVISIONS, APPLICABLE TO CUSTOMERS RECEIVING GAS SUPPLY FROM THIRD PARTY SUPPLIERS (TPS)

1. Service Agreement

The signing of a Service Agreement and possession by the Customer of a fully executed contract to purchase gas from a TPS are conditions precedent to receiving gas supply from a TPS.

2. Balancing Charge

Customers with a DCQ under 500 therms will be charged a balancing charge of $0.0171 per therm, which includes sales tax, in the months of November through March to offset system supply costs utilized to absorb the differences between the TPS delivered Average Daily Delivery Quantities and the actual daily gas supply requirements of the Customers.

3. Commingling

Service under this Service Classification is provided by the Company within its service territory for the Customer. The gas transported under this Service Classification is not the property of the Company. However, the Company reserves the right to commingle such gas with other supplies. Moreover, the Company reserves the right to utilize Customer's gas, when necessary, in accordance with the applicable curtailment provisions of this Tariff.

4. Transportation to Gas Company Facilities

The Company is not responsible for making arrangements for transportation service Customers for transporting the gas from its source to the Company's interconnection with the delivering pipeline supplier.

5. Nominations for Service

The Customer's TPS shall nominate on behalf of its Customers the total monthly requirements for that billing month. A TPS with Customers having a DCQ under 500 therms and those requiring an AMR not yet installed are required to deliver these customers natural gas requirements per an ADDQ determined as stated in the TPS section of this tariff.

SERVICE CLASSIFICATION – GENERAL DELIVERY SERVICE (GDS)
(continued)

II. SPECIAL PROVISIONS, APPLICABLE TO CUSTOMERS RECEIVING GAS SUPPLY FROM THIRD PARTY SUPPLIERS (TPS) (continued)

6. Utilizing a Third Party Supplier

A Customer choosing to contract with a TPS for supply service will be enrolled for this service with the Company by the TPS on their behalf. A Customer will receive a confirmation notice from the Company notifying them of their enrollment by a TPS and that the Customer should contact the TPS noted on the letter within seven (7) calendar days if they seek to have it rescinded. Customer agrees that as between the Company and Customer, the Company shall be entitled to rely upon information concerning deliveries of natural gas on behalf of Customer provided by the TPS.

7. Imbalance Charges

To the extent that a TPS ceases operations or under delivers gas, Customers shall be ultimately responsible for payment of any charges not paid for by their TPS, including but not limited to daily and or monthly imbalance charges for gas supplies consumed by Customer but not delivered by TPS. In the event a TPS fails to pay these charges the Customers shall be billed directly by the Company for their direct portion, if by their non-compliance to Company directives to cease gas use, and/or a prorata share by applying the Allocation of Supply terms of the TPS Service Classification, except that essential service gas Customers will first be credited with standby gas purchased by the TPS on their behalf.

SERVICE CLASSIFICATION – GENERAL DELIVERY SERVICE (GDS)
(continued)

II. SPECIAL PROVISIONS, APPLICABLE TO CUSTOMERS RECEIVING GAS SUPPLY FROM THIRD PARTY SUPPLIERS (TPS) (continued)

8. Automatic Meter Reading (AMR) Equipment for Customers with a DCQ of 500 therms or more.

AMR equipment is required for Customers with a DCQ of 500 or more therms, as determined by the Company. Customer shall pay for all costs to install AMR equipment including power, communications and other equipment as specified by the Company and provide access for such equipment. The cost of any Company equipment may be paid by Customer over a one (1) year, or some lesser, period by means of a monthly surcharge designed to recover the cost of the equipment plus interest equal to the Company's overall rate of return as authorized from time to time by the BPU. Payments made by the Customer shall not give the Customers ownership of the equipment which shall remain the sole property of the Company.

9. Unauthorized Use

This Service Classification is subject to Unauthorized Gas Use Section of the Standard Terms and Conditions.

10. Gas Supply Obligation

In the event that Customer's TPS fails to deliver, the Company may, in its sole discretion, provide replacement gas supplies. The Company shall have no obligation to provide natural gas supplies to Customers that contract for TPS Service, except for those whose TPS contracted for Standby Service, limited to Essential Gas User Customers. In the event that a Customer that is not covered by Standby Service seeks to purchase natural gas supplies from the Company, such sales may be made by the Company in its sole discretion under such terms and conditions as the Company may require.

11. Limitations on the Availability of TPS Transportation Service

TPS Service is not available to Customers who are defined as "Essential Gas Users" under the curtailment provision as set forth in Section 17 of the Standard Terms and Conditions of this Tariff unless such Customers' TPS, in an amount sufficient to meet such Customers' ADDQ and/or DCQ, agrees to contract and pay for Standby Service as defined in the TPS Service Classification or for such Customers' TPS demonstrates that it possesses Comparable Capacity as defined in the TPS Service Classification.

SERVICE CLASSIFICATION – GENERAL DELIVERY SERVICE (GDS)
(continued)

II. SPECIAL PROVISIONS, APPLICABLE TO CUSTOMERS RECEIVING GAS SUPPLY FROM THIRD PARTY SUPPLIERS (TPS) (continued)

12. Indemnification

As between Company and Customer, Customer warrants that it has clear title to any gas supplies delivered into the Company's system for redelivery to Customer and Customer shall be deemed to be in exclusive control and possession of gas prior to its delivery into the Company's system for redelivery to Customer. Customer agrees to indemnify, defend and hold harmless Company from any and all claims, suits or damage actions arising out of deliveries of gas on behalf of transporting Customer.

III. SPECIAL PROVISIONS, APPLICABLE TO VETERANS' ORGANIZATIONS:

Veterans' Organization Service: Pursuant to N.J.S.A 48:2-21.41, when natural gas service is delivered to a Customer that is a Veterans' Organization, serving the needs of veterans of the armed forces, the Customer may apply and be eligible for billing under this Special Provision.

Each Customer shall be eligible for billing under this Special Provision upon submitting an Application for Veterans' Organization Service under this service classification and by qualifying as a "Veterans' Organization" as defined by N.J.S.A. 48:2-21.41 defines a Veterans' Organization that qualifies for this Special Provision as "an organization dedicated to serving the needs of veterans of the armed forces that: is chartered under federal law, qualifies as a tax exempt organization under paragraph (19) of subsection (c) of section 501 of the federal Internal Revenue Code of 1986, 26 U.S.C. s.501(c)(19), or that is organized as a corporation under the 'New Jersey Nonprofit Corporation Act,' N.J.S.15A:1-1 et seq." Under N.J.S.A. 48:2-21.41, a qualified Veterans' Organization shall be charged the residential rate for service delivered to the property where the Veterans' Organization primarily operates, if the residential rate is lower than the commercial rate for service at that property.

The Customer shall furnish satisfactory proof of eligibility of service under this Special Provision to the Company. Once proof of eligibility is determined by the Company, service under this Special Provision shall begin with the next billing cycle following receipt of the Application.

The Customer will continue to be billed on this service classification. At least once annually, the Company shall review eligible Customers' charges for service delivered, defined to include Service Charges, Demand Charges and Distribution Charges, under this Special Provision for all relevant periods. If these comparable charges for service delivered under the Residential Delivery Service (RDS) classification are lower than the charges under this classification a credit in the amount of the difference shall be applied to the Customer's next bill.

SERVICE CLASSIFICATION
COMMERCIAL & INDUSTRIAL NATURAL GAS VEHICLE SERVICE (NGV)

APPLICABLE TO USE OF SERVICE FOR:

This Service Classification is available to any non-Residential Customer who wishes to purchase natural gas sales and/or transportation service and have the Company own and maintain facilities at Customer's premises to compress gas into CNG ("CNG Fueling Facilities") for use as fuel for self-propelled motor vehicles ("Vehicular Gas"). This Service Classification also sets forth the terms and conditions under which the Company may sell and/or distribute Vehicular Gas at CNG Fueling Facilities operated by the Company as Public Fueling Stations.

CHARACTER OF SERVICE:

Continuous to Customers signing a Natural Gas Vehicle ("NGV") Service Agreement ("Agreement").

CONDITIONS PRECEDENT:

A Customer must sign an NGV Agreement with the Company to receive continuous service under this Service Classification. Service under such NGV Agreement is for the term of the NGV Agreement and may be continued beyond the term of the NGV Agreement only by the mutual agreement of Company and Customer. Members of the general public who wish only to obtain Vehicular Gas at Public Fueling Stations need not sign an NGV Agreement. Such members of the public have no entitlement to continuous service under this Service Classification. Service under this Service Classification will be separately metered. Customers must indicate in their Agreements whether they will purchase gas supply from Company or from a TPS.

Section 6.01 of the Standard Terms and Conditions of this Tariff sets forth standards that establish the Company's liability for damages. Section 6.01 applies to any claim arising from services provided or facilities constructed, maintained or operated by Company under this Service Classification. Moreover, the specific provisions of Section 6.01 that apply to Customers will apply both to Customers signing an NGV Service Agreement and members of the public who obtain Vehicular Natural Gas under this Service Classification.

STANDARD TERMS AND CONDITIONS:

This Service Classification is subject to the Standard Terms and Conditions of this Tariff.

LICENSING, PERMITS AND LEGAL REQUIREMENTS:

Customers installing CNG Fueling Facilities on their premises must meet all applicable licensing, permitting and other legal requirements associated with operating CNG Fueling Facilities or Company may suspend or terminate service to such facilities without further liability.

SERVICE CLASSIFICATION
COMMERCIAL & INDUSTRIAL NATURAL GAS VEHICLE SERVICE (NGV)
(continued)

MAIN AND SERVICE EXTENSIONS FOR NGV SERVICE, CNG FUELING FACILITIES AND THE INCREMENTAL COSTS OF CNG-POWERED VEHICLES:

Under this Service Classification, Company may construct and/or install mains, services, automatic meter reading devices, and other facilities necessary to provide sales and transportation service to Customers. Company may also construct and/or install CNG Fueling Facilities located behind Customer's meter. Company may also construct Public Fueling Stations. On a not unduly discriminatory basis, Company may require revenue guarantees sufficient to enable Company to fully recover the costs of all such facilities over a negotiated period as set forth in the NGV Agreement. All negotiated charges under this Service Classification may be revised at the expiration of the term of an NGV Agreement and reflected in any new/replacement NGV Agreement.

Subject to an appropriate revenue guarantee, Company may invest up to ten times the projected annual Distribution Revenues from service provided under this Service Classification in facilities necessary to provide service under this Service Classification. To the extent that Company's investment exceeds ten times projected annual Distribution Revenues, Customer will be assessed a CNG Facilities Charge sufficient to recover Company's excess investment (including its authorized pre-tax return). In lieu of paying a Facilities Charge, Customer may provide a Contribution In Aid of Construction. To the extent that this Section of the NGV Service Classification conflicts with Section 3 of the Standard Terms and Condition of Company's Tariff with respect to service provided under this Service Classification, this Section will control.

I. COMPANY-OWNED AND MAINTAINED CNG FUELING FACILITIES ON CUSTOMERS' PREMISES

Customer may elect to have Company construct, own, and maintain CNG Fueling Facilities at Customer's Premises ("Customers' Premises Facilities"). Such service does not include the dispensing of CNG into vehicles. Under this option, the dispensing of CNG into vehicles shall be the sole responsibility of the Customer. In addition, Customer may, at its option, either contract and pay separately for electricity needed to operate the CNG Fueling Facility or have the Company contract for such electricity and pass through its actual electricity costs to Customer.

SERVICE CLASSIFICATION
COMMERCIAL & INDUSTRIAL NATURAL GAS VEHICLE SERVICE (NGV)
(continued)

Rates and Charges Applicable to Customers' Premises Facilities:*

The following rates and charges apply to service under this Service Classification at Customers' Premises Facilities:

1. Distribution Charge - $0.4500 per therm

2. Fueling Station Charge

   A Fixed monthly amount, designed on an individual Customer basis to recover the Company's projected cost of maintaining the Customer's specific CNG Fueling Facility.

3. Facilities Charge

   A Fixed monthly amount, designed on an individual Customer basis to recover Company investment in excess of ten times projected annual Distribution Revenues in facilities necessary to provide service under this Service Classification. The Facilities Charge shall be computed by multiplying the Company's investment in excess of ten times projected annual Distribution Revenue (including its authorized pre-tax return) by an appropriate percentage that will be based upon the term of the NGV Agreement.

4. Gas Cost

   BGSS-M rate applicable to month of sale for gas sold by Company, not applicable if supplied by a TPS.

5. Taxes and Fees

   Motor Fuel and all other taxes and fees or other similar charges applicable to sale and/or transportation of Vehicular Gas. The remittance of any applicable taxes related to such use shall be the sole responsibility of the Company.

*The charges set forth in this section exclude sales and use tax and will be adjusted for all other applicable Riders of this Tariff and any additional taxes, fees or similar charges that are lawfully imposed by the Company. A Customer that receives gas supply from a TPS will be charged for commodity according to the agreement between the Customer and the TPS.

SERVICE CLASSIFICATION
COMMERCIAL & INDUSTRIAL NATURAL GAS VEHICLE SERVICE (NGV)
(continued)

Sales of Vehicular Natural Gas to Third Parties:

Customer may agree in the Agreement to allow its CNG Fueling Station to be used to sell and dispense CNG to the general public. Such sales will be made at publicly posted prices as determined by the Customer. Distribution Charge revenues from sales to the public shall be credited against any revenue guarantee obligation of Customer.

II. PUBLIC FUELING STATIONS

Company may construct, operate and maintain CNG Fueling Facilities for the purpose of providing Vehicular Gas to the general public.

Rates and Charges Applicable to Company Owned Public Fueling Stations:*

If Company offers service to the general public, the Company shall charge the rates set forth below. The Company shall post such rates at each Public Fueling Facility owned and operated by the Company. The price shall be the Gasoline Gallon Equivalent ("GGE") of a price per therm that includes the following components:

Distribution Charge	$0.4500 per therm
Fueling Station Charge	$0.4100 per therm
Facilities Charge	$0.3771 per therm
Gas Cost	BGSS-M rate applicable to the month of sale
Taxes and Fees	Motor fuel and all other taxes and fees or other similar charges applicable to sales of Vehicular Gas. The remittance of any applicable taxes related to such use shall be the sole responsibility of the Company.

*The charges set forth in this section exclude sales and use tax and will be adjusted for all other applicable Riders of this Tariff and any taxes fees or similar charges that are lawfully imposed by the Company.

SERVICE CLASSIFICATION
COMMERCIAL & INDUSTRIAL NATURAL GAS VEHICLE SERVICE (NGV)
(continued)

SPECIAL PROVISIONS, APPLICABLE TO CUSTOMERS RECEIVING GAS SUPPLY FROM THIRD PARTY SUPPLIERS ("TPS"):

1. Service Agreement

The signing of a Service Agreement and possession by the Customer of a fully executed contract to purchase gas from a TPS are conditions precedent to receiving gas supply from a TPS.

2. Automatic Meter Reading (AMR) Equipment

Customer shall pay for all costs to install AMR equipment including power, communications and other equipment as specified by the Company and provide access for such equipment. Payments made by the Customer shall not give the Customers ownership of the equipment which shall remain the sole property of the Company.

3. Gas Commingling

Service under this Service Classification is provided by the Company within its service territory for the Customer. The gas transported under this Service Classification is not the property of the Company. However, the Company reserves the right to commingle such gas with other supplies. Moreover, the Company reserves the right to utilize Customer's gas, when necessary, in accordance with the applicable curtailment provisions of this Tariff.

4. Transportation to Gas Company Facilities

The Company is not responsible for making arrangements for transportation service Customers for transporting the gas from its source to the Company's interconnection with the delivering pipeline supplier.

5. Nominations for Service

The Customer's TPS shall nominate on behalf of its Customers the daily requirements.

SERVICE CLASSIFICATION
COMMERCIAL & INDUSTRIAL NATURAL GAS VEHICLE SERVICE (NGV)
(continued)

SPECIAL PROVISIONS, APPLICABLE TO CUSTOMERS RECEIVING GAS SUPPLY FROM THIRD PARTY SUPPLIERS ("TPS"): (continued)

6. Utilizing a Third Party Supplier

A Customer choosing to contract with a TPS for supply service will be enrolled for this service with the Company by the TPS on their behalf. A Customer will receive a confirmation notice from the Company notifying them of their enrollment by a TPS and that the Customer should contact the TPS noted on the letter within seven (7) calendar days if they seek to have it rescinded. Customer agrees that as between the Company and Customer, the Company shall be entitled to rely upon information concerning deliveries of natural gas on behalf of Customer provided by TPS.

7. Imbalance Charges

To the extent that a TPS ceases operations or under delivers gas, Customers shall be ultimately responsible for payment of any charges not paid for by their TPS, including but not limited to daily and/or monthly imbalance charges for gas supplies consumed by Customer but not delivered by TPS. In the event a TPS fails to pay these charges the Customers shall be billed directly by the Company for their direct portion, if by their non-compliance to Company directives to cease gas use, and/or a prorata share by applying the Allocation of Supply terms of the TPS Service Classification, except that essential service gas Customers will first be credited with standby gas purchased by the TPS on their behalf.

8. Gas Supply Obligation

In the event that Customer's TPS fails to deliver, the Company may, in its sole discretion, provide replacement gas supplies. The Company shall have no obligation to provide natural gas supplies to Customers that contract for TPS Service, except for those whose TPS contracted for Standby Service, limited to Essential Gas User Customers. In the event that a Customer that is not covered by Standby Service seeks to purchase natural gas supplies from the Company, such sales may be made by the Company in its sole discretion under such terms and conditions as the Company may require.

SERVICE CLASSIFICATION
COMMERCIAL & INDUSTRIAL NATURAL GAS VEHICLE SERVICE (NGV)
(continued)

SPECIAL PROVISIONS, APPLICABLE TO CUSTOMERS RECEIVING GAS SUPPLY FROM THIRD PARTY SUPPLIERS ("TPS"): (continued)

9. Indemnification

As between Company and Customer, Customer warrants that it has clear title to any gas supplies delivered into the Company's system for redelivery to Customer and Customer shall be deemed to be in exclusive control and possession of gas prior to its delivery into the Company's system for redelivery to Customer. Customer agrees to indemnify, defend and hold harmless Company from any and all claims, suits or damage actions arising out of deliveries of gas on behalf of transporting Customer.

SERVICE CLASSIFICATION – LARGE VOLUME DEMAND (LVD)

The signing of a service agreement is a condition precedent to receiving service under this classification. The Service Agreement will include the Customer's Demand Charge Quantity (DCQ).

APPLICABLE TO USE OF SERVICE FOR:

Applicable to Commercial and Industrial Users, with a DQQ of 2,000 or more up to the maximum daily demands as set forth in the Service Agreement, provided that all firm gas service is supplied under this rate, Gas Company's facilities are suitable, and the required quantity of gas is available for the service desired. The consumption of gas in different locations will not be combined for billing purposes.

CHARACTER OF SERVICE:

Continuous Customers may either purchase gas supply from a TPS or the Company's Rider "A", Basic Gas Supply Service ("BGSS").

*CHARGE PER MONTH:

	Tax-Exempt	Taxable
Service Charge	$380.00	$405.18
Demand Charge per DCQ	$1.750	$1.866
Distribution Charge per Therm	$0.0614	$0.0655
Commodity Charge	Per BGSS Rider "A" or TPS Agreement	

*The charges set forth in this Service Classification include sales and use tax and will be adjusted for all other applicable Riders of this Tariff and any additional taxes or similar charges that are lawfully imposed by the Company. A Customer that receives gas supply from a TPS will be charged for commodity according to any agreement between the Customer and the TPS.

DETERMINATION OF THE DEMAND CHARGE QUANTITY ("DCQ"):

The DCQ will be determined by the Customer's maximum daily requirements in terms of therms per day and included in the Service Agreement.

The DCQ level shall be the highest actual daily metered consumption registered from an approved automatic meter reading device at Customer's premises within a period of not less than two years, but up to three years immediately preceding the Customer obtaining service or renewing a Service Agreement under this Service Classification if such information is available. Otherwise DCQ shall be set equal to the product of (1) the highest winter monthly consumption for the most recent winter (October through April), normalized for weather, divided by the applicable

SERVICE CLASSIFICATION – LARGE VOLUME DEMAND (LVD)
(continued)

DETERMINATION OF THE DEMAND CHARGE QUANTITY (“DCQ”): (continued)

number of days in the respective billing month, and (2) 1.36, provided that DCQ shall not be less than the highest non-winter month consumption divided by the applicable number of days in the respective billing month. For process loads, the Company may base the DCQ on historical consumption. If historical consumption information is not available, then (a) the initial DCQ level shall be based upon the Customer’s gas utilization equipment expressed in consumption per day, and (b) after twelve (12) months of actual consumption has been metered, the DCQ level shall be redetermined.

If the Customer’s maximum daily usage exceeds the contract demand as stated in the Service Agreement more than three (3) times in twelve (12) months, the Company may increase the DCQ in the Service Agreement to the highest level experienced during the previous 12 months.

MINIMUM MONTHLY CHARGE:

The sum of the Service Charge and the Demand Charge.

TERM OF PAYMENT:

All bills are due upon presentation. Should the Customer fail to make payment in full, the Company may, within the time period specified in and in accordance with Section 7.10 of the Standard Terms and Conditions of this Tariff, assess late payment charges.

TERM OF CONTRACT:

The term of the contract will be as specified in the individual Service Agreement, however, the term shall not be less than one year. The term of the contract will automatically renew unless the Customer notifies the Company in writing sixty (60) days prior to contract termination. The Customer may switch to a firm transportation service to receive gas supply from a TPS per the provisions of this classification. In the event that a Customer ceases operations completely or moves its operations to a location where the Company does not provide service, Customer shall not be liable for further charges under the Service Agreement upon notification to the Company in writing.

STANDARD TERMS AND CONDITIONS:

This Service Classification is subject to the Standard Terms and Conditions of this Tariff.

SERVICE CLASSIFICATION – LARGE VOLUME DEMAND (LVD)
(continued)

SPECIAL PROVISIONS SECTIONS I & II:

I. SPECIAL PROVISIONS, APPLICABLE TO ALL CUSTOMERS RECEIVING SERVICE UNDER THIS SERVICE CLASSIFICATION

1. Plant Shutdowns

In the event Customer is compelled to shutdown operation of its entire manufacturing or commercial facilities because of a major disaster, major strike, or order of any court or administrative agency having jurisdiction, and said shutdown continues in effect through a full calendar month, Gas Company, upon written request from Customer, may adjust the Minimum Charge for the calendar month. Separate written requests by Customer must be made for each month in which an adjustment of the Minimum Charge is desired and said request shall set forth in detail the exact reasons therefor.

2. Standby Equipment and Fuel

It is the Customer's responsibility to provide for alternate energy facilities needed, if any to provide plant protection service, including cool down periods for refractory, during periods in which gas may be curtailed in accordance with curtailment plan authorized by the State of New Jersey or appropriate Federal Government Agency that are applicable to the Company's operation. In addition, the Gas Company reserves the right to interrupt or suspend service rendered hereunder by Customer if, in the sole judgement of the Company, it is necessary to meet system integrity or to meet other emergency demands under its Curtailment Action Plan as set forth in Section I of this tariff.

3. Facility Charges

The costs of any changes in the facilities of the Gas Company necessary to render this service will be paid for by the Customer.

4. Unauthorized Use

This Service Classification is subject to Unauthorized Gas Use Section of the Standard Terms and Conditions.

SERVICE CLASSIFICATION – LARGE VOLUME DEMAND (LVD)
(continued)

II. SPECIAL PROVISIONS, APPLICABLE TO CUSTOMERS RECEIVING GAS SUPPLY FROM THIRD PARTY SUPPLIERS (TPS)

1. Service Agreement

The signing of a Service Agreement and possession by the Customer of a fully executed contract to purchase gas from a TPS are conditions precedent to receiving gas supply from a TPS.

2. Gas Commingling

Service under this classification is provided by the Company within its service territory for the Customer. The gas transported under this Service Classification is not the property of the Company. However, the Company reserves the right to commingle such gas, when necessary, in accordance with the applicable curtailment provisions of this Tariff.

3. Transportation to Gas Company Facilities

The Company is not responsible for making arrangements for transportation service Customers for transporting the gas from its source to the Company's interconnection with the delivering pipeline supplier.

4. Nominations for Service

The Customer's TPS shall nominate on behalf of its Customer's total monthly requirements for that billing month.

5. Utilizing a Third Party Supplier

Customers utilizing a TPS (including brokers and marketers) either as agents or as suppliers of gas into the Company's system, must notify the Company in writing of the TPS that will be used in any particular month. Customer agrees that as between the Company and Customer, the Company shall be entitled to rely upon information concerning deliveries of natural gas on behalf of Customer provided by TPS. Any Customer or TPS that wishes to deliver gas into the Company's system prior to commencing deliveries must be a qualified under the Company's TPS service classification.

SERVICE CLASSIFICATION – LARGE VOLUME DEMAND (LVD)
(continued)

II. SPECIAL PROVISIONS, APPLICABLE TO CUSTOMERS RECEIVING GAS SUPPLY FROM THIRD PARTY SUPPLIERS (TPS) (continued)

6. Imbalance Charges

To the extent that a TPS ceases operations or under delivers gas, Customers shall be ultimately responsible for payment of any charges not paid for by their TPS, including but not limited to daily and or monthly imbalance charges for gas supplies consumed by Customer but not delivered by TPS. In the event a TPS fails to pay these charges, the Customer shall be billed directly by the Company for its direct portion, if by its non-compliance to Company directives to cease gas use, and/or a prorata share by applying the Allocation of Supply terms of the TPS Service Classification, except that essential service gas Customers will first be credited with standby gas purchased by the TPS on their behalf.

7. Automatic Meter Reading (AMR) Equipment for Customers

In order to utilize this service, (AMR) equipment is required. Customer shall pay for all costs to install (AMR) equipment including power, communications and other equipment as specified by the Company and provide access for such equipment. The cost of any Company equipment may be paid by Customer over a one (1) year or some lesser period by means of a monthly surcharge designed to recover the cost of the equipment plus interest equal to the Company's overall rate of return as authorized from time to time by the New Jersey Board of Public Utilities. Payments made by the Customer shall not give the Customers ownership of the equipment, which shall remain the sole property of the Company.

8. Unauthorized Use

This Service Classification is subject to Unauthorized Gas Use of the Standard Terms and Conditions.

9. Gas Supply Obligation

In the event that Customer's TPS fails to deliver, the Company may, in its sole discretion, provide replacement gas supplies. The Company shall have no obligation to provide natural gas supplies to Customers that contract for TPS Service, except for those whose TPS contracted for Standby Service, limited to Essential Gas User customers. In the event that a Customer that is not covered by Standby Service seeks to purchase natural gas supplies from the Company, such sales may be made by the Company in its sole discretion under such terms and conditions as the Company may require.

SERVICE CLASSIFICATION – LARGE VOLUME DEMAND (LVD)
(continued)

II. SPECIAL PROVISIONS, APPLICABLE TO CUSTOMERS RECEIVING GAS SUPPLY FROM THIRD PARTY SUPPLIERS (TPS) (continued)

10. Limitations on the Availability of Transportation Service

TPS Service is not available to Customers who are defined as “Essential Gas Users” under the curtailment provision as set forth in Section 16 of the Standard Terms and Conditions of this Tariff unless such Customers’ TPS, in an amount sufficient to meet such Customers’ DCQ, agrees to contract and pay for Standby Service as defined in the TPS Service Classification or for such Customers’ TPS demonstrates that it possesses Comparable Capacity as defined in the TPS Service Classification.

11. Indemnification

As between Company and Customer, Customer warrants that it has clear title to any gas supplies delivered into the Company’s system for redelivery to Customer and Customer shall be deemed to be in exclusive control and possession of gas prior to its delivery into the Company’s system for redelivery to Customer. Customer agrees to indemnify, defend and hold harmless Company from any and all claims, suits or damage actions arising out of deliveries of gas into Company’s system on behalf of transporting customer.

SERVICE CLASSIFICATION – ELECTRIC GENERATION FIRM SERVICE (EGF)

All Customers must sign a Service Agreement. Service will be restricted to the maximum annual and hourly requirements, and the location and equipment specified in the Agreement.

APPLICABLE TO USE OF SERVICE FOR:

Available to customers who utilize natural gas for Qualifying Cogeneration, as defined below, Distributive Generation, Micro Turbine and Fuel Cells at facilities with a rated production of over 500 Kilowatts (kW). Customers have the option of taking service under this Service Classification or negotiating a sales and/or transportation service contract which will be filed with the BPU.

A Qualifying Cogeneration Facility is one that meets the Federal Energy Regulatory Commission (FERC) certification of qualifying status for the sequential production of electrical and/or mechanical energy and useful thermal energy from the same fuel source by a facility as defined in Section 201 of the Regulatory Policies Act of 1978.

CHARACTER OF SERVICE:

Continuous

*CHARGE PER MONTH:

	Tax-Exempt (1)	Taxable (2)
Service Charge	$95.00	$101.29
Demand Charge per DCQ	$0.750	$0.800
Distribution Charge per Therm	$0.0395	$0.0421
Commodity Charge	Per Rider “A”	Per Rider “A”

* The charges set forth in this Service Classification include sales and use tax, unless noted tax-exempt and will be adjusted for all other applicable Riders of this Tariff and any additional taxes or similar charges that are lawfully imposed by the Company.

(1) Tax-Exempt rates apply to cogeneration facilities that are in compliance with the terms of N.J.S.A. 54:30A-50.

(2) Taxable rates apply to Customers, unless specifically exempted by law, entering Service Agreements with the Company after 3/10/1997.

SERVICE CLASSIFICATION – ELECTRIC GENERATION FIRM SERVICE - (EGF)
(continued)

DETERMINATION OF THE DEMAND CHARGE QUANTITY (“DCQ”):

The DCQ will be determined by the Customer’s maximum daily requirements in terms of therms per day and included in the Service Agreement.

The DCQ level shall be the highest actual daily metered consumption registered from an approved automatic meter reading device at Customer’s premises within a period of not less than two years, but up to three years immediately preceding the Customer obtaining service or renewing a Service Agreement under this Service Classification if such information is available. Otherwise DCQ shall be set equal to the product of (1) the highest winter monthly consumption for the most recent winter (October through April), normalized for weather, divided by the applicable number of days in the respective billing month, and (2) 1.36, provided that DCQ shall not be less than the highest non-winter month consumption divided by the applicable number of days in the respective billing month. For process loads, the Company may base the DCQ on historical consumption. If historical consumption information is not available, then (a) the initial DCQ level shall be based upon the Customer’s gas utilization equipment expressed in consumption per day, and (b) after twelve (12) months of actual consumption has been metered, the DCQ level shall be redetermined.

If the Customer’s maximum daily usage exceeds the DCQ as stated in the Service Agreement more than three (3) times in twelve (12) months, the Company may increase the DCQ in the Service Agreement to the highest level of usage experienced within the past 12 months.

The billing demand quantity for the initial month of gas consumption shall be the rated twenty-four (24) hour input of the connected equipment expressed in equivalent therms.

Demands established during the billing months of May through September, inclusive, will not be used for billing purposes to the extent that such demands exceed previously established billing demands.

MINIMUM MONTHLY CHARGE:

The sum of the Service Charge and the Demand Charge.

TERM OF PAYMENT:

All bills are due upon presentation. Should the Customer fail to make payment in full, the Company may, within the time period specified in and in accordance with Section 7.10 of the Standard Terms and Conditions of this Tariff, assess late payment charges.

SERVICE CLASSIFICATION – ELECTRIC GENERATION FIRM SERVICE - (EGF)
(continued)

TERM OF CONTRACT:

The term of the contract will be specified in the Service Agreement, but shall not be less than two years. Successive two-year terms shall be provided unless terminated by written notice prior to 60 days of the contract anniversary date.

STANDARD TERMS AND CONDITIONS:

This Service Classification is subject to the Standard Terms and Conditions of this Tariff.

SPECIAL PROVISIONS:

1. Maximum Gas Usage and Deliveries

Service will be restricted to the maximum annual and hourly requirements, and the location and equipment specified in the Service Agreement. Upon request by Customer, Company may deliver available quantities of gas in excess of maximum hourly requirement for limited periods. Such deliveries shall not be deemed to constitute a change in the requirements specified in the Service Agreement.

2. Qualifying Facilities and Reporting

Customer must certify that qualifying status has been granted by the FERC and any other agencies required to grant operating status to the facility. The Customer is required to file with the Company all publicly available reports, related to cogeneration operation, that are filed with State and Federal agencies.

3. Metering

Service supplied under this Service Classification shall be separately metered.

4. Unauthorized Use

This Service Classification is subject to Unauthorized Gas Use Section of the Standard Terms and Conditions.

SERVICE CLASSIFICATION – GAS LIGHT SERVICE (GLS)

This Service Classification is limited to un-metered Gas Lights whose cost of maintenance and repair shall be the responsibility of Customer.

APPLICABLE TO USE OF SERVICE FOR:

Customers who have the gas supply for their outdoor lighting fixtures connected directly to the gas service pipe without being metered.

CHARACTER OF SERVICE:

Continuous.

CHARGE PER MONTH:

The Distribution Charge for this service shall be at the flat rate of $11.31 per Mantel Equivalent, inclusive of taxes, for each .02 therms of hourly input rating of the lighting fixtures. Input ratings shall be those of the manufacturer of the gas lighting fixtures or as determined by actual test or calculation made by Gas Company. The rate set forth above will be adjusted for the Periodic Basic Gas Supply Service Charge (BGSS-P) of this Tariff as well as all other applicable Riders of this Tariff and any additional taxes or similar charges that are lawfully imposed by the Company. Per Therm charges shall be determined by the Company using the following factors times the applicable rates noted above:

Mantel Equivalents = fixture input rating / .02 therms of hourly input
Un Metered Billing Therms = Mantel Equivalents *.02 * 24 hours * 365 / 12

MINIMUM MONTHLY CHARGE:

Flat rate as shown above.

TERM OF PAYMENT:

All bills are due upon presentation. Should a non-residential GLS Customer fail to make payment in full, the Company may, within the time period specified in and in accordance with Section 7.10 of the Standard Terms and Conditions of this Tariff, assess late payment charges.

TERM OF CONTRACT:

One year, and thereafter until terminated by five (5) days written notice.

STANDARD TERMS AND CONDITIONS:

This Service Classification is subject to the Standard Terms and Conditions of this Tariff.

SERVICE CLASSIFICATION - COGENERATION SERVICE – INTERRUPTIBLE (CSI)
CLOSED TO NEW CUSTOMERS

This Service Classification is only available to qualifying cogeneration facilities served under this classification on or after January 1, 2010, as well as additional facilities added at these Customers existing cogeneration sites after this date.

The signing of a Service Agreement and Federal Energy Regulatory Commission (FERC) certification of qualifying status are conditions precedent to receiving service under this Service Classification.

APPLICABLE TO USE OF SERVICE FOR:

The sequential production of electrical and/or mechanical energy and useful thermal energy from the same fuel source by a Qualifying Facility as defined in Section 201 of the Regulatory Policies Act of 1978.

Customer must certify that qualifying status has been granted by the FERC and will be required to sign a Service Agreement. Service will be restricted to the maximum annual and hourly requirements, and the location and equipment specified in the Agreement.

CHARACTER OF SERVICE:

Interruptible.

Gas will be available at the sole option of the Gas Company when peaking supplies are not required to meet the gas demands of customers served under firm service classifications or other system requirements.

Service may be discontinued or curtailed at the sole option of the Gas Company after not less than three (3) hours notice by telephone or otherwise.

*CHARGE PER MONTH:

	Tax-Exempt	Taxable
Service Charge	$164.67	$175.58
Quantity Charge	*	*

*The Quantity Charge shall be the monthly Basic Gas Supply Service Charge (“BGSS-M”) plus $0.0300 per therm pre taxes. In addition, the total monthly charge will be adjusted for all applicable riders or taxes of this tariff.

Date of Issue: XXX1

Effective: Service Rendered on and after XXX2

Issued by: Christie McMullen, President
520 Green Lane
Union, New Jersey 07083

Filed Pursuant to Order of the Board of Public Utilities
Dated XXX3 in Docket No. XXX4

SERVICE CLASSIFICATION – COGENERATION SERVICE – INTERRUPTIBLE (CSI)
CLOSED TO NEW CUSTOMERS
(continued)

MINIMUM MONTHLY CHARGE:

Service Charge.

TERM OF PAYMENT:

All bills are due upon presentation. Should the Customer fail to make payment in full, the Company may, within the time period specified in and in accordance with Section 7.10 of the Standard Terms and Conditions of this Tariff, assess late payment charges.

TERM OF CONTRACT:

The term of the contract will be specified in the Service Agreement, but shall not be less than one year. Successive one-year term extensions shall be provided for thereafter, unless terminated by written notice prior to 60 days of the contract anniversary date.

STANDARD TERMS AND CONDITIONS:

This Service Classification is subject to the Standard Terms and Conditions of this Tariff.

SPECIAL PROVISIONS:

1. Reports

Customer is required to file with the Company all publicly available reports, related to cogeneration operation, that are filed with State and Federal agencies.

2. Metering

Service supplied under this Service Classification shall be separately metered.

3. FERC Status

Customer must certify that qualifying status has been granted by the FERC and will be required to sign a Service Agreement. Service will be restricted to maximum annual and hourly requirements, and the location and equipment specified in the agreement. Upon request by customer, Elizabethtown may deliver available volumes of gas in excess of maximum hourly requirements for limited periods. Such deliveries shall not be deemed to constitute a change in the requirements specified in the Agreement.

SERVICE CLASSIFICATION – COGENERATION SERVICE – INTERRUPTIBLE (CSI)
CLOSED TO NEW CUSTOMERS
(continued)

SPECIAL PROVISIONS: (continued)

4. Standby Equipment and Fuel

It is the Customer's full responsibility to have standby equipment installed and maintained in operating condition and a fuel supply adequate for its operation at all times.

5. Interruption of Service

The Company reserves the right to physically curtail the gas service to any Customer if, in the Company's sole judgment, such action is necessary to protect the operation of its system.

6. Gas Day

A "day" shall be a period of twenty-four (24) consecutive hours, beginning as near as practical to 8 a.m., or as otherwise agreed upon by Customer and Gas Company.

7. Tax Exemption

The cogeneration facility must be in compliance with N.J.S.A. 54:30A-50 in order to be exempt from applicable taxes.

UNAUTHORIZED USE:

This Service Classification is subject to Unauthorized Gas Use Section of the Standard Terms and Conditions.

TREATMENT OF REVENUES:

Eighty (80%) percent of all revenues produced under this Service Classification, exclusive of: Service Charges, and applicable Riders, taxes and the BGSS-M component of the Quantity Charge that shall be credited to the BGSS, after removing applicable taxes, shall be credited to the OSMC in accordance with the Board's Order in Docket No. GO99030122, 20% retained by the Company.

SERVICE CLASSIFICATION – INTERRUPTIBLE SERVICE (IS)

The signing of a service agreement is a condition precedent to receiving service under this classification. The Service Agreement will include the Customer's maximum daily requirements.

APPLICABLE TO USE OF SERVICE FOR:

Industrial boiler and commercial boiler use Customers having an alternate fuel capability with a daily demand of not less than 500 therms per day up to a maximum daily demand as set forth in the Service Agreement, providing the Gas Company facilities are suitable and when the Gas Company in its sole discretion deems sufficient gas supplies to be available for this service.

Gas delivered will be separately metered and shall not be used interchangeably with gas supplied under any other Service Classification.

CHARACTER OF SERVICE:

Interruptible

Gas will be available for interruptible service at the sole option of the Gas Company when peaking supplies are not required to meet the gas demands of Customers served under firm service classifications or other system requirements. Service may be discontinued or curtailed at the sole option of the Gas Company after not less than three (3) hours notice by telephone or otherwise. See also Special Provision – Alternative Fuel Requirement.

*CHARGE PER MONTH:

Service Charge	$735.71
Demand Charge per DCQ	$0.269
Quantity Charge per Therm	**

*The charges set forth above include sales and use tax, unless noted tax exempt, and will be adjusted for all other applicable Riders of this Tariff and any additional taxes or similar charges that are lawfully imposed by the Company.

**The Quantity Charge shall be $0.0843 per therm plus the BGSS-M Charge of Rider "A", plus all other applicable Riders of this Tariff and any additional taxes, or similar charges that are lawfully imposed by the Company. However, it may be adjusted at the sole discretion of the Company each month, upon five (5) days notice to the Board, to a price as described below:

A price equal to the estimated market price expressed in an equivalent rate per therm for No. 2 grade fuel oil using an average BTU content of 136,000 but not less than the floor price nor greater than the ceiling price as described as follows:

SERVICE CLASSIFICATION – INTERRUPTIBLE SERVICE (IS)
(continued)

CHARGE PER MONTH: (continued)

The floor price, as determined monthly, shall be the BGSS-M and an adjustment for applicable taxes plus applicable Riders of this tariff, plus $0.016 per therm during the period April through October or $0.032 per therm during the period November through March and any additional taxes or similar charges that are lawfully imposed by the Company.

The ceiling price shall be $0.9405 per therm plus the BGSS-M Charge of Rider “A”, plus applicable Riders of this Tariff and any additional taxes or similar charges that are lawfully imposed by the Company. The ceiling price will be reviewed for possible adjustment if the spot price for Futures Contract Crude Oil – Light Sweet, as published in the Wall Street Journal, exceeds $130.00 per barrel.

DETERMINATION OF THE DEMAND CHARGE QUANTITY (“DCQ”):

The DCQ will be determined by the Customer’s maximum daily requirements in terms of therms per day and included in the Service Agreement.

The DCQ level shall be the highest actual daily metered consumption registered from an approved automatic meter reading device at Customer’s premises within a period of not less than two years, but up to three years immediately preceding the Customer obtaining service or renewing a Service Agreement under this Service Classification if such information is available. Otherwise DCQ shall be set equal to the product of (1) the highest winter monthly consumption for the most recent winter (October through April), normalized for weather, divided by the applicable number of days in the respective billing month, and (2) 1.36, provided that DCQ shall not be less than the highest non-winter month consumption divided by the applicable number of days in the respective billing month. For process loads, the Company may base the DCQ on historical consumption. If historical consumption information is not available, then (a) the initial DCQ level shall be based upon the Customer’s gas utilization equipment expressed in consumption per day, and (b) after twelve (12) months of actual consumption has been metered, the DCQ level shall be redetermined. If the Customer’s maximum daily usage exceeds the DCQ as stated in the Service Agreement more than three (3) times in twelve (12) months, the Company may increase the DCQ in the Service Agreement to the highest level experienced during the previous 12 months.

MINIMUM MONTHLY CHARGE:

The sum of the Service Charge and the Demand Charge.

SERVICE CLASSIFICATION – INTERRUPTIBLE SERVICE (IS)
(continued)

TERM OF PAYMENT:

All bills are due upon presentation. Should the Customer fail to make payment in full, the Company may, within the time period specified in and in accordance with Section 7.10 of the Standard Terms and Conditions of this Tariff, assess late payment charges.

TERM OF CONTRACT:

Not less than one (1) year, and for successive one (1) year terms thereafter unless terminated by written notice prior to sixty (60) days of the contract anniversary date.

STANDARD TERMS AND CONDITIONS:

This Service Classification is subject to the Standard Terms and Conditions of this Tariff.

SPECIAL PROVISIONS:

1. Standby Equipment and Fuel

It is the Customer's full responsibility to have standby equipment installed and maintained in operating condition and a fuel supply adequate for its operation at all times. The Customer shall provide the Gas Company with an affidavit certifying the grade and sulphur content of fuel oil that can be utilized in the facilities served under this service classification or a description of the alternate fuel used.

2. Pilot Gas

Any gas consumed for pilot lights shall be billed at the GDS rate schedule. Separate metering shall be used where practicable. Where such metering is not practical, a fixed monthly charge based upon the rated input of the pilot will be billed to the Customer.

3. Emergency Service

If an IS Customer requests gas on an emergency basis when gas service would otherwise be precluded under the terms of this service classification, the Gas Company may in its sole discretion tender gas if it determines that an emergency does exist and the Gas Company has the ability to provide the gas service. Gas consumed under the provision will be priced at a rate per therm equal to the greater of:

SERVICE CLASSIFICATION – INTERRUPTIBLE SERVICE (IS)
(continued)

SPECIAL PROVISIONS: (continued)

3. Emergency Service (continued)

a) the incremental cost of gas, as determined by the Gas Company, during the time such service is rendered adjusted for the applicable taxes plus five (5) cents per therm, or

b) the Distribution Charge of the GDS Service Classification rate plus the BGSS-M charge of Rider "A".

4. Plant Shutdown

In the event Customer is compelled to shut down operation of its manufacturing or commercial facilities because of a major disaster, major strike, or a lawful order of any court or administrative agency having jurisdiction, Gas Company, upon written request from Customer, may not apply or collect from Customer the minimum monthly charge established herein during the period Customer's plant shall remain so shut down, and, upon receipt of such request, Gas Company shall have the right to terminate the contract as of the date when such request is received or at any other time during the period of suspension of said minimum monthly charge.

5. Unauthorized Use

This Service Classification is subject to Unauthorized Gas Use Section of the Standard Terms and Conditions.

6. Alternative Fuel Requirement

As of November 1 of each year, interruptible Customers using No. 2 fuel oil, No. 4 fuel, jet fuel or kerosene are required to have seven (7 days) of alternative fuel either on hand or, if a Customer's on-site storage capacity is less than seven (7) days, then full storage capacity plus additional firm contractual supply arrangements to equal seven (7) days. On or before November 1st, Customers shall submit an "Alternative Fuel Certification" indicating they have met the above requirements and the alternative fuel used or will agree to suspend operations during an interruption. Customers who fail to discontinue natural gas use, consistent with the terms and conditions of the relevant interruptible tariff, shall be assessed a charge based on Unauthorized Use.

SERVICE CLASSIFICATION – INTERRUPTIBLE SERVICE (IS)
(continued)

SPECIAL PROVISIONS: (continued)

7. Treatment of Revenues

Eighty (80%) percent of all revenues produced under this Service Classification, exclusive of: Service Charges, Demand Charges, applicable Riders; taxes and the floor price, which shall be credited to the BGSS, after removing applicable taxes shall be credited to the OSMC in accordance with the Board's Order in Docket No. GO99030122, 20% retained by the Company.

SERVICE CLASSIFICATION – CONTRACT SERVICE (CS)

This service classification is limited to those Customers or their successors and assigns under contract on July 18, 1977.

APPLICABLE TO USE OF SERVICE FOR:

Large volume boiler or turbine fuel with connected load in excess of 35,000 therms per day. Terms of service including pressure, capital repayment, operation condition are separately set forth in individual agreements between the Gas Company and the Customers.

Contracts in effect are with:

Service to Gilbert Generating Station and to Glen Gardner Generating Station per service initially begun with Jersey Central Power & Light Company.

CHARACTER OF SERVICE:

Gas will be available at the sole option of the Gas Company when peaking supplies are not required to meet the gas demands of Customers served under firm service classifications or other system requirements.

The Gas Company reserves the right to interrupt this service upon three (3) hours notice by telephone or otherwise if in its sole discretion continuance of service would adversely impact on its ability to adequately serve other Customers or for other operational reasons.

RATE:

Jersey Central Power and Light Company – not to exceed $0.0819 per therm plus the BGSS-M Charge, plus the applicable Riders of this Tariff, net of Sales and Use Tax, in effect at the time of rendering service, but not less than the floor price. The floor price, as determined monthly, shall be the BGSS-M plus pre tax rates of $0.0150 per therm during the period April through October or $0.0320 per therm during the period November through March, plus applicable Riders of this Tariff, plus an adjustment for any other charges lawfully imposed by the Company.

The rate to be charged will be determined solely by the Company within the range described above.

SERVICE CLASSIFICATION – CONTRACT SERVICE (CS)
(continued)

TERM OF PAYMENT:

All bills are due upon presentation. Should the Customer fail to make payment in full, the Company may, within the time period specified in and in accordance with Section 7.10 of the Standard Terms and Conditions of this Tariff, assess late payment charges.

TERM OF CONTRACT:

One year, and for successive one (1) year terms thereafter unless terminated by written notice prior to sixty (60) days of the contract anniversary date.

SPECIAL PROVISIONS:

1. BTU Adjustment

For purposes of billing, all gas volumes delivered under this service classification shall be converted to therms by multiplying the daily volume at standard conditions of pressure (14.73 psia) and temperature (60°F) by the average daily BTU value of the gas.

2. Emergency Service

Emergency service will be provided upon request if the Gas Company in its sole judgment has the facility capability and the gas supplies to render such service. The rate charged for such service shall be equal to the greater of: a) the incremental cost of gas required by the system at the time the emergency service is rendered plus five cents per therm or b) 145 percent of the “projected purchased gas cost used in determining the current BGSS-M Charge for the purposes of Rider A; plus an adjustment for applicable taxes or similar charges. Excess revenues derived from this provision (exclusive of any adjustments) will be applied to the BGSS Charge as recovered gas costs.

SERVICE CLASSIFICATION – CONTRACT SERVICE (CS)
(continued)

SPECIAL PROVISIONS: (continued)

3. Special Purchases

Gas purchased specifically for Service to Gilbert Generating Station and to Glen Gardner Generating Station shall be sold to the Customer(s) incrementally subject to the following conditions as agreed to in writing by all parties and to be in effect for the entire transaction period as specified below:

a) Type of Service

b) Duration of Agreement

c) If the rate agreed upon is to be based upon an oil parity, the following shall be specified in the agreement:

(1) Type of oil to be used for parity purposes

(2) The source from which oil prices will be taken and the method by which the oil parity rate will be computed

(3) The appropriate adjustments to be made to the oil parity rate

(4) The frequency with which the oil parity will be recomputed

d) The rate when an oil parity rate is not used

e) Special contract provisions

The BGSS Charge of this tariff shall not apply to the services provided under this provision. Similarly, all volumes shall be excluded from the calculations associated with the clause.

4. Transportation of Customer Gas

Gas purchased by the Customer and made available for Transportation through the Company system will be delivered to Customer subject to the terms and conditions of a Service Agreement signed by all parties.

SERVICE CLASSIFICATION – CONTRACT SERVICE (CS)
(continued)

SPECIAL PROVISIONS: (continued)

4. Transportation of Customer Gas (continued)

The Service Agreement shall specify the following:

a) Type of Service

b) Duration of Agreement

c) Charges associated with the Service

d) Special contract provisions

5. Storage Service

a) Firm Storage

Availability of Storage Service will be announced by the Company by February 1 of each year. The Customer may subscribe for Firm Storage Service by March 1 of each year. If oversubscribed, the available level of service will be offered pro rata, based on the Customer's actual usage during the 12 months ended December 31. Firm Storage Service will be available for a contract year running May 1 through April 30.

The Storage Service will be available at a 100 day withdrawal rate or a 150 day withdrawal rate. Injections into storage may be made between May 1 and October 31 at a daily rate not to exceed 1/180 of the contracted storage capacity. Withdrawals may be made between November 1 and April 30 at a daily rate not to exceed contract amount as set forth in the Service Agreement. All storage gas must be taken out by April 30. The Company may at times relax these operating conditions if it determines such can be done without adversely affecting service to its sales Customers.

SERVICE CLASSIFICATION – CONTRACT SERVICE (CS)
(continued)

SPECIAL PROVISIONS: (continued)

5. Storage Service (continued)

The charges for Firm Storage Service are as follows:

Customer Accounting Charge	$69.55	per month
Injection Charge	$0.086	per Dth
Withdrawal Charge	None	

Storage Demand Charge (Monthly Charge for 12 Months)

100 day withdrawal rate	$0.152	per Dth of contracted storage capacity
150 day withdrawal rate	$0.116	per Dth of contracted storage capacity

The Company and Customer will enter into a Service Agreement specifying the maximum daily delivery amount and total storage capacity amount. The Customer may not obtain a maximum daily delivery amount in excess of 50% of their maximum daily demand for gas and in no event greater than the maximum daily delivery amount in their Transportation Service Agreement.

b) Limited Storage Service

For the period May through October the Company may offer a limited Storage Service. The charges for such service shall be as follows:

Customer Accounting Charge	$69.55	per month
Injection Charge	$0.086	per Dth
Withdrawal Charge		None
Storage Demand Charge	$0.041	per Dth of contracted storage capacity

SERVICE CLASSIFICATION – CONTRACT SERVICE (CS)
(continued)

SPECIAL PROVISIONS: (continued)

b) Limited Storage Service (continued)

The Company and Customer will enter into a Service Agreement specifying the maximum daily delivery amount and the total storage capacity amount. The Service Agreement will also describe when and how injection and withdrawals can be made. The Customer may not obtain storage capacity for more than 50% of their most recent historical gas consumption for the period of May to October, however that level of consumption may be adjusted upward if the Customer were using alternate fuel instead of gas.

6. Treatment of Revenues

All revenues produced under this Service Classification, exclusive of; Service Charges, and applicable Riders, taxes, and revenues resulting from service under Special Provisions 2, will be apportioned as follows:

a) Sales made under the Rate provision of this service classification:

All remaining revenues in excess of the floor price of gas, after removing applicable taxes, shall be subject to revenue sharing – 80% credited to the OSMC in accordance with the Board's Order in Docket No. GO99030122, 20% retained by the Company.

b) Sales made under Special Provision 3 of this service classification:

All remaining revenues in excess of the costs associated with the special gas purchase shall be subject to revenue sharing – 80% credited to the OSMC in accordance with the Board's Order in Docket No. GO99030122, 20% retained by the Company.

c) Services provided under Special Provision 4 of this service classification:

All remaining revenues in excess of any incremental administrative costs incurred in providing this service shall be subject to revenue sharing – 80% credited to the OSMC in accordance with the Board's Order in Docket No. GO99030122, 20% retained by the Company.

d) Services provided under Special Provision 5 of this service classification:

All remaining revenues in excess of the Customer Accounting Charge shall be subject to revenue sharing – 80% credited to the OSMC in accordance with the Board's Order in Docket No. GO99030122, 20% retained by the Company.

SERVICE CLASSIFICATION – CONTRACT SERVICE (CS)
(continued)

SPECIAL PROVISIONS: (continued)

7. Contract Review

To the extent that any new contracts with terms in excess of three (3) years are entered into under Special Provision 3, 4 and/or 5 of this service classification or any existing contracts under Special Provision 3, 4 and/or 5 with terms in excess of three (3) years are amended, the Company is required to submit such contracts or amendments to the Staff of the Board of Public Utilities for review thirty days prior to the effective date of such contract or amendment.

8. Societal Benefits Charge

The rates set forth above will be adjusted for the Societal Benefits Charge of this Tariff, Rider "D".

9. Applicable Taxes

The charges in this Rate Schedule will include provision for the New Jersey Sales and Use Tax. When billed to Customers exempt from one or more of these taxes, such charges will be reduced by the relevant amount of such taxes included therein.

SERVICE CLASSIFICATION – SUPPLEMENTAL INTERRUPTIBLE SERVICE (SIS)

This service classification is for a limited term. The signing of a service agreement by the Customer with the Gas Company is a condition precedent to receiving service under this service classification.

APPLICABLE TO USE OF SERVICE FOR:

Customers under service classification EGF, CSI, LVD, IS or ITS up to a maximum daily demand as set forth in their existing service agreement, or as set forth in the service agreement under this service classification, providing that Gas Company facilities are suitable and gas supplies can be secured for this service.

CHARACTER OF SERVICE:

Gas will be made available for this service only to the extent that such gas supplies can be incrementally purchased or produced.

The Gas Company reserves the right to interrupt this service upon three (3) hours notice by telephone or otherwise if in its sole discretion continuance of service would adversely impact on its ability to adequately serve other Customers or for other operational reasons.

RATE:

1. Service Charge

Upon initial request of SIS service, Customer will be charged an amount equal to the monthly service charge of the Customer's existing rate. This charge will be reassessed for subsequent initial requests made after June 30 of any year. In addition, a $50.00 daily charge will be assessed, pre-taxes, for each day SIS is utilized.

2. Quantity Charge

The rate per therm for gas used shall be set within a range computed to be (a) the incremental cost of purchasing or producing said gas plus all applicable taxes plus $0.0755 per therm pre taxes and (b) the effective IS rate.

TERM OF PAYMENT:

All bills are due upon presentation. Should the Customer fail to make a payment in full, the Company may, within the time period specified in and in accordance with Section 7.10 of the Standard Terms and Conditions of this Tariff, assess late payment charges.

SERVICE CLASSIFICATION – SUPPLEMENTAL INTERRUPTIBLE SERVICE (SIS)
(continued)

SPECIAL PROVISIONS:

1. Offering of Service

Unless otherwise agreed to in the service agreement:

a) Any Customer who does not accept gas offered under this rate schedule within the period of time allotted by the Company shall be deemed to have rejected such offer and waived all entitlements to the offered gas.

b) Customers normally served under the IS service classification will be offered gas under this service classification only when Interruptible Gas Service does not satisfy total Customer requirements. Any gas supplies available under this service classification shall be offered to qualified Customers on a prorated basis utilizing the Daily Demand Requirements as set forth in the service agreements as the criteria for proration, subject to the operating capabilities and system requirements of the Company.

2. Basic Gas Supply Service Charge

Gas purchased for sale under this service classification shall not be included as part of the gas costs recoverable through the BGSS Charge.

3. Treatment of Revenues

The revenue (exclusive of any service charges and applicable riders, taxes and other similar charges) on a per therm basis produced under this service classification that exceeds the per therm cost of the incrementally purchased or produced gas including applicable taxes and other similar charges shall be subject to the revenue sharing formula associated with the Customer's regular service classification.

4. Obligation to Take Requested Service

If the Customer requests service be rendered under this service classification and if such gas when offered is not used by the Customer, the Customer will be subject to being charged a per therm rate equivalent to the difference between the average gas costs as shown in the then current BGSS Charge and the actual gas cost for all therms unsold by the Gas Company under this service classification during the applicable BGSS Charge period. These revenues will be applied to the BGSS Charge as recovered gas costs. The gas cost and volumes would be applied to the BGSS Charge as purchased gas costs and available volumes.

SERVICE CLASSIFICATION – SUPPLEMENTAL INTERRUPTIBLE SERVICE (SIS)
(continued)

SPECIAL PROVISIONS: (continued)

5. Pricing Modification

The methodology and pricing set forth in the Rate section of this Service Classification may be modified in the service agreement, if agreed to by the Customer and the Company, in order to accommodate market conditions or special Customer requirements (including special requirements if the Customer commits to use gas for a suitable cogeneration facility).

SERVICE CLASSIFICATION – INTERRUPTIBLE TRANSPORTATION SERVICE (ITS)

The signing of a Service Agreement and possession by the Customer of a fully executed contract to purchase gas from a third party are conditions precedent to receiving service under this Service Classification.

APPLICABLE TO USE OF SERVICE FOR:

Customers eligible for service under Service Classifications LVD, IS, or CSI and having clear title to gas that is made available for ITS on the Company's distribution system, except that such Customers need not comply with the alternate fuel requirement of those Service Classifications to receive service hereunder. However, the Customer must comply with the Alternate Fuel Requirement under this Service Classification.

CHARACTER OF SERVICE:

Interruptible Transportation Service will be available when system capacity is not required to meet the demands of Customers served under all other Service Classifications or other system requirements, including, but not limited to, conditions that may be imposed on the Company by its suppliers. The availability of this service, and all determinations and interpretations hereunder, shall be at the sole judgment of the Company. Service may be discontinued or curtailed at the sole option of the Company after not less than three (3) hours notice by telephone or otherwise.

*CHARGE PER MONTH:

	Tax-Exempt	Taxable
Service Charge	$690.00	$735.71
Demand Charge per DCQ	$0.500	$0.533
Distribution Charge per Therm	**	**

*The charges set forth above include sales and use tax, unless noted tax exempt, and will be adjusted for all other applicable Riders of this Tariff and any additional taxes or similar charges that are lawfully imposed by the Company.

**The ceiling for the Distribution Charge shall be $0.1391 per therm or $0.1305 per therm, for tax-exempt Customers, but may be reduced, upon five (5) days notice to the Board to a floor of $0.0262 per therm or $0.0246 for tax exempt Customers, if the Company determines that, without a rate reduction, competitive pressures may result in the loss of load or the Customer. Rates for Customers without alternate fuel capability will be set monthly without reference to a ceiling or floor price. The above rates will be further adjusted to include all other charges set forth in the applicable Riders of this Tariff and any additional taxes or similar charges that are lawfully imposed by the Company.

SERVICE CLASSIFICATION – INTERRUPTIBLE TRANSPORTATION SERVICE (ITS)
(continued)

DETERMINATION OF THE DEMAND CHARGE QUANTITY (DCQ):

DCQ will be determined by the Customer's maximum daily requirements in terms of therms per day and included in the Service Agreement.

The DCQ level shall be the highest actual daily metered consumption registered from an approved automatic meter reading device at Customer's premises within a period of not less than two years, but up to three years immediately preceding the Customer obtaining service or renewing a Service Agreement under this Service Classification if such information is available. Otherwise DCQ shall be set equal to the product of (1) the highest winter monthly consumption for the most recent winter (October through April), normalized for weather, divided by the applicable number of days in the respective billing month, and (2) 1.36, provided that DCQ shall not be less than the highest non-winter month consumption divided by the applicable number of days in the respective billing month. For process loads, the Company may base the DCQ on historical consumption. If historical consumption information is not available, then (a) the initial DCQ level shall be based upon the Customer's gas utilization equipment expressed in consumption per day, and (b) after twelve (12) months of actual consumption has been metered, the DCQ level shall be redetermined.

If the Customer's maximum daily usage exceeds the DCQ as stated in the Service Agreement more than three (3) times in twelve (12) months, the Company may increase the DCQ in the Service Agreement to the highest level experienced during the previous 12 months.

MINIMUM MONTHLY CHARGE:

The sum of the service charge and the demand charge.

TERM OF PAYMENT:

All bills are due upon presentation. Should the Customer fail to make payment in full, the Company may, within the time period specified in and in accordance with Section 7.10 of the Standard Terms and Conditions of this Tariff, assess late payment charges.

SERVICE CLASSIFICATION – INTERRUPTIBLE TRANSPORTATION SERVICE (ITS)
(continued)

TERM OF CONTRACT:

The term of the contract will be as specified in the individual Service Agreement; however, the term shall not be less than one year. The term of the contract will automatically renew unless the Customer notifies the Company in writing sixty (60) days prior to contract termination. In the event that a Customer ceases operations completely or moves its operations to a location where the Company does not provide service, Customer shall not be liable for further charges under the Service Agreement upon notification to the Company in writing.

STANDARD TERMS AND CONDITIONS:

This Service Classification is subject to the Standard Terms and Conditions of this Tariff.

SPECIAL PROVISIONS:

1. Gas Commingling

Service under this classification is provided by the Company within its service territory for the Customer. The gas transported under this Service Classification is not the property of the Company. However, the Company reserves the right to commingle such gas with other supplies. Moreover, the Company reserves the right to utilize Customer’s gas, when necessary, in accordance with the applicable provisions of this Tariff.

2. Transportation to Gas Company Facilities

The Company is not responsible for making arrangements for transportation service Customers for transporting the gas from its source to the Company’s interconnection with the delivering pipeline supplier.

3. Nominations for Service

The Customer’s TPS shall nominate on behalf of its Customers the total monthly requirements for that billing month.

SERVICE CLASSIFICATION – INTERRUPTIBLE TRANSPORTATION SERVICE (ITS)
(continued)

SPECIAL PROVISIONS: (continued)

4. Utilizing a Third Party Supplier

Customers utilizing brokers, marketers or other third party suppliers (collectively Third Party Suppliers, "TPS") either as agents or as suppliers of gas into the Company's system, must notify the Company in a manner acceptable to the Company of the TPS that will be used in any particular month. Customer agrees that as between the Company and Customer, the Company shall be entitled to rely upon information concerning deliveries of natural gas on behalf of Customer provided by TPS. Any Customer or TPS that wishes to deliver gas into the Company's system prior to commencing deliveries must be a qualified TPS under the Company's TPS service classification.

5. Imbalance Charges

To the extent that a TPS ceases operations or under delivers gas, Customers shall be ultimately responsible for payment of any charges not paid for by their TPS, including but not limited to daily and or monthly imbalance charges for gas supplies consumed by Customer but not delivered by TPS. In the event a TPS fails to pay these charges the Customers shall be billed directly by the Company for their direct portion, if by their non-compliance to Company directives to cease gas use, and/or a pro-rata share by applying the Allocation of Supply terms of the TPS Service Classification, except that essential service gas Customers will first be credited with standby gas purchased by the TPS on their behalf.

6. Automatic Meter Reading (AMR) Equipment for Customers

In order to utilize this service, AMR equipment is required. Customer shall pay for all costs to install AMR equipment including power, communications and other equipment as specified by the Company and provide access for such equipment. The cost of any Company equipment may be paid by Customer over a one (1) year, or some lesser, period by means of a monthly surcharge designed to recover the cost of the equipment plus interest equal to the Company's overall rate of return as authorized from time to time by the New Jersey Board of Public Utilities. Payments made by the Customer shall not give the Customers ownership of the equipment which shall remain the sole property of the Company.

7. Unauthorized Use

This Service Classification is subject to Unauthorized Gas Use Section of the Standard Terms and Conditions.

SERVICE CLASSIFICATION – INTERRUPTIBLE TRANSPORTATION SERVICE (ITS)
(continued)

SPECIAL PROVISIONS: (continued)

8. Treatment of Revenues

Revenues under this Service Classification, exclusive of applicable taxes shall be accounted for as follows: All service charge revenues derived from IS, CSI and LVD Customers shall be retained by the Company.

All demand charge revenues derived from LVD Customers shall be retained by the Company. The first $0.080 per therm of all demand charge revenues from IS Customers shall be retained by the Company. All remaining demand revenues derived from IS Customers shall be credited 80% to the OSMC in accordance with the Board's Order in Docket No. GO99030122 and 20% to the Company. All demand revenues derived from CSI Customers shall be credited 80% to the OSMC in accordance with the Board's Order in Docket No. GO99030122 and 20% to the Company.

All distribution charge revenues from LVD Customers shall be retained by the Company. All remaining distribution charge revenues from IS and CSI Customers shall be credited 80% to the OSMC in accordance with the Board's Order in Docket No. GO99030122 and 20% to the Company.

Revenues derived from the application of Riders shall be accounted for in accordance with the respective Riders. Revenues derived from the payment of imbalance charges, imbalance cash outs, or unauthorized use charges shall be credited to the BGSS Charge.

9. Gas Supply Obligation

In the event that Customer's TPS fails to deliver, the Company may, in its sole discretion, provide replacement gas supplies. The Company shall have no obligation to provide natural gas supplies to Customers that contract for TPS Service.

10. Limitations on the Availability of TPS Transportation Service

TPS Service is not available to Customers who are defined as "Essential Gas Users" under the curtailment provision as set forth in Section 16 of the Standard Terms and Conditions of this Tariff unless such Customers' TPS, in an amount sufficient to meet such Customers' DCQ, demonstrates that it possesses Comparable Capacity as defined in the TPS Service Classification. In addition, the TPS can serve such ITS Customers if they can demonstrate to the Company's satisfaction that they possess sufficient alternate fuel capability to meet their energy requirements for a period not less than fourteen (14) consecutive days.

SERVICE CLASSIFICATION – INTERRUPTIBLE TRANSPORTATION SERVICE (ITS)
(continued)

SPECIAL PROVISIONS: (continued)

11. Indemnification

As between Company and Customer, Customer warrants that it has clear title to any gas supplies delivered into the Company's system for redelivery to Customer and Customer shall be deemed to be in exclusive control and possession of gas prior to its delivery into the Company's system for redelivery to Customer. Customer agrees to indemnify, defend and hold harmless Company from any and all claims, suits or damage actions arising out of deliveries of gas on behalf of transporting Customer.

12. Availability of IS, LVD or CSI Service

ITS Customers who wish to do so may be made eligible to purchase sales service under the IS, LVD or CSI Service Classification also by designating the appropriate sales Service Classification in their ITS Service Agreements. Customer must meet the eligibility criteria applied to the designated sales Service Classification in order to obtain sales service. Customers may not designate more than one sales Service Classification. Customers that elect to purchase IS, LVD or CSI service may nominate sales or transportation service, but not both sales and transportation service, in any month. Customers who elect sales service under this provision shall remain subject to the Service and Demand Charges and the terms and conditions of this transportation Service Classification and in addition shall be liable for the Distribution and Rider Charges of the elected sales service.

13. Alternative Fuel Requirement

As of November 1 of each year, interruptible Customers using No. 2 fuel oil, No. 4 fuel, jet fuel or kerosene are required to have seven (7 days) of alternative fuel either on hand or, if a Customer's on-site storage capacity is less than seven (7) days, then full storage capacity plus additional firm contractual supply arrangements to equal seven (7) days. On or before November 1st, Customers shall submit an "Alternative Fuel Certification" indicating they have met the above requirements and the alternative fuel used or will agree to suspend operations during an interruption. Customers who fail to discontinue natural gas use, consistent with the terms and conditions of the relevant interruptible tariff, shall be assessed a charge based on Unauthorized Use. Also see, Special Provision, Limitation of the Availability of TPS Transportation Service.

SERVICE CLASSIFICATION – THIRD PARTY SUPPLIERS (TPS) SERVICE

The provisions of this Service Classification shall apply to brokers, marketers, customers intending to act as their own gas supplier, and other third party suppliers (collectively “Third Party Suppliers”) of natural gas who wish to either act as agents for Transportation Customers or deliver natural gas supplies to Company’s City Gate for Transportation Customers. Third Party Suppliers wishing to sell and/or deliver gas on the Company’s system will be required to sign a Service Agreement in which they will agree to be bound by the terms and conditions of this Service Classification as well as other applicable terms and conditions of the Company’s Tariff. By entering into a Service Agreement, TPS certifies that it is in compliance with all current applicable provisions of law, including N.J.S.A. 48:3-7.3. and will take steps to remain in compliance with all future applicable provisions and all other requirements mandated by the Board.

TERM OF CONTRACT:

The term of the contract shall be one (1) year and from month to month thereafter unless terminated on thirty (30) days written notice.

CREDITWORTHINESS:

Company shall not be required to permit any TPS who fails to meet Company’s standards for creditworthiness to sell or deliver gas on its system. Company may require that TPS provide the following information:

a) Current audited financial statements (to include a balance sheet, income statement and statement of cash flow), annual reports, 10-K reports or other filings with regulatory agencies, a list of all corporate affiliates, parent companies and subsidiaries and any reports from credit agencies which are available. If audited financial statements are not available, then TPS also should provide an attestation by its chief financial officer that the information shown in the unaudited statements submitted is true, correct and a fair representation of Buyer’s financial condition.

b) A bank reference and at least three trade references.

c) A written attestation that TPS is not operating under any chapter of the bankruptcy laws and is not subject to liquidation or debt reduction procedures under state laws, such as an assignment for the benefit of creditors, or any informal creditor’s committee agreement. An exception can be made for a TPS who is a debtor-in-possession operating under Chapter XI of the Federal Bankruptcy Act but only with adequate assurances that any charges from the Company will be paid promptly as a cost of administration.

SERVICE CLASSIFICATION – THIRD PARTY SUPPLIERS (TPS) SERVICE
(continued)

CREDITWORTHINESS: (continued)

d) A written attestation that TPS is not subject to the uncertainty of pending litigation or regulatory proceedings in state or federal courts which could cause a substantial deterioration in its financial condition or a condition of insolvency.

e) A written attestation from TPS that no significant collection lawsuits or judgments are outstanding which would seriously reflect upon the business entity's ability to remain solvent.

If TPS has an ongoing business relationship with Company, no uncontested delinquent balances should be outstanding for natural gas sales, storage, transportation services or imbalances previously billed by Company, and TPS must have paid its account during the past according to the established terms, and not made deductions or withheld payment for claims not authorized by contract.

TPS shall furnish Company at least annually, and at such other time as is requested by Company, updated credit information for the purpose of enabling Company to perform an updated credit appraisal. In addition, Company reserves the right to request such information at any time if Company is not reasonably satisfied with TPS's creditworthiness or ability to pay based on information available to Company at that time.

Company shall not be required to permit and shall have the right to suspend permission to sell or deliver gas on its system to any TPS who is or has become insolvent, fails to demonstrate creditworthiness, fails to timely provide information to Company as requested, or fails to demonstrate ongoing creditworthiness as a result of credit information obtained; provided, however, TPS may continue to sell/deliver gas on the Company's system if Third Party Supplier elects one of the following options:

(i) Payment in advance for up to three (3) months of TPS's obligations to Company.

(ii) A standby irrevocable letter of credit in form and substance satisfactory to Company in a face amount up to three (3) months of Third Party Supplier's obligations to Company. The letter of credit must be drawn upon a bank acceptable to Company.

(iii) A guaranty in form and substance satisfactory to Company, executed by a person that Company deems creditworthy, of TPS's performance of its obligations to Company.

(iv) Such other form of security as TPS may agree to provide and as may be acceptable to Company.

SERVICE CLASSIFICATION – THIRD PARTY SUPPLIERS (TPS) SERVICE
(continued)

CREDITWORTHINESS: (continued)

In the event Third Party Supplier fails to immediately prepay the required three (3) months of revenue or furnish security, Company may, without waiving any rights or remedies it may have, and subject to any necessary authorizations, suspend Third Party Supplier until security is received.

The insolvency of a TPS shall be evidenced by the filing by TPS, or any parent entity thereof, of a voluntary petition in bankruptcy or the entry of a decree or order by a court having jurisdiction adjudging the Third Party Supplier, or any parent entity thereof, bankrupt or insolvent, or approving as properly filed a petition seeking reorganization, arrangement, adjustment or composition of the TPS, or any parent entity thereof, under the Federal Bankruptcy Act or any other applicable federal or state law, or appointing a receiver, liquidator, assignee, trustee, sequestrator, (or similar official) of the TPS or any parent entity thereof or of any substantial part of its property, or the ordering of the winding-up or liquidation of its affairs.

NOMINATIONS FOR SERVICE:

A Third Party Supplier shall provide to the Company in writing, or by other means as determined by the Company, at least 10 working days prior to the beginning of the calendar month an estimate of its deliveries into the Company's system for the month. These nominations must, in the aggregate, match the nominations of all Customers that are required to submit nominations to Company and to whom the Third Party Supplier will be delivering during the month plus the ADDQ that the TPS is obligated to deliver to the Company's system. Failure to provide nominations may result in suspension of service to Customers of offending Third Party Suppliers.

Company will notify Third Party Supplier of its ADDQ obligation for each day of the next succeeding month in writing to be delivered by facsimile or by other means as determined by the Company no later than the fifteenth (15th) day of the month immediately preceding the month in which Third Party Supplier will be obligated to deliver the ADDQ. If Third Party Supplier does not agree with Company's determination of Third Party Supplier's ADDQ, it must notify Company in writing to be delivered by facsimile no later than 5:00 p.m. Eastern Standard Time on the seventeenth (17th) of the month immediately preceding the gas flow month. Company and Third Party Supplier will reconcile any differences no later than 5:00 p.m. Eastern Standard Time on the twentieth (20th) of the month.

In addition, TPS must identify interstate pipeline, shipper names and interstate pipeline shipper contract number(s) on which deliveries will be made at least twenty-four (24) hours prior to the flow of gas. Failure to comply with the Company's nominating procedures may result in curtailment of third party gas deliveries or additional monthly cash-outs. The Company reserves the right to specify which pipeline a TPS will deliver gas as a percentage of the TPS total monthly deliveries.

SERVICE CLASSIFICATION – THIRD PARTY SUPPLIERS (TPS) SERVICE
(continued)

DETERMINATION OF AVERAGE DAILY DELIVERY QUANTITY (“ADDQ”):

The individual ADDQ for all RDS, SGS, GDS Customers with a DCQ under 500 therms, and NGV Customers shall be calculated as follows:

1. Unadjusted ADDQ – Customer’s weather normalized usage for each of the most recent billing periods, covering an annual period, prorated to calendar months, divided by the total number of days in each billing month. This quotient will be the Customer’s Initial ADDQ. For new Customers, Customer’s Initial ADDQ will be estimated by Company.

2. ADDQ Adjustment – At the end of each billing period, Company will calculate the difference between Customer’s actual usage and actual deliveries for the billing period, taking into account any adjustments from prior months, and will adjust the Initial ADDQ for the next succeeding month by that difference divided by the total number of days in the month.

3. Adjusted ADDQ – The sum of items 1 and 2 will be adjusted by 1.5% for Company use and unaccounted for gas to determine the individual customers Adjusted ADDQ.

Company may adjust Customer’s individual ADDQ at any time due to changes in Customer’s gas equipment or pattern of usage.

The TPS’s ADDQ shall be the total of the individual Adjusted ADDQs of all customers it serves that require an ADDQ delivery.

PIPELINE IMBALANCES:

Company and TPS recognize that Company may be subjected to imbalance charges from its interstate pipeline suppliers as a result of TPS’s failure to deliver confirmed quantities of gas. Company and TPS shall use their best efforts to avoid such imbalance penalties. However, in the event that Company is assessed penalties as a result of TPS’s actions or omissions, TPS shall reimburse Company for such penalties as may be attributable to TPS’s actions or omissions.

INDEMNIFICATION:

As between the Company and TPS, TPS warrants that it has clear title to any gas delivered into the Company’s system, and TPS shall be deemed to be in exclusive control and possession of gas prior to its delivery into the Company’s system for redelivery to Customer. TPS agrees to indemnify, defend and hold harmless Company from any and all claims, suits or damage actions arising out of deliveries on behalf of a transporting customer.

SERVICE CLASSIFICATION – THIRD PARTY SUPPLIERS (TPS) SERVICE
(continued)

ALLOCATION OF SUPPLIES:

If a TPS is delivering gas to Customers under more than one Service Classification, such as RDS, GDS, LVD and/or ITS, and does not provide the supply allocations, then gas received by the Company in that month from the Third Party Supplier shall be allocated as follows:

1. First, to the ADDQ of RDS customers
2. Second, to the ADDQ of SGS, GDS and NGV customers
3. Third, to the GDS customers not subject to ADDQ and LVD customers
4. Last, to ITS and special contract customers

However, a TPS may specify individual supply allocations for its GDS customers not subject to the ADDQ, LVD, ITS and special contract Customers no later than one (1) business day following the date the TPS receives final month end measurement data for these customers from the Company.

DAILY AND MONTHLY CONTRACT BALANCING:

All balancing charges shall be charged to the TPS and are in addition to any other charges under this Service Classification. The Distribution Charge in the Charge Per Month of the Customers Service Classification is based upon actual consumption not Third Party Supplier deliveries.

a) Daily Imbalance Charge:

The Company shall, within the existing limitations of its system, provide for balancing between gas requirements and actual gas deliveries, net of an adjustment for Company Use and Unaccounted for Gas, received by the Company for the account of the Customers served by the TPS that day. The Company shall not be obligated to provide gas service during an hourly, daily or monthly period in excess of the levels specified in the Service Classifications under which Customers of the TPS are served.

During the months of November through April, the TPS will be required to balance daily deliveries and daily takes of transported gas by the customers it serves on any day when the average temperature at Newark Airport is forecast to be 27°F or less. However, the Company reserves the right to waive this requirement. The Company reserves the right during the months of November through April to require daily balancing on any other day in which the Company, in the exercise of its reasonable judgment, determines that such balancing is necessary for operational reasons. The Company will provide the TPS in all instances with at least twenty-four (24) hours advance notice that daily balancing will be imposed daily.

SERVICE CLASSIFICATION – THIRD PARTY SUPPLIERS (TPS) SERVICE
(continued)

DAILY AND MONTHLY CONTRACT BALANCING: (continued)

a) Daily Imbalance Charge (continued):

In the event that daily balancing is imposed in accordance with this section, TPS shall be assessed the following charges for daily imbalances:

	Imbalance *	Charge **
	0% to 5%	$0.00 per therm
	5% to 10%	$0.11 per therm for imbalances in excess of 5%
Underdeliveries	> 10%	$0.53 per therm for imbalances in excess of 10%
Overdeliveries	> 10%	$0.11 per therm for imbalances in excess of 10%

* The Company reserves the right to limit daily imbalances to plus or minus 5% of the actual quantity received. If the Company limits daily imbalances to plus or minus 5%, all underdeliveries in excess of 5% shall be considered Unauthorized Use and shall be subject to the Unauthorized Use charges specified in the Unauthorized Gas Use Section of this tariff.

**The Company may suspend overdelivery charges if it determines such overdeliveries would be beneficial to the systems operation.

All TPSs will automatically be placed in a non-discriminatory daily balancing pool. The Company will aggregate the deliveries and receipts of gas of all TPS customers participating in the pool for the purpose of determining whether imbalance charges will apply. In the event that charges are nonetheless assessed to certain TPSs, such charges will be no greater than the charges that otherwise would have been assessed if the Company did not have a daily balancing pool. TPSs trading imbalances will nonetheless have to set their own prices or methods by which over or under balances will be traded among individual TPSs.

b) Monthly Imbalance Cash-Out Charge:

At the conclusion of every month, the Company will cash out imbalances between TPS's deliveries and their Customers consumption made up of actual and or estimated volumes as follows:

SERVICE CLASSIFICATION – THIRD PARTY SUPPLIERS (TPS) SERVICE
(continued)

DAILY AND MONTHLY CONTRACT BALANCING: (continued)

b) Monthly Imbalance Cash-Out Charge: (continued)

Imbalance	Overdeliveries	Underdeliveries
0% to 5%	The Company's WACOG, defined as, the weighted average commodity cost of gas exclusive of peaking supplies as estimated by the Company for the month.	The monthly floor price for Interruptible Service tariff, less any Company margin embedded in the floor price.
>5% to 10%	90% of the Company's lowest cost supply for the month.	Higher of the: 1) The rate for the 0%-5% imbalance plus two (2) cents per therm -or- 2) The average of the month's four weekly prices published in Natural Gas Week for "Major Market Prices – New York City Gate" plus two (2) cents per therm.
>10%	75% of the Company's lowest cost supply for the month.	Higher of the: 1) The rate for the 0%-5% imbalance plus two (2) cents per therm times 125% -or- 2) The month's highest weekly price published in Natural Gas Week for "Major Market Prices – New York City Gate" plus two (2) cents per therm.

The offering of gas service above the 5% allowed imbalance for the month is at the sole discretion of the Company. If it determines that it cannot continue to provide such service or that it must limit such service, it will notify TPSs served under this Service Classification. The use of service above the level allowed by the Company after notification shall constitute Unauthorized Use and shall be subject to the Unauthorized Use charges specified in Unauthorized Gas Use Section of this tariff.

SERVICE CLASSIFICATION – THIRD PARTY SUPPLIERS (TPS) SERVICE
(continued)

ADJUSTMENT FOR COMPANY USE AND UNACCOUNTED FOR GAS:

A 1.5% adjustment for Company use and unaccounted for gas shall be made to the quantity of gas received from the TPS to serve its Customers.

STANDBY BALANCING SERVICE:

A TPS cannot contract for a greater level of Standby than its Essential Gas User Customers ("EGU") peak ADDQ month or Demand Charge Quantity ("DCQ") as applicable for their RDS, GDS or LVD Customers. A TPS who does not use Comparable Capacity for their EGU natural gas requirements, must contract for Standby Service to serve these customers to assure continued gas service when their own gas supply is interrupted or underdelivered for any reason. This service is available for a minimum term of three (3) years and is payable even if EGU Customers are no longer served by the TPS per the Customers last DCQ. The charge for this service will consist of a demand charge of $0.537 per therm of DCQ to be paid each month of the year whether or not Standby Service is used, and a commodity charge equal to: in the months October through April the greater of the Company's monthly weighted average cost of gas plus three (3) cents per therm, or the average of the month's four weekly prices published in Natural Gas Week for "Major Market Prices – New York City Gate," and in the months May through September the lesser of the Company's monthly weighted average cost of gas, or the average of the month's four weekly prices published in Natural Gas Week for "Major Market Prices – New York City Gate" plus two (2) cents per therm, as applied to any gas service rendered. All standby service charges shall be in addition to the rates otherwise charged under this Service Classification.

All standby revenues, exclusive of taxes and other similar charges and the three (3) cent per therm commodity surcharge in the months of October through April, shall be credited to the BGSS.

DELIVERED QUANTITIES:

Quantities billed to the end-use Customers shall be considered actual quantities delivered, whether based on actual or estimated meter readings.

SERVICE CLASSIFICATION – THIRD PARTY SUPPLIERS (TPS) SERVICE
(continued)

SPECIAL PROVISIONS:

In addition to the preceding terms and conditions of this Service Classification, the following terms and conditions shall apply to all TPSs providing service to Customers receiving service from Company under Service Classifications RDS, GDS, LVD and ITS. If, and to the extent that, any portion of the following is in conflict with previous terms of this Service Classification, the terms that follow shall govern.

1.
Enrollment of RDS, SGS, GDS and NGV Customers

TPS must enroll RDS, SGS, GDS and NGV Customers in accordance with the Company electronic enrollment procedures. Customer consent is assumed if the TPS provides the Company with the Customer's account number and service address and any other information that may be required by the Company, RDS customers will receive a confirmation notice from the Company noting their choice of supplier and that the RDS customer will have seven (7) calendar days from the date of the confirmation notice to contact the Company and rescind its selection, after which, if not rescinded, the RDS customer's TPS enrollment shall be accepted by the Company. TPS supply service will commence for all enrollments received by the 10th of a month, inclusive of those RDS customers that are not rescinded, on the customer's next month's cycle meter reading date. TPS shall indemnify and hold Company harmless from any costs incurred by Company as a result of TPS's erroneous or improper enrollment of Customers.

The Company must comply with all Customer instructions verbal or written to rescind or change service with a TPS. TPS must initiate all transactions required by the Company to rescind service on the day such instructions are received by the TPS from the Company or Customer. A Customer returning to sales service will be effective on the Customer's first billing cycle meter read date following the date on which the Company has changed the TPS's ADDQ requirement. A Customer will be switched to another TPS effective on the cycle read date following the reassignment of the Customer's ADDQ for gas nominations.

2. Requirements for RDS and Essential Gas Use Customers

Any TPS seeking to serve such Customers must demonstrate that it possesses Comparable Capacity or Standby in a quantity sufficient to serve Customers' Unadjusted ADDQ or DCQ requirements during the months of November through March.

"Comparable Capacity" is a firm non-recallable service at Elizabethtown's city gate(s). The Company reserves the right to limit the service to 70% on Transcontinental Gas Pipe Line Corporation's ("Transco") system and the remaining 30% on Texas Eastern Transmission Corporation's ("Tetco") system.

SERVICE CLASSIFICATION – THIRD PARTY SUPPLIERS (TPS) SERVICE
(continued)

SPECIAL PROVISIONS: (continued)

2. Requirements for RDS and Essential Gas Use Customers (continued)

In order to demonstrate Comparable Capacity, TPS shall be required to provide, at the time the Customer is enrolled, an affidavit signed by an officer stating that Comparable Capacity is being provided for the November through March period. This affidavit must be refiled annually. The Company reserves the right to request TPS to submit copies of its Comparable Capacity contracts supporting its affidavits in the event that a TPS fails to deliver.

3. Capacity Assignment

TPS serving RDS Customers may, if they choose, accept an assignment of base load, long haul interstate pipeline capacity from Company in a quantity equal to the amount of base load, long haul capacity used by the Company to serve the Customer's anticipated design day demand. 70% of such capacity will consist of capacity on Transcontinental Gas Pipe Line Corporation and 30% of such capacity will consist of capacity on Texas Eastern Transmission Corporation. Such capacity will be assigned for a one year term on a basis prorated to the underlying contracts at the same maximum rates paid by the Company. Such capacity will be immediately recallable in the event that TPS fails to deliver the RDS Customer's ADDQ or no longer serves such RDS Customers. A TPS wishing to accept assignment of Company's interstate pipeline capacity must notify Company at the time that Customer is enrolled in RDS service.

To the extent that TPS wishes to take assignment of interstate pipeline capacity in addition to its RDS Customer's portion of base load, long haul capacity, it shall notify the Company in writing. To the extent that the Company, in its sole discretion, determines that it has additional capacity available for release, it shall notify any TPSs that have advised the Company that they wish to take assignment of such capacity prior to making such capacity available to third parties. Company reserves the right to release any interstate pipeline capacity to the highest bidder or on a non-discriminatory basis. The Company shall be permitted to retain 15% of all revenues derived from the release of pipeline capacity, with all remaining revenue to be credited to the BGSS Charge.

To the extent that Company releases capacity to TPS, TPS is responsible for utilizing the assigned capacity consistent with the terms and conditions of the interstate pipelines' tariffs. TPS is responsible for payment of all upstream pipeline charges associated with the assigned firm transportation capacity, including but not limited to demand and commodity charges, shrinkage, GRI charges, cash outs, transition cost, pipeline overrun charges, penalties assessed to Company, actual cost adjustments and all other applicable charges. These charges will be billed directly to the TPS by Transco and Tetco.

SERVICE CLASSIFICATION – THIRD PARTY SUPPLIERS (TPS) SERVICE
(continued)

SPECIAL PROVISIONS: (continued)

3. Capacity Assignment (continued)

Capacity assignments will be effective for a one year period beginning on each annual period. Company reserves the right to recall capacity in the event and to the extent that TPS fails to deliver the sufficient volume to serve its customers on any day or days. Increases in assigned capacity will only be entertained by Company to become effective for annual periods.

If, and to the extent that, the TPS fails to deliver the required volume, and such failure is not excused as a result of a pipeline force majeure event that prevents the TPS from delivering the required volume, the TPS will be assessed an Unauthorized Use charge as specified in Section I, Item 18 for each therm that the TPS has failed to deliver and be subject to a recall of the interstate pipeline capacity that has been released by Company.

Assigned capacity may be reassigned by the TPS subject to recall by Company. The original TPS shall remain subject to all operational orders and recall provisions invoked or exercised by Company. If the TPS fails to pay any interstate pipeline for capacity released or assigned by Company, and Company is required to pay the pipeline for such capacity, TPS shall be liable to Company for any amounts Company is required to pay interstate pipeline for such capacity, as well as incidental and consequential damages and the costs of any reasonable collection efforts. Failure to pay Company within twenty (20) days of billing may result in suspension of service.

4. RDS Load Balancing Charge

A Load Balancing Charge of $0.0552 per therm, which includes sales tax, shall be billed to the TPS for all metered quantities for RDS customers it serves. Amounts due from TPS shall be paid in full within 20 days of the billing date. Any disputed amounts will be resolved by the TPS and Company and adjustments if any will be reflected on future billings. Failure to pay this charge in full within the time specified above will result in all RDS Customers of the TPS being returned to BGSS supply service.

5. Treatment of Revenues

All revenues produced under this Service Classification derived from penalties, imbalances and Load Balancing charges shall be credited to the BGSS.

RIDER "A"

BASIC GAS SUPPLY SERVICE CHARGE ("BGSS")

This Rider sets forth the method of determining the BGSS which shall be calculated to four (4) decimal places on a per therm basis established in accordance with the Board Order in Docket No. GX01050304 dated January 6, 2003. The BGSS charge is either BGSS-Monthly ("BGSS-M") or BGSS-Periodic ("BGSS-P") and will be applied to a Customer's Service Classification as follows:

1. The BGSS-M shall be applicable to all GDS, NGV, LVD, and EGF customers receiving gas supply from the Company effective on the first of each month as determined below.

2. The BGSS-P shall be applicable to all RDS, SGS, and GLS customers receiving gas supply from the Company.

The BGSS Charge, as defined herein, is designed to recover the cost to the Company of purchased gas or fuel used as a substitute for or supplemental to purchased gas including the cost of storing or transporting said gases or fuel, the cost of financial instruments employed to stabilize gas costs, other charges or credits as may result from the operation of other tariff provisions, and taxes and other similar charges in connection with the purchase and sale of gas.

BGSS per therm rates:

Effective Date	BGSS-M per therm	BGSS-P Per therm
December 1, 2020 *	$0.5088	$0.3783
January 1, 2021	$0.4620	$0.3783
February 1, 2021	$0.4940	$0.3783
March 1, 2021	$0.5042	$0.3783
April 1, 2021	$0.4750	$0.3783
May 1, 2021	$0.5120	$0.3783
June 1, 2021	$0.5184	$0.3783
July 1, 2021	$0.5874	$0.3783
August 1, 2021	$0.6340	$0.3783
September 1, 2021	$0.6695	$0.3783
October 1, 2021	$0.8299	$0.3783
November 1, 2021	$0.8692	$0.3783
December 1, 2021	$0.8022	$0.4798

* BGSS-M rate revised on January 14, 2021

RIDER "A"

BASIC GAS SUPPLY SERVICE CHARGE ("'BGSS")
(continued)

I. The BGSS-P Commodity Charge shall be determined as follows:

The BGSS-P Commodity Charge shall consist of a Gas Cost Component ("GCC"), a Capacity Cost Component ("CCC"), a Prior Period Adjustment ("PPA") and a Tax Factor ("TF") as follows:

BGSS-P = (GCC-P + CCC-P + PPA-P) X (TF)

Where:

GCC-P rate per therm shall be sum of the weighted average price, including any applicable transaction costs, based on the projected monthly quantities to be utilized in the remaining period of the BGSS Year ("Period"), of the following categories of gas:

a) Flowing gas, which will be equal to the arithmetic average of (i) the weighted-average, based on monthly sales, of the remaining New York Mercantile Exchange ("NYMEX") monthly prices for the Period as recorded on the close of trading for the forward contract month and (ii) the weighted average of the estimated Inside FERC prices for the respective locations where the Company purchases its gas for the remainder of the Period, as adjusted for the variable cost of transportation and fuel to the Company's city gate delivery points;

b) Any gas supplies for the remainder of the Period whose price was previously set by hedges or other financial instruments, adjusted for the variable cost of transportation and fuel to the Company's city gate delivery points;

c) The supplies of gas projected to be withdrawn from storage for the remainder of the Period, adjusted for the variable cost of transportation and fuel to the Company's city gate delivery points.

CCC-P shall be established each year in the Company's annual BGSS-P filing and shall consist of the Company's total estimated annual fixed pipeline costs, fixed supplier costs, and fixed storage costs, divided by the Company's projected annual BGSS firm gas sales.

RIDER "A"

BASIC GAS SUPPLY SERVICE CHARGE ("BGSS")
(continued)

PPA-P shall be the Company's actual cumulative (over) or under recovery of gas costs associated with the operation of the BGSS divided by the projected BGSS-P firm gas sales for the remainder of the Period. In the initial transition to the BGSS-P, the per therm rate derived from the Company's estimated BGSS under or (over) recovery balance at May 31, 2003 with applicable interest thereon divided by the Company's projected BGSS firm sales for the period ending May 31, 2004, shall be the PPA-P. The over under recovery of gas costs shall be the cost of gas, as previously defined, less:

1. Supplier or Pipeline refunds;
2. Gas cost recoveries from the implementation of the BGSS-P;
3. Gas cost recoveries from the implementation of the BGSS-M;
4. Other gas cost recoveries or credits to the BGSS derived from sales or services as set forth in the applicable service classifications of the tariff;
5. Interest on the cumulative (over) under recovery of cost from the preceding BGSS Year ending September 30 but only when the interest is a credit. Interest being calculated on the cumulative (over) under recovery for each month of the prior period on the average of the beginning and ending monthly balance at a rate equivalent to the Company's allowed overall rate of return.

TF shall be the factors to adjust the calculated rate for appropriate taxes and other similar charges.

The BGSS-P shall be in effect until changed by succeeding BGSS-P rate filings.

The Company shall have the discretion to implement up to two (2) self-implementing BGSS-P rate changes, one to be implemented December 1 and the other to be implemented February 1 upon written notice to the Staff of the Board of Public Utilities and the Division of Rate Counsel of the approximate amount of that increase based on current market conditions by the first of the month preceding the self-implementation dates, November 1 and January 1 respectively. Each requested rate change shall not be for an increase of greater than five percent (5%) of the average rate based on a typical 100 therm per month residential total bill. The notice shall contain the information necessary to derive the components of the BGSS-P as set forth above. The Public Notice for the annual filing shall include the specific rate change sought to be implemented on October 1, a paragraph indicating that the rate is subject to self-implementing rate changes on December 1 and February 1 subject to the aforementioned 5% cap and an estimate of the impact

RIDER "A"

BASIC GAS SUPPLY SERVICE CHARGE ("BGSS")
(continued)

from the two (2) possible five percent (5%) increases on a 100 therm residential bill. Upon establishing the initial BGSS-P, one self-implementing rate change to the BGSS-P for an increase not greater than five percent (5%) of the average rate based on a typical 100 therm per month residential total bill shall be permitted effective March 1, 2003 upon written notice made to the BPU and RC by February 1, 2003.

In accordance with the Board Order in Docket No. GX01050304 dated January 6, 2003 the Company shall have the discretion to return any over recovered balances to customers through a current bill credit or BGSS-P rate reduction upon five (5) days notice to the BPU and RC.

II. The BGSS-M Commodity Charge shall be determined as follows:

The BGSS-M Commodity Charge shall consist of a Gas Cost Component (“GCC”), a Capacity Cost Component (“CCC”), a Prior Period Adjustment (“PPA”) and a Tax Factor (“TF”) as follows:

BGSS-M = (GCC-M + CCC-M + PPA-M) X (TF)

Where:

GCC-M rate per therm shall be the arithmetic average of (i) the NYMEX Henry Hub gas contracts closing price for the last trading day prior to each respective month and (ii) the weighted-average of the estimated Inside FERC prices for the respective locations where purchases of gas for the ensuing month are projected to be made, as adjusted for the variable cost of fuel and transportation to the city gate delivery points of the Company.

CCC-M shall be the same as the CCC-P rate per therm as established each year in the Company’s annual BGSS-P filing.

PPA-M rate per therm in the initial transition to the BGSS-M shall be the estimated BGSS under or (over) recovery balance at May 31, 2003 with applicable interest thereon divided by the projected BGSS firm sales for the period ending May 31, 2004. This rate shall continue in effect on a monthly basis until the deferred balance, which initially shall be set equal to the PPA-M times the projected BGSS–M firm sales for the period ending May 31, 2004, becomes positive as an over recovery at which time the PPA-M shall cease to be a component of the BGSS-M starting in the subsequent month, and any over recovery in the deferred balance shall be credited to the BGSS-P.

TF shall be the factors to adjust the calculated rate for appropriate taxes and other similar charges.

RIDER "A"

BASIC GAS SUPPLY SERVICE CHARGE ("BGSS")
(continued)

The BGSS-M will be filed two (2) business days after the monthly close of the NYMEX Henry Hub gas contracts and shall be in effect for the entirety of the subsequent month and thereafter until changed by succeeding BGSS-M rate filings. The BGSS-M price shall be posted on the Company's WEB site within two (2) to four (4) days of the rate being filed with the BPU.

The Company shall make an annual BGSS filing on or before June 1 of each year. The filing shall provide for a review of the actual costs and recoveries for the previous period ending April 30 and projections of costs and recoveries through September 30. The filing shall also propose a new BGSS-P rate to be implemented on October 1. The proposed BGSS-P rate shall be based upon the projected cost of purchased gas and storage utilization to serve projected demand for gas service for the period October 1 through September 30 and an adjustment to recover or credit prior period under or over recovered gas costs as projected to exist on the preceding September 30. The Company shall provide the basis for its projected costs and the NYMEX projection of monthly gas prices for the projected period. In its annual filing the Company shall calculate the CCC-P component, as defined above, of the BGSS-P rate. Adjustments, if any, resulting from the Board's review of this filing shall be made following a Board Order.

The charges applicable under this Rider include provision for the New Jersey Sales and Use Tax, and when billed to customers exempt from this tax shall be reduced by the amount of such tax included therein.

RIDER "B"

WEATHER NORMALIZATION CLAUSE (“WNC”)

Applicable to all customers in service classifications RDS, SGS and GDS.

October 1, 2021 through May 31, 2022	$0.0171 per therm
June 1 through September 30 of any year	$0.0000 per therm

The charges applicable under this Rider include provision for the New Jersey Sales and Use Tax, and when billed to customers exempt from this tax shall be reduced by the amount of such tax included therein. In the winter months, October through May, a weather normalization charge shall be applied to the rate quoted in this Tariff under the service classifications shown above, except as may be otherwise provided for in the individual service classification. The weather normalization charge applied in each winter period shall be based on the differences between actual and normal weather during the preceding winter period.

METHOD OF DETERMINING WEATHER NORMALIZATION CHARGE:

The weather normalization charge shall be determined as follows:

I. Definition of Terms as Used Herein

1. Degree Days (DD) - the difference between 65°F and the twenty-four point average temperature for the day, as determined from the records of the National Oceanic and Atmospheric Administration (NOAA) at its weather observation station located at Newark International Airport, when such average falls below 65°F. A day is defined as a period corresponding with the Company's gas sendout day of 10 am to 10 am.

RIDER "B"

WEATHER NORMALIZATION CLAUSE ("WNC")
(continued)

METHOD OF DETERMINING WEATHER NORMALIZATION CHARGE: (continued)

I. Definition of Terms as Used Herein (continued)

2. Actual Calendar Month Degree Days - the accumulation of the actual Degree Days for each day of a calendar month.

3. Normal Calendar Month Degree Days - the level of calendar month degree days to which test year sales volumes were normalized in the base rate proceeding that established the current base rates for the service classifications to which this clause applies. The normal calendar month Degree Days used in this clause may be updated in base rate cases. The normal degree days for the defined winter months are as follows:

Month	Normal Degree Days	Leap Year Normal Degree Days
October	212	212
November	516	516
December	818	818
January	992	992
February.	834	860
March	693	693
April	340	340
May	52	52
Total	4,457	4,483

4. Winter Period - shall be the eight consecutive sales and calendar months from October of one calendar year through May of the following calendar year.

5. Degree Day Dead Band - shall be one-half (½%) percent of the monthly Normal Calendar Degree Days for the Winter Period.

RIDER "B"

WEATHER NORMALIZATION CLAUSE (“WNC”) (continued)

METHOD OF DETERMINING WEATHER NORMALIZATION CHARGE: (continued)

I. Definition of Terms as Used Herein (continued)

6. Degree Day Consumption Factor (“DDCF”) - the variable component (use per degree day) of the gas sendout for each month of the winter period normalized for weather and adjusted for lost and unaccounted for gas. The DDCF shall be updated annually in the Company’s WNC reconciliation filing annualizing to reflect the change in number of customers that has occurred since the base rate proceeding that established the initial degree day consumption factor in base rate cases. The base number of customers used to establish the normalized use in therms per Customer and the calculated DDCF approved in the Company’s most recent base rate case are as follows:

Month	Base Number of Customers	Therms per Degree Day
October	302,711	52,236
November	303,980	62,979
December	305,314	69,375
January	305,723	68,394
February	306,005	66,058
March	306,237	63,969
April	306,397	52,626
May	306,530	54,279

7. Margin Revenue Factor - the weighted average of the Distribution Charges as quoted in the individual service classes to which this clause applies net of applicable taxes and other similar charges and any other revenue charge not retained by the Company that these rates may contain in the future. The weighted average shall be determined by multiplying the margin revenue component of the Distribution Charges from each service class to which this clause applies by each class's percentage of total consumption of all the classes to which this clause applies for the winter period and summing this result for all the classes to which this clause applies. The Margin Revenue Factor shall be redetermined each time base rates or IIP rates are adjusted. The current Margin Revenue Factor is $0.5259 per therm pre taxes for purposes of calculating the weather-related portion of the CIP.

RIDER "B"

WEATHER NORMALIZATION CLAUSE ("WNC")
(continued)

METHOD OF DETERMINING WEATHER NORMALIZATION CHARGE (continued)

I. Definition of Terms as Used Herein (continued)

8. Annual Period: shall be the 12 consecutive months from October 1 of one calendar year through September 30 of the following calendar year.

9. Average 13 month common equity balance: shall be the common equity balance at the beginning of the Annual Period (i.e. October 1) and the month ending balances for each of the twelve months in the Annual Period divided by thirteen (13).

II. Determination of the Weather Normalization Rate

At the end of the Winter Period during the Annual Period, a calculation shall be made that determines for all months of the Winter Period the level by which margin revenues differed from what would have resulted if normal weather (as determined by reference to the Degree Day Dead Band) occurred.

The monthly calculation is made by multiplying the Degree Day Consumption Factor by the difference between Normal Calendar Month Degree Days as adjusted for the monthly Degree Day Dead Band, and Actual Calendar Month Degree Days and, in turn, multiplying the result by the Margin Revenue Factor. To the extent the Actual Calendar Month Degree Days exceeds Normal Calendar Month Degree Days as adjusted for the Degree Day Dead Band, an excess of margin revenues exist. To the extent Actual Calendar Month Degree Days were less than Normal Calendar Month Degree Days as adjusted for the Degree Day Dead Band, a deficiency of marginal revenue exists. In addition, the weather normalization clause shall not operate to permit the Company to recover any portion of a margin revenue deficiency that will cause the Company to earn in excess of 9.6% for the Annual Period; any portion which is not recovered shall not be deferred. For purposes of this section, the Company's rate of return on common equity shall be calculated by dividing the Company's regulated jurisdictional net income for the Annual Period by the Company's average 13-month common equity balance for such Annual Period, all as reflected in the Company's monthly reports to the BPU. The Company's regulated jurisdictional net income shall be calculated by subtracting from total net income (1) margins retained by the Company from non-firm sales and transportation services, net of associated taxes, (2) margins retained in the provision of sales in accordance with the Board Order pertaining to Docket No. GR90121391J and GM90090949, net of associated taxes and (3) net income derived from unregulated activities conducted by Elizabethtown.

RIDER "B"

WEATHER NORMALIZATION CLAUSE (“WNC”)
(continued)

METHOD OF DETERMINING WEATHER NORMALIZATION CHARGE (continued)

II. Determination of the Weather Normalization Rate (continued)

The Company's average thirteen-month common equity balance for any Annual Period shall be the Company's average total common equity less the Company's average common equity investment in unregulated subsidiaries.

The balance of margin revenue excess or deficiency at September 30 of the Annual Period shall be divided by the estimated applicable sales from the classes subject to this clause for the Winter Period over which this charge will be in effect, multiplied by a factor to adjust for increases in taxes and other similar charges. The product of this calculation shall be the Weather Normalization Charge. However, the Weather Normalization Charge will at no time exceed three (3%) percent of the then applicable Residential Distribution Service rate plus the BGSS. To the extent that the effect of this rate cap precludes the Company from fully recovering the margin deficiency for the Annual Period, the unrecovered balance will be added to or subtracted from the margin deficiency or margin excess used to calculate the weather normalization charge for the next Winter Period. The Weather Normalization Charge, so calculated, will be in effect for the Winter Period immediately following the Annual Period used in such calculation.

III. Tracking the Operation of the Weather Normalization Clause

The revenues billed, or credits applied, net of taxes and other similar charges, through the application of the Weather Normalization Rate shall be accumulated for each month when this rate is in effect and applied against the margin revenue excess or deficiency from the immediately preceding Winter Period and any cumulative balances remaining from prior Winter Periods.

The annual filing for the adjustment to the weather normalization rate shall be concurrent with the annual filing for the Rider "D" Societal Benefits Charge.

RIDER "C"

ON-SYSTEM MARGIN SHARING CREDIT (“OSMC”)

Applicable to all Firm Service Classifications that pay the BGSS of Rider A and RDS customers that receive gas supply from a TPS in accordance with the Board's Order in Docket No. GO99030122.

The OSMC is subject to change to reflect the Company's actual recovery of such margins and shall be adjusted annually in its BGSS filing.

($0.0021) per therm

The charges applicable under this Rider include provision for the New Jersey Sales and Use Tax, and when billed to customers exempt from this tax shall be reduced by the amount of such tax included therein.

<u>Determination of the OSMC</u>

On or about July 31 of each year, the Company shall file with the Board an OSMC rate filing based on the credits generated from on-system margin sharing during the previous OSMC year July 1 through June 30.

The OSMC shall be calculated by taking the current year’s credits, plus the prior year’s OSMC over or under recovery balance and dividing the resulting sum by the annual forecasted volumes for the service classifications set forth above. The resulting rate shall be adjusted for all applicable taxes and other similar charges.

RIDER "D"

SOCIETAL BENEFITS CHARGE ("SBC")

Applicable to all tariff Service Classifications except those Customers under special contracts that explicitly do not permit the Company to apply increased charges as filed and approved by the BPU and those customers exempted pursuant to the Long-Term Capacity Agreement Pilot Program (“LCAPP”), P.L. 2011, c.9, codified as N.J.S.A. 48:3-60.1. See the LCAPP Exemption Procedures at the end of this Rider.

The SBC is designed to recover the components listed below and any other new programs which the Board determines should be recovered through the Societal Benefits Charge.

	SBC Rate Components:		Per Therm
I.	Clean Energy Program (“CEP”)		$0.0276
II.	Remediation Adjustment Charge (“RAC”)		($0.0083)
III.	Universal Service Fund and Lifeline:		
	1. Universal Service Fund (“USF”)		$0.0133
	2. Lifeline		$0.0057
		TOTAL	$0.0383

The charges applicable under this Rider include provision for the New Jersey Sales and Use Tax, and when billed to customers exempt from this tax shall be reduced by the amount of such tax included therein.

I. Clean Energy Program Component (“CEP”)

The Comprehensive Resource Analysis (“CRA”) name was changed to the Clean Energy Program - CEP per Board Order dated January 22, 2003 in Docket No. EX99050347 *et.al*. The CEP is a mechanism that will (1) establish a rate to recover the costs of the Core and Standard Offer Programs in the Company's CEP Plan which was approved by the BPU” in Docket No. GE92020104, and (2) compensate the Company for the revenue erosion resulting from conservation savings created by the Standard Offer Program. The annual recovery period for the CEP is from October 1 through September 30. The CEP recovers program costs and revenue erosion incurred during the previous CEP year ended June 30.

1. CEP program costs include the costs of core programs, standard offer payments and any administrative costs not recovered directly from standard offer providers.

RIDER "D"

SOCIETAL BENEFITS CHARGE ("SBC")
(continued)

I. Clean Energy Program Component ("CEP") (continued)

2. The Standard Offer Program will reduce the volumes of gas sold by the Company and will reduce revenues corresponding to volumes of gas saved. This revenue loss will occur because the rates set in the Company's base rate case do not reflect a decrease in revenues resulting from program measures which will be implemented during the period in which the Company's CEP Plan is in effect. Consequently, the Company will not recover those fixed costs in base rates corresponding to the volumes of gas saved by the Standard Offer Program.

3. The CEP rate shall be determined as follows:

(a) The Company will project all program costs not recoverable directly from standard offer providers and revenue erosion, based upon current, approved rates, both of which elements are not currently collected through base rates for the annual period ("current annual period").

(b) The Company will include with the above projection, a statement of the prior annual period of any (over-) or under-recoveries, including interest at the rate applicable to the RAC component of the SBC. This statement will include estimated data for those months that occur after the date of filing but which correspond to the prior annual period. The CEP may be adjusted for material differences between estimates and actual results in the prior annual period.

(c) The sum of the program costs and recoveries for the CEP year ending June 30 plus the projected spending for the succeeding twelve month period, including interest calculated at a rate equal to that applied to the RAC component of the SBC, will be divided by the estimated sales and transportation throughput to all Customers subject to the SBC during the succeeding October 1 through September 30 period.

The formula for calculating the CEP rate is as follows:

$$\frac{PC + RE + [RB *(1+i)]}{AV}$$

RIDER "D"

SOCIETAL BENEFITS CHARGE ("SBC")
(continued)

I. Clean Energy Program Component ("CEP") (continued)

3. The CEP rate shall be determined as follows: (continued)

(c) where:

PC = all projected program costs not recoverable directly from standard offer providers

RE = cumulative annual margin revenue erosion from the date of effectiveness of the Plan until the time that new base rates take effect. Margin revenue erosion is determined by multiplying the actual measured annual decrease in firm sales attributable to implementation of certain CEP programs per Board Order EX99050347 *et.al.* and the DSM legacy standard offer programs by the net margin revenue associated with that decrease in each affected service classification.

RB = prior period recovery balance, the net of actual costs and recoveries.

i = interest rate applicable to recovery balance

AV = projected annual quantity for sales and transportation throughput to all Customers subject to the SBC.

4. There will be a reconciliation of over- or under-recovery of actual program costs not recovered directly from standard offer providers and revenue erosion, based upon approved rates in effect during the prior annual period, with the revenues collected through the CEP by maintaining an account showing the cumulative balance of the (over-) or under-recoveries. Any prior annual period balance will be included, with interest, along with current annual period projected costs and amortized over the current annual recovery period. Interest is calculated on the cumulative (over-) or under-recovery of the prior annual period on the average beginning and ending monthly balance at a rate equivalent to the rate applied to the RAC component of the SBC.

RIDER "D"

SOCIETAL BENEFITS CHARGE ("SBC")
(continued)

I. Clean Energy Program Component ("CEP") (continued)

5. The annual filing for the adjustment on or about October 1 of each year shall be made on or about July 31 of each year and shall be based on actual figures and experiences then available with estimates of remaining requirements.

II. Remediation Adjustment Clause Component ("RAC")

The RAC is a mechanism that will establish a rate to recover remediation costs, as defined herein. On or about July 31 of each year, the Company shall file with the Board a RAC rate component as part of the SBC based on remediation costs and third party expenses/claims in the preceding remediation years.

The RAC will be determined as follows:

A. Definition of Terms Used Herein

1. Remediation Costs - all investigation, testing, land acquisition if appropriate, remediation and/or litigation costs/expenses or other liabilities excluding personal injury claims and specifically relating to former gas manufacturing facility sites, disposal sites, or sites to which material may have migrated, as a result of the earlier operation or decommissioning of gas manufacturing facilities.

2. Interest Rate - for carrying costs and deferred tax benefit calculation shall be the rate paid on seven year constant maturities treasuries as shown in the Federal Reserve Statistical Release on or closest to August 31st of each year plus 60 basis points.

3. Carrying Cost - the Interest Rate applied to the unamortized balance of remediation costs.

4. Recovery Year - each October 1 to September 30 year and is the time period over which the amortized expenses incurred during the Remediation Year shall be recovered from Customers.

5. Remediation Year - each July 1 to June 30 year and is the time period over which the Remediation Costs and recoveries are incurred.

RIDER "D"
SOCIETAL BENEFITS CHARGE ("SBC")
(continued)

II. Remediation Adjustment Clause Component ("RAC")

A. Definition of Terms Used Herein (continued)

6. Third Party Claims - all claims brought by the Company against any entity, including insurance companies, from which recoveries may be received and will be charged through the RAC factor as follows:

a. Fifty percent of the reasonable transaction costs and expenses in pursuing Third Party Claims shall be included as Remediation Costs and shall be recovered as part of the RAC. The remaining 50% shall be deferred.

b. In the event that the Company is successful in obtaining a reimbursement from any Third Party, the Company shall be permitted to retain the deferred 50% as specified above. The balance of the reimbursement, if any, shall be applied against the Remediation Costs starting in the year it is received and will be amortized over seven years.

c. The Company is not required to account for transaction costs and expenses in pursuing third party claims on a claim-by-claim basis.

7. Deferred Tax Benefit (DTB) - the unamortized portion of actual remediation costs multiplied by the Company's effective statutory federal and state income tax rate, and the Interest Rate.

$DTB_{n,yr} = ARC_n * [(7-X)/7] * IR_{yr} * Tr_{yr}$

$DTB_{n,yr}$	=	Deferred Tax Benefit in recovery year (yr) to be subtracted from one seventh the amount of the remediation costs incurred in remediation year (n).
ARC_n	=	Actual Remediation Costs incurred in remediation year (n).
X	=	Number of years that the ARC incurred in year n have been subject to amortization (X = 1,2,3,4,5,6)
IR_{yr}	=	Interest Rate
TR_{yr}	=	Effective combined Federal and State income tax rate.

RIDER "D"

SOCIETAL BENEFITS CHARGE ("SBC")
(continued)

II. Remediation Adjustment Clause Component (“RAC”)

A. Definition of Terms Used Herein (continued)

8. Sale of Property shall be calculated by taking the proceeds over book value of any sale of a former manufacturing gas plant site, less all reasonable expenses associated with selling the site, and subtracting the total costs that were incurred in cleaning up the site and amortized through rates. The proceeds associated with the total costs that were incurred in cleaning up the site will be included as a credit to the remediation costs incurred in the year of the sale. The remainder shall be equally shared between the Company and Customers.

B. Determination of the Remediation Adjustment

At the end of the remediation year, the Company shall file with the Board (1) copies of all bills and receipts relating to the amount of any remediation costs incurred in the preceding remediation year(s) for which it seeks to begin recovery; (2) similar material and information to support any expenses and/or recoveries resulting from Third Party claims; (3) a computation of the carrying cost on the unamortized balance of remediation cost; (4) a projection of remediation costs for the following remediation year.

The RAC factor shall be calculated by taking one seventh of the Actual Remediation Costs, plus applicable Third Party Claims and Sale of Property allocations incurred each year, until fully amortized, less the Deferred Tax Benefit plus the prior years' RAC over or under-recovery plus appropriate carrying costs. This amount is then divided by all applicable forecasted quantities to all Service Classifications for the upcoming recovery year.

The total annual charge to the Company's ratepayers for remediation costs during any recovery year shall not exceed five (5%) percent of the Company's total revenues from sales, transportation and storage services during the preceding Remediation Year. If this limitation results in the Company recovering less than the amount that would otherwise be recovered in a particular Recovery Year then the Company will continue to accumulate carrying costs which will be recovered by the Company from its Customers in a subsequent RAC proceeding.

RIDER "D"

SOCIETAL BENEFITS CHARGE ("SBC")
(continued)

II. Remediation Adjustment Clause Component ("RAC") (continued)

C. Tracking the Operation of the Remediation Adjustment Clause

The revenues billed, net of taxes and other similar charges through the application of the Remediation Adjustment factor shall be accumulated for each month and be applied against the total amortized Remediation Costs calculated for that year. Any over or under collection at the end of the Recovery Year will be included in the determination of the following year's RAC factor.

III. Universal Service Fund ("USF") and Lifeline Components

An interim USF program was approved by the BPU in Docket No. EX00020091 dated November 21, 2001. A permanent USF program and Lifeline charge was approved by the BPU in Docket No. EX00020091 dated April 30, 2003. The Orders authorized the Company to collect costs associated with the program through the SBC. The USF and Lifeline rate components of the SBC will be determined as follows:

A. Definition of Terms

1. Program Costs includes all costs incurred in connection with the implementation of Board ordered services, inclusive of carrying costs.

2. Program Year is the period October 1 to September 30 as approved by the BPU in Docket No. EX00020091 dated June 22, 2005.

B. Determination of the USF and Lifeline Components

The USF and Lifeline Components will be determined and issued by the Board and shall remain in effect until changed. The USF true up between credits given customers and amounts recovered will be made annually in accordance with the Board's directives.

RIDER "D"

SOCIETAL BENEFITS CHARGE ("SBC")
(continued)

III. Universal Service Fund ("USF") and Lifeline Components (continued)

C. Carrying Costs

Per Board Order dated October 21, 2008 in Docket No. ER08060455, the interest rate on USF under and over recoveries shall be the interest rate based on a two-year constant maturity Treasuries as published in the Federal Reserve Statistical Release on the first day of each month (or the closest day thereafter on which rates are published), plus sixty basis points, but shall not exceed the overall rate of return for each utility as authorized by the Board. The calculation shall be based on the net of tax beginning and end average monthly balance, accruing simple interest with an annual roll-in at the end of each reconciliation period.

IV. LCAPP Exemption Procedures

The following procedures to obtain the LCAPP exemption from the SBC charge shall apply:

A customer seeking an SBC rate exemption for all or part of its usage must submit an Annual Certification form, provided by the Company, declaring and certifying, for any applicable meter, the percentage of natural gas purchased and used for the generation of electricity sold for resale during the previous calendar year. For facilities with less than twelve months of history, estimates supported by engineering and operational plans may be used.

A. Annual Procedures

In December of each year the Company will mail an Annual Certification form to customers currently receiving the exemption, addressed to the customer's designated representative, to be returned to the Company's designated representative by the following January 15th.

The certified percentage will be used to determine the SBC rate to be charged for the twelve (12) month period beginning February 1st, for example:

RIDER "D"

SOCIETAL BENEFITS CHARGE ("SBC")
(continued)

IV. LCAPP Exemption Procedures (continued)

A. Annual Procedures (continued)

If the full SBC rate to be charged equaled $0.0400 per them pre tax and other similar charges and the certified percentage was seventy-five percent (75%) then the rate charged and applied to the metered volume would be calculated as: $0.0400 * (1.00 - .75) = $0.0100 per therm before any applicable taxes and other similar charges.

If the customer fails to return the form by January 15th then the full SBC rate will be assessed on all of the customer's natural gas usage until a completed Annual Certification form is received. Any exemption will become effective after the customer's next subsequent meter reading.

Notwithstanding the foregoing, the Company will provide customers that it reasonably believes may be eligible for the exemption with a certification form for the period of January 28, 2011 through January 31, 2012 on which the customer may certify the percentage of natural gas purchased and used for the generation of electricity sold for resale during the calendar year 2010. Any adjustments to the customer's bill associated with this exemption period shall be billed or credited to the customer in the billing period following the adjustment determination.

B. Interim Period Procedures

Customers may obtain the exemption at any time during a year by obtaining and submitting to the Company's designated representative a completed Annual Certification form. The certified percentage will be used to determine the exemption which will become effective after the next subsequent meter reading. Customers will be required to re-certify for the subsequent period beginning February 1 in accordance with the Annual Procedures.

RIDER "E"

ENERGY EFFICIENCY PROGRAM ("EEP")

Applicable to all Customers except those Customers under special contracts as filed and approved by the BPU and those customers exempted pursuant to the Long-Term Capacity Agreement Pilot Program ("LCAPP"), P.L. 2011 c.9, codified as N.J.S.A. 48:3-60.1. See the LCAPP Exemption Procedures at the end of the SBC, Rider "D."

The EEP shall be collected on a per therm basis and shall remain in effect until changed by order of the BPU. The applicable EEP rate is as follows:

Docket No. GR19070872, per a four-year amortization	$0.0062 per therm
Docket No. GO20090619, per a ten-year amortization	$0.0063 per therm
TOTAL	$0.0125 per therm

The rate applicable under this Rider includes provision for the New Jersey Sales and Use Tax, and when billed to customers exempt from this tax shall be reduced by the amount of such tax included therein.

In the "Global Warming Act," *N.J.S.A.*26-2C-45. or "RGGI Legislation" the State Legislature determined that global warming is a pervasive and dangerous threat that should be addressed through the establishment of a statewide greenhouse gas emissions reduction program. On May 8, 2008, the Board issued an Order (the "RGGI Order") pursuant to *N.J.S.A.* 48:3-98.1(c). The RGGI Order allowed electric and gas public utilities to offer energy efficiency and conservation programs on a regulated basis. The Company's energy efficiency programs were first authorized pursuant to Board orders issued in Docket Nos. EO09010056 and GO09010060. They were subsequently extended pursuant to Board orders issued in GO10070446, GO11070399, GO12100946, GO15050504, GR16070618 and GO18070682. The Company's current energy efficiency programs are effective through June 30, 2024. On May 23, 2018, the Clean Energy Act of 2018 ("CEA" or the "Act") was signed into law. The BPU directed utilities to file changes pursuant to Board orders issued in Docket Nos. QO1901040, QO19060748 and QO17091004 Dated June 10, 2020, ("the 2020 Orders").The EEP enables the Company to recover all costs associated with energy efficiency programs approved by the Board.

RIDER "E"

ENERGY EFFICIENCY PROGRAM (“EEP”)
(continued)

Determination of the EEP

On or about July 31 of each year, the Company shall file with the Board an EEP rate filing based on the Board’s August 21, 2013 Order in Docket No. GO12100946 and one based on the 2020 Orders for the costs and recoveries incurred during the previous EEP year ending June 30th as well as estimates, if applicable, through the upcoming calendar year to develop the total EEP rate to be effective October 1st as follows:

The EEP monthly recoverable expenditure amounts shall be derived from taking the average of the cumulative beginning and end of month expenditures associated with the EEP investments less accumulated amortization and accumulated deferred income tax credits times the after tax weighted average cost of capital grossed up for the Company’s revenue factor, as directed in the Board’s August 21, 2013 Order in Docket No. GO12100946, plus monthly amortization using a four year amortization period. Costs recoveries incurred under this and previous Dockets will continue until near zero and then be subsumed in the filings made under the 2020 Orders. The 2020 Orders monthly amortization will be a ten (10) year amortization period. The 2020 Orders also include a customer loan component that will earn a monthly rate of return recovery derived from taking the average of the cumulative beginning and end of month balances associated with the loan investments times the pre-tax rate of return grossed up using a revenue factor after removing the Federal and State corporate business tax. Any changes in the above authorized by the Board in a subsequent base rate case will be reflected in the subsequent monthly calculations.

The EEP rate shall be calculated by summing the (i) prior year’s EEP over or under recovery balance, plus (ii) current year monthly recoverable expenditure amounts, inclusive of amounts any customer fails to repay for their portion of costs associated with installed measures less any subsequent payments received for such measures, less (iii) current year recoveries, plus (iv) current year carrying costs based on the monthly average over or under recovered balances, at a rate equal to the weighted average of the Company’s monthly commercial paper rate or interest rate on its bank credit lines. In the event that commercial paper or bank credit lines were not utilized by the Company in the preceding month, the last calculated rate shall be used. Until such time when ETG has a commercial paper program, the Company will adjust its short-term debt rate to reflect the commercial paper rate proxy reduction of 1.64%. The interest on monthly EEP Rider rate under and over recoveries shall be determined by applying the interest rate based on the Company’s weighted interest rate for the corresponding month obtained on its commercial paper and bank credit lines, but shall not exceed the Company’s after tax weighted average cost of capital utilized to set rates in its most recent base rate case or as authorized in Elizabethtown’s subsequent base rate cases, plus (v) an estimated amount to recover the upcoming year’s recoverable expenditures amount and dividing the resulting sum by the annual forecasted per therm quantities for the applicable Customers set forth above. The resulting rate shall be adjusted for all applicable taxes. The EEP rate shall be self-implementing on a refundable basis as directed by the BPU.

RIDER "F"

INFRASTRUCTURE INVESTMENT PROGRAM ("IIP")

Applicable to all RDS, SGS, GDS, NGV, LVD, EGF and GLS classes and Firm Special Contract customers receiving service through the Company's distribution system. The IIP rate shall be collected on a per therm basis and shall remain in effect until changed by order of the NJBPU.

		Per Therm
RDS	Residential	$0.0000
SGS	Small General Service	$0.0000
GDS	General Delivery Service	$0.0000
GDS	Seasonal SP#1 May-Oct	$0.0000
NGV	Natural Gas Vehicles	$0.0000
LVD	Large Volume Demand	$0.0000
EGF	Electric Generation	$0.0000
GLS	Gas Lights	$0.0000
Firm Special Contracts		$0.0000

The charges applicable under this Rider include provision for the New Jersey Sales and Use Tax, and when billed to customers exempt from this tax shall be reduced by the amount of such tax included therein.

The IIP is a five-year program to modernize and enhance the reliability and safety of the Company's gas distribution system by replacing its vintage, at-risk facilities which include aging cast iron mains, unprotected and bare steel mains and services, ductile iron and vintage plastic mains and vintage plastic and copper services. As part of the IIP, Elizabethtown is upgrading its legacy low pressure system to an elevated pressure system, and installing excess flow valves and retiring district regulators that are presently required to operate the existing low pressure system. The costs recovered through the IIP Rider rate include the Company's after-tax weighted average cost of capital as adjusted upward for the revenue expansion factor, depreciation expense and applicable taxes.

RIDER "G"

CONSERVATION INCENTIVE PROGRAM ("CIP")

Applicable to all Customers served under RDS, SGS and GDS rate classes.

The CIP shall be collected on a per therm basis and shall remain in effect until changed by order of the BPU. The applicable CIP rates are as follows:

RDS Non-Heat	RDS Heat	SGS	GDS
$0.0000 per therm	$0.0000 per therm	$0.0000 per therm	$0.0000 per therm

The rates applicable under this Rider include provision for the New Jersey Sales and Use Tax, and when billed to customers exempt from this tax shall be reduced by the amount of such tax included therein.

The annual filing for the adjustment to the CIP rate shall be concurrent with the annual filing for BGSS. The CIP factor shall be credited/collected on a per therm basis for the service classifications stated above. The level of BGSS savings referenced in (d) in this Rider shall be identified in the annual CIP filing, and serve as an offset to the non-weather related portion of the CIP charge provided in (f) in this Rider. The Periodic and Monthly BGSS rates identified in Rider "A" to this tariff shall include the BGSS savings, as applicable.

(a) This Rider shall be utilized to adjust the Company's revenues in cases wherein the Actual Usage per Customer experienced during Monthly Periods varies from the Baseline Usage per Customer ("BUC"). This adjustment will be effectuated through a credit or surcharge applied to customers' bills during the Adjustment Period. The credit or surcharge will also be adjusted to reflect prior year under recoveries or over recoveries pursuant to this CIP.

RIDER "G"

CONSERVATION INCENTIVE PROGRAM (“CIP”)
(continued)

(b) The BUC in therms for each Customer Class Group by month is as follows:

Month	RDS Non-Heat	RDS Heat	SGS	GDS
July	9.2	19.8	23.8	511.0
August	8.4	18.6	23.9	512.3
September	9.3	22.0	23.9	512.7
October	14.0	45.2	60.5	980.5
November	25.1	109.9	122.9	1,767.1
December	32.8	161.7	230.0	2,524.8
January	41.0	193.3	304.4	3,109.8
February	35.6	158.1	270.5	2,804.6
March	21.6	127.7	176.7	2,048.1
April	13.5	63.6	84.9	1,075.1
May	11.8	31.8	28.5	508.6
June	10.7	22.4	23.6	561.1
Total Annual	233.0	974.1	1,373.6	16,915.7

The BUC shall be reset each time new base rates are placed into effect as the result of a base rate case proceeding.

(c) At the end of the Annual Period, a calculation shall be made that determines for each Customer Class Group the deficiency (“Deficiency”) or excess (“Excess”) to be surcharged or credited to customers pursuant to the CIP mechanism. The Deficiency or Excess shall be calculated each month by multiplying the result obtained from subtracting the Baseline Usage per Customer from the Actual Usage per Customer by the actual number of customers, and then multiplying the resulting therms by the Margin Revenue Factor.

RIDER "G"

CONSERVATION INCENTIVE PROGRAM (“CIP”)
(continued)

(d) Recovery of any Deficiency in accordance with Paragraph (c), above, associated with non-weather-related changes in customer usage will be limited to the level of BGSS savings achieved pursuant to Board orders issued in Docket Nos. QO1901040, QO19060748 and QO17091004 Dated June 10, 2020.The value of the weather-related changes in customer usage shall be calculated in accordance with WNC Rider of this tariff without a dead band which result shall be allocated to applicable classes by the Company.

(e) Except as limited by Paragraph (d), above, the amount to be surcharged or credited to the Customer Class Group shall equal the aggregate Deficiency or Excess for all months during the Annual Period determined in accordance with the provisions herein, divided by the Forecast Annual Usage (“FAU”) for the Customer Class Group.

(f) The CIP shall not operate to cause the Company to earn in excess of its allowed rate of return on common equity of 9.6% for any twelve-month period ending June 30; any revenue which is not recovered will not be deferred. For purposes of this paragraph the Company's rate of return on common equity shall be calculated by dividing the Company's net income for such annual period by the Company's average 13 month common equity balance for such annual period, all data as reflected in the Company's monthly reports to the Board of Public Utilities. The Company's regulated jurisdictional net income shall be calculated by subtracting from total net income (1) margins retained by the Company from non-firm sales and transportation services, net of associated taxes, (2) margins retained in the provision of sales in accordance with the Board Order pertaining to Docket No. GR90121391J and GM90090949, net of associated taxes and (3) net income derived from unregulated activities conducted by Elizabethtown and (4) the Energy Efficiency Program and (5) the Infrastructure Investment Program.

RIDER "G"

CONSERVATION INCENTIVE PROGRAM ("CIP")
(continued)

(g) As used in this Rider, the following terms shall have the meanings ascribed to them herein:

(i) Actual Number of Customers ("ANC") – shall be determined on a monthly basis for each of the Customer Class Groups to which the CIP Clause applies, plus any Incremental Large Customer Count Adjustment for the Customer Class Group.

(ii) Actual Usage per Customer ("AUC") – shall be determined in therms on a monthly basis for each of the Customer Class Groups to which the CIP applies. The AUC shall equal the aggregate actual booked sales for the month as recorded on the Company's books divided by the Actual Number of Customers for the corresponding month.

(iii) Adjustment Period – shall be the calendar year beginning immediately following the conclusion of the Annual Period.

(iv) Annual Period – shall be the twelve consecutive months from July 1 of one calendar year through June 30 of the following calendar year.

(v) Baseline Usage per Customer ("BUC") – shall be the average normalized consumption per customer by month derived from the Company's most recent base rate case and stated in therms on a monthly basis for each Customer Class Group to which the CIP applies. The BUC shall be rounded to the nearest one tenth of one therm.

(vi) Customer Class Group – For purposes of determining and applying the CIP, customers shall be aggregated into three separate recovery class groups, RDS, SGS and GDS.

(vii) Forecast Annual Usage ("FAU") – shall be the projected total annual throughput for all customers within the applicable Customer Class Group. The FAU shall be estimated on normal weather.

RIDER "G"

CONSERVATION INCENTIVE PROGRAM (“CIP”)
(continued)

(viii) Incremental Large Customer Count Adjustment – the Company shall maintain a list of incremental commercial and industrial customers added to its system on or after May 31, 2020 whose connected load is greater than that typical for the Company’s average commercial and industrial customer in the GDS rate schedule. For purposes of the CIP, large incremental customers shall be those GDS customers whose connected load exceeds 5,400 cubic feet per hour (“CFH”). A new customer at an existing location previously connected to the Company’s facilities shall not be considered an incremental customer. The Actual Number of Customers for the Customer Class Group shall be adjusted to reflect the impact of all such incremental commercial or industrial customers. Specifically, the Incremental Large Customer Count Adjustment for the GDS customer class for the applicable month shall equal the aggregate connected load for all new active customers that exceed the 5,400 CFH threshold divided by 2,700 CFH, rounded to the nearest whole number.

(ix) Margin Revenue Factor – the Margin Revenue Factor (“MRF”) for the CIP shall be each class’s Distribution Charge and applicable IIP rate on a pre-tax basis.

RATE SUMMARIES

Rates per therm except for the Service Charge

	RDS Non-Heat	RDS Heat	SGS	GDS
Service Charge (monthly)	$13.27	$13.27	$36.79	$61.84
Distribution	$0.6424	$0.6424	$0.5596	$0.3682
Demand	na	na	na	$1.162
Riders				
A - BGSS	$0.4798	$0.4798	$0.4798	BGSS-M
B - WNC	$0.0171	$0.0171	$0.0171	$0.0171
C - OSMC	($0.0021)	($0.0021)	($0.0021)	($0.0021)
D - SBC	$0.0383	$0.0383	$0.0383	$0.0383
E - EEP	$0.0125	$0.0125	$0.0125	$0.0125
F - IIP	$0.0000	$0.0000	$0.0000	$0.0000
G - CIP	$0.0000	$0.0000	$0.0000	$0.0000

-The BGSS rate is only applicable to gas supplied by the Company. TPS customers are billed for gas supply at the contract gas supply rate as agreed with the TPS.

-For SGS customers and GDS customers with a DCQ under 500 therms, a Balancing Charge of $0.0171 and related to TPS is applicable from November to March.

-The WNC rate is applicable between the months of October and May.

-“na” indicates a rate is not applicable for the specific rate class.

-Rates above include taxes; tax exempt customers’ rates will be adjusted at the time of billing.

RATE SUMMARIES
(continued)
Rates per therm except for the Service Charge

	LVD	EGF	IS	ITS
Service Charge (monthly)	$405.18	$101.29	$735.71 (ceiling)	$735.71 (ceiling)
Distribution	$0.0655	$0.0421	$0.0843	$0.1391
Demand	$1.866	$0.800	$0.269	$0.533
Riders				
A - BGSS	BGSS-M	BGSS-M	BGSS-M	TPS only
B - WNC	na	na	na	na
C - OSMC	($0.0021)	($0.0021)	na	na
D - SBC	$0.0383	$0.0383	$0.0383	$0.0383
E - EEP	$0.0125	$0.0125	$0.0125	$0.0125
F - IIP	$0.0000	$0.0000	na	na
G - CIP	na	$0.0000	na	na

-The BGSS rate is only applicable to gas supplied by the Company. TPS customers are billed for gas supply at the contract gas supply rate as agreed with the TPS.

-“na” indicates a rate is not applicable for the specific rate class.

-Rates above include taxes; tax exempt customers’ rates will be adjusted at the time of billing.

ELIZABETHTOWN GAS COMPANY

TARIFF FOR GAS SERVICE
B.P.U. NO. ~~17~~18

2021 Rate Case

ELIZABETHTOWN GAS COMPANY

TARIFF FOR GAS SERVICE

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SERVICE CLASSIFICATIONS LISTED BELOW ARE AVAILABLE IN
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SERVICE CLASSIFICATIONS LISTED BELOW ARE AVAILABLE IN
THE ENTIRE TERRITORY SERVED BY ELIZABETHTOWN GAS COMPANY

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TERRITORY SERVED
WHOLLY WITHIN THE STATE OF NEW JERSEY

ELIZABETHTOWN DIVISION

Middlesex County

1. Carteret
2. Edison (part)
3. Metuchen
4. Perth Amboy
5. Woodbridge
   - Avenel
   - Colonia
   - Fords
   - Iselin
   - Keasbey
   - Port Reading
   - Sewaren

Union County

1. Clark
2. Cranford
3. Elizabeth
4. Fanwood
5. Garwood
6. Hillside
7. Kenilworth
8. Linden
9. Mountainside
10. Rahway
11. Roselle
12. Roselle Park
13. Scotch Plains
14. Union
15. Westfield
16. Winfield
17. Winfield Park

NORTHWEST DIVISION

Hunterdon County (Southern District)

1. Alexandria
2. Bethlehem
3. Bloomsbury
4. Califon
5. Clinton (Town)
6. Clinton (Twp.)/ Annandale
7. Delaware
8. East Amwell/ Ringoes
9. Flemington
10. Franklin
11. Frenchtown
12. Glen Gardner
13. Hampton
14. High Bridge
15. Holland
16. Kingwood (Twp.)
17. Lambertville
18. Lebanon (Bor.)
19. Lebanon (Twp.)/Stockton
20. Milford (Bor.)
21. Raritan
22. Readington (part)
23. Stockton
24. Union
25. West Amwell

Mercer County (Southern District)

1. Hopewell (Bor.)
2. Hopewell (Twp. Part)
3. Lawrence
4. Pennington

Morris County (Central District)

1. Mount Olive (Twp. Part) / Budd Lake
2. Washington (Twp. Part) / Long Valley

Sussex County
(Northern District)

1. Andover (Bor.)
2. Andover (Twp.)
3. Branchville
4. Byram (Twp.)
5. Frankford
6. Franklin (Bor.)
7. Fredon
8. Green
9. Hamburg
10. Hampton
11. Hardyston
12. Lafayette
13. Newton
14. Ogdensburg
15. Sparta
16. Sussex
17. Vernon
18. Wantage

Warren County
(Central District)

1. Allamuchy
2. Alpha
3. Belvidere
4. Franklin
5. Greenwich
6. Hackettstown
7. Harmony
8. Independence
9. Lopatcong
10. Mansfield
11. Oxford
12. Phillipsburg
13. Pohatcong
14. Washington (Bor.)
15. Washington (Twp.)
16. White

STANDARD TERMS AND CONDITIONS

1. GENERAL

1.01 - Applicability

These Standard Terms and Conditions, filed as part of the Tariff of Elizabethtown Gas Company (hereinafter referred to as "Gas Company" or "Company"), set forth the terms and conditions under which service is rendered and will be supplied. They govern all classes of service to the extent applicable and are made a part of all agreements for the supply of gas service unless specifically modified by the terms of a particular service classification or by special terms written in and made a part of a contract for service.

Failure by the Gas Company to enforce any provisions, terms, or conditions set forth in this Tariff shall not be deemed a waiver thereof.

Per the New Jersey Administrative Code ("N.J.A.C.") 14:3 ("Chapter") Section 14:3-1.3(i) Tariffs states: If there is any inconsistency with this Chapter and a tariff, these rules shall govern, except if the tariff provides for more favorable treatment of Customers than does this Chapter, in which case the tariff shall govern.

1.02 – Termination or Revision of Tariff

This Tariff is subject to the orders of the Board of Public Utilities of the State of New Jersey (hereinafter referred to as "Board" or "BPU"), effective as of this date or as may be promulgated and become legally effective in the future.

Gas Company reserves the right at all times and in any manner permitted by law and the applicable rules and regulations of the Board to terminate, change or modify by revision, amendment, supplement, or otherwise, this Tariff or any part thereof, or any revision, amendment or supplement thereto. All contracts for service are accepted subject to the above reservations.

1.03 – Agents

No representative or agent of Gas Company has the authority to modify, alter, or waive any provision contained in this Tariff or to bind Gas Company by any promise or representation thereto.

1.04 – Application of Tariff

Receipt of gas service from Gas Company makes the receiver a "Customer", as defined in Section 2.01 hereof. However, Gas Company will not be required to continue to render service unless, if upon request of Gas Company, (a) Customer makes, or has made, an application for service in accordance with the Standard Terms and Conditions set forth herein and (b) such application is accepted by Gas Company in accordance with the terms of said Standard Terms and Conditions.

Service furnished by Gas Company prior to its acceptance of Customer's application shall, nevertheless, be charged for at the rates contained in the applicable service classification. The applicable service classification, in a case where more than one service classification might apply and Customer has failed to make a selection, shall be that service classification which in the sole judgement of Gas Company is most advantageous to Customer. (See Section 2.03)

1.05 – Inspection of Tariff

The tariff is available to all Customers for public inspection in each office where applications for service may be made. The Tariff is also available for review or copying at the Company's website at www.Elizabethtowngas.com.

2. OBTAINING SERVICE

2.01 – Application for Service

An application for service may be made at any commercial office of Gas Company, either in person, by mail, by telephone, or by any other means made available by the Company. A written application form or agreement may be required from any person, firm, organization, partnership, corporation, or otherwise, applying for or using gas service (hereinafter referred to as "Customer"). If the Company requires a written application, the application may be subsequently submitted to the Customer for signature. There will be a $15.00 administration charge to establish service to a new Customer or re-establish service to an existing Customer.

Applicant(s) may be required by the Gas Company to supply proof of identity and prior address. Any such requirement to provide proof of identity or prior address shall be in accordance with the provisions of N.J.A.C. 14:3-3.2 as may be amended or superseded.

Separate application may be required in each case where gas service is applied to the same person, firm, organization, partnership, corporation, or otherwise, at two or more non-contiguous properties. For purposes of applying these rates, service at each non-contiguous location shall be considered as service to a separate Customer.

Customer shall state, at the time of making application for service, the conditions under which service will be required. Customer may be required to sign an agreement covering special circumstances necessary for the supply of service in accordance with Customer's requirements. In the case in which the Customer signs a main and/or service extension agreement and subsequently does not install any of the indicated equipment within a reasonable time, not to exceed one year, or purchase the requested quantities of gas, the Company reserves the right to charge the Customer for the full cost of providing the service and main, as applicable.

Gas Company reserves the right to place limitations on the amount and character of gas service it will supply; to refuse service to new Customers or to existing Customers for additional load, if unable to obtain the necessary equipment and facilities to supply such service; to reject applications for service or additional service where such service is not available or where such service might affect the supply of gas to other Customers; or for other good and sufficient reasons.

In accordance with the provisions in N.J.A.C. 14:3-3.2(g), within two business days of receipt of the Customer's application for utility service, or on a mutually agreed upon date, the utility shall initiate the service, except in those cases where the utility or Customer must install or contract to install an extension, as defined at N.J.A.C. 14:3-8.2, to the structure where said service shall be received.

2.02 – Form of Application

Standard applications or agreements to supply gas service shall be in accordance with the particular service classification. Agreements for longer term than that specified in the service classification may be required where large or special investment is necessary to supply service, where special facilities are required to serve a Customer, or where the hourly capacity of the Gas Company's facilities required to serve the Customer's demand, in the opinion of the Gas Company, may be out of proportion to the monthly or annual use of gas service for occasional, intermittent, or low load factor purposes. Gas Company reserves the right to require contributions towards the investment required for such service and to establish such minimum charges and facilities charges as may be equitable under the circumstances involved.

2.03 – Selection of Rate

Gas Company will assist in the selection of the available rate which is most desirable from the standpoint of Customer. However, the responsibility for making the selection shall, at all times, rest with Customer. Any advice given by Gas Company will be based on Customer's statements.

Customer may request Gas Company to change the service classification under which they are billed. However, Gas Company shall not be obligated to make such a change more than once in 12 calendar months even though Customer may qualify for service under more than one service classification.

2.04 – Deposit and Guarantee

Where an applicant's credit is not established, where the credit of a Customer with Gas Company has become impaired, or where Gas Company deems it necessary for other reasons, a deposit or other guarantee satisfactory to Gas Company may be required as security for the payment of future and final bills for gas service and other charges resulting from the rendering of gas service before Gas Company will commence or continue to render service. Service shall not be discontinued for failure to make such deposit, unless said deposit had been included on prior bills, or notices to the Customer. All requests for deposits shall be in accordance with N.J.A.C. 14:3-3.4.

All deposits shall bear simple interest at the rate equal to the average yield on new six-month Treasury Bills for the twelve month period ending each September 30 and shall be paid by the utility on all deposits held by it. Said rate shall become effective on January 1 of the following year. The Board shall perform the annual calculation to determine the applicable interest rate and shall notify the Gas Company of said rate.

Interest accrued from deposits for Residential Service accounts shall be credited to Customer's bill, unless the Customer requests a separate check, at least once during a 12-month period for such service rendered or to be rendered. Customers not purchasing gas under the Residential Service classification will be refunded interest accrued from their service deposit at the time that the deposit is refunded to the Customer. A deposit shall bear interest until it is returned or applied to an outstanding balance.

Gas Company shall review a residential Customer's account at least once every year and non-residential Customer's account at least once every two years and if such review indicates that a Customer has established good credit, the Gas Company will apply the deposit to the outstanding balance on the Customers' account, unless the Customer requests a separate check.

Gas Company reserves the right to apply a deposit, plus accrued interest on said deposit, against unpaid bills for service or other charges resulting from the rendering of gas service. If such action is taken and the Customer continues to receive gas service the Customer shall be required to restore the deposit to the original amount or such other reasonable amount as Gas Company may determine. If the account is closed only the remaining balance will be refunded.

Gas Company shall have a reasonable time in which to read meters and to ascertain that all the obligations of Customer have been fully performed before being required to refund any deposit, in accordance with N.J.A.C. 14:3-3.5.

2.05 – Gas Main Extensions and Service Connections

An extension deposit or contribution in aid of construction may be required from Customer for the extension of gas mains towards the cost of installing a service connection, as set forth in Sections 3 and 4 of these Standard Terms and Conditions.

The making of a deposit or contribution in aid of construction in connection with the extension of a main or service shall not under any circumstances give Customer any interest in the gas main or service or appurtenances thereto, the ownership being at all times vested in Gas Company.

2.06 – Permits

The Gas Company shall obtain or cause to be obtained all easements, licenses or permits necessary to enable the Gas Company or its agents access to connect its mains to the Customer's equipment. This shall be construed to mean all permits and certificates, municipal or otherwise, required by law or the Gas Company's rules. The Gas Company shall not be obliged to furnish service unless and until such permits, instruments, consents and certificates shall have been delivered to the Company. The Company reserves the right to require that Customer obtain or cause to be obtained all easements, licenses, or permits necessary to enable the Company or its agents access to connect its mains to the Customer's equipment.

The Customer may be responsible for payment of the amount by which such easements, licenses or permit fees exceeds $15.00. Payment shall be made prior to the Company filing for said documents.

By making application for service, Customer grants to Gas Company a right-of-way for its lines and other facilities, across, over, under or along the property owned or controlled by Customer, to the extent that the same is necessary to enable Gas Company to render service to premises.

2.07 – Temporary Service

Where service is to be used for a limited period, the use of the service shall be classified as temporary and Customer shall be required to assume the actual cost of the facilities required to furnish service and also their connection and removal, which shall not be less than twice the minimum charge per month for residential service. The minimum period for billing of gas consumption shall be one (1) month. Temporary service will be furnished only where Gas Company's facilities are suitable and quantity of gas is available without in any way interfering with other Customers of Gas Company.

2.08 – Authorization to Turn On Gas to the Meter

Only duly authorized employees or agents of Gas Company shall be permitted to turn on gas.

3. EXTENSIONS OF MAINS AND/OR SERVICE LINES

3.01 –General Provisions

The provisions and definitions within N.J.A.C. 14:3-8.1, *et seq.*, shall be applicable.

The construction of main extensions are subject to the regulations at N.J.A.C. 14:3-8.1, *et seq.* The Company may construct and will own and maintain distribution mains located on streets, highways, and right of way, used or usable as a part of its distribution system. The making of a deposit or contribution by the Customer shall not give the Customer any interest in the facilities, the ownership being vested exclusively in the Company.

The Company may require up-front contributions, or deposits, pursuant to N.J.A.C. 14:3-8.1, *et seq.* These charges shall be increased for any tax consequences to the Company. If the Company accepts an application for an extension, the Company may furnish and place, at no cost to the Customer, up to 200 feet of normal residential facilities.

Deposits that are received from Customers pursuant to the Extensions of Mains and Services shall be refunded without interest in accordance with the applicable formula contained in N.J.A.C. 14:3-8.10 and N.J.A.C. 14:3-8.11. In no event shall the Company refund more than the total deposit amount received from the Customer. Any deposit amount not refunded within ten (10) years from the date service was initiated, shall remain with the Company and shall constitute a contribution in aid of construction.

3.02 Main and Service Extensions Requested by Customers

1) Residential

The Company shall extend its gas mains and services to serve an individual residential Customer at no charge where the Extension Cost does not exceed ten (10) times the annual Distribution Revenue. The Distribution Revenue shall be the incremental initial or actual total annual billings, as determined by the Gas Company, derived from the Applicant's and/or existing Customer's applicable Service Classification, inclusive of Sales and Use Tax, minus the Basic Gas Supply Service, inclusive of Sales and Use Tax. The Company shall require a deposit equal to the Extension Cost in excess of ten (10) times the annual Distribution Revenue and shall include any tax consequences to the Company. The Company will waive the deposit requirement where the excess cost is $3,000 or less.

2) - Non-Residential

The Company will extend its gas mains and services to an individual firm commercial or industrial Customer and shall require a deposit equal to the Extension Costs, increased by any tax consequences to the Company. The Company will waive the deposit requirement where the excess cost is $3,000 or less. In lieu of a deposit for Extension Costs, the Company and the Customer may agree upon a satisfactory revenue guarantee.

3) - Extension of Service to New Developments

The Company shall require a deposit for an extension subject to this Section, in the amount of the Extension Cost required to serve the development. The deposit shall be increased by any tax consequences to the Company. The Company will waive the deposit requirement where the excess cost is $3,000 or less. In lieu of a deposit for Extension Costs, the Company and the Customer may agree upon a satisfactory revenue guarantee.

3.03 - Service Connection Location

Service connections will be measured at right angles from the nearest curb line to the Applicant's building, at the point of service entrance designated by the Company. Meters and regulators will be furnished and installed by the Company. The costs of meters and regulators (including the installation) may be waived by the Company.

The Applicant shall consult the Company as to the exact point at which the service pipe will enter the building before installing interior gas piping or starting any other work dependent upon the location of the service pipe. The Company will determine the location of the service pipe depending upon physical constraints in the street and other practical considerations.

4. SERVICE CONNECTIONS

4.01 – General

Subject to the provisions of the Extensions of Mains and/or Service Lines section of this tariff, gas service will normally be supplied to each premise through a single service pipe, except where, in the judgment of Gas Company, it is deemed desirable to install more than one service pipe. The Gas Company may also choose to install multiple meters on one service pipe providing service to several premises. If more than one service is installed for the convenience of the Customer, each location will be considered as a separate Customer. In addition, at its expense and option, the Company may include a "customer valve" on the premise side of the meter on new, existing and/or re-established existing services. The ownership of the valve will be transferred to the Customer upon gas flowing through the valve.

4.02 – Change in Existing Installations

Any change in the location of the existing service pipe or meter set requested by Customer and approved by Gas Company shall be made at the expense of Customer. The Gas Company reserves the right to change the location of an existing service pipe or meter set to a placement and location determined solely by the Gas Company upon giving the Customer ten (10) days notice, unless it is done as part of an unforeseen repair or an upgrade to the main. The Gas Company shall bear all costs related to such changes including re-connecting pipes to the premise side of the meter and appurtenances related to any meter reading devices.

A Customer who qualifies pursuant to 49 CFR Section 192 and/or has a service line that is 2" or less and has a system minimum pressure of ten (10) pounds per square inch gauge or more may request installation of an Excess Flow Valve (EFV). If a Customer does not qualify for an EFV the Company will offer to install a Curb Stop. The Customer will be required to pay all EFV or Curb Stop installation costs associated with such installation before the Company begins work if:

a) the Company has not scheduled the Customer's premises for a service line replacement or a new service line or,
b) the Customer requests the installation prior to the Company's scheduled installation time.

5. METERS AND ASSOCIATED EQUIPMENT

5.01 – General

Subject to the provisions of the Extensions of Mains and/or Service Lines section of this tariff, the Gas Company will furnish, install and maintain meters for each premise and/or service. In addition, where appropriate, when a Customer has two or more service classifications, the Customer will have separate meters.

Where more than one meter is installed in a premise, the readings of all such meters supplying a Customer under the same service classification may be combined for billing purposes. The Customer may be charged a monthly service charge for each meter even if said meters are combined for billing purposes.

5.02 - Customer's Responsibility

Customer shall provide and maintain, without charge to Gas Company, a suitable space for the metering and associated equipment. Such space shall be as near as practicable to the point of entrance of the service pipe, adequately ventilated, dry, free from corrosive vapors, not subject to extreme temperatures, free from appreciable vibrations or any other conditions that may impact the meter as well as being readily accessible to authorized employees or agents of Gas Company. In apartment houses, office buildings, townhouses or condominiums with multiple service, all meters shall, whenever possible, be grouped together. Adequate passageway, maintained free of obstacles and unsafe and hazardous conditions, shall be provided at all times.

Customer shall not tamper with or remove meters or other equipment or permit access thereto, except by authorized employees or agents of Gas Company.

With the exception of the "customer valve" on the premise side of the meter, when installed (see Section 4.01), all equipment furnished by the Gas Company shall remain its property and may be replaced whenever deemed necessary by the Gas Company or as required by the Board and may be removed by Gas Company at any time after discontinuance of service.

In case of loss or damage from the act or negligence of Customer or the Customer's agents, employees and or contractors, or of failure to return property supplied by Gas Company, Customer shall pay to Gas Company the value of such property.

5.03 – Automatic Meter Reading Equipment (AMR)

The Company in its sole discretion may install, at its expense, an AMR device to monitor a Customer's gas consumption. However, when gas is to be delivered at a pressure in excess of the Company's standard gauge pressure noted in Section 7.02, or such equipment is required by the service classification under which the Customer will receive service, the Company shall determine any necessary equipment inclusive of compensating and AMR devices to be installed at the Customer's expense. When such devices require attachment to telephone and/or electric utilities, the Customer shall provide and pay for suitable connections unless the Company elects to make such connections. When an AMR device is requested by the Customer, the AMR device and any necessary appurtenances shall be installed at the Customer's expense if the installation is deemed feasible by the Company. Where feasible, the Company will make data from the AMR device or other equipment available to the Customer upon the signing of a Service Agreement.

Payments made by the Customer shall not give the Customer ownership of the equipment. All equipment remains the sole property of the Company. Installation of an AMR does not relieve the Customer of the obligations of Sections 5.02 – Customer's Responsibility or Section 9 Access to Premises.

6. CUSTOMER'S INSTALLATION

6.01 – General

No material change in the size, total capacity, or method of operation of Customer's equipment shall be made without previous written notice to the Gas Company and subsequent approval by the Gas Company.

The Gas Company will assume no responsibility for the condition of Customer's gas installation or for accidents, fires, or failures which may occur as the result of the condition of such gas installation.

Neither by inspection or non-rejection, nor in any other way, does the Gas Company give any warranty, expressed or implied, as to the adequacy, safety, or other characteristics of any structure, equipment, wires, pipes, appliances, or devices used by the Customer.

Gas Company shall not be liable for damages to the Customer's equipment or injuries sustained by Customer due to the condition or character of Customer's facilities and equipment. The Gas Company will not be responsible for the use, care or handling of the gas delivered to Customer after same passes beyond the point at which the Company's service facilities connect to the Customer's facility. Gas Company also shall not be liable for any claim for damage resulting from the supply, use, care or handling of the gas or from the presence or operation of the Company's structures, equipment, pipes or devices except for direct damages resulting from the Gas Company's negligence, recklessness or willful misconduct. The Gas Company will not be liable for special or consequential damages.

6.02 – Equipment, Piping and Installation

Customer appliances, piping and installations shall be made and maintained in accordance with the standards and specifications set forth in American National Standard, National Fuel Gas Code, ANSI Z223.1, and such other regulations as may be promulgated from time to time by any governmental agency having jurisdiction over the Customer's installation.

6.03 – Back Pressure and Suction

When the nature of Customer's gas equipment is such that it may cause back pressure or suction in the piping system, meters, or other associated equipment of Gas Company, suitable protective devices, subject to inspection and approval by Gas Company, shall be furnished, installed, and maintained by Customer.

6.04 – Adequacy and Safety of Installation

Gas Company shall not be required to supply gas service until Customer's installation has been approved by the authorities, if any, having jurisdiction, and Gas Company further reserves the right to withhold its service or to discontinue its service whenever such installation, or part thereof, is deemed by Gas Company to be unsafe, inadequate or unsuitable for receiving service, to interfere with or impair the continuity or quality of service to Customer or others, or for other good and sufficient reason.

7. METER READINGS AND BILLING

7.01 – General

Gas Company will select the type and make of metering equipment and may, from time to time, change or alter such equipment. It shall be the obligation of Gas Company to supply meters that will accurately and adequately furnish records for billing purposes. Bills will be based upon registration of Gas Company meters, except as otherwise provided for herein.

At such time as Gas Company may deem proper or as the Board may require, Gas Company will test its meters in accordance with the standards and bases prescribed by the Board. The performance of a test outside of these standards is at the Company's option. Any Customer requesting such a meter test more than once in a twelve (12) month period shall be charged all related costs to test the equipment, inclusive but not limited to time and material costs with overhead factors for the second and subsequent tests. In the event of a dispute the Gas Company's meter will be presumed to be correct, subject to test results in accordance with N.J.A.C. 14:3-4.5 and 14:3-4.6.

7.02 – Correction for Pressure and/or Temperature

For purposes of measurement, a cubic foot of gas is that volume occupying one cubic foot (12" x 12" x 12") at the Company's standard gauge pressure of five (5) inches water column and at a temperature of 60°F.

In any case where Gas Company measures or the Customer has requested that the gas delivered is at a pressure greater than five (5) inches of water column or at temperatures other than 60° F, the cubic feet of gas registered by the meter shall be subject to correction for billing purposes by the application of proper correction factors or by the use of pressure and/or temperature compensating devices under Section 5.03 – Automatic Meter Reading Equipment (AMR).

7.03 – Therm Conversion Factor

Meter readings of Customers shall be converted from cubic feet to therms by applying a therm conversion factor. A therm is defined as a unit of heat energy equal to 100,000 British Thermal Units (B.T.U.'s). For billing purposes, the Customer's gas usage in cubic feet will be converted to therms using a therm conversion factor representing the actual weighted average BTU value per 100 cubic feet of gas that was delivered into the Company's system in the second preceding calendar month as adjusted to a dry basis as reported each month to the Board in accordance with N.J.A.C. 14:6-3.2. This therm conversion factor expressed to precision of at least three decimal places, shall be applied in calculating bills on a service rendered basis. The Gas Company may at its option, upon 30 day notice to Board and the New Jersey Division of Rate Counsel ("Rate Counsel or RC"), modify the calendar period used in determining the BTU factor, if it is modified toward or at a period closer to that of the Customer billing periods. In that event, the Company's reports to the Board concerning the BTU value of gas delivered into the Company's system shall contain sufficient detail to allow the Board to review the Company's calculation of therm conversion factors.

7.04 – Billing Period

Unless otherwise specified, the charges in this Tariff are stated on a "monthly" basis. The term "month" for billing purposes, shall mean a period of thirty (30) days.

Bills for service furnished will normally be rendered monthly. However, the Company reserves the right to bill bi-monthly. Gas Company also expressly reserves the right to render to any Customer bills based on meter reading periods which may be shorter than a month. Such bills will be prorated as provided in Section 7.05 hereof and are due as provided in Section 7.10 hereof.

7.05 – Proration of Monthly Charges

Except for temporary service accounts, the monthly charges for all initial bills, all final bills, and all bills for periods longer than five (5) days more, or shorter than five (5) days less, than the regular monthly billing period shall be prorated on the basis of a thirty-day month or the actual number of days in the billing period. For temporary service accounts, the minimum billing period for billing purposes shall be one month.

7.06 – Estimated Bills and Discontinuance of Service for Excessive Estimated Reads

Where Gas Company is unable for any reason to read the meter, Gas Company reserves the right to estimate the amount of gas supplied based upon past usage and other information available and submit a bill determined on that basis. Such a bill shall be marked as to the fact that it is an estimated bill. During the summer period (defined here as May 15th through September 15th) the Gas Company may suspend the reading of manually read meters when the Company determines such suspension is necessary to permit the Company to redirect its work force to higher priority projects, provided, however, that the Company may not suspend meter readings for any individual Customer for four (4) or more consecutive billing periods (monthly accounts) or two (2) or more consecutive billing periods (bimonthly and quarterly accounts). During such time the accounts will be billed based on estimated usage. Adjustment of Customer's estimated use to actual use shall be made when an actual reading is next obtained. Notwithstanding the above, the Gas Company reserves the right to discontinue gas service when a meter reading is not obtained in accordance with N.J.A.C. 14:3-7.2(e)(3) which states "When a utility estimates an account for four consecutive billing periods (monthly accounts), or two consecutive billing periods (bimonthly and quarterly accounts), the utility shall mail a notice marked "Important Notice" to the Customer on the fifth and seventh months, respectively, explaining that a meter reading must be obtained and said notice shall explain the penalty for failure to complete an actual meter reading. After all reasonable means to obtain a meter reading have been exhausted, including, but not limited to, offering to schedule meter readings for evenings and on weekends, the utility may discontinue service provided at least eight months have passed since the last meter reading was obtained, the Board has been so notified and the Customer has been properly notified by prior mailing. If service is discontinued and subsequently restored, the utility may charge a reconnection charge equal to the reconnection charge for restoring service after discontinuance for nonpayment."

7.07 – Billing Adjustments Due to Inaccurate Meter Recordings

When it is determined that the Gas Company's meter is inaccurate or defective, the use of gas service shall be determined by a test of the meter, or by registration of the meter set in its place during the period next following, or after due consideration of previous or subsequent properly measured deliveries. Whenever a meter is found to be registering fast by more than 2% an adjustment of charges shall be made in accordance with the provisions of N.J.A.C. 14:3-4.6.

If a meter is found to be registering less than 100% of the service provided, the Gas Company shall not adjust the charges retrospectively and/or require the Customer to repay the amount undercharged except if: 1) the meter was tampered with; 2) the meter failed to register at all; or 3) the circumstances are such that the Customer should reasonably have known that the bill did not reflect the actual usage. In rebilling a Customer under such conditions, the Gas Company may, per its determination, utilize previous or subsequent properly measured deliveries, perform a load analysis and/or a degree day analysis to estimate the usage. The Gas Company shall allow the Customer to make payment over a period of time equal to that during which the undercharges occurred, in accordance with N.J.A.C. 14:3-4.6(f).

Any adjustment to the Customer's account resulting from the terms in this section will be billed or applied to the account as the case may be. If the adjustment results in a credit, such amount may be refunded upon request by the Customer, in lieu of bill credit, in accordance with N.J.A.C. 14:3-4.6, as may be amended or superseded.

7.08 – Separate Billing for Each Installation

The service classifications are based upon the rendering of service through a single delivery and metering point. Service rendered to the same Customer at other points of delivery shall be separately metered and billed, except as provided in Section 5.01 hereof.

7.09 – Sale for Resale of Gas Service and Sub-Metering

1. General

Gas service supplied by the Company shall not be resold by Customer to others except where the Customer is another publicly regulated gas utility, where the gas is used for conversion to Compressed Natural Gas ("CNG"), or the Customer of record is sub-metering in accordance with the conditions set forth below.

2. Sub-Metering

a. Gas sub-metering is the practice in which a Customer of record of the Gas Company, through the use of direct metering devices, monitors, evaluates or measures the Customer of record's own utility consumption or the consumption of a tenant for accounting or conservation purposes.

   Gas sub-meters are devices that measure the volume of gas being delivered to particular locations in a system after measurement by a Company owned meter.

b. If the Customer of record charges the tenant for the usage incurred by the tenant, the sum of such charge(s) to the tenant shall not exceed the cost incurred by the Customer of record for providing gas service, including reasonable administrative expenses. Further, the sum of such charge(s) to the tenant shall not exceed the amount the utility would have charged such tenant if the tenant had been served and billed by the Company directly. The reselling of sub-metering gas service for profit is prohibited.

c. Gas sub-metering, in accordance with the conditions described hereinabove, is permitted in new or existing buildings or premises where the basic characteristic of use is industrial or commercial. Gas sub-metering is not permitted in existing buildings or premises where the basic characteristic of use is residential except where such buildings or premises are publicly financed or government owned or are charitable in nature or are condominiums or cooperative housing.

d. The Customer of record shall contact the Company prior to the installation of any gas sub-metering device, in order to ascertain whether the affected premises is located within a low pressure portion of the Company's supply system and whether or not the installation of a gas check metering device will cause any significant pressure drop to the affected premises.

e. All gas consuming devices in any unit must be metered through a single gas sub- meter.

7.10 – Payment of Bills

At least 15 days' time for payment shall be allowed after the date a bill is mailed. Bills are payable at any commercial office at Gas Company or at any duly authorized collection agency or by mail or any other means made available by the Company. The Gas Company may discontinue service for nonpayment of bills provided the amount is greater than $100 and or more than three (3) months delinquent and it gives the Customer at least 10 days' written notice of its intention to discontinue service. The notice of discontinuance shall not be mailed until the expiration of the said initial 15-day period. However, in cases of fraud, illegal use, or when it is clearly indicated that the Customer is preparing to leave, immediate payment of accounts may be required. The Gas Company reserves the right to request wire transfer of funds for payment of bills when the Company reasonably determines that payment by wire transfer is required.

A late payment charge equal to one-twelfth of the lower of 18% or the highest rate allowed by law shall be applied to the monthly billing for all non-residential Customers. However, service to a governmental entity will not be subject to a late payment charge. Per Section 14:3-7.1(e) of the N.J.A.C., the utility shall not apply a late payment charge sooner than twenty five (25) days after a bill is rendered. Therefore, the Company may, beginning on the twenty-sixth (26th) day after rendering a bill, assess late payment charges. The charge will be applied to all amounts previously billed including late payment charges and accounts payable that are not received by Gas Company within the days specified above. The amount of the late payment charge to be added to the unpaid balance shall be calculated by multiplying the unpaid balance by the late charge rate. When payment is received by the Company from a Customer who has an unpaid balance which includes charges for late payment, the Customer's payment shall be applied first to such late payment charges and then the remainder to the unpaid balance.

7.11 – Reimbursement of Expense for Processing Uncollectible Checks

A charge of $15.00 will be made to reimburse the Company for the expense of processing Customer checks which are returned by the Company's bank as uncollectible. A charge of $8.00 will be made to reimburse the Company for the expense of processing Customer checks that are re-submitted and again returned by the Company's bank as uncollectible.

7.12 – Beginning and Ending Service

Any Customer starting the use of service without making application for service and enabling Gas Company to read the meter will be held liable for any amount due for service supplied to the premises from the last reading of the meter immediately preceding the Customer's occupancy, as shown by the records of Gas Company.

Customers shall give reasonable notice of intended removal from any premises wherein they are receiving gas service. Customer shall be liable for service taken after notice of termination has been received by the Company until such time as the meter is read and disconnected, not to exceed forty-eight (48) hours. Notice to discontinue service does not relieve a Customer from any minimum or guaranteed payment under any service classification or contract.

7.13 – Budget Plan

Heating Customers billed under Service Classification RDS have the option of paying for their use of total service in equal estimated monthly installments as set forth in the applicable Gas Company's House Heat Budget Plan. The Company may offer a budget plan to all classes of Customers.

8. LEAKAGE

Customer shall immediately give notice to Gas Company of any escape of gas in or about Customer's premises.

9. ACCESS TO PREMISES

Properly identified employees or agents of Gas Company shall have access to Customer's premises at all reasonable times for any and all necessary purposes in connection with the rendering of service or the removal of its property.

10. RIGHT TO SUSPEND, CURTAIL, OR DISCONTINUE SERVICE

Gas Company shall have, upon reasonable notice, when it can be reasonably given, the right to suspend, curtail or discontinue its service for any of the following reasons:

(1) For the purpose of making repairs, changes, replacements, or improvements in any part of its system.

(2) For compliance in good faith with any governmental order or directive, whether federal, state, municipal, or otherwise, notwithstanding such order or directive subsequently may be held to be invalid.

(3) For any of the following act(s) or omission(s) on the part of Customer:

a. Non-payment of a valid bill due for service furnished at the present or any previous locations. However, nonpayment for business service shall not be a reason for discontinuance of residential service.

b. Tampering with any facility of Gas Company.

c. Fraudulent representation in relation to the use of gas service.

d. Customer moving from the premises unless the Customer requests that service be continued.

e. Delivering gas service to others without written approval of Gas Company except as permitted under Section 7.09 – Sale for Resale of Gas Service and Sub-Metering.

f. Failure to make or increase an advance payment or deposit when requested by Gas Company.

g. Refusal to contract for service where such contract is required.

h. Connecting and operating equipment in such a manner as to produce disturbing effects on the gas system of Gas Company or on systems of other Customers.

i. Failure to comply with any of these Standard Terms and Conditions.

j. Where the conditions of Customer's installation or facilities presents a hazard to life or property.

k. Failure of Customer to repair any faulty facility of Customer.

l. Failure to provide access to the meter to obtain a reading as permitted under Section 7.06 – Estimated Bills and Discontinuance of Service for Excessive Estimated Reads.

(4) For refusal of reasonable access to Customer's premises for necessary purposes in connection with the rendering of service, including meter installation, reading or testing, or the maintenance or removal of the property of Gas Company.

Failure of Gas Company to exercise its rights to suspend, curtail or discontinue service, for any of the above reasons, shall not be deemed a waiver thereof.

Should gas service be terminated for any of the above reasons, the minimum charge for the unexpired portion of the term shall become due and payable immediately, provided, however, that if satisfactory arrangements are subsequently made by Customer for reconnection of the service, the immediate payment of the minimum charge for the unexpired portion of the contract term may be waived or modified as the circumstances indicate would be just and reasonable.

11. RECONNECTION AND TAMPERING CHARGES

11.01 – Reconnection and Collection Charges

A charge of $15.00 shall be made when the Company makes a collection visit to the customer or the premises and/or to restore service when service has been suspended or discontinued for any of the reasons cited in Sections 10.(3), excepting 10.(3)d, and 10.(4) of these Standard Terms and Conditions. Recurring reconnection charges in any 12-month period shall be charged at the approved regular rates for Customer service otherwise performed by Gas Company but not less than $30.00.

A charge of $200.00 may be made when service has been terminated for any of the reasons cited in Sections 10.(3), excepting 10.(3)d, and 10.(4), and which required the installation of a curb box for said termination.

11.02 – Tampering Charge

In the event it is established that a Company's meters or other equipment on the Customer's premises have been tampered with, and such tampering results in incorrect measurement of the service supplied as determined by the Company, the cost for such gas service, based upon the Company's estimate from available data and not registered by the Company's meter, shall be paid by the beneficiary of such service. The beneficiary shall be any person who benefits from such tampering. The actual cost of investigation, inspection and determination of such tampering, and other costs, such as but not limited to the installation of protective equipment, legal fees, and other costs relating to the administrative, civil or criminal proceedings, shall be billed to the beneficiary of such tampering in the case of non-residential accounts. In the case of residential accounts, all such costs shall be billed to the responsible party. The responsible party shall be the party who either tampered with or caused the tampering with a meter or other equipment or knowingly received the benefit to tampering by or caused by another. In the event a residential Customer unknowingly received the benefit of meter or equipment tampering, the Company shall only seek from the benefiting Customer the cost of the service provided but not the cost of investigation.

Under certain conditions, tampering with the Company's facilities may also be punishable by fine and/or imprisonment under New Jersey law.

11.03 – Diversion of Service

Diversion is an unauthorized connection to pipes and/or wiring by which the utility service registers on the tenant Customers' meter although such service is being used by other than the tenant-customer of record without the tenant-customer's knowledge or cooperation. Where a tenant-customer alleges or it is established that service has been diverted outside of such Customers' premises, that tenant-customer shall not be required to pay for such service without that tenant-customer's consent. The definitions, procedures, investigations and determination of N.J.A.C. 14:3-7.8 shall apply.

12. CONTINUITY OF SERVICE

Gas Company will use reasonable diligence to provide a regular and uninterrupted supply of service; but, should the supply be suspended, curtailed, or discontinued by Gas Company for any of the reasons set forth in Section 10 of these Standard Terms and Conditions or should the supply of service be interrupted, curtailed, deficient, defective, or fail, by reason of any act of God, accident, strike, legal process, governmental interference, acts of third parties, or by reason of compliance in good faith with any governmental order or directive, notwithstanding such order or directive subsequently may be held to be invalid, provided such reasons are not the product of the Company's negligence, or willful misconduct, Gas Company shall not be liable for any loss or damage, direct or consequential, resulting from any such suspension, discontinuance, interruption, curtailment, deficiency, defect, or failure.

Additionally, Gas Company may curtail or interrupt service to any Customer or Customers in the event of emergency threatening the integrity of its system or the systems to which it is directly or indirectly connected if, in its sole judgement, such action will prevent or alleviate the emergency condition.

13. LIMITATION OF SERVICE AVAILABILITY

Where the facilities of Gas Company and/or the quantity of gas available are restricted or limited, preference may be given by Gas Company in supplying service to Customers giving consideration to such factors as 1) annual gas use, 2) volume of gas, 3) load factor, 4) end use of gas, 5) capital investment costs, and 6) number of appliances.

14. CHARACTERISTICS OF SUPPLIED GAS

Type(s) of gas supplied:

1. Natural gas

2. Natural gas mixed with Propane-Air Gas and or Manufactured Gases and or Liquefied Natural Gas

3. In areas where natural gas service is not available, undiluted commercial grade propane gas distributed through Gas Company facilities and having a minimum heating value of 2,400 BTU per cubic foot.

15. GENERAL

15.01 – Inspection of Customer Facilities

Neither by inspection, approval nor non-rejection, nor in any other way does Gas Company give any guarantee or assume any responsibility, expressed or implied, as to the adequacy, safety, or characteristics of any structures, equipment, pipes, appliances, or devices owned, installed, or maintained by Customer or leased by Customer from third parties, except in those instances in which the above equipment or facilities are owned, or leased by Gas Company.

15.02 – Force Majeure

Neither Gas Company, TPS, or Customer shall be liable for damages to the other for any act, omission, or circumstance occasioned by or in consequence of any acts of God, strikes, lockouts, acts of the public enemy, wars, blockades, insurrections, riots, epidemics, landslides, lightning, earthquakes, fires, storms, floods, washouts, arrests and restraints of rulers and people, civil disturbances, explosions, breakage or accident to machinery or lines of pipe, temporary failure of gas supply, temporary failure of firm transportation arrangements, the binding order of any court or governmental authority which has been resisted in good faith by all reasonable legal means, acts of third parties, and any other cause, whether of the kind herein enumerated or otherwise, not within the control of the party claiming suspension and which by the exercise of due diligence such party is unable to prevent or overcome.

Such cause or contingencies affecting the performance by Gas Company, TPS or Customer, however, shall not relieve it of liability in the event of its concurrent negligence or in the event of its failure to use due diligence to remedy the situation and remove the cause in an adequate manner and with all reasonable dispatch, nor shall such causes or contingencies affecting performance relieve either party from its obligations to make payments of amounts then due hereunder in respect of gas theretofore delivered.

16. GAS CURTAILMENT PLAN

16.01- Purpose

The purpose of this plan is to preserve the ability to continue to provide essential gas services, as defined below, to the broadest base of Customers given limited gas supply and/or delivery capacity.

16.02 - Definition of Essential Gas Users

Essential Gas Users are defined as gas service to individual residential dwellings, multi-family residential dwellings, schools, hospitals, day care centers, nursing homes, dormitories, correctional facilities, twenty-four hour emergency facilities such as municipal police, fire or emergency medical departments and similar facilities which do not have installed alternate fuel equipment and an alternate fuel supply.

16.03 – Actions Required Before Implementation of the Gas Curtailment Plan

The Gas Curtailment Plan will be implemented only after the Company has:

1. Exercised all of its rights to interrupt service to interruptible service classifications – ITS, IS, CS, CSI, as provided for in the Company's Tariff;

2. Availed itself of all cogeneration firm recall gas;

3. Interrupted SIS service, if being provided.

Nothing in the Gas Curtailment Plan shall inhibit the Company from managing and scheduling interruptions in service as covered above in a manner that it determines is appropriate to meet the conditions on its system. However, the Gas Curtailment Plan Action Steps will not go into effect until such time as all options available above have been exercised.

16.04 – Curtailment Plan Action Steps

1. The Company shall request all transportation Customers and their TPS to maximize deliveries of gas into the Company's system and request excess deliveries be made available to the Company at a compensation price agreed to by the parties.

2. The Company shall reduce gas service to its own facilities to a minimum;

3. The Company shall appeal to firm large industrial and commercial Customers to voluntarily reduce gas consumption;

4. The Company shall appeal to its general population of Customers to reduce gas consumption by lowering thermostats 5° F, closing off unused rooms, reducing non-essential uses of gas – i.e., gas lights, clothes drying;

5. The Company shall declare the existence of a gas curtailment emergency on its system and notify the BPU and other appropriate state agencies;

6. The Company shall seek emergency supplies from pipelines, suppliers and other gas companies;

7. The Company shall curtail service to all firm industrial services greater than 2,000 therms/day other than plant protection;

8. The Company shall curtail service to all firm industrial services less than 2,000 therms/but greater than 500 therms/day other than plant protection;

9. The Company shall curtail non-essential firm commercial usage 500 therms/day or greater;

10. The Company shall curtail remaining non-essential commercial and industrial usage;

11. The Company shall curtail service for industrial plant protection;

12. The Company shall systematically curtail essential uses employing the Company's emergency plan.

16.05 – Appropriation of End User Transportation Gas

When a gas curtailment emergency is declared (Step 5 in Section 16.04 above), any third-party transportation gas being delivered into the Company's system for end-use Customers shall be appropriated by the Company to serve the priority of service under this curtailment plan. Customers and TPSs whose gas is so appropriated shall be compensated for such gas at its replacement cost but not less than the equivalent price of #2 fuel oil and to the extent the Customer's actual delivered service is curtailed, that Customer shall receive curtailment credits equal to a proration of any fixed monthly service charge and demand charges to correspond to the amount of the curtailed service.

16.06 – Liability Exclusion

The declaration of a gas curtailment emergency shall constitute a force majeure condition under Section 15.02 of these Standard Terms and Conditions. Consequently, the Company shall not be liable for any damages, loss of product or other business losses suffered by Customers as a result of curtailed gas service.

17. UNAUTHORIZED GAS USE

Unauthorized Use includes, but is not limited to, any volume of gas taken by Customer in excess of its maximum daily requirement as set forth in its Service Agreement with Gas Company or the quantity of gas allowed by Gas Company on any day for any reason, including as a result of a curtailment or interruption notice issued by the Company in accordance with its tariff and/or the Board of Public Utilities of the State of New Jersey or any other governmental agency having jurisdiction. A "day" shall be a period of twenty-four (24) consecutive hours, beginning as near as practical to 8 a.m., or as otherwise agreed upon by Customer and Gas Company.

The Company reserves the right to physically curtail the gas service to any Customer if, in the Company's sole judgement, such action is necessary to protect the operation of its system.

If a Customer uses gas after having been notified that gas is not available under their Service Classification, and or if applicable, uses gas in excess of the maximum daily quantity or requirements as established in the Service Agreement then unauthorized gas charges shall apply.

Furthermore, if a TPS fails to deliver gas in the quantities and or imbalance ranges specified in the TPS Service Classification then unauthorized gas charges shall apply to the TPS.

In addition to the above, the following conditions have been ordered by the BPU specifically related to Interruptible Customers and their suppliers: A Customer who fails to discontinue natural gas use, consistent with the terms and conditions of the relevant interruptible service agreements, and suppliers who fail to deliver natural gas during a critical period/OFO notice, consistent with the terms and conditions of applicable service agreements and TPS Agreements, shall be charged a penalty equal to the charges for Unauthorized Gas Use.

All Unauthorized Usage shall be billed at the higher of $2.50 per therm or a rate equal to ten times the highest price of the daily ranges which are published in Gas Daily on the table "Daily Price Survey" for delivery in Transco Zone 6 or Texas Eastern Zone M-3. This rate shall not be lower than the maximum penalty charge for unauthorized daily overruns as provided for in the FERC-approved gas tariffs of the interstate pipelines which deliver gas into New Jersey. This is in addition to all applicable taxes and charges of the Customer's service class.

Nothing herein shall be construed to prevent the Company from taking all lawful steps to stop the unauthorized use of gas by Customer, including disconnecting Customers service.

Such payment for unauthorized use shall not be deemed as giving Customer or TPS any rights to use such gas.

The Gas Company may, in its sole discretion, permanently discontinue service upon a finding by the Gas Company that the Customer has not complied with the conditions and provisions of the tariff.

TPSs that have subscribed to Standby for their Essential Use Customers are not subject to Unauthorized Use Charges for volumes that are within the limits of their Standby Service but will be billed the Standby Rate determined at month end. Any revenues from Unauthorized Gas Use penalty charges shall be credited to the BGSS.

All Unauthorized Use Charges applicable to transportation services will be billed to and payable by the TPS providing gas supply for such services. In the event a TPS fails to pay these charges, the Customers of that TPS shall be billed directly by the Company for either: 1) their proportionate share, based on the Allocation of Supplies as set forth in the TPS service classification; or 2) their direct share identified through their non-compliance to Company directives to ease or curtail gas use.

18. NEW JERSEY SALES AND USE TAX

In accordance with P.L. 1997, c. 162 (the "energy tax reform statute"), as amended by P.L. 2016, c. 57, provision for the New Jersey Sales and Use Tax ("SUT") has been included in all charges applicable under this tariff by multiplying the charges that would apply before application of the SUT by the factor 1.06625. The energy tax reform statute exempts the following customers from the SUT provision, and when billed to such Customers, the charges otherwise applicable under this tariff shall be reduced by the provision for the SUT included therein:

1. Franchised providers of utility services (gas, electricity, water, waste water and telecommunications services provided by local exchange carriers) within the State of New Jersey.

2. Cogenerators in operation, or which have filed an application for an operating permit or a construction permit and a certificate of operation in order to comply with air quality standards under P.L. 1954, c. 212 (C.26:2C-1 et seq.) with the New Jersey Department of Environmental Protection, on or before March 10, 1997.

3. Special contract Customers for which a Customer-specific tax classification was approved by a written Order of the BPU prior to January 1, 1998.

4. Agencies or instrumentalities of the federal government.

5. International organizations of which the United States of America is a member.

In accordance with P.L. 2004, c. 65 "The Business Retention and Relocation Assistance Act" and subsequent amendment (P.L. 2005, c.374) exempts the following Customers from the SUT provision, and when billed to such Customers, the charges otherwise applicable shall be reduced by the provision for the SUT included therein:

1. A qualified business that employs at least 250 people within an enterprise zone, at least 50 % of whom are directly employed in a manufacturing process, for the exclusive use or consumption of such business within an enterprise zone.

2. A group of two or more persons:

   a. Each of which is a qualified business that are all located within a single redevelopment area adopted pursuant to the "Local Redevelopment and Housing Law," P.L.1992, c.79 (C.40A:12A-1 et seq.);

b. That collectively employ at least 250 people within an enterprise zone, at least 50% of whom are directly employed in a manufacturing process;

c. Are each engaged in a vertically integrated business, evidenced by the manufacture and distribution of a product or family of products that, when taken together, are primarily used, packaged and sold as a single product; and

d. Collectively use the energy and utility service for the exclusive use or consumption of each of the persons that comprise a group within an enterprise zone.

3. A business facility located within a county that is designated for the 50% tax exemption under Section 1 of P.L.1993, c.373 (C.54:32B-8.45) provided that the business certifies that it employs at least 50 people at that facility, at least 50% of whom are directly employed in a manufacturing process, and provided that the energy and utility services are consumed exclusively at that facility.

A business that meets the requirements in (1), (2) or (3) above shall not be provided the exemption described in this section until it has complied with such requirements for obtaining the exemption as may be provided pursuant to P.L.1983, c.303 (C.52:27H-60 et seq.) and P.L.1966, c.30 (C.54:32B-1 et seq.) and the Company has received a sales tax exemption letter issued by the New Jersey Department of Treasury, Division of Taxation.

19. NEGOTIATED RATES, TERMS AND CONDITIONS

In accordance with the BPU's Order dated August 18, 2011 in BPU Docket No. GR10100761 ("Order") the Company has developed the following criteria for determining whether it will, in individual circumstances, negotiate rates, terms and conditions of service with Customers that otherwise would not take service under the terms of the service classifications set forth in this tariff. Any individually negotiated rates, terms or conditions agreed to pursuant to this tariff provision are subject to prior approval by the BPU. Negotiated rates, terms and conditions that may be made available are intended to address unique circumstances applicable at the time that the negotiated rates, terms and conditions are agreed to with individual Customers.

Negotiated rates, terms and conditions will be offered by the Company in circumstances in which it determines in its sole reasonable judgment, that such individual rates, terms and conditions are necessary to prevent (i) physical bypass of the Company's distribution system, (ii) economic bypass of the Company's distribution system or, (iii) the loss of load that could otherwise be served at rates that would exceed marginal costs.

Customers seeking negotiated rates, terms and conditions, and claiming that such rates, terms and conditions are necessary to prevent the Customer from physically bypassing the Company's distribution system, must provide the Company with the following:

(i) a statement from an interstate pipeline involved in such bypass that the proposed interconnection between Customer and the pipeline is operationally viable, that sufficient capacity is available to serve such Customer, and that the pipeline would serve the Customer if requested;

(ii) maps or flow diagrams that identify the proposed route of the pipeline needed to serve the Customer from the interconnection with the pipeline and the Customer's site, the size of the connecting pipeline and any other appurtenant facilities required;

(iii) engineering studies related to the estimated costs to complete construction of facilities interconnecting the pipeline and the Customer;

(iv) information concerning the status of all reliability and environmental or other permits and approvals from local, state and federal agencies;

(v) a description of any other benefits that the Customer proposes to provide the Company under a service agreement between the Company and Customer; and

(vi) such other information as the Company may require.

Customers seeking negotiated rates, terms and conditions for reasons other than to avoid physical bypass must provide the Company (i) such information as the Customer deems relevant to its request, and (ii) such information as the Company may require given the particular circumstances.

In determining whether to offer individually negotiated rates, terms and conditions to a particular Customer, the Company will consider all relevant information provided by the Customer and make a judgment as to whether negotiated rates, terms and conditions are necessary to prevent physical or economic bypass or the loss of load that could otherwise be served at rates that exceed marginal costs. Customers may apply for negotiated rates, terms and conditions by contacting the Company in writing. The Company will respond to any request for negotiated rates, terms and conditions within sixty (60) days of receiving a Customer's written request and all required information.

SERVICE CLASSIFICATION – RESIDENTIAL DELIVERY SERVICE (RDS)

APPLICABLE TO USE OF SERVICE FOR:

All residential purposes in individual residences and in individual flats, individual apartments in multiple family buildings, only where each individual flat or individual apartment is served through its own separate meter and religious institutions where the total rated input capacity of all gas utilization equipment does not exceed 500,000 BTU per hour. The rate is not available for hotels, nor for recognized rooming or boarding houses where the number of rented bedrooms is more than twice the number of bedrooms used by Customer. This rate is not applicable for industrial or commercial use of gas. In residential premises, use for purposes other than residential will be permitted only where such use is incidental to Customer's own residential use. Service for heating and/or cooling of premises will be rendered at this rate. Service to detached outbuildings or outside appliances appurtenant to the residence will be included in this rate provided Customer installs the necessary piping so that the gas used in such facilities may be measured by the meter located at the residence.

Service will be provided if Gas Company's facilities are suitable.

CHARACTER OF SERVICE:

Continuous, however, Customers may either purchase gas supply from a Third Party Supplier ("TPS") or the Company's Rider "A", Basic Gas Supply Service ("BGSS")

*CHARGES PER MONTH:

	Gas Supply from BGSS	Gas Supply from TPS
Service Charge	$~~10.00~~13.27	$~~10.00~~13.27
Distribution Charge per Therm	$~~0.4382~~0.6424	$~~0.4382~~0.6424
Commodity Charge	Per Rider "A"	Per TPS Agreement

* The charges set forth in this Service Classification include sales and use tax and will be adjusted for all other applicable Riders of this Tariff and any additional taxes or similar charges that are lawfully imposed by the Company. A customer that receives gas supply from a TPS will be charged for commodity according to any agreement between the Customer and the TPS.

SERVICE CLASSIFICATION – RESIDENTIAL DELIVERY SERVICE (RDS)
(continued)

MINIMUM MONTHLY CHARGE:

Service Charge.

TERM OF PAYMENT:

All bills are due upon presentation.

TERM OF CONTRACT:

One year, and thereafter until terminated by five (5) days written notice.

STANDARD TERMS AND CONDITIONS:

This Service Classification is subject to the Standard Terms and Conditions of this Tariff.

SPECIAL PROVISIONS, APPLICABLE TO CUSTOMERS RECEIVING GAS SUPPLY FROM THIRD PARTY SUPPLIERS

1.
Utilizing a Third Party Supplier

A Customer choosing to contract with a TPS for supply service will be enrolled for this service with the Company by the TPS on their behalf. A Customer will receive a confirmation notice from the Company noting their choice of supplier and that the Customer will have seven (7) calendar days from the date of the confirmation notice to contact the Company and rescind its selection, after which, if not rescinded, the residential Customer's TPS enrollment shall be accepted by the Company. Customer agrees that as between the Company and Customer, the Company shall be entitled to rely upon information concerning deliveries of natural gas on behalf of Customer provided by the TPS.

2. Switching Suppliers

Customer may switch TPSs or return to the Company's BGSS service at any time subject to the conditions of Customer enrollment. A Customer electing to return to the BGSS service should contact their TPS who will carry out the necessary steps with the Company. The decision and steps necessary to switch TPSs are carried out between the newly selected TPS and the Customer. Customer will not be charged a fee to change its TPS or return to BGSS service.

SERVICE CLASSIFICATION – RESIDENTIAL DELIVERY SERVICE (RDS)
(continued)

SPECIAL PROVISIONS, APPLICABLE TO CUSTOMERS RECEIVING GAS SUPPLY FROM THIRD PARTY SUPPLIERS (continued)

3. Limitations on the Availability of Transportation Service

Customer's TPS must demonstrate that it possesses Comparable Capacity or Standby Balancing Service sufficient to provide their Customers' Unadjusted Average Daily Delivery Quantity, as defined under the TPS Service Classification, during the months of November through March. If at any time it is determined that TPS does not meet this provision, then TPS's Customers will be returned to BGSS gas supply service.

4. Load Balancing Charge

A Load Balancing Charge of $0.0552 per therm, which includes taxes, shall be billed to the TPS for all metered quantities of its RDS Customers.

5. Gas Commingling

Service under this Service Classification is provided by the Company within its service territory for the Customer. The gas transported under this Service Classification is not the property of the Company. However, the Company reserves the right to commingle such gas with other supplies. Moreover, the Company reserves the right to utilize Customer's gas, when necessary, in accordance with the applicable curtailment provisions of this Tariff.

6. Transportation to Gas Company Facilities

The Company is not responsible for making arrangements for Customers for transporting gas from its source to the Company's interconnection with delivering pipeline suppliers. All such responsibility rests with Customer's TPS. Company shall have no responsibility with respect to such gas before Customer delivers or has delivered on its behalf such gas to Company or after Company redelivers such gas to Customer at the meter at Customer's premises or on account of anything which may be done, happen or arise with respect to such gas before such delivery or after such redelivery. Customer agrees that as between the Company and Customer, the Company shall be entitled to rely upon information concerning deliveries of natural gas on behalf of Customer provided by TPS.

7. Gas Supply Obligation

In the event that Customer's TPS ceases operations, or for any other reason fails to deliver the Average Daily Delivery Quantity ("ADDQ"), the Company shall provide replacement gas supplies under the BGSS service.

SERVICE CLASSIFICATION – RESIDENTIAL DELIVERY SERVICE (RDS)
(continued)

SPECIAL PROVISIONS, APPLICABLE TO CUSTOMERS RECEIVING GAS SUPPLY FROM THIRD PARTY SUPPLIERS (continued)

8. Indemnification

As between Company and Customer, Customer warrants that it has clear title to any gas supplies delivered into the Company's system for redelivery to Customer and Customer shall be deemed to be in exclusive control and possession of gas prior to its delivery into the Company's system for redelivery to Customer. Customer agrees to indemnify, defend and hold harmless Company from any and all claims, suits or damage actions arising out of deliveries of gas into Company's system on behalf of Customer.

SERVICE CLASSIFICATION – SMALL GENERAL SERVICE (SGS)

APPLICABLE TO USE OF SERVICE FOR:

Small General Service is available to those Customers whose annual weather normalized usage as determined by the Company is less than 5,000 therms per year and where Gas Company's facilities are suitable and the quantity of gas is available for the service desired. In August of each year the Company shall review each Customer's eligibility based on their annual normalized usage and if in excess of 5,500 therms for two consecutive years will transfer the Customer to General Delivery Service.

CHARACTER OF SERVICE:

Continuous.

*CHARGES PER MONTH:

	Gas Supply from BGSS	Gas Supply from TPS
Service Charge	$~~27.01~~36.79	$~~27.01~~36.79
Distribution Charge per Therm	$~~0.3807~~0.5596	$~~0.3807~~0.5596
Commodity Charge	Per Rider "A"	Per TPS Agreement

* The charges set forth in this Service Classification include sales and use tax and will be adjusted for all other applicable Riders of this Tariff and any additional taxes or similar charges that are lawfully imposed by the Company. A Customer that receives gas supply from a TPS will be charged for commodity according to any agreement between the Customer and the TPS.

MINIMUM MONTHLY CHARGE:

The Service Charge.

TERM OF PAYMENT:

All bills are due upon presentation. Should the Customer fail to make payment in full, the Company may, within the time period specified in and in accordance with Section 7.10 of the Standard Terms and Conditions of this Tariff, assess late payment charges.

TERM OF CONTRACT:

One year, and thereafter until terminated by five (5) days written notice.

SERVICE CLASSIFICATION – SMALL GENERAL SERVICE (SGS)
(continued)

STANDARD TERMS AND CONDITIONS:

This Service Classification is subject to the Standard Terms and Conditions of this Tariff.

SPECIAL PROVISIONS, APPLICABLE TO CUSTOMERS RECEIVING GAS SUPPLY FROM THIRD PARTY SUPPLIERS (TPS)

1. Service Agreement

The signing of a Service Agreement and possession by the Customer of a fully executed contract to purchase gas from a TPS are conditions precedent to receiving gas supply from a TPS.

2. Balancing Charge

Customers will be charged a balancing charge of $0.0171 per therm, which includes sales tax, in the months of November through March to offset system supply costs utilized to absorb the differences between the TPS delivered Average Daily Delivery Quantities and the actual daily gas supply requirements of the Customers.

3. Commingling

Service under this Service Classification is provided by the Company within its service territory for the Customer. The gas transported under this Service Classification is not the property of the Company. However, the Company reserves the right to commingle such gas with other supplies. Moreover, the Company reserves the right to utilize Customer's gas, when necessary, in accordance with the applicable curtailment provisions of this Tariff.

4. Transportation to Gas Company Facilities

The Company is not responsible for making arrangements for transportation service Customers for transporting the gas from its source to the Company's interconnection with the delivering pipeline supplier.

5. Nominations for Service

The Customer's TPS shall nominate on behalf of its Customers the total monthly requirements for that billing month per an Average Daily Delivery Quantity ("ADDQ") determined as stated in the TPS section of this tariff.

SERVICE CLASSIFICATION – SMALL GENERAL SERVICE (SGS)
(continued)

6. Utilizing a Third Party Supplier

A Customer choosing to contract with a TPS for supply service will be enrolled for this service with the Company by the TPS on their behalf. A Customer will receive a confirmation notice from the Company notifying them of their enrollment by a TPS and that the Customer should contact the TPS noted on the letter within seven (7) calendar days if they seek to have it rescinded. Customer agrees that as between the Company and Customer, the Company shall be entitled to rely upon information concerning deliveries of natural gas on behalf of Customer provided by the TPS.

7. Imbalance Charges

To the extent that a TPS ceases operations or under delivers gas, Customers shall be ultimately responsible for payment of any charges not paid for by their TPS, including but not limited to daily and or monthly imbalance charges for gas supplies consumed by Customer but not delivered by TPS. In the event a TPS fails to pay these charges the Customers shall be billed directly by the Company for their direct portion, if by their non-compliance to Company directives to cease gas use, and/or a prorata share by applying the Allocation of Supply terms of the TPS Service Classification, except that essential service gas Customers will first be credited with standby gas purchased by the TPS on their behalf.

8. Unauthorized Use

This Service Classification is subject to Unauthorized Gas Use Section of the Standard Terms and Conditions.

9. Gas Supply Obligation

In the event that Customer's TPS fails to deliver, the Company may, in its sole discretion, provide replacement gas supplies. The Company shall have no obligation to provide natural gas supplies to Customers that contract for TPS Service, except for those whose TPS contracted for Standby Service, limited to Essential Gas User Customers. In the event that a Customer that is not covered by Standby Service seeks to purchase natural gas supplies from the Company, such sales may be made by the Company in its sole discretion under such terms and conditions as the Company may require.

Filed Pursuant to Order of the Board of Public Utilities
Dated ~~November 13, 2019~~XXX3 in Docket No.
~~GR19040486~~XXX4

SERVICE CLASSIFICATION – SMALL GENERAL SERVICE (SGS)
(continued)

10. Limitations on the Availability of TPS Transportation Service

TPS Service is not available to Customers who are defined as "Essential Gas Users" under the curtailment provision as set forth in Section 17 of the Standard Terms and Conditions of this Tariff unless such Customers' TPS, in an amount sufficient to meet such Customers' ADDQ and/or DCQ, agrees to contract and pay for Standby Service as defined in the TPS Service Classification or for such Customers' TPS demonstrates that it possesses Comparable Capacity as defined in the TPS Service Classification.

11. Indemnification

As between Company and Customer, Customer warrants that it has clear title to any gas supplies delivered into the Company's system for redelivery to Customer and Customer shall be deemed to be in exclusive control and possession of gas prior to its delivery into the Company's system for redelivery to Customer. Customer agrees to indemnify, defend and hold harmless Company from any and all claims, suits or damage actions arising out of deliveries of gas on behalf of transporting Customer.

12. SPECIAL PROVISIONS, APPLICABLE TO VETERANS' ORGANIZATIONS:

Veterans' Organization Service: Pursuant to N.J.S.A 48:2-21.41, when natural gas service is delivered to a Customer that is a Veterans' Organization, serving the needs of veterans of the armed forces, the Customer may apply and be eligible for billing under this Special Provision.

Each Customer shall be eligible for billing under this Special Provision upon submitting an Application for Veterans' Organization Service under this service classification and by qualifying as a "Veterans' Organization" as defined by N.J.S.A. 48:2-21.41 defines a Veterans' Organization that qualifies for this Special Provision as "an organization dedicated to serving the needs of veterans of the armed forces that: is chartered under federal law, qualifies as a tax exempt organization under paragraph (19) of subsection (c) of section 501 of the federal Internal Revenue Code of 1986, 26 U.S.C. s.501(c)(19), or that is organized as a corporation under the 'New Jersey Nonprofit Corporation Act,' N.J.S.15A:1-1 et seq." Under N.J.S.A. 48:2-21.41, a qualified Veterans' Organization shall be charged the residential rate for service delivered to the property where the Veterans' Organization primarily operates, if the residential rate is lower than the commercial rate for service at that property.

SERVICE CLASSIFICATION – SMALL GENERAL SERVICE (SGS)
(continued)

12. SPECIAL PROVISIONS, APPLICABLE TO VETERANS' ORGANIZATIONS (continued):

The Customer shall furnish satisfactory proof of eligibility of service under this Special Provision to the Company. Once proof of eligibility is determined by the Company, service under this Special Provision shall begin with the next billing cycle following receipt of the Application.

The Customer will continue to be billed on this service classification. At least once annually, the Company shall review eligible Customers' charges for service delivered, defined to include Service Charges and Distribution Charges, under this Special Provision for all relevant periods. If these comparable charges for service delivered under the Residential Delivery Service (RDS) classification are lower than the charges under this classification a credit in the amount of the difference shall be applied to the Customer's next bill.

SERVICE CLASSIFICATION – GENERAL DELIVERY SERVICE (GDS)

APPLICABLE TO USE OF SERVICE FOR:

General Delivery Service is available to those Customers whose annual weather normalized usage as determined by the Company is 5,000 or more therms per year and where Gas Company's facilities are suitable and the quantity of gas is available for the service desired. In August of each year the Company shall review Customer usages and those Customers whose weather normalized usage, as determined by the Company, is less than 4,500 therms for two consecutive years will be transferred to Small General Service.

CHARACTER OF SERVICE:

Continuous, however, customers may either purchase gas supply from a Third Party Supplier ("TPS") or the Company's Rider "A", Basic Gas Supply Service ("BGSS").

*CHARGES PER MONTH:

	Gas Supply from BGSS	Gas Supply from TPS
Service Charge	$~~37.50~~61.84	$~~37.50~~61.84
Demand Charge per DCQ	$~~0.960~~1.162	$~~0.960~~1.162
Distribution Charge per Therm	$~~0.2301~~0.3682	$~~0.2301~~0.3682
Commodity Charge	Per Rider "A"	Per TPS Agreement

* The charges set forth in this Service Classification include sales and use tax and will be adjusted for all other applicable Riders of this Tariff and any additional taxes or similar charges that are lawfully imposed by the Company. A Customer that receives gas supply from a TPS will be charged for commodity according to any agreement between the Customer and the TPS.

DETERMINATION OF THE DEMAND CHARGE QUANTITY (DCQ)

The DCQ will be determined by the Customer's maximum daily requirements in terms of therm units per day. The DCQ level shall be the highest actual daily metered consumption registered from an approved automatic meter reading device at Customer's premises within a period of not less than two years, but up to three years immediately preceding the Customer obtaining service or renewing a Service Agreement under this Service Classification if such information is available. Otherwise DCQ shall be set equal to the product of (1) the highest winter monthly consumption for the most recent winter (October through April), normalized for weather, divided by the applicable number of days in the respective billing month, and (2) 1.36, provided that DCQ shall not be less than the highest non-winter month consumption divided by the applicable number of days in the respective billing month. For process loads, the Company may base the DCQ on historical consumption. If historical consumption information is not available, then (a) the initial DCQ level shall be based upon the Customer's gas utilization equipment expressed in consumption per day, and (b) after twelve (12) months of actual consumption has been metered, the DCQ level shall be redetermined.

SERVICE CLASSIFICATION – GENERAL DELIVERY SERVICE (GDS)
(continued)

DETERMINATION OF THE DEMAND CHARGE QUANTITY (DCQ) (continued)

If the Customer's maximum daily usage exceeds the DCQ as stated in the Service Agreement more than three (3) times in twelve (12) months, the Company may increase the DCQ in the Service Agreement to the highest level experienced during the previous 12 months.

MINIMUM MONTHLY CHARGE:

The sum of the Service Charge and the Demand Charge.

TERM OF PAYMENT:

All bills are due upon presentation. Should the Customer fail to make payment in full, the Company may, within the time period specified in and in accordance with Section 7.10 of the Standard Terms and Conditions of this Tariff, assess late payment charges.

TERM OF CONTRACT:

One year, and thereafter until terminated by five (5) days written notice.

STANDARD TERMS AND CONDITIONS:

This Service Classification is subject to the Standard Terms and Conditions of this Tariff.

SERVICE CLASSIFICATION – GENERAL DELIVERY SERVICE (GDS)
(continued)

SPECIAL PROVISIONS SECTIONS I & II:

I. SPECIAL PROVISIONS, APPLICABLE TO ALL CUSTOMERS RECEIVING SERVICE UNDER THIS SERVICE CLASSIFICATION

1. Distributed Generation of 12 kW or More and Gas Cooling & Refrigeration of 10 Tons or More

Under separate application Customers who are using gas for distributive generation with a rated capacity of twelve (12) kW or more, and/or gas cooling equipment with a rated capacity of ten (10) tons or more, and where gas consumed is separately metered, will be billed at the above rates, except that the applicable Distribution Charges will be billed at a rate of $~~0.0589~~0.0647 per therm commencing with the first meter reading taken in the ordinary course of business in May and concluding with the meter reading taken in the ordinary course of business in October. During all other periods, the Distribution and Commodity Charge per therm stated in this service classification shall apply.

SERVICE CLASSIFICATION – GENERAL DELIVERY SERVICE (GDS)
(continued)

I. SPECIAL PROVISIONS, APPLICABLE TO ALL CUSTOMERS RECEIVING SERVICE UNDER THIS SERVICE CLASSIFICATION (continued)

2. Economic Development Service (EDS):

Any new Customer employing a minimum of ten (10) full time equivalent employees, who locates in or expands a new or vacant building within the Company's service territory and enters into a GDS service agreement and (2) any existing Customer who expands into a new or vacant building and adds a minimum of ten (10) full time equivalent employees at the facility within the Company's service territory and is a party to a GDS service agreement shall be eligible for an EDS discount. For new Customers, this building must be new or have been vacant for a minimum of three (3) months. For existing Customers, the space utilized for operations must expand by more than 5,000 square feet. Gas used subject to the EDS discount for existing Customers will be calculated by the Company and will be based solely on the Customer's incremental usage. This service is offered to any eligible Customer for a period of five (5) years, continuing to meet the above requirements, from the date of the initial Service Agreement under this service. The EDS Customers shall receive a fifty (50) percent pre tax discount in this Service Class's Distribution Charge during the period of eligibility.

3. Boiler Limitation

This service classification is not available for new or additional boiler equipment with a rated input in excess of 12.5 million BTU's per hour. The Gas Company may waive this limitation in cases where the Customer enters into a longer term contract or agrees to guarantee a monthly minimum revenue level as may be determined by the Gas Company.

SERVICE CLASSIFICATION – GENERAL DELIVERY SERVICE (GDS)
(continued)

II. SPECIAL PROVISIONS, APPLICABLE TO CUSTOMERS RECEIVING GAS SUPPLY FROM THIRD PARTY SUPPLIERS (TPS)

1. Service Agreement

The signing of a Service Agreement and possession by the Customer of a fully executed contract to purchase gas from a TPS are conditions precedent to receiving gas supply from a TPS.

2. Balancing Charge

Customers with a DCQ under 500 therms will be charged a balancing charge of $0.0171 per therm, which includes sales tax, in the months of November through March to offset system supply costs utilized to absorb the differences between the TPS delivered Average Daily Delivery Quantities and the actual daily gas supply requirements of the Customers.

3. Commingling

Service under this Service Classification is provided by the Company within its service territory for the Customer. The gas transported under this Service Classification is not the property of the Company. However, the Company reserves the right to commingle such gas with other supplies. Moreover, the Company reserves the right to utilize Customer's gas, when necessary, in accordance with the applicable curtailment provisions of this Tariff.

4. Transportation to Gas Company Facilities

The Company is not responsible for making arrangements for transportation service Customers for transporting the gas from its source to the Company's interconnection with the delivering pipeline supplier.

5. Nominations for Service

The Customer's TPS shall nominate on behalf of its Customers the total monthly requirements for that billing month. A TPS with Customers having a DCQ under 500 therms and those requiring an AMR not yet installed are required to deliver these customers natural gas requirements per an ADDQ determined as stated in the TPS section of this tariff.

SERVICE CLASSIFICATION – GENERAL DELIVERY SERVICE (GDS)
(continued)

II. SPECIAL PROVISIONS, APPLICABLE TO CUSTOMERS RECEIVING GAS SUPPLY FROM THIRD PARTY SUPPLIERS (TPS) (continued)

6. Utilizing a Third Party Supplier

A Customer choosing to contract with a TPS for supply service will be enrolled for this service with the Company by the TPS on their behalf. A Customer will receive a confirmation notice from the Company notifying them of their enrollment by a TPS and that the Customer should contact the TPS noted on the letter within seven (7) calendar days if they seek to have it rescinded. Customer agrees that as between the Company and Customer, the Company shall be entitled to rely upon information concerning deliveries of natural gas on behalf of Customer provided by the TPS.

7. Imbalance Charges

To the extent that a TPS ceases operations or under delivers gas, Customers shall be ultimately responsible for payment of any charges not paid for by their TPS, including but not limited to daily and or monthly imbalance charges for gas supplies consumed by Customer but not delivered by TPS. In the event a TPS fails to pay these charges the Customers shall be billed directly by the Company for their direct portion, if by their non-compliance to Company directives to cease gas use, and/or a prorata share by applying the Allocation of Supply terms of the TPS Service Classification, except that essential service gas Customers will first be credited with standby gas purchased by the TPS on their behalf.

SERVICE CLASSIFICATION – GENERAL DELIVERY SERVICE (GDS)
(continued)

II. SPECIAL PROVISIONS, APPLICABLE TO CUSTOMERS RECEIVING GAS SUPPLY FROM THIRD PARTY SUPPLIERS (TPS) (continued)

8. Automatic Meter Reading (AMR) Equipment for Customers with a DCQ of 500 therms or more.

AMR equipment is required for Customers with a DCQ of 500 or more therms, as determined by the Company. Customer shall pay for all costs to install AMR equipment including power, communications and other equipment as specified by the Company and provide access for such equipment. The cost of any Company equipment may be paid by Customer over a one (1) year, or some lesser, period by means of a monthly surcharge designed to recover the cost of the equipment plus interest equal to the Company's overall rate of return as authorized from time to time by the BPU. Payments made by the Customer shall not give the Customers ownership of the equipment which shall remain the sole property of the Company.

9. Unauthorized Use

This Service Classification is subject to Unauthorized Gas Use Section of the Standard Terms and Conditions.

10. Gas Supply Obligation

In the event that Customer's TPS fails to deliver, the Company may, in its sole discretion, provide replacement gas supplies. The Company shall have no obligation to provide natural gas supplies to Customers that contract for TPS Service, except for those whose TPS contracted for Standby Service, limited to Essential Gas User Customers. In the event that a Customer that is not covered by Standby Service seeks to purchase natural gas supplies from the Company, such sales may be made by the Company in its sole discretion under such terms and conditions as the Company may require.

11. Limitations on the Availability of TPS Transportation Service

TPS Service is not available to Customers who are defined as "Essential Gas Users" under the curtailment provision as set forth in Section 17 of the Standard Terms and Conditions of this Tariff unless such Customers' TPS, in an amount sufficient to meet such Customers' ADDQ and/or DCQ, agrees to contract and pay for Standby Service as defined in the TPS Service Classification or for such Customers' TPS demonstrates that it possesses Comparable Capacity as defined in the TPS Service Classification.

SERVICE CLASSIFICATION – GENERAL DELIVERY SERVICE (GDS)
(continued)

II. SPECIAL PROVISIONS, APPLICABLE TO CUSTOMERS RECEIVING GAS SUPPLY FROM THIRD PARTY SUPPLIERS (TPS) (continued)

12. Indemnification

As between Company and Customer, Customer warrants that it has clear title to any gas supplies delivered into the Company's system for redelivery to Customer and Customer shall be deemed to be in exclusive control and possession of gas prior to its delivery into the Company's system for redelivery to Customer. Customer agrees to indemnify, defend and hold harmless Company from any and all claims, suits or damage actions arising out of deliveries of gas on behalf of transporting Customer.

III. SPECIAL PROVISIONS, APPLICABLE TO VETERANS' ORGANIZATIONS:

Veterans' Organization Service: Pursuant to N.J.S.A 48:2-21.41, when natural gas service is delivered to a Customer that is a Veterans' Organization, serving the needs of veterans of the armed forces, the Customer may apply and be eligible for billing under this Special Provision.

Each Customer shall be eligible for billing under this Special Provision upon submitting an Application for Veterans' Organization Service under this service classification and by qualifying as a "Veterans' Organization" as defined by N.J.S.A. 48:2-21.41 defines a Veterans' Organization that qualifies for this Special Provision as "an organization dedicated to serving the needs of veterans of the armed forces that: is chartered under federal law, qualifies as a tax exempt organization under paragraph (19) of subsection (c) of section 501 of the federal Internal Revenue Code of 1986, 26 U.S.C. s.501(c)(19), or that is organized as a corporation under the 'New Jersey Nonprofit Corporation Act,' N.J.S.15A:1-1 et seq." Under N.J.S.A. 48:2-21.41, a qualified Veterans' Organization shall be charged the residential rate for service delivered to the property where the Veterans' Organization primarily operates, if the residential rate is lower than the commercial rate for service at that property.

The Customer shall furnish satisfactory proof of eligibility of service under this Special Provision to the Company. Once proof of eligibility is determined by the Company, service under this Special Provision shall begin with the next billing cycle following receipt of the Application.

The Customer will continue to be billed on this service classification. At least once annually, the Company shall review eligible Customers' charges for service delivered, defined to include Service Charges, Demand Charges and Distribution Charges, under this Special Provision for all relevant periods. If these comparable charges for service delivered under the Residential Delivery Service (RDS) classification are lower than the charges under this classification a credit in the amount of the difference shall be applied to the Customer's next bill.

SERVICE CLASSIFICATION
COMMERCIAL & INDUSTRIAL NATURAL GAS VEHICLE SERVICE (NGV)

APPLICABLE TO USE OF SERVICE FOR:

This Service Classification is available to any non-Residential Customer who wishes to purchase natural gas sales and/or transportation service and have the Company own and maintain facilities at Customer's premises to compress gas into CNG ("CNG Fueling Facilities") for use as fuel for self-propelled motor vehicles ("Vehicular Gas"). This Service Classification also sets forth the terms and conditions under which the Company may sell and/or distribute Vehicular Gas at CNG Fueling Facilities operated by the Company as Public Fueling Stations.

CHARACTER OF SERVICE:

Continuous to Customers signing a Natural Gas Vehicle ("NGV") Service Agreement ("Agreement").

CONDITIONS PRECEDENT:

A Customer must sign an NGV Agreement with the Company to receive continuous service under this Service Classification. Service under such NGV Agreement is for the term of the NGV Agreement and may be continued beyond the term of the NGV Agreement only by the mutual agreement of Company and Customer. Members of the general public who wish only to obtain Vehicular Gas at Public Fueling Stations need not sign an NGV Agreement. Such members of the public have no entitlement to continuous service under this Service Classification. Service under this Service Classification will be separately metered. Customers must indicate in their Agreements whether they will purchase gas supply from Company or from a TPS.

Section 6.01 of the Standard Terms and Conditions of this Tariff sets forth standards that establish the Company's liability for damages. Section 6.01 applies to any claim arising from services provided or facilities constructed, maintained or operated by Company under this Service Classification. Moreover, the specific provisions of Section 6.01 that apply to Customers will apply both to Customers signing an NGV Service Agreement and members of the public who obtain Vehicular Natural Gas under this Service Classification.

STANDARD TERMS AND CONDITIONS:

This Service Classification is subject to the Standard Terms and Conditions of this Tariff.

LICENSING, PERMITS AND LEGAL REQUIREMENTS:

Customers installing CNG Fueling Facilities on their premises must meet all applicable licensing, permitting and other legal requirements associated with operating CNG Fueling Facilities or Company may suspend or terminate service to such facilities without further liability.

SERVICE CLASSIFICATION
COMMERCIAL & INDUSTRIAL NATURAL GAS VEHICLE SERVICE (NGV)
(continued)

MAIN AND SERVICE EXTENSIONS FOR NGV SERVICE, CNG FUELING FACILITIES AND THE INCREMENTAL COSTS OF CNG-POWERED VEHICLES:

Under this Service Classification, Company may construct and/or install mains, services, automatic meter reading devices, and other facilities necessary to provide sales and transportation service to Customers. Company may also construct and/or install CNG Fueling Facilities located behind Customer's meter. Company may also construct Public Fueling Stations. On a not unduly discriminatory basis, Company may require revenue guarantees sufficient to enable Company to fully recover the costs of all such facilities over a negotiated period as set forth in the NGV Agreement. All negotiated charges under this Service Classification may be revised at the expiration of the term of an NGV Agreement and reflected in any new/replacement NGV Agreement.

Subject to an appropriate revenue guarantee, Company may invest up to ten times the projected annual Distribution Revenues from service provided under this Service Classification in facilities necessary to provide service under this Service Classification. To the extent that Company's investment exceeds ten times projected annual Distribution Revenues, Customer will be assessed a CNG Facilities Charge sufficient to recover Company's excess investment (including its authorized pre-tax return). In lieu of paying a Facilities Charge, Customer may provide a Contribution In Aid of Construction. To the extent that this Section of the NGV Service Classification conflicts with Section 3 of the Standard Terms and Condition of Company's Tariff with respect to service provided under this Service Classification, this Section will control.

I. COMPANY-OWNED AND MAINTAINED CNG FUELING FACILITIES ON CUSTOMERS' PREMISES

Customer may elect to have Company construct, own, and maintain CNG Fueling Facilities at Customer's Premises ("Customers' Premises Facilities"). Such service does not include the dispensing of CNG into vehicles. Under this option, the dispensing of CNG into vehicles shall be the sole responsibility of the Customer. In addition, Customer may, at its option, either contract and pay separately for electricity needed to operate the CNG Fueling Facility or have the Company contract for such electricity and pass through its actual electricity costs to Customer.

SERVICE CLASSIFICATION
COMMERCIAL & INDUSTRIAL NATURAL GAS VEHICLE SERVICE (NGV)
(continued)

Rates and Charges Applicable to Customers' Premises Facilities:*

The following rates and charges apply to service under this Service Classification at Customers' Premises Facilities:

1. Distribution Charge - $~~0.3133~~0.4500 per therm

2. Fueling Station Charge

   A Fixed monthly amount, designed on an individual Customer basis to recover the Company's projected cost of maintaining the Customer's specific CNG Fueling Facility.

3. Facilities Charge

   A Fixed monthly amount, designed on an individual Customer basis to recover Company investment in excess of ten times projected annual Distribution Revenues in facilities necessary to provide service under this Service Classification. The Facilities Charge shall be computed by multiplying the Company's investment in excess of ten times projected annual Distribution Revenue (including its authorized pre-tax return) by an appropriate percentage that will be based upon the term of the NGV Agreement.

4. Gas Cost

   BGSS-M rate applicable to month of sale for gas sold by Company, not applicable if supplied by a TPS.

5. Taxes and Fees

   Motor Fuel and all other taxes and fees or other similar charges applicable to sale and/or transportation of Vehicular Gas. The remittance of any applicable taxes related to such use shall be the sole responsibility of the Company.

*The charges set forth in this section exclude sales and use tax and will be adjusted for all other applicable Riders of this Tariff and any additional taxes, fees or similar charges that are lawfully imposed by the Company. A Customer that receives gas supply from a TPS will be charged for commodity according to the agreement between the Customer and the TPS.

SERVICE CLASSIFICATION
COMMERCIAL & INDUSTRIAL NATURAL GAS VEHICLE SERVICE (NGV)
(continued)

Sales of Vehicular Natural Gas to Third Parties:

Customer may agree in the Agreement to allow its CNG Fueling Station to be used to sell and dispense CNG to the general public. Such sales will be made at publicly posted prices as determined by the Customer. Distribution Charge revenues from sales to the public shall be credited against any revenue guarantee obligation of Customer.

II. PUBLIC FUELING STATIONS

Company may construct, operate and maintain CNG Fueling Facilities for the purpose of providing Vehicular Gas to the general public.

Rates and Charges Applicable to Company Owned Public Fueling Stations:*

If Company offers service to the general public, the Company shall charge the rates set forth below. The Company shall post such rates at each Public Fueling Facility owned and operated by the Company. The price shall be the Gasoline Gallon Equivalent ("GGE") of a price per therm that includes the following components:

Distribution Charge	$~~0.3133~~0.4500 per therm
Fueling Station Charge	$~~0.3600~~0.4100 per therm
Facilities Charge	$~~0.2987~~0.3771 per therm
Gas Cost	BGSS-M rate applicable to the month of sale
Taxes and Fees	Motor fuel and all other taxes and fees or other similar charges applicable to sales of Vehicular Gas. The remittance of any applicable taxes related to such use shall be the sole responsibility of the Company.

*The charges set forth in this section exclude sales and use tax and will be adjusted for all other applicable Riders of this Tariff and any taxes fees or similar charges that are lawfully imposed by the Company.

SERVICE CLASSIFICATION
COMMERCIAL & INDUSTRIAL NATURAL GAS VEHICLE SERVICE (NGV)
(continued)

SPECIAL PROVISIONS, APPLICABLE TO CUSTOMERS RECEIVING GAS SUPPLY FROM THIRD PARTY SUPPLIERS ("TPS"):

1. Service Agreement

The signing of a Service Agreement and possession by the Customer of a fully executed contract to purchase gas from a TPS are conditions precedent to receiving gas supply from a TPS.

2. Automatic Meter Reading (AMR) Equipment

Customer shall pay for all costs to install AMR equipment including power, communications and other equipment as specified by the Company and provide access for such equipment. Payments made by the Customer shall not give the Customers ownership of the equipment which shall remain the sole property of the Company.

3. Gas Commingling

Service under this Service Classification is provided by the Company within its service territory for the Customer. The gas transported under this Service Classification is not the property of the Company. However, the Company reserves the right to commingle such gas with other supplies. Moreover, the Company reserves the right to utilize Customer's gas, when necessary, in accordance with the applicable curtailment provisions of this Tariff.

4. Transportation to Gas Company Facilities

The Company is not responsible for making arrangements for transportation service Customers for transporting the gas from its source to the Company's interconnection with the delivering pipeline supplier.

5. Nominations for Service

The Customer's TPS shall nominate on behalf of its Customers the daily requirements.

SERVICE CLASSIFICATION
COMMERCIAL & INDUSTRIAL NATURAL GAS VEHICLE SERVICE (NGV)
(continued)

SPECIAL PROVISIONS, APPLICABLE TO CUSTOMERS RECEIVING GAS SUPPLY FROM THIRD PARTY SUPPLIERS ("TPS"): (continued)

6. Utilizing a Third Party Supplier

A Customer choosing to contract with a TPS for supply service will be enrolled for this service with the Company by the TPS on their behalf. A Customer will receive a confirmation notice from the Company notifying them of their enrollment by a TPS and that the Customer should contact the TPS noted on the letter within seven (7) calendar days if they seek to have it rescinded. Customer agrees that as between the Company and Customer, the Company shall be entitled to rely upon information concerning deliveries of natural gas on behalf of Customer provided by TPS.

7. Imbalance Charges

To the extent that a TPS ceases operations or under delivers gas, Customers shall be ultimately responsible for payment of any charges not paid for by their TPS, including but not limited to daily and/or monthly imbalance charges for gas supplies consumed by Customer but not delivered by TPS. In the event a TPS fails to pay these charges the Customers shall be billed directly by the Company for their direct portion, if by their non-compliance to Company directives to cease gas use, and/or a prorata share by applying the Allocation of Supply terms of the TPS Service Classification, except that essential service gas Customers will first be credited with standby gas purchased by the TPS on their behalf.

8. Gas Supply Obligation

In the event that Customer's TPS fails to deliver, the Company may, in its sole discretion, provide replacement gas supplies. The Company shall have no obligation to provide natural gas supplies to Customers that contract for TPS Service, except for those whose TPS contracted for Standby Service, limited to Essential Gas User Customers. In the event that a Customer that is not covered by Standby Service seeks to purchase natural gas supplies from the Company, such sales may be made by the Company in its sole discretion under such terms and conditions as the Company may require.

SERVICE CLASSIFICATION
COMMERCIAL & INDUSTRIAL NATURAL GAS VEHICLE SERVICE (NGV)
(continued)

SPECIAL PROVISIONS, APPLICABLE TO CUSTOMERS RECEIVING GAS SUPPLY FROM THIRD PARTY SUPPLIERS ("TPS"): (continued)

9. Indemnification

As between Company and Customer, Customer warrants that it has clear title to any gas supplies delivered into the Company's system for redelivery to Customer and Customer shall be deemed to be in exclusive control and possession of gas prior to its delivery into the Company's system for redelivery to Customer. Customer agrees to indemnify, defend and hold harmless Company from any and all claims, suits or damage actions arising out of deliveries of gas on behalf of transporting Customer.

SERVICE CLASSIFICATION – LARGE VOLUME DEMAND (LVD)

The signing of a service agreement is a condition precedent to receiving service under this classification. The Service Agreement will include the Customer's Demand Charge Quantity (DCQ).

APPLICABLE TO USE OF SERVICE FOR:

Applicable to Commercial and Industrial Users, with a DQQ of 2,000 or more up to the maximum daily demands as set forth in the Service Agreement, provided that all firm gas service is supplied under this rate, Gas Company's facilities are suitable, and the required quantity of gas is available for the service desired. The consumption of gas in different locations will not be combined for billing purposes.

CHARACTER OF SERVICE:

Continuous Customers may either purchase gas supply from a TPS or the Company's Rider "A", Basic Gas Supply Service ("BGSS").

*CHARGE PER MONTH:

	Tax-Exempt	Taxable
Service Charge	$~~304.81~~380.00	$~~325.00~~405.18
Demand Charge per DCQ	$~~1.250~~1.750	$~~1.333~~1.866
Distribution Charge per Therm	$~~0.0400~~0.0614	$~~0.0427~~0.0655
Commodity Charge	Per BGSS Rider "A" or TPS Agreement	

*The charges set forth in this Service Classification include sales and use tax and will be adjusted for all other applicable Riders of this Tariff and any additional taxes or similar charges that are lawfully imposed by the Company. A Customer that receives gas supply from a TPS will be charged for commodity according to any agreement between the Customer and the TPS.

DETERMINATION OF THE DEMAND CHARGE QUANTITY ("DCQ"):

The DCQ will be determined by the Customer's maximum daily requirements in terms of therms per day and included in the Service Agreement.

The DCQ level shall be the highest actual daily metered consumption registered from an approved automatic meter reading device at Customer's premises within a period of not less than two years, but up to three years immediately preceding the Customer obtaining service or renewing a Service Agreement under this Service Classification if such information is available. Otherwise DCQ shall be set equal to the product of (1) the highest winter monthly consumption for the most recent winter (October through April), normalized for weather, divided by the applicable

SERVICE CLASSIFICATION – LARGE VOLUME DEMAND (LVD)
(continued)

DETERMINATION OF THE DEMAND CHARGE QUANTITY ("DCQ"): (continued)

number of days in the respective billing month, and (2) 1.36, provided that DCQ shall not be less than the highest non-winter month consumption divided by the applicable number of days in the respective billing month. For process loads, the Company may base the DCQ on historical consumption. If historical consumption information is not available, then (a) the initial DCQ level shall be based upon the Customer's gas utilization equipment expressed in consumption per day, and (b) after twelve (12) months of actual consumption has been metered, the DCQ level shall be redetermined.

If the Customer's maximum daily usage exceeds the contract demand as stated in the Service Agreement more than three (3) times in twelve (12) months, the Company may increase the DCQ in the Service Agreement to the highest level experienced during the previous 12 months.

MINIMUM MONTHLY CHARGE:

The sum of the Service Charge and the Demand Charge.

TERM OF PAYMENT:

All bills are due upon presentation. Should the Customer fail to make payment in full, the Company may, within the time period specified in and in accordance with Section 7.10 of the Standard Terms and Conditions of this Tariff, assess late payment charges.

TERM OF CONTRACT:

The term of the contract will be as specified in the individual Service Agreement, however, the term shall not be less than one year. The term of the contract will automatically renew unless the Customer notifies the Company in writing sixty (60) days prior to contract termination. The Customer may switch to a firm transportation service to receive gas supply from a TPS per the provisions of this classification. In the event that a Customer ceases operations completely or moves its operations to a location where the Company does not provide service, Customer shall not be liable for further charges under the Service Agreement upon notification to the Company in writing.

STANDARD TERMS AND CONDITIONS:

This Service Classification is subject to the Standard Terms and Conditions of this Tariff.

SERVICE CLASSIFICATION – LARGE VOLUME DEMAND (LVD)
(continued)

SPECIAL PROVISIONS SECTIONS I & II:

I. SPECIAL PROVISIONS, APPLICABLE TO ALL CUSTOMERS RECEIVING SERVICE UNDER THIS SERVICE CLASSIFICATION

1. Plant Shutdowns

In the event Customer is compelled to shutdown operation of its entire manufacturing or commercial facilities because of a major disaster, major strike, or order of any court or administrative agency having jurisdiction, and said shutdown continues in effect through a full calendar month, Gas Company, upon written request from Customer, may adjust the Minimum Charge for the calendar month. Separate written requests by Customer must be made for each month in which an adjustment of the Minimum Charge is desired and said request shall set forth in detail the exact reasons therefor.

2. Standby Equipment and Fuel

It is the Customer's responsibility to provide for alternate energy facilities needed, if any to provide plant protection service, including cool down periods for refractory, during periods in which gas may be curtailed in accordance with curtailment plan authorized by the State of New Jersey or appropriate Federal Government Agency that are applicable to the Company's operation. In addition, the Gas Company reserves the right to interrupt or suspend service rendered hereunder by Customer if, in the sole judgement of the Company, it is necessary to meet system integrity or to meet other emergency demands under its Curtailment Action Plan as set forth in Section I of this tariff.

3. Facility Charges

The costs of any changes in the facilities of the Gas Company necessary to render this service will be paid for by the Customer.

4. Unauthorized Use

This Service Classification is subject to Unauthorized Gas Use Section of the Standard Terms and Conditions.

SERVICE CLASSIFICATION – LARGE VOLUME DEMAND (LVD)
(continued)

II. SPECIAL PROVISIONS, APPLICABLE TO CUSTOMERS RECEIVING GAS SUPPLY FROM THIRD PARTY SUPPLIERS (TPS)

1. Service Agreement

The signing of a Service Agreement and possession by the Customer of a fully executed contract to purchase gas from a TPS are conditions precedent to receiving gas supply from a TPS.

2. Gas Commingling

Service under this classification is provided by the Company within its service territory for the Customer. The gas transported under this Service Classification is not the property of the Company. However, the Company reserves the right to commingle such gas, when necessary, in accordance with the applicable curtailment provisions of this Tariff.

3. Transportation to Gas Company Facilities

The Company is not responsible for making arrangements for transportation service Customers for transporting the gas from its source to the Company's interconnection with the delivering pipeline supplier.

4. Nominations for Service

The Customer's TPS shall nominate on behalf of its Customer's total monthly requirements for that billing month.

5. Utilizing a Third Party Supplier

Customers utilizing a TPS (including brokers and marketers) either as agents or as suppliers of gas into the Company's system, must notify the Company in writing of the TPS that will be used in any particular month. Customer agrees that as between the Company and Customer, the Company shall be entitled to rely upon information concerning deliveries of natural gas on behalf of Customer provided by TPS. Any Customer or TPS that wishes to deliver gas into the Company's system prior to commencing deliveries must be a qualified under the Company's TPS service classification.

SERVICE CLASSIFICATION – LARGE VOLUME DEMAND (LVD)
(continued)

II. SPECIAL PROVISIONS, APPLICABLE TO CUSTOMERS RECEIVING GAS SUPPLY FROM THIRD PARTY SUPPLIERS (TPS) (continued)

6. Imbalance Charges

To the extent that a TPS ceases operations or under delivers gas, Customers shall be ultimately responsible for payment of any charges not paid for by their TPS, including but not limited to daily and or monthly imbalance charges for gas supplies consumed by Customer but not delivered by TPS. In the event a TPS fails to pay these charges, the Customer shall be billed directly by the Company for its direct portion, if by its non-compliance to Company directives to cease gas use, and/or a prorata share by applying the Allocation of Supply terms of the TPS Service Classification, except that essential service gas Customers will first be credited with standby gas purchased by the TPS on their behalf.

7. Automatic Meter Reading (AMR) Equipment for Customers

In order to utilize this service, (AMR) equipment is required. Customer shall pay for all costs to install (AMR) equipment including power, communications and other equipment as specified by the Company and provide access for such equipment. The cost of any Company equipment may be paid by Customer over a one (1) year or some lesser period by means of a monthly surcharge designed to recover the cost of the equipment plus interest equal to the Company's overall rate of return as authorized from time to time by the New Jersey Board of Public Utilities. Payments made by the Customer shall not give the Customers ownership of the equipment, which shall remain the sole property of the Company.

8. Unauthorized Use

This Service Classification is subject to Unauthorized Gas Use of the Standard Terms and Conditions.

9. Gas Supply Obligation

In the event that Customer's TPS fails to deliver, the Company may, in its sole discretion, provide replacement gas supplies. The Company shall have no obligation to provide natural gas supplies to Customers that contract for TPS Service, except for those whose TPS contracted for Standby Service, limited to Essential Gas User customers. In the event that a Customer that is not covered by Standby Service seeks to purchase natural gas supplies from the Company, such sales may be made by the Company in its sole discretion under such terms and conditions as the Company may require.

SERVICE CLASSIFICATION – LARGE VOLUME DEMAND (LVD)
(continued)

II. SPECIAL PROVISIONS, APPLICABLE TO CUSTOMERS RECEIVING GAS SUPPLY FROM THIRD PARTY SUPPLIERS (TPS) (continued)

10. Limitations on the Availability of Transportation Service

TPS Service is not available to Customers who are defined as "Essential Gas Users" under the curtailment provision as set forth in Section 16 of the Standard Terms and Conditions of this Tariff unless such Customers' TPS, in an amount sufficient to meet such Customers' DCQ, agrees to contract and pay for Standby Service as defined in the TPS Service Classification or for such Customers' TPS demonstrates that it possesses Comparable Capacity as defined in the TPS Service Classification.

11. Indemnification

As between Company and Customer, Customer warrants that it has clear title to any gas supplies delivered into the Company's system for redelivery to Customer and Customer shall be deemed to be in exclusive control and possession of gas prior to its delivery into the Company's system for redelivery to Customer. Customer agrees to indemnify, defend and hold harmless Company from any and all claims, suits or damage actions arising out of deliveries of gas into Company's system on behalf of transporting customer.

SERVICE CLASSIFICATION – ELECTRIC GENERATION FIRM SERVICE (EGF)

All Customers must sign a Service Agreement. Service will be restricted to the maximum annual and hourly requirements, and the location and equipment specified in the Agreement.

APPLICABLE TO USE OF SERVICE FOR:

Available to customers who utilize natural gas for Qualifying Cogeneration, as defined below, Distributive Generation, Micro Turbine and Fuel Cells at facilities with a rated production of over 500 Kilowatts (kW). Customers have the option of taking service under this Service Classification or negotiating a sales and/or transportation service contract which will be filed with the BPU.

A Qualifying Cogeneration Facility is one that meets the Federal Energy Regulatory Commission (FERC) certification of qualifying status for the sequential production of electrical and/or mechanical energy and useful thermal energy from the same fuel source by a facility as defined in Section 201 of the Regulatory Policies Act of 1978.

CHARACTER OF SERVICE:

Continuous

*CHARGE PER MONTH:

	Tax-Exempt (1)	Taxable (2)
Service Charge	$~~70.34~~95.00	$~~75.00~~101.29
Demand Charge per DCQ	$~~0.600~~0.750	$~~0.640~~0.800
Distribution Charge per Therm	$0.0395	$0.0421
Commodity Charge	Per Rider "A"	Per Rider "A"

* The charges set forth in this Service Classification include sales and use tax, unless noted tax-exempt and will be adjusted for all other applicable Riders of this Tariff and any additional taxes or similar charges that are lawfully imposed by the Company.

(1) Tax-Exempt rates apply to cogeneration facilities that are in compliance with the terms of N.J.S.A. 54:30A-50.

(2) Taxable rates apply to Customers, unless specifically exempted by law, entering Service Agreements with the Company after 3/10/1997.

SERVICE CLASSIFICATION – ELECTRIC GENERATION FIRM SERVICE - (EGF)
(continued)

DETERMINATION OF THE DEMAND CHARGE QUANTITY ("DCQ"):

The DCQ will be determined by the Customer's maximum daily requirements in terms of therms per day and included in the Service Agreement.

The DCQ level shall be the highest actual daily metered consumption registered from an approved automatic meter reading device at Customer's premises within a period of not less than two years, but up to three years immediately preceding the Customer obtaining service or renewing a Service Agreement under this Service Classification if such information is available. Otherwise DCQ shall be set equal to the product of (1) the highest winter monthly consumption for the most recent winter (October through April), normalized for weather, divided by the applicable number of days in the respective billing month, and (2) 1.36, provided that DCQ shall not be less than the highest non-winter month consumption divided by the applicable number of days in the respective billing month. For process loads, the Company may base the DCQ on historical consumption. If historical consumption information is not available, then (a) the initial DCQ level shall be based upon the Customer's gas utilization equipment expressed in consumption per day, and (b) after twelve (12) months of actual consumption has been metered, the DCQ level shall be redetermined.

If the Customer's maximum daily usage exceeds the DCQ as stated in the Service Agreement more than three (3) times in twelve (12) months, the Company may increase the DCQ in the Service Agreement to the highest level of usage experienced within the past 12 months.

The billing demand quantity for the initial month of gas consumption shall be the rated twenty-four (24) hour input of the connected equipment expressed in equivalent therms.

Demands established during the billing months of May through September, inclusive, will not be used for billing purposes to the extent that such demands exceed previously established billing demands.

MINIMUM MONTHLY CHARGE:

The sum of the Service Charge and the Demand Charge.

TERM OF PAYMENT:

All bills are due upon presentation. Should the Customer fail to make payment in full, the Company may, within the time period specified in and in accordance with Section 7.10 of the Standard Terms and Conditions of this Tariff, assess late payment charges.

SERVICE CLASSIFICATION – ELECTRIC GENERATION FIRM SERVICE - (EGF)
(continued)

TERM OF CONTRACT:

The term of the contract will be specified in the Service Agreement, but shall not be less than two years. Successive two-year terms shall be provided unless terminated by written notice prior to 60 days of the contract anniversary date.

STANDARD TERMS AND CONDITIONS:

This Service Classification is subject to the Standard Terms and Conditions of this Tariff.

SPECIAL PROVISIONS:

1. Maximum Gas Usage and Deliveries

Service will be restricted to the maximum annual and hourly requirements, and the location and equipment specified in the Service Agreement. Upon request by Customer, Company may deliver available quantities of gas in excess of maximum hourly requirement for limited periods. Such deliveries shall not be deemed to constitute a change in the requirements specified in the Service Agreement.

2. Qualifying Facilities and Reporting

Customer must certify that qualifying status has been granted by the FERC and any other agencies required to grant operating status to the facility. The Customer is required to file with the Company all publicly available reports, related to cogeneration operation, that are filed with State and Federal agencies.

3. Metering

Service supplied under this Service Classification shall be separately metered.

4. Unauthorized Use

This Service Classification is subject to Unauthorized Gas Use Section of the Standard Terms and Conditions.

SERVICE CLASSIFICATION – GAS LIGHT SERVICE (GLS)

This Service Classification is limited to un-metered Gas Lights whose cost of maintenance and repair shall be the responsibility of Customer.

APPLICABLE TO USE OF SERVICE FOR:

Customers who have the gas supply for their outdoor lighting fixtures connected directly to the gas service pipe without being metered.

CHARACTER OF SERVICE:

Continuous.

CHARGE PER MONTH:

The Distribution Charge for this service shall be at the flat rate of $~~7.85~~11.31 per Mantel Equivalent, inclusive of taxes, for each .02 therms of hourly input rating of the lighting fixtures. Input ratings shall be those of the manufacturer of the gas lighting fixtures or as determined by actual test or calculation made by Gas Company. The rate set forth above will be adjusted for the Periodic Basic Gas Supply Service Charge (BGSS-P) of this Tariff as well as all other applicable Riders of this Tariff and any additional taxes or similar charges that are lawfully imposed by the Company. Per Therm charges shall be determined by the Company using the following factors times the applicable rates noted above:

Mantel Equivalents = fixture input rating / .02 therms of hourly input
Un Metered Billing Therms = Mantel Equivalents *.02 * 24 hours * 365 / 12

MINIMUM MONTHLY CHARGE:

Flat rate as shown above.

TERM OF PAYMENT:

All bills are due upon presentation. Should a non-residential GLS Customer fail to make payment in full, the Company may, within the time period specified in and in accordance with Section 7.10 of the Standard Terms and Conditions of this Tariff, assess late payment charges.

TERM OF CONTRACT:

One year, and thereafter until terminated by five (5) days written notice.

STANDARD TERMS AND CONDITIONS:

This Service Classification is subject to the Standard Terms and Conditions of this Tariff.

SERVICE CLASSIFICATION - COGENERATION SERVICE – INTERRUPTIBLE (CSI)
CLOSED TO NEW CUSTOMERS

This Service Classification is only available to qualifying cogeneration facilities served under this classification on or after January 1, 2010, as well as additional facilities added at these Customers existing cogeneration sites after this date.

The signing of a Service Agreement and Federal Energy Regulatory Commission (FERC) certification of qualifying status are conditions precedent to receiving service under this Service Classification.

APPLICABLE TO USE OF SERVICE FOR:

The sequential production of electrical and/or mechanical energy and useful thermal energy from the same fuel source by a Qualifying Facility as defined in Section 201 of the Regulatory Policies Act of 1978.

Customer must certify that qualifying status has been granted by the FERC and will be required to sign a Service Agreement. Service will be restricted to the maximum annual and hourly requirements, and the location and equipment specified in the Agreement.

CHARACTER OF SERVICE:

Interruptible.

Gas will be available at the sole option of the Gas Company when peaking supplies are not required to meet the gas demands of customers served under firm service classifications or other system requirements.

Service may be discontinued or curtailed at the sole option of the Gas Company after not less than three (3) hours notice by telephone or otherwise.

*CHARGE PER MONTH:

	Tax-Exempt	Taxable
Service Charge	$~~122.65~~164.67	$~~130.78~~175.58
Quantity Charge	*	*

*The Quantity Charge shall be the monthly Basic Gas Supply Service Charge ("BGSS-M") plus $0.0300 per therm pre taxes. In addition, the total monthly charge will be adjusted for all applicable riders or taxes of this tariff.

SERVICE CLASSIFICATION – COGENERATION SERVICE – INTERRUPTIBLE (CSI)
CLOSED TO NEW CUSTOMERS
(continued)

MINIMUM MONTHLY CHARGE:

Service Charge.

TERM OF PAYMENT:

All bills are due upon presentation. Should the Customer fail to make payment in full, the Company may, within the time period specified in and in accordance with Section 7.10 of the Standard Terms and Conditions of this Tariff, assess late payment charges.

TERM OF CONTRACT:

The term of the contract will be specified in the Service Agreement, but shall not be less than one year. Successive one-year term extensions shall be provided for thereafter, unless terminated by written notice prior to 60 days of the contract anniversary date.

STANDARD TERMS AND CONDITIONS:

This Service Classification is subject to the Standard Terms and Conditions of this Tariff.

SPECIAL PROVISIONS:

1. Reports

Customer is required to file with the Company all publicly available reports, related to cogeneration operation, that are filed with State and Federal agencies.

2. Metering

Service supplied under this Service Classification shall be separately metered.

3. FERC Status

Customer must certify that qualifying status has been granted by the FERC and will be required to sign a Service Agreement. Service will be restricted to maximum annual and hourly requirements, and the location and equipment specified in the agreement. Upon request by customer, Elizabethtown may deliver available volumes of gas in excess of maximum hourly requirements for limited periods. Such deliveries shall not be deemed to constitute a change in the requirements specified in the Agreement.

SERVICE CLASSIFICATION – COGENERATION SERVICE – INTERRUPTIBLE (CSI)
CLOSED TO NEW CUSTOMERS
(continued)

SPECIAL PROVISIONS: (continued)

4. Standby Equipment and Fuel

It is the Customer's full responsibility to have standby equipment installed and maintained in operating condition and a fuel supply adequate for its operation at all times.

5. Interruption of Service

The Company reserves the right to physically curtail the gas service to any Customer if, in the Company's sole judgment, such action is necessary to protect the operation of its system.

6. Gas Day

A "day" shall be a period of twenty-four (24) consecutive hours, beginning as near as practical to 8 a.m., or as otherwise agreed upon by Customer and Gas Company.

7. Tax Exemption

The cogeneration facility must be in compliance with N.J.S.A. 54:30A-50 in order to be exempt from applicable taxes.

UNAUTHORIZED USE:

This Service Classification is subject to Unauthorized Gas Use Section of the Standard Terms and Conditions.

TREATMENT OF REVENUES:

Eighty (80%) percent of all revenues produced under this Service Classification, exclusive of: Service Charges, and applicable Riders, taxes and the BGSS-M component of the Quantity Charge that shall be credited to the BGSS, after removing applicable taxes, shall be credited to the OSMC in accordance with the Board's Order in Docket No. GO99030122, 20% retained by the Company.

SERVICE CLASSIFICATION – INTERRUPTIBLE SERVICE (IS)

The signing of a service agreement is a condition precedent to receiving service under this classification. The Service Agreement will include the Customer's maximum daily requirements.

APPLICABLE TO USE OF SERVICE FOR:

Industrial boiler and commercial boiler use Customers having an alternate fuel capability with a daily demand of not less than 500 therms per day up to a maximum daily demand as set forth in the Service Agreement, providing the Gas Company facilities are suitable and when the Gas Company in its sole discretion deems sufficient gas supplies to be available for this service.

Gas delivered will be separately metered and shall not be used interchangeably with gas supplied under any other Service Classification.

CHARACTER OF SERVICE:

Interruptible

Gas will be available for interruptible service at the sole option of the Gas Company when peaking supplies are not required to meet the gas demands of Customers served under firm service classifications or other system requirements. Service may be discontinued or curtailed at the sole option of the Gas Company after not less than three (3) hours notice by telephone or otherwise. See also Special Provision – Alternative Fuel Requirement.

*CHARGE PER MONTH:

Service Charge	$~~628.55~~735.71
Demand Charge per DCQ	$~~0.098~~0.269
Quantity Charge per Therm	**

*The charges set forth above include sales and use tax, unless noted tax exempt, and will be adjusted for all other applicable Riders of this Tariff and any additional taxes or similar charges that are lawfully imposed by the Company.

**The Quantity Charge shall be $0.0843 per therm plus the BGSS-M Charge of Rider "A", plus all other applicable Riders of this Tariff and any additional taxes, or similar charges that are lawfully imposed by the Company. However, it may be adjusted at the sole discretion of the Company each month, upon five (5) days notice to the Board, to a price as described below:

A price equal to the estimated market price expressed in an equivalent rate per therm for No. 2 grade fuel oil using an average BTU content of 136,000 but not less than the floor price nor greater than the ceiling price as described as follows:

SERVICE CLASSIFICATION – INTERRUPTIBLE SERVICE (IS)
(continued)

CHARGE PER MONTH: (continued)

The floor price, as determined monthly, shall be the BGSS-M and an adjustment for applicable taxes plus applicable Riders of this tariff, plus $0.016 per therm during the period April through October or $0.032 per therm during the period November through March and any additional taxes or similar charges that are lawfully imposed by the Company.

The ceiling price shall be $0.9405 per therm plus the BGSS-M Charge of Rider "A", plus applicable Riders of this Tariff and any additional taxes or similar charges that are lawfully imposed by the Company. The ceiling price will be reviewed for possible adjustment if the spot price for Futures Contract Crude Oil – Light Sweet, as published in the Wall Street Journal, exceeds $130.00 per barrel.

DETERMINATION OF THE DEMAND CHARGE QUANTITY ("DCQ"):

The DCQ will be determined by the Customer's maximum daily requirements in terms of therms per day and included in the Service Agreement.

The DCQ level shall be the highest actual daily metered consumption registered from an approved automatic meter reading device at Customer's premises within a period of not less than two years, but up to three years immediately preceding the Customer obtaining service or renewing a Service Agreement under this Service Classification if such information is available. Otherwise DCQ shall be set equal to the product of (1) the highest winter monthly consumption for the most recent winter (October through April), normalized for weather, divided by the applicable number of days in the respective billing month, and (2) 1.36, provided that DCQ shall not be less than the highest non-winter month consumption divided by the applicable number of days in the respective billing month. For process loads, the Company may base the DCQ on historical consumption. If historical consumption information is not available, then (a) the initial DCQ level shall be based upon the Customer's gas utilization equipment expressed in consumption per day, and (b) after twelve (12) months of actual consumption has been metered, the DCQ level shall be redetermined. If the Customer's maximum daily usage exceeds the DCQ as stated in the Service Agreement more than three (3) times in twelve (12) months, the Company may increase the DCQ in the Service Agreement to the highest level experienced during the previous 12 months.

MINIMUM MONTHLY CHARGE:

The sum of the Service Charge and the Demand Charge.

SERVICE CLASSIFICATION – INTERRUPTIBLE SERVICE (IS)
(continued)

TERM OF PAYMENT:

All bills are due upon presentation. Should the Customer fail to make payment in full, the Company may, within the time period specified in and in accordance with Section 7.10 of the Standard Terms and Conditions of this Tariff, assess late payment charges.

TERM OF CONTRACT:

Not less than one (1) year, and for successive one (1) year terms thereafter unless terminated by written notice prior to sixty (60) days of the contract anniversary date.

STANDARD TERMS AND CONDITIONS:

This Service Classification is subject to the Standard Terms and Conditions of this Tariff.

SPECIAL PROVISIONS:

1. Standby Equipment and Fuel

It is the Customer's full responsibility to have standby equipment installed and maintained in operating condition and a fuel supply adequate for its operation at all times. The Customer shall provide the Gas Company with an affidavit certifying the grade and sulphur content of fuel oil that can be utilized in the facilities served under this service classification or a description of the alternate fuel used.

2. Pilot Gas

Any gas consumed for pilot lights shall be billed at the GDS rate schedule. Separate metering shall be used where practicable. Where such metering is not practical, a fixed monthly charge based upon the rated input of the pilot will be billed to the Customer.

3. Emergency Service

If an IS Customer requests gas on an emergency basis when gas service would otherwise be precluded under the terms of this service classification, the Gas Company may in its sole discretion tender gas if it determines that an emergency does exist and the Gas Company has the ability to provide the gas service. Gas consumed under the provision will be priced at a rate per therm equal to the greater of:

SERVICE CLASSIFICATION – INTERRUPTIBLE SERVICE (IS)
(continued)

SPECIAL PROVISIONS: (continued)

3. Emergency Service (continued)

a) the incremental cost of gas, as determined by the Gas Company, during the time such service is rendered adjusted for the applicable taxes plus five (5) cents per therm, or

b) the Distribution Charge of the GDS Service Classification rate plus the BGSS-M charge of Rider "A".

4. Plant Shutdown

In the event Customer is compelled to shut down operation of its manufacturing or commercial facilities because of a major disaster, major strike, or a lawful order of any court or administrative agency having jurisdiction, Gas Company, upon written request from Customer, may not apply or collect from Customer the minimum monthly charge established herein during the period Customer's plant shall remain so shut down, and, upon receipt of such request, Gas Company shall have the right to terminate the contract as of the date when such request is received or at any other time during the period of suspension of said minimum monthly charge.

5. Unauthorized Use

This Service Classification is subject to Unauthorized Gas Use Section of the Standard Terms and Conditions.

6. Alternative Fuel Requirement

As of November 1 of each year, interruptible Customers using No. 2 fuel oil, No. 4 fuel, jet fuel or kerosene are required to have seven (7 days) of alternative fuel either on hand or, if a Customer's on-site storage capacity is less than seven (7) days, then full storage capacity plus additional firm contractual supply arrangements to equal seven (7) days. On or before November 1st, Customers shall submit an "Alternative Fuel Certification" indicating they have met the above requirements and the alternative fuel used or will agree to suspend operations during an interruption. Customers who fail to discontinue natural gas use, consistent with the terms and conditions of the relevant interruptible tariff, shall be assessed a charge based on Unauthorized Use.

SERVICE CLASSIFICATION – INTERRUPTIBLE SERVICE (IS)
(continued)

SPECIAL PROVISIONS: (continued)

7. Treatment of Revenues

Eighty (80%) percent of all revenues produced under this Service Classification, exclusive of: Service Charges, Demand Charges, applicable Riders; taxes and the floor price, which shall be credited to the BGSS, after removing applicable taxes shall be credited to the OSMC in accordance with the Board's Order in Docket No. GO99030122, 20% retained by the Company.

SERVICE CLASSIFICATION – CONTRACT SERVICE (CS)

This service classification is limited to those Customers or their successors and assigns under contract on July 18, 1977.

APPLICABLE TO USE OF SERVICE FOR:

Large volume boiler or turbine fuel with connected load in excess of 35,000 therms per day. Terms of service including pressure, capital repayment, operation condition are separately set forth in individual agreements between the Gas Company and the Customers.

Contracts in effect are with:

Service to Gilbert Generating Station and to Glen Gardner Generating Station per service initially begun with Jersey Central Power & Light Company.

CHARACTER OF SERVICE:

Gas will be available at the sole option of the Gas Company when peaking supplies are not required to meet the gas demands of Customers served under firm service classifications or other system requirements.

The Gas Company reserves the right to interrupt this service upon three (3) hours notice by telephone or otherwise if in its sole discretion continuance of service would adversely impact on its ability to adequately serve other Customers or for other operational reasons.

RATE:

Jersey Central Power and Light Company – not to exceed $0.0819 per therm plus the BGSS-M Charge, plus the applicable Riders of this Tariff, net of Sales and Use Tax, in effect at the time of rendering service, but not less than the floor price. The floor price, as determined monthly, shall be the BGSS-M plus pre tax rates of $0.0150 per therm during the period April through October or $0.0320 per therm during the period November through March, plus applicable Riders of this Tariff, plus an adjustment for any other charges lawfully imposed by the Company.

The rate to be charged will be determined solely by the Company within the range described above.

SERVICE CLASSIFICATION – CONTRACT SERVICE (CS)
(continued)

TERM OF PAYMENT:

All bills are due upon presentation. Should the Customer fail to make payment in full, the Company may, within the time period specified in and in accordance with Section 7.10 of the Standard Terms and Conditions of this Tariff, assess late payment charges.

TERM OF CONTRACT:

One year, and for successive one (1) year terms thereafter unless terminated by written notice prior to sixty (60) days of the contract anniversary date.

SPECIAL PROVISIONS:

1. BTU Adjustment

For purposes of billing, all gas volumes delivered under this service classification shall be converted to therms by multiplying the daily volume at standard conditions of pressure (14.73 psia) and temperature (60°F) by the average daily BTU value of the gas.

2. Emergency Service

Emergency service will be provided upon request if the Gas Company in its sole judgment has the facility capability and the gas supplies to render such service. The rate charged for such service shall be equal to the greater of: a) the incremental cost of gas required by the system at the time the emergency service is rendered plus five cents per therm or b) 145 percent of the "projected purchased gas cost used in determining the current BGSS-M Charge for the purposes of Rider A; plus an adjustment for applicable taxes or similar charges. Excess revenues derived from this provision (exclusive of any adjustments) will be applied to the BGSS Charge as recovered gas costs.

SERVICE CLASSIFICATION – CONTRACT SERVICE (CS)
(continued)

SPECIAL PROVISIONS: (continued)

3. Special Purchases

Gas purchased specifically for Service to Gilbert Generating Station and to Glen Gardner Generating Station shall be sold to the Customer(s) incrementally subject to the following conditions as agreed to in writing by all parties and to be in effect for the entire transaction period as specified below:

a) Type of Service

b) Duration of Agreement

c) If the rate agreed upon is to be based upon an oil parity, the following shall be specified in the agreement:

(1) Type of oil to be used for parity purposes

(2) The source from which oil prices will be taken and the method by which the oil parity rate will be computed

(3) The appropriate adjustments to be made to the oil parity rate

(4) The frequency with which the oil parity will be recomputed

d) The rate when an oil parity rate is not used

e) Special contract provisions

The BGSS Charge of this tariff shall not apply to the services provided under this provision. Similarly, all volumes shall be excluded from the calculations associated with the clause.

4. Transportation of Customer Gas

Gas purchased by the Customer and made available for Transportation through the Company system will be delivered to Customer subject to the terms and conditions of a Service Agreement signed by all parties.

SERVICE CLASSIFICATION – CONTRACT SERVICE (CS)
(continued)

SPECIAL PROVISIONS: (continued)

4. Transportation of Customer Gas (continued)

The Service Agreement shall specify the following:

a) Type of Service

b) Duration of Agreement

c) Charges associated with the Service

d) Special contract provisions

5. Storage Service

a) Firm Storage

Availability of Storage Service will be announced by the Company by February 1 of each year. The Customer may subscribe for Firm Storage Service by March 1 of each year. If oversubscribed, the available level of service will be offered pro rata, based on the Customer's actual usage during the 12 months ended December 31. Firm Storage Service will be available for a contract year running May 1 through April 30.

The Storage Service will be available at a 100 day withdrawal rate or a 150 day withdrawal rate. Injections into storage may be made between May 1 and October 31 at a daily rate not to exceed 1/180 of the contracted storage capacity. Withdrawals may be made between November 1 and April 30 at a daily rate not to exceed contract amount as set forth in the Service Agreement. All storage gas must be taken out by April 30. The Company may at times relax these operating conditions if it determines such can be done without adversely affecting service to its sales Customers.

SERVICE CLASSIFICATION – CONTRACT SERVICE (CS)
(continued)

SPECIAL PROVISIONS: (continued)

5. Storage Service (continued)

The charges for Firm Storage Service are as follows:

Customer Accounting Charge	$69.55	per month
Injection Charge	$0.086	per Dth
Withdrawal Charge	None	

Storage Demand Charge (Monthly Charge for 12 Months)

100 day withdrawal rate	$0.152	per Dth of contracted storage capacity
150 day withdrawal rate	$0.116	per Dth of contracted storage capacity

The Company and Customer will enter into a Service Agreement specifying the maximum daily delivery amount and total storage capacity amount. The Customer may not obtain a maximum daily delivery amount in excess of 50% of their maximum daily demand for gas and in no event greater than the maximum daily delivery amount in their Transportation Service Agreement.

b) Limited Storage Service

For the period May through October the Company may offer a limited Storage Service. The charges for such service shall be as follows:

Customer Accounting Charge	$69.55	per month
Injection Charge	$0.086	per Dth
Withdrawal Charge		None
Storage Demand Charge	$0.041	per Dth of contracted storage capacity

SERVICE CLASSIFICATION – CONTRACT SERVICE (CS)
(continued)

SPECIAL PROVISIONS: (continued)

b) Limited Storage Service (continued)

The Company and Customer will enter into a Service Agreement specifying the maximum daily delivery amount and the total storage capacity amount. The Service Agreement will also describe when and how injection and withdrawals can be made. The Customer may not obtain storage capacity for more than 50% of their most recent historical gas consumption for the period of May to October, however that level of consumption may be adjusted upward if the Customer were using alternate fuel instead of gas.

6. Treatment of Revenues

All revenues produced under this Service Classification, exclusive of; Service Charges, and applicable Riders, taxes, and revenues resulting from service under Special Provisions 2, will be apportioned as follows:

a) Sales made under the Rate provision of this service classification:

All remaining revenues in excess of the floor price of gas, after removing applicable taxes, shall be subject to revenue sharing – 80% credited to the OSMC in accordance with the Board's Order in Docket No. GO99030122, 20% retained by the Company.

b) Sales made under Special Provision 3 of this service classification:

All remaining revenues in excess of the costs associated with the special gas purchase shall be subject to revenue sharing – 80% credited to the OSMC in accordance with the Board's Order in Docket No. GO99030122, 20% retained by the Company.

c) Services provided under Special Provision 4 of this service classification:

All remaining revenues in excess of any incremental administrative costs incurred in providing this service shall be subject to revenue sharing – 80% credited to the OSMC in accordance with the Board's Order in Docket No. GO99030122, 20% retained by the Company.

d) Services provided under Special Provision 5 of this service classification:

All remaining revenues in excess of the Customer Accounting Charge shall be subject to revenue sharing – 80% credited to the OSMC in accordance with the Board's Order in Docket No. GO99030122, 20% retained by the Company.

SERVICE CLASSIFICATION – CONTRACT SERVICE (CS)
(continued)

SPECIAL PROVISIONS: (continued)

7. Contract Review

To the extent that any new contracts with terms in excess of three (3) years are entered into under Special Provision 3, 4 and/or 5 of this service classification or any existing contracts under Special Provision 3, 4 and/or 5 with terms in excess of three (3) years are amended, the Company is required to submit such contracts or amendments to the Staff of the Board of Public Utilities for review thirty days prior to the effective date of such contract or amendment.

8. Societal Benefits Charge

The rates set forth above will be adjusted for the Societal Benefits Charge of this Tariff, Rider "D".

9. Applicable Taxes

The charges in this Rate Schedule will include provision for the New Jersey Sales and Use Tax. When billed to Customers exempt from one or more of these taxes, such charges will be reduced by the relevant amount of such taxes included therein.

SERVICE CLASSIFICATION – SUPPLEMENTAL INTERRUPTIBLE SERVICE (SIS)

This service classification is for a limited term. The signing of a service agreement by the Customer with the Gas Company is a condition precedent to receiving service under this service classification.

APPLICABLE TO USE OF SERVICE FOR:

Customers under service classification EGF, CSI, LVD, IS or ITS up to a maximum daily demand as set forth in their existing service agreement, or as set forth in the service agreement under this service classification, providing that Gas Company facilities are suitable and gas supplies can be secured for this service.

CHARACTER OF SERVICE:

Gas will be made available for this service only to the extent that such gas supplies can be incrementally purchased or produced.

The Gas Company reserves the right to interrupt this service upon three (3) hours notice by telephone or otherwise if in its sole discretion continuance of service would adversely impact on its ability to adequately serve other Customers or for other operational reasons.

RATE:

1. Service Charge

Upon initial request of SIS service, Customer will be charged an amount equal to the monthly service charge of the Customer's existing rate. This charge will be reassessed for subsequent initial requests made after June 30 of any year. In addition, a $50.00 daily charge will be assessed, pre-taxes, for each day SIS is utilized.

2. Quantity Charge

The rate per therm for gas used shall be set within a range computed to be (a) the incremental cost of purchasing or producing said gas plus all applicable taxes plus $0.0755 per therm pre taxes and (b) the effective IS rate.

TERM OF PAYMENT:

All bills are due upon presentation. Should the Customer fail to make a payment in full, the Company may, within the time period specified in and in accordance with Section 7.10 of the Standard Terms and Conditions of this Tariff, assess late payment charges.

SERVICE CLASSIFICATION – SUPPLEMENTAL INTERRUPTIBLE SERVICE (SIS)
(continued)

SPECIAL PROVISIONS:

1. Offering of Service

Unless otherwise agreed to in the service agreement:

a) Any Customer who does not accept gas offered under this rate schedule within the period of time allotted by the Company shall be deemed to have rejected such offer and waived all entitlements to the offered gas.

b) Customers normally served under the IS service classification will be offered gas under this service classification only when Interruptible Gas Service does not satisfy total Customer requirements. Any gas supplies available under this service classification shall be offered to qualified Customers on a prorated basis utilizing the Daily Demand Requirements as set forth in the service agreements as the criteria for proration, subject to the operating capabilities and system requirements of the Company.

2. Basic Gas Supply Service Charge

Gas purchased for sale under this service classification shall not be included as part of the gas costs recoverable through the BGSS Charge.

3. Treatment of Revenues

The revenue (exclusive of any service charges and applicable riders, taxes and other similar charges) on a per therm basis produced under this service classification that exceeds the per therm cost of the incrementally purchased or produced gas including applicable taxes and other similar charges shall be subject to the revenue sharing formula associated with the Customer's regular service classification.

4. Obligation to Take Requested Service

If the Customer requests service be rendered under this service classification and if such gas when offered is not used by the Customer, the Customer will be subject to being charged a per therm rate equivalent to the difference between the average gas costs as shown in the then current BGSS Charge and the actual gas cost for all therms unsold by the Gas Company under this service classification during the applicable BGSS Charge period. These revenues will be applied to the BGSS Charge as recovered gas costs. The gas cost and volumes would be applied to the BGSS Charge as purchased gas costs and available volumes.

SERVICE CLASSIFICATION – SUPPLEMENTAL INTERRUPTIBLE SERVICE (SIS)
(continued)

SPECIAL PROVISIONS: (continued)

5. Pricing Modification

The methodology and pricing set forth in the Rate section of this Service Classification may be modified in the service agreement, if agreed to by the Customer and the Company, in order to accommodate market conditions or special Customer requirements (including special requirements if the Customer commits to use gas for a suitable cogeneration facility).

SERVICE CLASSIFICATION – INTERRUPTIBLE TRANSPORTATION SERVICE (ITS)

The signing of a Service Agreement and possession by the Customer of a fully executed contract to purchase gas from a third party are conditions precedent to receiving service under this Service Classification.

APPLICABLE TO USE OF SERVICE FOR:

Customers eligible for service under Service Classifications LVD, IS, or CSI and having clear title to gas that is made available for ITS on the Company's distribution system, except that such Customers need not comply with the alternate fuel requirement of those Service Classifications to receive service hereunder. However, the Customer must comply with the Alternate Fuel Requirement under this Service Classification.

CHARACTER OF SERVICE:

Interruptible Transportation Service will be available when system capacity is not required to meet the demands of Customers served under all other Service Classifications or other system requirements, including, but not limited to, conditions that may be imposed on the Company by its suppliers. The availability of this service, and all determinations and interpretations hereunder, shall be at the sole judgment of the Company. Service may be discontinued or curtailed at the sole option of the Company after not less than three (3) hours notice by telephone or otherwise.

*CHARGE PER MONTH:

	Tax-Exempt	Taxable
Service Charge	$~~589.50~~690.00	$~~628.55~~735.71
Demand Charge per DCQ	$~~0.400~~0.500	$~~0.427~~0.533
Distribution Charge per Therm	**	**

*The charges set forth above include sales and use tax, unless noted tax exempt, and will be adjusted for all other applicable Riders of this Tariff and any additional taxes or similar charges that are lawfully imposed by the Company.

**The ceiling for the Distribution Charge shall be $~~0.0987~~0.1391 per therm or $~~0.0926~~0.1305 per therm, for tax-exempt Customers, but may be reduced, upon five (5) days notice to the Board to a floor of $0.0262 per therm or $0.0246 for tax exempt Customers, if the Company determines that, without a rate reduction, competitive pressures may result in the loss of load or the Customer. Rates for Customers without alternate fuel capability will be set monthly without reference to a ceiling or floor price. The above rates will be further adjusted to include all other charges set forth in the applicable Riders of this Tariff and any additional taxes or similar charges that are lawfully imposed by the Company.

Date of Issue: ~~November 14, 2019~~XXX1

Effective: Service Rendered on and after ~~November 15, 2019~~XXX2

Issued by: Christie McMullen, President
520 Green Lane
Union, New Jersey 07083

Filed Pursuant to Order of the Board of Public Utilities
Dated ~~November 13, 2019~~XXX3 in Docket No. ~~GR19040486~~XXX4

SERVICE CLASSIFICATION – INTERRUPTIBLE TRANSPORTATION SERVICE (ITS)
(continued)

DETERMINATION OF THE DEMAND CHARGE QUANTITY (DCQ):

DCQ will be determined by the Customer's maximum daily requirements in terms of therms per day and included in the Service Agreement.

The DCQ level shall be the highest actual daily metered consumption registered from an approved automatic meter reading device at Customer's premises within a period of not less than two years, but up to three years immediately preceding the Customer obtaining service or renewing a Service Agreement under this Service Classification if such information is available. Otherwise DCQ shall be set equal to the product of (1) the highest winter monthly consumption for the most recent winter (October through April), normalized for weather, divided by the applicable number of days in the respective billing month, and (2) 1.36, provided that DCQ shall not be less than the highest non-winter month consumption divided by the applicable number of days in the respective billing month. For process loads, the Company may base the DCQ on historical consumption. If historical consumption information is not available, then (a) the initial DCQ level shall be based upon the Customer's gas utilization equipment expressed in consumption per day, and (b) after twelve (12) months of actual consumption has been metered, the DCQ level shall be redetermined.

If the Customer's maximum daily usage exceeds the DCQ as stated in the Service Agreement more than three (3) times in twelve (12) months, the Company may increase the DCQ in the Service Agreement to the highest level experienced during the previous 12 months.

MINIMUM MONTHLY CHARGE:

The sum of the service charge and the demand charge.

TERM OF PAYMENT:

All bills are due upon presentation. Should the Customer fail to make payment in full, the Company may, within the time period specified in and in accordance with Section 7.10 of the Standard Terms and Conditions of this Tariff, assess late payment charges.

SERVICE CLASSIFICATION – INTERRUPTIBLE TRANSPORTATION SERVICE (ITS)
(continued)

TERM OF CONTRACT:

The term of the contract will be as specified in the individual Service Agreement; however, the term shall not be less than one year. The term of the contract will automatically renew unless the Customer notifies the Company in writing sixty (60) days prior to contract termination. In the event that a Customer ceases operations completely or moves its operations to a location where the Company does not provide service, Customer shall not be liable for further charges under the Service Agreement upon notification to the Company in writing.

STANDARD TERMS AND CONDITIONS:

This Service Classification is subject to the Standard Terms and Conditions of this Tariff.

SPECIAL PROVISIONS:

1. Gas Commingling

Service under this classification is provided by the Company within its service territory for the Customer. The gas transported under this Service Classification is not the property of the Company. However, the Company reserves the right to commingle such gas with other supplies. Moreover, the Company reserves the right to utilize Customer's gas, when necessary, in accordance with the applicable provisions of this Tariff.

2. Transportation to Gas Company Facilities

The Company is not responsible for making arrangements for transportation service Customers for transporting the gas from its source to the Company's interconnection with the delivering pipeline supplier.

3. Nominations for Service

The Customer's TPS shall nominate on behalf of its Customers the total monthly requirements for that billing month.

SERVICE CLASSIFICATION – INTERRUPTIBLE TRANSPORTATION SERVICE (ITS)
(continued)

SPECIAL PROVISIONS: (continued)

4. Utilizing a Third Party Supplier

Customers utilizing brokers, marketers or other third party suppliers (collectively Third Party Suppliers, "TPS") either as agents or as suppliers of gas into the Company's system, must notify the Company in a manner acceptable to the Company of the TPS that will be used in any particular month. Customer agrees that as between the Company and Customer, the Company shall be entitled to rely upon information concerning deliveries of natural gas on behalf of Customer provided by TPS. Any Customer or TPS that wishes to deliver gas into the Company's system prior to commencing deliveries must be a qualified TPS under the Company's TPS service classification.

5. Imbalance Charges

To the extent that a TPS ceases operations or under delivers gas, Customers shall be ultimately responsible for payment of any charges not paid for by their TPS, including but not limited to daily and or monthly imbalance charges for gas supplies consumed by Customer but not delivered by TPS. In the event a TPS fails to pay these charges the Customers shall be billed directly by the Company for their direct portion, if by their non-compliance to Company directives to cease gas use, and/or a pro-rata share by applying the Allocation of Supply terms of the TPS Service Classification, except that essential service gas Customers will first be credited with standby gas purchased by the TPS on their behalf.

6. Automatic Meter Reading (AMR) Equipment for Customers

In order to utilize this service, AMR equipment is required. Customer shall pay for all costs to install AMR equipment including power, communications and other equipment as specified by the Company and provide access for such equipment. The cost of any Company equipment may be paid by Customer over a one (1) year, or some lesser, period by means of a monthly surcharge designed to recover the cost of the equipment plus interest equal to the Company's overall rate of return as authorized from time to time by the New Jersey Board of Public Utilities. Payments made by the Customer shall not give the Customers ownership of the equipment which shall remain the sole property of the Company.

7. Unauthorized Use

This Service Classification is subject to Unauthorized Gas Use Section of the Standard Terms and Conditions.

SERVICE CLASSIFICATION – INTERRUPTIBLE TRANSPORTATION SERVICE (ITS)
(continued)

SPECIAL PROVISIONS: (continued)

8. Treatment of Revenues

Revenues under this Service Classification, exclusive of applicable taxes shall be accounted for as follows: All service charge revenues derived from IS, CSI and LVD Customers shall be retained by the Company.

All demand charge revenues derived from LVD Customers shall be retained by the Company. The first $0.080 per therm of all demand charge revenues from IS Customers shall be retained by the Company. All remaining demand revenues derived from IS Customers shall be credited 80% to the OSMC in accordance with the Board's Order in Docket No. GO99030122 and 20% to the Company. All demand revenues derived from CSI Customers shall be credited 80% to the OSMC in accordance with the Board's Order in Docket No. GO99030122 and 20% to the Company.

All distribution charge revenues from LVD Customers shall be retained by the Company. All remaining distribution charge revenues from IS and CSI Customers shall be credited 80% to the OSMC in accordance with the Board's Order in Docket No. GO99030122 and 20% to the Company.

Revenues derived from the application of Riders shall be accounted for in accordance with the respective Riders. Revenues derived from the payment of imbalance charges, imbalance cash outs, or unauthorized use charges shall be credited to the BGSS Charge.

9. Gas Supply Obligation

In the event that Customer's TPS fails to deliver, the Company may, in its sole discretion, provide replacement gas supplies. The Company shall have no obligation to provide natural gas supplies to Customers that contract for TPS Service.

10. Limitations on the Availability of TPS Transportation Service

TPS Service is not available to Customers who are defined as "Essential Gas Users" under the curtailment provision as set forth in Section 16 of the Standard Terms and Conditions of this Tariff unless such Customers' TPS, in an amount sufficient to meet such Customers' DCQ, demonstrates that it possesses Comparable Capacity as defined in the TPS Service Classification. In addition, the TPS can serve such ITS Customers if they can demonstrate to the Company's satisfaction that they possess sufficient alternate fuel capability to meet their energy requirements for a period not less than fourteen (14) consecutive days.

SERVICE CLASSIFICATION – INTERRUPTIBLE TRANSPORTATION SERVICE (ITS)
(continued)

SPECIAL PROVISIONS: (continued)

11. Indemnification

As between Company and Customer, Customer warrants that it has clear title to any gas supplies delivered into the Company's system for redelivery to Customer and Customer shall be deemed to be in exclusive control and possession of gas prior to its delivery into the Company's system for redelivery to Customer. Customer agrees to indemnify, defend and hold harmless Company from any and all claims, suits or damage actions arising out of deliveries of gas on behalf of transporting Customer.

12. Availability of IS, LVD or CSI Service

ITS Customers who wish to do so may be made eligible to purchase sales service under the IS, LVD or CSI Service Classification also by designating the appropriate sales Service Classification in their ITS Service Agreements. Customer must meet the eligibility criteria applied to the designated sales Service Classification in order to obtain sales service. Customers may not designate more than one sales Service Classification. Customers that elect to purchase IS, LVD or CSI service may nominate sales or transportation service, but not both sales and transportation service, in any month. Customers who elect sales service under this provision shall remain subject to the Service and Demand Charges and the terms and conditions of this transportation Service Classification and in addition shall be liable for the Distribution and Rider Charges of the elected sales service.

13. Alternative Fuel Requirement

As of November 1 of each year, interruptible Customers using No. 2 fuel oil, No. 4 fuel, jet fuel or kerosene are required to have seven (7 days) of alternative fuel either on hand or, if a Customer's on-site storage capacity is less than seven (7) days, then full storage capacity plus additional firm contractual supply arrangements to equal seven (7) days. On or before November 1st, Customers shall submit an "Alternative Fuel Certification" indicating they have met the above requirements and the alternative fuel used or will agree to suspend operations during an interruption. Customers who fail to discontinue natural gas use, consistent with the terms and conditions of the relevant interruptible tariff, shall be assessed a charge based on Unauthorized Use. Also see, Special Provision, Limitation of the Availability of TPS Transportation Service.

SERVICE CLASSIFICATION – THIRD PARTY SUPPLIERS (TPS) SERVICE

The provisions of this Service Classification shall apply to brokers, marketers, customers intending to act as their own gas supplier, and other third party suppliers (collectively "Third Party Suppliers") of natural gas who wish to either act as agents for Transportation Customers or deliver natural gas supplies to Company's City Gate for Transportation Customers. Third Party Suppliers wishing to sell and/or deliver gas on the Company's system will be required to sign a Service Agreement in which they will agree to be bound by the terms and conditions of this Service Classification as well as other applicable terms and conditions of the Company's Tariff. By entering into a Service Agreement, TPS certifies that it is in compliance with all current applicable provisions of law, including N.J.S.A. 48:3-7.3. and will take steps to remain in compliance with all future applicable provisions and all other requirements mandated by the Board.

TERM OF CONTRACT:

The term of the contract shall be one (1) year and from month to month thereafter unless terminated on thirty (30) days written notice.

CREDITWORTHINESS:

Company shall not be required to permit any TPS who fails to meet Company's standards for creditworthiness to sell or deliver gas on its system. Company may require that TPS provide the following information:

a) Current audited financial statements (to include a balance sheet, income statement and statement of cash flow), annual reports, 10-K reports or other filings with regulatory agencies, a list of all corporate affiliates, parent companies and subsidiaries and any reports from credit agencies which are available. If audited financial statements are not available, then TPS also should provide an attestation by its chief financial officer that the information shown in the unaudited statements submitted is true, correct and a fair representation of Buyer's financial condition.

b) A bank reference and at least three trade references.

c) A written attestation that TPS is not operating under any chapter of the bankruptcy laws and is not subject to liquidation or debt reduction procedures under state laws, such as an assignment for the benefit of creditors, or any informal creditor's committee agreement. An exception can be made for a TPS who is a debtor-in-possession operating under Chapter XI of the Federal Bankruptcy Act but only with adequate assurances that any charges from the Company will be paid promptly as a cost of administration.

SERVICE CLASSIFICATION – THIRD PARTY SUPPLIERS (TPS) SERVICE
(continued)

CREDITWORTHINESS: (continued)

d) A written attestation that TPS is not subject to the uncertainty of pending litigation or regulatory proceedings in state or federal courts which could cause a substantial deterioration in its financial condition or a condition of insolvency.

e) A written attestation from TPS that no significant collection lawsuits or judgments are outstanding which would seriously reflect upon the business entity's ability to remain solvent.

If TPS has an ongoing business relationship with Company, no uncontested delinquent balances should be outstanding for natural gas sales, storage, transportation services or imbalances previously billed by Company, and TPS must have paid its account during the past according to the established terms, and not made deductions or withheld payment for claims not authorized by contract.

TPS shall furnish Company at least annually, and at such other time as is requested by Company, updated credit information for the purpose of enabling Company to perform an updated credit appraisal. In addition, Company reserves the right to request such information at any time if Company is not reasonably satisfied with TPS's creditworthiness or ability to pay based on information available to Company at that time.

Company shall not be required to permit and shall have the right to suspend permission to sell or deliver gas on its system to any TPS who is or has become insolvent, fails to demonstrate creditworthiness, fails to timely provide information to Company as requested, or fails to demonstrate ongoing creditworthiness as a result of credit information obtained; provided, however, TPS may continue to sell/deliver gas on the Company's system if Third Party Supplier elects one of the following options:

(i) Payment in advance for up to three (3) months of TPS's obligations to Company.

(ii) A standby irrevocable letter of credit in form and substance satisfactory to Company in a face amount up to three (3) months of Third Party Supplier's obligations to Company. The letter of credit must be drawn upon a bank acceptable to Company.

(iii) A guaranty in form and substance satisfactory to Company, executed by a person that Company deems creditworthy, of TPS's performance of its obligations to Company.

(iv) Such other form of security as TPS may agree to provide and as may be acceptable to Company.

SERVICE CLASSIFICATION – THIRD PARTY SUPPLIERS (TPS) SERVICE
(continued)

CREDITWORTHINESS: (continued)

In the event Third Party Supplier fails to immediately prepay the required three (3) months of revenue or furnish security, Company may, without waiving any rights or remedies it may have, and subject to any necessary authorizations, suspend Third Party Supplier until security is received.

The insolvency of a TPS shall be evidenced by the filing by TPS, or any parent entity thereof, of a voluntary petition in bankruptcy or the entry of a decree or order by a court having jurisdiction adjudging the Third Party Supplier, or any parent entity thereof, bankrupt or insolvent, or approving as properly filed a petition seeking reorganization, arrangement, adjustment or composition of the TPS, or any parent entity thereof, under the Federal Bankruptcy Act or any other applicable federal or state law, or appointing a receiver, liquidator, assignee, trustee, sequestrator, (or similar official) of the TPS or any parent entity thereof or of any substantial part of its property, or the ordering of the winding-up or liquidation of its affairs.

NOMINATIONS FOR SERVICE:

A Third Party Supplier shall provide to the Company in writing, or by other means as determined by the Company, at least 10 working days prior to the beginning of the calendar month an estimate of its deliveries into the Company's system for the month. These nominations must, in the aggregate, match the nominations of all Customers that are required to submit nominations to Company and to whom the Third Party Supplier will be delivering during the month plus the ADDQ that the TPS is obligated to deliver to the Company's system. Failure to provide nominations may result in suspension of service to Customers of offending Third Party Suppliers.

Company will notify Third Party Supplier of its ADDQ obligation for each day of the next succeeding month in writing to be delivered by facsimile or by other means as determined by the Company no later than the fifteenth (15^{th}) day of the month immediately preceding the month in which Third Party Supplier will be obligated to deliver the ADDQ. If Third Party Supplier does not agree with Company's determination of Third Party Supplier's ADDQ, it must notify Company in writing to be delivered by facsimile no later than 5:00 p.m. Eastern Standard Time on the seventeenth (17^{th}) of the month immediately preceding the gas flow month. Company and Third Party Supplier will reconcile any differences no later than 5:00 p.m. Eastern Standard Time on the twentieth (20^{th}) of the month.

In addition, TPS must identify interstate pipeline, shipper names and interstate pipeline shipper contract number(s) on which deliveries will be made at least twenty-four (24) hours prior to the flow of gas. Failure to comply with the Company's nominating procedures may result in curtailment of third party gas deliveries or additional monthly cash-outs. The Company reserves the right to specify which pipeline a TPS will deliver gas as a percentage of the TPS total monthly deliveries.

SERVICE CLASSIFICATION – THIRD PARTY SUPPLIERS (TPS) SERVICE
(continued)

DETERMINATION OF AVERAGE DAILY DELIVERY QUANTITY ("ADDQ"):

The individual ADDQ for all RDS, SGS, GDS Customers with a DCQ under 500 therms, and NGV Customers shall be calculated as follows:

1. Unadjusted ADDQ – Customer's weather normalized usage for each of the most recent billing periods, covering an annual period, prorated to calendar months, divided by the total number of days in each billing month. This quotient will be the Customer's Initial ADDQ. For new Customers, Customer's Initial ADDQ will be estimated by Company.

2. ADDQ Adjustment – At the end of each billing period, Company will calculate the difference between Customer's actual usage and actual deliveries for the billing period, taking into account any adjustments from prior months, and will adjust the Initial ADDQ for the next succeeding month by that difference divided by the total number of days in the month.

3. Adjusted ADDQ – The sum of items 1 and 2 will be adjusted by 1.5% for Company use and unaccounted for gas to determine the individual customers Adjusted ADDQ.

Company may adjust Customer's individual ADDQ at any time due to changes in Customer's gas equipment or pattern of usage.

The TPS's ADDQ shall be the total of the individual Adjusted ADDQs of all customers it serves that require an ADDQ delivery.

PIPELINE IMBALANCES:

Company and TPS recognize that Company may be subjected to imbalance charges from its interstate pipeline suppliers as a result of TPS's failure to deliver confirmed quantities of gas. Company and TPS shall use their best efforts to avoid such imbalance penalties. However, in the event that Company is assessed penalties as a result of TPS's actions or omissions, TPS shall reimburse Company for such penalties as may be attributable to TPS's actions or omissions.

INDEMNIFICATION:

As between the Company and TPS, TPS warrants that it has clear title to any gas delivered into the Company's system, and TPS shall be deemed to be in exclusive control and possession of gas prior to its delivery into the Company's system for redelivery to Customer. TPS agrees to indemnify, defend and hold harmless Company from any and all claims, suits or damage actions arising out of deliveries on behalf of a transporting customer.

SERVICE CLASSIFICATION – THIRD PARTY SUPPLIERS (TPS) SERVICE
(continued)

ALLOCATION OF SUPPLIES:

If a TPS is delivering gas to Customers under more than one Service Classification, such as RDS, GDS, LVD and/or ITS, and does not provide the supply allocations, then gas received by the Company in that month from the Third Party Supplier shall be allocated as follows:

1. First, to the ADDQ of RDS customers
2. Second, to the ADDQ of SGS, GDS and NGV customers
3. Third, to the GDS customers not subject to ADDQ and LVD customers
4. Last, to ITS and special contract customers

However, a TPS may specify individual supply allocations for its GDS customers not subject to the ADDQ, LVD, ITS and special contract Customers no later than one (1) business day following the date the TPS receives final month end measurement data for these customers from the Company.

DAILY AND MONTHLY CONTRACT BALANCING:

All balancing charges shall be charged to the TPS and are in addition to any other charges under this Service Classification. The Distribution Charge in the Charge Per Month of the Customers Service Classification is based upon actual consumption not Third Party Supplier deliveries.

a) Daily Imbalance Charge:

The Company shall, within the existing limitations of its system, provide for balancing between gas requirements and actual gas deliveries, net of an adjustment for Company Use and Unaccounted for Gas, received by the Company for the account of the Customers served by the TPS that day. The Company shall not be obligated to provide gas service during an hourly, daily or monthly period in excess of the levels specified in the Service Classifications under which Customers of the TPS are served.

During the months of November through April, the TPS will be required to balance daily deliveries and daily takes of transported gas by the customers it serves on any day when the average temperature at Newark Airport is forecast to be 27°F or less. However, the Company reserves the right to waive this requirement. The Company reserves the right during the months of November through April to require daily balancing on any other day in which the Company, in the exercise of its reasonable judgment, determines that such balancing is necessary for operational reasons. The Company will provide the TPS in all instances with at least twenty-four (24) hours advance notice that daily balancing will be imposed daily.

SERVICE CLASSIFICATION – THIRD PARTY SUPPLIERS (TPS) SERVICE
(continued)

DAILY AND MONTHLY CONTRACT BALANCING: (continued)

a) Daily Imbalance Charge (continued):

In the event that daily balancing is imposed in accordance with this section, TPS shall be assessed the following charges for daily imbalances:

	Imbalance *	Charge **
	0% to 5%	$0.00 per therm
	5% to 10%	$0.11 per therm for imbalances in excess of 5%
Underdeliveries	> 10%	$0.53 per therm for imbalances in excess of 10%
Overdeliveries	> 10%	$0.11 per therm for imbalances in excess of 10%

* The Company reserves the right to limit daily imbalances to plus or minus 5% of the actual quantity received. If the Company limits daily imbalances to plus or minus 5%, all underdeliveries in excess of 5% shall be considered Unauthorized Use and shall be subject to the Unauthorized Use charges specified in the Unauthorized Gas Use Section of this tariff.

**The Company may suspend overdelivery charges if it determines such overdeliveries would be beneficial to the systems operation.

All TPSs will automatically be placed in a non-discriminatory daily balancing pool. The Company will aggregate the deliveries and receipts of gas of all TPS customers participating in the pool for the purpose of determining whether imbalance charges will apply. In the event that charges are nonetheless assessed to certain TPSs, such charges will be no greater than the charges that otherwise would have been assessed if the Company did not have a daily balancing pool. TPSs trading imbalances will nonetheless have to set their own prices or methods by which over or under balances will be traded among individual TPSs.

b) Monthly Imbalance Cash-Out Charge:

At the conclusion of every month, the Company will cash out imbalances between TPS's deliveries and their Customers consumption made up of actual and or estimated volumes as follows:

SERVICE CLASSIFICATION – THIRD PARTY SUPPLIERS (TPS) SERVICE
(continued)

DAILY AND MONTHLY CONTRACT BALANCING: (continued)

b) Monthly Imbalance Cash-Out Charge: (continued)

Imbalance	Overdeliveries	Underdeliveries
0% to 5%	The Company's WACOG, defined as, the weighted average commodity cost of gas exclusive of peaking supplies as estimated by the Company for the month.	The monthly floor price for Interruptible Service tariff, less any Company margin embedded in the floor price.
>5% to 10%	90% of the Company's lowest cost supply for the month.	Higher of the: 1) The rate for the 0%-5% imbalance plus two (2) cents per therm -or- 2) The average of the month's four weekly prices published in Natural Gas Week for "Major Market Prices – New York City Gate" plus two (2) cents per therm.
>10%	75% of the Company's lowest cost supply for the month.	Higher of the: 1) The rate for the 0%-5% imbalance plus two (2) cents per therm times 125% -or- 2) The month's highest weekly price published in Natural Gas Week for "Major Market Prices – New York City Gate" plus two (2) cents per therm.

The offering of gas service above the 5% allowed imbalance for the month is at the sole discretion of the Company. If it determines that it cannot continue to provide such service or that it must limit such service, it will notify TPSs served under this Service Classification. The use of service above the level allowed by the Company after notification shall constitute Unauthorized Use and shall be subject to the Unauthorized Use charges specified in Unauthorized Gas Use Section of this tariff.

SERVICE CLASSIFICATION – THIRD PARTY SUPPLIERS (TPS) SERVICE
(continued)

ADJUSTMENT FOR COMPANY USE AND UNACCOUNTED FOR GAS:

A 1.5% adjustment for Company use and unaccounted for gas shall be made to the quantity of gas received from the TPS to serve its Customers.

STANDBY BALANCING SERVICE:

A TPS cannot contract for a greater level of Standby than its Essential Gas User Customers ("EGU") peak ADDQ month or Demand Charge Quantity ("DCQ") as applicable for their RDS, GDS or LVD Customers. A TPS who does not use Comparable Capacity for their EGU natural gas requirements, must contract for Standby Service to serve these customers to assure continued gas service when their own gas supply is interrupted or underdelivered for any reason. This service is available for a minimum term of three (3) years and is payable even if EGU Customers are no longer served by the TPS per the Customers last DCQ. The charge for this service will consist of a demand charge of $0.537 per therm of DCQ to be paid each month of the year whether or not Standby Service is used, and a commodity charge equal to: in the months October through April the greater of the Company's monthly weighted average cost of gas plus three (3) cents per therm, or the average of the month's four weekly prices published in Natural Gas Week for "Major Market Prices – New York City Gate," and in the months May through September the lesser of the Company's monthly weighted average cost of gas, or the average of the month's four weekly prices published in Natural Gas Week for "Major Market Prices – New York City Gate" plus two (2) cents per therm, as applied to any gas service rendered. All standby service charges shall be in addition to the rates otherwise charged under this Service Classification.

All standby revenues, exclusive of taxes and other similar charges and the three (3) cent per therm commodity surcharge in the months of October through April, shall be credited to the BGSS.

DELIVERED QUANTITIES:

Quantities billed to the end-use Customers shall be considered actual quantities delivered, whether based on actual or estimated meter readings.

SERVICE CLASSIFICATION – THIRD PARTY SUPPLIERS (TPS) SERVICE
(continued)

SPECIAL PROVISIONS:

In addition to the preceding terms and conditions of this Service Classification, the following terms and conditions shall apply to all TPSs providing service to Customers receiving service from Company under Service Classifications RDS, GDS, LVD and ITS. If, and to the extent that, any portion of the following is in conflict with previous terms of this Service Classification, the terms that follow shall govern.

1.
Enrollment of RDS, SGS, GDS and NGV Customers

TPS must enroll RDS, SGS, GDS and NGV Customers in accordance with the Company electronic enrollment procedures. Customer consent is assumed if the TPS provides the Company with the Customer's account number and service address and any other information that may be required by the Company, RDS customers will receive a confirmation notice from the Company noting their choice of supplier and that the RDS customer will have seven (7) calendar days from the date of the confirmation notice to contact the Company and rescind its selection, after which, if not rescinded, the RDS customer's TPS enrollment shall be accepted by the Company. TPS supply service will commence for all enrollments received by the 10th of a month, inclusive of those RDS customers that are not rescinded, on the customer's next month's cycle meter reading date. TPS shall indemnify and hold Company harmless from any costs incurred by Company as a result of TPS's erroneous or improper enrollment of Customers.

The Company must comply with all Customer instructions verbal or written to rescind or change service with a TPS. TPS must initiate all transactions required by the Company to rescind service on the day such instructions are received by the TPS from the Company or Customer. A Customer returning to sales service will be effective on the Customer's first billing cycle meter read date following the date on which the Company has changed the TPS's ADDQ requirement. A Customer will be switched to another TPS effective on the cycle read date following the reassignment of the Customer's ADDQ for gas nominations.

2. Requirements for RDS and Essential Gas Use Customers

Any TPS seeking to serve such Customers must demonstrate that it possesses Comparable Capacity or Standby in a quantity sufficient to serve Customers' Unadjusted ADDQ or DCQ requirements during the months of November through March.

"Comparable Capacity" is a firm non-recallable service at Elizabethtown's city gate(s). The Company reserves the right to limit the service to 70% on Transcontinental Gas Pipe Line Corporation's ("Transco") system and the remaining 30% on Texas Eastern Transmission Corporation's ("Tetco") system.

SERVICE CLASSIFICATION – THIRD PARTY SUPPLIERS (TPS) SERVICE
(continued)

SPECIAL PROVISIONS: (continued)

2. Requirements for RDS and Essential Gas Use Customers (continued)

In order to demonstrate Comparable Capacity, TPS shall be required to provide, at the time the Customer is enrolled, an affidavit signed by an officer stating that Comparable Capacity is being provided for the November through March period. This affidavit must be refiled annually. The Company reserves the right to request TPS to submit copies of its Comparable Capacity contracts supporting its affidavits in the event that a TPS fails to deliver.

3. Capacity Assignment

TPS serving RDS Customers may, if they choose, accept an assignment of base load, long haul interstate pipeline capacity from Company in a quantity equal to the amount of base load, long haul capacity used by the Company to serve the Customer's anticipated design day demand. 70% of such capacity will consist of capacity on Transcontinental Gas Pipe Line Corporation and 30% of such capacity will consist of capacity on Texas Eastern Transmission Corporation. Such capacity will be assigned for a one year term on a basis prorated to the underlying contracts at the same maximum rates paid by the Company. Such capacity will be immediately recallable in the event that TPS fails to deliver the RDS Customer's ADDQ or no longer serves such RDS Customers. A TPS wishing to accept assignment of Company's interstate pipeline capacity must notify Company at the time that Customer is enrolled in RDS service.

To the extent that TPS wishes to take assignment of interstate pipeline capacity in addition to its RDS Customer's portion of base load, long haul capacity, it shall notify the Company in writing. To the extent that the Company, in its sole discretion, determines that it has additional capacity available for release, it shall notify any TPSs that have advised the Company that they wish to take assignment of such capacity prior to making such capacity available to third parties. Company reserves the right to release any interstate pipeline capacity to the highest bidder or on a non-discriminatory basis. The Company shall be permitted to retain 15% of all revenues derived from the release of pipeline capacity, with all remaining revenue to be credited to the BGSS Charge.

To the extent that Company releases capacity to TPS, TPS is responsible for utilizing the assigned capacity consistent with the terms and conditions of the interstate pipelines' tariffs. TPS is responsible for payment of all upstream pipeline charges associated with the assigned firm transportation capacity, including but not limited to demand and commodity charges, shrinkage, GRI charges, cash outs, transition cost, pipeline overrun charges, penalties assessed to Company, actual cost adjustments and all other applicable charges. These charges will be billed directly to the TPS by Transco and Tetco.

SERVICE CLASSIFICATION – THIRD PARTY SUPPLIERS (TPS) SERVICE
(continued)

SPECIAL PROVISIONS: (continued)

3. Capacity Assignment (continued)

Capacity assignments will be effective for a one year period beginning on each annual period. Company reserves the right to recall capacity in the event and to the extent that TPS fails to deliver the sufficient volume to serve its customers on any day or days. Increases in assigned capacity will only be entertained by Company to become effective for annual periods.

If, and to the extent that, the TPS fails to deliver the required volume, and such failure is not excused as a result of a pipeline force majeure event that prevents the TPS from delivering the required volume, the TPS will be assessed an Unauthorized Use charge as specified in Section I, Item 18 for each therm that the TPS has failed to deliver and be subject to a recall of the interstate pipeline capacity that has been released by Company.

Assigned capacity may be reassigned by the TPS subject to recall by Company. The original TPS shall remain subject to all operational orders and recall provisions invoked or exercised by Company. If the TPS fails to pay any interstate pipeline for capacity released or assigned by Company, and Company is required to pay the pipeline for such capacity, TPS shall be liable to Company for any amounts Company is required to pay interstate pipeline for such capacity, as well as incidental and consequential damages and the costs of any reasonable collection efforts. Failure to pay Company within twenty (20) days of billing may result in suspension of service.

4. RDS Load Balancing Charge

A Load Balancing Charge of $0.0552 per therm, which includes sales tax, shall be billed to the TPS for all metered quantities for RDS customers it serves. Amounts due from TPS shall be paid in full within 20 days of the billing date. Any disputed amounts will be resolved by the TPS and Company and adjustments if any will be reflected on future billings. Failure to pay this charge in full within the time specified above will result in all RDS Customers of the TPS being returned to BGSS supply service.

5. Treatment of Revenues

All revenues produced under this Service Classification derived from penalties, imbalances and Load Balancing charges shall be credited to the BGSS.

RIDER "A"

BASIC GAS SUPPLY SERVICE CHARGE ("BGSS")

This Rider sets forth the method of determining the BGSS which shall be calculated to four (4) decimal places on a per therm basis established in accordance with the Board Order in Docket No. GX01050304 dated January 6, 2003. The BGSS charge is either BGSS-Monthly ("BGSS-M") or BGSS-Periodic ("BGSS-P") and will be applied to a Customer's Service Classification as follows:

1. The BGSS-M shall be applicable to all GDS, NGV, LVD, and EGF customers receiving gas supply from the Company effective on the first of each month as determined below.

2. The BGSS-P shall be applicable to all RDS, SGS, and GLS customers receiving gas supply from the Company.

The BGSS Charge, as defined herein, is designed to recover the cost to the Company of purchased gas or fuel used as a substitute for or supplemental to purchased gas including the cost of storing or transporting said gases or fuel, the cost of financial instruments employed to stabilize gas costs, other charges or credits as may result from the operation of other tariff provisions, and taxes and other similar charges in connection with the purchase and sale of gas.

BGSS per therm rates:

Effective Date	BGSS-M per therm	BGSS-P Per therm
December 1, 2020 *	$0.5088	$0.3783
January 1, 2021	$0.4620	$0.3783
February 1, 2021	$0.4940	$0.3783
March 1, 2021	$0.5042	$0.3783
April 1, 2021	$0.4750	$0.3783
May 1, 2021	$0.5120	$0.3783
June 1, 2021	$0.5184	$0.3783
July 1, 2021	$0.5874	$0.3783
August 1, 2021	$0.6340	$0.3783
September 1, 2021	$0.6695	$0.3783
October 1, 2021	$0.8299	$0.3783
November 1, 2021	$0.8692	$0.3783
December 1, 2021	$0.8022	$0.4798

* BGSS-M rate revised on January 14, 2021

Date of Issue: ~~November 29, 2021~~XXX1

Effective: Service Rendered on and after ~~December 1, 2021~~XXX2

Issued by: Christie McMullen, President
520 Green Lane
Union, New Jersey 07083

Filed Pursuant to Order of the Board of Public Utilities
Dated ~~January 6, 2003~~XXX3 in Docket No. ~~GX01050304~~XXX4 ~~and November 17, 2021 in Docket No.GR21060876~~

RIDER "A"

BASIC GAS SUPPLY SERVICE CHARGE ('"BGSS")
(continued)

I. The BGSS-P Commodity Charge shall be determined as follows:

The BGSS-P Commodity Charge shall consist of a Gas Cost Component (“GCC”), a Capacity Cost Component (“CCC”), a Prior Period Adjustment (“PPA”) and a Tax Factor (“TF”) as follows:

BGSS-P = (GCC-P + CCC-P + PPA-P) X (TF)

Where:

GCC-P rate per therm shall be sum of the weighted average price, including any applicable transaction costs, based on the projected monthly quantities to be utilized in the remaining period of the BGSS Year (“Period”), of the following categories of gas:

a) Flowing gas, which will be equal to the arithmetic average of (i) the weighted-average, based on monthly sales, of the remaining New York Mercantile Exchange (“NYMEX”) monthly prices for the Period as recorded on the close of trading for the forward contract month and (ii) the weighted average of the estimated Inside FERC prices for the respective locations where the Company purchases its gas for the remainder of the Period, as adjusted for the variable cost of transportation and fuel to the Company’s city gate delivery points;

b) Any gas supplies for the remainder of the Period whose price was previously set by hedges or other financial instruments, adjusted for the variable cost of transportation and fuel to the Company’s city gate delivery points;

c) The supplies of gas projected to be withdrawn from storage for the remainder of the Period, adjusted for the variable cost of transportation and fuel to the Company’s city gate delivery points.

CCC-P shall be established each year in the Company’s annual BGSS-P filing and shall consist of the Company’s total estimated annual fixed pipeline costs, fixed supplier costs, and fixed storage costs, divided by the Company’s projected annual BGSS firm gas sales.

RIDER "A"

BASIC GAS SUPPLY SERVICE CHARGE ("BGSS")
(continued)

PPA-P shall be the Company's actual cumulative (over) or under recovery of gas costs associated with the operation of the BGSS divided by the projected BGSS-P firm gas sales for the remainder of the Period. In the initial transition to the BGSS-P, the per therm rate derived from the Company's estimated BGSS under or (over) recovery balance at May 31, 2003 with applicable interest thereon divided by the Company's projected BGSS firm sales for the period ending May 31, 2004, shall be the PPA-P. The over under recovery of gas costs shall be the cost of gas, as previously defined, less:

1. Supplier or Pipeline refunds;
2. Gas cost recoveries from the implementation of the BGSS-P;
3. Gas cost recoveries from the implementation of the BGSS-M;
4. Other gas cost recoveries or credits to the BGSS derived from sales or services as set forth in the applicable service classifications of the tariff;
5. Interest on the cumulative (over) under recovery of cost from the preceding BGSS Year ending September 30 but only when the interest is a credit. Interest being calculated on the cumulative (over) under recovery for each month of the prior period on the average of the beginning and ending monthly balance at a rate equivalent to the Company's allowed overall rate of return.

TF shall be the factors to adjust the calculated rate for appropriate taxes and other similar charges.

The BGSS-P shall be in effect until changed by succeeding BGSS-P rate filings.

The Company shall have the discretion to implement up to two (2) self-implementing BGSS-P rate changes, one to be implemented December 1 and the other to be implemented February 1 upon written notice to the Staff of the Board of Public Utilities and the Division of Rate Counsel of the approximate amount of that increase based on current market conditions by the first of the month preceding the self-implementation dates, November 1 and January 1 respectively. Each requested rate change shall not be for an increase of greater than five percent (5%) of the average rate based on a typical 100 therm per month residential total bill. The notice shall contain the information necessary to derive the components of the BGSS-P as set forth above. The Public Notice for the annual filing shall include the specific rate change sought to be implemented on October 1, a paragraph indicating that the rate is subject to self-implementing rate changes on December 1 and February 1 subject to the aforementioned 5% cap and an estimate of the impact

RIDER "A"

BASIC GAS SUPPLY SERVICE CHARGE ("BGSS")
(continued)

from the two (2) possible five percent (5%) increases on a 100 therm residential bill. Upon establishing the initial BGSS-P, one self-implementing rate change to the BGSS-P for an increase not greater than five percent (5%) of the average rate based on a typical 100 therm per month residential total bill shall be permitted effective March 1, 2003 upon written notice made to the BPU and RC by February 1, 2003.

In accordance with the Board Order in Docket No. GX01050304 dated January 6, 2003 the Company shall have the discretion to return any over recovered balances to customers through a current bill credit or BGSS-P rate reduction upon five (5) days notice to the BPU and RC.

II. The BGSS-M Commodity Charge shall be determined as follows:

The BGSS-M Commodity Charge shall consist of a Gas Cost Component (“GCC”), a Capacity Cost Component (“CCC”), a Prior Period Adjustment (“PPA”) and a Tax Factor (“TF”) as follows:

BGSS-M = (GCC-M + CCC-M + PPA-M) X (TF)

Where:

GCC-M rate per therm shall be the arithmetic average of (i) the NYMEX Henry Hub gas contracts closing price for the last trading day prior to each respective month and (ii) the weighted-average of the estimated Inside FERC prices for the respective locations where purchases of gas for the ensuing month are projected to be made, as adjusted for the variable cost of fuel and transportation to the city gate delivery points of the Company.

CCC-M shall be the same as the CCC-P rate per therm as established each year in the Company’s annual BGSS-P filing.

PPA-M rate per therm in the initial transition to the BGSS-M shall be the estimated BGSS under or (over) recovery balance at May 31, 2003 with applicable interest thereon divided by the projected BGSS firm sales for the period ending May 31, 2004. This rate shall continue in effect on a monthly basis until the deferred balance, which initially shall be set equal to the PPA-M times the projected BGSS–M firm sales for the period ending May 31, 2004, becomes positive as an over recovery at which time the PPA-M shall cease to be a component of the BGSS-M starting in the subsequent month, and any over recovery in the deferred balance shall be credited to the BGSS-P.

TF shall be the factors to adjust the calculated rate for appropriate taxes and other similar charges.

RIDER "A"

BASIC GAS SUPPLY SERVICE CHARGE ("BGSS")
(continued)

The BGSS-M will be filed two (2) business days after the monthly close of the NYMEX Henry Hub gas contracts and shall be in effect for the entirety of the subsequent month and thereafter until changed by succeeding BGSS-M rate filings. The BGSS-M price shall be posted on the Company's WEB site within two (2) to four (4) days of the rate being filed with the BPU.

The Company shall make an annual BGSS filing on or before June 1 of each year. The filing shall provide for a review of the actual costs and recoveries for the previous period ending April 30 and projections of costs and recoveries through September 30. The filing shall also propose a new BGSS-P rate to be implemented on October 1. The proposed BGSS-P rate shall be based upon the projected cost of purchased gas and storage utilization to serve projected demand for gas service for the period October 1 through September 30 and an adjustment to recover or credit prior period under or over recovered gas costs as projected to exist on the preceding September 30. The Company shall provide the basis for its projected costs and the NYMEX projection of monthly gas prices for the projected period. In its annual filing the Company shall calculate the CCC-P component, as defined above, of the BGSS-P rate. Adjustments, if any, resulting from the Board's review of this filing shall be made following a Board Order.

The charges applicable under this Rider include provision for the New Jersey Sales and Use Tax, and when billed to customers exempt from this tax shall be reduced by the amount of such tax included therein.

RIDER "B"

WEATHER NORMALIZATION CLAUSE (“WNC”)

Applicable to all customers in service classifications RDS, SGS and GDS.

October 1, 2021 through May 31, 2022	$0.0171 per therm
June 1 through September 30 of any year	$0.0000 per therm

The charges applicable under this Rider include provision for the New Jersey Sales and Use Tax, and when billed to customers exempt from this tax shall be reduced by the amount of such tax included therein. In the winter months, October through May, a weather normalization charge shall be applied to the rate quoted in this Tariff under the service classifications shown above, except as may be otherwise provided for in the individual service classification. The weather normalization charge applied in each winter period shall be based on the differences between actual and normal weather during the preceding winter period.

METHOD OF DETERMINING WEATHER NORMALIZATION CHARGE:

The weather normalization charge shall be determined as follows:

I. Definition of Terms as Used Herein

1. Degree Days (DD) - the difference between 65°F and the twenty-four point average temperature for the day, as determined from the records of the National Oceanic and Atmospheric Administration (NOAA) at its weather observation station located at Newark International Airport, when such average falls below 65°F. A day is defined as a period corresponding with the Company's gas sendout day of 10 am to 10 am.

RIDER "B"

WEATHER NORMALIZATION CLAUSE ("WNC")
(continued)

METHOD OF DETERMINING WEATHER NORMALIZATION CHARGE: (continued)

I. Definition of Terms as Used Herein (continued)

2. Actual Calendar Month Degree Days - the accumulation of the actual Degree Days for each day of a calendar month.

3. Normal Calendar Month Degree Days - the level of calendar month degree days to which test year sales volumes were normalized in the base rate proceeding that established the current base rates for the service classifications to which this clause applies. The normal calendar month Degree Days used in this clause may be updated in base rate cases. The normal degree days for the defined winter months are as follows:

Month	Normal Degree Days	Leap Year Normal Degree Days
October	212 ~~244~~	212 ~~244~~
November	516 ~~516~~	516 ~~516~~
December	818 ~~828~~	818 ~~828~~
January	992 ~~998~~	992 ~~998~~
February.	834 ~~829~~	860 ~~854~~
March	693 ~~689~~	693 ~~680~~
April	340 ~~355~~	340 ~~344~~
May	52 ~~120~~	52 ~~117~~
Total	4,457 ~~4,579~~	4,483 ~~4,581~~

4. Winter Period - shall be the eight consecutive sales and calendar months from October of one calendar year through May of the following calendar year.

5. Degree Day Dead Band - shall be one-half (½%) percent of the monthly Normal Calendar Degree Days for the Winter Period.

RIDER "B"

WEATHER NORMALIZATION CLAUSE (“WNC”) (continued)

METHOD OF DETERMINING WEATHER NORMALIZATION CHARGE: (continued)

I. Definition of Terms as Used Herein (continued)

6. Degree Day Consumption Factor (“DDCF”) - the variable component (use per degree day) of the gas sendout for each month of the winter period normalized for weather and adjusted for lost and unaccounted for gas. The DDCF shall be updated annually in the Company’s WNC reconciliation filing annualizing to reflect the change in number of customers that has occurred since the base rate proceeding that established the initial degree day consumption factor in base rate cases. The base number of customers used to establish the normalized use in therms per Customer and the calculated DDCF approved in the Company’s most recent base rate case are as follows:

Month	Base Number of Customers	Therms per Degree Day
October	302,711 ~~293,159~~	52,236 ~~51,81~~
November	303,980 ~~293,834~~	62,979 ~~62,593~~
December	305,314 ~~294,633~~	69,375 ~~69,064~~
January	305,723 ~~295,059~~	68,394 ~~68,081~~
February	306,005 ~~295,322~~	66,058 ~~67,808~~
March	306,237 ~~295,477~~	63,969 ~~63,693~~
April	306,397 ~~295,126~~	52,626 ~~52,489~~
May	306,530 ~~294,483~~	54,279 ~~54,279~~

7. Margin Revenue Factor - the weighted average of the Distribution Charges as quoted in the individual service classes to which this clause applies net of applicable taxes and other similar charges and any other revenue charge not retained by the Company that these rates may contain in the future. The weighted average shall be determined by multiplying the margin revenue component of the Distribution Charges from each service class to which this clause applies by each class's percentage of total consumption of all the classes to which this clause applies for the winter period and summing this result for all the classes to which this clause applies. The Margin Revenue Factor shall be redetermined each time base rates or IIP rates are adjusted. The current Margin Revenue Factor is $~~0.3814~~0.5259 per therm pre taxes for purposes of calculating the weather-related portion of the CIP.

RIDER "B"

WEATHER NORMALIZATION CLAUSE (“WNC”)
(continued)

METHOD OF DETERMINING WEATHER NORMALIZATION CHARGE (continued)

I. Definition of Terms as Used Herein (continued)

8. Annual Period: shall be the 12 consecutive months from October 1 of one calendar year through September 30 of the following calendar year.

9. Average 13 month common equity balance: shall be the common equity balance at the beginning of the Annual Period (i.e. October 1) and the month ending balances for each of the twelve months in the Annual Period divided by thirteen (13).

II. Determination of the Weather Normalization Rate

At the end of the Winter Period during the Annual Period, a calculation shall be made that determines for all months of the Winter Period the level by which margin revenues differed from what would have resulted if normal weather (as determined by reference to the Degree Day Dead Band) occurred.

The monthly calculation is made by multiplying the Degree Day Consumption Factor by the difference between Normal Calendar Month Degree Days as adjusted for the monthly Degree Day Dead Band, and Actual Calendar Month Degree Days and, in turn, multiplying the result by the Margin Revenue Factor. To the extent the Actual Calendar Month Degree Days exceeds Normal Calendar Month Degree Days as adjusted for the Degree Day Dead Band, an excess of margin revenues exist. To the extent Actual Calendar Month Degree Days were less than Normal Calendar Month Degree Days as adjusted for the Degree Day Dead Band, a deficiency of marginal revenue exists. In addition, the weather normalization clause shall not operate to permit the Company to recover any portion of a margin revenue deficiency that will cause the Company to earn in excess of 9.6% for the Annual Period; any portion which is not recovered shall not be deferred. For purposes of this section, the Company's rate of return on common equity shall be calculated by dividing the Company's regulated jurisdictional net income for the Annual Period by the Company's average 13-month common equity balance for such Annual Period, all as reflected in the Company's monthly reports to the BPU. The Company's regulated jurisdictional net income shall be calculated by subtracting from total net income (1) margins retained by the Company from non-firm sales and transportation services, net of associated taxes, (2) margins retained in the provision of sales in accordance with the Board Order pertaining to Docket No. GR90121391J and GM90090949, net of associated taxes and (3) net income derived from unregulated activities conducted by Elizabethtown.

RIDER "B"

WEATHER NORMALIZATION CLAUSE ("WNC")
(continued)

METHOD OF DETERMINING WEATHER NORMALIZATION CHARGE (continued)

II. Determination of the Weather Normalization Rate (continued)

~~retained by the Company from non-firm sales and transportation services, net of associated taxes, (2) margins retained in the provision of sales in accordance with the Board Order pertaining to Docket No. GR90121391J and GM90090949, net of associated taxes and (3) net income derived from unregulated activities conducted by Elizabethtown.~~

The Company's average thirteen-month common equity balance for any Annual Period shall be the Company's average total common equity less the Company's average common equity investment in unregulated subsidiaries.

The balance of margin revenue excess or deficiency at September 30 of the Annual Period shall be divided by the estimated applicable sales from the classes subject to this clause for the Winter Period over which this charge will be in effect, multiplied by a factor to adjust for increases in taxes and other similar charges. The product of this calculation shall be the Weather Normalization Charge. However, the Weather Normalization Charge will at no time exceed three (3%) percent of the then applicable Residential Distribution Service rate plus the BGSS. To the extent that the effect of this rate cap precludes the Company from fully recovering the margin deficiency for the Annual Period, the unrecovered balance will be added to or subtracted from the margin deficiency or margin excess used to calculate the weather normalization charge for the next Winter Period. The Weather Normalization Charge, so calculated, will be in effect for the Winter Period immediately following the Annual Period used in such calculation.

III. Tracking the Operation of the Weather Normalization Clause

The revenues billed, or credits applied, net of taxes and other similar charges, through the application of the Weather Normalization Rate shall be accumulated for each month when this rate is in effect and applied against the margin revenue excess or deficiency from the immediately preceding Winter Period and any cumulative balances remaining from prior Winter Periods.

The annual filing for the adjustment to the weather normalization rate shall be concurrent with the annual filing for the Rider "D" Societal Benefits Charge.

RIDER "C"

ON-SYSTEM MARGIN SHARING CREDIT ("OSMC")

Applicable to all Firm Service Classifications that pay the BGSS of Rider A and RDS customers that receive gas supply from a TPS in accordance with the Board's Order in Docket No. GO99030122.

The OSMC is subject to change to reflect the Company's actual recovery of such margins and shall be adjusted annually in its BGSS filing.

($0.0021) per therm

The charges applicable under this Rider include provision for the New Jersey Sales and Use Tax, and when billed to customers exempt from this tax shall be reduced by the amount of such tax included therein.

Determination of the OSMC

On or about July 31 of each year, the Company shall file with the Board an OSMC rate filing based on the credits generated from on-system margin sharing during the previous OSMC year July 1 through June 30.

The OSMC shall be calculated by taking the current year's credits, plus the prior year's OSMC over or under recovery balance and dividing the resulting sum by the annual forecasted volumes for the service classifications set forth above. The resulting rate shall be adjusted for all applicable taxes and other similar charges.

RIDER "D"

SOCIETAL BENEFITS CHARGE ("SBC")

Applicable to all tariff Service Classifications except those Customers under special contracts that explicitly do not permit the Company to apply increased charges as filed and approved by the BPU and those customers exempted pursuant to the Long-Term Capacity Agreement Pilot Program ("LCAPP"), P.L. 2011, c.9, codified as N.J.S.A. 48:3-60.1. See the LCAPP Exemption Procedures at the end of this Rider.

The SBC is designed to recover the components listed below and any other new programs which the Board determines should be recovered through the Societal Benefits Charge.

	SBC Rate Components:		Per Therm
I.	~~New Jersey~~ Clean Energy Program ("CEP")		$0.0276
II.	Remediation Adjustment Charge ("RAC")		($0.0083)
III.	Universal Service Fund and Lifeline:		
	1. Universal Service Fund ("USF")		$0.0133
	2. Lifeline		$0.0057
		TOTAL	$0.0383

The charges applicable under this Rider include provision for the New Jersey Sales and Use Tax, and when billed to customers exempt from this tax shall be reduced by the amount of such tax included therein.

I. ~~New Jersey~~ Clean Energy Program Component ("CEP")

The Comprehensive Resource Analysis ("CRA") name was changed to the Clean Energy Program - CEP per Board Order dated January 22, 2003 in Docket No. EX99050347 *et.al*. The CEP is a mechanism that will (1) establish a rate to recover the costs of the Core and Standard Offer Programs in the Company's CEP Plan which was approved by the BPU" in Docket No. GE92020104, and (2) compensate the Company for the revenue erosion resulting from conservation savings created by the Standard Offer Program. The annual recovery period for the CEP is from October 1 through September 30. The CEP recovers program costs and revenue erosion incurred during the previous CEP year ended June 30.

1. CEP program costs include the costs of core programs, standard offer payments and any administrative costs not recovered directly from standard offer providers.

RIDER "D"

SOCIETAL BENEFITS CHARGE ("SBC")
(continued)

I. ~~New Jersey~~ Clean Energy Program Component ("CEP") (continued)

2. The Standard Offer Program will reduce the volumes of gas sold by the Company and will reduce revenues corresponding to volumes of gas saved. This revenue loss will occur because the rates set in the Company's base rate case do not reflect a decrease in revenues resulting from program measures which will be implemented during the period in which the Company's CEP Plan is in effect. Consequently, the Company will not recover those fixed costs in base rates corresponding to the volumes of gas saved by the Standard Offer Program.

3. The CEP rate shall be determined as follows:

(a) The Company will project all program costs not recoverable directly from standard offer providers and revenue erosion, based upon current, approved rates, both of which elements are not currently collected through base rates for the annual period ("current annual period").

(b) The Company will include with the above projection, a statement of the prior annual period of any (over-) or under-recoveries, including interest at the rate applicable to the RAC component of the SBC. This statement will include estimated data for those months that occur after the date of filing but which correspond to the prior annual period. The CEP may be adjusted for material differences between estimates and actual results in the prior annual period.

(c) The sum of the program costs and recoveries for the CEP year ending June 30 plus the projected spending for the succeeding twelve month period, including interest calculated at a rate equal to that applied to the RAC component of the SBC, will be divided by the estimated sales and transportation throughput to all Customers subject to the SBC during the succeeding October 1 through September 30 period.

The formula for calculating the CEP rate is as follows:

$$\frac{PC + RE + [RB *(1+i)]}{AV}$$

RIDER "D"

SOCIETAL BENEFITS CHARGE ("SBC")
(continued)

I. ~~New Jersey~~ Clean Energy Program Component ("CEP") (continued)

3. The CEP rate shall be determined as follows: (continued)

(c) where:

PC = all projected program costs not recoverable directly from standard offer providers

RE = cumulative annual margin revenue erosion from the date of effectiveness of the Plan until the time that new base rates take effect. Margin revenue erosion is determined by multiplying the actual measured annual decrease in firm sales attributable to implementation of certain CEP programs per Board Order EX99050347 *et.al.* and the DSM legacy standard offer programs by the net margin revenue associated with that decrease in each affected service classification.

RB = prior period recovery balance, the net of actual costs and recoveries.

i = interest rate applicable to recovery balance

AV = projected annual quantity for sales and transportation throughput to all Customers subject to the SBC.

4. There will be a reconciliation of over- or under-recovery of actual program costs not recovered directly from standard offer providers and revenue erosion, based upon approved rates in effect during the prior annual period, with the revenues collected through the CEP by maintaining an account showing the cumulative balance of the (over-) or under-recoveries. Any prior annual period balance will be included, with interest, along with current annual period projected costs and amortized over the current annual recovery period. Interest is calculated on the cumulative (over-) or under-recovery of the prior annual period on the average beginning and ending monthly balance at a rate equivalent to the rate applied to the RAC component of the SBC.

RIDER "D"

SOCIETAL BENEFITS CHARGE ("SBC")
(continued)

I. ~~New Jersey~~ Clean Energy Program Component ("CEP") (continued)

5. The annual filing for the adjustment on or about October 1 of each year shall be made on or about July 31 of each year and shall be based on actual figures and experiences then available with estimates of remaining requirements.

II. Remediation Adjustment Clause Component ("RAC")

The RAC is a mechanism that will establish a rate to recover remediation costs, as defined herein. On or about July 31 of each year, the Company shall file with the Board a RAC rate component as part of the SBC based on remediation costs and third party expenses/claims in the preceding remediation years.

The RAC will be determined as follows:

A. Definition of Terms Used Herein

1. Remediation Costs - all investigation, testing, land acquisition if appropriate, remediation and/or litigation costs/expenses or other liabilities excluding personal injury claims and specifically relating to former gas manufacturing facility sites, disposal sites, or sites to which material may have migrated, as a result of the earlier operation or decommissioning of gas manufacturing facilities.

2. Interest Rate - for carrying costs and deferred tax benefit calculation shall be the rate paid on seven year constant maturities treasuries as shown in the Federal Reserve Statistical Release on or closest to August 31st of each year plus 60 basis points.

3. Carrying Cost - the Interest Rate applied to the unamortized balance of remediation costs.

4. Recovery Year - each October 1 to September 30 year and is the time period over which the amortized expenses incurred during the Remediation Year shall be recovered from Customers.

5. Remediation Year - each July 1 to June 30 year and is the time period over which the Remediation Costs and recoveries are incurred.

RIDER "D"
SOCIETAL BENEFITS CHARGE ("SBC")
(continued)

II. Remediation Adjustment Clause Component (“RAC”)

A. Definition of Terms Used Herein (continued)

6. Third Party Claims - all claims brought by the Company against any entity, including insurance companies, from which recoveries may be received and will be charged through the RAC factor as follows:

a. Fifty percent of the reasonable transaction costs and expenses in pursuing Third Party Claims shall be included as Remediation Costs and shall be recovered as part of the RAC. The remaining 50% shall be deferred.

b. In the event that the Company is successful in obtaining a reimbursement from any Third Party, the Company shall be permitted to retain the deferred 50% as specified above. The balance of the reimbursement, if any, shall be applied against the Remediation Costs starting in the year it is received and will be amortized over seven years.

c. The Company is not required to account for transaction costs and expenses in pursuing third party claims on a claim-by-claim basis.

7. Deferred Tax Benefit (DTB) - the unamortized portion of actual remediation costs multiplied by the Company's effective statutory federal and state income tax rate, and the Interest Rate.

$DTB_{n,yr} = ARC_n * [(7-X)/7] * IR_{yr} * Tr_{yr}$

$DTB_{n,yr}$	=	Deferred Tax Benefit in recovery year (yr) to be subtracted from one seventh the amount of the remediation costs incurred in remediation year (n).
ARC_n	=	Actual Remediation Costs incurred in remediation year (n).
X	=	Number of years that the ARC incurred in year n have been subject to amortization (X = 1,2,3,4,5,6)
IR_{yr}	=	Interest Rate
TR_{yr}	=	Effective combined Federal and State income tax rate.

RIDER "D"

SOCIETAL BENEFITS CHARGE ("SBC")
(continued)

II. Remediation Adjustment Clause Component (“RAC”)

A. Definition of Terms Used Herein (continued)

8. Sale of Property shall be calculated by taking the proceeds over book value of any sale of a former manufacturing gas plant site, less all reasonable expenses associated with selling the site, and subtracting the total costs that were incurred in cleaning up the site and amortized through rates. The proceeds associated with the total costs that were incurred in cleaning up the site will be included as a credit to the remediation costs incurred in the year of the sale. The remainder shall be equally shared between the Company and Customers.

B. Determination of the Remediation Adjustment

At the end of the remediation year, the Company shall file with the Board (1) copies of all bills and receipts relating to the amount of any remediation costs incurred in the preceding remediation year(s) for which it seeks to begin recovery; (2) similar material and information to support any expenses and/or recoveries resulting from Third Party claims; (3) a computation of the carrying cost on the unamortized balance of remediation cost; (4) a projection of remediation costs for the following remediation year.

The RAC factor shall be calculated by taking one seventh of the Actual Remediation Costs, plus applicable Third Party Claims and Sale of Property allocations incurred each year, until fully amortized, less the Deferred Tax Benefit plus the prior years' RAC over or under-recovery plus appropriate carrying costs. This amount is then divided by all applicable forecasted quantities to all Service Classifications for the upcoming recovery year.

The total annual charge to the Company's ratepayers for remediation costs during any recovery year shall not exceed five (5%) percent of the Company's total revenues from sales, transportation and storage services during the preceding Remediation Year. If this limitation results in the Company recovering less than the amount that would otherwise be recovered in a particular Recovery Year then the Company will continue to accumulate carrying costs which will be recovered by the Company from its Customers in a subsequent RAC proceeding.

RIDER "D"

SOCIETAL BENEFITS CHARGE ("SBC")
(continued)

II. Remediation Adjustment Clause Component (“RAC”) (continued)

C. Tracking the Operation of the Remediation Adjustment Clause

The revenues billed, net of taxes and other similar charges through the application of the Remediation Adjustment factor shall be accumulated for each month and be applied against the total amortized Remediation Costs calculated for that year. Any over or under collection at the end of the Recovery Year will be included in the determination of the following year's RAC factor.

III. Universal Service Fund (“USF”) and Lifeline Components

An interim USF program was approved by the BPU in Docket No. EX00020091 dated November 21, 2001. A permanent USF program and Lifeline charge was approved by the BPU in Docket No. EX00020091 dated April 30, 2003. The Orders authorized the Company to collect costs associated with the program through the SBC. The USF and Lifeline rate components of the SBC will be determined as follows:

A. Definition of Terms

1. Program Costs includes all costs incurred in connection with the implementation of Board ordered services, inclusive of carrying costs.

2. Program Year is the period October 1 to September 30 as approved by the BPU in Docket No. EX00020091 dated June 22, 2005.

B. Determination of the USF and Lifeline Components

The USF and Lifeline Components will be determined and issued by the Board and shall remain in effect until changed. The USF true up between credits given customers and amounts recovered will be made annually in accordance with the Board’s directives.

RIDER "D"

SOCIETAL BENEFITS CHARGE ("SBC")
(continued)

III. Universal Service Fund ("USF") and Lifeline Components (continued)

C. Carrying Costs

Per Board Order dated October 21, 2008 in Docket No. ER08060455, the interest rate on USF under and over recoveries shall be the interest rate based on a two-year constant maturity Treasuries as published in the Federal Reserve Statistical Release on the first day of each month (or the closest day thereafter on which rates are published), plus sixty basis points, but shall not exceed the overall rate of return for each utility as authorized by the Board. The calculation shall be based on the net of tax beginning and end average monthly balance, accruing simple interest with an annual roll-in at the end of each reconciliation period.

IV. LCAPP Exemption Procedures

The following procedures to obtain the LCAPP exemption from the SBC charge shall apply:

A customer seeking an SBC rate exemption for all or part of its usage must submit an Annual Certification form, provided by the Company, declaring and certifying, for any applicable meter, the percentage of natural gas purchased and used for the generation of electricity sold for resale during the previous calendar year. For facilities with less than twelve months of history, estimates supported by engineering and operational plans may be used.

A. Annual Procedures

In December of each year the Company will mail an Annual Certification form to customers currently receiving the exemption, addressed to the customer's designated representative, to be returned to the Company's designated representative by the following January 15th.

The certified percentage will be used to determine the SBC rate to be charged for the twelve (12) month period beginning February 1st, for example:

RIDER "D"

SOCIETAL BENEFITS CHARGE ("SBC")
(continued)

IV. LCAPP Exemption Procedures (continued)

A. Annual Procedures (continued)

If the full SBC rate to be charged equaled $0.0400 per them pre tax and other similar charges and the certified percentage was seventy-five percent (75%) then the rate charged and applied to the metered volume would be calculated as: $0.0400 * (1.00 - .75) = $0.0100 per therm before any applicable taxes and other similar charges.

If the customer fails to return the form by January 15th then the full SBC rate will be assessed on all of the customer's natural gas usage until a completed Annual Certification form is received. Any exemption will become effective after the customer's next subsequent meter reading.

Notwithstanding the foregoing, the Company will provide customers that it reasonably believes may be eligible for the exemption with a certification form for the period of January 28, 2011 through January 31, 2012 on which the customer may certify the percentage of natural gas purchased and used for the generation of electricity sold for resale during the calendar year 2010. Any adjustments to the customer's bill associated with this exemption period shall be billed or credited to the customer in the billing period following the adjustment determination.

B. Interim Period Procedures

Customers may obtain the exemption at any time during a year by obtaining and submitting to the Company's designated representative a completed Annual Certification form. The certified percentage will be used to determine the exemption which will become effective after the next subsequent meter reading. Customers will be required to re-certify for the subsequent period beginning February 1 in accordance with the Annual Procedures.

RIDER "E"

ENERGY EFFICIENCY PROGRAM ("EEP")

Applicable to all Customers except those Customers under special contracts as filed and approved by the BPU and those customers exempted pursuant to the Long-Term Capacity Agreement Pilot Program ("LCAPP"), P.L. 2011 c.9, codified as N.J.S.A. 48:3-60.1. See the LCAPP Exemption Procedures at the end of the SBC, Rider "D."

The EEP shall be collected on a per therm basis and shall remain in effect until changed by order of the BPU. The applicable EEP rate is as follows:

Docket No. GR19070872, per a four-year amortization	$0.0062 per therm
Docket No. GO20090619, per a ten-year amortization	$0.0063 per therm
TOTAL	$0.0125 per therm

The rate applicable under this Rider includes provision for the New Jersey Sales and Use Tax, and when billed to customers exempt from this tax shall be reduced by the amount of such tax included therein.

In the "Global Warming Act," *N.J.S.A.*26-2C-45. or "RGGI Legislation" the State Legislature determined that global warming is a pervasive and dangerous threat that should be addressed through the establishment of a statewide greenhouse gas emissions reduction program. On May 8, 2008, the Board issued an Order (the "RGGI Order") pursuant to *N.J.S.A.* 48:3-98.1(c). The RGGI Order allowed electric and gas public utilities to offer energy efficiency and conservation programs on a regulated basis. The Company's energy efficiency programs were first authorized pursuant to Board orders issued in Docket Nos. EO09010056 and GO09010060. They were subsequently extended pursuant to Board orders issued in GO10070446, GO11070399, GO12100946, GO15050504, GR16070618 and GO18070682. The Company's current energy efficiency programs are effective through June 30, 2024. On May 23, 2018, the Clean Energy Act of 2018 ("CEA" or the "Act") was signed into law. The BPU directed utilities to file changes pursuant to Board orders issued in Docket Nos. QO1901040, QO19060748 and QO17091004 Dated June 10, 2020, ("the 2020 Orders").The EEP enables the Company to recover all costs associated with energy efficiency programs approved by the Board.

RIDER "E"

ENERGY EFFICIENCY PROGRAM ("EEP")
(continued)

Determination of the EEP

On or about July 31 of each year, the Company shall file with the Board an EEP rate filing based on the Board's August 21, 2013 Order in Docket No. GO12100946 and one based on the 2020 Orders for the costs and recoveries incurred during the previous EEP year ending June 30th as well as estimates, if applicable, through the upcoming calendar year to develop the total EEP rate to be effective October 1st as follows:

The EEP monthly recoverable expenditure amounts shall be derived from taking the average of the cumulative beginning and end of month expenditures associated with the EEP investments less accumulated amortization and accumulated deferred income tax credits times the after tax weighted average cost of capital grossed up for the Company's revenue factor, as directed in the Board's August 21, 2013 Order in Docket No. GO12100946, plus monthly amortization using a four year amortization period. Costs recoveries incurred under this and previous Dockets will continue until near zero and then be subsumed in the filings made under the 2020 Orders. The 2020 Orders monthly amortization will be a ten (10) year amortization period. The 2020 Orders also include a customer loan component that will earn a monthly rate of return recovery derived from taking the average of the cumulative beginning and end of month balances associated with the loan investments times the pre-tax rate of return grossed up using a revenue factor after removing the Federal and State corporate business tax. Any changes in the above authorized by the Board in a subsequent base rate case will be reflected in the subsequent monthly calculations.

The EEP rate shall be calculated by summing the (i) prior year's EEP over or under recovery balance, plus (ii) current year monthly recoverable expenditure amounts, inclusive of amounts any customer fails to repay for their portion of costs associated with installed measures less any subsequent payments received for such measures, less (iii) current year recoveries, plus (iv) current year carrying costs based on the monthly average over or under recovered balances, at a rate equal to the weighted average of the Company's monthly commercial paper rate or interest rate on its bank credit lines. In the event that commercial paper or bank credit lines were not utilized by the Company in the preceding month, the last calculated rate shall be used. Until such time when ETG has a commercial paper program, the Company will adjust its short-term debt rate to reflect the commercial paper rate proxy reduction of 1.64%. The interest on monthly EEP Rider rate under and over recoveries shall be determined by applying the interest rate based on the Company's weighted interest rate for the corresponding month obtained on its commercial paper and bank credit lines, but shall not exceed the Company's after tax weighted average cost of capital utilized to set rates in its most recent base rate case or as authorized in Elizabethtown's subsequent base rate cases, plus (v) an estimated amount to recover the upcoming year's recoverable expenditures amount and dividing the resulting sum by the annual forecasted per therm quantities for the applicable Customers set forth above. The resulting rate shall be adjusted for all applicable taxes. The EEP rate shall be self-implementing on a refundable basis as directed by the BPU.

Dated ~~April 7, 2021~~XXX3 in Docket ~~Nos.~~No. ~~QO19010040 and GO20090619~~XXX4

ELIZABETHTOWN GAS COMPANY
B. P. U. NO. ~~17 – GAS~~18 – GAS ~~1st REVISED SHEET NO. 125.1~~ORIGINAL SHEET NO. 126

RIDER "F"

INFRASTRUCTURE INVESTMENT PROGRAM ("IIP")

Applicable to all RDS, SGS, GDS, NGV, LVD, EGF and GLS classes and Firm Special Contract customers receiving service through the Company's distribution system. The IIP rate shall be collected on a per therm basis and shall remain in effect until changed by order of the NJBPU.

		Per Therm
RDS	Residential	$~~0.0427~~0.0000
SGS	Small General Service	$~~0.0471~~0.0000
GDS	General Delivery Service	$~~0.0280~~0.0000
GDS	Seasonal SP#1 May-Oct	$~~0.0154~~0.0000
NGV	Natural Gas Vehicles	$~~0.0761~~0.0000
LVD	Large Volume Demand	$~~0.0134~~0.0000
EGF	Electric Generation	$~~0.0088~~0.0000
GLS	Gas Lights	$~~0.0395~~0.0000
	Firm Special Contracts	$~~0.0022~~0.0000

The charges applicable under this Rider include provision for the New Jersey Sales and Use Tax, and when billed to customers exempt from this tax shall be reduced by the amount of such tax included therein.

The IIP is a five-year program to modernize and enhance the reliability and safety of the Company's gas distribution system by replacing its vintage, at-risk facilities which include aging cast iron mains, unprotected and bare steel mains and services, ductile iron and vintage plastic mains and vintage plastic and copper services. As part of the IIP, Elizabethtown is upgrading its legacy low pressure system to an elevated pressure system, and installing excess flow valves and retiring district regulators that are presently required to operate the existing low pressure system. The costs recovered through the IIP Rider rate include the Company's after-tax weighted average cost of capital as adjusted upward for the revenue expansion factor, depreciation expense and applicable taxes.

Date of Issue: ~~September 22, 2021~~XXX1

Effective: Service Rendered on and after ~~October 1, 2021~~XXX2

Issued by: Christie McMullen, President
520 Green Lane
Union, New Jersey 07083

Filed Pursuant to Order of the Board of Public Utilities

Dated ~~September 14, 2021~~XXX3 in Docket No. ~~GR21040747~~XXX4

ELIZABETHTOWN GAS COMPANY
B. P. U. NO. ~~17 – GAS~~18 – GAS ORIGINAL SHEET ~~NO. 125.2~~NO. 127

RIDER "G"

CONSERVATION INCENTIVE PROGRAM ("CIP")

Applicable to all Customers served under RDS, SGS and GDS rate classes.

The CIP shall be collected on a per therm basis and shall remain in effect until changed by order of the BPU. The applicable CIP rates are as follows:

RDS Non-Heat	RDS Heat	SGS	GDS
$0.0000 per therm	$0.0000 per therm	$0.0000 per therm	$0.0000 per therm

The rates applicable under this Rider include provision for the New Jersey Sales and Use Tax, and when billed to customers exempt from this tax shall be reduced by the amount of such tax included therein.

The annual filing for the adjustment to the CIP rate shall be concurrent with the annual filing for BGSS. The CIP factor shall be credited/collected on a per therm basis for the service classifications stated above. The level of BGSS savings referenced in (d) in this Rider shall be identified in the annual CIP filing, and serve as an offset to the non-weather related portion of the CIP charge provided in (f) in this Rider. The Periodic and Monthly BGSS rates identified in Rider "A" to this tariff shall include the BGSS savings, as applicable.

(a) This Rider shall be utilized to adjust the Company's revenues in cases wherein the Actual Usage per Customer experienced during Monthly Periods varies from the Baseline Usage per Customer ("BUC"). This adjustment will be effectuated through a credit or surcharge applied to customers' bills during the Adjustment Period. The credit or surcharge will also be adjusted to reflect prior year under recoveries or over recoveries pursuant to this CIP.

Date of Issue: ~~June 21, 2021~~XXX1

Effective: Service Rendered on and after ~~July 1, 2021~~XXX2

Issued by: Christie McMullen, President
520 Green Lane
Union, New Jersey 07083

Filed Pursuant to Order of the Board of Public Utilities
Dated ~~April 7, 2021~~XXX3 in Docket ~~Nos.~~No. ~~QO19010040 and GO20090619~~XXX4

RIDER "G"

CONSERVATION INCENTIVE PROGRAM ("CIP")
(continued)

(b) The BUC in therms for each Customer Class Group by month is as follows:

Month	RDS Non-Heat	RDS Heat	SGS	GDS
July	9.2	19.8 ~~14.1~~	23.8 ~~17.5~~	511.0 ~~526.5~~
August	8.4	18.6 ~~14.1~~	23.9 ~~18.0~~	512.3 ~~531.2~~
September	9.3	22.0 ~~15.1~~	23.9 ~~23.3~~	512.7 ~~602.0~~
October	14.0	45.2 ~~39.0~~	60.5 ~~54.5~~	980.5 ~~1,143.8~~
November	25.1	109.9 ~~85.4~~	122.9 ~~117.0~~	1,767.1 ~~1,801.4~~
December	32.8	161.7 ~~140.2~~	230.0 ~~217.5~~	2,524.8 ~~2,670.3~~
January	41.0	193.3 ~~174.8~~	304.4 ~~277.7~~	3,109.8 ~~3,201.7~~
February	35.6	158.1 ~~149.6~~	270.5 ~~231.4~~	2,804.6 ~~2,700.7~~
March	21.6	127.7 ~~118.5~~	176.7 ~~164.0~~	2,048.1 ~~2,198.0~~
April	13.5	63.6 ~~57.9~~	84.9 ~~71.3~~	1,075.1 ~~1,292.9~~
May	11.8	31.8 ~~22.5~~	28.5 ~~31.8~~	508.6 ~~781.5~~
June	10.7	22.4 ~~12.8~~	23.6 ~~19.7~~	561.1 ~~514.5~~
Total Annual	233.0	974.1 ~~844.0~~	1,373.6 ~~1,243.7~~	16,915.7 ~~17,964.5~~

The BUC shall be reset each time new base rates are placed into effect as the result of a base rate case proceeding.

(c) At the end of the Annual Period, a calculation shall be made that determines for each Customer Class Group the deficiency ("Deficiency") or excess ("Excess") to be surcharged or credited to customers pursuant to the CIP mechanism. The Deficiency or Excess shall be calculated each month by multiplying the result obtained from subtracting the Baseline Usage per Customer from the Actual Usage per Customer by the actual number of customers, and then multiplying the resulting therms by the Margin Revenue Factor.

RIDER "G"

CONSERVATION INCENTIVE PROGRAM ("CIP")
(continued)

(d) Recovery of any Deficiency in accordance with Paragraph (c), above, associated with non-weather-related changes in customer usage will be limited to the level of BGSS savings achieved pursuant to Board orders issued in Docket Nos. QO1901040, QO19060748 and QO17091004 Dated June 10, 2020.The value of the weather-related changes in customer usage shall be calculated in accordance with WNC Rider of this tariff without a dead band which result shall be allocated to applicable classes by the Company.

(e) Except as limited by Paragraph (d), above, the amount to be surcharged or credited to the Customer Class Group shall equal the aggregate Deficiency or Excess for all months during the Annual Period determined in accordance with the provisions herein, divided by the Forecast Annual Usage ("FAU") for the Customer Class Group.

(f) The CIP shall not operate to cause the Company to earn in excess of its allowed rate of return on common equity of 9.6% for any twelve-month period ending June 30; any revenue which is not recovered will not be deferred. For purposes of this paragraph the Company's rate of return on common equity shall be calculated by dividing the Company's net income for such annual period by the Company's average 13 month common equity balance for such annual period, all data as reflected in the Company's monthly reports to the Board of Public Utilities. The Company's regulated jurisdictional net income shall be calculated by subtracting from total net income (1) margins retained by the Company from non-firm sales and transportation services, net of associated taxes, (2) margins retained in the provision of sales in accordance with the Board Order pertaining to Docket No. GR90121391J and GM90090949, net of associated taxes and (3) net income derived from unregulated activities conducted by Elizabethtown and (4) the Energy Efficiency Program and (5) the Infrastructure Investment Program.

RIDER "G"

CONSERVATION INCENTIVE PROGRAM ("CIP")
(continued)

(g) As used in this Rider, the following terms shall have the meanings ascribed to them herein:

(i) Actual Number of Customers ("ANC") – shall be determined on a monthly basis for each of the Customer Class Groups to which the CIP Clause applies, plus any Incremental Large Customer Count Adjustment for the Customer Class Group.

(ii) Actual Usage per Customer ("AUC") – shall be determined in therms on a monthly basis for each of the Customer Class Groups to which the CIP applies. The AUC shall equal the aggregate actual booked sales for the month as recorded on the Company's books divided by the Actual Number of Customers for the corresponding month.

(iii) Adjustment Period – shall be the calendar year beginning immediately following the conclusion of the Annual Period.

(iv) Annual Period – shall be the twelve consecutive months from July 1 of one calendar year through June 30 of the following calendar year.

(v) Baseline Usage per Customer ("BUC") – shall be the average normalized consumption per customer by month derived from the Company's most recent base rate case and stated in therms on a monthly basis for each Customer Class Group to which the CIP applies. The BUC shall be rounded to the nearest one tenth of one therm.

(vi) Customer Class Group – For purposes of determining and applying the CIP, customers shall be aggregated into three separate recovery class groups, RDS, SGS and GDS.

(vii) Forecast Annual Usage ("FAU") – shall be the projected total annual throughput for all customers within the applicable Customer Class Group. The FAU shall be estimated on normal weather.

RIDER "G"

CONSERVATION INCENTIVE PROGRAM ("CIP")
(continued)

(viii) Incremental Large Customer Count Adjustment – the Company shall maintain a list of incremental commercial and industrial customers added to its system on or after May 31, 2020 whose connected load is greater than that typical for the Company's average commercial and industrial customer in the GDS rate schedule. For purposes of the CIP, large incremental customers shall be those GDS customers whose connected load exceeds 5,400 cubic feet per hour ("CFH"). A new customer at an existing location previously connected to the Company's facilities shall not be considered an incremental customer. The Actual Number of Customers for the Customer Class Group shall be adjusted to reflect the impact of all such incremental commercial or industrial customers. Specifically, the Incremental Large Customer Count Adjustment for the GDS customer class for the applicable month shall equal the aggregate connected load for all new active customers that exceed the 5,400 CFH threshold divided by 2,700 CFH,~~.~~ rounded to the nearest whole number.

(ix) Margin Revenue Factor – the Margin Revenue Factor ("MRF") for the CIP shall be each class's Distribution Charge and applicable IIP rate on a pre-tax basis.

~~RATE SUMMARIES~~

~~Per Therm~~

		~~RDS (sales)~~	~~RDS (transportation)~~
~~Service Charge~~		~~10.00~~	~~10.00~~
~~Distribution Charges~~		~~0.4382~~	~~0.4382~~
~~Riders:~~			
~~A~~	~~BGSS~~	~~BGSS-P~~	~~per TPS~~
~~B~~	~~WNC*~~	~~WNC*~~	~~WNC*~~
~~C~~	~~OSMC~~	~~(0.0021)~~	~~(0.0021)~~
~~D~~	~~SBC~~	~~0.0383~~	~~0.0383~~
~~E~~	~~EEP~~	~~0.0125~~	~~0.0125~~
~~F~~	~~IIP~~	~~IIP~~	~~IIP~~
~~G~~	~~CIP~~	~~CIP~~	~~CIP~~

~~* The WNC will apply to Customers during the months as stated in Rider B.~~

~~Rates shown include taxes if applicable; rates that are tax exempt are noted "exempt."~~

~~RATE SUMMARIES~~
~~(continued)~~

~~Per Therm~~

		SGS (sales)	SGS (transportation)[1]
~~Service Charge~~		~~27.01~~	~~27.01~~
~~Distribution Charges~~		~~0.3807~~	~~0.3807~~
~~Riders:~~			
~~A~~	~~BGSS~~	~~BGSS-P~~	~~Per TPS~~
~~B~~	~~WNC~~	~~WNC*~~	~~WNC*~~
~~C~~	~~OSMC~~	~~(0.0021)~~	~~na~~
~~D~~	~~SBC~~	~~0.0383~~	~~0.0383~~
~~E~~	~~EEP~~	~~0.0125~~	~~0.0125~~
~~F~~	~~IIP~~	~~IIP~~	~~IIP~~
~~G~~	~~CIP~~	~~CIP~~	~~CIP~~

~~[1] Balancing Charge of $0.0171 per therm applies to Customers November to March with a DCQ under 500 therms.~~

~~* The WNC will apply to Customers during the months as stated in Rider B.~~

~~Rates shown include taxes if applicable; rates that are tax exempt are noted "exempt."~~

~~" na " rider not applicable~~

~~RATE SUMMARIES~~
~~(continued)~~

~~Per Therm~~	~~GDS (sales)~~	~~GDS (transportation)[1]~~	~~GDS SP #1 May – October~~
~~Service Charge~~	~~37.50~~	~~37.50~~	~~37.50~~
~~Demand Charge, per DCQ~~	~~0.960~~	~~0.960~~	~~0.960~~
~~Distribution Charges~~	~~0.2301~~	~~0.2301~~	~~0.0589~~
~~Riders:~~			
~~A Commodity Charge~~	~~BGSS-M~~	~~per TPS~~	~~BGSS-M~~
~~B WNC~~	~~WNC*~~	~~WNC*~~	~~na~~
~~C OSMC~~	~~(0.0021)~~	~~na~~	~~na~~
~~D SBC~~	~~0.0383~~	~~0.0383~~	~~0.0383~~
~~E EEP~~	~~0.0125~~	~~0.0125~~	~~0. 0125~~
~~F IIP~~	~~IIP~~	~~IIP~~	~~IIP~~
~~G CIP~~	~~CIP~~	~~CIP~~	~~CIP~~

~~[1] Balancing Charge of $0.0171 per therm applies to Customers November to March with a DCQ under 500 therms.~~

~~*The WNC will apply to Customers during the months as stated in Rider B.~~

~~Rates shown include taxes if applicable; rates that are tax exempt are noted "exempt."~~

~~" na " rider not applicable~~

~~Date of Issue: November 30, 2021~~ ~~Effective: Service Rendered on and after December 1, 2021~~

~~Issued by: Christie McMullen, President~~
~~520 Green Lane~~
~~Union, New Jersey 07083~~

~~Filed Pursuant to Order of the Board of Public Utilities~~
~~Dated November 17, 2021 in Docket No. GR21071018~~

~~RATE SUMMARIES~~
~~(continued)~~

~~Per Therm~~

	~~LVD (exempt)~~	~~LVD (taxable)~~
~~Service Charge~~	~~304.81~~	~~325.00~~
~~Demand Charge, per DCQ~~	~~1.250~~	~~1.333~~
~~Distribution Charges~~	~~0.0400~~	~~0.0427~~
~~Riders:~~		
~~A BGSS *~~	~~BGSS-M~~	~~BGSS-M~~
~~B WNC~~	~~na~~	~~na~~
~~C OSMC *~~	~~(0.0020)~~	~~(0.0021)~~
~~D SBC~~	~~0.0359~~	~~0.0383~~
~~E EEP~~	~~0.0117~~	~~0.0125~~
~~F IIP~~	~~IIP~~	~~IIP~~

~~Rates shown include taxes if applicable; rates that are tax exempt are noted "exempt."~~

~~" na " rider not applicable~~

~~* Not applicable to Customer receiving gas supply from a TPS~~

~~RATE SUMMARIES~~
~~(continued)~~

~~Per Therm~~		~~IS~~	~~ITS Exempt~~	~~ITS taxable~~
		~~(ceiling)~~	~~(ceiling)~~	~~(ceiling)~~
~~Service Charge~~		~~628.55~~	~~589.50~~	~~628.55~~
~~Demand Charge, per DCQ~~		~~0.098~~	~~0.400~~	~~0.427~~
~~Distribution Charges~~		~~0.9405~~	~~0.0926~~	~~0.0987~~
~~Riders:~~				
~~A~~	~~Commodity Charge~~	~~BGSS-M~~	~~per TPS~~	~~per TPS~~
~~B~~	~~WNC~~	~~na~~	~~na~~	~~na~~
~~C~~	~~OSMC~~	~~na~~	~~na~~	~~na~~
~~D~~	~~SBC~~	~~0.0383~~	~~0.0359~~	~~0.0383~~
~~E~~	~~EEP~~	~~0.0125~~	~~0.0017~~	~~0.0125~~
~~F~~	~~IIP~~	~~na~~	~~na~~	~~na~~

~~Rates shown include taxes if applicable; rates that are tax exempt are noted "exempt."~~

~~" na " rider not applicable~~

~~RATE SUMMARIES~~
~~(continued)~~

~~Per Therm~~	~~EGF (exempt)~~	~~EGF (taxable)~~
~~Service Charge~~	~~70.34~~	~~75.00~~
~~Demand Charge, per DCQ~~	~~0.600~~	~~0.640~~
~~Distribution Charges~~	~~0.0395~~	~~0.0421~~
~~Riders:~~		
~~A BGSS~~	~~BGSS-M~~	~~BGSS-M~~
~~B WNC~~	~~na~~	~~na~~
~~C OSMC~~	~~(0.0020)~~	~~(0.0021)~~
~~D SBC~~	~~0.0359~~	~~0.0383~~
~~E EEP~~	~~0.0117~~	~~0.0125~~
~~F IIP~~	~~IIP~~	~~IIP~~

~~Rates shown include taxes if applicable; rates that are tax exempt are noted "exempt."~~

~~" na " rider not applicable~~

~~Date of Issue: November 30, 2021~~ ~~Effective: Service Rendered on and after December 1, 2021~~

~~Issued by: Christie McMullen, President~~
~~520 Green Lane~~
~~Union, New Jersey 07083~~

~~Filed Pursuant to Order of the Board of Public Utilities~~
~~Dated November 17, 2021 in Docket No. GR21071018~~

RATE SUMMARIES

Rates per therm except for the Service Charge

	RDS Non-Heat	RDS Heat	SGS	GDS
Service Charge (monthly)	$13.27	$13.27	$36.79	$61.84
Distribution	$0.6424	$0.6424	$0.5596	$0.3682
Demand	na	na	na	$1.162
Riders				
A - BGSS	$0.4798	$0.4798	$0.4798	BGSS-M
B - WNC	$0.0171	$0.0171	$0.0171	$0.0171
C - OSMC	($0.0021)	($0.0021)	($0.0021)	($0.0021)
D - SBC	$0.0383	$0.0383	$0.0383	$0.0383
E - EEP	$0.0125	$0.0125	$0.0125	$0.0125
F - IIP	$0.0000	$0.0000	$0.0000	$0.0000
G - CIP	$0.0000	$0.0000	$0.0000	$0.0000

-The BGSS rate is only applicable to gas supplied by the Company. TPS customers are billed for gas supply at the contract gas supply rate as agreed with the TPS.

-For SGS customers and GDS customers with a DCQ under 500 therms, a Balancing Charge of $0.0171 and related to TPS is applicable from November to March.

-The WNC rate is applicable between the months of October and May.

-“na” indicates a rate is not applicable for the specific rate class.

-Rates above include taxes; tax exempt customers’ rates will be adjusted at the time of billing.

Filed Pursuant to Order of the Board of Public Utilities
Dated XXX3 in Docket No. XXX4

ELIZABETHTOWN GAS COMPANY
B. P. U. NO. 18 – GAS ORIGINAL SHEET NO. 133

RATE SUMMARIES
(continued)
Rates per therm except for the Service Charge

	LVD	EGF	IS	ITS
Service Charge (monthly)	$405.18	$101.29	$735.71	$735.71
			(ceiling)	(ceiling)
Distribution	$0.0655	$0.0421	$0.0843	$0.1391
Demand	$1.866	$0.800	$0.269	$0.533
Riders				
A - BGSS	BGSS-M	BGSS-M	BGSS-M	TPS only
B - WNC	na	na	na	na
C - OSMC	($0.0021)	($0.0021)	na	na
D - SBC	$0.0383	$0.0383	$0.0383	$0.0383
E - EEP	$0.0125	$0.0125	$0.0125	$0.0125
F - IIP	$0.0000	$0.0000	na	na
G - CIP	na	$0.0000	na	na

-The BGSS rate is only applicable to gas supplied by the Company. TPS customers are billed for gas supply at the contract gas supply rate as agreed with the TPS.

-“na” indicates a rate is not applicable for the specific rate class.

-Rates above include taxes; tax exempt customers’ rates will be adjusted at the time of billing.

Date of Issue: XXX1

Effective: Service Rendered
on and after XXX2

Issued by: Christie McMullen, President
520 Green Lane
Union, New Jersey 07083

Filed Pursuant to Order of the Board of Public Utilities
Dated XXX3 in Docket No. XXX4

IN THE MATTER OF THE PETITION OF ELIZABETHTOWN GAS COMPANY FOR APPROVAL OF INCREASED BASE TARIFF RATES AND CHARGES FOR GAS SERVICE, CHANGES TO DEPRECIATION RATES AND OTHER TARIFF REVISIONS

BPU DOCKET NO. GR21__________

DIRECT TESTIMONY

OF

MICHAEL P. SCACIFERO

Director of Engineering Services

On Behalf Of
Elizabethtown Gas Company

Exhibit P-4

December 28, 2021

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Exhibit P-4

ELIZABETHTOWN GAS COMPANY
DIRECT TESTIMONY OF
MICHAEL P. SCACIFERO

I. INTRODUCTION

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

A. My name is Michael P. Scacifero and I am the Director of Engineering Services for Elizabethtown Gas Company ("Elizabethtown" or "Company"). My business address is 520 Green Lane, Union, New Jersey 07083.

Q. PLEASE DESCRIBE YOUR PROFESSIONAL RESPONSIBILITIES.

A. As Director of Engineering Services for Elizabethtown, I oversee engineering and system planning design and budgeting for all of Elizabethtown's distribution system improvements, renewals, pressure improvements, New Jersey Department of Transportation ("DOT") projects, and large new business projects. I am responsible for conducting system modeling and analysis and providing engineering support to Field Operations and Construction Operations. I am also involved with the development of Elizabethtown's capital budget and I am familiar with its components.

Q. WHAT ARE YOUR PROFESSIONAL AND EDUCATIONAL QUALIFICATIONS?

A. I received a B.S. in Civil Engineering from the New Jersey Institute of Technology in 1988. I am a Licensed Professional Engineer in the State of New Jersey. I have been employed by Elizabethtown for 30 years in Engineering and Operations. Two of those years were spent as a Project Engineer, five years as a Division Engineer, and the remaining 23 years as Manager of Engineering, Manager of Operations and, currently, Director of Engineering Services. Prior to joining Elizabethtown, I was a Project Engineer for four years with Johnson Engineering Inc., specializing in highway and infrastructure design. Prior to that, I was employed for three years by the Township of Warren, New Jersey as a Staff Engineer specializing in municipal engineering. I am a member of the National Society of Professional Engineers, the American Gas Association, and the New Jersey Utilities Association.

Q. HAVE YOU PREVIOUSLY TESTIFIED BEFORE THE NEW JERSEY BOARD OF PUBLIC UTILITIES ("BPU")?

A. Yes, I have submitted testimony on behalf of Elizabethtown in several proceedings, including the Company's 2016 Base Rate Case[1] and 2019 Base Rate Case[2]), several proceedings involving Elizabethtown's accelerated infrastructure proceedings, including the Company's ENDURE and AIR Programs (BPU Docket Nos. GO13090826, GR15060656 and GO12090693) and in Elizabethtown's Infrastructure Investment Program ("IIP") proceeding in BPU Docket Nos. GR18101197, GR20050327 and GR21040747.

II. PURPOSE OF TESTIMONY

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

A. My testimony in this case will address the recovery of capital expenditures incurred since the Company's 2019 Base Rate Case. Specifically, I will provide a summary of Elizabethtown's capital expenditures for the twelve-month test year period ending March 31, 2022 and the six-month post-test year period from April 1, 2022 through September 30, 2022, as well as a description of the categories of expenditures that comprise the capital

[1] *In the Matter of the Petition of Pivotal Utility Holdings, Inc. D/B/A Elizabethtown Gas for Approval of Increased Base Tariff Rates and Charges for Gas Service and Other Tariff Revisions,* Docket No. GR16090826, "Decision and Order Approving Initial Decision and Stipulation" (June 30, 2017) ("2016 Base Rate Case").

[2] *In the Matter of the Petition of Elizabethtown Gas Company for Approval of Increased Base Tariff Rates and Charges for Gas Service, Changes to Depreciation Rates, and Other Tariff Revisions*, Docket No. GR19040486, "Decision and Order Approving Initial Decision and Stipulation" (November 13, 2019) ("2019 Base Rate Case").

expenditures forecast. I will also discuss the Company's progress under its current IIP. Finally, I will discuss certain elements of the major capital projects that will be placed in service during the post-test year period.

Q. DO YOU SPONSOR ANY SCHEDULES AS PART OF YOUR DIRECT TESTIMONY?

A. Yes. I am sponsoring the following schedules, supporting the Company's capital expenditures utilized in rate base, which were prepared by me or under my supervision or direction:

- Schedule MPS-1 – Utility Plant in Service ("UPIS")
- Schedule MPS-2 – Test Year Plant Additions;
- Schedule MPS-3 – Post-Test Year Plant Additions; and
- Schedule MPS-4 – Major Capital Projects.

This information will be updated over the course of the proceeding to include actual data for the full twelve-month test year period ending March 31, 2022.

III. <u>OVERVIEW OF THE COMPANY'S DISTRIBUTION SYSTEM</u>

Q. PLEASE PROVIDE A BRIEF OVERVIEW OF ELIZABETHTOWN'S DISTRIBUTION SYSTEM.

A. Elizabethtown provides natural gas service to approximately 303,000 residential, business and industrial customers in seven counties in two areas of New Jersey: the Union and Northwest Divisions. The Union Division, which encompasses the eastern portion of Elizabethtown's service territory, consists of 131 square miles and covers portions of Union and Middlesex Counties. The Union Division is a relatively mature service area where the majority of Elizabethtown's capital expenditures are made to replace and upgrade aging infrastructure. The Northwest Division, which encompasses the northwest portion of the Company's service territory, consists of 1,373 square miles and covers portions of Sussex, Warren, Hunterdon, Mercer and Morris counties. The Northwest Division contains relatively newer facilities and therefore, most of this area's capital expenditures are associated with new business and work required by municipalities and/or the New Jersey DOT.

Q. WHAT ARE THE PHYSICAL CHARACTERISTICS OF ELIZABETHTOWN'S DISTRIBUTION SYSTEM?

A. Elizabethtown operates and maintains approximately 3,275 miles of various pressure gas distribution and transmission main, and related services. As of December 31, 2020, approximately 11 percent of the Company's system included cast iron, ductile iron or bare and unprotected steel and 18 percent is comprised of vintage steel (pre-1970) and vintage plastic (pre-1984). As discussed below, Elizabethtown has made significant progress and capital investments in retiring and replacing its vintage infrastructure as part of the IIP and various other improvements projects.

IV. UTILITY PLANT IN SERVICE/CAPITAL EXPENDITURES

Q. PLEASE DESCRIBE ELIZABETHTOWN'S CAPITAL SPENDING SINCE ITS LAST BASE RATE CASE.

A. The Company's distribution rates were last reset in the 2019 Base Rate Case. Since the conclusion of that case, Elizabethtown has continued to invest a substantial amount of capital in new distribution plant and services and replacement plant and services. Since the conclusion of the 2019 Base Rate Case, Elizabethtown has invested approximately $214.8 million of plant additions net of retirements, excluding IIP, that are not currently reflected in rates, and projects that an additional $175.2 million of capital investment net of retirements, excluding IIP, will be added to the UPIS balance by September 30, 2022, to ensure that our customers continue to receive safe and reliable natural gas service. As reflected on MPS-1, the Company's actual UPIS as of September 30, 2021 totaled approximately $1.8 billion. The majority of plant additions since the 2019 Base Rate Case were related to the replacement of our aging infrastructure and the hardening of our distribution system.

Q. PLEASE SUMMARIZE THE CAPITAL EXPENDITURES DURING THE TEST YEAR.

A. Schedule MPS-2, attached hereto, provides a summary of the test year capital expenditures based on six months of actual data and six months of projected data. The projected six months of capital expenditures from October 1, 2021 through March 31, 2022, as well as projected plant retirements for the same period, were utilized to calculate the projected UPIS balance for the test year ending March 31, 2022. As shown on Schedule MPS-1, the total projected plant additions and plant retirements for the remaining months of the test year period are approximately $53.1 million and $9.2 million, respectively. In addition, Year 3 IIP Program amounts of approximately $15.9 million for the period July through September 2021 have been removed. This results in a total projected UPIS balance of approximately $1.9 billion as of March 31, 2022, which is reflected in Schedule TK-2 (Statement of Rate Base). As the test year is fully realized, Elizabethtown will replace the projected data with actual data through March 2022 in the Company's 12-month update to be submitted in this case.

Q. PLEASE SUMMARIZE THE POST-TEST YEAR CAPITAL EXPENDITURES FOR WHICH ELIZABETHTOWN IS SEEKING RATE RELIEF IN THIS PROCEEDING.

A. Elizabethtown is proposing to include in rate base capital expenditures in the post-test year period which are known and measurable, and consistent with Board precedent, including *In Re Elizabethtown Water Company Rate Case*, BPU Docket No. WR8504330 (May 23, 1985). Elizabethtown's proposed post-test year capital expenditures are "prudent and major in nature and consequence," and therefore, should be included in rate base.

In this initial filing, I am sponsoring post-test year adjustments based upon a projection of capital expenditures to be made by the Company during the six-month period April 1, 2022 through September 30, 2022. These expenditures consist of approximately $65.8 million of post-test year plant additions, summarized in Schedule MPS-3, and approximately $75.0 million of major capital projects that are projected to be placed in-service during the post-test year period, summarized in Schedule MPS-4. These major capital projects are related to the Erie Street LNG project (discussed in detail in the panel testimony of Company Witnesses Madden and Willey), the New Village RNG gate station (addressed in the Madden/Willey panel testimony and by Company witness McMullen), several large diameter projects (discussed further in my testimony below), and those related to bringing the Gas Supply function in-house (discussed further in the Madden/Willey panel testimony). As reflected on Schedule MPS-1, by the end of the post-test year, net of plant retirements of $9.5 million, the Company projects a UPIS balance of approximately $2.0 billion.

Q. WHAT ARE THE CAPITAL EXPENDITURE CATEGORIES REFLECTED ON SCHEDULES MPS-2 AND MPS-3?

A. The expenditure categories reflected on Schedules MPS-2 and MPS-3 include those associated with New Business, Facilities, Fleet, Measurement Operations, LNG, Information Technology ("IT"), Mandatory, DOT, Periodic Testing ("PT") of Meters, Pressure Improvements ("PRIM"), Corrosion Work, Relocation, Security, Tools and Equipment, IIP, IIP Base Spending, Distribution Integrity Management Program ("DIMP") and Transmission Integrity Management Program ("TIMP").

Q. PLEASE EXPLAIN THE TYPES OF COSTS ASSOCIATED WITH THE CAPITAL EXPENDITURE CATEGORIES REFLECTED ON SCHEDULES MPS-2 AND MPS-3.

A. I will address the IIP, IIP Base Spending, DIMP and TIMP categories later in my testimony. The costs associated with the other capital expenditure categories are as follows:

New Business includes costs associated with connecting new residential, commercial, and industrial gas customers to Elizabethtown's distribution system. This category includes the costs associated with the expansion of the Company's gas distribution system into new areas in its service territory, including the costs to serve approximately 8,800 new customers. These investments are driven in large part by the addition of new distribution infrastructure targeting existing developed areas in the Company's Northwest Division, as well as a new franchise area in Byram Township, Sussex County.

Facilities include costs associated with the purchase of a new building located in Lafayette, New Jersey to replace the existing Andover Service Center building in the Sussex County area of the Northwest Division. In addition, various building and grounds improvements, such as Call Center renovations, a Virtual Reality Training Center, HVAC upgrades, yard lighting and other interior and exterior building and site work at the Company's operations facilities are included in these expenditures.

Fleet includes costs associated with the Company's operations vehicles, such as pick-up trucks, responder vans, dump trucks, crew trucks, automobiles and forklifts. In total, the Fleet expenditures include the purchase and upfitting of 52 operations vehicles needed to effectively operate the Company's system and maintain safe and reliable service to customers. The vehicles being purchased are replacing those with leases ending or vehicles that have exceeded their life cycle. Costs include those incurred from the purchase of the vehicle, modifying them for dual fuel operation, and body modifications consisting of tool box installations, shelving, equipment holders, compressors and decaling.

Measurement Operations include costs related to measurement operations, including asset replacement of meter and regulation functions station controls and station heater replacements.

LNG includes costs related to peaking costs related to Liquified Natural Gas Plant operations and the addition of liquefaction equipment necessary to ensure the continued availability and reliability of gas supply to our customers. Once again, this project is addressed in the Madden/Willey panel testimony.

Information Technology (IT) includes costs associated with various system implementations or upgrades including necessary cybersecurity projects. Specifically, this category includes, but is not limited to, IT costs related to the construction of a new building in Andover, the renewal of an Oracle license, activities required to support the

Transportation Security Administration ("TSA") Security directives, an enterprise data warehouse expansion, a tracking and traceability system for physical assets, digitization of service line data, annual replacements of hardware and expansion of the technical training center.

<u>Mandatory</u> includes costs associated with projects that are required to be undertaken by the Company for compliance related improvements within State and Federal regulations.

<u>DOT</u> includes costs associated with distribution improvements related to state, municipal and county roadway improvement projects. Post-test year expenditures for this category reflect projects that have been identified for that period by state, municipal, and county authorities.

<u>Periodic Testing (PT) Meters</u> include costs arising from the periodic testing of the Company's meter inventory, primarily for the purchase of new meters.

<u>Pressure Improvement (PRIM)</u> include costs related to projects that improve the system pressures within the distribution mains and services to reliably serve customers.

<u>Corrosion Work</u> includes costs to improve the cathodic protection of the Company's steel distribution or transmission systems.

<u>Relocation</u> projects include pipeline relocations due to private development which, by design, is in conflict with Company's facilities. This type of work is usually reimbursable as the relocation is for the benefit of the private developer. During the test year, the Company performed a relocation of a pipeline in Lopatcong Township, New Jersey that was not subject to reimbursement. The relocation was warranted due to erosion of a water course that the pipeline traversed. The pipeline had to be lowered in order to avoid further erosion from storm runoff activity.

Security includes fencing upgrades to the Company's critical facilities such as Gate Stations and Regulator Stations.

Tools and Equipment includes the costs associated with larger scale items needed to perform capital replacement work, such as pressure control equipment, jackhammers, and similar large mechanical tools.

Q. PLEASE DESCRIBE THE CAPITAL EXPENDITURES INCLUDED IN THE IIP INVESTMENT CATEGORY

A. Pursuant to the IIP Order[3], Elizabethtown received approval to implement an IIP to invest up to $300 million over a five-year period beginning July 1, 2019 and continuing until June 30, 2024. Under the IIP, the Company is authorized to replace up to 250 miles of cast iron and bare steel mains and related services, as well as the installation of excess flow valves on new service lines. These investments will modernize and enhance the safety and reliability of Elizabethtown's gas distribution system. Please see Company Witness Kaufmann's testimony for further details on the treatment of IIP expenditures in this case.

Q. PLEASE EXPLAIN THE IIP BASELINE SPENDING REQUIREMENT ASSOCIATED WITH THE IIP.

A. Pursuant to the IIP Order, the Company is required to maintain baseline capital spending amounts consisting of (1) a Total Capital Baseline Spend and (2) an IIP Baseline Spend. These capital expenditures are not reflected in the recovery mechanism in the approved IIP program and instead are to be recovered through Elizabethtown's base rates. The IIP Base Spending Category reflected on Schedules MPS-2 and MPS-3 pertains to the latter

[3] *In the Matter of the Petition of Elizabethtown Gas Company to implement an Infrastructure Investment Program ("IIP") and Associated Recovery Mechanism Pursuant to N.J.S.A 48:2-21 and N.J.A.C 14:3-2A,* Docket No. GR18101197, "Final Decision and Order Approving Stipulation" (June 12, 2019) ("IIP Order").

category -- the IIP Baseline Spend. Under the IIP, the Company must maintain baseline spending on projects similar to those eligible for recovery under the IIP equal to 10 percent of the IIP budget; this amounts to approximately $6 million per year or a total of approximately $30 million over the five-year program. Since the inception of the IIP, the Company has maintained this minimum level of spend for program years one and two, specifically approximately $6.5 million and $6.8 million, respectively. Schedules MPS-2 reflects the actual IIP in-service capital spending amounts through June 30, 2021 and approved for inclusion in rates in BPU Docket No. GR21040747.

Q. **PLEASE EXPLAIN THE TOTAL CAPITAL BASELINE SPEND REQUIREMENT ASSOCIATED WITH THE IIP.**

A. Under the IIP, Total Capital Baseline Spend must equal an average annual amount of $79 million per IIP year or $395 million over the five (5) year IIP investment period beginning July 1, 2019 through June 30, 2024. The specific capital investments made by the Company as part of the Total Capital Baseline Spend are within the discretion of Elizabethtown and include certain investments that are excluded from the IIP, such as replacement of vintage plastic mains and services and relocation of meters, among other costs, as well as costs in excess of the $1.2 million per mile cap imposed on IIP replacements. The Company may also include up to $10 million of new business expenditures in Total Capital Baseline Spend. Since the inception of the IIP, the Company has maintained the Total Capital Baseline Spend for program years one and two, specifically, $117.6 million and $88.6 million, respectively, with new business capped at $10 million each year.

Q. PURSUANT TO THE BOARD'S ORDER APPROVING THE IIP, THE PRUDENCE OF THE COMPANY'S INVESTMENTS ARE TO BE REVIEWED IN THE COMPANY'S NEXT BASE RATE CASE. DO YOU BELIEVE THAT THE COMPANY'S IIP INVESTMENTS WERE PRUDENT CAPITAL INVESTMENTS?

A. Yes. Since the inception of the IIP, through June 30, 2021, Elizabethtown has installed 105.5 miles of mains, 13,004 services and 12,960 Excess Flow Valves ("EFVs"). The aforementioned quantities include miles of mains and number of services and EFVs related to the IIP program only. In accordance with the intent of the IIP, the replacement of these facilities has enhanced and will enhance the Company's distribution system safety and reliability to the benefit of Elizabethtown's customers. The IIP work will also support the environment by helping to reduce Elizabethtown's open leak inventory as discussed below and will facilitate economic development and employment in New Jersey.

Q. HAS THE COMPANY ENGAGED AN INDEPENDENT MONITOR WHO REVIEWS AND REPORTS ON THE EFFECTIVENESS OF THE IIP TO BOARD STAFF AND RATE COUNSEL?

A. Yes, as required by the IIP Order, following consultation with Board Staff and Rate Counsel, in December 2019, Elizabethtown retained an IIP Independent Monitor. The Independent Monitor has issued 5 reports covering program activity through December 2020 and found that the IIP investments were effective in meeting IIP objectives and that they were cost effective and efficient. The Independent Monitor's results were reported to Board Staff and Rate Counsel. These reports support a finding that the Company's investments have been prudent.

Q. PLEASE ADDRESS THE COMPANY'S IIP OPEN LEAK INVENTORY REQUIREMENT.

A. The IIP Order requires the Company to reduce its year-end open leak inventory by one percent for each year of the IIP, absent certain extraordinary circumstances that prevent that result. This open leak reduction metric includes all post-approval open leaks subject to a cap for each year of the IIP. The cap for Year 1 of the IIP is 3,315, which is the average number of year-end open leaks the Company has experienced during the last five calendar years. Hereafter, the cap will be reduced by one percent for each of the remaining four years of the IIP. In other words, by June 30, 2021, the Company must demonstrate a one percent reduction in the 3,315 cap. Subsequent years must be reduced by one percent per year measured against the previous year. Since the inception of the IIP, the Company has satisfied the IIP open leak target requirement by meeting the required reduction in the established cap. In any event, as of November 30, 2021, the Company's actual open leak inventory is 1,934.

Q. PLEASE DESCRIBE THE COSTS REFLECTED IN THE INTEGRITY MANAGEMENT CATEGORY (I.E., DIMP AND TIMP) OF SCHEDULES MPS-2 AND MPS-3.

A. The Pipeline and Hazardous Materials Safety Administration's ("PHMSA") regulations require the Company to maintain a DIMP and TIMP to ensure the integrity of its distribution and transmission pipeline. PHMSA's regulations require Elizabethtown to take a risk-based approach to identify, evaluate, and rank pipeline integrity threats and take appropriate action to mitigate those threats. Capital expenditures for the DIMP category, excluding those listed on Schedule MPS-4, total approximately $32.8 million and $14.9

million during the test year and post-test year periods, respectively, and are associated with Elizabethtown's ongoing efforts to replace vintage, at-risk facilities in the distribution system identified in the DIMP.

TIMP Projects include asset replacements necessary to meet compliance requirements associated with operating the Company's transmission pipelines. These expenditures usually require retrofitting of pipelines for in-line inspections and replacements of anomalies in the pipeline as discovered by said inspections. TIMP expenditures total approximately $235,000 in the test year and $216,000 in the Post-Test year.

Q. PLEASE DESCRIBE THE MAJOR PROJECTS INCLUDED ON SCHEDULE MPS-4.

A. There are six major projects included on Schedule MPS-4: Erie Street, New Village RNG, Elmora Avenue, Phase 2 Westfield Yard to Nomahegan Park, Oxford-Independence HP interconnect, and Gas Supply In-House. Company Witnesses Madden and Willey will discuss the Erie Street and New Village RNG projects in their panel testimony. Company Witness Christie McMullen also addresses the New Village RNG project in her testimony. Company Witnesses Madden and Willey will discuss the Gas Supply In-House project. Regarding the Phase 2 Westfield Yard to Nomahegan Park and the Elmora Avenue projects, the Company plans to replace 16,200 ft of 16-inch elevated pressure ("EP") cast iron main and 3,800 ft of 20-inch EP cast iron main, respectively, as part of the Company's commitment to replace its aging cast iron system for safety and reliability. The Oxford-Independence High Pressure interconnect is a 5-mile, 8-inch diameter pipeline to support distribution pressures in the Sussex County area of the Company's northwest territory during peak winter loads.

Q. ARE THERE ANY PENDING PHMSA REGULATIONS THAT COULD INCREASE TRANSMISSION INTEGRITY MANAGEMENT COSTS?

A. Yes. In 2016, PHMSA issued a Notice of Proposed Rulemaking ("NPRM") proposing new pipeline safety regulations that include a requirement for increased inspections over the level that is currently required, among other requirements. On October 1, 2019, PHMSA issued the first part of the new pipeline safety regulation "Pipeline Safety: Safety of Gas Transmission Pipelines: MAOP Reconfirmation, Expansion of Assessment requirements, and Other Related Amendments" (i.e. PHMSA Transmission Mega Rule). This new pipeline safety regulation was only the first of three parts to the original NPRM from 2016. The PHMSA Transmission Mega Rule provides additional regulatory requirements in PHMSA's safety regulations. The enactment of these regulations along with the remaining parts of the original NPRM from 2016 are expected to impact gas distribution operating costs, particularly the requirement related to material verification on existing transmission pipelines. As discussed by Company witness Mr. Houseman, the Company proposes to continue to retain the authority to establish a TIMP regulatory asset, as approved in the 2019 Base Rate Case, to track and defer for later recovery the Company's incremental transmission integrity management costs.

Q. WHAT STEPS DOES ELIZABETHTOWN TAKE TO ENSURE THE REASONABLENESS OF CAPITAL PROJECTS EXPENDITURES?

A. Elizabethtown follows a number of practices to ensure that its capital expenditures are reasonable. These include competitive bidding, contractor quality assurance and cost tracking. With respect to competitive bidding, once a project is approved, individual project design documents are prepared for competitive bid so that the project can be bid for construction immediately following design and permitting. Contractor bids are evaluated utilizing a combination of criteria including safety, cost, contractor quality, experience, availability, and timing. As to contractor quality, we continuously monitor the performance of our contractors and we use that information to evaluate the bids we receive from contractors who have worked for us previously. This helps us to ensure that the work they perform delivers pipeline assets constructed in a safe, quality, compliant, and most cost-effective way possible. Finally, we closely track our capital expenditures after a project commences to monitor the financial performance of each of our capital projects. Specifically, we examine each project through the project life cycle with monthly (or more frequently as needed) reviews on original cost estimates in relation to actual costs to determine the existence of any variances. If there are significant variances, we undertake a review to determine the causes, identify potential cost mitigation solutions and/or modify the scope of the project as appropriate.

V. <u>SUMMARY</u>

Q. CAN YOU BRIEFLY SUMMARIZE YOUR TESTIMONY?

A. The issues discussed in my testimony address the significant levels of capital expenditures for both the test year and post-test year periods that are prudent and necessary to provide safe and reliable service to Elizabethtown's customers. Elizabethtown's construction program has increased the safety, operation and reliability of our distribution system. Additionally, the Company's IIP investments have significantly reduced leak inventory and help to ensure continued safety and reliability. As such, I request the Board's approval of the proposals set forth herein.

Q. DOES THIS CONCLUDE YOUR TESTIMONY?

A. Yes, it does.

ELIZABETHTOWN GAS COMPANY
STATEMENT OF RATE BASE
UTILITY PLANT IN SERVICE (UPIS)

Line No.			Reference
1	**Actual UPIS at 9/30/2021**	**$1,831,644,600**	
2	UPIS Year 3 IIP Removal July - Sep 2021	($15,882,824)	
3	Projected Test Year Plant Additions	$53,104,273	MPS-2
4	Projected Test Year Major Capital Projects	$0	MPS-4
5	Projected Test Year Plant Retirements	($9,247,510)	
6	**Projected Test Year Ending UPIS at 3/31/2022**	**$1,859,618,539**	
7	Projected Post Test Year Plant Additions	$65,785,946	MPS-3
8	Projected Post Test Year Major Capital Projects	$75,041,191	MPS-4
9	Projected Post Test Year Plant Retirements	($9,485,578)	
10	**Projected Post Test Year Ending UPIS at 9/30/2022**	**$1,990,960,098**	

Schedule MPS-2
6+6

ELIZABETHTOWN GAS COMPANY
TEST YEAR PLANT ADDITIONS
12 MONTHS ENDING 3/31/2022
Includes OH and AFUDC

WP-2 #'s		Apr-21 Actual	May-21 Actual	Jun-21 Actual	Jul-21 Actual	Aug-21 Actual	Sep-21 Actual	Oct-21 Projected	Nov-21 Projected	Dec-21 Projected	Jan-22 Projected	Feb-22 Projected	Mar-22 Projected	Test Year
1	New Business	4,180,419	3,391,408	2,146,927	5,018,662	4,784,836	4,180,415	5,307,880	4,640,540	3,809,433	2,512,229	2,360,298	1,976,048	44,309,095
2	Facilities	235,068	472,506	(287,581)	64,004	306,316	132,159	235,692	663,355	155,373	1,556	126,624	774,573	2,879,645
3	Fleet	119,910	4,930	231,497	27,420	-	121,907	33,089	44,119	44,079	200,109	275,368	275,667	1,378,095
4	Measurement Operations	136,482	184,284	12,592	174,784	137,416	218,514	196,504	304,034	302,398	242	242	242	1,667,734
5	LNG	255,171	185,649	149,963	354,225	258,749	36,270	2,569	13,564	24,414	349,819	285,418	437,425	2,353,236
6	Information Technology (IT)	407,204	2,264,153	785,249	249,668	899,037	847,016	637,030	602,283	628,360	1,460,143	1,426,305	1,178,041	11,384,489
7	Mandatory	293,073	303,697	300,470	142,640	227,429	392,550	292,701	291,600	290,120	268,865	268,865	280,774	3,352,784
8	Distribution Integrity Management (DIMP)	3,379,761	3,416,953	4,507,623	3,601,606	3,125,574	2,023,707	2,643,579	3,956,751	1,427,334	1,575,698	1,617,009	1,529,984	32,805,579
9	Transmission Integrity Mgt Prog (TIMP)	47,537	100,393	18,064	8,935	24,048	7,710	17,323	6,381	4,244	-	-	-	234,635
10	DOT	23,952	64,094	19,649	255,286	11,595	(25,280)	232	232	154	2	2	2	349,920
11	Periodic Testing (PT) Meter	305,322	428,657	302,740	614,799	309,292	702,520	322,791	309,073	308,795	377,891	377,891	377,891	4,737,662
12	Pressure Improvement (PRIM)	18,124	121,706	(3,354)	298,863	969,001	437,434	153,555	662,749	552,075	217,557	217,557	-	3,645,267
13	Corrosion Work	233,621	103,418	5,146	11,280	12,272	5,389	-	-	-	-	-	-	371,126
14	Relocation	1,765	1,693	18,677	3,032	1,100	5,612	56,012	221,240	111,527	-	-	-	420,658
15	Security	326	290	5,453	(2,618)	1,405	1,990	71,291	100,979	97,042	6,748	6,748	10,419	300,073
16	Tools and Equipment	-	-	-	-	-	-	-	-	-	-	-	-	-
17	IIP Base Spending	1,044,649	1,624,785	508,849	698,730	1,196,139	923,280	603,129	25,368	664,472	506,126	629,064	359,366	8,783,957
WP-5	IIP in excess of $1.2 Mill. Per Mile Cap			5,276,017										5,276,017
WP-5	Excludes IIP Program Spend July-21 Forward	6,449,553	4,315,067	5,311,697										16,076,317
	TOTAL ETG PLANT ADDITIONS	**17,131,937**	**16,983,683**	**19,309,678**	**11,521,316**	**12,264,209**	**10,011,193**	**10,573,377**	**11,842,268**	**8,419,820**	**7,476,985**	**7,591,391**	**7,200,432**	**140,326,289**

ELIZABETHTOWN GAS COMPANY
POST-TEST YEAR PLANT ADDITIONS
6 MONTHS ENDING 9/30/2022
Includes OH and AFUDC

WP-2 #'s		Apr-22 Projected	May-22 Projected	Jun-22 Projected	Jul-22 Projected	Aug-22 Projected	Sep-22 Projected	Post-Test Year
1	New Business	3,086,611	2,859,358	3,532,939	4,093,585	4,183,783	4,364,003	22,120,279
2	Facilities	935,996	854,259	616,226	702,421	625,193	625,193	4,359,288
3	Fleet	376,320	309,124	128,086	39,883	29,182	29,182	911,777
4	Measurement Operations	1,261,074	27,369	27,464	432,117	81,218	216,179	2,045,421
5	LNG	388,637	460,341	556,485	1,676,744	1,892,324	879,927	5,854,458
6	Information Technology (IT)	1,228,407	1,241,890	1,089,726	920,778	899,769	650,592	6,031,162
7	Mandatory	280,819	280,854	280,911	281,886	281,886	281,886	1,688,242
8	Distribution Integrity Management (DIMP)	2,892,292	2,242,592	2,384,906	2,256,178	2,316,330	2,770,414	14,862,712
9	Transmission Integrity Mgt Prog (TIMP)	-	-	-	-	107,969	107,969	215,938
10	DOT	3	3	108,026	431,995	685,112	217,271	1,442,410
11	Periodic Testing (PT) Meter	377,951	377,999	378,075	377,891	377,891	377,891	2,267,698
12	Pressure Improvement (PRIM)	238,649	-	235,487	107,969	97,172	106	679,383
13	Corrosion Work	-	108,000	108,021	107,969	107,969	-	431,959
14	Relocation	-	-	-	-	-	-	-
15	Security	6,754	6,756	6,759	6,752	6,752	6,752	40,525
16	Tools and Equipment	-	-	-	-	-	-	-
17	IIP Base Spending	176,762	31,810	29,745	156,776	1,014,239	1,425,362	2,834,694
WP-5	IIP in excess of $1.2 Mill. Per Mile Cap							-
WP-5	Excludes IIP Program Spend July-21 Forward							-
	TOTAL ETG PLANT ADDITIONS	**11,250,275**	**8,800,355**	**9,482,856**	**11,592,944**	**12,706,789**	**11,952,727**	**65,785,946**

Schedule MPS-4
6+6

ELIZABETHTOWN GAS COMPANY
PRO FORMA ADJUSTMENTS
MAJOR CAPITAL PROJECTS -IN-SERVICE AMOUNTS

FERC	Project Name	Projected In Service Date	Projected Test Year Ending Mar-22	Projected Post Test Year Beginning Apr-22	Projected TY and PTY Total
36320	Erie Street Project	Jul-22	$0	$45,674,084	$ 45,674,084
36900	New Village RNG Project	Sep-22	$0	$2,724,964	$ 2,724,964
37600	Elmora Ave Project-Mains	Jun-22	$0	$6,692,941	$ 6,692,941
38000	Elmora Ave Project-Services	Jul-22	$0	$2,384,446	$ 2,384,446
37600	Phase 2 Westfield Yard to Nomahegan Park 16" EP CI Replacement-Mains	Aug-22	$0	$5,899,565	$ 5,899,565
38000	Phase 2 Westfield Yard to Nomahegan Park 16" EP CI Replacement-Services	Sep-22	$0	$2,073,427	$ 2,073,427
37600	Oxford-Independence HP Interconnect	Sep-22	$0	$8,541,189	$ 8,541,189
39000	Gas Supply In-House - Structures & Improvements	Sep-22	$0	$1,000,000	$ 1,000,000
39100	Gas Supply In-House- Office Furniture & Equipment	Sep-22	$0	$30,000	$ 30,000
39110	Gas Supply In-House - OFE - Software Non-Enterprise	Sep-22	$0	$20,575	$ 20,575
	Total Pro Forma Adjustment		$ -	$ 75,041,191	**$ 75,041,191**

IN THE MATTER OF THE PETITION OF ELIZABETHTOWN GAS COMPANY FOR APPROVAL OF INCREASED BASE TARIFF RATES AND CHARGES FOR GAS SERVICE, CHANGES TO DEPRECIATION RATES AND OTHER TARIFF REVISIONS

BPU DOCKET NO. GR21__________

DIRECT TESTIMONY

OF

JOHN L. HOUSEMAN

On Behalf Of
Elizabethtown Gas Company

Exhibit P-5

December 28, 2021

TABLE OF CONTENTS

ELIZABETHTOWN GAS COMPANY
DIRECT TESTIMONY OF
JOHN L. HOUSEMAN

I. INTRODUCTION

Q. PLEASE STATE YOUR NAME AND BUSINESS ADDRESS.

A. My name is John Houseman. My business address is 1 South Jersey Plaza, Folsom, New Jersey 08037.

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

A. I am employed by South Jersey Industries, Inc. ("SJI") as the Director of Accounting.

Q. PLEASE DESCRIBE YOUR PROFESSIONAL RESPONSIBILITIES.

A. I manage overall accounting functions of SJI Utilities, Inc. ("SJIU") and its subsidiaries, specifically including Elizabethtown Gas Company ("Elizabethtown" or "Company"). My responsibilities include all general accounting, plant accounting and finance functions including, but not limited to, the review of monthly and quarterly consolidations and reporting packages, the preparation and review of quarterly and annual SEC filings (SEC Forms 10-Q and 10-K, respectively), and the preparation and review of technical accounting support and related analysis.

Q. WHAT ARE YOUR PROFESSIONAL AND EDUCATIONAL QUALIFICATIONS?

A. I graduated from Rutgers University in 1996 with a Bachelor of Science in Accounting. I am a Certified Public Accountant, holding a license from the State of New Jersey. After receiving my degree, I was initially employed by Baratz & Associates, P.A. as a Staff Accountant. After that I was employed by New Jersey American Water Company holding roles in Accounting and Finance, serving as a Senior Financial Analyst before joining Pinnacle Foods Group, Inc. as a Financial Reporting Manager. I was then employed by

American Water from 2006 through 2020 working principally in the Controller's organization, most recently as a Divisional Controller. I joined SJI in March 2020 as a Director of Accounting.

II. PURPOSE OF TESTIMONY

Q. WHAT IS THE PURPOSE OF YOUR DIRECT TESTIMONY?

A. The purpose of my direct testimony is to support Elizabethtown's December 2021 base rate filing with the New Jersey Board of Public Utilities ("BPU" or "Board"). I will discuss Elizabethtown's proposals to reflect and recover certain regulatory assets in the revenue requirement in this proceeding. These regulatory assets are associated with pension and other post-employment benefits ("OPEB") costs, costs related to federal pipeline safety regulations, costs related to the Transportation Security Administration ("TSA") Security Directives, certain costs related to liquefaction equipment at the Company's Erie Street Liquefied Natural Gas ("LNG") facility, and costs to bring Elizabethtown's gas supply function in-house. I will also discuss certain elements of the revenue requirement, including the calculation of depreciation expense, the interest synchronization adjustment, and the determination of the amounts of accumulated depreciation and accumulated deferred federal and state income taxes included in rate base. I will also sponsor various financial and accounting data required by the Board's regulations as set forth in Section 14:1-5.12 of the New Jersey Administrative Code ("N.J.A.C."). The information required by the Board's regulations consists of balance sheets, income statements and other financial data.

Q. DO YOU SPONSOR ANY SCHEDULES IN YOUR DIRECT TESTIMONY?

A. Yes. I am sponsoring the following schedules:

- Schedule JLH-1 – Elizabethtown's Balance Sheets at December 31, 2018, 2019 and 2020 and September 30, 2021;
- Schedule JLH-2 – Pivotal Utility Holdings, Inc.'s ("Pivotal") Statement of Income for the six months ended June 30, 2018 and Elizabethtown's Statements of Income for the six months ended December 31, 2018 and the twelve months ended December 31, 2019 and 2020;
- Schedule JLH-3 – Elizabethtown's Statement of Gas Operating Revenues for the twelve months ended December 31, 2020;
- Schedule JLH-4 – Elizabethtown's Payments and Accruals to Affiliates for the twelve months ended December 31, 2020;
- Schedule JLH-5 – Pro Forma Depreciation Expense & Accumulated Depreciation;
- Schedule JLH-6 – Adjusted Deferred Federal Income Tax ("DFIT") Included in Rate Base;
- Schedule JLH-7 – Adjusted Deferred Corporate Business Tax ("DCBT") Included in Rate Base;
- Schedule JLH-8 – Interest Synchronization Adjustment; and
- Schedule JLH-9 – Pension & Other Post-Employment Benefits ("OPEB") Regulatory Assets.

III. FILING REQUIREMENTS UNDER N.J.A.C.

Q. PLEASE DESCRIBE SCHEDULES JLH-1 THROUGH JLH-4.

A. Schedules JLH-1 through JLH-4 present statements and financial data required by the Board's regulations. Schedule JLH-1 provides comparative balance sheets for Elizabethtown at December 31, 2018, 2019 and 2020 as well as September 30, 2021.

Schedule JLH-2 provides comparative statements of income for Pivotal, the previous owner of Elizabethtown's assets, for the six months ended June 30, 2018 as well as for Elizabethtown for the six months ended December 31, 2018 and the twelve months ended December 31, 2019 and 2020. Schedule JLH-3 provides Elizabethtown's statement of gas operating revenues for the twelve months ended December 31, 2020. Finally, Schedule JLH-4 provides Elizabethtown's payments and accruals to affiliates for the twelve months ended December 31, 2020.

Q. PLEASE EXPLAIN WHY ELIZABETHTOWN DOES NOT HAVE CERTAIN FINANCIAL DATA REQUIRED BY THE BOARD'S REGULATIONS FOR PERIODS PRIOR TO JULY 1, 2018.

A. On July 1, 2018, SJI acquired the assets of Elizabethtown from Pivotal, an indirect subsidiary of the Southern Company ("Southern"). That transaction was approved by the Board's Order dated June 22, 2018 in BPU Docket No. GM17121309. Because that transaction was structured as an asset sale, the assets of Elizabethtown were transferred from one corporation, Pivotal, to another corporation, ETG Acquisition Corporation, which has since been renamed Elizabethtown Gas Company. Elizabethtown and Pivotal are separate corporations and taxable entities and, as such, maintain separate books and records. Thus, Elizabethtown's financial data dates only from July 1, 2018. Financial data prior to that date was recorded on the books and records of Pivotal, which operated Elizabethtown as a standalone division.

To address the unavailability of financial data for Elizabethtown prior to July 1, 2018, the Company is providing a comparative income statement for Pivotal, the previous owner of Elizabethtown's assets, for the six-month period ending June 30, 2018. Thus, in total, Elizabethtown is providing financial information for past periods that are consistent with the timeframes applicable under the Board's regulations.

IV. DEPRECIATION ADJUSTMENTS

Q. PLEASE EXPLAIN THE COMPANY'S CALCULATION OF DEPRECIATION EXPENSE AND ACCUMULATED DEPRECIATION.

A. Schedule JLH-5 is a summary of *pro forma* adjustments to depreciation expense and accumulated depreciation. These adjustments are reflected on line 8 on Schedule TK-3 (Operating Income Statement) and on line 2 on Schedule TK-2 (Statement of Rate Base), to Company witness Thomas Kaufmann's testimony.

The first adjustment on Schedule JLH-5 is the annualization of depreciation expense utilizing the Company's proposed depreciation rates, as discussed in the Direct Testimony of Dane A. Watson (Exhibit P-9). The resulting adjustment totaling $9,841,191 (Schedule JLH-5, line 4) is based upon projected depreciable plant as of the test year ending March 31, 2022. This adjustment is necessary to reflect the proper annual level of depreciation expense as of the end of the test year.

The second adjustment reflects additional annual depreciation expense associated with projected post-test year net plant additions of $131,341,559 from April 2022 through September 2022, as discussed in the Direct Testimony of Company witnesses Scacifero, Madden, Willey and Kaufmann. The resulting increase in depreciation expense related to post-test year plant is $4,064,913 (line 5).

Also included in Schedule JLH-5 is the impact of the additional post-test year depreciation expense, retirements, and cost of removal on the Company's provision for Accumulated Depreciation. The total adjustments result in a $13,003,820 increase in the provision for Accumulated Depreciation, which is included in line 2 of Schedule TK-2 (Statement of Rate Base) to Mr. Kaufmann's testimony.

Q. DOES THE ACCUMULATED DEPRECIATION BALANCE SET FORTH ON SCHEDULE JLH-5 REFLECT ANY ADDITIONAL ADJUSTMENTS?

A. Yes. The Accumulated Depreciation balance as of September 30, 2021 reflects a credit of $130 million based on an acquisition adjustment of $160 million amortized over ten years as required by the Board's Order dated November 13, 2019 in BPU Docket No. GR19040486. While the accumulated depreciation credit reduces rate base, the amortization of the credit has no impact on Elizabethtown's income or revenues.

V. <u>FEDERAL AND STATE DEFERRED INCOME TAXES</u>

Q. PLEASE EXPLAIN THE COMPANY'S CALCULATION OF FEDERAL AND STATE DEFERRED INCOME TAXES AS SET FORTH ON SCHEDULES JLH-6 AND JLH-7.

A. The calculation of deferred taxes, DFIT and DCBT, used to reduce rate base reflects the normalization of timing differences between book and tax accounting. The deferred taxes are the accumulation of vintage years' net timing differences calculated at the statutory rates. DFIT and DCBT included in rate base for the adjusted test year ending March 31, 2022 are ($73,645,196) and ($34,683,766), respectively. DFIT and DCBT included in rate base for the adjusted post-test year ending September 30, 2022 are ($81,870,087) and ($38,557,341), respectively. The derivation of these amounts is shown in Schedules JLH-6 and JLH-7. The deferred income taxes utilized in rate base also reflect a reduction for excess deferred income taxes as provided by Company witness Alan Felsenthal. The total from each of these schedules is included in Schedule TK-2 to Mr. Kaufmann's testimony.

VI. <u>INTEREST SYNCHRONIZATION</u>

Q. PLEASE EXPLAIN THE COMPANY'S INTEREST SYNCHRONIZATION ADJUSTMENT AS SET FORTH ON SCHEDULE JLH-8.

A. Schedule JLH-8 sets forth the calculation of the *pro forma* adjustment to income tax expense related to interest expense synchronization. The interest expense synchronization adjustment is based on the tax effect of the difference in projected annualized interest expense and test year interest expense. The annualized interest expense is calculated on the projected rate base shown on Schedule TK-2 (Statement of Rate Base) to Mr. Kaufmann's testimony, multiplied by the total weighted cost of long-term debt of 1.73 percent, as set forth in the Direct Testimony of Paul Moul. This adjustment is necessary to synchronize the Federal income tax associated with interest expense in the test period with the projected tax expense based on an interest calculation using the weighted average cost of debt in the capital structure utilized to support Rate Base. The resulting $3,264,844 adjustment shown on Schedule JLH-8 is an increase to Federal Income Taxes and is included on line 10 of Schedule TK-3 (Operating Income Statement) to Mr. Kaufmann's testimony.

VII. <u>REGULATORY ASSETS</u>

Q. PLEASE DESCRIBE THE PENSION AND OPEB REGULATORY ASSETS THAT ARE REFLECTED ON ELIZABETHTOWN'S BOOKS.

A. In Pivotal's base rate proceeding in BPU Docket No. GR16090826, Elizabethtown was authorized to establish regulatory assets for its costs associated with the accelerated recognition of pension and OPEB liabilities arising from the acquisition of Southern Company Gas, Pivotal's former owner, by Southern. SJI purchased the unamortized balance of these regulatory assets associated with Elizabethtown's New Jersey employees as part of its acquisition of Pivotal's New Jersey assets. Elizabethtown's current rates reflect the amortization of the pension regulatory asset over a 15-year period and the amortization of the OPEB regulatory asset over a 9.2-year period.

Q. HOW IS THE COMPANY PROPOSING TO REFLECT THESE ASSETS IN ITS REVENUE REQUIREMENT?

A. The Company proposes to continue the existing rate treatment of these regulatory assets as approved by the Board in Pivotal's previous base rate proceeding and reaffirmed in the Company's last base rate proceeding in BPU Docket No. GR19040486. Thus, the Company proposes to continue the 15-year amortization of the pension regulatory asset and the 9.2-year amortization of the OPEB regulatory asset. The Company further proposes to include in rate base the unamortized balance of these regulatory assets and the total accrued pension and OPEB liabilities as of the end of the post-test year period. Information concerning these balances has been provided to Company witness Kaufmann and is reflected on Schedule JLH-9.

Q. PLEASE DESCRIBE HOW ELIZABETHTOWN ACCOUNTS FOR TRANSMISSION INTEGRITY MANAGEMENT PROGRAM ("TIMP")-RELATED COSTS.

A. In the Company's last rate case proceeding in BPU Docket No. GR19040486, it was authorized to create a regulatory asset for TIMP costs, should the Company incur such costs prior to the effective date of rates in its next base rate proceeding. No regulatory asset has been established to date as the Company has yet to spend any material O&M expense amounts related to the program. However, the federal pipeline safety regulations are continuing to evolve and likely will result in costs associated with new requirements applicable to Elizabethtown and its transmission lines. Therefore, the Company proposes to continue the authority to establish a TIMP regulatory asset, as approved in its previous base rate case. The need for this deferral is discussed more fully in Mr. Scacifero's testimony.

Q. PLEASE DESCRIBE THE COMPANY'S PROPOSED TRANSPORTATION SECURITY ADMINISTRATION ("TSA") REGULATORY ASSET.

A. The Company is requesting authority to create a new regulatory asset to defer any costs which would otherwise be expensed related to the TSA Security Directives. Costs related to evaluating and studying vulnerabilities and generating an action plan to remediate such will be recorded in Account 183.2 – Other Preliminary Survey and Investigation Charges. It is likely that a portion of these costs will be allocated to capital projects that result from the evaluations recommendations. The Company is requesting authorization to create a new regulatory asset and recover the difference between any costs relating to the TSA Security Directives that are not eligible for capitalization under Generally Accepted Accounting Principles ("GAAP") incurred and the costs that are ultimately included in the rates established in this proceeding for that purpose.

Q. PLEASE EXPLAIN THE COMPANY'S PROPOSAL TO CREATE A REGULATORY ASSET RELATED TO THE ERIE STREET LNG FACILITY.

A. The Company is requesting authority to establish a regulatory asset to defer and recover the remaining undepreciated costs of the liquefaction equipment at the Erie Street LNG Facility that were not reimbursed by the vendor/manufacturer and are not serviceable for the new liquefaction facility, as set forth in Schedule TK-13 to the testimony of Company witness Thomas Kaufmann. The Company proposes to amortize these costs over an extended period. The operational issues associated with the liquefaction equipment at the Erie Street LNG Facility are further discussed in the testimony of Company witnesses James Madden and Leonard J. Willey. The net book value of the Erie Street assets to be recovered via the regulatory asset is $6,751,219 as of June 30, 2021.

Q. PLEASE DESCRIBE THE COMPANY'S PROPOSAL TO CREATE A REGULATORY ASSET RELATED TO ESTABLISHING AN IN-HOUSE GAS SUPPLY FUNCTION AT ELIZABETHTOWN.

A. The Company proposes to establish a regulatory asset to defer and recover the difference between the costs incurred to establish an in-house gas supply function at the Company and the costs that are ultimately included in the rates established in this proceeding for that purpose. The Company's projected operations and maintenance costs of bringing its gas supply function in house included in this case are set forth in Schedule TK-13 to the testimony of Company witness Thomas Kaufmann and the capital costs are set forth on Schedule MPS-4 to the testimony of Company witness Michael P. Scacifero. The Company's proposal to move the gas supply function in-house is further discussed in the testimony of Company witnesses James Madden and Leonard J. Willey.

VIII. CONCLUSION

Q. DOES THIS CONCLUDE YOUR DIRECT TESTIMONY?

A. Yes, it does.

Elizabethtown Gas Company
Balance Sheet
At December 31,

		2018
Assets and Other Debits		
Utility Plant		
101-106, 114	Utility Plant	2,081,235,768
107	Construction Work in Progress	64,951,395
108, 111, 115	(Less) Accum. Prov. for Depr. Amort. Depl.	(306,725,819)
	Net Utility Plant	1,839,461,344
Current and Accrued Assets		
131	Cash	459,264
142	Customer Accounts Receivable	66,877,041
143	Other Accounts Receivable	2,874,167
144	(Less) Accum. Prov. for Uncollectible Acct.-Credit	(4,902,917)
154	Plant Materials & Operating Supplies	293,663
164.1	Gas Stored Underground - Current	17,486,320
164.2	Liquefied Natural Gas Stored and Held for Processing	1,646,671
165	Prepayments	1,558,744
175	Derivative Instrument Assets - Hedges	1,073,144
	Total Current and Accrued Assets	87,366,097
Deferred Debits		
181	Unamortized Debt Expense	6,003,958
182.3	Other Regulatory Assets	165,766,974
186	Miscellaneous Deferred Debits	1,666,099
189	Unamortized Loss on Reacquired Debt	4,153,413
190	Accumulated Deferred Income Taxes	52,620,948
	Total Deferred Debits	230,211,392
Total Assets and Other Debits		**$ 2,157,038,833**
Liabilities and Other Credits		
Proprietary Capital		
208-211	Other Paid-In Capital	$1,199,397,342
215,215.1,216	Retained Earnings	(5,040,638)
	Total Proprietary Capital	1,194,356,704
Long-Term Debt		
224	Other Long-Term Debt	530,000,000
	Total Long-Term Debt	530,000,000
Other Non-Current Liabilities		
228.3	Accumulated Provision for Pensions and Benefits	5,019,238
228.4	Accumulated Miscellaneous Operating Provisions	654,874
	Total Other Non-Current Liabilities	5,674,112
Current and Accrued Liabilities		
231	Notes Payable	86,000,000
232	Accounts Payable	31,119,999
234	Accounts Payable to Associated Companies	40,295,031
235	Customer Deposits	3,895,777
236	Taxes Accrued	495,631
237	Interest Accrued	688,151
241	Tax Collections Payable	2,717,225
242	Miscellaneous Current and Accrued Liabilities	1,254,875
244	Derivative Instrument Liabilities - Hedges	242,068
	Total Current and Accrued Liabilities	166,708,757
Deferred Credits		
252	Customer Advances for Construction	1,291,283
253	Other Deferred Credits	104,591,590
254	Other Regulatory Liabilities	124,545,845
255	Accumulated Deferred Investment Tax Credits	38,078
282	Accumulated Deferred Income Taxes - Other Property	21,936,060
283	Accumulated Deferred Income Taxes - Other	7,896,404
	Total Deferred Credits	260,299,260
Total Liabilities and Other Credits		**$ 2,157,038,833**

Elizabethtown Gas Company
Balance Sheet
At December 31,

		2019
Assets and Other Debits		
Utility Plant		
101-106, 114	Utility Plant	$ 2,355,429,832
107	Construction Work in Progress	95,409,835
108, 111, 115	(Less) Accum. Prov. for Depr. Amort. Depl.	(321,706,625)
	Net Utility Plant	2,129,133,042
Other Property and Investments		
124	Other Investments	8,523,293
	Total Other Property and Investments	8,523,293
Current and Accrued Assets		
131	Cash	92,661
142	Customer Accounts Receivable	76,086,577
143	Other Accounts Receivable	19,451,726
144	(Less) Accum. Prov. for Uncollectible Acct.-Credit	(5,618,294)
154	Plant Materials & Operating Supplies	401,032
164.1	Gas Stored Underground - Current	13,117,124
164.2	Liquefied Natural Gas Stored and Held for Processing	921,722
165	Prepayments	3,432,232
175	Derivative Instrument Assets	9,110
	Total Current and Accrued Assets	107,893,890
Deferred Debits		
181	Unamortized Debt Expense	6,536,221
182.3	Other Regulatory Assets	160,287,002
186	Miscellaneous Deferred Debits	7,706,614
189	Unamortized Loss on Reacquired Debt	3,643,336
190	Accumulated Deferred Income Taxes	83,475,661
191	Unrecovered Purchased Gas Costs	5,301,452
175	Derivative Instrument Assets	15,303
	Total Deferred Debits	266,965,589
Total Assets and Other Debits		**$ 2,512,515,814**
Liabilities and Other Credits		
Proprietary Capital		
208-211	Other Paid-In Capital	$1,183,797,343
215,215.1,216	Retained Earnings	29,202,523
	Total Proprietary Capital	1,212,999,866
Long-Term Debt		
224	Other Long-Term Debt	675,000,000
	Total Long-Term Debt	675,000,000
Other Non-Current Liabilities		
228.3	Accumulated Provision for Pensions and Benefits	2,826,937
228.4	Accumulated Miscellaneous Operating Provisions	496,224
230	Asset Retirement Obligation	167,154,909
	Total Other Non-Current Liabilities	170,478,070
Current and Accrued Liabilities		
231	Notes Payable	103,700,000
232	Accounts Payable	10,688,769
234	Accounts Payable to Associated Companies	18,561,918
235	Customer Deposits	11,604,687
236	Taxes Accrued	-
237	Interest Accrued	1,287,058
242	Miscellaneous Current and Accrued Liabilities	23,185,942
244	Derivative Instrument Liabilities	5,467,220
	Total Current and Accrued Liabilities	174,495,594
Deferred Credits		
252	Customer Advances for Construction	1,674,001
253	Other Deferred Credits	101,407,380
254	Other Regulatory Liabilities	121,415,313
282	Accumulated Deferred Income Taxes - Other Property	50,498,953
283	Accumulated Deferred Income Taxes - Other	3,879,225
244	Derivative Instrument Liabilities	667,412
	Total Deferred Credits	279,542,284
Total Liabilities and Other Credits		**$ 2,512,515,814**

Elizabethtown Gas Company
Balance Sheet
At December 31,

		2020
Assets and Other Debits		
Utility Plant		
101-106, 114	Utility Plant	$ 1,845,896,603
107	Construction Work in Progress	31,933,616
108, 111, 115	(Less) Accum. Prov. for Depr. Amort. Depl.	(307,196,632)
	Net Utility Plant	1,570,633,587
Other Property and Investments		
124	Other Investments	2,858,416
	Total Other Property and Investments	2,858,416
Current and Accrued Assets		
131	Cash	565,973
142	Customer Accounts Receivable	90,710,755
143	Other Accounts Receivable	7,876,610
144	(Less) Accum. Prov. for Uncollectible Acct.-Credit	(13,126,743)
146	Accounts Receivable from Associated Companies	894,841
154	Plant Materials & Operating Supplies	1,942,470
164.1	Gas Stored Underground - Current	8,883,241
164.2	Liquefied Natural Gas Stored and Held for Processing	1,072,577
165	Prepayments	6,172,697
175	Derivative Instrument Assets	2,234,301
	Total Current and Accrued Assets	107,226,722
Deferred Debits		
181	Unamortized Debt Expense	7,543,528
182.3	Other Regulatory Assets	175,775,326
186	Miscellaneous Deferred Debits	700,926,826
189	Unamortized Loss on Reacquired Debt	3,133,259
190	Accumulated Deferred Income Taxes	113,540,936
191	Unrecovered Purchased Gas Costs	-
175	Derivative Instrument Assets	512,607
	Total Deferred Debits	1,001,432,482
Total Assets and Other Debits		**$ 2,682,151,207**
Liabilities and Other Credits		
Proprietary Capital		
208-211	Other Paid-In Capital	$1,183,797,343
215,215.1,216	Retained Earnings	76,935,104
	Total Proprietary Capital	1,260,732,447
Long-Term Debt		
224	Other Long-Term Debt	800,000,000
	Total Long-Term Debt	800,000,000
Other Non-Current Liabilities		
228.2	Accumulated Provision for Injuries and Damages	1,017,238
228.3	Accumulated Provision for Pensions and Benefits	6,866,083
228.4	Accumulated Miscellaneous Operating Provisions	-
230	Asset Retirement Obligation	112,603,591
	Total Other Non-Current Liabilities	120,486,912
Current and Accrued Liabilities		
231	Notes Payable	73,900,000
232	Accounts Payable	11,041,350
234	Accounts Payable to Associated Companies	19,739,507
235	Customer Deposits	11,580,102
236	Taxes Accrued	1,876,569
237	Interest Accrued	1,387,461
242	Miscellaneous Current and Accrued Liabilities	16,916,145
244	Derivative Instrument Liabilities	1,036,521
	Total Current and Accrued Liabilities	137,477,655
Deferred Credits		
252	Customer Advances for Construction	1,772,542
253	Other Deferred Credits	92,276,531
254	Other Regulatory Liabilities	168,247,035
255	Accumulated Deferred Investment Tax Credits	-
282	Accumulated Deferred Income Taxes - Other Property	73,568,476
283	Accumulated Deferred Income Taxes - Other	27,147,364
244	Derivative Instrument Liabilities	442,245
	Total Deferred Credits	363,454,193
Total Liabilities and Other Credits		**$ 2,682,151,207**

Elizabethtown Gas Company
Balance Sheet
At September 30,

		2021
Assets and Other Debits		
Utility Plant		
101-106, 114	Utility Plant	$ 1,942,835,650
107	Construction Work in Progress	66,095,664
108, 111, 115	(Less) Accum. Prov. for Depr. Amort. Depl.	(322,796,306)
	Net Utility Plant	1,686,135,008
Other Property and Investments		
124	Other Investments	-
	Total Other Property and Investments	-
Current and Accrued Assets		
131	Cash	287,496
142	Customer Accounts Receivable	51,556,015
143	Other Accounts Receivable	7,927,727
144	(Less) Accum. Prov. for Uncollectible Acct.-Credit	(19,098,748)
146	Accounts Receivable from Associated Companies	13,505,135
154	Plant Materials & Operating Supplies	446,941
164.1	Gas Stored Underground - Current	19,306,034
164.2	Liquefied Natural Gas Stored and Held for Processing	1,092,712
165	Prepayments	26,584,565
175	Derivative Instrument Assets	32,072,792
	Total Current and Accrued Assets	133,680,669
Deferred Debits		
181	Unamortized Debt Expense	7,567,781
182.3	Other Regulatory Assets	186,652,666
186	Miscellaneous Deferred Debits	701,552,133
189	Unamortized Loss on Reacquired Debt	2,750,701
190	Accumulated Deferred Income Taxes	-
191	Unrecovered Purchased Gas Costs	-
175	Derivative Instrument Assets	7,070,548
	Total Deferred Debits	905,593,829
Total Assets and Other Debits		**$ 2,725,409,506**
Liabilities and Other Credits		
Proprietary Capital		
208-211	Other Paid-In Capital	$1,183,797,343
215,215.1,216	Retained Earnings	109,869,954
	Total Proprietary Capital	1,293,667,297
Long-Term Debt		
224	Other Long-Term Debt	925,000,000
	Total Long-Term Debt	925,000,000
Other Non-Current Liabilities		
228.2	Accumulated Provision for Injuries and Damages	1,061,150
228.3	Accumulated Provision for Pensions and Benefits	4,562,039
228.4	Accumulated Miscellaneous Operating Provisions	-
230	Asset Retirement Obligation	113,030,038
	Total Other Non-Current Liabilities	118,653,227
Current and Accrued Liabilities		
231	Notes Payable	10,000,000
232	Accounts Payable	41,383,673
234	Accounts Payable to Associated Companies	15,196,121
235	Customer Deposits	13,557,471
236	Taxes Accrued	235,543
237	Interest Accrued	10,036,156
241	Tax Collections Payable	1,414,223
242	Miscellaneous Current and Accrued Liabilities	23,389,324
244	Derivative Instrument Liabilities	273,428
	Total Current and Accrued Liabilities	115,485,939
Deferred Credits		
252	Customer Advances for Construction	1,791,796
253	Other Deferred Credits	77,884,620
254	Other Regulatory Liabilities	191,863,227
255	Accumulated Deferred Investment Tax Credits	
282	Accumulated Deferred Income Taxes - Other Property	
283	Accumulated Deferred Income Taxes - Other	1,041,973
244	Derivative Instrument Liabilities	21,427
	Total Deferred Credits	272,603,043
Total Liabilities and Other Credits		**$ 2,725,409,506**

Pivotal Utility Holdings, Inc.
d/b/a Elizabethtown Gas Company
Statement of Income For
the Six Months Ending June 30,

		2018
Utility Operating Income		
400	Gas Operating Revenues	$ 183,896,802
Operating Expenses		
401	Operation Expenses	117,800,613
402	Maintenance Expenses	4,507,441
403	Depreciation Expense	14,795,905
404-405	Amortization and Depletion of Utility Plant	-
408.1	Taxes Other Than Income Taxes	2,128,272
409.1	Income Taxes - Federal	5,412,192
409.1	Income Taxes - Other	4,096,805
410.1	Provision for Deferred Income Taxes	679,379
411.4	Investment Tax Credit Adjustment - Net	(24,385)
	Total Operating Expenses	149,396,222
	Net Operating Income (Loss)	34,500,580
Other Income (Deductions)		
415-421.1	Other Income	488,665
426.1-426.5	Miscellaneous Income Deductions	(108,056)
408.2-420	Income Taxes	-
	Net Other Income (Deductions)	380,609
Interest Charges	Interest Charges	
427	Interest on Long-Term Debt	1,961,894
428	Amort. of Debt Disc. and Expense	22,666
428.1	Amortization of Loss on Reacquired Debt	232,373
430	Interest on Debt to Assoc. Companies	8,193,182
431	Other Interest Expense	(25,365)
432	(Less) Allow. for Borrowed Funds Used During Construction-Cr.	(219,336)
	Net Interest Charges	10,165,414
Net Income (Loss)		**$ 24,715,775**

Elizabethtown Gas Company
Statements of Income For
the Six Months Ending December 31,

		2018
Utility Operating Income		
400	Gas Operating Revenues	$ 125,605,299
Operating Expenses		
401	Operation Expenses	105,625,276
402	Maintenance Expenses	3,309,571
403	Depreciation Expense	12,976,876
404-405	Amortization and Depletion of Utility Plant	-
408.1	Taxes Other Than Income Taxes	1,614,204
409.1	Income Taxes - Federal	-
409.1	Income Taxes - Other	-
410.1	Provision for Deferred Income Taxes	(3,085,553)
411.4	Investment Tax Credit Adjustment - Net	-
	Total Operating Expenses	120,440,374
	Net Operating Income (Loss)	5,164,925
Other Income (Deductions)		
415-421.1	Other Income	372,233
426.1-426.5	Miscellaneous Income Deductions	(65,875)
408.2-410.2	Income Taxes	-
	Net Other Income (Deductions)	306,358
Interest Charges	Interest Charges	
427	Interest on Long-Term Debt	10,011,393
428	Amort. of Debt Disc. and Expense	603,357
428.1	Amortization of Loss on Reacquired Debt	255,038
430	Interest on Debt to Assoc. Companies	-
431	Other Interest Expense	83,235
432	(Less) Allow. for Borrowed Funds Used During Construction-Cr.	(441,101)
	Net Interest Charges	10,511,922
Net Income (Loss)		**$ (5,040,639)**

Elizabethtown Gas Company
Statements of Income For
the Twelve Months Ending December 31,

		2019
Utility Operating Income		
400	Gas Operating Revenues	$ 325,132,721
Operating Expenses		
401	Operation Expenses	218,015,119
402	Maintenance Expenses	6,116,206
403	Depreciation Expense	28,449,579
404-405	Amortization and Depletion of Utility Plant	-
408.1	Taxes Other Than Income Taxes	3,814,711
409.1	Income Taxes - Federal	-
409.1	Income Taxes - Other	-
410.1	Provision for Deferred Income Taxes	7,799,117
411.4	Investment Tax Credit Adjustment - Net	(38,078)
	Total Operating Expenses	264,156,654
	Net Operating Income (Loss)	60,976,067
Other Income (Deductions)		
415-421.1	Other Income	806,987
426.1-426.5	Miscellaneous Income Deductions	(214,899)
408.2-420	Income Taxes	32,924
	Net Other Income (Deductions)	625,012
Interest Charges	Interest Charges	
427	Interest on Long-Term Debt	23,494,927
428	Amort. of Debt Disc. and Expense	600,964
428.1	Amortization of Loss on Reacquired Debt	510,077
430	Interest on Debt to Assoc. Companies	
431	Other Interest Expense	4,294,355
432	(Less) Allow. for Borrowed Funds Used During Construction-Cr.	(1,542,404)
	Net Interest Charges	27,357,919
Net Income (Loss)		**$ 34,243,160**

Elizabethtown Gas Company
Statements of Income For
the Twelve Months Ending December 31,

			2020
Utility Operating Income			
400	Gas Operating Revenues	$	349,392,098
Operating Expenses			
401	Operation Expenses		211,170,631
402	Maintenance Expenses		4,513,502
403	Depreciation Expense		40,300,014
404-405	Amortization and Depletion of Utility Plant		-
408.1	Taxes Other Than Income Taxes		3,482,029
409.1	Income Taxes - Federal		-
409.1	Income Taxes - Other		-
410.1	Provision for Deferred Income Taxes		12,465,410
411.4	Investment Tax Credit Adjustment - Net		-
	Total Operating Expenses		271,931,586
	Net Operating Income (Loss)		77,460,512
Other Income (Deductions)			
415-421.1	Other Income		343,340
426.1-426.5	Miscellaneous Income Deductions		(88,860)
408.2-420	Income Taxes		14,744
	Net Other Income (Deductions)		269,224
Interest Charges	Interest Charges		
427	Interest on Long-Term Debt		27,184,403
428	Amort. of Debt Disc. and Expense		1,194,730
428.1	Amortization of Loss on Reacquired Debt		510,077
430	Interest on Debt to Assoc. Companies		
431	Other Interest Expense		2,325,350
432	(Less) Allow. for Borrowed Funds Used During Construction-Cr.		(1,217,405)
	Net Interest Charges		29,997,155
Net Income (Loss)		**$**	**47,732,581**

Schedule JLH-3

Elizabethtown Gas Company
Statement of Gas Operating Revenues
For the Twelve Months Ending December 31, 2020

		Jurisdictional	Non-Jurisdictional	Total
Sales of Gas				
480	Residential	$ 229,187,625		$ 229,187,625
481	Commercial and industrial	73,712,031		73,712,031
	Total Sales of Gas	302,899,656	-	302,899,656
Other Gas Revenue				
480-495	Miscellaneous	1,610,067		1,610,067
489	Revenue From Transportation of Gas of Others	44,882,375		44,882,375
	Total Other Gas Revenues	46,492,442	-	46,492,442
Total Revenues		**$ 349,392,098**	**$ -**	**$ 349,392,098**

Exhibit P-5

Schedule JLH-4

Elizabethtown Gas Company
Payments and Accruals to Affiliates
For the Twelve Months Ended December 31, 2020

Description	Amount	
Payment and Accrual to Affiliate for Services Provided to Elizabethtown		
South Jersey Industries, Inc.		
Management Fee and Intercompany Payroll Allocations	$ 16,873,802	*
Allocation of Shared Asset Depreciation	90,875	*
Capitalization of O&M Costs	2,350,365	
	19,315,042	
SJI Utilities, Inc.		
Management Fee	2,299,921	*
Capitalization of O&M Costs	2,155,301	
	4,455,221	
South Jersey Gas Company		
Intercompany Payroll Allocation	-	
	-	
Total Costs for Services Provided to Elizabethtown	$ 23,770,263	
Payment and Accrual to Affiliate for Flowthrough Costs		
South Jersey Industries, Inc.		
Medical and Benefit Costs Allocation	$ 6,870,313	
Accounts Payable Reimbursements (Primarily insurance policy and miscellaneous expenses)	2,615,684	
Accounts Payable Reimbursements (Primarily shared IT and debt issuance costs)	11,005,195	
	20,491,192	
South Jersey Resources Group, Inc		
Gas Purchases, net of asset management fees	97,018,256	
South Jersey Gas Company		
Medical and Benefit Costs Allocation	4,355,246	
Accounts Payable Reimbursements (Primarily shared IT and utilities costs)	1,142,628	
	5,497,874	
Total Flowthrough Costs	$ 123,007,322	

* These costs are equivalent to the costs that would have been allocated to Pivotal by affilates had the acquisition of Pivotal's assets not occurred.

ELIZABETHTOWN GAS COMPANY
PRO FORMA ADJUSTMENTS TO MARCH 31, 2022 OPERATING INCOME AND RATE BASE
DEPRECIATION EXPENSE AND ACCUMULATED DEPRECIATION

Line No.		Utility Plant in Service	Depreciation Expense (Proposed Rates)	
1	**Depreciation Expense:**			
2	Test Year Utility Plant In Service-UPIS and Depr. Exp. at Proposed Rates at 3/31/2022	$1,859,618,539	$56,913,877	
3	Test Year Depreciation Expense at Current Rates		$47,072,686	
4	Test Year Difference of Annual Depreciation Expense Current to Proposed Rates		$9,841,191	
5	Post Test Year UPIS Change and Depreciation Expense for UPIS Additions	$131,341,559	$4,064,913	
6	**Total Pro Forma Adjustment to Depreciation Expense (Income Statement)**	**$1,990,960,098**	**$13,906,104**	
7				
8	**Accumulated Depreciation & Amortization Balance at Current Rates**			
9	Accumulated Depreciation & Amortization Balance at 9/30/2021		($329,742,514)	
10	Acquisition Adjustment Balance as of 9/30/2021		($130,000,007)	(1)
11	Adjusted Balance at 9/30/2021		($459,742,521)	
12				
13	**Accumulated Depreciation Test Year Adjustments per 6 Months of Projections**			
14	UPIS Depreciation Expense per Remaing Projected Months at Current Rates		($23,536,343)	
15	Acquisition Adjustment Amortization, Balance Reduction		$7,999,998	(2)
16	Retirements		$9,247,510	
17	Cost of Removal		$88	
18	**Test Year Balance as of 3/31/2022**		**($466,031,268)**	
19				
20	**Accumulated Depreciation Changes plus 6 Months of Post Test Year Adjustments:**			
21	Incremental UPIS Additions Depreciation Expense at Proposed Rates		($2,032,457)	
22	UPIS Post Test Year Depreciation Expense Proposed Rates		($28,456,939)	
23	Acquisition Adjustment Amortization, Balance Reduction		$7,999,998	(3)
24	Retirements		$9,485,578	
25	Cost of Removal		$0	
26	**Post Test Year Balance as of 9/30/2022**		**($479,035,088)**	

Notes:
2019 rate case in Docket No. GR19040486 in Order dated 11/13/19 effective 11/15/19 having a 10 Year Amortization:

		Months	Monthly Amort.	Adj. & Balances
	Start Date and as of Dates:			
	11/15/2019	120	**$1,333,333**	($160,000,000)
	9/30/2021	22.5	$1,333,333	$29,999,993
(1)	Acquisition Adjustment Balance as of 9/30/2021			($130,000,007)
	Balance Reductions Test Year and Post Test Year ending:			
(2)	3/31/2022	6.0	$1,333,333	$7,999,998
(3)	9/30/2022	6.0	$1,333,333	$7,999,998
	Acquisition Adjustment Balance as of 9/30/2022			($114,000,011)

ELIZABETHTOWN GAS COMPANY
CALCULATION OF ADJUSTED TEST YEAR
DEFERRED FEDERAL INCOME TAX (DFIT) INCLUDED IN RATE BASE

Line No.			POST TEST YEAR ADDITIONS	ADDED TAX DEPRECIATION	DFIT IN RATE BASE
1	DFIT Rate Base Balance 3/31/2022				(73,645,196)
2	**Normalization of TY Plant through 3/31/2022:**				
3	Book Depreciation at Current Rates		23,536,343		
4	Tax Depreciation-Federal		(66,145,872)		
5	Federal Tax Depreciation Over Book			(42,609,529)	
6	**Normalization of PTY Plant Additions to 9/30/2022:**				
7	Book Depreciation at Proposed Rates		2,032,457		
8	Tax Depreciation-Federal		(2,462,654)		
9	Federal Tax Depreciation Over Book			(430,197)	
10	Total Added Tax Depreciation			(43,039,726)	
11	Deferred FIT (@ effective FIT rate of 21%)				(9,038,342)
12	Federal benefit of Deferred CBT state taxes	21%			813,451
13	**Adjusted DFIT Rate Base Balance 9/30/2022:**				**(81,870,087)**

ELIZABETHTOWN GAS COMPANY
CALCULATION OF ADJUSTED TEST YEAR
DEFERRED NJ CORPORATE BUSINESS TAX (CBT) INCLUDED IN RATE BASE

Line No.			POST TEST YEAR ADDITIONS	ADDED TAX DEPRECIATION	DFIT IN RATE BASE
1	DCBT Rate Base Balance 3/31/2022				(34,683,766)
2	**Normalization of TY Plant through 3/31/2022:**				
3	Book Depreciation at Current Rates		23,536,343		
4	Tax Depreciation-Federal		(66,145,872)		
5	Federal Tax Depreciation Over Book			(42,609,529)	
6	**Normalization of PTY Plant Additions to 9/30/2022:**				
7	Book Depreciation		2,032,457		
8	Tax Depreciation-Federal		(2,462,654)		
9	Federal Tax Depreciation Over Book			(430,197)	
10	Total Added Tax Depreciation			(43,039,726)	
11	Pro Forma Adjustment - Deferred NJ CBT @	9.00%			(3,873,575)
12	**Adjusted DCBT Rate Base Balance 9/30/2022:**				**(38,557,341)**

Schedule JLH-8
6+6

ELIZABETHTOWN GAS COMPANY
PRO FORMA ADJUSTMENTS TO MARCH 31, 2022 OPERATING INCOME
INCOME TAXES - INTEREST SYNCHRONIZATION

Line No.		
1	Adjusted Rate Base	$1,392,067,037
2	Total Weighted Cost of Long Term Debt	1.7300%
3	Annualized Interest Expense	$24,082,760
4	Less: Test Year Interest Expense	($35,697,287)
5	Net Interest Expense	($11,614,527)
6	Income Tax Rate	28.11%
7	**Total (Increase)/Decrease to test year income taxes**	**($3,264,844)**

Schedule JLH-9
6+6

ELIZABETHTOWN GAS COMPANY
PRO FORMA ADJUSTMENTS TO RATE BASE
PENSION AND OPEB REGULATORY ASSETS

Line No.		
1	Pension and OPEB as of 9/30/2021	**$35,573,617**
2	Adjusted for amortization expense and net periodic benefit costs	($99,822)
3	Projected / Actual Pension and OPEB as of 3/31/2022	**$35,473,795**
4	Adjusted for amortization expense and net periodic benefit costs	($99,822)
5	Projected Pension and OPEB as of 9/30/2022	**$35,373,973**

IN THE MATTER OF THE PETITION OF ELIZABETHTOWN GAS COMPANY FOR APPROVAL OF INCREASED BASE TARIFF RATES AND CHARGES FOR GAS SERVICE, CHANGES TO DEPRECIATION RATES AND OTHER TARIFF REVISIONS

BPU DOCKET NO. GR21____________

DIRECT TESTIMONY

OF

JAMES MADDEN

and

LEONARD J. WILLEY

On Behalf of
Elizabethtown Gas Company

Exhibit P-6

December 28, 2021

TABLE OF CONTENTS

ELIZABETHTOWN GAS COMPANY
DIRECT TESTIMONY OF
THE GAS SUPPLY PANEL

I. INTRODUCTION

Q. PLEASE STATE YOUR NAMES AND BUSINESS ADDRESSES.

A. My name is Leonard J. Willey. My business address is 520 Green Lane, Union, New Jersey 07083.

My name is James Madden. My business address is 215 Cates Road, Egg Harbor Township, New Jersey 08234.

Collectively, we are testifying as the Gas Supply Panel.

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

A. [Mr. Willey] I am employed by Elizabethtown Gas Company ("Elizabethtown" or "Company") as Manager, Gas Supply.

[Mr. Madden] I am employed by South Jersey Industries Utilities, Inc. ("SJIU") as Manager, Gas Production.

Q. PLEASE DESCRIBE YOUR PROFESSIONAL RESPONSIBILITIES.

A. [Mr. Willey] As Manager of Gas Supply, I am responsible for all aspects of the natural gas purchase function including management and oversight of the Company's Asset Management Agreement with South Jersey Resources Group, LLC ("SJRG") as well as the physical purchase of natural gas supply. I participate in supply contract negotiations and execution, evaluate new storage and capacity assets and manage and oversee execution of the financial hedge program. I provide gas supply-related testimony supporting the Company's annual Basic Gas Supply Service ("BGSS") filings and base rate case filings as appropriate. I also co-ordinate with James Madden on the use of Elizabethtown's Erie Street Liquefied Natural Gas ("LNG") Facility to meet operational and peaking needs.

[Mr. Madden] As Manager of Gas Production, my responsibilities include the operations, maintenance, compliance, and capital investments of Elizabethtown's Erie Street LNG Facility, and South Jersey Gas Company's McKee City LNG Facility and New Sentury Compressor Station.

Q. PLEASE DESCRIBE YOUR PROFESSIONAL QUALIFICATIONS AND BUSINESS EXPERIENCE.

A. [Mr. Willey] I received a Bachelor of Arts degree in Computer Science from Rutgers, The State University of New Jersey, with a minor in Economics in 1991. I have been employed by Elizabethtown since September 1983, and have held a number of positions in the demand forecasting, capacity planning and gas supply procurement area. During my tenure with Elizabethtown, I have attended the American Gas Association's ("AGA") "Demand Modeling and Forecasting" seminar, the Institute of Gas Technology's "Energy Modeling" seminar, the Institute for Professional Education ("IPE")courses "Applied Time Series: Analysis and Forecasting" and "Forecasting: Methods and Applications." In addition, I have attended various conferences and seminars on other topics and issues related to my job function.

[Mr. Madden] I received a Bachelor of Science degree in Civil Engineering from Rutgers, The State University of New Jersey. I have been employed by South Jersey Gas Company and SJIU since September of 2013, working as a System Integrity Analyst before becoming the Supervisor of Gas Production, and ultimately managing multiple facilities (LNG and Compression) for SJIU. I have chaired and currently am an Associate member with the AGA Supplemental Gas Committee, and a member of the Northeast Gas Association LNG Training and Emergency Response Committee. I have certification from the Gas Technology Institute and OverNite LNG Training. In addition, I have attended various conferences and seminars on topics and issues related to my job function.

Q. HAVE YOU PREVIOUSLY TESTIFIED OR SUBMITTED TESTIMONY BEFORE THE NEW JERSEY BOARD OF PUBLIC UTILITIES ("BPU" OR "BOARD") OR OTHER REGULATORY COMMISSIONS?

A. [Mr. Willey] Yes, I have submitted testimony in numerous proceedings before the Board including the Company's 2016 base rate case in BPU Docket No. GR16090826, the Company's annual Basic Gas Supply Service ("BGSS") proceedings and in other proceedings related to gas supply.

[Mr. Madden] No. I have not.

Q. WHAT IS THE PURPOSE OF YOUR TESTIMONY?

A. The purpose of our testimony is to describe the natural Gas liquefaction project that is being developed at Elizabethtown's Erie Street LNG Facility ("Erie Street Liquefaction Project" or "Project"). This Project will be placed in service during the post-test year of this base rate case. The capital costs associated with the Erie Street Liquefaction Project are set forth in Schedule MPS-4 to Company witness Michael P. Scacifero's testimony and total approximately $45.7 million. The operations and maintenance ("O&M") costs associated with the Erie Street Liquefaction Project are discussed below. In addition, as we discuss below, Elizabethtown has commissioned an analysis of the benefits and costs of the Project by JEI Engineering ("JEI") ("JEI Report"). The JEI Report is included as Schedule GSP-1 to our testimony.

In addition, we will describe Elizabethtown's proposals to augment its natural gas supplies with purchases of renewable natural gas ("RNG") and to recover potential costs associated with bringing its gas supply function back into the utility in the event that the Board requires that result in BPU Docket No. GR21040723, a proceeding in which Elizabethtown has proposed to extend its current Asset Management Arrangement with SJRG.

II. <u>LNG LIQUEFACTION PROJECT</u>

Q. PLEASE DESCRIBE ELIZABETHTOWN'S LNG FACILITY.

A. Elizabethtown's LNG Facility can store up to 1,890,000 gallons of LNG. Depending on the thermal content of the LNG, 1,890,000 gallons equates to approximately 135,000 Dekatherms ("Dth") of LNG that can be vaporized and injected into the Company's distribution system, thereby providing a local source of gas controlled by the Company. The LNG Facility is capable of vaporizing up to 25,000 Dth of LNG per day, which represents approximately five percent of the Company's firm customers' peak day demand requirements for natural gas.

Elizabethtown serves a significant amount of weather-sensitive customer demand that will increase significantly during periods of extreme cold. Because the Company typically experiences five days or less of extreme cold temperatures per year, the LNG facility provides a cost-effective way to meet peak day customer demand requirements during periods that are typically characterized by high prices for natural gas supplies.

Q. IN ADDITION TO ITS ROLE IN SERVING A PORTION OF CUSTOMERS' GAS SUPPLY REQUIREMENTS DURING PEAK PERIODS, DOES THE LNG FACILITY PROVIDE ANY OTHER BENEFITS TO ELIZABETHTOWN'S DISTRIBUTION SYSTEM?

A. Yes. In addition to its role in serving the Company's peak demand, the LNG Facility also provides a back-up supply in the event that deliveries of gas to the Company's system by its interstate pipeline suppliers are disrupted. This back-up function has become more critical in recent years as the risks of supply disruptions have increased due to the ageing of pipeline infrastructure and the increasing threat of cybersecurity or third party terrorist attacks on pipeline infrastructure.

The loss of supply on a gas distribution system can have catastrophic consequences as a result of the fact that it can allow customers' appliances' burners to extinguish. Once that occurs, it is not safe to restore gas service until all affected gas burning appliances have been shut off. Once such a shut-off occurs, all affected gas burning appliances must be re-lit. In a densely populated area such as the Company's Union Division where its Erie Street LNG Project is located, a loss of gas supply would pose both a substantial safety risk and a considerable management challenge to effectuate the shut-off and relighting of all affected customers' gas burning appliances. The Company's LNG Facility provides a critical source of back-up in the event of a loss of supply.

Q. YOU STATED THAT THE RISKS OF SUPPLY DISRUPTIONS TO ELIZABETHTOWN'S DISTRIBUTION SYSTEM HAVE INCREASED IN RECENT YEARS, CAN YOU PROVIDE SPECIFIC EXAMPLES OF HOW THESE RISKS HAVE AFFECTED ELIZABETHTOWN?

A. Yes. The two pipeline suppliers to Elizabethtown's populous Union Division are Transcontinental Gas Pipe Line Company, LLC ("Transco") and Texas Eastern Transmission, LP ("Texas Eastern"). During the past few years the instances of partial service outages on those pipeline have increased. Most significantly in 2016, Texas Eastern experienced a failure of its 30-inch diameter pipeline near Delmont, Pennsylvania. This failure resulted in a *force majeure* event that lasted 20 days and resulted in reductions in service to Elizabethtown and other natural gas utilities. Following this incident the BPU expressed concern about the potential for future pipeline failures having a significant impact on New Jersey's gas utilities.

In addition, in May 2021, the Colonial Pipeline was cyber-attacked and forced to shut down service of flowing supplies of liquid fuels for several days. While this shutdown did not affect Elizabethtown, it considerably raised awareness of the need to build as much resiliency as possible into the facilities that Elizabethtown relies upon to provide back-up supply in the event of a similar attack on one of the Company's major pipeline suppliers.

Q. PLEASE DESCRIBE THE ERIE STREET LIQUEFACTION PROJECT.

A. The Erie Street Liquefaction Project involves the installation of a nitrogen expander ("Nitrogen Expander" or "N2") liquefier at the Erie Street LNG Facility. The N2 liquefier is capable of liquefying a total of 50,000 gallons (or 4,000 dekatherms) of LNG per day. The supply for these units ("Feed Gas") will be sourced from natural gas delivered by the interstate pipeline transporters that interconnect with Elizabethtown's facilities at the Erie Street site. Once the Feed Gas is liquefied, it will be stored in the LNG storage tank at Erie Street. The N2 liquefaction capability will allow Elizabethtown to fill its tank completely in 34 days, and to replace the vaporization of one days' worth of the maximum daily vaporization capability of the facility – 25,000 dekatherms – in less than a week.

Q. DID ELIZABETHTOWN INSTALL LIQUEFACTION EQUIPMENT AT THE ERIE STREET FACILITY IN 2016?

A. Yes. Elizabethtown installed liquefaction equipment at the Erie Street facility that was placed in service in 2017. However, the Company experienced significant operational issues with that equipment. After a period of time, the Company was unable to utilize that liquefaction equipment and engaged in negotiations with Siemens – the vendor who manufactured and installed the equipment -- concerning its removal and replacement. The Company was able to resolve its dispute with Siemens, and as a result, the malfunctioning equipment was removed from the Erie Street facility at the vendor's expense. Elizabethtown was able to utilize a portion of its investment in the previous liquefier to reduce the cost of the replacement liquefaction equipment. Company witnesses Thomas Kaufmann and John Houseman address the proposed ratemaking and accounting treatment associated with the Company's investment in its prior liquefaction equipment, as well as the Project.

Q. AFTER THAT EARLIER LIQUEFACTION EQUIPMENT BECAME UNUSABLE, DID ELIZABETHTOWN WEIGH DIFFERENT OPTIONS FOR THE ERIE STREET LNG FACILITY?

A. Yes. The JEI Report contains a detailed analysis of the options Elizabethtown evaluated. The Company considered different technologies for the new liquefaction equipment, including N2 and Mixed Refrigerant ("MR"). The Company also re-evaluated whether to continue to rely solely on trucked LNG to supply the LNG Facility and whether there were any alternative sources of incremental supply that could address the Company's reliability/gas supply needs. Ultimately, the installation of new N2 liquefaction equipment was determined to be the best option from operational, reliability and long-term cost-effectiveness standpoints. Installing new N2 liquefaction capability at the Company's LNG Facility is more cost-effective than using MR liquefaction technology, as explained in detail in the JEI Report.

Q. WHAT ARE THE ANNUAL ONGOING O&M COSTS ASSOCIATED WITH THE ERIE STREET LIQUEFACTION PROJECT?

A. The annual ongoing O&M costs associated with the Erie Street Liquefaction Project will amount to approximately $455,000. These costs relate largely to incremental staffing needs and costs associated with the operation of the liquefaction facility.

Q. WHAT ARE THE BENEFITS FROM THE ERIE STREET LIQUEFACTION PROJECT?

A. Historically, Elizabethtown had its LNG supply delivered to the LNG facility by truck. For many years, the Company was able to obtain supplies delivered by truck from LNG facilities in Northern New Jersey or Eastern Pennsylvania. Over the last several years, due to increased market demand largely related to increased use of LNG for non-traditional uses (i.e., to fuel trucks), Elizabethtown has been increasingly forced to obtain LNG supply from LNG facilities located as far away as Alabama. This results in increased costs for long-haul trucking and compromises reliability. Completely refilling the LNG facility by truck requires approximately 180 separate truck deliveries. By installing the new N2 liquefier at the Erie Street LNG Facility, the Company will be able to source natural gas locally and liquefy on site far more rapidly than the Company could ever obtain replacement supplies by truck. Installing the new liquefier will enable the Company to avoid potential reliability issues and the uncertain costs associated with long-haul trucking. The JEI Report (Schedule GSP-1 at Appendix C) discusses the benefits of on-site liquefaction versus trucked-in LNG in detail.

In addition, on-site liquefaction capability provides a reliable, consistent supply of LNG that can be replenished far more rapidly than trucked-in LNG supply. The installation of the new N2 liquefier will provide Elizabethtown with the opportunity to use the LNG supply at Erie Street to a far greater degree in the future while significantly enhancing the capabilities of the LNG Facility to support the resiliency and reliability of Elizabethtown's Union Division distribution services. In addition, the liquefaction capability will enable Elizabethtown to more rapidly and efficiently replace LNG in the tank that "boils off" during the normal operation of a LNG storage facility. The benefits of the Project as compared to alternatives are discussed more thoroughly in the JEI Report contained in Schedule GSP-1.

Q. CAN YOU PROVIDE SPECIFIC EXAMPLES AS TO HOW THE ERIE STREET LIQUEFACTION PROJECT WILL ENABLE ELIZABETHTOWN TO MAKE GREATER USE OF THE LNG FACILITY?

A. Yes. Assume that the Company experiences significant cold weather in early December such that it needs to call upon 50,000 dekatherms or approximately two days of peak supply, from its LNG Facility to serve its firm customers' demands. In the absence of the liquefier, it would have been unlikely that the Company would have been able to replace that supply using trucking for the remainder of the winter. With the liquefier, the Company would need only thirteen days following a return to more normal weather to replace the supply and guarantee that it would have five days of available supply for the remainder of the winter. A similar benefit would be available if a *force majeure* event occurred that resulted in a loss of delivered gas supplies that was offset by the use of LNG. A withdrawal of a full day of supply from the LNG facility – 25,000 dth – could be replaced with liquefaction in less than a week once a *force majeure* circumstance has been remedied.

Q. PLEASE EXPLAIN HOW THE COMPANY WILL OPERATE THE ERIE STREET LNG FACILITY ONCE THE NEW LIQUEFIER IS IN SERVICE.

A. Elizabethtown will operate the Facility to maximize the vaporization capacity to best serve its customers during peak demand conditions or other conditions in which an immediate source of supply is needed. The liquefier will be used to efficiently replace the vaporized and boiled off gases utilized in the distribution system.

Q. WHAT IS THE STATUS OF THE ERIE STREET LIQUEFACTION PROJECT?

A. The Erie Street Liquefaction Project is projected to be placed in service by July 15, 2022.

III. RENEWABLE NATURAL GAS

Q. PLEASE DESCRIBE THE COMPANY'S PROPOSAL TO ADD RNG TO ITS GAS SUPPLY MIX.

A. As discussed in the testimony by Company witness McMullen, the Company is proposing to construct an interconnection that will enable Elizabethtown to purchase and take delivery of compressed RNG by truck from a Connecticut producer beginning March 1, 2022, as well as compressed natural gas ("CNG") if it is needed in the future. The capital costs of this project total approximately $2.7 million and are set forth on Schedule MPS-4 to Mr. Scacifero's testimony.

Q. WHAT IS RNG AND WHAT ARE ITS BENEFITS?

A. RNG is anaerobically generated biogas that has been processed for use as a substitute for natural gas. There are various organic raw materials that are used to generate RNG that can be sourced from farm waste, landfills and waste treatment facilities. This waste, if not turned into RNG, would naturally decay or breakdown into methane and other constituents and vent into the atmosphere, thereby increasing greenhouse gases. Therefore, a significant benefit of processing the waste is the reduction of greenhouse gases that would otherwise have been released into the atmosphere through the natural decay of organic material.

Q. PLEASE DESCRIBE THE RNG SUPPLY THE COMPANY PLANS TO ACQUIRE.

A. The Company will purchase RNG from a Connecticut producer, starting March 1, 2022, that is generated from raw organic material. The Company will receive truckloads – approximately three trucks per week – of compressed RNG that will be injected into its distribution system in northwest New Jersey. The RNG will be priced in a manner that will not impact the system average cost of gas. The RNG will be used as supply for a portion of the Company's service territory that currently is supplied by Transco. Thus, the RNG will enhance reliability and supply diversity of the Company's service territory.

Q. IS THE COMPANY CONSIDERING ANY CHANGES TO HOW IT PERFORMS ITS GAS SUPPLY FUNCTION?

A. The Company's gas supply and upstream capacity management is currently managed by its affiliate, SJRG pursuant to an Asset Management Agreement ("SJRG AMA") approved by the Board in its June 22, 2018 Order in BPU Docket No. GM17121309. In April 2021 the Company filed a petition with the Board requesting approval of a new AMA with SJRG, which is currently under consideration in BPU Docket No. GR21040723. At the same time, Elizabethtown has begun preparing to bring its gas supply function in-house, in the event that the new SJRG AMA is not approved by the Board.

Q. PLEASE DESCRIBE WHAT RESOURCES ELIZABETHTOWN WILL NEED TO BRING ITS GAS SUPPLY FUNCTION IN-HOUSE.

A. To re-establish an in-house gas supply function, Elizabethtown will need to hire experienced gas supply asset management traders and other support personnel. Consistent with industry best practices, the Company would implement a three office model consisting of a front office staffed with at least two traders that would develop and execute the gas supply and asset management and optimization strategies, a middle office staffed with at least two schedulers and one contract administrator to confirm and monitor the risk of all deals and contracts, and a back office staffed with at least one accountant and one billing analyst that would be responsible for invoicing, accounting for, and reporting financial results. The new gas supply department will require at least seven positions as well as office space and necessary information and trading systems. Elizabethtown currently possesses none of these resources.

Q. WHAT COSTS WILL ELIZABETHTOWN INCUR FOR THE RESOURCES DURING THE POST-TEST YEAR PERIOD ENDING DECEMBER 31, 2022?

A. Elizabethtown has included approximately $474 thousand of operation and maintenance costs in this filing to bring its gas supply function in-house. In addition, Elizabethtown projects that it will incur approximately $1.05 million of capital costs associated with office space, software and equipment needed to support an in-house gas supply function. These costs are set forth on Schedule MPS-4 to Mr. Scacifero's testimony. These costs may not be incurred depending on the Board's decision concerning the Company's petition for approval of a new AMA. The ratemaking and accounting treatment of the costs related to bringing the gas supply function in-house at Elizabethtown are discussed in the testimony and schedules of Company witnesses Thomas Kaufmann and John Houseman.

Q. DOES THIS CONCLUDE YOUR TESTIMONY?

A. Yes, it does.

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REPORT:

Elizabethtown Gas Company Erie Street LNG Liquefier -- Cost Benefit Analysis

ISSUED: **DECEMBER 20, 2021**

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1.0 Executive Summary

Ensuring the availability and reliability of gas supply is a primary objective of the Elizabethtown Gas Company ("ETG"). To that end, ETG has undertaken an investigation of potential alternatives to improve the reliability of refilling its Erie Street Liquefied Natural Gas ("LNG") facility ("Erie LNG") with LNG liquid. ETG has determined that the best such alternative would be the installation of a nitrogen expander ("Nitrogen Expander" or "N2") LNG liquefaction plant. It is JEI's opinion that the installation of a N2 liquefier at Erie LNG is the best engineering, safety, ease of operations and least cost alternative to address the reliability concerns of LNG liquid supply delivered to ETG's Erie LNG facility. It is further JEI's opinion that, the determination to install a N2 liquefier was a prudent ETG management decision.

The Erie LNG tank has been in service since 1971. Historically, and at present, this facility is filled by LNG liquid tanker trucks. This facility is a critical part of ETG's peak day and near peak day gas system resources, as Erie LNG is required to deliver 25,000 Dth[1]/day of peaking gas supply into the gas system during times of high gas demand. This facility has also been needed during non-peak weather as emergency gas supply of last resort for the ETG gas system, i.e., when upstream interstate pipeline capacity curtailments occur.

To provide this integral part of the system design day capacity, the Erie LNG facility has a total storage capacity of only 150,000 Dth, of which 135,000 Dth[2] is usable to support system reliability. This limited volume of LNG can be exhausted in approximately five days. It must be recognized that the LNG dispatched from Erie LNG should be replaced as soon as possible in order to maintain Erie LNG's readiness to meet a cold weather snap and/or a gas system supply emergency. Examples of such emergencies are upstream interstate pipeline compressor failures, upstream pipeline failures, cyber-attacks or sabotage on an interstate pipeline supplying ETG that causes a reduction in the interstate pipeline's ability to deliver 100% of the daily scheduled gas volume. Volumes not delivered must be made up by additional volumes dispatched from Erie LNG and an inability to resupply Erie LNG would become a supply crisis for ETG and its customers

The reason that such a situation would become critical for ETG customers is because the gas system must maintain a minimum amount of supply to maintain adequate minimum system pressures. It is never permissible to allow the gas system to operate at below a minimum pressure threshold, which could allow customers' appliance burners to extinguish. The reason for this is that it is unknown how many and which appliances do not have temperature shut-off safety devices. Such appliances, which experiences flame-outs during a low-pressure dip, may continue to blead gas into a building after the gas pressure is restored.

In particular, distribution systems that are grid connected (similar to ETG's) are most susceptible to such risks because such systems render very large geographical areas exposed to such pressure dips

[1] Dth (Dekatherm) and Mscf (thousand cubic feet) are proportional to each other and dependent on the heating value of the gas being discussed. Unless otherwise stated, JEI assumes for purposes of this report that they are equivalent, and the terms are used interchangeably.

[2] The remaining 15,000 Dth must remain in the tank to protect it and is referred to as the "heel"

in the event pipeline supplies are interrupted for a period of time. Such an interruption would likely render a large geographic area insecure, and a prudent LDC would likely need to shut down a large segment of their territory because there may not be enough time to load-shed selective large customers in time to remove the risk to the larger geographic area.

If the LDC were to opt to do nothing after a drop in pressure due to a supply shortage, they run the risk to life and property that may result from an unpredictable number of follow-on premise fire-related incidents.

To avoid such an unpredictable loss of pressure due to a loss of supply, many LDCs have in place an LNG plant to jump into action when an insufficient supply occurs. It is not a matter of if such a supply shortage will occur, but when an insufficient supply will occur. Any of many plausible scenarios can cause such a supply shortfall.

The loss of supply and associated system pressure is a potentially catastrophic event that is mitigated by the reliability of an LDC LNG plant that is reliably supplied with LNG.

ETG is especially vulnerable to such a risk because of the reasons stated and due to the very small size of the Erie LNG tank. At a usable capacity of only 135,000 Dth, ETG needs to assure that their ability to refill their LNG tank is not dependent on the many supply risks associated with trucked LNG.

When the earlier Erie LNG liquefier was included in rate base as part of ETG's 2016 rate case, a critical concern had to do with the significant difficulty to ensure a reliable supply of LNG which is provided to the facility by truck trailer delivery. The lack of availability, as seen in disappointing responses to the Company's Truck Fill RFPs and associated high costs, were a major concern and provided justification for the liquefier addition. This supply concern existed for a host of reasons but most especially because of the domestic and international demand for LNG increasing over time while the regional sources of LNG have not significantly changed.

Today, while ETG has more recently experienced more reasonable Truck Trailer Fill RFP responses, it is JEI's opinion that the reliability and cost of supply issues that drove the LNG trucking market just a few years ago may certainly reappear with little or no warning. This is especially concerning in the era of ever-increasing Cyber-attacks and sabotage on critical energy infrastructure, as well as the risk of a breakdown in the LNG trucked-in delivery system due to a lack of available LNG supply to be purchased, increased competition among buyers of LNG, a lack of LNG truck drivers, a serious incident involving an LNG truck that results in changes in regulations that impact LNG trucking, and acts of nature (winter storms, extreme weather, floods, earthquakes, hurricanes, etc.). This is discussed further in this report.

In addition to the need for ETG to be in control of the availability of its peak shaving LNG supply, ETG also recognizes its commitment to the community, environment and the New Jersey Energy Master Plan. To fulfill the spirit and letter of that commitment, ETG recognizes the fact that compared to trucking-in LNG by tanker trucks, self-liquefaction lowers ETG's carbon footprint, lowers other harmful air emissions and serves the local community in other significant ways.

JEI believes that ETG has been properly concerned for many years now regarding the issues that could occur that would negatively affect the availability and delivery of supplies of LNG by truck and thus severely impact ETG's gas system and its customers. ETG made the determination that to ensure supply reliability, it was necessary to construct a liquefier. JEI agrees with that decision.

The next issue addressed is the liquefier technology which best meets the needs of ETG's customers. JEI explains further in this report the technical and economic reasons why a liquefier using a N2 technology compared to a Mixed Refrigerant (MR) is the best option for ETG's customers and employees. While other types of liquefaction processes are available for large scale facilities, the N2 and MR are the most widely used and cost-effective options for the location and size of the Erie LNG facility. Non-LNG options are not reasonable alternatives and are discussed in Appendices C, D and E.

1.1 COMPARISON OF N2 VS. MR LIQUEFIER COSTS AND BENEFITS

The capital expenditures (CapEx) related to installing a 4,000 Dth/day N2 liquefier at Erie LNG is estimated to be $36.7 million compared to $40.6 million for an MR system. However, our review revealed that both the N2 and MR systems had elements included in their total cost estimates that are similar. Such similar elements include site preparation, transmission pressure pipeline extension, electrical, etc. The estimated cost of these similar elements is $10.5 million. For JEI's cost comparison purposes, the CapEx for each technology was reduced by $10.5 million where the cost for a N2 system is $26.2 million and $30.2 million for an MR system.

Each technology has different operating efficiencies and therefore different operating expenses (OpEx).

CHI Engineering[3] prepared an analysis for ETG that illustrates an MR system with a slightly higher CapEx and lower OpEx. The analysis shows that economically it makes sense to use the N2 process to meet the needs of ETG's customers.

Further, in JEI's opinion, while cost is important, the safety benefits and ease of operation are typically the main factors that drive the decision for this size utility owned and operated LNG peak shaving liquefaction facility.

JEI prepared the following Table 1 to illustrate the difference in ETG's annual revenue requirements to recover the CapEx plus OpEx associated with a N2 liquefier and an MR liquefier.

Table 1 – Annual Revenue Requirements and OpEx Cost Comparison of N2 vs. MR Liquefiers

Viable options	Initial CapEx less costs common to both	Annual Revenue Requirements	Annual operating costs	Total Annual costs
N2 Liquefier	$ 26,257,000	$ 3,106,081	$ 149,829	$ 3,255,910
MR Liquefier	$ 30,152,616	$ 3,566,914	$ 136,481	$ 3,703,395

[3] CHI Engineering is a well-respected provider of Engineering Procurement and Construction services in the natural gas and oil industry, including LNG.

Among what JEI considers the viable liquefier options, the N2 liquefier is the best cost option in addition to having the following benefits over MR systems:

- Eliminates the need to handle and store flammable refrigerants on site
- Less fire/explosion risk because it eliminates the need to handle and store flammable MR refrigerants
- Not needing to frequently adjust MR refrigerant components to optimize liquefaction efficiency and capacity
- No need to manage de-inventoried MR
- Ease of maintenance as there would be no need to purge out the MR refrigeration loop for maintenance
- Greater source of spare parts and qualified repair technicians. N2 expansion parts are interchangeable with many parts used in air separation plants
- System can be restarted if off time is less than 8 hours. Thus, the unit could be shut down during peak hours and be put back on immediately thereafter (great operational flexibility)
- Make up refrigerant is readily available via a nitrogen generator or via liquid nitrogen (LN) storage
- Lower Capital Cost
- Additional equipment is not required to import, process, store inject and receive MR components
- Less need for expert training for a more complex liquefaction system
- Less consultant expenses needed to operate and maintain an MR system
- Offset of OpEx electric charge expenses by eliminating loss of MR refrigerant resulting from shutdowns and seal leakage
- Less downtime (more system availability) due to a less complex liquefaction system
- Less maintenance (more system availability) due to a less complex liquefaction system

It is JEI's opinion that among liquefier technologies suitable for the size and scope of ETG's operations, a N2 expander liquefier is a better value for ETG and its customers, compared to an MR system in terms of costs, plant safety and ease of operation.

1.2 FINDINGS AND RECOMMENDATIONS

It is JEI's opinion that the installation of a N2 expander liquefier at Erie LNG is the best engineering, safety, ease of operations and least cost alternative to address the reliability concerns of LNG liquid supply delivered to ETG's Erie LNG facility. The economics of this option provide a benefit to consumers when compared to an MR liquefier.

JEI's recommendations are as follows:

1) Continue ETG's plan to install a N2 expander liquefier. This liquefier will make ETG self-sufficient for producing LNG liquid for the Erie LNG storage tank.

2) Since ETG already has a functioning receiving facility for trucked-in LNG, JEI believes it is prudent to continue to maintain the ability to receive trucked-in LNG supplies as a back-up to the liquefier operations. This is a contingency measure to protect ETG's customers from a loss of gas supply in the event a system supply emergency happens, and for example, while the liquefier is undergoing some maintenance. If such an emergency happens, Erie LNG supply would likely be dispatched into the system and the supply being sent out into the distribution system to would need to be replaced ASAP. Receiving LNG by truck would be the only viable back-up solution to ensure the readiness of the Erie LNG facility.

2.0 Engineering Review – Background

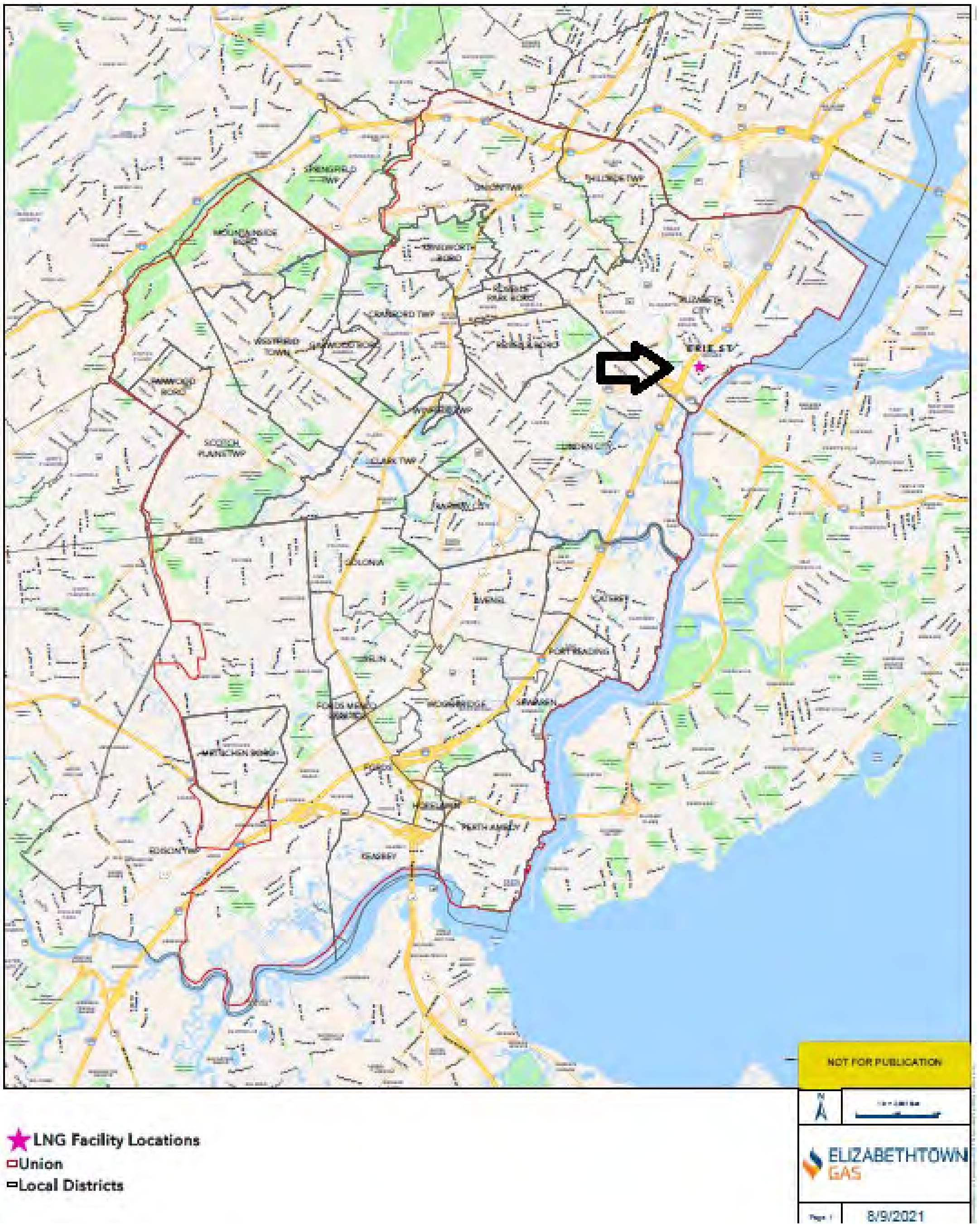
2.1 THE ETG SYSTEM

ETG's territory is made up of two non-contiguous geographic regions that are not interconnected with ETG owned pipeline infrastructure. They are the Northwest Division and the Union Division as shown on the following map.

ETG serves approximately 300,000 residential, commercial, and industrial natural gas customers in New Jersey of which the overwhelming majority are firm customers. Further, 73% of the peak day customer load is in the Union Division.

LEGAL\55601440\1

ETG owns and operates an LNG storage facility on Erie Street, which is located on the eastern edge of the Union Division as seen in the Figure 2 map.



The customers in the Union Division are served by only two interstate pipelines and ETG's Erie LNG. The two interstate pipelines are Williams' Transco (Transco) and Enbridge's Texas Eastern Pipeline (TETCO).

ETG's firm sales design peak day sendout is approximately 463,000 Dth. ETG's gas supply portfolio includes various contracts for peaking supplies plus Erie LNG. Erie LNG provides 16% of ETG's peaking supplies and 5% of the total gas supply portfolio needed to meet firm sales customer needs on a design / peak day. However, the only supply that is fully under the control of ETG is Erie LNG.

2.1 THE RISK OF LOSS OF SUPPLY

The gas delivery system is complicated, and by its nature an extremely difficult and time-consuming system to restart once interrupted.

The loss of supply can create a situation that would become critical for ETG customers because the gas system must maintain a minimum amount of supply to maintain adequate minimum system pressures. It is never permissible to allow the gas system to operate at below a minimum pressure threshold which could allow customers' appliance burners to extinguish. The reason for this is that it is unknown how many and which appliances do not have temperature shut-off safety devices. Such appliances, (example: an electronic ignition stove) which experiences flame-outs during a low-pressure dip, may continue to blead gas into a building after the gas pressure is restored.

In particular, distribution systems that are grid connected (similar to ETG's) are most susceptible to such risks because, such systems render very large geographical areas exposed to such pressure dips in the event pipeline supplies are interrupted. Such an interruption would likely render a large geographic area insecure and a prudent LDC would likely need to shut down a large segment of its territory because there may not be enough time to load-shed selective large customers in time to remove the risk to the larger geographic area.

If the LDC were to opt to do nothing after a drop in pressure due to a supply shortage, it would run the risk to life and property that may result from an unpredictable number of follow-on premise fire related incidents.

To avoid such an unpredictable loss of pressure due to a loss of supply, many LDCs have in place an LNG plant to jump into action when an insufficient supply occurs. It is not a matter of if such a supply shortage will occur, but when an insufficient supply will occur. Any of many plausible scenarios can cause such a supply shortfall.

The loss of supply and associated system pressure is a potential event that is mitigated by the reliability of an LDC LNG plant that is reliably supplied with LNG.

ETG is especially vulnerable to such a risk because of the reasons stated above, as well as due to the very small size of the Erie LNG tank. At a usable capacity of only 135,000 Dth, ETG needs to assure that its ability to refill the LNG tank is not dependent on the many supply risks associated with trucked LNG.

Any large-scale shutdown would require an enormous amount of resources over an extended period to safely restore service to gas customers. The larger the outage area, the more arduous it is to restore supply due to safety concerns and issues with gaining access to premises. Additionally, in severe cases, mutual aid from neighboring gas distribution companies may not be available due to the potential for broader regional impact on other natural gas utilities.

Although loss of gas supply would be problematic at any time of the year, an outage during cold weather would be exceptionally difficult to manage and could expose ETG's customers to unnecessary safety, health, and property damage risks. Negative consequences are exacerbated during cold weather, as hospitals, health care facilities, schools, and places designated as emergency crisis shelters may be without gas for an extended period, thus necessitating the relocation of large numbers of people. Water pipes in residential and commercial buildings may freeze and burst, resulting in wide-scale property damage that could take months to repair.

Over recent decades the threats against natural gas transmission infrastructure have increased along with economic and societal dependence on this infrastructure. Physical and cyber threats have become an ever-increasing concern in the wake of events on September 11, 2001.

For ETG, these risks are in addition to risks associated with potential changes in the trucking LNG market and the availability of suppliers and truck drivers. Today more than ever before, we recognize that these critical infrastructure assets are at risk of cyber-attacks and sabotage from domestic and foreign bad actors.

For example, the U.S. Department of Energy issued the following statement in its "Multiyear Plan for Energy Sector Cyber Security" (March 2018).

> "The frequency, scale, and sophistication of cyber threats have increased, and attacks have become easier to launch. Nation-states, criminals, and terrorists regularly probe energy systems to actively exploit cyber vulnerabilities in order to compromise, disrupt, or destroy energy systems. Growing interdependence among the nation's energy systems increases the risk that disruptions might cascade across organizational and geographic boundaries."[4]

Another example is the cyberattack reported by the NY Times, "Cyberattack Shows Vulnerability of Gas Pipeline Network" on April 4, 2018.[5]

> "A cyberattack on a shared data network forced four of the nation's natural-gas pipeline operators to temporarily shut down computer communications with their customers over the last week" These four pipelines: "Oneok; Energy Transfer Partners; Boardwalk Pipeline Partners; and Eastern Shore Natural Gas, a Chesapeake Utilities subsidiary, all reported communications system interruptions".

Major news media were reporting (as of January 2020) that the U.S. Government is cautioning owners and operators of critical infrastructure to be on high alert for potential Iranian cyber-attacks. These attacks are anticipated as a reaction to the U.S. drone strike killing of a high-level Iranian General.[6&7]

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[4] https://www.pipelaws.com/wp-content/uploads/sites/451/2018/06/4.-DOE-5-year-strategy-May-2018.pdf
[5] https://www.nytimes.com/2018/04/04/business/energy-environment/pipeline-cyberattack.html
[6] https://www.washingtonpost.com/technology/2020/01/03/cyber-attack-should-be-expected-us-strike-iranian-leader-sparks-fears-major-digital-disruption/
[7] https://thehill.com/policy/cybersecurity/476699-senior-officials-warn-of-potential-for-iranian-cyberattacks-on-the-us

On January 4, 2020, the U.S. Department of Homeland Security ("DHS") Acting Secretary issued a National Terrorism Advisory System Bulletin that included the following statement: "Iran maintains a robust cyber program and can execute cyber-attacks against the United States. Iran is capable, at a minimum, of carrying out attacks with temporary disruptive effects against critical infrastructure in the United States."[8]

On May 7, 2021, Colonial Pipeline was cyber-attacked in the form of Ransomware and the pipeline had to shut down operations for flowing supplies of liquid fuels for several days.[9]

Most recently, the DHS Transportation Security Administration issued its second Security Directive on July 20, 2021, "DHS Announces New Cybersecurity Requirements for Critical Pipeline Owners and Operators."

DHS defines Critical Infrastructure as follows: "Critical infrastructure describes the physical and cyber systems and assets that are so vital to the United States that their incapacity or destruction would have a debilitating impact on our physical or economic security or public health or safety. The nation's critical infrastructure provides the essential services that underpin American society."[10]

The purpose of highlighting these risks is that if an upstream piece of pipeline infrastructure was to be attacked (cyber or physical), and there was a shortfall of gas deliveries to ETG, the last source of supply for its customers would be ETG's LNG storage. For example, if Transco was to be forced to curtail 25,000 Dth of supply to the Erie gate station, Erie LNG could supplement that loss of supply. Without Erie LNG, ETG would need to shed an amount of gas equivalent to the consumption of approximately 10,400 residential heating customers. This is why ETG requires a reliable source of LNG that is under its control and supervision.

2.2 THE ERIE LNG PLANT

Erie LNG began operation in 1971 and stores the equivalent of 150,000 Dth of natural gas in vapor form. Its usable volume is 135,000 Dth with the balance (15,000 Dth) needing to remain in the tank to protect it (a.k.a. the heel). The plant has three vaporizers, each capable of producing 10,000 Dth/day (30,000 Dth/day combined maximum), if required to support ETG's gas network. On a peak day, ETG's gas supply portfolio requires Erie LNG to produce 25,000 Dth per day. At this daily rate, the usable capacity of the tank is exhausted in approximately 5 days. Although each pump/vaporizer set is rated at 10,000 Dth/day for a total of 30,000 Dth/day, the daily rating is 25,000 Dth to account for pump cool down time and pump/vaporizer ramp up time.

The facility is currently filled via LNG tanker trucks that deliver LNG liquid from as far away as Trussville, Alabama. The facility has no other way to fill the tank with LNG. Each truck delivers approximately 850 Dth (765 Dth after accounting for flash gas during unloading) of LNG.

[8] https://www.dhs.gov/ntas/advisory/national-terrorism-advisory-system-bulletin-january-4-2020
[9] Colonial Pipeline Hack Reveals Weaknesses in US Cybersecurity - The New York Times (nytimes.com)
[10] https://www.dhs.gov/topic/critical-infrastructure-security

In addition to the amount of LNG that is vaporized and dispatched into ETG's distribution network to meet customer demand during periods of cold weather, throughout the year the LNG in the tank will experience boil-off[11] as part of the natural process of storing LNG and that gas needs to be replaced by the equivalent of 65 truckloads per year of LNG (approximately 50,000 Dth). The need for additional LNG liquid supply to fill the tank depends on winter weather, work on the ETG gas system, or an unplanned reduction in supply from one of the interstate pipelines that supply ETG.

The LNG dispatched from Erie LNG needs to be replaced as soon as possible in order to maintain Erie LNG's readiness to meet a cold weather snap and/or a gas system emergency. Examples of such an emergency are a compressor failure, pipeline failure, cyber-attack or sabotage on an interstate pipeline supplying ETG that causes a reduction or curtailment in the interstate pipeline's ability to deliver 100% of the daily scheduled volume. Volumes not delivered must be made up by additional volumes of LNG to be dispatched from Erie LNG.

[11] Boil-off refers to the on-going natural process at the surface of the LNG where LNG evaporates due to heat leak into the tank. This boil-off gas (BOG) has to be put into ETG's distribution pipelines

3.0 Engineering Analysis: LNG Background

3.1 GAS STORAGE

In general, natural gas utilities, also known as local distribution companies (LDCs), provide the last segment of natural gas fuel delivery to the end-use customer. Much of the gas delivered to end use customers comes from wells thousands of miles away from the end-users.

End-users may be residential, commercial, industrial or other. Some of these customers may, by tariff, be guaranteed gas service for part of the year and have their service intentionally interrupted during periods of very high gas demand. However, the vast majority of gas utility customers are "firm" customers. A firm customer is guaranteed gas service every hour of every day of the year regardless of how severe the weather may be. Because firm customers are guaranteed natural gas supply, typically they do not have an alternate source of fuel for heating, cooking and/or process.

Many of these customers could suffer severe injuries and or property damage resulting from the loss of gas service during extreme cold weather conditions. This can be in the form of damaged property or even injury/death if health-compromised individuals are exposed to a no-heat situation for an extended period.

For example, a gas outage involving 10,400 customers over such a large geography, especially during cold weather, would be difficult to manage, costly, and may indeed expose ETG's customers to unnecessary safety, health, and property damage risks. Even with extensive mutual aid from other utilities, the required process of first shutting-off, making safe and then relighting each individual customer's gas appliances in a large geographic area during sub-freezing temperatures may require weeks to months to complete, resulting in the need to relocate people to safe locations and the potential freezing of water pipes in many structures.

Recent examples of very large gas customer outages and the extraordinary amount of time required to restore service can be found in reviews of the Columbia Gas of MA outage in the Merrimack Valley region of MA in the Fall of 2018, National Grid of RI loss of gas supply to Aquidneck Island in January 2019, and the State of Texas in February 2021.

Such an event would severely threaten the welfare of the residents and staff of ETG alike and would severely strain the emergency response capabilities. An additional concern regarding an off-system event is that the resources required to manage and safely restore gas service to customers would likely go beyond ETG staff and contractors. Such an event would likely trigger a request for mutual aid from other gas distribution companies; however, others may also be impacted and need to restore their own systems, and this could lessen or negate their ability to provide mutual aid to ETG.

Because the safety and welfare of the LDC's customers is mission critical for the Gas Industry, LDCs have numerous programs specifically in place to assure their safety and welfare. For example, each LDC has in place processes to prevent gas leakage and to assure that any leaks are made safe with a follow-on repair if necessary. Another example is that LDCs use many methods to assure that the gas system does not run low of gas supply during the highest demand days.

The highest gas demand day is not always the lowest temperature day, but for many companies, the peak load day (peak day) is coincident with the coldest day of the year. To meet the load requirements of the peak day, the LDCs deploy many methods including load shedding management, gas storage methods, line pack, and special pipeline contracts for peaking services.

Preparing for and meeting peak day demands is mission critical to any prudent LDC. Typically, when an LDC is experiencing a peak day, the regional companies in that area are also experiencing their peak day. Thus, pipeline capacity is typically not there to purchase additional pipeline gas supplies. I.e., there is just no more capacity on the pipeline to get additional gas supplies to the LDC.

During such a peak day, the LDC would be getting its maximum contracted amount off the gas pipeline. Some of that gas may be from gas producing wells hundreds to thousands of miles away and some may be from underground storage systems that are filled when there is excess gas supply and drawn upon during times of short supply.

The peak day design of the gas system is also critical. It is not only important to get the gas into the distribution system, but it is also important to get it distributed to each customer through adequately sized pipes. To this end, a prudent operator makes sure reinforcement, reliability and redundancy studies are performed and the recommendations of the studies are implemented to assure that the gas system is adequate on that peak day.

The use of storage gas is needed not only to meet peak day supply, but also to maintain system pressures to assure deliverability and to counter a system failure. Such a failure may be on an interstate pipeline whereby the pipeline needs to declare a force majeure cutting deliverability to the receiving LDC.

Above, underground storage was mentioned. Underground storage can be man-made in deep earth formations to store gas under high pressure or refilled old gas wells that are used like surge tanks to provide gas supplies when well-head production cannot keep up with the demand. Underground storage is critically important to the LDC. However, it is also typically hundreds to thousands of miles away from the LDC. So, although an LDC may be able to purchase additional storage capacity at the storage location, getting it up the pipeline is often not economically viable for the gas customer as it may require many of miles of additional pipelines and/or many additional compressor stations along the run from the storage location to the LDC.

3.2 LNG A STORAGE OPTION

A storage methodology used in lieu of underground storage is the use of LNG. LNG is natural gas that has been cleaned of impurities that would hinder liquefaction and has been refrigerated to such a cold temperature that it converts to a liquid. The benefit of LNG is that a cubic foot of liquid, when heated up, converts to approximately 600 standard cubic feet of natural gas.

LNG is used in Peak Shaving plants. Such plants liquefy and store LNG or tanker truck import and store LNG. The stored LNG is then converted to its vapor state and dispatched into the distribution system during times of high gas system demand or for system reliability needs.

There are approximately 94 LNG peak shaving or satellite facilities in the United States. Approximately 47% percent (44 plants) are in the Northeast United States. Approximately 30% of the 44 peak shavers and satellite facilities use a liquefier to make LNG on-site and the remaining sites truck-in LNG.

When planning on having storage to meet a gas system's demands, it is better to have the storage inside the LDC's territory. This is because it eliminates any situation whereby the LDC may have storage in a facility far from its territory but cannot have it delivered to the LDC due to some pipeline constraint.

3.3 TO TRUCK-IN LNG OR TO LIQUEFY

The Northeast United States has been and still is today significantly dependent on LNG peak shaving. This is because much of the load growth occurring in the 1970s through 1990s was possible only because Everett LNG (formerly Distrigas LNG now owned by Exelon) took in LNG via ocean-going tankers and distributed that LNG via LNG trucking to the peak shaving plants within several hundred miles of Everett, Massachusetts. Everett LNG has and is planning to continue to ship thousands of tanker trucks of LNG to the Northeast LDCs each year. However, this single source of trucked-in LNG makes the Northeast very vulnerable to a single source failure if for some reason, Everett LNG were unable to accept or deliver LNG for any extended period of time.

This vulnerability is the very reason some utility LNG facilities have chosen to build LNG liquefiers instead of trucking-in LNG. Certainly, trucking-in LNG is an easy solution for securing LNG; however, the ability to truck-in LNG has been very volatile and problematic. As an example, in 2012 South Jersey Gas (SJG) sent out an RFP to truckers/suppliers of LNG. None of the bidders were able to fulfill the number of trucks needed to assure the reliable supply of LNG to SJG and some of the RFP recipients did not even respond to the RFP. For the security of the SJG gas system, SJG then built a liquefier at their LNG facility. A similar unnerving result happened to ETG in 2013. In that year, ETG issued an RFP for LNG supply and did not receive any offers. During the following summer of 2014, ETG's traditional LNG suppliers in northern New Jersey or eastern Pennsylvania were unable to meet ETG's needs, forcing ETG to consider suppliers as far away as the mid-west, Alabama and Canada; even Everett LNG did not have the capacity to supply ETG's needs. That year ETG had to source its LNG supplies from a facility in Alabama, adding significant cost due to trucking.

LNG is a temporary storage. A typical LNG tank may take 1,000 or so truckloads to fill in a year, depending on the size of the tank and the usage during the year. However, even if the tank were to be filled and never needed for peak shaving, the LNG is constantly boiling-off, thereby requiring trucking or liquefier operation each and every year. A typical LNG tank just sitting idle loses approximately 18% of its capacity each year due to boiling-off while it sits idle. That 18% loss continues year after year. In two years, the tank will have lost 36% of its original volume and, by the end of year three, the amount of LNG remaining it that tank would be down to 48%. What is worse is that the 48% of LNG remaining would no longer be interchangeable with pipeline gas as the LNG would have weathered. Weathering is a phenomenon whereby the most volatile gas boils-off preferentially early on in the boil-off, leaving mostly the heavier hydrocarbon components behind. The use of weathered LNG is extremely difficult as it requires the LNG plant operator to highly dilute the vaporized LNG with a gas low in heavy hydrocarbon composition. Further, even with 48% left in the tank, one is never able to drive the tank down to empty. It is always necessary to leave approximately a 10% heel in the tank to assure that the tank does not warm up and self-empty as this could be stressful to the tank and very costly to remedy.

In addition to the above discussion regarding boil-off, note that receiving trucked in LNG is less efficient than an uninformed observer may realize. Not only is there a large amount of trucking needed to replenish LNG, but the amount of LNG charged for a truckload is significantly less than that which actually enters the tank. This is illustrated in Appendix B, where it is assumed that the truck is held at a constant pressure by the ambient vaporizer on the truck while the LNG is flashed to the lower pressure of the LNG storage tank. For short haul trucks, the amount of LNG entering the LNG facilities gate may be charged as a deliverable amount of approximately 30,000 lbm (pound mass), but the amount of LNG liquid entering the LNG tank is typically only 90% of that for short haul deliveries and can be as little as 82% of that for long haul deliveries. This is because of the viscous dissipation of the LNG as it travels along the route to the LNG plant and the heat leak into the LNG tanker truck.

This inherently increases the cost of LNG trucking by 10 to 18% more than what is typically calculated. This loss of 10 to 18% of the delivered cargo is due to flash gas produced when the LNG cargo pressure is let down from tanker truck pressure to an atmospheric LNG storage tank pressure.

As mentioned earlier, the ability to obtain LNG via truck is problematic. In the Northeast, not only is it highly dependent on the availability of the Everett LNG facility, but it is also vulnerable to weather conditions, union disputes, acts of terrorism, and the socio-economic swings of the energy industry.

Everett LNG is not the only play in town. Other facilities with liquefiers provide LNG trucking services as well. However, since Everett LNG is such a large majority of the LNG trucking industry of the Northeast, any event affecting their ability to truck LNG impacts all the Northeast LNG suppliers.

As for the socio-economic swings, that is in the form of more and more of the transportation sector leaning towards LNG as a motor fuel or bunkering fuel for boats. Such demands for LNG are unpredictable, but they certainly are becoming a drain on the existing stock of LNG trucks and LNG truck loading capabilities.

For these reasons, it is clearly a more reliable delivery system if an LNG plant has its own liquefier rather than to rely on trucked-in LNG. It may or may not be less expensive based on the market price of trucked LNG; however, if maintaining the reliability of the LNG supply is paramount, then having a liquefier has greater reliability benefits than only having truck unloading facilities. One should also keep in mind that having a liquefier at the LNG plant does not negate the plant's ability to truck in LNG. If spot LNG pricing is right, an LNG facility can opt to both liquefy and truck-in LNG.

The size of the tank in question is also a major issue. In the case of ETG's LNG facility, the maximum usable tank capacity is only 135,000 Dth. This means that if the tank was completely filled and if the plant was needed to provide maximum output to offset a system-wide supply shortfall, the tank would be essentially emptied (at its heel) in just over five days of operation If such an event were to happen, all regional facilities would also be hard pressed to use their LNG resources to the maximum in order to offset the system-wide supply shortfall. Such a situation happened several years ago, when a pipeline rupture in southwestern Pennsylvania curtailed much of the gas deliverability for points north and east of the pipeline break. That pipeline rupture was due to a corrosion defect, and it rendered the pipeline severely curtailed for nearly nine months. If that had been due to an intentional attack on the gas system, it is likely that the curtailment would have been more severe and may have lasted for an even longer period of time.

3.4 TYPES OF LNG LIQUEFIERS

There are many types of LNG liquefiers. These range from the very efficient (uses a low power consumption) type to the inefficient (uses a high-power consumption) type. And then there are mid-efficiency systems as well (MR or Cascade systems). Most Cascade systems use pure substance hydrocarbon gases for refrigerants. It sounds like a simple choice, but the choice is anything but simple. Each system has its pros and cons. The system that is chosen for a facility is an economic/operational decision that is based on many factors.

The following Figure 4 shows the LNG cooling curve for a specific composition of gas compared to the refrigeration curve of several different types of liquefaction cycles. The closer the cooling curve can match the refrigeration curve and the closer they are in temperatures, the higher the system efficiency.

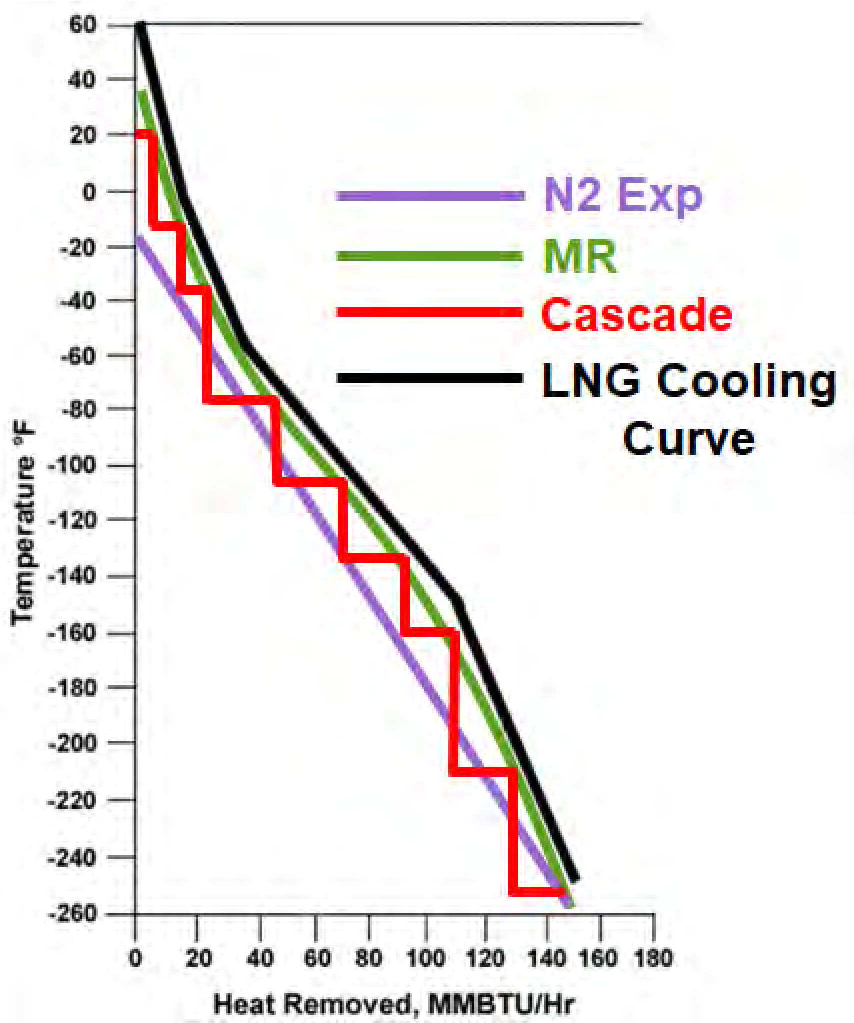

Figure 4: Illustration of N2 Expansion, MR and Cascade Liquefaction Over Cooling Curve Presented in Handbook of LNG.[12]

This figure shows only one curve as representative of a single gas composition. It needs to be realized that each system is only as efficient as it is properly matched to the composition of the actual feed gas stream. However, this figure can be used to give a relative representation of the efficiency of the various systems. The cascade system is limited by the fact that at each pure substance pressure there is an associated saturation temperature. That saturated temperature results in a large gap between the LNG cooling curve and the boiling refrigerant liquid. The N2 Expansion curve is limited by the relatively low heat transfer available from the gaseous nitrogen resulting in requiring a higher delta T. The MR curve, if properly adjusted can give a better match than the other two processes, if the composition and

[12] Modified from Cascade Drawing of Handbook of Liquefied natural Gas, 2014.

pressure of the MR is adjusted properly. The key for achieving the MR's high efficiency is the proper adjustment of the MR composition and pressure. It is unfortunate when an MR system is selected based on its theoretical higher efficiency, only to have it perform poorly because the operators cannot accomplish that proper adjustment.

As seen in this figure, the best match of the cooling curve to the liquefaction curve is via the green line mixed refrigerant process. After that, the red Cascade system curve shows as fairly efficient. Lastly, the least efficient match is the purple N2 expansion system curve. This graph could have shown many more curves but having it show just these three representative curves presents the point to be made. That is that different processes have differing efficiencies and that no two systems have all pros to getting the liquefaction job done. Each system has its own set of complexities and its own advantages and disadvantages.

In general, the highest efficiency systems are reserved for the very large capacity liquefiers that are intended to run for long periods of time without shutdown. These systems are typically run by expert operators who are well trained in system optimization. On the other hand, the lower efficiency systems are typically selected for small peak shaving plants with less experienced operators who can afford higher operating cost but whose priority is "reliably" (keeping the plant on-line after a prolonged shutdown by using operators who do not do liquefaction full time as a dedicated job function).

However, on a positive note, the expansion process is simple and very forgiving to less experienced operators who can operate it essentially just by turning the system on. There is no need to de-inventory large amounts of flammable refrigerant and no need to adjust the refrigerant mixture in order to match the cooling curve. The feed gas can swing in composition and in temperature and the N2 expansion system self-adjusts to the refrigeration conditions.

On the other hand, the operator of the Cascade system needs to continually adjust in pressure set points. The MR system operator also needs to adjust continually the MR composition as atmospheric and feed gas conditions and/or composition changes.

For very large liquefiers with high capacity and utilization (for example operating at over 300 days per year compared to ETG's situation for approximately 40 days per year), one of the most efficient systems available today is the C3 MR system. One such system was installed at Cove Point in 2017. It has performed very well at high efficiency. That is a very large and complex system requiring constant adjustments to meet optimization as well as production goals.

In JEI's informed opinion, the C3 MR system was a good process selection for this liquefaction system at Cove Point as its design intent was to make the least cost LNG in very high quantities using expertly trained liquefaction technicians. Today, the Cove Point plant is producing LNG at a rate equivalent to filling ETG's tank 5 times per day.

An example of a less efficient system is the N2 Expander system installed at SJG's LNG facility in McKee City. While it expectedly operates at a lesser efficiency than the Cove Point facility, it has performed exceptionally well, giving high reliability and a service that well fits its application. SJG's operators can turn this system on or off as needed without the need to de-inventory flammable refrigerant and without concern about differing feed gas composition.

Where the difference comes in is the scale of the plant and the type of operation considered. The C3 MR system at Cove Point is intended to be a high throughput base load facility. It is essentially an MR system made to operate more efficiently and with less complexity by using a C3 (propane) pre-chiller on the MR and feed gas system. This C3 system lessens the need for operator intervention due to ambient temperature changes and due to minor gas composition changes.

A major part of the decision process when selecting a liquefier type is the refrigerant choice. If an N2 Expansion type of system is chosen, the refrigerant is nitrogen which can be leaked or discharged into the atmosphere without much hazard. On the other hand, if any of the MR or Cascade systems are chosen, the flammable refrigerants must be vented to flare or, if possible, mixed with large quantities of boil-off gas (BOG) before being sent into the distribution system. It is not practical to store MR or all of the cascade refrigerants once the refrigeration is stopped for maintenance if the storage system is full.

Further, all refrigerants leak to some degree at the seals of the compressors. These emissions need to be considered when designing the plants. In the case of nitrogen, this seal leakage can be vented directly to the atmosphere. In the case of an MR system, this leakage must be flared (emitting greenhouse gases and at a higher cost than N2 system as shown in Tables 3 and 4) or mixed with BOG before sending out to the distribution system.

All MRs and Cascade systems use flammable gases as refrigerants. These include but are not limited to Methane, Ethane, Ethylene, Propane, and iso-pentane. It is typical to include a certain amount of nitrogen in the MR mixture as well, but nitrogen is not flammable. The composition of the MR is adjusted to accommodate the cooling curve of the feed gas based on the feed gas composition and temperature.

Although these MR systems deliver a high efficiency, they are complex systems that involve a flammable refrigerant. This means there must be many subsystems involved in the balance of plant including impoundment, additional fire protection systems, additional leakage sensing and response systems, etc. Also, storage of the MR components becomes problematic at best. Ethane in particular is difficult to store on-site. Typically, it is stored at low refrigerated temperatures and elevated pressure in underground vessels.

A comparison of some of these liquefaction systems is shown in Table 2. Just a few processes are shows.

Table 2 – Comparison of Some of These Liquefaction Systems Is Shown Below

Comparison of Liquefaction Systems	CapEx	OpEx	Ease of Operation	Flammable Refrigerant
C3 MR	High	Low	Difficult	Yes
SMR	Middle range	Midrange	Midrange	Yes

DMR	Middle range	Midrange	Midrange	Yes
Cascade	Middle range	Midrange	Midrange	Yes
N2 Expansion	Low to Middle range	High	Easy	No

The following two figures (Figure 5 and Figure 6) illustrate schematics of a N2 nitrogen expansion system and a single MR system.

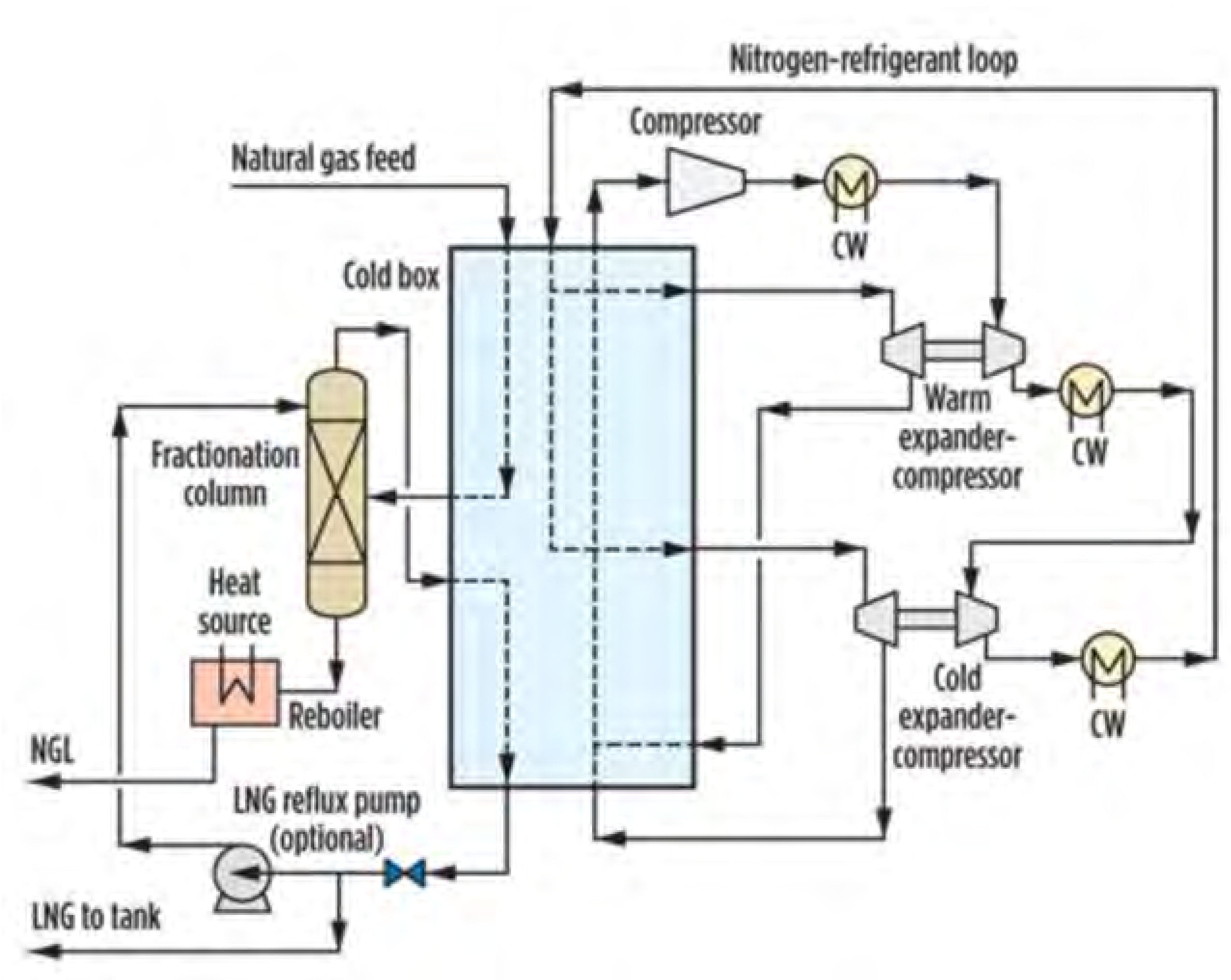

Figure 5: N2 Expander System Not Showing Pretreatment Plant[13]

[13] Gas Processing and LNG, Nitrogen expansion cycle enhances flexibility of small-scale LNG, J. Pak et.al.

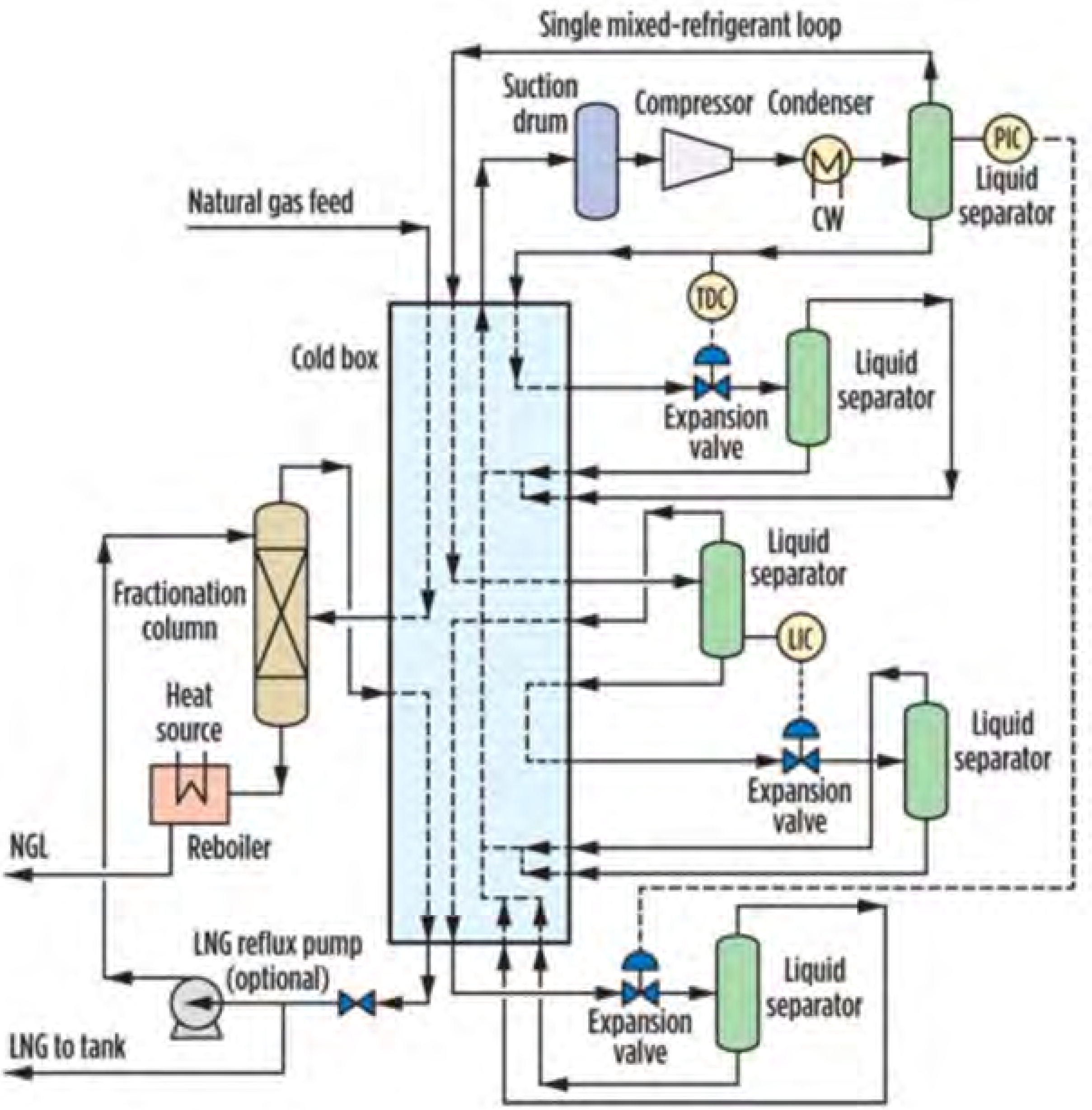

Figure 6: Single Mixed Refrigerant Liquefaction System Not Showing Pretreatment Plant[14]

After seeing the success of its N2 liquefier at McKee City and understanding that for its needs a N2 system was economically more desirable, South Jersey Industries (SJI) management decided to install a N2 Expander liquefaction system at is ETG LNG facility which is a small LNG facility. This decision was also supported by SJI's desire to minimize potential additional safety risks with any system that would require the storage and handling of a flammable refrigerants, such as MR systems.

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[14] Gas Processing and LNG, Nitrogen expansion cycle enhances flexibility of small-scale LNG, J. Pak et.al.

JEI concurs with this choice as prudent since any savings in operating costs would, in our opinion, be offset by the need for more extensive training and the venting of flammable refrigerant to either the flare or into the gas distribution system.

4.0 Engineering Analysis: The Decision to Select a 50,000 gallon/day (4,000 Dth/day) Nitrogen Expansion Liquefaction System is Reasonable

4.1 ETG'S LIQUEFACTION SELECTION PROCESS

It has been established earlier in this report that having a reliable gas supply for ETG's customers is a prudent, mission critical objective of ETG. JEI concurs with this objective as prudent for the safety and welfare of ETG's customers.

For this reason, it was concluded earlier in this report that for a supply to be "reliable," it needs to be in the control of ETG at their Erie LNG tank location. This decision to install a liquefier at the Erie LNG Facility isolates ETG's Erie LNG storage security from events outside of ETG that might have interfered with a secure supply of LNG.

Furthermore, in order to assure the objective of having a reliable supply of LNG to the Erie LNG Facility, ETG has selected to install the N2 Expansion liquefier. In JEI's informed opinion, this was a prudent decision for system reliability. The N2 Expansion liquefier is considered to be one of the most reliable liquefiers available. Its simplicity of design, ease of operation, and resistance to refrigerant borne corrosives such as mercury make it an ideal system for providing a high degree of reliability.

Air Products, one of the largest owners and producers of air separation and LNG liquefiers, stated in an article that "Air Products also owns and operates more than 100 nitrogen recycle liquefiers and over 300 cryogenic plants. Year in and year out, our system-wide availability exceeds 99 percent, while achieving the industry's lowest levels of operating and maintenance costs."[15]

For the purpose of this study, Appendix A provides the technical details needed to understand the natural gas to LNG cooling curve and the refrigeration cooling curve for the respective LNG liquefaction processes, and their energy efficiency and exergy implications in accordance with the 1st and 2nd laws of thermodynamics. Appendix A also shows the process schematics associated with the various processes.

There is no hard fast rule on how to select a liquefaction system; however, the prime objective in the selection process is to provide a cost-effective "balanced" engineering approach which provides plant life long high system availability. The plant must be available when needed to come on-line.

The issue of high system availability is especially important at the Erie LNG plant site because the Erie LNG Tank is extremely small and its capability to supply can be brought down to zero within 5 days after having a full tank, if maximum demands are placed on the plant's sendout capacity. The N2 Expansion system's unique flexibility greatly enhances this ability to refill on the same days as sendout by having the ability to restart within 8 hours of the last run time, allowing operators to sendout during peak hourly load periods and liquefy during lower load hours.

[15] Air Products, Small-Scale LNG Pant Capabilities – Simple design, low unit cost and fast schedule, 2019

The relevant literature (Air Products[16] and CHI[17]) states that N2 Expansion systems have a lower CapEx and a higher OpEx as compared to competing systems. Here is where JEI believes ETG used a prudent "balanced" engineering approach to the selection of the N2 Expander system. In the discussion that follows, JEI will explain why it believes the selection of the N2 Expansion liquefier was indeed prudent from a cost perspective.

4.2 LIQUEFACTION SYSTEMS (SEE APPENDIX A FOR ADDITIONAL DETAILS)

The Gas Industry embraced LNG significantly in the 1960 - 1980 timeframe. At that time, liquefaction systems were not nearly as advanced as they are today. There were, and still are, many different styles of liquefaction systems to choose from, each having their best fit for site specific applications.

There are three basic categories of liquefiers and many subcategories. The three main categories are (refer to Appendix A for details):

1) **The Cascade Systems.** The Cascade System uses pure substance refrigerants to cascade a cooling effect to the coldest section of the plant. The refrigerants are typically hydrocarbon refrigerants that are all flammable. These refrigerants are typically Methane, Ethylene, and Propane; however, each design may be different, and the designers may choose refrigerants outside this grouping. An oversimplification concept of the Cascade System would be to think of the Cascade System like having a freezer in your basement that brings the temperature down to -20 F inside the freezer box. Then, inside that freezer box is another smaller freezer that's outside at -20F and it brings its inside freezer box temperature down to -100 F. Then, inside that second freezer there is yet another freezer box that brings its inside freezer box an even lower temperature of -180 F.

   This is cold enough to make LNG at high pressure. When that high pressure LNG is flashed down to tank pressure, LNG and BOG are produced and near -260 F.

   These systems can be characterized as having a high CapEx, a low OpEx and requiring a secondary plant for the mercury removal, dehydration storage and management of hydrocarbon refrigerants. The operator skill for such a plant is higher than for the N2 Expansion plant.

2) **Mixed Refrigerant (MR) Systems.** MR plants use a mixture of refrigerants to accomplish high efficiency and, thus, low operating costs. These systems can be enhanced by using dual mixed refrigerants or by adding on a front-end cooler that chills the incoming gas and the front end of the MR refrigerant loop. The front-end chiller is typically a 3-4 temperature step propane refrigeration system. Adding on this front-end chiller is costly, but for very high-volume applications it pays off in efficiency and stability of the plant during daily ambient temperature swings.

[16] Ibid
[17] J. PAK, Cosmodyne LLC "Nitrogen expansion cycle enhances flexibility of small-scale LNG" Gas Processing & LNG Technology, September 2021

These systems can be characterized as having a high CapEx, a low OpEx and requiring a secondary plant for the mercury removal, dehydration storage and management of hydrocarbon refrigerants. The operator skill required for operating such a plant is higher than for the N2 Expansion plant. There are many different MR systems and here are just a few of mention:

- **C3/MR system.** This is one of the most efficient systems available and it is best suited for large scale export terminals where the liquefier will operate almost continuously, typically with multiple trains to liquefy large quantities of natural gas. It is typical for such facilities to liquefy 10 – 20 million gallons per day. Although these systems are not called dual MR systems, it is typical for such systems to split the refrigerant into MR Vapor (MRV) and MR Liquid (MRL). The MRV is cooled to become a liquid and there are actually 2 separate MR loops providing different levels of refrigeration to a temperature below that of the LNG stored in the tank.

  As an example, such a system is used at Cove Point and it liquefies almost 10 million gallons per day. For comparison, that is about 200 times the capacity of the size of the unit being installed at the Erie LNG Facility. Such a unit requires about 300,000 shaft horse power and numerous auxiliary systems.

  The balance of plant for this process is huge. Such complexity and efficiency do not come without a high CapEx, but because the OpEx is lower due to the very large quantity of LNG produced, the "balanced" engineering choice for Cove Point was to use this process.

  These systems can be characterized as having a high CapEx, a low OpEx and requiring a secondary plant for the mercury removal, dehydration storage and management of hydrocarbon refrigerants. The operator skill required for operating such a plant is significantly higher than for the N2 Expansion plant.

- **Dual MR system.** The dual MR system uses a mixture of pure substances as a refrigerant. Since there are dual systems, the refrigerant mixture is different for each refrigerant loop.

  The balance of plant for this process is large. Such complexity and efficiency do not come without a high CapEx, but because the OpEx is lower if the quantity of LNG produced is very large, the "balanced" engineering choice would be to use this process.

  These systems can be characterized as having a high CapEx, a low OpEx and requiring a secondary plant for the mercury removal, dehydration storage and management of hydrocarbon refrigerants. The operator skill required for operating such a plant is significantly higher than for the N2 Expansion plant.

- **Single MR system.** This is the simplest of MR systems. It offers high efficiency, but it is the on the low end of the high efficiency systems as it does not make as good of a fit to the LNG cooling curve as shown in Appendix A. These type systems are in use where the specific site conditions, expected life of the plant and the system capacity warrant this type of system to make a balanced engineering choice.

These systems can be characterized as having a medium to high CapEx, a medium to low OpEx and requiring a secondary plant for the mercury removal, dehydration storage and management of hydrocarbon refrigerants. The operator skill required for operating such a plant is higher than for the N2 Expansion plant.

3) **Nitrogen or Methane Expansion Systems.** "While MR cycles dominate at world-class and medium-scale LNG plants, the reverse Brayton nitrogen (N2) cycle (or N2 expansion cycle) has enjoyed a resurgence at small-scale LNG plants. Here, the different liquefaction cycles available for small-scale LNG plants, and the specific factors that contribute to the N2 cycle becoming the cycle of choice."[18]

This type of system is totally different than the above systems and stands in a class of its own. Although this type of system will work on either Nitrogen or Methane as a refrigerant, in this study we will discuss only the expansion of Nitrogen for the obvious reason that, with all else equal, having a non-flammable refrigerant is desirable over having a flammable refrigerant.

The first two systems mentioned above, the Cascade and MR systems, use refrigerants that change phase during the cooling process. The Cascade System changes phase at fixed temperatures and pressures (as many as 9 different steps of fixed temperature/pressure equilibrium saturation conditions, typically using 3 different pure substance refrigerants).

The MR system refrigerant smoothly changes phase but not at a fixed temperature. Instead, the zeotropic refrigerant changes composition as it preferentially boils off the more volatile components of the refrigerant allowing it to closely follow the LNG cooling curve across a large range of temperatures.

Both processes, the Cascade and the MR systems, allow for a close fit to the LNG cooling curve resulting in high efficiency.

The Expansion System (could use either nitrogen or methane as a refrigerant) does not change phase. Instead, it just cools down as it does work through an Expander. The first law of Thermodynamics governs this process. The first law states that in a system that is not increasing in energy inventory, the energy into a control volume is equal to the energy out of the control volume. As the refrigerant expands, it produces shaft work in the expander (sometimes incorrectly called a turbine) and that removal of work can only come from extracting heat energy from the refrigerant. Thus, as an example, high-pressure nitrogen refrigerant enters an expander at say -100 F and leaves the expander at a lower pressure and -180 F. The cold low temperature (-180F) refrigerant is used to cool feed gas which is converted to LNG.

[18] Gas Processing and LNG "Nitrogen expansion cycle enhances flexibility of small-scale LNG" by, J. PAK, Cosmodyne LLC, Seal Beach, California

Once the refrigerant absorbs heat from the feed gas and is compressed back up to high pressure, it has heat removed and is again sent through the expander to produce temperatures' cold enough to produce LNG.

A power turbine uses the same theoretical concepts but with the goal of producing shaft work instead of producing a cold temperature, yet the cooling effect still occurs. In a power turbine, the inlet temperature to the turbine is approximately 1,700 F and the outlet temperature is approximately 1,000 F. It is called a turbine instead of an expander because the usable end product is shaft work instead of cooling.

The balance of plant for this process is small. Such simplicity results in a lower CapEx, but a higher OpEx due to a poorer matching of the refrigerant cooling curve to the feed gas cooling curve. The "balanced" engineering choice for selecting this type of liquefaction process is a function of the quantity of LNG produced each year and the human resources available for the plant operation. If the LNG production is relatively small and the available operating staff is not highly technically skilled, this type of plant would be a well-balanced engineering choice.

These N2 Expansion systems can be characterized as having a low CapEx, a higher OpEx and not requiring a secondary plant for the mercury removal, dehydration storage and management of hydrocarbon refrigerants. The operator skill required for operating such a plant is significantly lower than for the MR or Cascade systems.

4.3 GAS UTILITY LNG PEAK SHAVING HISTORY

The U.S. Peak Shaving Industry started in the war years of the early 1940s. In Cleveland, Ohio, three spherical and one cylindrical small LNG tanks were erected and put into service for a few years. The Peak Shaving Industry was a fledgling to the use of LNG at that time and their knowledge about handling and designing systems for LNG service was limited. The war time shortages made it even more difficult due to the scarcity of alloy steels. The tanks were made of 3.5% nickel steel which was tough down to -150F. But LNG is stored at -260 F, a temperature too cold for 3.5% nickel steel to retain its ductility.

One afternoon in 1944 one of the LNG tanks leaked with a brittle failure which spilled out its contents. The LNG tank did not have a dike around it to prevent the LNG from entering the community. The LNG flowed down the streets into sewers where the water vaporized the LNG by adding heat to it and pressurized the sewer system with odorless flammable gas vapor. The pressurized sewer system blew odorless vaporized gas into buildings for blocks around the plant. One manhole cover was found miles from the plant. Over 130 people were killed and 680 were left homeless as multiple explosions destroyed over 160 acres of the neighborhood.

The LNG Peak Shaving Industry learned a lot from that incident, and it became the basis for the NFPA 59A and 49CRF part 193 codes. The LNG Peak Shaving Industry did not go back to its building of Peak Shavers until more than 20 years later. Of the approximately 91 peak shaving and satellite LNG facilities in the United States today, approximately 78% of them were built from the mid-1960s to mid-1980s.

Many of these plants used either MR systems or N2 Expansion systems. At that time, both MR systems and N2 Expansion systems were only fair performers as compared to the optimized systems of today. The technology was still in its infancy as it had not grown much during the 20+ years of zero growth since 1944. In fact, the use of submerged pumps had not yet begun, and plants were typically all bottom penetration tanks. As an example, the Erie LNG facility was built in 1971.

At this same time, a major import terminal was built in Everett, Massachusetts. This facility was, and still is today, capable of importing LNG via sea-going LNG tankers. The Everett facility has two large storage tanks, and these are well matched to comfortably accept one ship a week provided they have sent out the LNG from the prior ship. The Everett LNG facility sends out LNG via direct vaporizing with injection of vapor into pipelines, and by trucking out LNG via tanker trucks. Their trucking out operations have been in the 6,000 to 12,000 truckloads per year range for at least the past 30 years. The northeast LNG peaking facilities are significantly dependent on this single facility.

To give an order of magnitude, a 1 BCF peaking tank would require approximately 1,200 trucks to fill it. The Erie LNG Facility would require approximately 188 tanker trucks to fill it. The Everett tanks hold approximately the equivalent of 3,800 tanker truckloads and a tanker ship holds approximately the equivalent volume of 3,600 tanker truckloads.

Many of the peaking and satellite LNG facilities installed since the 1960s were installed without liquefaction plants and arrangements were made to truck-in LNG via LNG tanker trucks. This practice still is in place today with approximately 50% of all LNG peaking facilities being filled by trucked-in LNG. In this study, JEI is considering satellite facilities as a subset of peaking facilities.

4.4 LIQUEFIER TYPE DECISION PROCESS

As mentioned earlier, approximately 78% of the U.S. inventory of LNG peak shavers and satellite facilities were built during the 1960s through mid-1980s. Those legacy plants are mostly still in place, but the original liquefiers, if they had liquefiers, have for the most part been refurbished or replaced.

During those early years, theoretical CapEx and OpEx projections were considered when making the purchasing decisions, but real-life operating experience was very limited. Today, such CapEx and OpEx projections are more precise as they are based real-world operating experience.

JEI can attest to the fact that many of the earlier liquefiers were not operating at optimal conditions mostly due to:

- Poor operator training (lack of understanding of the process and thermodynamics)
- Not removing mercury from the feed gas and/or the refrigerants
- Not installing or cleaning feed gas and system filters
- Lack of adequate maintenance
- Poor MR mixture control
- Shutdown equipment overrides during anomalies
- A general lack of well-developed and well-followed procedures

In response to these real-life conditions, manufacturers started to produce more robust systems and better optimization technologies. For instance, today's systems include provision for condition monitoring and pre-action to developing trends to repair components prior to equipment failure. The practice of a using tribology, thermography and vibration sensing is the norm today as compared to breakdown maintenance with bailing wire of the 1970s and preventive maintenance of the 1990s (which often broke that which was not broken).

The efficiencies have also changed significantly. In the 1960s-70s time frame, MR liquefaction units would "technically" typically operate at nearly twice the efficiency of N2 Expansion systems. And many MR units were sold under that premise. However, in order to achieve such theoretical efficiencies, engineers would need to control the MR compositions and carefully calculated system adjustments were needed. Further, it was not typical to take into account the real-world refrigerant losses that accompanied shutdowns and the other costs associated with operating and maintaining these more complex systems. It was realized that system simplicity was needed for plants that stood idle for a good part of the year and were then called upon to operate just prior to the winter operating season. Further, additional maintenance as a result of operator error caused by operating a more complex system with a lesser skilled workforce was eating up the perceived cost benefit of the lower OpEx hoped for.

On the other hand, the N2 Expansion systems were less in need of proficient operators and essentially were systems that operated as designed giving reliable operation without expert care.

Thus, in the early years of LNG peak shaving, the liquefier efficiency advantages of the MR systems were used to make purchase decisions, but the OpEx savings were seldom fully realized. In particular, the plant operators of the MR system were now distracted by needing to operate a complete import, storage, processing, filling loading and holding system for the MR components in addition to operating the LNG process. In particular, Ethane is difficult to store as it needs to be stored either as a very high-pressure gas or as a refrigerated pressurized liquid.

4.5 THE CASCADE AND MR HAZARD

A major concern that is seldom discussed is that of the Cascade and MR system refrigerant. This refrigerant is typically a brew of methane, ethane, propane and a small amount of nitrogen in both liquid and vapor form. Sometimes ethylene and iso-pentane are also used. This requires purging equipment when turning over the equipment for maintenance and purging when returning equipment back from maintenance. This further taxes the training needs of the operating staff who are used to dealing with typically only natural gas and BOG, both of which are lighter than air.

4.6 SEAL LEAKAGE

One might be able to stop all connection leaks, but all of the liquefaction systems leak refrigerant at the compressor seals (both labyrinth and dry seals). This is a given. However, only the N2 Expansion system leaks a non-greenhouse gas that does not pose a fire or environmental hazard. In the past, such leakage was simply vented or flared or mixed into regeneration gas exiting the plant or being used as fuel gas.

Today, every pound of hydrocarbon must be reported and credited or debited from the gas operators' allowable amount of emissions. This may not be a big issue this year, but initiatives like 50% net zero by 2030 and full net zero by 2050 may be a harsh awakening for all industries including the Peak Shaving Industry.

With ETG's Erie LNG facility being in a severe ozone non-attainment zone, it is prudent to select an LNG liquefaction process that would have no hydrocarbon seal leakage. The only such system is the N2 Expansion system.

4.7 N2 EXPANSION IMPROVEMENTS OVER THE PAST 20 YEARS.

While the MR and Cascade systems have been approaching their projected OpEx efficiencies via better training of operators over the past 50 years, and making design and manufacturing improvements, the N2 Expansion liquefaction systems have been making very significant design and hardware improvements achieving real-life higher efficiencies without needing highly skilled engineers to operate the systems. Much of the improvements realized in the N2 Expander technology is related to the aerospace industry advances as both rely on improved efficiency of turbines and compressors.

- Turbo compressor and expander design and manufacturing processes have resulted in equipment efficiencies not thought possible 40, or even 20, years ago
  - Computer Fluid Dynamics (CFD) and Finite Element (FE) software is used to optimize equipment design replacing the trial-and-error approach of the 1970s.
  - Computer simulations (including 3D simulations) give designers a better understanding of flow patterns, fluid dynamics, pressure drops, film layer effects and stress loads on rotating equipment allowing for better designs and more effective contours for nozzles and impellers. The impact of such software not only improves design but also allows for lower price systems as it eliminates much of the trial-and-error testing.
  - Computer aided manufacturing, along with the CFD and FE software mentioned above, has sometimes greater than 10% efficiency improvements as compared to units of the 1960s and 1970s. As an example, the manufacturing impellers using 5 axis machine computer numerical controlled (CNC) machines has improved impeller efficiency alone by 2-5% as compared to the older casting impellers.[19] These machines allow for precision sculpturing of diffusers, vanes and tighter tolerance for all sealing components resulting in lower losses in efficiency lower seal leakage and an overall higher quality product at a reduced cost.
  - The range of integrally geared centrifugal compressors has resulted in N2 Expansion cycles to be available at competitive efficiencies.[20] Integrally geared compressors have higher efficiencies due to interstage cooling at each stage and the use of two or more pinion shafts for optimal impeller speeds. These compressors are also less expensive

[19] Cameron, "Centrifugal compressor performance upgrades" 2010

[20] J. PAK, Cosmodyne LLC "Nitrogen expansion cycle enhances flexibility of small-scale LNG" Gas Processing & LNG Technology, September 2021

than custom designed compressors[21]. Due to their compact size, they require a smaller footprint and a simple and economical foundation.[22] This standardization has resulted in readily available spare parts at lower costs.[23]

- Newer N2 Expansion systems are designed to better follow the natural gas cooling curve thus increasing efficiency and lowering energy requirements.
- Newer N2 Expansion systems are load adjustable. Thus, plant operators can run the unit at a reduced capacity during times of high electric demand charges or when the tank is nearly full, to allow the plant to be in a cold and ready state for longer periods while keeping the tank at the nearly full mark. This not only permits the operator to have capacity adjustment but also lessens cyclic temperature shocks to the liquefaction systems.

4.8 ANALYSIS OF N2 VS. MR COST AND OTHER BENEFITS

Clearly, by reading many theoretical analyses regarding the cost of LNG liquefiers both CapEx and OpEx are important. However, the literature indicates that any real comparison needs to be made based on a site-specific facility. CHI has made that analysis for the Erie Street facility and found that the CapEx for the N2 Expansion system is less than the CapEx for the MR system.[24] This is consistent with what JEI would expect, as maintaining a separate hydrocarbon refrigerant processing facility to support the LNG facility is a costly part of the balance of plant. This is further supported by the Air Products reference made earlier.

Further, the literature clearly indicates that a dollar spent on extra CapEx in order to obtain a lower OpEx only works for large, nearly continuously operated liquefiers. Such large scale liquefier operators maintain a staff of highly skilled engineers and well trained operators who on a daily basis are training while operating their plant. The fewer hours the liquefier is on-line the less opportunity there is to offset the extra dollar spent on CapEx.

Thus, for this analysis, JEI is going to accept the CHI data that the CapEx for the N2 Expander is lower than that for the MR system. JEI bases this decision on the fact that an MR system requires a separate plant to import, process, store, receive and inject the various refrigerant components into the liquefier.

JEI also recognizes that this separate plant needs to process the gas coming off the liquefier when a refrigerant de-inventory is needed. MR cannot be stored as a liquid, unless it is refrigerated, because it contains nitrogen which gives it a very high vapor pressure. This removal and disposal of de-inventoried MR can become very expensive and is typically not covered in any economic cost analysis. Further, the Elizabethtown territory in New Jersey is in a "serious ozone non-attainment zone" making it nearly impossible to discharge new emission sources into the atmosphere.

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[21] Ibid
[22] Ibid
[23] Ibid
[24] Presentation to South Jersey Gas CHI Capabilities Liquefaction Discussion

In JEI's informed opinion, CHI (the EPC contractor for the Erie LNG liquefier) is correct in claiming that the operating cost of the N2 Expansion system would be more expensive per gallon than a comparable MR system.[25] Further, JEI opines that this can be offset in the future by adding on a pre-chilling system to the N2 Expansion plant, but this would then drive up the CapEx for this plant.

With this data in hand, the JEI economic analysis is as follows:

- It is JEI's informed opinion is that the CapEx for the N2 Expansion system is calculated to be less than that for the MR system.[26]
- The higher OpEx electrical (higher electrical charges) for the N2 Expansion system is more than offset by the many benefits of the N2 Expansion technology. This is significantly supported by the fact that the liquefier is not a base load liquefier that will operate every day and will be used only as needed to either make up boil-off gas or to restore peaking gas supply. Thus, the number of operating hours is small compared to that of any base load facility. Since OpEx is proportional to the hours of operation, the savings related to an MR system over a N2 Expansion system would be minimal due to the fewer hours of operation. The N2 Expansion benefits include but are not limited to:
  - Less fire/explosion risk associated with not needing to process and storing MR components
  - Not needing to expertly adjust refrigerant components on an hourly and daily basis
  - No need to manage de-inventoried MR
  - Ease of maintenance as there would be no need to purge out and refrigeration loop for maintenance
  - Greater source of spare parts and qualified repair technicians. N2 expansion parts are interchangeable with many parts used in air separation plants.
  - Allows for subcooling to lessen BOG production, thus lessening run times required to fill tank and reducing electric consumption of the BOG compressors.
  - System can be restarted if off time is less than 8 hours. Thus, the unit could be shut down during peak hours and put back on immediately thereafter (a great operational flexibility)
  - Make up refrigerant is readily available via a nitrogen generator or via liquid LN storage
  - Lower Capital Cost
  - Not needing a separate plant to import, process, store inject and receive MR components
  - Less need for expert training
  - Less consultant expenses needed to operate and maintain an MR system
  - Offset of any OpEx electric charge expenses due to loss of MR refrigerant resulting from to shutdowns and or seal leakage.
  - Less downtime (more system availability) due to a less complex liquefaction system
  - Ease of system operation

[25] Ibid
[26] Ibid

- Less maintenance (more system availability) due to a less complex liquefaction system

This is supported by the following cost comparison (Table 3) provided to ETG by CHI Engineering, which demonstrates that an MR system has a higher CapEx and a lower OpEx. In addition to the reasons stated previously, economically it makes sense to use the N2 process to meet the needs of ETG's customers.

While CHI's analysis is for a larger liquefier (10,000 Mscf/day vs. ETG's 4,000 Mscf/day), it illustrates the point that an N2 system with higher OpEx and lower CapEx, compared to an MR system would take 62 years[27] to make up the additional capital cost to install an MR liquefier.

Table 3 – CHI Engineering's Cost Analysis of 10,000 Mscf/day N2 vs. MR Liquefiers Prepared for ETG

		N2 Liquefier	MR Liquefier	Delta $ (MR-N2)	Delta % (NR vs N2)
Capital Cost		**$ 48,604,000.00**	**$53,758,000.00**	**$ 5,154,000**	**9.6%**
Liquefier Capacity	**MMSCFD**	**10**	**10**		
	GPD	121,000	121,000		
Refrigerant Costs					
Initial Fill		$ 335	$ 48,128	$ 47,793	99.3%
Daily Refrigerant Cost		$ 262	$ 682	$ 420	61.6%
Electrical Costs					
Specific Power	KW/Gal	1.13	0.89	-0.24	
Electrical Rate	$/KW	$ 0.10	$ 0.10	$ -	
Daily Electric Cost		$ 13,673	$ 10,769	$ (2,904)	-27.0%
Daily Operating Cost (Electrical & Refrigerant)		**$ 13,935.00**	**$ 11,451.00**	**$ 2,484**	**-21.69%**
Annual Operating Cost					
Average Annual Days of Operation		40	40	0	**0.0%**
Electrical Costs		$ 546,920	$ 430,760	$ (116,160)	**-27.0%**
Refrigerant Annual Fill (33% of total fill)		$ 111	$ 15,882	$ 15,772	**99.3%**
Refrigerant (Operating Day)		$ 10,480	$ 27,280	$ 16,800	**61.6%**
Annual Operating Cost (40 days)		**$ 557,511**	**$ 473,922**	**$ (83,588)**	**-17.6%**
Simple Payback - Capital Cost Delta / Annual Operating Cost Delta				**$ 62**	**yrs.**
This cost analysis does not Include the following:					
Additional fuel gas required for flare operation (required to handle PSV discharges/venting)					
The fact that the specific power gap between the MR and N2 systems decreases with the size of the liquefier					
Additional maintenance costs associated with additional fire protection equipment calibration, testing and maintenance (for flammable refrigerant storage area)					

JEI has adjusted the CHI analysis to reflect the smaller size of ETG's liquefier and it too demonstrates that the N2 system is economically the best choice for ETG and its customers. Table 4 illustrates the point that a 4,000 Mscf/day N2 system with higher OpEx and lower CapEx, compared to an MR system, would take nearly 300 years[28] to make up the additional capital cost to install an MR liquefier.

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[27] Difference in Capital costs divided by difference in Operating costs ($5,154,000 / $83,588)
[28] Difference in Capital costs divided by difference in Operating costs ($3,895,616 / $13,347)

Table 4 – JEI's Cost Analysis of 4,000 Mscf/day N2 vs. MR Liquefiers

	units	N2 Liquefier	MR Liquefier	MR Delta$ MR-N2)	MR Delta % MR-N2
CapEx before common costs are removed		$ 36,737,000	$ 40,632,616	$ 3,895,616	9.6%
CapEx after common costs are removed		$ 26,257,000	$ 30,152,616	$ 3,895,616	12.9%
		capex less common capex costs for both systems			
Liquefier Capacity	mmscf/d	4	4		
	GPD	50,000	50,000		
Refrigerant costs					
Initial fill		$ 134	$ 19,251	$ 19,117	99.3%
Daily refrigerant cost		$ 105	$ 273	$ 168	61.6%
Electrical costs					
specific power	kW-hr /gal	1.13	0.89	(0.24)	-27.0%
electric rate	$/kW-hr	$ 0.053	$ 0.053		
Daily electric cost		$ 2,995	$ 2,359	$ (636)	-27.0%
Electric Demand Charge per day	$/day	$ 467	$ 467	$ -	0.0%
Daily operating cost, (electrical and refrigerant)		$ 3,463	$ 2,826	$ (636)	-22.5%
Annual operating costs					
Average annual days of operation		42	42		
electrical kW-hr costs		$ 125,769	$ 99,057	$ (26,712)	-27.0%
electric demand		$ 19,614	$ 19,614	$ -	0.0%
refrigerant annual fill (33% of total fill)		$ 44	$ 6,353	$ 6,309	99.3%
refrigerant (operating day)		$ 4,402	$ 11,458	$ 7,056	61.6%
Annual operating costs		$ 149,829	$ 136,481	$ (13,347)	-9.8%
Simple Payback (CapEx delta /Annual Operating costs)				**(292)**	**years**

This analysis does not include the following:

Additional fuel gas required for flare operation (required to handle PSV discharge/venting)

The fact that the specific power gap between the MR and N2 systems decreases with the size of the liquefier

Additional maintenance costs associated with the additional fire protection equipment calibration, testing and maintenance for flammable refrigerant storage area)

The fuel gas and other consumables are essentially the same for both types

Table 5 compares the annual cost impact on ETG's customers in terms of annual revenue requirement and OpEx for 4,000 Dth/day N2 and MR liquefiers.

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Table 5 –Comparison of N2 vs. MR Liquefiers Annual Revenue Requirements Plus OpEx

Viable options	Initial CapEx less costs common to both	Annual Revenue Requirements	Annual operating costs	Total Annual costs
N2 Liquefier	$ 26,257,000	$ 3,106,081	$ 149,829	$ 3,255,910
MR Liquefier	$ 30,152,616	$ 3,566,914	$ 136,481	$ 3,703,395

5.0 Recommendations

For the reasons stated throughout this report, it is JEI's informed opinion that the installation of a N2 liquefier at Erie LNG is the best engineering, safety, ease of operations and least cost alternative to address the reliability concerns of LNG liquid supply delivered to ETG's Erie LNG facility. It is further JEI's opinion that the determination to install a N2 liquefier is the decision that should be made by a reasonable and prudent public utility management.

JEI's recommendations are as follows:

1) Continue ETG's plan to install a N2 expander liquefier. This liquefier will make ETG self-sufficient for producing LNG liquid for the Erie LNG storage tank.
2) Since ETG already has a functioning receiving facility for trucked-in LNG, JEI believes it is prudent to continue to maintain the ability to receive trucked-in LNG supplies as a back-up to the liquefier operations. This is a contingency measure to protect ETG's customers from a loss of gas supply in in the event a system supply emergency happens, and for example, while the liquefier is undergoing some maintenance. If such an emergency happens, Erie LNG supply would likely be dispatched into the system and the supply being sent out into the distribution system would need to be replaced ASAP. Receiving LNG by truck would be the only viable back-up solution to ensure the readiness of the Erie LNG facility.

Appendix A: Common LNG Liquefaction Systems

Natural gas is a mixture of many gases. The most abundant of the gases is methane and the next most abundant is ethane. Transporting natural gas is easily accomplished by pipelines; however, pipeline transport across oceans is difficult. Thus, for transport of natural gas across oceans, it is common to liquefy the natural gas before transport and then to vaporize it near the end point of use.

Natural gas is also a commodity that is used at varied rates at its point of use. For example, a city would use large quantities of natural gas on a very cold day and very little natural gas on a mild weather day. The same holds true when natural gas is used for electric generation. For example, during a hot spell when a large amount of electric generation is needed, a large draw of natural gas is utilized to generate electricity. During times when these large gas demands are required, the pipelines may not be able to fully supply such loads. During those times, stored natural gas is used to supplement the pipeline supply of gas.

Using LNG to supplement the supply of natural gas during peak load times is called peak shaving. The name is derived from the fact that use of this supplemental gas is to shave the peaks off the load demand curve. Perhaps, defining it as supplemental supply services would have been a more correct terminology; however, the Gas Industry has adopted the term peak shaving and we will continue to use that term for this study.

LNG is nothing more than natural gas that has been cleaned of some components that would hinder liquefaction and is then liquefied by cooling. It is liquefied in order to store a large amount of natural gas into a small volume. Approximately 600 standard cubic feet (a standard cubic foot is a cubic foot at standard condition of 60 F and 14.73 psia) is stored in one cubic foot of LNG.

The typical components that are removed are removed in what is called the pretreatment plant. For the purpose of this study, we will not focus on the pretreatment plant, other than to state that any of the liquefaction cycles considered in this study would all require a pretreatment plant. Thus, whichever liquefaction process were to be selected by ETG, they all would have in common a pretreatment plant. In general, the pretreatment system removes the following components: pipeline solids and liquids, hydrogen sulfide, carbon dioxide, mercaptans, mercury, water vapor, and heavy hydrocarbons (typically hydrocarbons with greater than 3 carbon atoms). These contaminants are not fully removed but are removed to a concentration level that will avoid having them freeze to a solid during the liquefaction process.

Thus, with no further discussion needed on pretreating the natural gas, the remainder of this appendix will focus on the liquefaction processes evaluated for the ETG Erie LNG Facility.

The 3 main types of liquefiers considered for application are the Cascade System, the MR system and the Expansion system. The merits of these 3 systems are explained in the body of this report and the purpose of this appendix is to explain the technical operation and design implications of each of these systems.

Before getting into an explanation of the various processes, it is best to first describe the LNG cooling curve and the implications related to using systems that allow heat to be transferred from the feed gas stream. After the feed gas is pretreated, it is cooled by a refrigeration system.

As the gas is cooled, the feed gas starts to liquefy. The composition of the very first droplets that form is not LNG but instead is a liquid consisting of the least volatile components of LNG. Those first droplets contain high concentrations of C4+[29], (heavy hydrocarbons) and propane. While some ethane and methane and a trace amount of nitrogen are also in those first droplets, their concentration is very small as compared to the heavier hydrocarbons.

As the feed gas is cooled further and as the heavier hydrocarbons are depleted from the feed gas, then the follow-on droplets start to contain more propane and ethane. As the propane and ethane is depleted from the feed gas, then the follow-on droplets formed from the feed gas will contain the more volatile components of the feedstock.

The final droplets to condense out of the feedstock is nearly pure methane and nitrogen.

Because of this preferential condensation of the least volatile components ahead of more volatile components, the LNG cooling curve is not a straight line and has inflection points. This is shown in Figure 7 below. Thus, the shape of the LNG cooling curve is a function of the composition of the feedstock. If the feedstock is rich in ethane and propane, the condensing hydrocarbons occur early in the cooling of the feedstock resulting in the curve starting to flatten out early on in the cooling process.

The following Figure 7 shows multiple cooling curves for the very same gas composition. However, by observation one can see that the shape of the cooling curve is also a function of the feedstock pressure. This is because the dew point of the gas is a function of the gas pressure. Thus, the shape of the cooling curve is a function of both the gas composition and the gas pressure. Matching a best fit refrigeration system to that cooling curve is the job of the design engineers who select and design the refrigeration process as well as the operating personnel who control the operation of the refrigeration system.

To liquefy a feedstock stream, one merely needs to cool down the stream. However, at the extremely cold temperatures needed to make LNG, the process selected can make a large difference in the energy required to make LNG.

The energy consumption of a liquefaction system as compared to the amount of LNG produced is a primary driver when selecting different process designs for achieving the highest refrigeration efficiency to produce LNG. Exergy analysis can help engineers identify where irreversible energy losses are occurring in a liquefaction system.

The measure of exergy is the measure of the maximum desired work or energy output one can extract from a given process with respect to its surroundings using totally reversible processes. For instance, a 92% efficient furnace is said to have conserved all of its energy input but destroyed 8% of its exergy. Energy cannot be destroyed but exergy can be destroyed by irreversible inefficiencies. In the case of the furnace, the energy was not destroyed but the exergy was destroyed as losses prevented it

[29] C4+ are hydrocarbons with 4 or more carbon atoms in each molecule

from producing 100% of its potential output. Exergy is totally different from energy as energy exists in a body independent of its surrounds, but exergy only exists if its surrounds are at a different potential energy level.

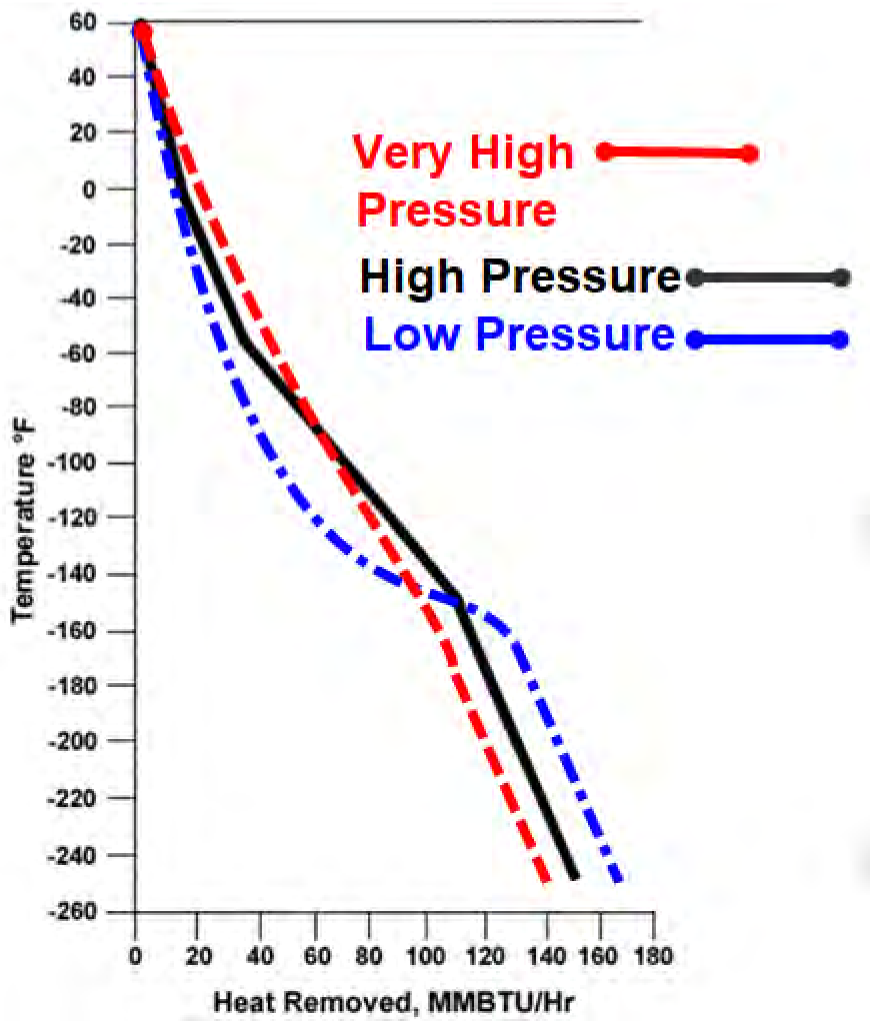


Figure 7: Illustration of Various cooling curves of the Same Gas at Varied Pressures

In designing an LNG liquefaction system, major causes of exergy destruction are the irreversible processes of non-isentropic compression, non-isentropic expansion, isenthalpic pressure expansion, friction losses and heat transfer across a large delta temperatures. These irreversible losses destroy the energy's availability to do work, thus they are by definition the destruction of exergy. Design engineers focus on lessening the destruction of exergy by developing higher efficiency compressors and expanders, by replacing JT valves with liquid turbines and by designing refrigeration systems with refrigeration curves that closely match those of the natural gas cooling curve. This has led to a large variety of liquefaction processes. The more complicated systems require less energy to produce LNG but do so at a higher CapEx cost. Thus, the selection of an LNG liquefier process is dependent on the service time the LNG liquefier will be called upon to operate. A base load process that operates 90%+ of the year would typically be a high CapEx complex system that focuses on high efficiency LNG production. A peak shaving liquefier would typically be a low CapEx system with more of a focus on simplicity of operation.

The most difficult irreversibility to design out of a liquefaction system is designing a refrigeration system that produces a refrigeration cooling curve that closely matches that of the natural gas cooling curve. That is because every natural gas cooling curve is different based on the gas composition as well as the temperature and pressure at which the feed gas enters the LNG plant.

In the ideal case, the refrigeration cooling curve would be the same shape and temperature at every point along the curve. However, although such a refrigeration curve to cooling curve match would eliminate the destruction of exergy, it would not work in the real world as heat does not transfer without a temperature differential and even at an infinitesimally small delta temperatures, the heat exchanger surface area would approach infinity.

Thus, the process engineer's design goals need to be "balanced"! The highest efficiency refrigeration processes are hardware intensive, costly and complex with lower destruction of exergy while the lowest efficiency systems are least cost, least complex systems with higher destruction of exergy and thus have a high OpEx associated with their operation. The balance needs to account not only for technical issues but for non-technical issues like the skill level of the operating staff.

Efficiencies of turbo machinery have continually made great improvements since the 1960's for the reasons mentioned in the body of this study. Heat exchanger designs have also made great improvements as proprietary techniques have been used to lessen viscous dissipation within the exchangers and to evenly disperse liquid and gas mixtures across the entire heat exchanger manifold. This provides balanced heat exchange across the entire heat exchanger with the least pressure drop and the highest heat transfer across the smallest delta temperature.

The rest of this appendix will be focused on some of the various processes developed to match the refrigerant cooling curve to the liquefaction cooling curve.

For this explanation, an LNG cooling curve will be selected and various cooling technologies will be overlaid to provide the reader with an understanding of the cooling technologies used to best fit match the LNG cooling curve shape with a nearly constant small delta temperature.

In order to best describe the complexities of an LNG liquefier, it is best to start with simple concepts. Figure 8 is schematic of a car air conditioning system. It shows the compressor sending hot high pressure gas refrigerant to the condenser (the radiator in front of the car). In the condenser the refrigerant condenses to a liquid as heat is removed. That liquid is sent to the JT valve where the isenthalpic reduction in pressure converts the liquid refrigerant to a cold temperature mixture of liquid and vapor. The liquid/vapor mix is sent to the evaporator where the liquid continues to boil-off as it extracts heat from the car's cabin air. Then the refrigerant vapor is sent into the inlet of the compressor where the process starts all over again.

Figure 9 is a representation of a pressure enthalpy diagram for R134a refrigerant (standard automobile refrigerant). Figure 10 shows the cabin air cooling curve and refrigeration (evaporator) cooling curve (a mostly straight line).

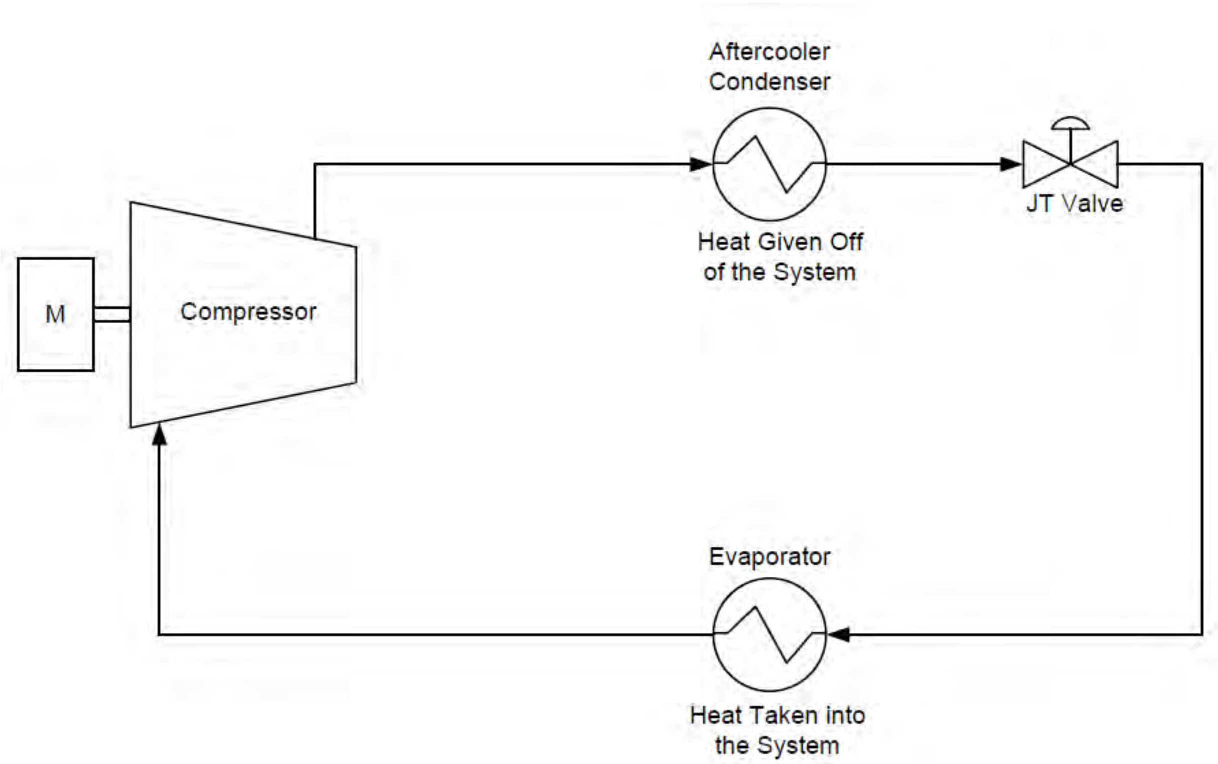


Figure 8: Simple Automobile Air Conditioning System

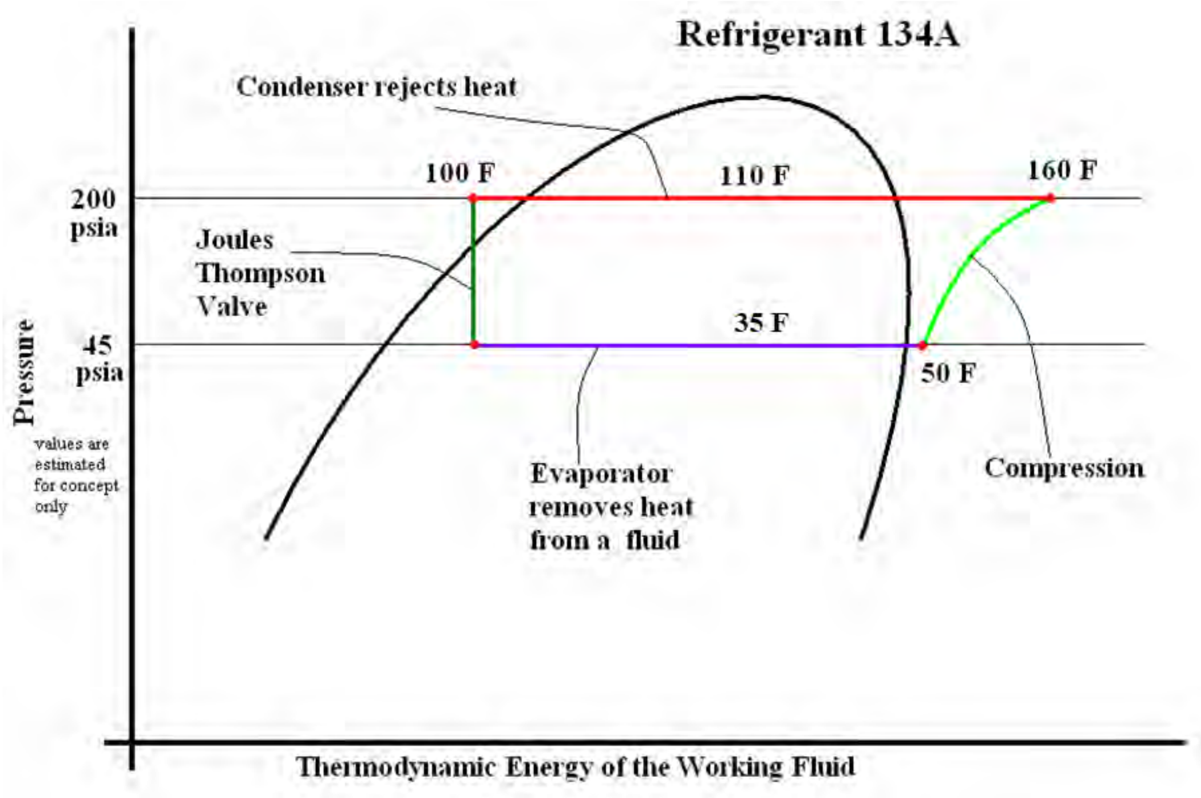


Figure 9: Pressure Enthalpy Diagram for R134a Used in an Automobile Air Conditioning System

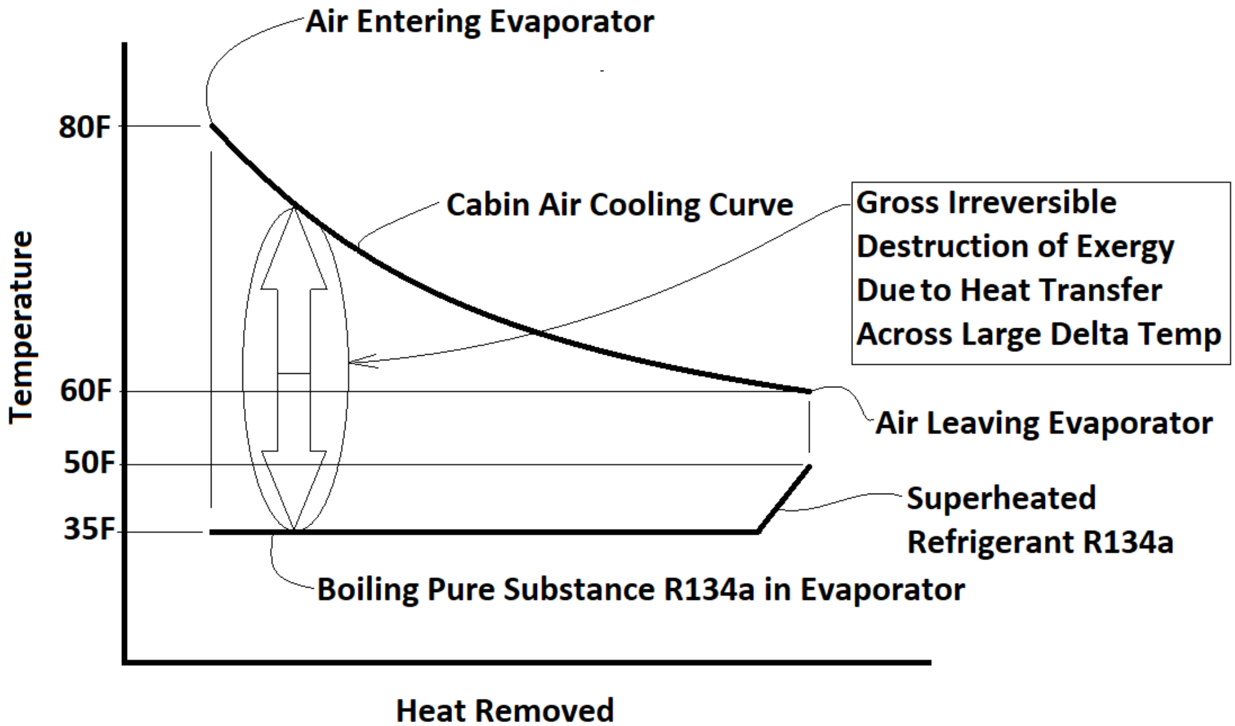


Figure 10: Automobile Air Conditioning Cooling Curve shown with refrigerant cooling curve

Take note that this is a very simple system which is inefficient due, in particular, to the large differential temperature between the cabin air temperature and the boiling off of the R134a refrigerant. However, in a balanced engineering decision, these losses are acceptable due to the amount of CapEx that would be needed to offset those losses due to the cycle irreversible processes.

As the desired temperature gets lower and lower, the energy required to produce that lower temperature increases exponentially. Systems that produce 50 F are not as energy intensive as compared to systems that are required to produce temperatures of -50 F. The lower the temperature required, the higher energy requirement and that is when a higher CapEx may be justified to increase efficiency.

Measures that could be used to lessen the destruction of exergy include: making the above system a multi-stage system, using a liquid turbine in lieu of a JT valve, using a greater heat exchanger area coupled with a higher evaporator temperature, or recycling the superheated vapor to the compressor, as little cooling is accomplished by the superheated vapor yet it takes up heat exchanger area and efficiency with little if any beneficial heat transfer to the cabin air.

Figure 11 shows a schematic with the superheated vapor being sent back to the compressor rather than sending it through the evaporator. In other words, a simple air conditioning system with liquid vapor separation occurring prior to the liquid refrigerant entering the evaporator. The vapor with little heat capacity is sent back to the compressor inlet allowing the evaporator to operate more efficiently.

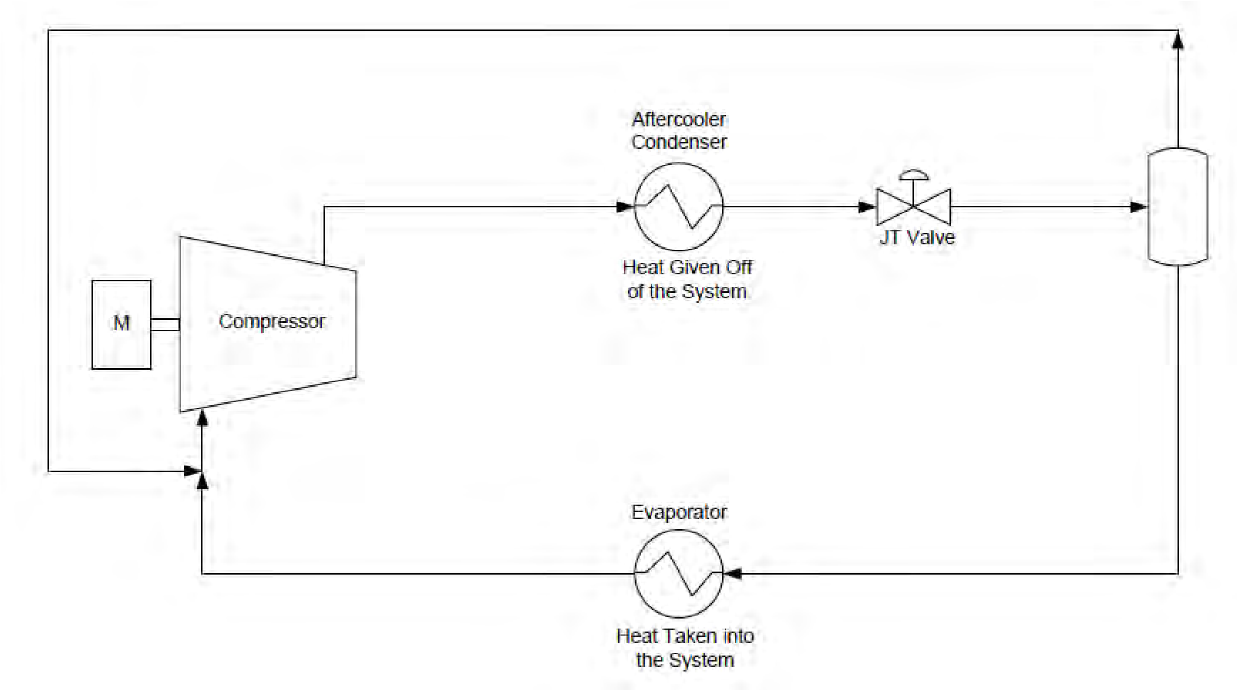


Figure 11: A Simple Air Conditioning System with Liquid Vapor Separation Occurring Prior to The Liquid Refrigerant Entering the Evaporator

The losses associated with an automobile air conditioner are trivial when compared to the total energy use of the car and the CapEx required to lower the air conditioner OpEx just does not warrant any such improvements. However, as the desired temperature becomes lower and lower, the operating cost of a refrigeration system increases exponentially resulting in the OpEx becoming more significant. This is shown in a refrigeration system that needs to drive a temperature down to -40F. This time the refrigerant used is propane. Propane boils at atmospheric pressure at -44 F.

As we move to lower and lower temperatures in this study, the terminology is changed from air conditioning to refrigeration. Figure 12 shows a single stage refrigeration system with an evaporator temperature of -20F. At this much lower temperature, much more compressor work is required and measures to lower OpEx may be warranted.

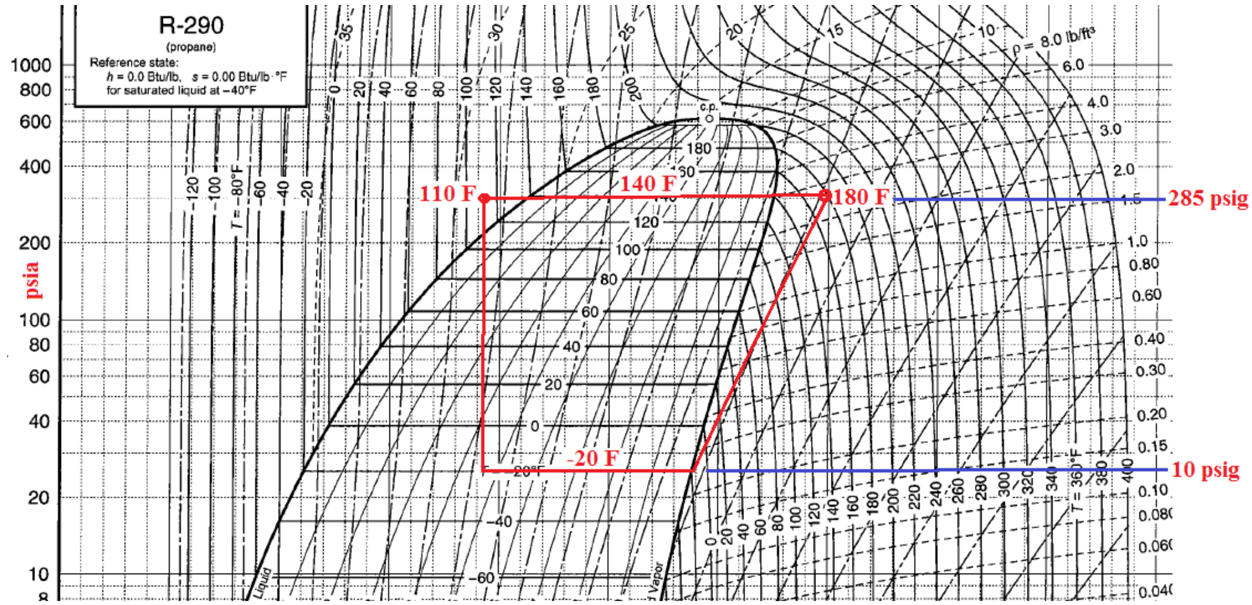


Figure 12: A Single Stage Propane Refrigerant Refrigeration Cycle Producing -20 F. High Energy Usage is Associated with Dropping Down to -20 F in a Single Stage Process.

The OpEx of the process shown in Figure 12 can be improved by using multi stages to accomplish the -20 F desired temperature with a lower energy input. Figure 13 shows the process hardware needed to accomplish this temperature in 2 stages. The added complexity will result in a higher CapEx for the additional hardware associated with this system.

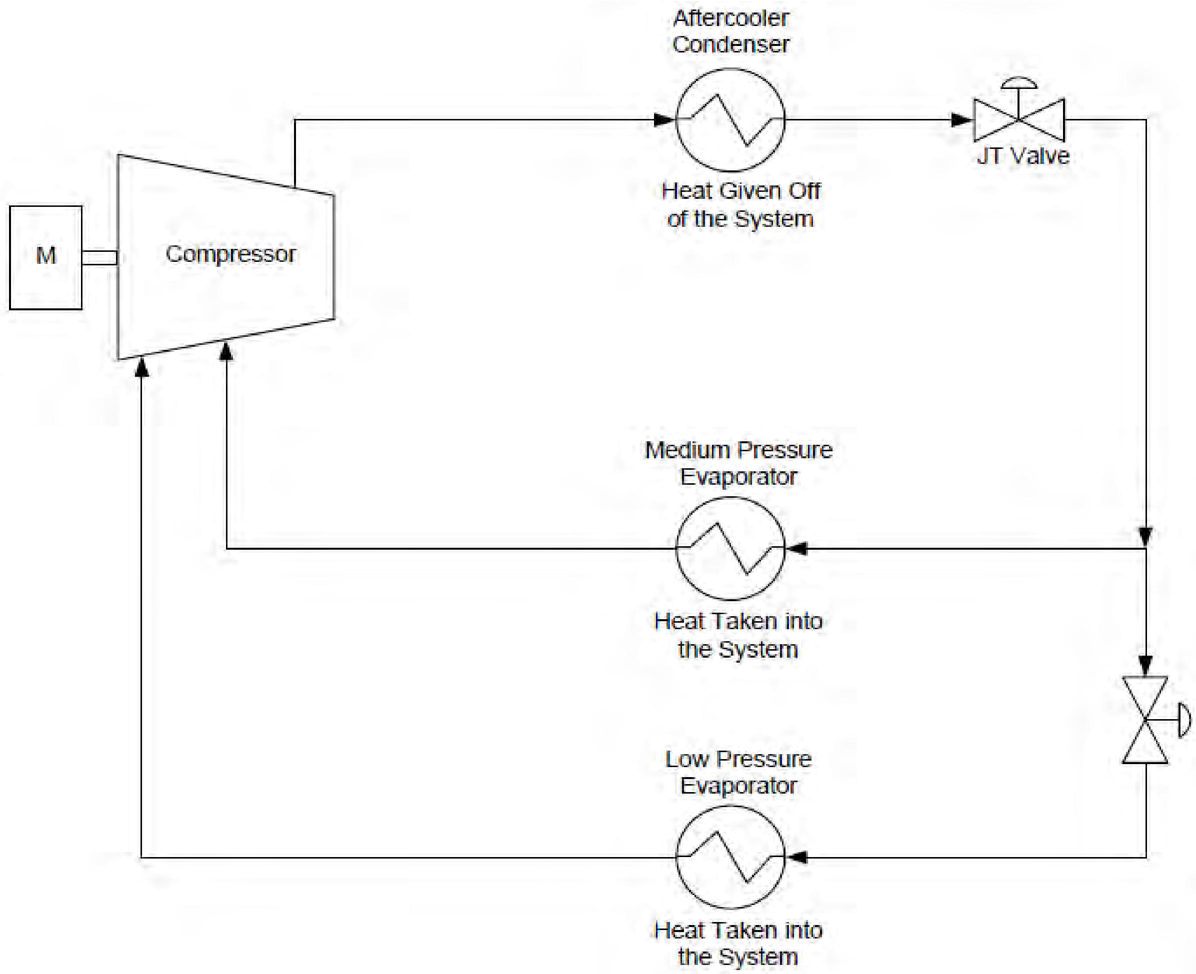


Figure 13: Refrigeration System Using 2 Stages of Compression And 2 Stages of Pressure Drop to Obtain -20F. Higher Capex with Lowered OpEx.

The process in Figure 14 has been enhanced further by returning to the compressor the vapor generated after the JT valve.

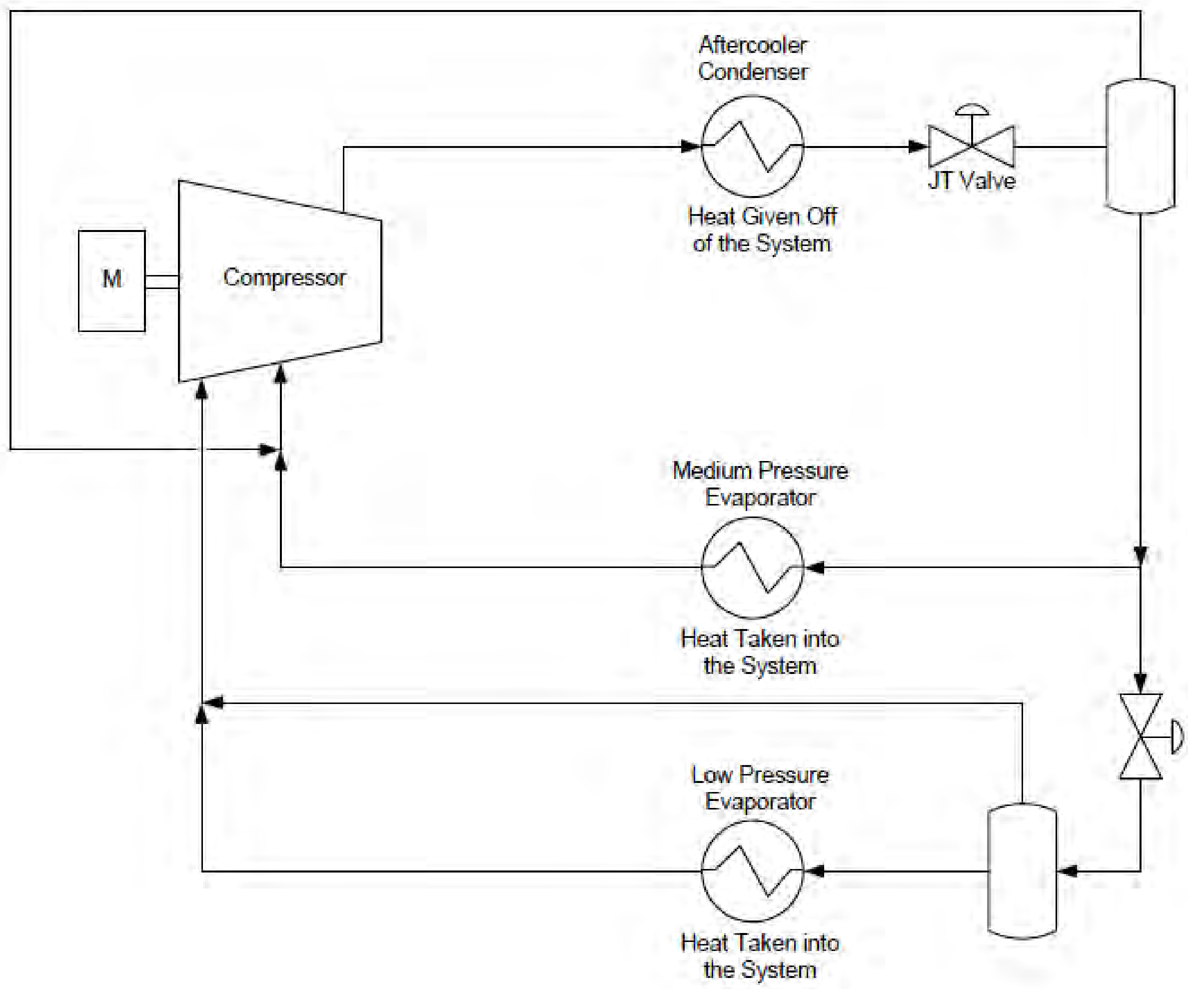


Figure 14: Refrigeration System Using 2 Stages of Compression and 2 Stages of Pressure Drop to Obtain -20F and Return Of Vapor From The JT Valve Outlets to the Compressor Inlet. Higher Capex with Lowered OpEx.

Care must be taken here for engineers to use "balance" in their design. The law of diminishing returns applies. For instance, one could theoretically make such a system super-efficient by adding 50 stages of compression and refrigeration. The return on such a CapEx investment would not only produce a minimal amount of work requirement reduction but could actually increase, instead of decrease, OpEx because of the shear amount of hardware needing maintenance (including shaft seals which may potentially leak, and added cold surfaces which could gain heat from the environment).

Many LNG liquefiers use a 3 or 4 stage pre-chiller to chill the natural gas before liquefaction. This isolates the plant from fluctuating feed gas temperatures which would cause the refrigeration system to constantly need adjustments.

Where a mixed refrigerant is used, it is also a common practice to use 3 or 4 stage pre-chiller to separate mixed refrigerant (MR) into mixed refrigerant liquid (MRL) and mixed refrigerant vapor (MRV). The MRL and MRV are made up of different distilled refrigerant compositions and thus can be used as two distinct mixed refrigerants. Figure 15 shows a 4-stage propane refrigeration system with temperatures and pressures that are commonly used on the highest efficiency C3MR system mentioned in the body of this study and shown in Figure 16.

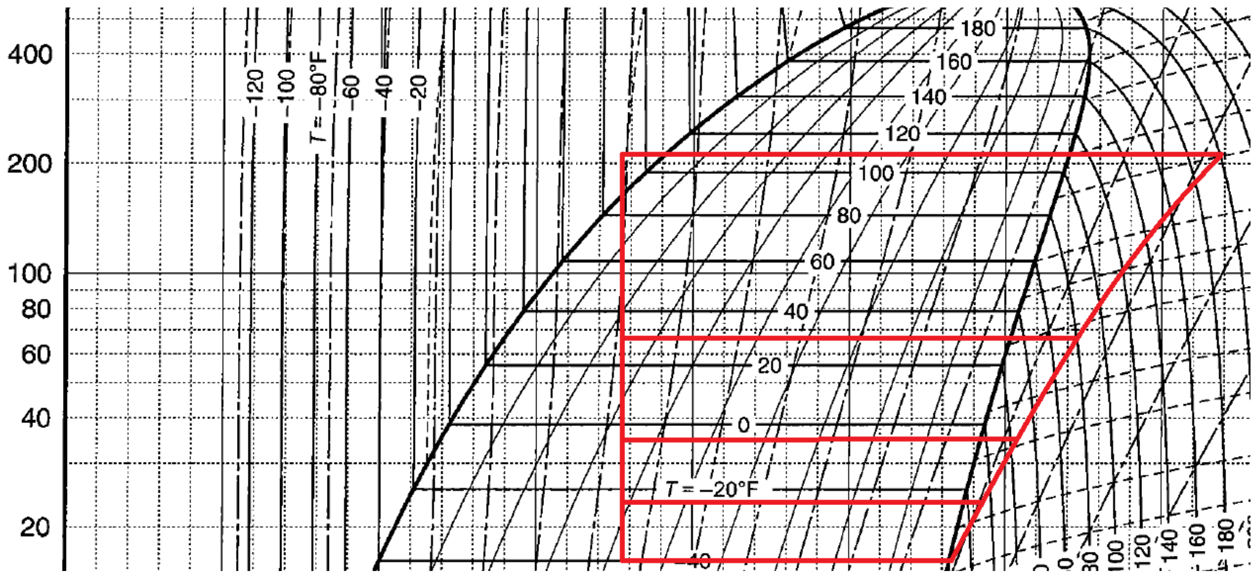


Figure 15: A Four Stage Propane Refrigerant Prechilling Process Shown on a Propane PH Diagram.

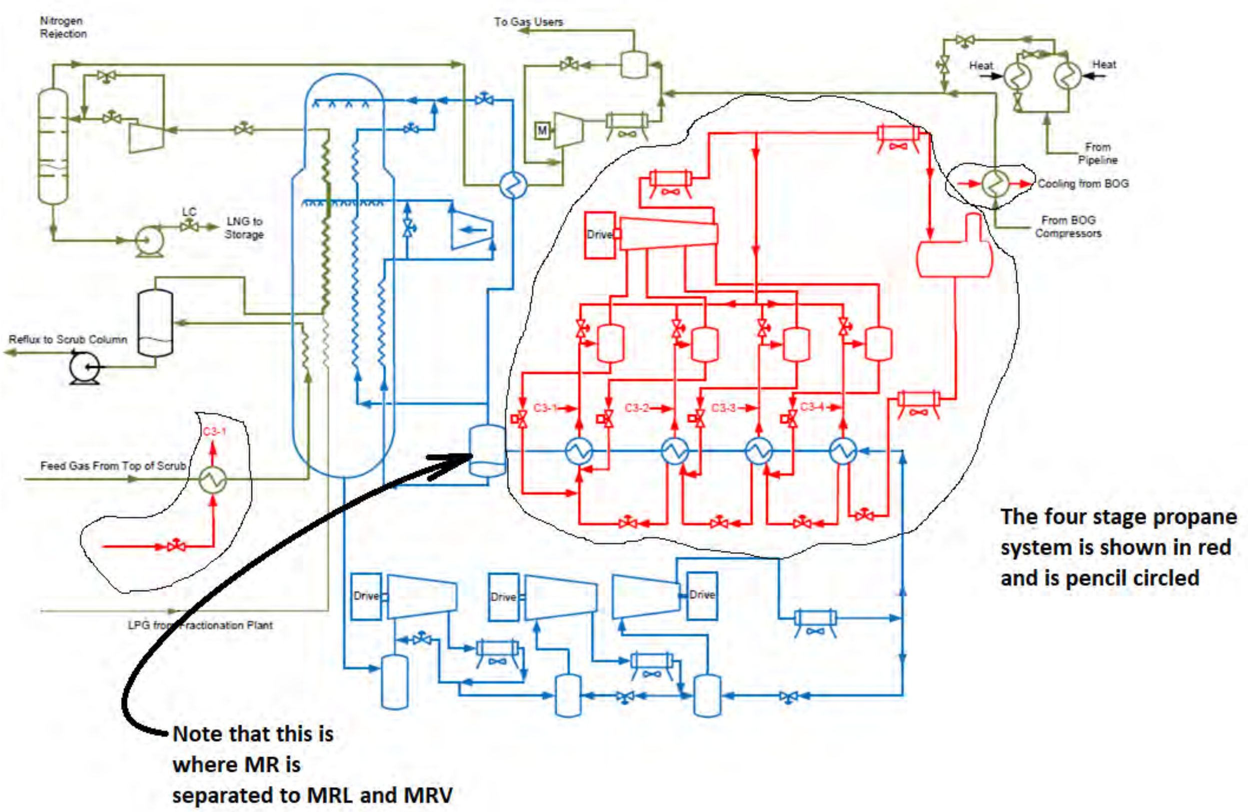


Figure 16: Schematic of a C3/MR System Using Four Stages of Pre-Chilling For Feed Gas And MR Chilling

The same logic is used for LNG facilities. If the on-time is large, like in a baseload export terminal where operating energy costs are huge, then high CapEx is prudent to reduce the OpEx to a minimum. Such a base load terminal would be expected to be on-line over 90% of the year. On the other hand, for a peak shaving facility like the Erie LNG facility which is expected to be on-line less than 8% of the year, low CapEx resulting in a higher OpEx would be considered prudent.

For the Erie LNG Facility, each of a Cascade, MR and Nitrogen Expansion System were considered. Due to the very small tank size, it is projected that the run time of the liquefier would be approximately 40 days per year. For this reason, the lower CapEx Nitrogen Expander system was selected as the best "balanced" approach to result in a low CapEx and a theoretically slightly higher OpEx, as illustrated in Table 4. Because of the complexity of the MR and Cascade systems, they may actually be more costly to maintain due to the usage of flammable hydrocarbons which are harder to inventory and transfer. Thus, although the electric usage may be higher for the N2 Expansion system, this extra electric expense may be offset by savings in not needing to manage hydrocarbon refrigerant inventories.

The following Figure 17 will describe the natural gas cooling curve and the temperature relationship to the Cascade, MR and N2 Expansion Refrigeration curves.

Figure 17 shows a natural gas cooling curve.

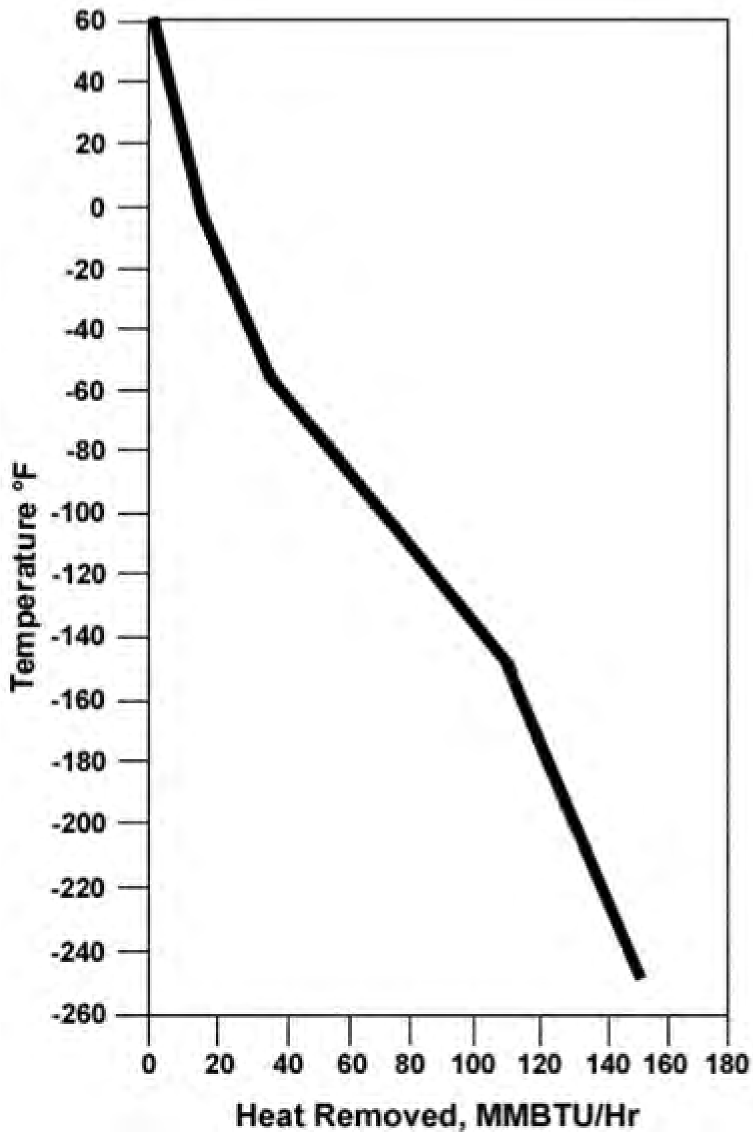


Figure 17: Natural Gas Cooling Curve[30]

Figure 18 shows a natural gas cooling curve and a 9-stage pure substance cascade refrigeration curve. Take note of the area between the curves. This area represents inefficiencies. One could reduce these inefficiencies by using a 12 or 15 stage pure substance cascade refrigeration system, but this would significantly increase the CapEx over that of the 9 stage pure substance cascade refrigeration system.

[30] Handbook of Liquefied natural Gas, 2014

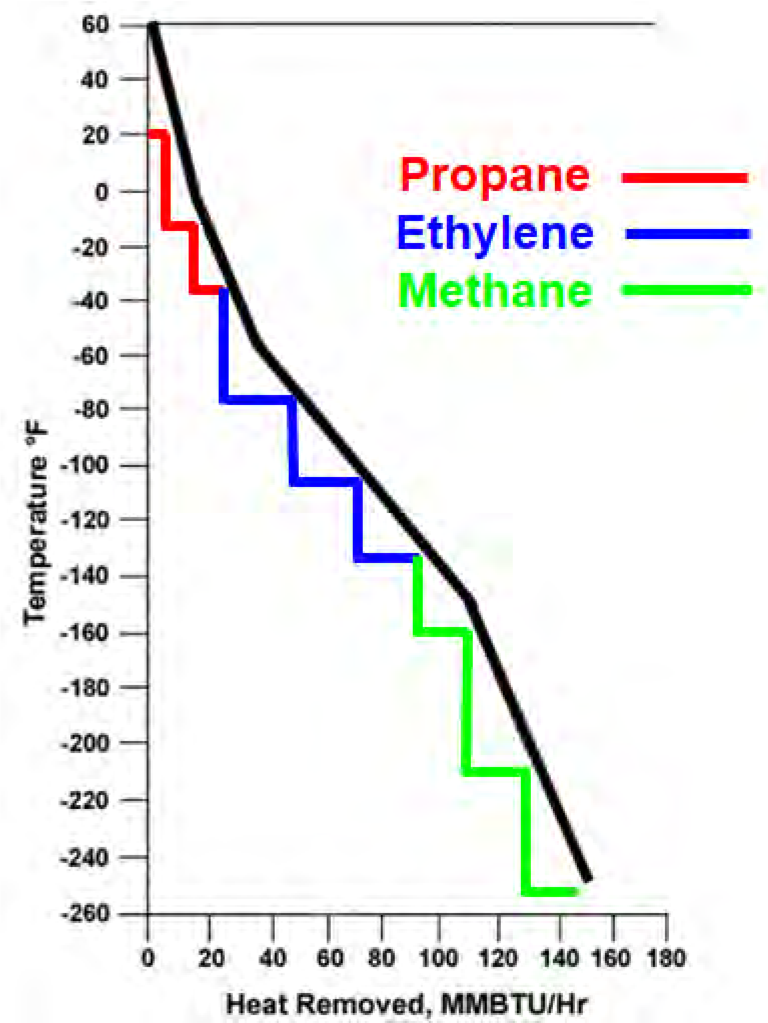


Figure 18 : Illustration of Natural Gas Cooling Curve and a 9-Stage Pure Substance Refrigeration Curve Overlaid on the Same Plane[31]

Figure 19 shows a schmatic of a 9 stage Cascade system. Beginning with a propane chiller with its 3 stages of propane chilling. Each stage is at a fixed temperature and pressure. Note also that the 3 stages of propane chilling cools down the ethyelne flow. There are 3 stages of ethylene chilling. Take note that the ethylene chilling also cools down the methane flow. Lastly, note that all 3 of the cooling processes chills the feed gas which produces LNG. The method of adjusting this system to match the LNG cooling curve is via adjusting each of the 9 pressure levels. Since the three Cascade system sections use pure substances as refrigerants, the fixed pressures are directly associated with the saturation temperature

[31] Handbook of Liquefied natural Gas, 2014

for each pressure level. This is a flexible system but it does use methane, ethylene and propane as refrigerants all of which are flammable gases.

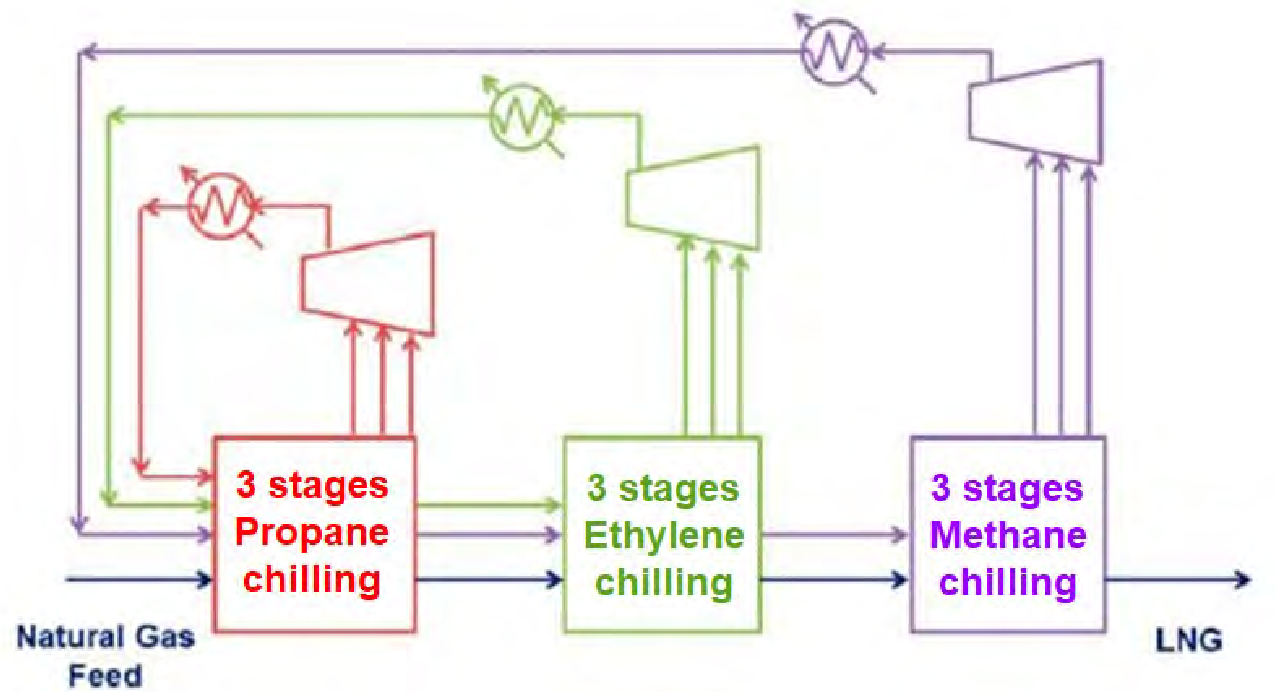


Figure 19: A 9-Stage Pure Substance Cascade Refrigeration System[32]

Another type of refrigeration system used for liquefying LNG is the MR system. This system uses a mix of zeotropic gases that condense preferentially, resulting in a boiling and condensing of the MR with changing compositions across a range of temperatures as shown in Figure 20. The mass mixture shown in figure 20 is 20% ethylene, 2% nitrogen, 38% propane and 40% methane.

[32] Liquefied Natural Gas and Floating LNG, a technology review, Gabriel Castaneda (clarified by JEI)

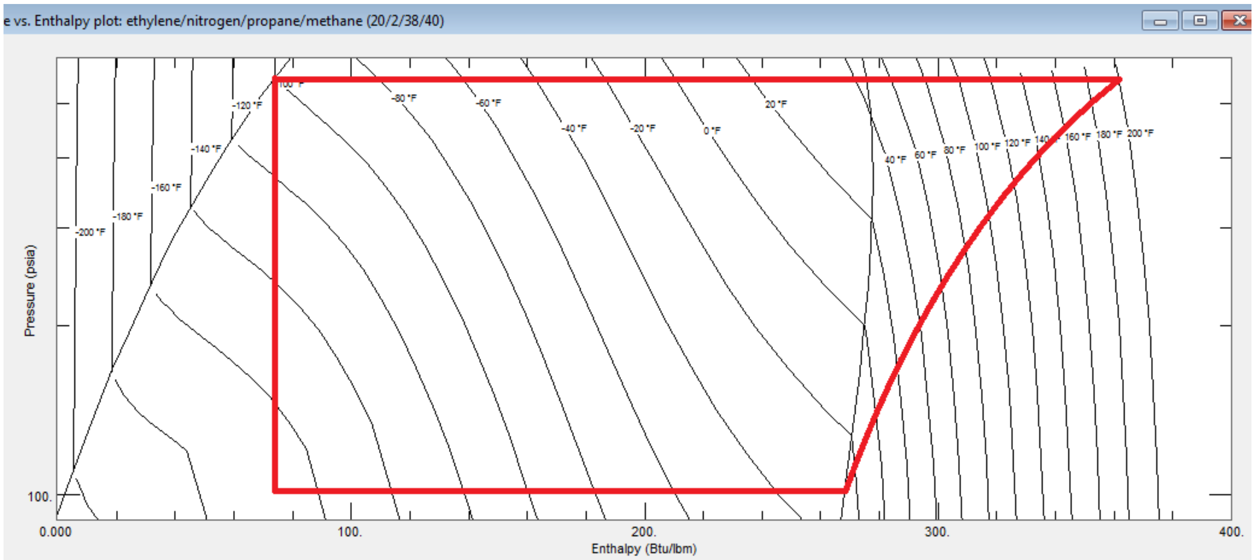


Figure 20: PH Diagram of a Mixed Refrigerant

Earlier in this appendix, a MR system with propane prechilling was shown in Figure 16. An approximation of the LNG cooling curve along with the refrigeration curve are shown in Figure 21 below.

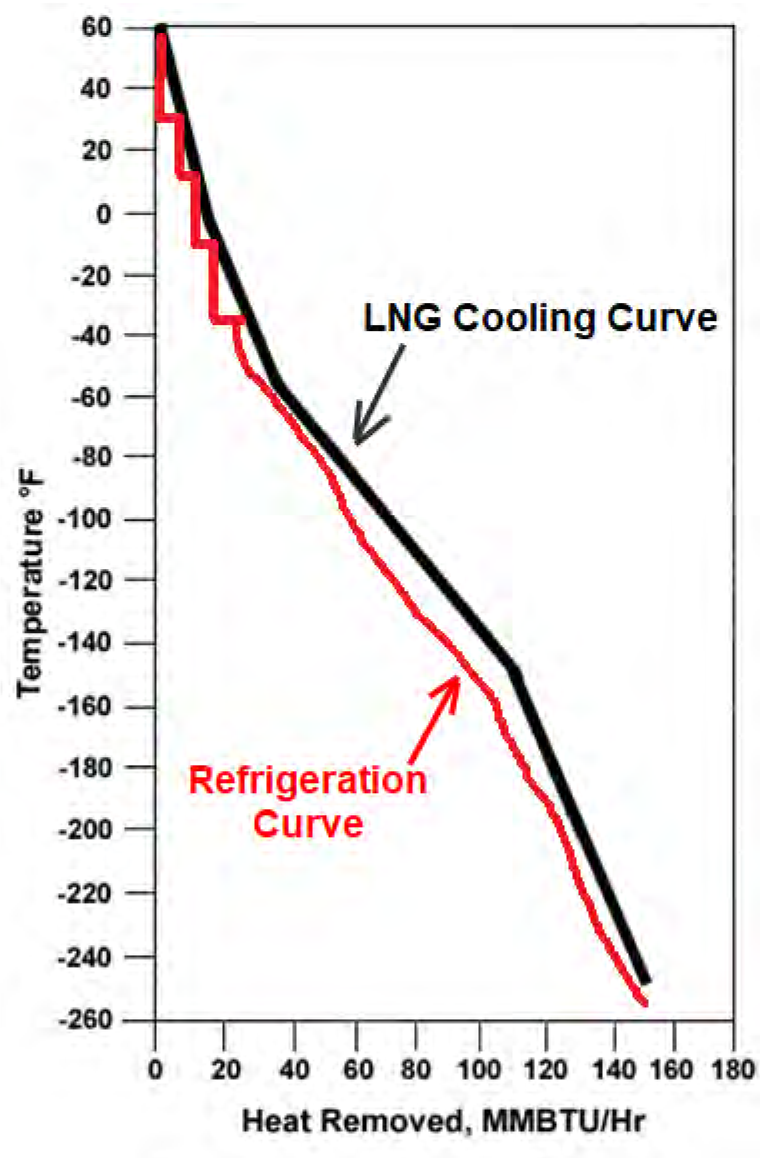


Figure 21: LNG Cooling Curve for a C3/MR Liquefaction System.

MR systems need not have propane prechilling; however, the prechilling does make the operation more efficient and easier to control. Having the prechilling isolates the operation from ambient temperature fluctuations.

MR systems without prechilling can be either a single MR system or a dual MR system. A simple MR system is shown in Figure 22 and a simple MR system with prechilling is shown in Figure 23. Take note that the MR is liquefied in the heat exchanger before being pressure dropped across a JT valve. The key feature about the MR system is that it changes phase across a range of temperatures and refrigerant concentrations. This means that after the JT valve, the most volatile gases preferentially boil-off at a very cold temperature and as the composition of the liquid changes, it boils off at a warmer and warmer temperature. This allows the MR refrigeration curve to closely match the LNG cooling curve.

However, it also means that the LNG operator must adjust the composition of the MR to make sure the cooling curves match closely. The efficiency savings associated with an MR system could be quickly lost by only one or two shifts of poor operator attention to the constantly needed MR adjustments. Further, the MR system is in constant need of adjustment because there is a certain amount of normal MR seal leakage and when MR make up is applied, it needs to be done in the correct proportions to minimize the destruction of exergy.

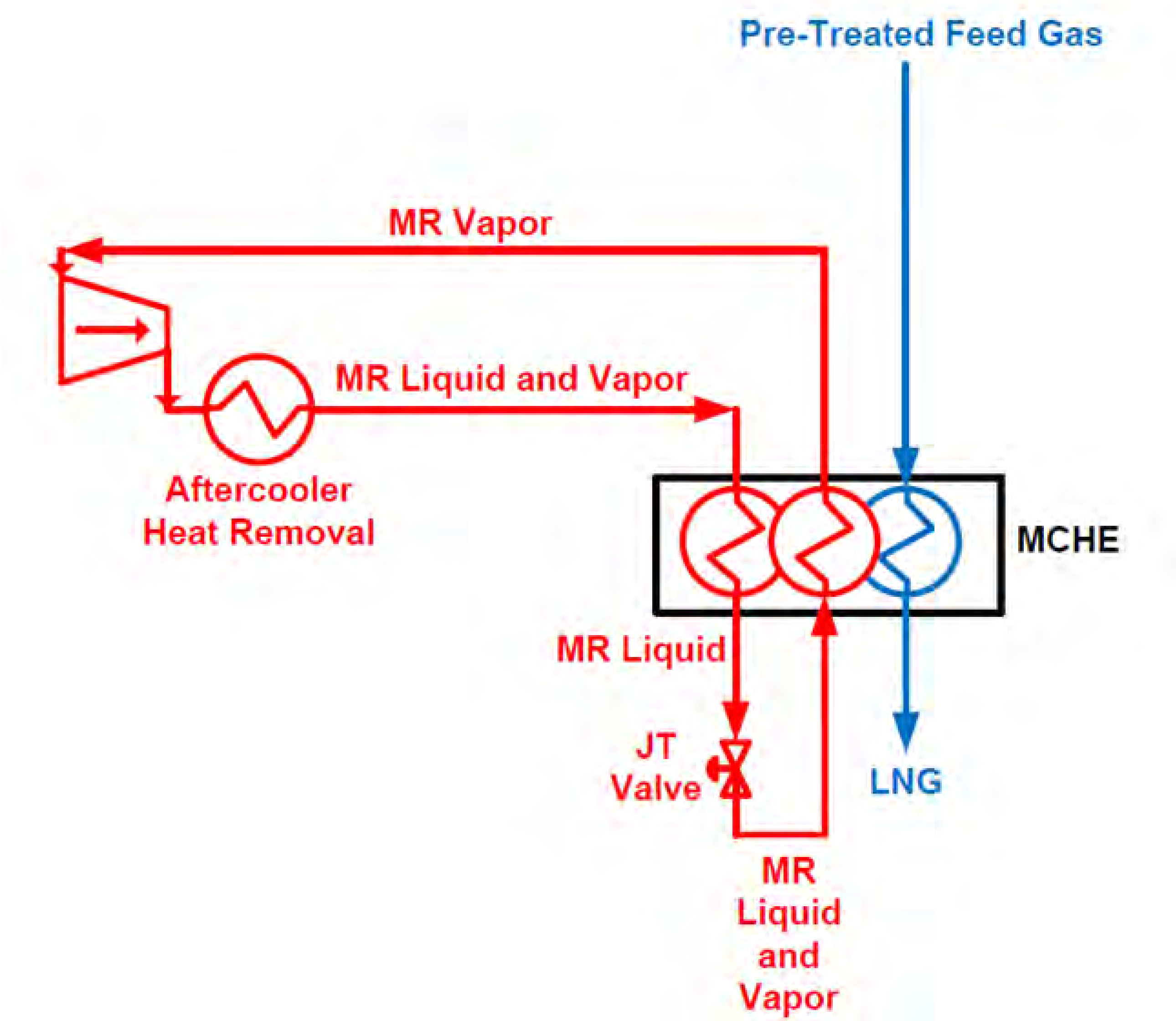


Figure 22: Simple Mixed Refrigerant Cycle

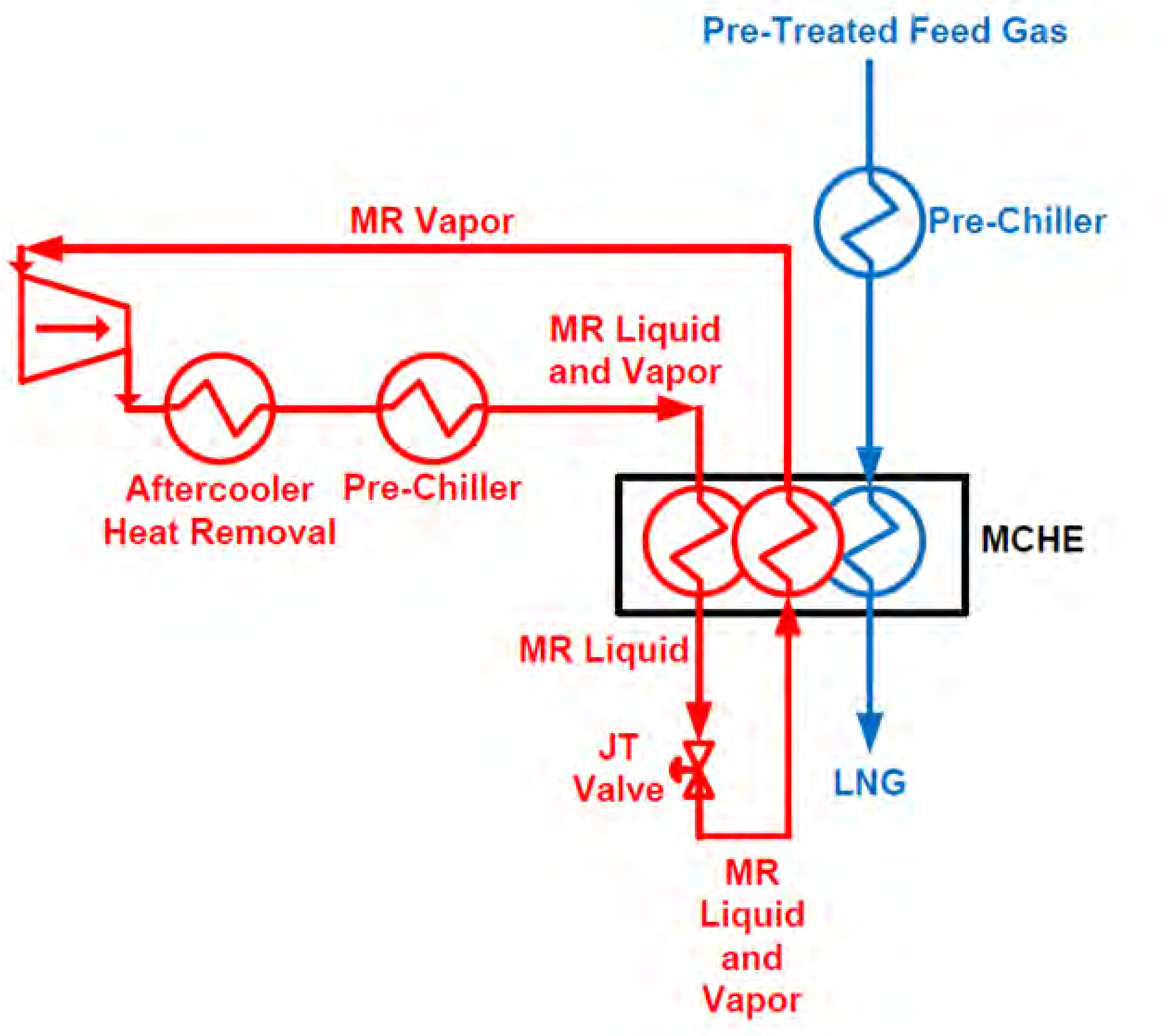


Figure 23: Simple MR System with Prechilling. Prechilling Need Not be Propane but Could Be Any Chilling Medium. However, on the Feed Gas Side, the Pretreated Gas Needs to be Dehydrated Prior to Prechilling.

The PRICO process shown in Figure 24 is a specific style of MR system which includes a chilling part of the main cryogenic heat exchanger (MCHE) to bring the feed gas down to a temperature where heavy hydrocarbons can be dropped out and the then cleaned gas is returned to the MCHE. This process also includes a proprietary method of distributing the MR into the MCHE. This process involves the spraying of liquid MR along with the injection of vapor MR into the distributor box of the MCHE.

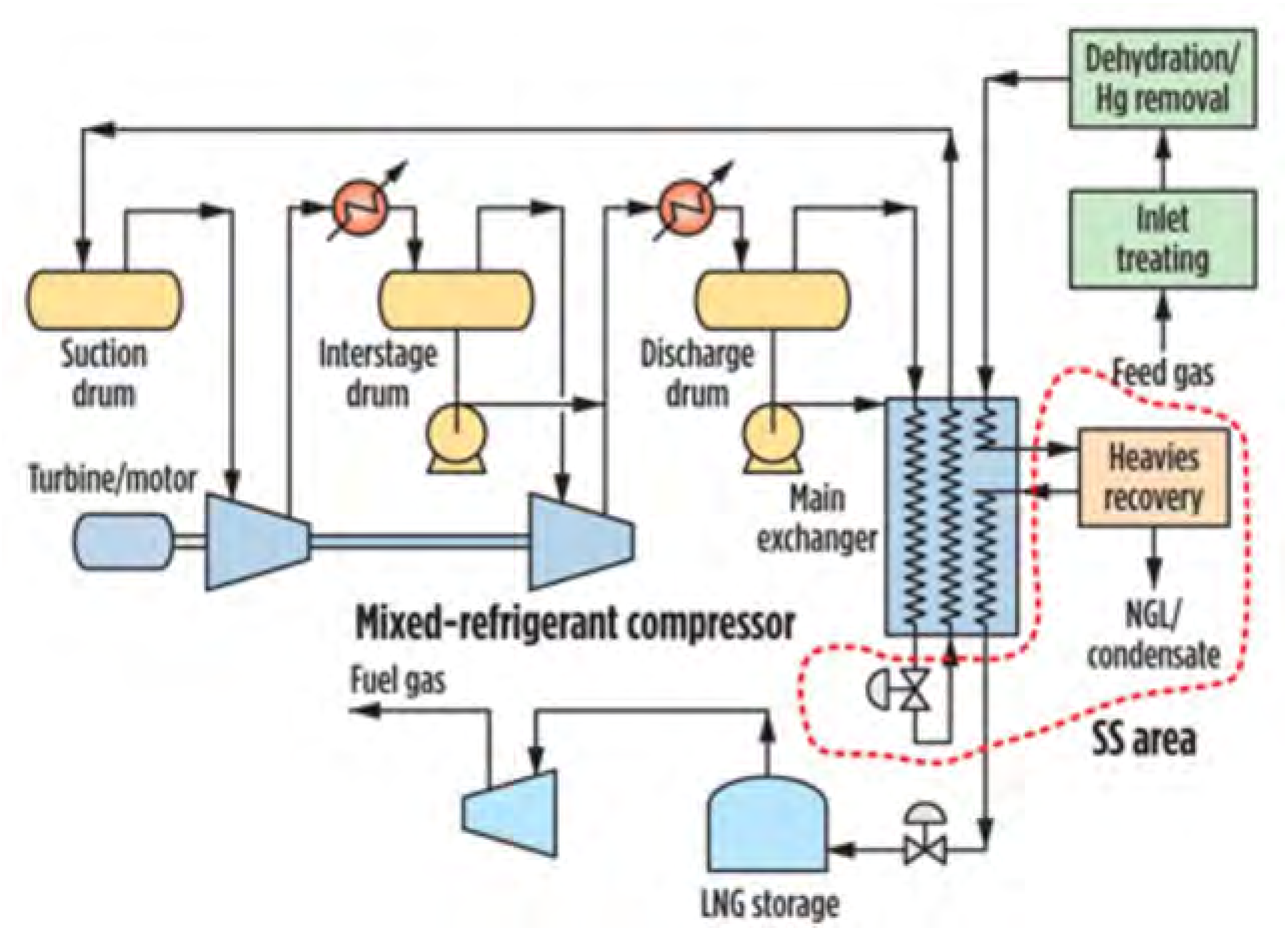


Figure 24: PRICO liquefaction System Separates Heavy Hydrocarbons and Contains a Proprietary Method of Distributing the 2 Phase MR into the MCHE[33]

Up to this point, all processes discussed have used multiple hydrocarbon refrigerants that change phase. The next technology will use an inert refrigerant and that refrigerant will not change phase. This technology is the N2 Expansion Liquefaction system.

According to the first law of thermodynamics, if a control volume has a steady state mass flow entering and leaving it and has work leaving it and no energy or mass inventory change over time, this would be a steady state steady flow process. Then the outlet flow would be of a lower enthalpy. Simply put, if an expander has a gas entering it at say -100F and is producing a shaft work output, then the fluid leaving the expander (sometimes called a turbine) must be colder. The first law of thermodynamics is also sometimes called the law of conservation of energy. Thus, an LNG liquefier can be made simply by expanding a gas through an expander that puts out shaft work. That is exactly the process shown in Figure 25 below.

In Figure 25, the very top N2 compressor is driven by a prime mover (typically either an electric motor or a gas turbine). This compressor has hot, high pressure N2 coming off the compressor. That N2

[33] Gas Processing and LNG, Flexibility is key to FLNG project success, J. Talib et.al.

gas is cooled in an aftercooler. The gas is further cooled to approximately -80F and then it enters a nitrogen expander. The expander generates shaft work which is often used to help compress the gas stream compressed by the top compressor (but that is not shown in this Figure 25). Because shaft work is exiting the expander, the N2 exiting the expander is much colder (typically -160F). This very cold gas is used to chill the feed gas and to chill the nitrogen feed to the expander. After this gas gives up its refrigeration, it is sent through a 2nd expander again producing shaft work and a very cold exiting N2 stream (typically at -180 F). This very cold gas is used to convert the feed gas to LNG. Again, the shaft work is used to reduce the power requirement of the very top compressor.

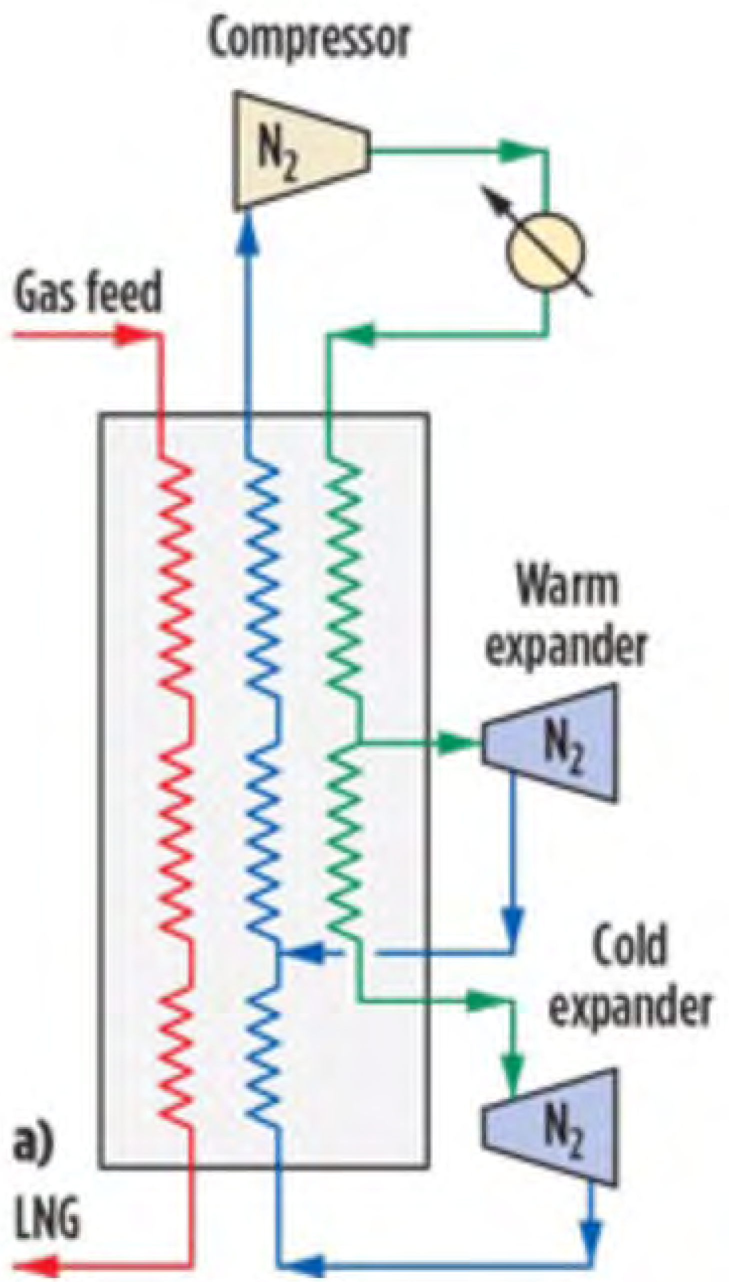


Figure 25: N2 Expander LNG liquefier[34]

It is typical to use the shaft work in a compander arrangement (a compressor directly connected to an expander as shown in Figure 26). This is the process diagram for the Erie LNG facility liquefier.

[34] Gas Processing and LNG, Brayton refrigeration cycles for small-scale LNG, M. Roberts et.al.

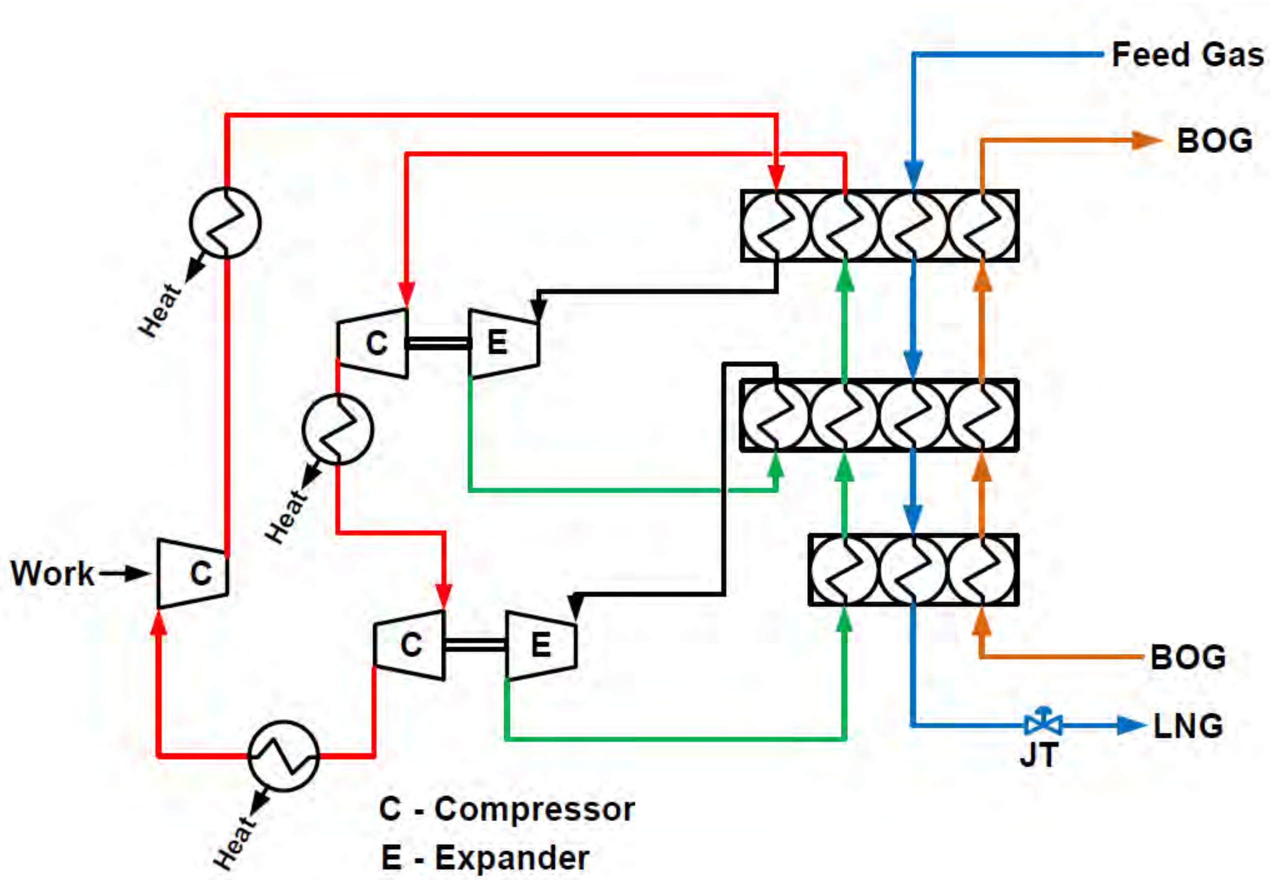


Figure 26: N2 Expansion System Shown with Companders (Booster Compressors Connected to Cold Expanders)

Figure 27 shows an estimate of how the gas cooling curve would look for a hypothetical N2 Expansion system. Note that since there is no phase change, the temperature drop of the refrigerant would solely be a function the specific heat of the nitrogen.

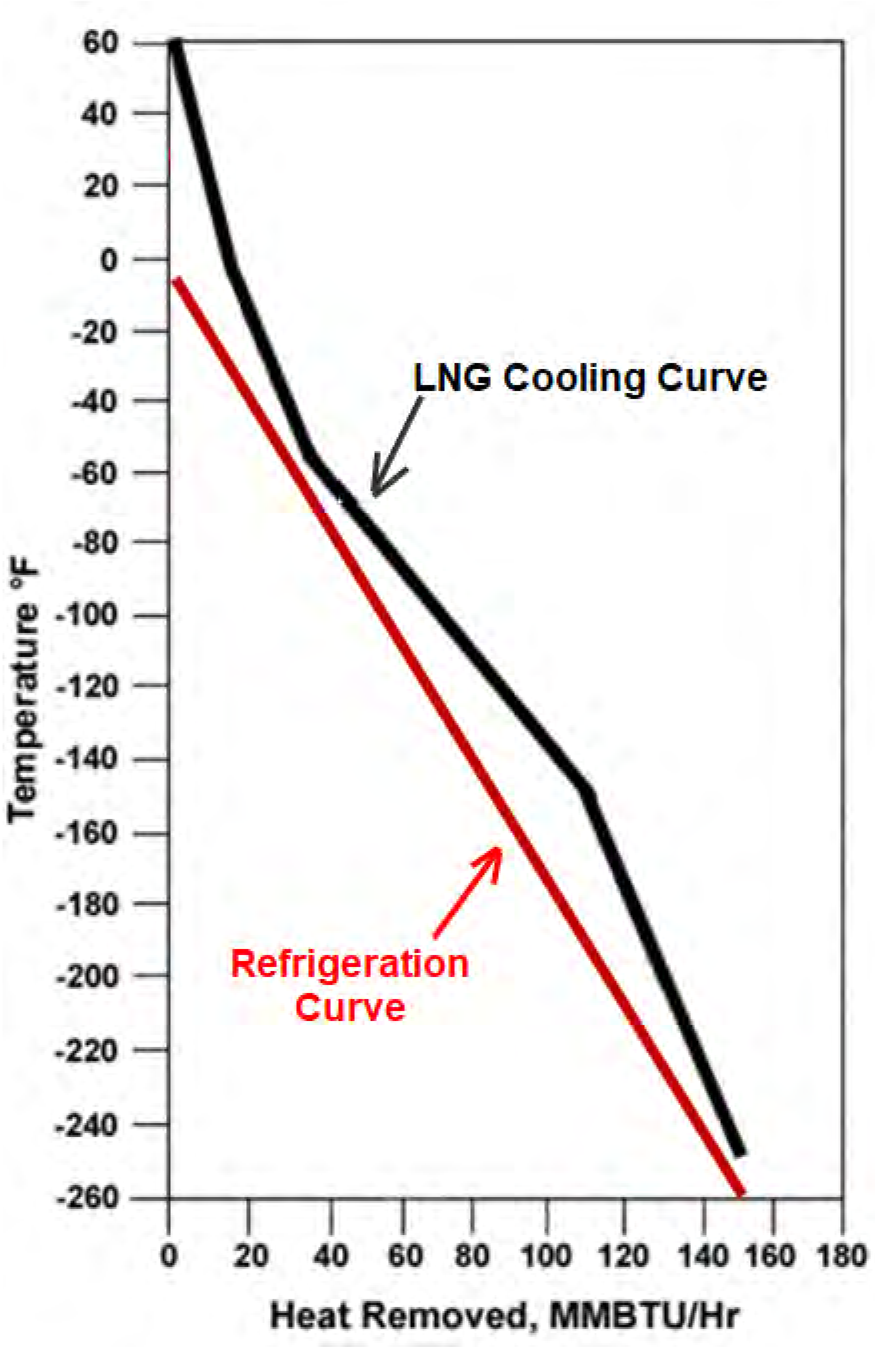


Figure 27: Hypothetical (shown for concept only) LNG Cooling Curve Vs. Refrigerant Cooling Curve for an N2 Expansion Liquefaction Process

Figure 28 is a representative display of how various Cascade, MR and N2 Expansion systems stack up compared to each other. The MR and Cascade systems are only as efficient as the skill and training level of the operators controlling the process. On the N2 Expansion system, the process is a lot more forgiving as there is only one concentration of refrigerant – only pure nitrogen.

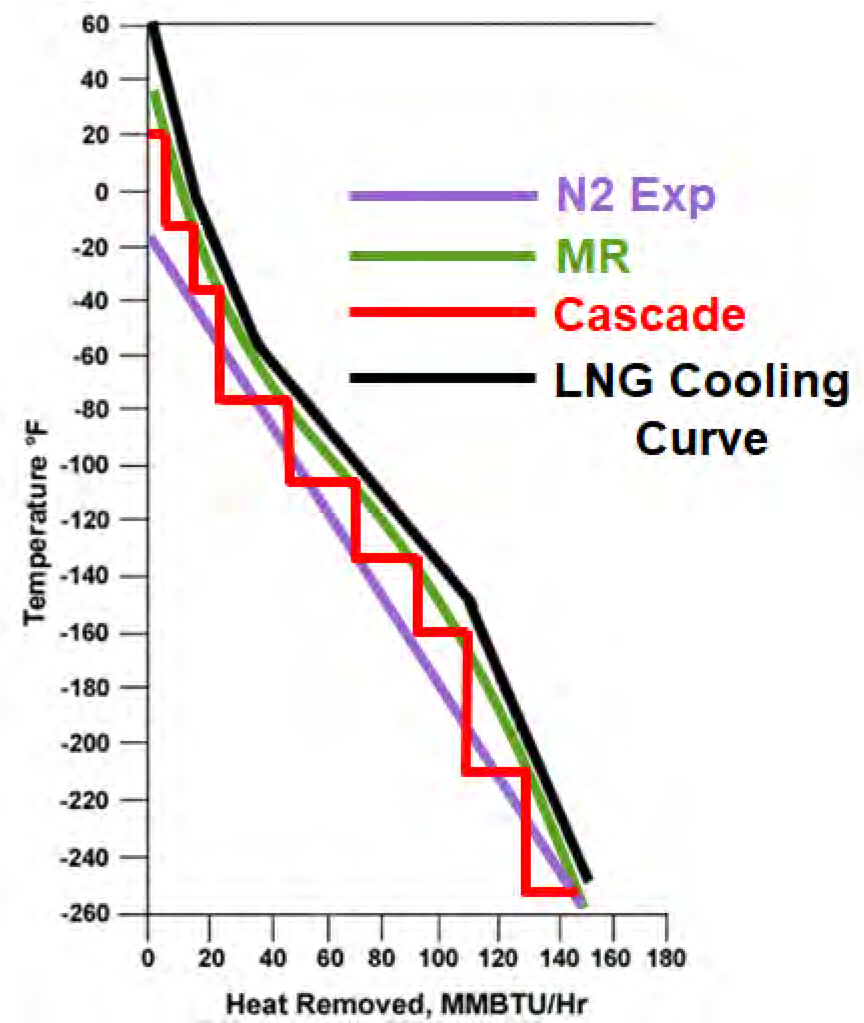


Figure 28: Illustration of Various Refrigerant Cooling Curves Vs. And LNG Cooling Curve. Note: The Cooling Curve Benefit of The Cascade and MR Systems Are Dependent on The Skill Level of The Operators Who Adjust the Pressure of The Cascade System Steps or MR Composition.[35]

[35] Illustration of Cascade Drawing of Handbook of Liquefied natural Gas, 2014

Appendix B: Calculation of Flash Gas

Calculation of flash gas for pure methane (worst case condition long haul from 70 psig to 1.3 psig tank pressure)

Table 6 – Calculation of Flash Gas for Pure Methane (Worst Case Condition Long Haul from 70 psig to 1.3 psig Tank Pressure)

1: Methane: Saturation points (at equilibrium)

	Temperature (°F)	Pressure (psia)	Liquid Density (lbm/ft³)	Vapor Density (lbm/ft³)	Liquid Enthalpy (Btu/lbm)	Vapor Enthalpy (Btu/lbm)	Liquid Entropy (Btu/lbm-°R)	Vapor Entropy (Btu/lbm-°R)
1	-210.76	85.000	23.718	0.58128	41.574	235.22	0.18294	0.96091
2	-256.79	16.000	26.272	0.12260	1.5685	220.51	0.0077217	1.0869

Initial condition LNG saturated at 70 psig (85 psia), 10,000 gallons of liquid (1336.894 ft3 of LNG)

Saturated condition -210.76 F and 85 pisa, liquid density is 23.718 lbm/ft3 Mass of LNG = 31,708.6 lbm of LNG

Think of it this way. The LNG is pressure dropped across a JT valve from 85 psia to 16 psia. The JT valve is a constant enthalpy process.

Do this for 1 lbm of liquid methane flashing from saturation at 85 psia to 16 psia

41.574 Btu/lbm = (1-X) 1.5685 Btu/lbm + X 220.51 Btu/lbm
41.574 Btu/lbm = 1.5685 Btu/lbm – X (1.5685 Btu/lbm) + X 220.51 Btu/lbm
41.574 Btu/lbm – 1.5685 Btu/lbm = X (220.51-1.5685) Btu/lbm
40.0055 Btu/lbm = 218.9415 X
X= 0.18226

Thus 1 lbm of liquid delivered to the front gate results in 0.82 lbm of LNG entering the tank and 0.18 lbm of gas flashing off as vapor. That is an 18% loss to vapor flash.

Do the same calculation for a truck coming in at 30 psig. Probably a more normal case when a truck comes in from a short haul. Assume that the LNG unloading operator maintains 30 psig on the tanker truck by use of the ambient vaporizer.

Table 7 – Calculation of Flash Gas For Pure Methane (Worst Case Condition Long Haul from 30 psig to 1.3 psig Tank Pressure)

1: Methane: Saturation points (at equilibrium)

	Temperature (°F)	Pressure (psia)	Liquid Density (lbm/ft³)	Vapor Density (lbm/ft³)	Liquid Enthalpy (Btu/lbm)	Vapor Enthalpy (Btu/lbm)	Liquid Entropy (Btu/lbm-°R)	Vapor Entropy (Btu/lbm-°R)
1	-230.62	45.000	24.879	0.31878	23.896	229.81	0.11022	1.0092
2	-256.79	16.000	26.272	0.12260	1.5685	220.51	0.0077217	1.0869
3								

Initial condition LNG saturated at 30 psig (45 psia), 10,000 gallons of liquid (1336.894 ft3 of LNG)

Saturated condition -230.62F and 45 pisa, liquid density is 24.879lbm/ft3 Mass of LNG = 33,260.58 lbm of LNG

Think of it this way. The LNG is pressure dropped across a JT valve from 45 psia to 16 psia. The JT valve is a constant enthalpy process.

Do this for 1 lbm of liquid methane flashing from saturation at 45 psia to 16 psia
23.896 Btu/lbm = (1-X) 1.5685 Btu/lbm + X 220.51 Btu/lbm
23.896 Btu/lbm = 1.5685 Btu/lbm – X (1.5685 Btu/lbm) + X 220.51 Btu/lbm
23.896 Btu/lbm – 1.5685 Btu/lbm = X (220.51-1.5685) Btu/lbm
22.3275 Btu/lbm = 218.9415 X
X= 0.102

Thus 1 lbm of liquid delivered to the front gate results in 0.898 lbm of LNG entering the tank and 0.102 lbm of gas flashing off as vapor. That is a 10.2% loss to vapor.

This increases the real cost of trucking because it takes 10 – 18% more trucks to fill the tank. It would also account for the excessively high recorded boil-off.

Appendix C: Discussion Regarding former alternative of Continued Trucking-in LNG

ETG has advised JEI that ETG has required approximately 150 truckloads per year of LNG delivered to the plant.

During the 2016 rate case, ETG explained that it contracts annually for LNG by issuing Requests for Proposals ("RFPs") to suppliers that supply the liquid LNG market in the region. Typically, ETG invites several suppliers to bid.

ETG has stated that this process had worked well for many years; however, ETG has become more and more concerned about the availability of LNG liquid because of: (1) increased demand for liquid in the over the road transportation market; (2) a reduction in deliveries of liquid into Everett LNG facility in Everett, MA; (3) suppliers of LNG liquid are seeking more ways to sell their liquid into higher-priced foreign markets; and (4) few new liquefiers have been built to serve the region's LNG liquid market. ETG's concerns have become more evident with the responses received from LNG suppliers in the past.

In 2013, ETG issued the RFP with disappointing results. No company replied to its RFP with commitments to supply the amount of LNG needed.

In subsequent years, while there were suppliers, the cost of supply had gone up because of the distance from the source of the LNG being trucked. During the Summer of 2014 through January 2017, ETG was buying LNG from as far away as Trussville, Alabama. And with distance being a large factor in the delivered cost of trucked-in LNG, far away sources of LNG are a financial burden on ETG's customers.

More recently, ETG has been able to source supplies more locally which has reduced its cost. However, there remains a trucking-in dilemma.

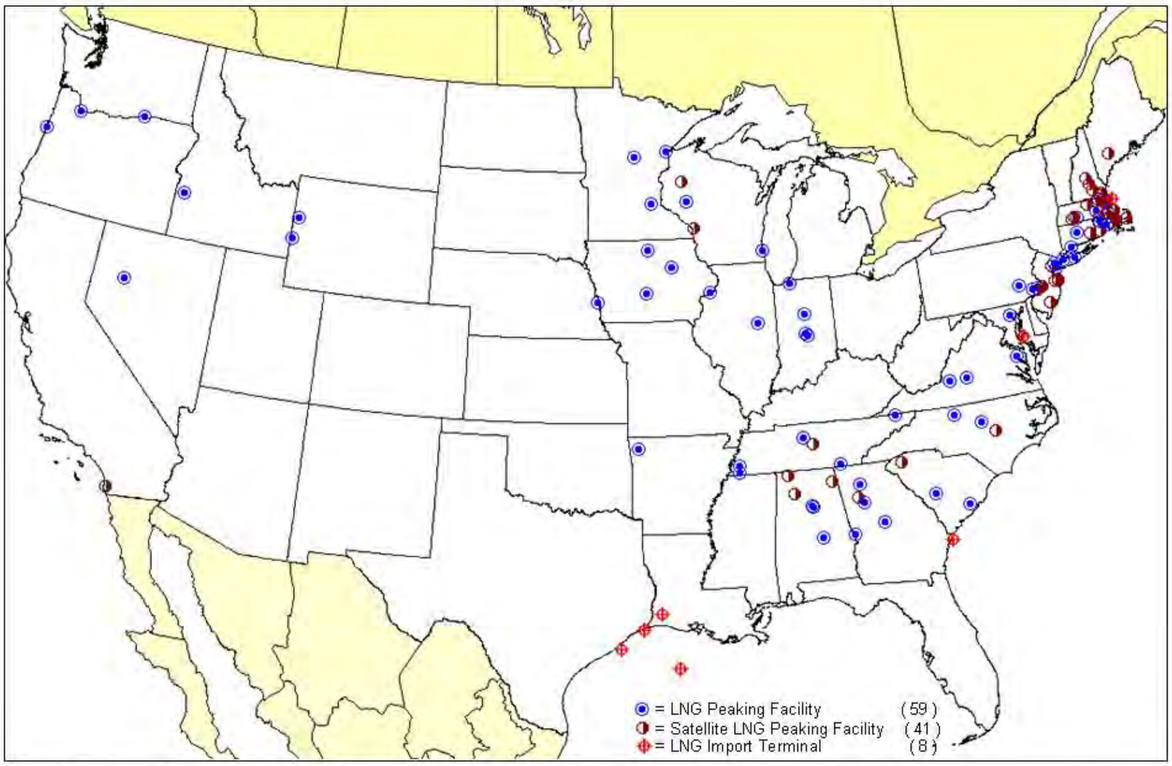
THE TRUCKING-IN DILEMMA

The following map (Figure 29) provides an overview of U.S. LNG peaking facilities. Expansion of liquefaction capacity in recent years has been limited. Less than thirty (30) LNG peaking facilities with liquefaction capability are located within a reasonable trucking distance to ETG.

The majority of these peaking facilities are owned and operated by local distribution companies to serve peak demand. As a result, there are very few merchant facilities that could supply LNG to the market. For example, Pivotal LNG owns and operates three commercial facilities. Its 60,000 gallon/day (5,000 Dth/day) plant located in Trussville, Alabama, the 50,000 gallon/day is located in Towanda, PA and the 120,000 gal/day JAX LNG facility located in Jacksonville, F. They were constructed to serve the merchant market. Other merchant LNG suppliers include UGI's Temple plant in Pennsylvania, Transco's plant in Carlstadt, NJ, Columbia Gas Transmission's Chesapeake plant in Virginia, and East Tennessee Gas

Transmission's plant in Tennessee. All facilities operated by interstate pipeline companies have firm contract customers for the LNG liquefaction and storage capacity.

The map in Figure 29 illustrates where LNG facilities are located in the U.S.



Note: Satellite LNG facilities have no liquefaction facilities. All supplies are transported to the site via tanker truck.
Source: Energy Information Administration, Office of Oil & Gas, Natural Gas Division Gas, Gas Transportation Information System, December 2008.

Figure 29 – LNG Peaking Facilities Map

To evaluate the LNG trucking capabilities of the Northeast, JEI selected 15 States that in our opinion are within a "reasonable" driving distance of Elizabethtown, New Jersey. The source data for this list is the Pipeline and Hazardous Materials Safety Administration (PHMSA) annual report[36]. An eight-hour drive was considered a reasonable drive. This is a simplification since the primary supplier in all of the Northeast for LNG trucking supply is by the Exelon Everett LNG facility in Everett, Massachusetts[37].

This single LNG facility accounts for approximately 10,000 truckloads of LNG per year. And although there are other suppliers of LNG in the Northeast, in reality, Northeast trucked LNG is virtually sole sourced by the single supplier Everett LNG.

[36] Liquefied Natural Gas Annual Report Form F 7100.3-1
[37] Formerly Distrigas LNG now owned by Exelon

In selecting the northeast regional area as a block of states containing LNG facilities, JEI selected the following states as being within the regional transport eight-hour traveling distance of ETG. They are shown in Figure 30 below and listed as follows:

Maine	Rhode Island	Delaware
New Hampshire	New York	Maryland
Vermont	Ohio	West Virginia
Massachusetts	Pennsylvania	Virginia
Connecticut	New Jersey	North Carolina

Figure 30: Selection of Regional States Within Eight-Hour Drive From ETG

For this discussion, we compute the number of peak-shaving / satellite plants or mobile plants and their yearly demand for trucked-in LNG if they do not have the ability to self-produce LNG. Also remove from this list any outliers like Cove Point which are used to supply wholesale energy marketer's services and for ocean tanker LNG export. Also remove the Everett LNG plant since it is an import terminal in the

Northeast located in Everett, Massachusetts. Since this plant takes on LNG by ship and barge, it can be removed from this list.

After removal of the facilities that are not within driving distance and are not applicable to the present analysis, the list is narrowed down to contain 54 peaking / satellite facilities that supplement vaporized LNG to their gas territories, 21 of which have liquefiers on-site. This means that 33 of these facilities receive their LNG inventory via LNG truck.

Assuming that each facility uses its complete storage during a year due to both boil-off and sendout, this would result, at a minimum, in needing a total of 3,423,620 bbls of LNG to be transported by truck. That equates to 14,379 tanker truck loads of LNG needed per year. Since Everett LNG accounts for approximately 70+% of that LNG supply, one can clearly see how the entire Northeast is essentially linked to the availability of the Everett LNG facility, which itself has a significant lack of redundancy.

For example, the Everett LNG facility has two tanks, a single berth and a single waterway entrance. In addition, this facility is vulnerable to terrorism shutdown, as it was shut in for a time following the 911 attacks. Further, it was constructed under less stringent requirements in a populated area, where public opposition could result in political pressure on this facility to close.

An example of such closures have occurred in the nuclear industry, including Plymouth, Indian Point and Shoreham power plants, to name a few. All that would be needed to ignite public opposition is a single incident involving either the Everett LNG facility or LNG trucking with casualties.

ADDITIONAL CONCERNS RELATED TO TRUCKING

In addition to the need for ETG to be in control of the availability of its peak Shaving LNG supply, ETG also recognizes its commitment to the community, environment and the New Jersey Energy Master Plan. To fulfill the spirit and letter of that commitment, ETG recognizes the fact that self-liquefaction lowers ETGs carbon footprint, lowers other harmful air emissions and serves the local community in other significant ways as mentioned below:

1. Producing LNG and then shipping it to its end point of peak shaving use location produces more greenhouse gases than to perform liquefaction on the site of the end point of peak shaving use for the following reasons.
    a. At the loading station, LNG pumps are used to load the LNG trucks. These pumps consume energy which is generated using greenhouse gas and emissions producing processes.
    b. The pumps stated in (a) above produce heat and viscous dissipation within LNG being pumped, resulting in some of the LNG vaporizing and thus requiring additional liquefaction system on-time to make up the liquid that is vaporized.
    c. Based on the Erie LNG facility requiring 120,000 MSCF/yr results in the need to deliver approximately 150 to 170 truckloads per year. At an estimated round trip travel distance of 200 miles, this adds up to 34,000 miles of tanker truck travel engine

emissions to the air pollution in the area within a 100 mile radius of ETG. These trucks are for the most part 80,000 lbm GVW tractor trailers with large diesel engines.

d. The travel of these LNG trucks adds transferred heat and viscous dissipation heat to the transported LNG. This heat results in approximately 10% of the transported LNG being flashed to vapor at the point of unloading (at the Erie LNG facility). This results in the need for additional liquefaction being needed to replace the LNG that is flashed during unloading. Not only does this require additional liquefaction energy consumption with its associated greenhouse gas and other emissions, but it also requires additional trucking to transport that make-up LNG for the 10% of resulting flash gas.
e. Further, this flash gas needs to be heated and then this gas needs to be compressed to over 25 psig in order to inject it into the 25 psig sendout system. This heating and compression require even more energy which is generated using greenhouse gas producing and air polluting processes.
f. Finally, the flash gas which needs to be injected into the 25 psig, also needs to be odorized which has its own associated manufacturing and distribution greenhouse and other emission gases associated with it.

2. The transport of 150 to 170 truckloads of LNG places its strain on the local community in the form of additional truck traffic, road wear, road hazards (similar to that of an additional 150-170 truck transports of any hazardous liquids across the city) and air pollution. Although LNG is considered an acceptable transportation risk, these transport truck tankers do have a high center of gravity and care must be taken to avoid rollovers. When a roll over does occur, unlike with a gasoline tanker truck, there is an added risk because the relief devices which are designed to relieve vaporized LNG are now submerged under the LNG liquid. Furthermore, the LNG is pressurized and cryogenic, which adds additional layers of risk. On a positive note, LNG trucks are double shelled, insulated and made of a thicker inner tank than that of a gasoline tanker truck. However, the handling and procedures needed to make an LNG rollover situation safe require additional first responder training and any additional transport of any hazardous liquid is associated with additional risks. Although the LNG Transport Industry has a very high safety record, there is a relationship between the number of accidents of any hazardous liquid transport industry to the number of miles traveled. JEI believes that 34,000 fewer traveled miles traveled, reduces that risk.

WHAT DOES THIS MEAN TO ETG?

Erie LNG is required to meet the design day and near design day gas supply requirements of the ETG system. Erie LNG is also a critical on-system component to the reliability of the ETG system. A single component failure that needs to be considered is the inability to continue to truck liquid into Erie LNG. This can occur for a variety of reasons, including:

- LNG trucking embargos
- LNG trucking labor issues

- LNG ship import shortages
  - Federal embargos like post 9/11/2001
  - Export company issues (wars, political embargos etc.)
  - Shipping issues (a host of issues can be postulated)
- International and domestic competition for LNG liquid causing a market induced shortage of LNG liquid available by tanker truck.

As a prudent gas system operator, ETG has been keeping a close watch on the LNG market and is concerned because it understands the risks of availability of LNG by truck potentially being constrained in the future.

Furthermore, today, while ETG has more recently experienced more reasonable Truck Trailer Fill RFP responses, it is JEI's opinion that the reliability and cost of supply issues that drove the LNG trucking market just a few years ago may certainly reappear with little or no warning.

This is especially concerning in the era of ever-increasing Cyber-attacks and sabotage on critical energy infrastructure in addition to the risk of a breakdown in the LNG trucked-in delivery system due to a lack of available LNG supply to be purchased, increased competition among buyers of LNG, a lack of LNG truck drivers, a serious incident involving an LNG truck that results in changes in regulations that impact LNG trucking, and acts of nature (winter storms, extreme weather, floods, earthquakes, hurricanes, etc.).

For these reasons, JEI fully supports ETG's decision to move from supply dependency of trucked-in LNG and build its own liquefier because the issues are not simply the variations in cost differences, but rather the overwhelming need to have a reliable source of critical peaking supplies for ETG's customers.

JEI concludes that it is prudent for ETG to build a liquefier at their Erie Street Facility. This is based on the logic presented above and by the overall findings of SJG's McKee City Liquefier report of 2012.

Appendix D: Discussion Regarding former alternative of Propane-air

OVERVIEW

This discussion considers replacing the Erie LNG capacity of 150 MMscf of natural gas. That is a Btu content of approximately 160,500,000 MBtu (based on a Btu value of 1070 Btu/scf . This Btu value is used because it is typical for LNG to have a higher Btu value than pipeline gas).

A gallon of propane has an energy content of approximately 93 MBtu/gallon. In order to replace the usable content of LNG in the Erie LNG facility, ETG would need to store 1,725,806 gallons of propane.

The use of 60,000 gallon tanks is typical is many LPG[38] facilities. Although larger tanks are made, they often cannot be used because their large size is difficult to transport.

The useable storage of a 60,000 gallon tank is 48,000[39] gallons. To store 1,725,788 gallons, ETG would need to have 36 – 60,000 gallon propane tanks.

Based on our experience. we estimate that a bare bones propane system providing 36 - 60,000 gallon tanks would cost $6 million each. These costs do not include the costs associated with providing air compression equipment, associated power supplies, mixing equipment, control instrumentation needed to maintain safe interchangeable mixtures, or main extensions needed to connect the plant to the gas system or acquisition of land.

Using this data, it is concluded that 6 such stations (each site having 6 – 60,000 gallon tanks) would have a CapEx of approximately $36 million. Furthermore, these costs do not include the costs associated with obtaining land in the Union division, providing air compression equipment, associated power supplies, mixing equipment, control instrumentation needed to maintain safe interchangeable mixtures, or main extensions needed to connect the plant to the gas system. Such stations would not substitute the reliability provided by Erie LNG because Erie LNG can be a sole supplier of a natural gas substitute without the need for natural gas mixing. Propane-air is not an acceptable natural gas replacement without dilution with natural gas. Further, even with dilution, propane-air/natural gas mixtures in the compositions needed do not meet the FERC guidelines for gas interchangeability.

Further, JEI believes that even if one were to conceive of a way to install all the propane needs at a single site, for cost and logistical reasons, the propane option would not be viable.

Lastly, the use of propane vs. natural gas emits more greenhouse gases to the environment.

[38] Liquefied propane gas

[39] Typically, propane tank allowable fills by code are ~80 – 85% tank water capacity dependent on temperature and specific gravity of the propane (80% is used in this analysis).

INTRODUCTION

The following analysis is intended to assess if it would have been feasible to plan on installing propane-air systems within ETG's service territory as an option to replace the need to truck LNG to Erie.

A mixture of propane and air and natural gas can be used as a substitute for natural gas for many, but not all, natural gas applications. If an existing propane facility is in place, it can continue to fill a spot need for supply. However, for new supply requirements, the advantages and disadvantages of a propane-air facility must be compared to LNG or pipeline supply and evaluated based on the potential customer impacts as well as cost.

INTERCHANGEABILITY

To use propane-air as a substitute for natural gas, it needs to be interchangeable with natural gas.

Because end use equipment has become more fuel composition sensitive over the past several decades (I.e. a propane-air substitution may not be acceptable for use in Compressed Natural Gas ("CNG") applications for internal combustion engines (such as NGV vehicles), or specific processes that require exact control of the fuel composition.), and because flowing gas supplies are expected to vary more in the future, the Federal Energy Regulatory Commission (FERC) has undertaken an initiative to examine and update natural gas interchangeability standards. The Natural Gas Council (a body of industry experts) has undertaken this task. They authored the Council's "White Paper on Natural Gas Interchangeability and Non-Combustion End Use." The Council has issued a set of interim guidelines (included in this White Paper). According to these guidelines, the introduction of propane-air into a territory that does not currently have propane-air substitution, such as ETG, should be restricted to limitations including the following: A maximum Wobbe Index[40] of 1400, a final delivered gas Wobbe Index that does not deviate more than 4% from the historical average, a maximum Heating Value Limit of 1,110 Btu/scf and a maximum total inerts of 4 percent. These parameters were set based on a historical gas similar to that presently being delivered to the ETG system. As propane is added, the Wobbe Index and the Heating Value increases. As air is added, the Wobbe Index and Heating Value decreases. It is JEI's opinion that the use of propane-air to substitute for 25,000 Dth/day of Erie LNG capacity in the ETG system would be outside these guidelines for all mixtures studied. In particular, a propane air substitution would be in excess of 4% inerts and would be detrimental to certain industrial customer processes (an in-depth analysis would need to be conducted to confirm if any such processes exist in the area where such propane-air mixtures were to be installed).

[40] The Wobbe Index (Number) is sometimes referred to as the Interchangeability Factor. The definition of the Wobbe Number is based on the heating value and specific gravity of a gas, and it is related to the thermal input to a burner (Btu per hour). It should be noted that while Wobbe is an effective, easy to use screening tool for interchangeability, the industry historically recognizes that the Wobbe Number alone is also not sufficient to completely predict gas interchangeability because it does not adequately predict all combustion phenomena. Alone, it is also not sufficient to completely predict gas interchangeability because it does not adequately predict all combustion phenomena

INTEGRATION OF PROPANE-AIR SYSTEMS INTO THE ETG SYSTEM

Due to the vapor pressure of propane, only integration of propane-air systems attached to the 60 psi or less systems would be considered. Thus, the only points at which a propane-air facility would integrated into the ETG system, would be at the points of pressure reduction to mains operating at 60 psi or less.

In JEI's opinion, the costs associated with propane and the logistics of managing 6 propane-air sites would put ETG's customers at a significant financial disadvantage. Also, the managing of so many plants would pose significant system control and reliability risks. For this reason and for the interchangeability reasons presented, JEI concluded that propane injection in ETG's Union region to supply up to 25,000 Dth/day for 4-5 days is not a viable option. This being concluded, no further analysis was made for providing propane-air in the eastern region of the ETG territory.

The estimated one-time cost to offset the reliable peaking capacity of Erie LNG using a propane-air alternative is, at a minimum, $36 million (which does not include procuring of land for 6 separate sites for propane-air facilities within the Union Division, plus additional plant facilities needed for air compression and mixing). This would be far more that the annual carrying cost of a new liquefier.

Further, the propane alternative is neither practical (replacing LNG truck deliveries with propane truck deliveries) nor recommended for ETG due to significant technical and emission issues discussed above.

Appendix E: Discussion Regarding former alternative of Incremental Interstate Pipeline Capacity

ETG has advised JEI that it is having ongoing discussions with each of its interstate pipeline suppliers and that they are participating in the various interstate pipeline incremental capacity projects that can help alleviate ETG's need for additional peak day firm interstate pipeline capacity.

These projects, when eventually placed in service, will still leave ETG with a firm interstate pipeline capacity shortfall, compared to its peak day estimated customer demand, that is currently made up through the purchase of third party bundled delivered service and Erie LNG.

ETG needs an additional 25,000 Dth/day if it were to replace Erie LNG's sendout.

The interstate pipeline project that may have had the potential to help the Union portion of ETG's territory is the Williams Transco Regional Energy Access project. However, this project is fully subscribed and does not have the ability to deliver an additional 25,000 Dth/day to Union.

Further, if it had additional capacity, and the cost of that capacity was the same as its fully subscribed expansion project, the cost to ETG would be approximately $7.8 million per year in fixed demand charges for each of the next 15 years of the contract. This would be far more that the annual carrying cost of a new liquefier.

IN THE MATTER OF THE PETITION OF ELIZABETHTOWN GAS COMPANY FOR APPROVAL OF INCREASED BASE RATE TARIFF RATES AND CHANGES FOR GAS SERVICE, CHANGES TO DEPRECIATION RATES AND OTHER TARIFF REVISIONS

BPU DOCKET NO. GR21_______

DIRECT TESTIMONY

OF

PAUL R. MOUL

P. Moul & Associates

On Behalf of
Elizabethtown Gas Company

Exhibit P-7

December 28, 2021

TABLE OF CONTENTS

GLOSSARY OF ACRONYMS AND DEFINED TERMS	
ACRONYM	**DEFINED TERM**
AFUDC	Allowance for Funds Used During Construction
β	Beta
b	Represents the retention rate that consists of the fraction of earnings that are not paid out as dividends
b x r	Represents internal growth
BPU	New Jersey Board of Public Utilities
CAPM	Capital Asset Pricing Model
CCR	Corporate Credit Rating
CE	Comparable Earnings
CIP	Conservation Incentive Program
DCF	Discounted Cash Flow
ETG	Elizabethtown Gas Company
FOMC	Federal Open Market Committee
g	Growth rate
IGF	Internally Generated Funds
LDC	Local Distribution Company
LT	Long Term
OFO	Operational flow orders
r	Represents the expected rate of return on common equity
RDM	Revenue Decoupling Mechanism
Rf	Risk-free rate of return
Rm	Market risk premium
RP	Risk Premium
s	Represents the new common shares expected to be issued by a Firm
SJI	South Jersey Industries
s x v	Represents external growth
S&P	S&P Global Ratings

GLOSSARY OF ACRONYMS AND DEFINED TERMS	
ACRONYM	**DEFINED TERM**
v	Represents the value that accrues to existing shareholders from selling stock at a price different from book value
WNC	Weather Normalization Adjustment Clause
ytm	Yield to maturity

ELIZABETHTOWN GAS COMPANY
DIRECT TESTIMONY OF
PAUL R. MOUL

I. INTRODUCTION AND SUMMARY OF RECOMMENDATIONS

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

A. My name is Paul Ronald Moul. My business address is 251 Hopkins Road, Haddonfield, New Jersey 08033-3062. I am Managing Consultant at the firm P. Moul & Associates, an independent financial and regulatory consulting firm. My educational background, business experience and qualifications are provided in Appendix A, which follows my direct testimony.

Q. WHAT IS THE PURPOSE OF YOUR DIRECT TESTIMONY?

A. My testimony presents evidence, analysis, and a recommendation concerning the appropriate cost of common equity, support for the Company's proposed capital structure, and overall rate of return that the New Jersey Board of Public Utilities ("BPU" or the "Board") should recognize in the determination of the revenues that Elizabethtown Gas Company ("Elizabethtown" or the "Company") should be authorized as a result of this proceeding. My analysis and recommendation are supported by the detailed financial data contained in fifteen (15) schedules that are attached to my testimony. My testimony is based on discussions with the Company's management and information obtained from the Company including specific financial data.

Q. BASED UPON YOUR ANALYSIS, WHAT IS YOUR CONCLUSION CONCERNING THE APPROPRIATE RATE OF RETURN FOR THE COMPANY IN THIS CASE?

A. Based upon my analysis of the Company, it is my opinion that the rate of return on common equity should be set within the range of 10.75% to 11.75%. My cost of equity determination should be viewed in the context of the need for supportive regulation at a time of increased infrastructure improvements now underway for the Company. As shown on page 1 of Schedule PRM-1, I have presented the weighted average cost of capital for the Company, which is calculated for the test year ending March 31, 2022. My recommended range of the rate of return and return on equity range are shown below:

Type of Capital	Ratios	Cost Rate	Weighted Cost Rate
Long-Term Debt	45.11%	3.83%	1.73%
Common Equity	54.89%	10.75%	5.90%
Total	100.00%		7.63%

Type of Capital	Ratios	Cost Rate	Weighted Cost Rate
Long-Term Debt	45.11%	3.83%	1.73%
Common Equity	54.89%	11.75%	6.45%
Total	100.00%		8.18%

The resulting overall cost of capital, which is the product of weighting the individual capital costs by the proportion of each respective type of capital, should establish a compensatory level of return for the use of capital and, if achieved, will provide the Company with the ability to attract capital on reasonable terms.

Q. IS THE MARKET IMPACT OF THE COVID-19 PANDEMIC REFLECTED IN YOUR ANALYSIS OF THE COST OF EQUITY OF THE COMPANY?

A. Yes. My cost of equity analysis reflects the impact of the coronavirus pandemic. These events had a significant impact on the capital markets -- both debt and equity. Extraordinary events around the COVID-19 pandemic have produced significant turmoil that has rocked the stock and bond markets beginning in the February-March 2020 time frame. During this period, we saw abrupt reaction to the coronavirus pandemic and declines in the price of crude oil. These events led to the end of the record-setting 128-month economic expansion. As we entered a recession in February 2020, extraordinary actions were taken by the Federal Open Market Committee ("FOMC") to address these disruptions. Over the course of the pandemic, stock prices have rebounded and have reached new highs. In the most recent months renewed economic growth has accelerated inflation to levels not seen in three decades. Supply shortages have also significantly impacted the consumer sector of the economy. Energy prices have increased as well, with the commodity cost of natural gas spiking upward. While short-term interest rates remain at historically low levels, longer term interest rates began to rise in February 2021. At this point, short-term interest rates are poised to increase when the FOMC tapers its bond buying program. Stock and bond market performance has reacted to renewed economic growth as business fundamentals began to return to more normal levels. I have considered these events as they impact the inputs that I used in the various models of the cost of equity. That is to say, I have analyzed the cost of equity models using input data that follows the onset of these factors.

Q. WHAT BACKGROUND INFORMATION HAVE YOU CONSIDERED IN REACHING A CONCLUSION CONCERNING THE COMPANY'S COST OF CAPITAL?

A. The Company is a wholly-owned subsidiary of South Jersey Industries, Inc. ("SJI"). The common stock of SJI is traded on the New York Stock Exchange.

The Company provides natural gas distribution service to over 300,000 customers located in northern and northwestern New Jersey. Throughput to on-system customers in 2020 was represented by approximately 61% to sales and 39% to transportation customers. Elizabethtown obtains its natural gas supplies from producers and marketers and has transportation arrangements through connections to seven interstate pipelines. The Company has storage arrangements with several suppliers and it owns a liquefied natural gas facility to supplement flowing gas.

Q. HOW HAVE YOU DETERMINED THE COST OF COMMON EQUITY IN THIS CASE?

A. The cost of common equity is established using capital market and financial data relied upon by investors to assess the relative risk, and hence, the cost of equity for a natural gas utility, such as Elizabethtown. In this regard, I have considered four (4) well-recognized models. These methods include: the Discounted Cash Flow ("DCF") model, the Risk Premium ("RP") analysis, the Capital Asset Pricing Model ("CAPM"), and the Comparable Earnings ("CE") approach. The results of a variety of approaches indicate that the Company's rate of return on common equity is in the range of 10.75% to 11.75%.

Q. IN YOUR OPINION, WHAT FACTORS SHOULD THE BOARD CONSIDER WHEN DETERMINING THE COMPANY'S COST OF CAPITAL IN THIS PROCEEDING?

A. The Board's rate of return allowance must be set to cover the Company's interest and dividend payments, provide a reasonable level of earnings retention, produce an adequate level of internally generated funds to meet capital requirements, be commensurate with the risk to which the Company's capital is exposed, assure confidence in the financial integrity of the Company, support reasonable credit quality, and allow the Company to raise capital on reasonable terms. The return that I propose fulfills these established standards of a fair rate of return set forth by the landmark Bluefield and Hope cases.[1] That is to say, my proposed rate of return is commensurate with returns available on investments having corresponding risks.

Q. HOW HAVE YOU MEASURED THE COST OF EQUITY IN THIS CASE?

A. The models that I used to measure the cost of common equity for the Company were applied with market and financial data developed from a group of companies engaged in the distribution of natural gas. I will refer to these companies as the Gas Group throughout my testimony. I began with all of the gas utilities contained in The Value Line Investment Survey, which consists of ten companies. Value Line is an investment advisory service that is a widely used source in public utility rate cases. I eliminated one company from the Value Line group. UGI Corporation was removed due to its diversified businesses consisting of six reportable segments, including propane, two international liquefied petroleum gas ("LPG") segments, natural gas utility, energy services, and electric generation. The remaining nine (9) companies in the Gas Group are identified on page 2 of Schedule PRM-3.

Q. HOW HAVE YOU PERFORMED YOUR COST OF EQUITY ANALYSIS WITH THE MARKET DATA FOR THE GAS GROUP?

A. I have applied the models/methods for estimating the cost of equity using the average data for the Gas Group. I have not measured separately the cost of equity for the individual companies within the Gas Group, because the determination of the cost of equity for an

[1] Bluefield Water Works & Improvement Co. v. P.S.C. of West Virginia, 262 U.S. 679 (1923) and F.P.C. v. Hope Natural Gas Co., 320 U.S. 591 (1944).

individual company can be problematic. The use of group average data will reduce the effect of potentially anomalous results for an individual company if a company-by-company approach were utilized.

Q. PLEASE SUMMARIZE YOUR COST OF EQUITY ANALYSIS.

A. My cost of equity determination was derived from the results of the methods/models identified above. In general, the use of more than one method provides a superior foundation to arrive at the cost of equity. At any point in time, a single method can provide an incomplete measure of the cost of equity. The specific application of these methods/models will be described later in my testimony. The following table provides a summary of the indicated costs of equity using each of these approaches.

	Excluding Flotation Costs[2]
DCF	11.21%
Risk Premium	10.50%
CAPM	13.55%
Comparable Earnings[3]	12.70%

I have also provided the cost of equity analysis that includes flotation costs as shown later in my testimony. From these measures, I recommend a cost of equity in the range of 10.75% to 11.75%. The low end of my range is based on the average of the DCF and Risk Premium, i.e., the 10.86% (11.21% + 10.50% = 21.71% ÷ 2) return, rounded down to

[2] Flotation costs are defined as the out-of-pocket costs associated with the issuance of common stock. Those costs typically consist of the underwriters' discount and company issuance expenses.
[3] Average of historical and forecast returns.

10.75%. The upper end of my range is represented by the average of the market-based models, i.e., DCF, Risk Premium and CAPM (11.21% + 10.50% + 13.55% = 35.26% ÷ 3 = 11.75%). The midpoint of the range is 11.25%. To obtain new capital and retain existing capital, the rate of return on common equity must be high enough to satisfy investors' requirements.

II. NATURAL GAS RISK FACTORS

Q. WHAT FACTORS CURRENTLY AFFECT THE BUSINESS RISK OF NATURAL GAS UTILITIES?

A. Gas utilities face risks arising from competition, economic regulation, the business cycle, and customer usage patterns. Today, they operate in a complex environment with time frames for decision-making considerably shortened. Their business profile is influenced by market-oriented pricing for the commodity distributed to customers and open access for the transportation of natural gas for customers. The gas distribution industry also faces the risk associated with increased availability of renewable energy sources, expanded emphasis on energy efficiency, and potential initiatives directed toward decarbonization as a national energy policy.

Natural gas utilities have focused increased attention on safety and reliability issues and on conservation. In order to address these issues and to comply with new and pending pipeline safety regulations, natural gas companies are now allocating more of their resources to addressing aging infrastructure issues. The testimony of Company witnesses discusses the investments that the Company has made and will make to address these issues.

Q. WHAT SPECIFIC RISKS SHOULD THE BOARD CONSIDER WHEN SETTING THE RATE OF RETURN FOR ELIZABETHTOWN IN THIS CASE?

A. Those risks fall in the general categories of regulatory, operational and infrastructure.

Q. PLEASE DETAIL THE REGULATORY RISKS FACED BY THE COMPANY?

A. Among other factors, regulatory risks faced by the Company are elevated when it comes to permits and approvals necessary for the siting of projects that assure reliable supply of natural gas. Obtaining these permits and approvals has become a time consuming and increasingly risky process that adds delay and costs to the projects that will assure adequate gas supply for the Company.

Q. PLEASE DISCUSS SOME OF THE OPERATIONAL RISKS FACED BY THE COMPANY?

A. Risks that affect the Company's operations relate to adequate delivery capability, counterparty risk and risks related to cyber-security. The Company is also faced with counterparty risk should suppliers fail to perform their obligations, especially with regard to hedging obligations. In addition, the handling of natural gas is inherently risky. Finally, cyber-security has created increased risk when systems that deliver gas to customers are vulnerable to attack from foreign enemies and domestic terrorists.

Q. WHAT RISKS ARE ASSOCIATED WITH THE COMPANY'S INFRASTRUCTURE?

A. The Company's infrastructure is aging rapidly and is in the process of rehabilitation and replacement. Investments that address these issues cause costs to increase without any corresponding increase in throughput that would add to revenues. This places pressure on the price paid by customers that may prompt them to seek alternative energy sources.

Q. ARE THERE OTHER FEATURES OF THE COMPANY'S BUSINESS THAT SHOULD BE CONSIDERED WHEN ASSESSING THE COMPANY'S RISK?

A. Yes. Most of the Company's residential and commercial customers use natural gas for space heating purposes. This indicates that a large proportion of the Company's residential and commercial customers present a low load factor profile and their energy demands are significantly influenced by temperature conditions, over which the Company has absolutely no control. To help deal with this issue, Elizabethtown has a Conservation Incentive Program ("CIP") as part of its tariff.

Q. DOES YOUR COST OF EQUITY ANALYSIS AND RECOMMENDATIONS TAKE INTO ACCOUNT THE CIP?

A. Yes. The Company currently operates under a CIP that provides revenue decoupling and promotes conservation programs. It is intended to reconcile actual weather-adjusted sales margins with those approved in the Company's most recent rate case. Weather variations are also part of the CIP, which formerly was handled through the Weather Normalization Clause ("WNC"). My cost of equity analysis takes into account the Company's CIP.

Q. HOW HAVE YOU ADDRESSED THIS ISSUE?

A. The LDCs included in my Gas Group already have tariff mechanisms similar to decoupling, and therefore, my analysis already reflects the impact of decoupling on investor expectations through the use of market-determined models. All of the companies in my Gas Group have some form of revenue decoupling mechanism ("RDM") that is intended to accomplish the same result as the Company's CIP. As a group, the market prices of these companies' common equity reflect the expectations of investors that the companies' revenues are stabilized to some extent by a decoupling mechanism. Therefore, my analysis reflects the impacts of decoupling on investor expectations through the use of market-determined models. As such, the market prices of these companies' common stocks reflect the expectations of investors related to a regulatory mechanism that adjusts revenues for conservation, abnormal weather, and other items. The trend in the industry is to stabilize the recovery of fixed costs, which are unaffected by usage. Indeed, there has been a proliferation of tracking mechanisms in the LDC business. Because my Gas Group that I use to measure the cost of equity has the risk attributes related to the RDM "baked in" to their stock prices, the absence of the benefit of the RDM would increase the cost of equity as determined by the models that are applied with the Gas Group data.

Q. PLEASE INDICATE HOW THE COMPANY'S CONSTRUCTION PROGRAM AFFECTS ITS RISK PROFILE.

A. The Company is faced with the requirement to undertake investments to maintain and upgrade existing facilities in its service territory. To maintain safe and reliable service to existing customers, the Company must invest to upgrade its infrastructure. The rehabilitation of the Company's infrastructure represents capital expenditures that do not increase the Company's customer base. Although the Company has made significant strides in reducing its percentage of unprotected steel and iron pipe, these facilities represent 320 miles (or 9.8%) of its distribution mains as of year-end 2020. Also, the Company has 2,013 services constructed of unprotected steel. For the future, the Company expects its capital expenditures to be:

Year	Capital Expenditures
	($000)
2021	$ 169,300
2022	$ 172,400
2023	$ 162,600
2024	$ 135,900
2025	$ 140,900
Total	$ 781,100

The Company's total capital expenditures over the next five years will represent approximately 50% ($781,100 ÷ $1,570,634) of the net utility plant in service at December 31, 2020.

Q. HOW SHOULD THE BOARD RESPOND TO THE ISSUES FACING THE NATURAL GAS UTILITIES AND IN PARTICULAR ELIZABETHTOWN?

A. The Board should recognize and take into account the heightened capital requirements for the Company in determining the rate of return in this case. It is essential that the Board provide a reasonable opportunity for the Company to actually earn its authorized rate of return so that it can raise the capital necessary to fund its large capital program.

III. FUNDAMENTAL RISK ANALYSIS

Q. IS IT NECESSARY TO CONDUCT A FUNDAMENTAL RISK ANALYSIS TO PROVIDE A FRAMEWORK FOR A DETERMINATION OF THE UTILITY'S COST OF EQUITY?

A. Yes, it is. It is necessary to establish a company's relative risk position within its industry through a fundamental analysis of various quantitative and qualitative factors that bear upon investors' assessment of overall risk. The qualitative factors that bear upon Company risk have already been discussed. The items that influence investors' evaluation of risk and their required returns were described above. The quantitative risk analysis follows. For this purpose, I compared the Company to the S&P Public Utilities, an industry-wide proxy consisting of various regulated businesses, and to the Gas Group.

Q. WHAT ARE THE COMPONENTS OF THE S&P PUBLIC UTILITIES?

A. The S&P Public Utilities is a widely recognized index that is comprised of electric power and natural gas companies. These companies are identified on page 3 of Schedule PRM-4.

Q. WHAT COMPANIES COMPRISE THE GAS GROUP?

A. As explained previously, my Gas Group consists of the following companies: Atmos Energy Corp., Chesapeake Utilities Corporation, New Jersey Resources Corp., NiSource, Inc., Northwest Natural Holding Co., ONE Gas, Inc., South Jersey Industries, Inc., Southwest Gas Holdings, and Spire, Inc.

Q. IS KNOWLEDGE OF A UTILITY'S BOND RATING AN IMPORTANT FACTOR IN ASSESSING ITS RISK AND COST OF CAPITAL?

A. Yes. Knowledge of a company's credit quality rating is important because the cost of each type of capital is directly related to the associated risk of the firm. So, while a company's credit quality risk is shown directly by the rating and yield on its bonds, these relative risk assessments also bear upon the cost of equity. This is because a firm's cost of equity is represented by its borrowing cost plus compensation to recognize the higher risk of an equity investment compared to debt.

Q. HOW DO THE CREDIT QUALITY RATINGS COMPARE FOR THE COMPANY, THE GAS GROUP, AND THE S&P PUBLIC UTILITIES?

A. The Company currently carries a rating from S&P Global Ratings ("S&P") of the South Jersey Industries parent company of BBB with a stable outlook. The rating represents the Long Term ("LT") issuer rating by S&P, which focuses upon the credit quality of the issuer of the debt rather than upon the debt obligation itself. For the Gas Group, the average LT issuer rating is A3 by Moody's and A- by S&P, as displayed on page 2 of Schedule PRM-3. For the S&P Public Utilities, the average credit quality rating is A3 by Moody's and BBB+ by S&P, as displayed on page 3 of Schedule PRM-4. Many of the financial indicators that I will subsequently discuss are considered during the rating process.

Q. HOW DO THE FINANCIAL DATA COMPARE FOR THE COMPANY, THE GAS GROUP, AND THE S&P PUBLIC UTILITIES?

A. The broad categories of financial data that I will discuss are shown on Schedules PRM-2, PRM-3, and PRM-4. The data cover the five-year period 2016-2020. The important categories of relative risk may be summarized as follows:

<u>Size.</u> In terms of capitalization, the Company is smaller than the average size of the Gas Group, and smaller still than the average size of the S&P Public Utilities. All other things being equal, a smaller company is riskier than a larger company because a given change in revenue and expense has a proportionately greater impact on a small firm. As I will demonstrate later, the size of a firm can impact its cost of equity.

<u>Market Ratios.</u> Market-based financial ratios, such as earnings/price ratios and dividend yields, provide a partial measure of the investor-required cost of equity. If all other factors are equal, investors will require a higher rate of return for companies that

exhibit greater risk, in order to compensate for that risk. That is to say, a firm that investors perceive to have higher risks will experience a lower price per share in relation to expected earnings.[5]

There are no market ratios available for the Company because its stock is owned by South Jersey Industries. The five-year average price-earnings multiple was somewhat higher for the Gas Group compared to the S&P Public Utilities. The five-year average dividend yield was lower for the Gas Group as compared to the S&P Public Utilities. The five-year average market-to-book ratio was slightly lower for the Gas Group as compared to the S&P Public Utilities.

Common Equity Ratio. The level of financial risk is measured by the proportion of long-term debt and other senior capital that is contained in a company's capitalization. Financial risk is also analyzed by comparing common equity ratios (the complement of the ratio of debt and other senior capital). That is to say, a firm with a high common equity ratio has lower financial risk, while a firm with a low common equity ratio has higher financial risk. The five-year average common equity ratios, based on permanent capital, were 59.40% for Elizabethtown, 51.5% for the Gas Group, and 41.3% for the S&P Public Utilities. The Company's common equity ratio was higher than the Gas Group, thereby indicating lower financial risk.

Return on Book Equity. Greater variability (i.e., uncertainty) of a firm's earned returns signifies relatively greater levels of risk, as shown by the coefficient of variation (standard deviation ÷ mean) of the rate of return on book common equity. The higher the

[5] For example, two otherwise similarly situated firms each reporting $1.00 in earnings per share would have different market prices at varying levels of risk (i.e., the firm with a higher level of risk will have a lower share value, while the firm with a lower risk profile will have a higher share value).

coefficients of variation, the greater degree of variability. For the five-year period, the coefficients of variation were 0.511 (2.4% ÷ 4.7%) for the Company, 0.079 (0.7% ÷ 8.9%) for the Gas Group, and 0.039 (0.4% ÷ 10.3%) for the S&P Public Utilities. The variability of the Company's rates of return was vastly higher than the Gas Group and the S&P Public Utilities, thereby signifying higher risk for the Company.

Operating Ratios. I have also compared operating ratios (the percentage of revenues consumed by operating expense, depreciation, and taxes other than income).[6] The five-year average operating ratios were 79.4% for the Company, 83.6% for the Gas Group, and 78.8% for the S&P Public Utilities. The Company's operating ratios were somewhat lower than the Gas Group, thereby indicating slightly lower risk.

Coverage. The level of fixed charge coverage (i.e., the multiple by which available earnings cover fixed charges, such as interest expense) provides an indication of the earnings protection for creditors. Higher levels of coverage, and hence earnings protection for fixed charges, are usually associated with superior grades of creditworthiness. Excluding Allowance for Funds Used During Construction (AFUDC), the five-year average pre-tax interest coverage was 3.03 times for the Company, 4.05 times for the Gas Group, and 3.02 times for the S&P Public Utilities. The interest coverages were lower for the Company as compared to the Gas Group, thereby indicating higher credit risk.

Quality of Earnings. Measures of earnings quality usually are revealed by the percentage of AFUDC related to income available for common equity, the effective income tax rate, and other cost deferrals. These measures of earnings quality usually influence a firm's internally generated funds because poor quality of earnings would not generate high

[6] The complement of the operating ratio is the operating margin which provides a measure of profitability. The higher the operating ratio, the lower the operating margin.

levels of cash flow. During the COVID pandemic, there is further pressure on cash flows due to the suspension of collection activities and the moratorium against shut off service due to nonpayment. Moreover, the Company has created a regulatory asset consisting of COVID-related costs that have been deferred. Such actions have a negative impact on the Company's cash flow. Quality of earnings has not been a significant concern for the Company, the Gas Group and the S&P Public Utilities. During the recent period of heightened construction, the AFUDC percentage has spiked upward for the Company.

Internally Generated Funds. Internally generated funds ("IGF") provide an important source of new investment capital for a utility and represent a key measure of credit strength. Historically, the five-year average percentage of IGF to capital expenditures was 33.2% for the Company, 56.0% for the Gas Group and 69.5% for the S&P Public Utilities. The Company's IGF to construction percentage has been well below the Gas Group and S&P Public Utilities, thereby signifying higher risk.

Betas. The financial data that I have been discussing relate primarily to company-specific risks. Market risk for firms with publicly-traded stock is measured by beta coefficients. Beta coefficients attempt to identify systematic risk, i.e., the risk associated with changes in the overall market for common equities.[7] Value Line publishes such a statistical measure of a stock's relative historical volatility to the rest of the market. A comparison of market risk is shown by the Value Line beta of 0.88 as the average for the Gas Group (see page 2 of Schedule PRM-3) and 0.91 as the average for the S&P Public

[7] Beta is a relative measure of the historical sensitivity of the stock's price to overall fluctuations in the New York Stock Exchange Composite Index. The ''Beta coefficient'' is derived from a regression analysis of the relationship between weekly percentage changes in the price of a stock and weekly percentage changes in the NYSE Index over a period of five years. The betas are adjusted for their long-term tendency to converge toward 1.00. A common stock that has a beta less than 1.0 is considered to have less systematic risk than the market as a whole and would be expected to rise and fall more slowly than the rest of the market. A stock with a beta above 1.0 would have more systematic risk.

Utilities (see page 3 of Schedule PRM-4). The systematic risk for the Gas Group as measured by the Value Line beta is fairly similar to the S&P Public Utilities.

Q. PLEASE SUMMARIZE YOUR RISK EVALUATION.

A. In several aspects, principally related to its smaller size, its much higher earnings variability, its somewhat lower operation ratio, its lower interest coverage, and much lower IGF to construction, Elizabethtown's risk is higher than the Gas Group. Its common equity ratio points to lower financial risk for Elizabethtown. Quality of earnings shows similar risk for Elizabethtown and the Gas Group. On balance, the cost of equity measured with the Gas Group data will provide a reasonable, albeit very conservative, representation of the Company's cost of equity.

IV. CAPITAL STRUCTURE RATIOS

Q. PLEASE EXPLAIN THE SELECTION OF CAPITAL STRUCTURE RATIOS FOR ELIZABETHTOWN.

A. It is appropriate that Elizabethtown's capital structure ratios be employed for rate of return purposes. In the situation where the operating public utility raises its own debt directly in the capital markets, as is the case for the Company, it is proper to employ the capital structure ratios and senior capital cost rates of the regulated public utility for rate of return purposes. Furthermore, consistency requires that the embedded cost rate of the Company's senior securities also be employed. This procedure is consistent with the ratemaking procedures used by the Board in prior rate cases for Elizabethtown.

Q. DOES SCHEDULE PRM-5 PROVIDE THE COMPANY'S CAPITALIZATION AND CAPITAL STRUCTURE RATIOS?

A. Yes. Schedule PRM-5 presents the Company's capitalization and related capital structure ratios. The March 31, 2022 capitalization corresponds with the end of the test year in this case. The Company's initial filing contains the actual September 30, 2021 capital structure for informational purposes. The test year data will be updated as the case progresses. The Company's capital structure estimated at March 31, 2022 reflects the forecast increase in retained earnings, which assumes no common dividend payments during the period.

Q. WHAT CAPITAL STRUCTURE RATIOS DO YOU RECOMMEND BE ADOPTED FOR RATE OF RETURN PURPOSES IN THIS PROCEEDING?

A. Since ratemaking is prospective, the rate of return should, at a minimum, reflect known or reasonably foreseeable changes that will occur during the course of the test year. The Company's capital structure ratios shown on Schedule PRM-5 have been adjusted to remove the debt and equity components of the goodwill that arose from its purchase in 2018. The acquisition order by the Board specified that the Company cannot obtain recovery of goodwill in its rates. For this adjustment, I have assigned 30.65% of goodwill to debt and 69.35% of goodwill to equity. The assignment percentages represent the initial capitalization of Elizabethtown, which consisted of $530.000 million of variable rate debt (subsequently refinanced with permanent capital) and $1,199.397 million of equity. As a result, I will adopt the Company's test year-end capital structure ratios of 45.11% long-term debt and 54.89% common equity. These capital structure ratios are the best approximation of the mix of capital the Company will employ to finance its rate base during the period new rates are effective. This capital structure is reasonable.

I have not reflected short-term debt in the Company's capital structure ratios for this case because it is not a permanent source of financing for its rate base. The Company uses short-term debt as bridge financing until it accumulates to a size that makes a permanent financing economical. That is to say, short-term debt represents interim financing that will be replaced with long-term debt and common equity on a periodic basis. Moreover, the Company uses short-term debt to finance non-rate base items. One non-rate base capital item is the Remediation Adjustment Clause ("RAC") deferred balance. The deferred balance of the RAC is expected to be $90.045 million, as the twelve month average during the test year. This amount will far exceed the projected balance of short-term debt outstanding. Therefore, it is reasonable to assume that short-term debt represents the source of funds used to finance the RAC and not the rate base. To avoid double counting, short-term debt must be excluded from the capital structure when setting base rates. As a consequence, no amount of short-term debt can be assumed to finance the rate base in this case.

Further, there is no need to consider short-term debt in the capital structure to set base rates because short-term debt is used first to finance construction work in progress ("CWIP"). Hence, short-term debt should be excluded from the capital structure because CWIP is not included in the rate base. Rather, the cost of short-term debt is reflected fully in the AFUDC rate calculation. As a consequence, customers receive the benefit of the cost of short-term debt in a lower AFUDC rate that is capitalized in the property, plant and equipment accounts. To avoid double-counting, short-term debt must be excluded from the capital structure ratios when setting base rates.

Q. HAVE YOU MADE SPECIFIC RATEMAKING ADJUSTMENT TO THE COMPANY'S CAPITAL STRUCTURE TO RECOGNIZE THE EARLY REDEMPTION OF LONG-TERM DEBT?

A. Yes. I have made a ratemaking adjustment to the capital structure for the call premiums paid to redeem long-term debt. In this regard, the principal amount of long-term debt has been reduced by the amounts used to finance the call premiums for the early redemption of long-term debt (see pages 1 and 2 of Schedule PRM-6). To do otherwise would deny the Company the full return on the premiums paid to redeem this long-term debt because additional amounts of capital were used to pay the call premiums. The Company's long-term debt amount must be adjusted for this disparity so that the return necessary to service the capitalization is produced from rate base investment times the overall rate of return. The unamortized amount of the original issuance expenses on the debt that was redeemed was added to the issuance costs on the new debt.

These adjustments are equitable because customers receive the cost savings resulting from the refinancing in the form of a lower overall rate of return, and the Company recovers all costs incurred in providing these benefits to customers. To accomplish these savings, the Company paid the debt holders a premium over the principal amount for surrendering their securities prior to maturity. These premiums represented an investment made by the Company to reduce its overall cost of capital. Because the reduced interest costs are reflected in the lower cost of capital to customers, it is appropriate that the Company recover the costs incurred to produce these savings. That is to say, the Company is proposing to recover only those costs that produced interest cost savings that are passed through to customers. Adjusting the principal amounts as shown on pages 1 and 2 of Schedule PRM-6 provides a return on the premium.

V. <u>COST OF SENIOR CAPITAL</u>

Q. WHAT COST RATE HAVE YOU ASSIGNED TO THE DEBT PORTION OF ELIZABETHTOWN'S CAPITAL STRUCTURE?

A. Consistency with the capital structure ratios for the Company requires that the embedded cost rates of Elizabethtown's senior securities must also be employed. This procedure is consistent with the ratemaking procedures used by the Board in prior Elizabethtown rate cases. The determination of the cost of debt is essentially an arithmetic exercise. This is due to the fact that the Company has contracted for the use of this capital for a specific period of time at a specified cost rate. As shown on page 2 of Schedule PRM-6, the embedded cost rate of long-term debt is 3.90% at March 31, 2022. As previously explained, I have also recognized the cost associated with the call premium for the early redemption of long-term debt. The details leading to the development of the individual effective cost rates for each series of long-term debt, using the yield to maturity ("ytm") technique, are shown on page 3 of Schedule PRM-6. The ytm is the rate of discount that equates the present value of all future interest and principal payments with the net proceeds of the bond after recognizing issuance costs.

I will adopt the 3.90% embedded cost of debt for rate of return purposes. The 3.90% debt cost rate is related to the amount of long-term debt shown on Schedule PRM-5 which provides the basis for the 45.11% long-term debt ratio.

VI. COST OF EQUITY – GENERAL APPROACH

Q. PLEASE DESCRIBE HOW YOU DETERMINED THE COST OF EQUITY FOR THE COMPANY.

A. Although my fundamental financial analysis provides the required framework to establish the risk relationships among Elizabethtown, the Gas Group, and the S&P Public Utilities, the cost of equity must be measured by standard financial models that I identified above. Differences in risk traits, such as size, business diversification, geographical diversity, regulatory policy, financial leverage, and bond ratings must be considered when analyzing the cost of equity.

It is also important to reiterate that no one method or model of the cost of equity can be applied in an isolated manner. Rather, informed judgment must be used to take into consideration the relative risk traits of the firm. It is for this reason that I have used more than one method to measure the Company's cost of equity. As I describe below, each of the methods used to measure the cost of equity contains certain incomplete and/or overly restrictive assumptions and constraints that are not optimal. Therefore, I favor considering the results from a variety of methods. In this regard, I applied each of the methods with data taken from the Gas Group and arrived at a cost of equity in the range of 10.75% to 11.75%.

VII. DISCOUNTED CASH FLOW

Q. PLEASE DESCRIBE THE DCF MODEL.

A. The DCF model seeks to explain the value of an asset as the present value of future expected cash flows discounted at the appropriate risk-adjusted rate of return. In its simplest form, the DCF-determined return on common stock consists of a current cash (dividend) yield and future price appreciation (growth) of the investment. The dividend discount equation is the familiar DCF valuation model, which assumes that future dividends are systematically related to one another by a constant growth rate. The DCF formula is derived from the standard valuation model: P = D/(k-g), where P = price, D = dividend, k = the cost of equity, and g = growth in cash flows. By rearranging the terms, we obtain the familiar DCF equation: k= D/P + g. All of the terms in the DCF equation represent investors' assessment of expected future cash flows that they will receive in relation to the value that they set for a share of stock (P). The DCF equation is sometimes referred to as the "Gordon" model.[8] My DCF results are provided on Schedule PRM-1, page 2, for the Gas Group. The DCF return is 11.21% with the leverage adjustment and 10.26% without the leverage adjustment for the Gas Group. The leverage adjustment is discussed more fully below.

Among the limitations of the model, there is a certain element of circularity in the DCF method when applied in rate cases. This is because investors' expectations for the future depend upon regulatory decisions. In turn, when regulators depend upon the DCF model to set the cost of equity, they rely upon investor expectations that include an assessment of how regulators will decide rate cases. Due to this circularity, the DCF model may not fully reflect the true risk of a utility.

Q. WHAT IS THE DIVIDEND YIELD COMPONENT OF A DCF ANALYSIS?

A. The dividend yield reveals the portion of investors' cash flow that is generated by the return provided by the dividends an investor receives. It is measured by the dividends per share

[8] Although the popular application of the DCF model is often attributed to the work of Myron J. Gordon in the mid-1950's, J. B. Williams exposited the DCF model in its present form nearly two decades earlier.

relative to the price per share. The DCF methodology requires the use of an expected dividend yield to establish the investor-required cost of equity. For the twelve months ended September 2021, the monthly dividend yields are shown on Schedule PRM-7. The month-end prices were adjusted to reflect the buildup of the dividend in the price that has occurred since the last ex-dividend date (i.e., the date by which a shareholder must own the shares to be entitled to the dividend payment – usually about two to three weeks prior to the actual payment).

For the twelve months ended September 2021 the average dividend yield was 3.49% for the Gas Group based upon a calculation using annualized dividend payments and adjusted month-end stock prices. The dividend yields for the more recent six-month and three-month periods were 3.39% and 3.51%, respectively. For applying the DCF model, I have used the six-month average dividend yield of 3.39% for the Gas Group. The use of this dividend yield will reflect current capital costs, while avoiding spot yields. For the purpose of a DCF calculation, the average dividend yield must be adjusted to reflect the prospective nature of the dividend payments, i.e., the higher expected dividends for the future. Recall that the DCF is an expectational model that must reflect investors' anticipated cash flows. I have adjusted the six-month average dividend yield in three different, but generally accepted, manners and used the average of the three adjusted values as calculated in the lower panel of data presented on Schedule PRM-7. This adjustment adds twelve basis points to the six-month average historical yield, thus producing the 3.51% adjusted dividend yield for the Gas Group.

Q. WHAT FACTORS INFLUENCE INVESTORS' GROWTH EXPECTATIONS?

A. As noted previously, investors are interested principally in the dividend yield and future growth of their investment (i.e., the price per share of the stock). Future growth in earnings per share is the DCF model's primary focus because, under the model's assumption that the price-earnings multiple remains constant, the price per share of stock will grow at the same rate as earnings per share. A growth rate analysis considers a variety of variables to reach a consensus of prospective growth, including historical data and widely available analysts' forecasts of earnings, dividends, book value, and cash flow (all stated on a per-share basis). A fundamental growth rate analysis is frequently based upon internal growth (b x r), where "r" is the expected rate of return on common equity and "b" is the retention rate (a fraction representing the proportion of earnings not paid out as dividends). To be complete, the internal growth rate should be modified to account for sales of new common stock (external growth), which is represented by the formula s x v, where "s" is the number of new common shares the firm expects to issue and "v" is the value that accrues to existing shareholders from selling stock at a price above book value. Fundamental growth, which combines internal and external growth, encompasses the factors that cause book value per share to grow over time.

Growth also can be expressed in multiple stages. This expression of growth consists of an initial "growth" stage where a firm enjoys rapidly expanding markets, high profit margins, and abnormally high growth in earnings per share. Thereafter, a firm enters a "transition" stage where fewer technological advances and increased product saturation begin to reduce the growth rate and profit margins come under pressure. During the "transition" phase, investment opportunities begin to mature, capital requirements decline, and a firm begins to pay out a larger percentage of earnings to shareholders. Finally, the mature or "steady-state" stage is reached when a firm's earnings growth, payout ratio, and return on equity stabilize at levels where they remain for the life of a firm. The three stages of growth assume a step-down of high initial growth to lower sustainable growth. Even if these three stages of growth can be envisioned for a firm, the third "steady-state" growth stage, which is assumed to remain fixed in perpetuity, represents an unrealistic expectation because the three stages of growth can be repeated. That is to say, the stages can be repeated where growth for a firm ramps-up and ramps-down in cycles over time. For these reasons, there is no need to analyze growth rates individually for each cycle, but rather to rely upon analysts' growth forecasts, which are those used by investors when pricing common stocks.

Q. HOW DID YOU DETERMINE AN APPROPRIATE GROWTH RATE?

A. The growth rate used in a DCF calculation should measure investor expectations. Investors consider both company-specific variables and overall market sentiment (i.e., level of inflation rates, interest rates, economic conditions, etc.) when balancing their capital gains expectations with their dividend yield requirements. Investors are not influenced solely by a single set of company-specific variables weighted in a formulaic manner. Therefore, all relevant growth rate indicators should be evaluated using a variety of techniques when formulating a judgment of investor-expected growth.

Q. WHAT DATA FOR THE GAS GROUP HAVE YOU CONSIDERED IN YOUR GROWTH RATE ANALYSIS?

A. I considered the growth in the financial variables shown on Schedules PRM-8 and PRM-9, which reflect historical (Schedule PRM-8) and projected (Schedule PRM-9) rates of growth in earnings per share, dividends per share, book value per share, and cash flow per share for the Gas Group. While analysts will review all measures of growth, as I have done, earnings per share growth directly influences the expectations of investors for the future performance of utility stocks. Forecasts of earnings growth are required because the DCF model is forward-looking, and, with the constant price-earnings multiple and constant payout ratio that the DCF model assumes, all other measures of growth will mirror earnings growth. The historical growth rates were obtained from the Value Line publication that provides those data. While historical data cannot be ignored, it is much less significant in applying the DCF model than projections of future growth. Investors cannot purchase the past earnings of a utility. To the contrary, they are only entitled to future earnings, which are the focus of growth projections. Furthermore, if significant weight is assigned to historical performance, the historical data are double counted because they are already factored into analysts' forecasts of earnings growth.

Q. IS A FIVE-YEAR INVESTMENT HORIZON ASSOCIATED WITH THE ANALYSTS' FORECASTS CONSISTENT WITH THE TRADITIONAL DCF MODEL?

A. Yes, it is. Although the constant form of the DCF model assumes an infinite stream of cash flows, investors do not expect to hold an investment indefinitely. Rather than viewing the DCF in the context of an endless stream of growing dividends (e.g., a century of cash flows), the growth in the share value (i.e., capital appreciation, or capital gains yield) is most relevant to investors' total return expectations. Hence, the sale price of a stock can be viewed as a liquidating dividend that can be discounted along with the annual dividend receipts during the investment-holding period to arrive at the investors' expected return.

The growth in the price per share will equal the growth in earnings per share if, as the DCF model assumes, there is no change in the price-earnings (P-E) multiple. As such, my company-specific growth analysis, which focuses principally upon five-year forecasts of earnings per share growth, conforms with the type of analysis that influences investors' expectations of their actual total return. Moreover, academic research focuses also on five-year growth rates specifically because market outcomes occurring over that investment horizon are what influence stock prices. Indeed, if investors required forecasts beyond five years in order to properly value common stocks, then it would be reasonable to expect that some investment advisory service would begin publishing that information for individual stocks in order to meet the demands of the marketplace. The absence of such a publication suggests that there is no market for this information because investors do not require forecasts for an infinite series of future data points in order to make informed decisions to purchase and sell stocks.

Q. WHAT ARE THE ANALYSTS' FORECASTS OF FUTURE GROWTH THAT YOU CONSIDERED?

A. Schedule PRM-9 provides projected earnings per share growth rates taken from analysts' five-year forecasts compiled by IBES/First Call, Zacks, and Value Line. These are all reliable authorities of projected growth that investors use to make buy, sell and hold decisions. The IBES/First Call, and Zacks estimates are obtained from the Internet and are widely available to investors. The growth rates reported by IBES/First Call and Zacks are consensus forecasts taken from a survey of analysts that make growth projections for these companies. Notably, First Call's earnings forecasts are frequently quoted in the financial press. The Value Line forecasts also are widely available to investors and can be obtained by subscription or free-of-charge at most public and collegiate libraries. The IBES/First Call, and Zacks forecasts are limited to earnings per share growth, while Value Line makes projections of other financial variables. The Value Line forecasts of dividends per share, book value per share, and cash flow per share for the Gas Group are also included on Schedule PRM-9.

Q. WHAT ARE THE PROJECTED GROWTH RATES PUBLISHED BY THE SOURCES YOU DISCUSSED?

A. Schedule PRM-9 shows the prospective five-year earnings per share growth rates projected for the Gas Group by IBES/First Call (5.41%), Zacks (5.88%), and Value Line (7.61%).

Q. ARE CERTAIN GROWTH RATE FORECASTS ENTITLED TO GREATER WEIGHT IN DEVELOPING A GROWTH RATE FOR USE IN THE DCF MODEL?

A. Yes. While a variety of factors should be examined to reach a reasonable conclusion on the DCF growth rate, growth in earnings per share should receive the greatest emphasis. Growth in earnings per share is the primary determinant of investors' expectations of the total returns they will obtain from stocks because the capital gains yield (i.e., price appreciation) will track earnings growth if the P-E multiple remains constant, as the DCF model assumes. Moreover, earnings per share (derived from net income) are the source of dividend payments and are the primary driver of retention growth and its surrogate, i.e., book value per share growth. As such, under these circumstances, greater emphasis must be placed upon projected earnings per share growth. In fact, Professor Myron Gordon, the foremost proponent of the use of the DCF model in setting utility rates, concluded that the best measure of growth for use in the DCF model is a forecast of earnings per-share growth.[9] Consistent with Professor Gordon's findings, projections of earnings per share growth, such as those published by IBES/First Call, Zacks, and Value Line, provide the best indication of investor expectations.

Q. WHAT GROWTH RATE DO YOU USE IN YOUR DCF MODEL?

A. The forecasts shown on Schedule PRM-9 for the Gas Group exhibit a range of average earnings per share growth rates from 5.41% to 7.61%. DCF growth rates should not be established by mathematical formulation, and I have not done so. In my opinion, a growth rate of 6.75% is a reasonable estimate of investor-expected growth for the Gas Group. This value is within the array of analysts' forecasts of five-year earnings per share growth rates and is below the midpoint of that data set. The reasonableness of this growth rate is also supported by the expected continuation of gas utility infrastructure spending.

Q. ARE THE DIVIDEND YIELD AND GROWTH COMPONENTS OF THE DCF ADEQUATE TO ACCURATELY DEPICT THE RATE OF RETURN ON COMMON EQUITY WHEN IT IS USED TO CALCULATE A UTILITY'S WEIGHTED AVERAGE OVERALL COST OF CAPITAL?

A. The components of the DCF model are adequate for that purpose only if the capital structure ratios are measured by the market value of debt and equity. In the case of the Gas Group, average capital structure ratios are 43.49% long-term debt, 0.46% preferred stock, and 56.06% common equity, as shown on Schedule PRM-10. If book values are used to compute the capital structure ratios, then a leverage adjustment is required.

Q. WHAT IS A LEVERAGE ADJUSTMENT?

A. If a firm's capitalization, as measured by its stock price, diverges from its capitalization,

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[9] Gordon, Gordon & Gould, "Choice Among Methods of Estimating Share Yield," The Journal of Portfolio Management (Spring 1989).

measured at book value, the potential exists for a financial risk difference. Such a risk difference arises because a market-valued capitalization contains more equity and less debt than a book-value capitalization and, therefore, has less risk than the book-value capitalization. A leverage adjustment properly accounts for the risk differential between market-value and book-value capital structures.

Q. WHY IS A LEVERAGE ADJUSTMENT NECESSARY?

A. In order to make the DCF results relevant to the capitalization measured at book value (as is done for rate setting purposes), the market-derived cost rate must be adjusted to account for this difference in financial risk. The only perspective that is important to investors is the return that they can realize on the market value of their investment. As I have measured the DCF, the simple yield (D/P) plus growth (g) provides a return applicable strictly to the price (P) that an investor is willing to pay for a share of stock. The need for the leverage adjustment arises when the results of the DCF model (k) are to be applied to a capital structure that is different from the capital structure indicated by the market price (P). From the market perspective, the financial risk of the Gas Group is accurately measured by the capital structure ratios calculated from the market-valued capitalization of a firm. If the ratemaking process utilized the market capitalization ratios, then no additional analysis or adjustment would be required, and the simple yield (D/P) plus growth (g) components of the DCF would satisfy the financial risk associated with the market value of the equity capitalization. Because the ratemaking process uses ratios calculated from a firm's book value capitalization, further analysis is required to synchronize the financial risk of the book capitalization with the required return on the book value of the firm's equity. This adjustment is developed through precise mathematical calculations, using well recognized analytical procedures that are widely accepted in the financial literature. To arrive at that return, the rate of return on common equity is the unleveraged cost of capital (or equity return at 100% equity) plus one or more terms reflecting the increase in financial risk resulting from the use of leverage in the capital structure. The calculations presented in the lower panel of data shown on Schedule PRM-10, under the heading "M&M,"[10] provides a return of 7.52% when applicable to a capital structure with 100% common equity.

Q. ARE THERE SPECIFIC FACTORS THAT INFLUENCE MARKET-TO-BOOK RATIOS THAT DETERMINE WHETHER THE LEVERAGE ADJUSTMENT SHOULD BE MADE?

A. No. The leverage adjustment is not intended, nor was it designed, to address the reasons that stock prices vary from book value. Hence, any observations concerning market prices relative to book are not on point. The leverage adjustment deals with the issue of financial risk and does not transform the DCF result to a book value return through a market-to-book adjustment. Again, the leverage adjustment that I propose is based on the fundamental financial precept that the cost of equity is equal to the rate of return for an unleveraged firm (i.e., where the overall rate of return equates to the cost of equity with a capital structure that contains 100% equity) plus the additional return required for introducing debt and/or preferred stock leverage into the capital structure.

Further, as noted previously, the relatively high market prices of utility stocks cannot be attributed solely to the notion that these companies are expected to earn a return

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[10] Franco Modigliani and Merton H. Miller, The Cost of Capital, Corporation Finance, and the Theory of Investments, American Economic Review, June 1958, at 261-297. Franco Modigliani and Merton H. Miller, Taxes and the Cost of Capital: A Correction, American Economic Review, June 1963, at 433-443.

on the book value of equity that differs from their cost of equity determined from stock market prices. Stock prices above book value are common for utility stocks, and indeed the stock prices of non-regulated companies exceed book values by even greater margins. It is difficult to accept that the vast majority of all firms operating in our economy are generating returns far in excess of their cost of capital. Certainly, in our free-market economy, competition should contain such "excesses" if they actually existed.

Finally, the leverage adjustment adds stability to the final DCF cost rate. That is to say, as the market capitalization increases relative to its book value, the leverage adjustment increases while the simple yield (D/P) plus growth (g) result declines. The reverse is also true: when the market capitalization declines, the leverage adjustment also declines as the simple yield (D/P) plus growth (g) result increases.

Q. IS THE LEVERAGE ADJUSTMENT THAT YOU PROPOSE DESIGNED TO TRANSFORM THE MARKET RETURN INTO ONE THAT IS DESIGNED TO PRODUCE A PARTICULAR MARKET-TO-BOOK RATIO?

A. No, it is not. What I label a "leverage adjustment" is merely a convenient way of showing the amount that must be added to (or subtracted from) the result of the simple DCF model (i.e., D/P + g) when the DCF return applies to a capital structure used for ratemaking that is computed with book-value weighting rather than market-value weighting. Although I specify a separate factor, which I call the leverage adjustment, there is no need to do so other than to identify this factor. If I expressed my return solely in the context of the book value weighting that we use to calculate the weighted average cost of capital and ignore the familiar D/P + g expression entirely, then a separate element in the DCF cost of equity determination would not be needed to reflect the differential in financial leverage between a market-value and book-value capitalization. As shown in the bottom panel of data on Schedule PRM-10, the equity return applicable to the book value common equity ratio is equal to 7.52%, which is the return for the Gas Group appropriate for a capital structure with no debt (i.e., a 100% equity ratio) plus 3.67% to compensate investors for the risk of a 51.07% debt ratio and 0.02% for a 0.54% preferred stock ratio. Under this approach, the parts sum to 11.21% (7.52% + 3.67% + 0.02%), and there is no need to even address the cost of equity in terms of D/P + g. To express this same return in the context of the familiar DCF model, I summed the 3.51% dividend yield, the 6.75% growth rate, and 0.95% for the leverage adjustment in order to arrive at the same 11.21% (3.51% + 6.75% + 0.95%) return. I know of no means to mathematically solve for the 0.95% leverage adjustment by expressing it in the terms of any particular relationship of market price to book value. The 0.95% adjustment is merely a convenient way to compare the 11.21% return computed using the Modigliani & Miller formulas to the 10.26% return generated by the DCF model (i.e., D_1/P_0 + g, or the traditional form of the DCF shown on Schedule PRM-7, page 1) based on a market-value capital structure. A 11.21% return assigned to anything other than the market value of equity cannot equate to a reasonable return on book value that has higher financial risk. My point is that when we use a market-determined cost of equity developed from the DCF model, it reflects a level of financial risk that is different (in this case, lower) from the capital structure stated at book value. This process has nothing to do with targeting any particular market-to-book ratio.

Q. PLEASE PROVIDE THE DCF RETURN BASED UPON YOUR PRECEDING DISCUSSION OF DIVIDEND YIELD, GROWTH, AND LEVERAGE.

A. As explained previously, I have utilized a six-month average dividend yield (D_1/P_0) adjusted in a forward-looking manner for my DCF calculation. This dividend yield is used in conjunction with the growth rate (g) previously developed. The DCF also includes the leverage modification (lev.) required when the book value equity ratio is used in determining the weighted average cost of capital in the ratemaking process rather than the market value equity ratio related to the price of stock. The cost of equity must also include an adjustment to cover flotation costs (flot.), as shown on Schedule PRM-11. In developing the flotation cost adjustment factor, I reduced the 3.9% issuance and selling expenses shown on Schedule PRM-11 to 1.5%. I did this because I applied the adjustment factor (i.e., 1.000 + 0.015) to the entire DCF return, rather than to just the dividend yield component. The resulting DCF cost rate is 11.38%, computed as follows:

	D_1/P_0	+	g	+	lev.	=	k	x	flot.	=	K
Gas Group	3.51%	+	6.75%	+	0.95%	=	11.21%	x	1.015	=	11.38%

As indicated by the DCF result shown above, the flotation cost adjustment adds 0.17% (11.38% - 11.21%) to the rate of return on common equity for the Gas Group. The DCF result shown above represents the simplified (i.e., Gordon) form of the model that contains a constant-growth assumption. I should reiterate, however, that the DCF-indicated cost rate provides an explanation of the rate of return on common stock market prices without regard to the prospect of a change in the price-earnings multiple. An assumption that there will be no change in the price-earnings multiple is not supported by the realities of the equity market because price-earnings multiples do not remain constant. This is one of the constraints of this model that makes it important to consider the results of other models when determining a company's cost of equity.

VIII. RISK PREMIUM ANALYSIS

Q. PLEASE DESCRIBE YOUR USE OF THE RISK PREMIUM APPROACH TO DETERMINE THE COST OF EQUITY.

A. With the Risk Premium approach, the cost of equity capital is determined by corporate bond yields plus a premium to account for the fact that common equity is exposed to greater investment risk than debt capital. The result of my Risk Premium study is shown on Schedule PRM-1, page 2. That result is 10.50% excluding flotation costs and somewhat higher including flotation costs.

Q. WHAT LONG-TERM PUBLIC UTILITY DEBT COST RATE DID YOU USE IN YOUR RISK PREMIUM ANALYSIS?

A. In my opinion, and as I will explain in more detail further in my testimony, a 3.75% yield represents a reasonable estimate of the prospective yield on long-term A-rated public utility bonds.

Q. WHAT HISTORICAL DATA ARE SHOWN BY THE MOODY'S DATA?

A. I have analyzed the historical yields on the Moody's index of long-term public utility debt as shown on Schedule PRM-12, page 1. For the twelve months ended September 2021, the average monthly yield on Moody's index of A-rated public utility bonds was 3.06%. For the six and three-month periods ended December 2020, the yields were 3.11% and 2.95%, respectively. During the twelve-months ended September 2021, the range of the yields on A-rated public utility bonds was 2.77% to 3.44%. Page 2 of Schedule PRM-12 shows the long-run spread in yields between A-rated public utility bonds and long-term

Treasury bonds. As shown on page 3 of Schedule PRM-12, the yields on A-rated public utility bonds have exceeded those on Treasury bonds by 1.09% on a twelve-month average basis, 1.01% on a six-month average basis, and 1.02% on a three-month average basis. Giving greater emphasis to the six-month average spread, 1.00% represents a reasonable spread for the yield on A-rated public utility bonds over Treasury bonds.

Q. WHAT FORECASTS OF INTEREST RATES HAVE YOU CONSIDERED IN YOUR ANALYSIS?

A. I have determined the prospective yield on A-rated public utility debt by using the Blue Chip Financial Forecasts ("Blue Chip") along with the spread in the yields that I describe below. Blue Chip is a reliable authority and contains consensus forecasts of a variety of interest rates compiled from a panel of banking, brokerage, and investment advisory services. In early 1999, Blue Chip stopped publishing forecasts of yields on A-rated public utility bonds because the Federal Reserve deleted these yields from its Statistical Release H.15. To independently project a forecast of the yields on A-rated public utility bonds, I have combined the forecast yields on long-term Treasury bonds published on October 1, 2021, and a yield spread of 1.00%, derived from historical data.

Q. HOW HAVE YOU USED THESE DATA TO PROJECT THE YIELD ON A-RATED PUBLIC UTILITY BONDS FOR THE PURPOSE OF YOUR RISK PREMIUM ANALYSES?

A. Shown below is my calculation of the prospective yield on A-rated public utility bonds using the building blocks discussed above, i.e., the Blue Chip forecast of Treasury bond yields and the public utility bond yield spread. For comparative purposes, I also have shown the Blue Chip forecasts of Aaa-rated and Baa-rated corporate bonds. These forecasts are:

		Blue Chip Financial Forecasts				
		Corporate		30-Year	A-rated Public Utility	
Year	Quarter	Aaa-rated	Baa-rated	Treasury	Spread	Yield
2021	Fourth	2.9%	3.6%	2.2%	1.25%	3.45%
2022	First	3.0%	3.8%	2.3%	1.25%	3.55%
2022	Second	3.1%	4.0%	2.4%	1.25%	3.65%
2022	Third	3.2%	4.1%	2.5%	1.25%	3.75%
2022	Fourth	3.3%	4.2%	2.6%	1.25%	3.85%
2023	First	3.4%	4.3%	2.7%	1.25%	3.95%

Q. ARE THERE ADDITIONAL FORECASTS OF INTEREST RATES THAT EXTEND BEYOND THOSE SHOWN ABOVE?

A. Yes. Twice yearly, Blue Chip provides long-term forecasts of interest rates. In its June 1, 2021 publication, Blue Chip published longer-term forecasts of interest rates, which were reported to be:

	Blue Chip Financial Forecasts		
	Corporate		30-Year
Averages	Aaa-rated	Baa-rated	Treasury
2023-2027	4.3%	5.3%	3.5%
2028-2032	4.8%	5.8%	3.9%

The longer-term forecasts by Blue Chip suggest that interest rates will move up from the levels revealed by the near-term forecasts. A 3.75% yield on A-rated public utility bonds represents a reasonable benchmark for measuring the cost of equity in this case. All the data I used to formulate my conclusion as to a prospective yield on A-rated public utility debt are available to investors, who regularly rely upon those data to make investment decisions.

Q. WHAT EQUITY RISK PREMIUM HAVE YOU DETERMINED FOR PUBLIC UTILITIES?

A. To develop an appropriate equity risk premium, I analyzed the results from 2021 SBBI Yearbook, Stocks, Bonds, Bills and Inflation. My investigation reveals that the equity risk premium varies according to the level of interest rates. That is to say, the equity risk premium increases as interest rates decline, and it declines as interest rates increase. This inverse relationship is revealed by the summary data presented below and shown on Schedule PRM-13, page 1.

Common Equity Risk Premiums

Low Interest Rates	6.63%
Average Across All Interest Rates	5.67%
High Interest Rates	4.69%

Based on my analysis of the historical data, the equity risk premium was 6.63% when the marginal cost of long-term government bonds was low (i.e., 2.85%, which was the average yield during periods of low rates). Conversely, when the yield on long-term government bonds was high (i.e., 7.09% on average during periods of high interest rates), the spread narrowed to 4.69%. Over the entire spectrum of interest rates, the equity risk premium was 5.67% when the average government bond yield was 4.95%. I have utilized a 6.75% equity risk premium. The equity risk premium of 6.75% that I employed is near the risk premiums associated with low interest rates.

Q. WHAT COMMON EQUITY RATE DID YOU DETERMINE BASED ON YOUR RISK PREMIUM ANALYSIS?

A. The cost of equity (i.e., k) is represented by the sum of the prospective yield for long-term public utility debt (i.e., i), and the equity risk premium (i.e., RP), and the adjustment for flotation costs (i.e., flot.). The Risk Premium approach provides a cost of equity of:

	i	**+**	***RP***	**=**	***k***	**+**	***flot.***	**=**	***K***
Gas Group	3.75%	+	6.75%	=	10.50%	+	0.17%	=	10.67%

IX. CAPITAL ASSET PRICING MODEL

Q. HOW IS THE CAPM USED TO MEASURE THE COST OF EQUITY?

A. The CAPM uses the yield on a risk-free interest-bearing obligation plus a rate of return premium that is proportional to the systematic risk of an investment. As shown on page 2 of Schedule PRM-1, the result of the CAPM is 13.55% for the Gas Group with the leverage adjustment. Without the leverage adjustment, the CAPM result is 12.38% (13.55% - (.12 x 9.78%)). To compute the cost of equity with the CAPM, three components are necessary: a risk-free rate of return (Rf), the beta measure of systematic risk (β), and the market risk premium (Rm-Rf) derived from the total return on the market of equities reduced by the risk-free rate of return. The CAPM specifically accounts for differences in systematic risk (i.e., market risk as measured by the beta) between an individual firm or group of firms and the entire market of equities.

Q. WHAT BETAS HAVE YOU CONSIDERED IN THE CAPM?

A. For my CAPM analysis, I initially considered the Value Line betas. As shown on page 2 of Schedule PRM-3, the average beta is 0.88 for the Gas Group.

Q. DID YOU USE THE <u>VALUE LINE</u> BETAS IN THE CAPM DETERMINED COST OF EQUITY?

A. I used the <u>Value Line</u> betas as a foundation for the leverage adjusted betas that I used in the CAPM. The betas must be reflective of the financial risk associated with the ratemaking capital structure that is measured at book value. Therefore, <u>Value Line</u> betas cannot be used directly in the CAPM, unless the cost rate developed using those betas is applied to a capital structure measured with market values. To develop a CAPM cost rate applicable to a book-value capital structure, the <u>Value Line</u> (market value) betas have been unleveraged and re-leveraged for the book value common equity ratios using the Hamada formula,[11] as follows:

$$\beta l = \beta u \ [1 + (1 - t)\ D/E + P/E]$$

where ßl = the leveraged beta, ßu = the unleveraged beta, t = income tax rate, D = debt ratio, P = preferred stock ratio, and E = common equity ratio. The betas published by <u>Value Line</u> have been calculated with the market price of stock and are related to the market value capitalization. By using the formula shown above and the capital structure ratios measured at market value, the beta would become 0.54 for the Gas Group if it employed no leverage and was 100% equity financed. Those calculations are shown on Schedule PRM-10 under the section labeled “Hamada,” who is credited with developing those formulas. With the unleveraged beta as a base, I calculated the leveraged beta of 1.00 for the book value capital structure of the Gas Group.

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[11] Robert S. Hamada, “The Effects of the Firm’s Capital Structure on the Systematic Risk of Common Stocks” *The Journal of Finance* Vol. 27, No. 2, Papers and Proceedings of the Thirtieth Annual Meeting of the American Finance Association, New Orleans, Louisiana, December 27-29, 1971. (May 1972), pp. 435-452.

Q. WHAT RISK-FREE RATE HAVE YOU USED IN THE CAPM?

A. As shown on page 1 of Schedule PRM-14, I provided the historical yields on Treasury notes and bonds. For the twelve months ended September 2021, the average yield on 30-year Treasury bonds was 1.97%. For the six- and three-months ended September 2021, the yields on 30-year Treasury bonds were 2.10% and 1.93%, respectively. During the twelve-months ended September 2021, the range of the yields on 30-year Treasury bonds was 1.57% to 2.34%. The low yields that existed during recent periods can be traced to weakness in business fixed investment and exports due in part to the United States' trade war with China. Thereafter, extraordinary events associated with the COVID-19 pandemic induced significant turmoil that jolted the capital markets in the February-May 2020 time frame. During this period, we saw abrupt reaction to the COVID-19 pandemic and significant declines in the price of crude oil. These events led to the end of the record-setting 128-month economic expansion. As the recession unfolded in February 2020, the FOMC acted to address these disruptions. The FOMC continues to support the money and capital markets during the recovery from the coronavirus pandemic. Presently, the Fed Funds rate is near zero. It is expected that a transition in FOMC policy will prospectively produce higher interest rates as the pandemic nears its end. A forward-looking assessment of the capital markets is especially relevant now because the Company's rates will be based on financial conditions in 2022 and beyond. Higher inflation expectations are a contributing factor that points to higher interest rates. Indeed, higher inflation today is revealed by a 5.9% increase in social security payments announced on October 13, 2021, the largest one-year increase in nearly four decades. FOMC has signaled that it plans to taper its bond buying program (i.e., quantitative easing) in November 2021 and to end it completely by mid-2022. The Fed Funds rate is also likely to increase from very low levels that existed during the pandemic. Higher interest rates clearly point to higher capital costs prospectively. I will describe the forecasts of interest below.

As shown on page 2 of Schedule PRM-14, forecasts published by Blue Chip on October 1, 2022 indicate that the yields on long-term Treasury bonds are expected to be in the range of 2.2% to 2.7% during the next six quarters. The longer-term forecasts described previously show that the yields on 30-year Treasury bonds will average 3.5% from 2023 through 2027 and 3.9% from 2028 to 2032. For the reasons explained previously, forecasts of interest rates should be emphasized at this time in selecting the risk-free rate of return in CAPM. Hence, I have used a 2.75% risk-free rate of return for CAPM purposes, which considers the Blue Chip forecasts.

Q. WHAT MARKET PREMIUM HAVE YOU USED IN THE CAPM?

A. As shown in the lower panel of data presented on Schedule PRM-14, page 2 the market premium is derived from historical data and the forecast returns. For the historically based market premium, I have used the arithmetic mean obtained from the data presented on Schedule PRM-13, page 1. On that schedule, the market return was 12.06% on large stocks during periods of low interest rates. During those periods, the yield on long-term government bonds was 2.85% when interest rates were low. As such, I carried over to Schedule PRM-14, page 2, the average large common stock returns of 12.06% and the average yield on long-term government bonds of 2.85%. The resulting market premium is 9.21% (12.06% - 2.85%) based on historical data, as shown on Schedule PRM-14, page 2. As also shown on Schedule PRM-14, page 2, I calculated the forecast returns, which show a 13.10% total market return. With this forecast, I calculated a market premium of 10.35%

(13.10% - 2.75%) using forecast data. The resulting market premium applicable to the CAPM derived from these sources equals 9.78% (10.35% + 9.21% = 19.56% ÷ 2).

Q. ARE THERE ADJUSTMENTS TO THE CAPM THAT ARE NECESSARY TO FULLY REFLECT THE RATE OF RETURN ON COMMON EQUITY?

A. Yes. The technical literature supports an adjustment relating to the size of the company or portfolio for which the calculation is performed. As the size of a firm decreases, its risk and required return increases. Moreover, in his discussion of the cost of capital, Professor Brigham has indicated that smaller firms have higher capital costs than otherwise similar larger firms. Also, the Fama/French study (see "The Cross-Section of Expected Stock Returns"; The Journal of Finance, June 1992) established that the size of a firm helps explain stock returns. In an October 15, 1995 article in Public Utility Fortnightly, entitled "Equity and the Small-Stock Effect," it was demonstrated that the CAPM could understate the cost of equity significantly according to a company's size. Indeed, it was demonstrated in the SBBI Yearbook that the returns for stocks in lower deciles (i.e., smaller stocks) had returns in excess of those shown by the simple CAPM. As noted previously, Elizabethtown is relatively smaller than the Gas Group. To recognize this fact, I used the mid-cap adjustment of 1.02%, as revealed on page 3 of Schedule PRM-14, for the CAPM calculation.

Q. WHAT DOES YOUR CAPM ANALYSIS SHOW?

A. Using the 2.75% risk-free rate of return, the leverage adjusted beta of 1.00 for the Gas Group, the 9.78% market premium, the 1.02% size adjustment, and the flotation cost adjustment the following result is indicated.

	Rf	+	*ß*	x (	*Rm-Rf*	) +	*size*	=	*k*	+	*flot.*	=	*K*
Gas Group	2.75%	+	1.00	x (	9.78%	) +	1.02%	=	13.55%	+	0.17%	=	13.72%

X. COMPARABLE EARNINGS APPROACH

Q. WHAT IS THE COMPARABLE EARNINGS APPROACH?

A. The Comparable Earnings approach estimates a fair return on equity by comparing returns realized by non-regulated companies to returns that a public utility with similar risks characteristics would need to realize in order to compete for capital. Because regulation is a substitute for competitively determined prices, the returns realized by non-regulated firms with comparable risks to a public utility provide useful insight into investor expectations for public utility returns. The firms selected for the Comparable Earnings approach should be companies whose prices are not subject to cost-based price ceilings (i.e., non-regulated firms) so that circularity is avoided.

There are two avenues available to implement the Comparable Earnings approach. One method involves the selection of another industry (or industries) with comparable risks to the public utility in question, and the results for all companies within that industry serve as a benchmark. The second approach requires the selection of parameters that represent similar risk traits for the public utility and the comparable risk companies. Using this approach, the business lines of the comparable companies become unimportant. The latter approach is preferable with the further qualification that the comparable risk companies exclude regulated firms in order to avoid the circular reasoning implicit in the use of the achieved earnings/book ratios of other regulated firms. The United States Supreme Court has held that:

> 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. The return should be reasonably sufficient to assure confidence in the financial soundness of the utility and should be adequate, under efficient and economical management, to maintain and support its credit and enable it to raise the money necessary for the proper discharge of its public duties. Bluefield Water Works vs. Public Service Commission, 262 U.S. 668 (1923).

It is important to identify the returns earned by firms that compete for capital with a public utility. This can be accomplished by analyzing the returns of non-regulated firms that are subject to the competitive forces of the marketplace.

Q. DID YOU COMPARE THE RESULTS OF YOUR DCF AND CAPM ANALYSES TO THE RESULTS INDICATED BY A COMPARABLE EARNINGS APPROACH?

A. Yes. I selected companies from The Value Line Investment Survey for Windows that have six categories of comparability designed to reflect the risk of the Gas Group. These screening criteria were based upon the range as defined by the rankings of the companies in the Gas Group. The items considered were: Timeliness Rank, Safety Rank, Financial Strength, Price Stability, Value Line betas, and Technical Rank. The definition for these parameters is provided on Schedule PRM-15, page 3. The identities of the companies comprising the Comparable Earnings group and their associated rankings within the ranges are identified on Schedule PRM-15, page 1.

I relied upon Value Line data because it provides a comprehensive basis for evaluating the risks of the comparable firms. As to the returns calculated by Value Line for these companies, there is some downward bias in the figures shown on Schedule PRM-15, page 2, because Value Line computes the returns on year-end rather than average book value. If average book values had been employed, the rates of return would have been slightly higher. Nevertheless, these are the returns considered by investors when taking positions in these stocks. Because many of the comparability factors, as well as the published returns, are used by investors in selecting stocks, and the fact that investors rely on the Value Line service to gauge returns, it is an appropriate database for measuring comparable return opportunities.

Q. WHAT DATA DID YOU CONSIDER IN YOUR COMPARABLE EARNINGS ANALYSIS?

A. I used both historical realized returns and forecasted returns for non-utility companies. As noted previously, I have not used returns for utility companies in order to avoid the circularity that arises from using regulatory-influenced returns to determine a regulated return. It is appropriate to consider a relatively long measurement period in the Comparable Earnings approach in order to cover conditions over an entire business cycle. A ten-year period (five historical years and five projected years) is sufficient to cover an average business cycle. Unlike the DCF and CAPM, the results of the Comparable Earnings method can be applied directly to the book value capitalization. In other words, the Comparable Earnings approach does not contain the potential misspecification contained in market models when the market capitalization and book value capitalization diverge significantly. A point of demarcation was chosen to eliminate the results of highly profitable enterprises, which the Bluefield case stated were not the type of returns that a utility was entitled to earn. For this purpose, I used 20% as the point where those returns could be viewed as highly profitable and should be excluded from the Comparable Earnings approach. The average historical rate of return on book common equity was 12.5% using only the returns that were less than 20%, as shown on Schedule PRM-15, page 2. The average forecasted rate of return as published by Value Line is 12.9% also using values less than 20%, as provided on Schedule PRM-15, page 2. Using the average of these data my Comparable Earnings result is 12.70%, as shown on Schedule PRM-1, page 2.

XI. <u>CONCLUSION ON COST OF EQUITY</u>

Q. WHAT IS YOUR CONCLUSION REGARDING THE COMPANY'S COST OF COMMON EQUITY?

A. Based upon the application of a variety of methods and models described previously, it is my opinion that a reasonable rate of return on common equity is 10.75% to 11.75% for Elizabethtown. It is essential that the Board employ a variety of techniques to measure the Company's cost of equity because of the limitations/infirmities that are inherent in each method. In summary, the Company should be provided an opportunity to realize a 10.75% to 11.75% rate of return on common equity so that it can compete in the capital markets and retain reasonable credit quality.

Q. DOES THIS COMPLETE YOUR DIRECT TESTIMONY?

A. Yes. However, I reserve the right to supplement my testimony, if necessary, and to respond to witnesses presented by other parties.

EDUCATION BACKGROUND, BUSINESS EXPERIENCE AND QUALIFICATIONS

I was awarded a degree of Bachelor of Science in Business Administration by Drexel University in 1971. While at Drexel, I participated in the Cooperative Education Program which included employment, for one year, with American Water Works Service Company, Inc., as an internal auditor, where I was involved in the audits of several operating water companies of the American Water Works System and participated in the preparation of annual reports to regulatory agencies and assisted in other general accounting matters.

Upon graduation from Drexel University, I was employed by American Water Works Service Company, Inc., in the Eastern Regional Treasury Department where my duties included preparation of rate case exhibits for submission to regulatory agencies, as well as responsibility for various treasury functions of the thirteen New England operating subsidiaries.

In 1973, I joined the Municipal Financial Services Department of Betz Environmental Engineers, a consulting engineering firm, where I specialized in financial studies for municipal water and wastewater systems.

In 1974, I joined Associated Utility Services, Inc., now known as AUS Consultants. I held various positions with the Utility Services Group of AUS Consultants, concluding my employment there as a Senior Vice President.

In 1994, I formed P. Moul & Associates, an independent financial and regulatory consulting firm. In my capacity as Managing Consultant and for the past twenty-nine years, I have continuously studied the rate of return requirements for cost of service-regulated firms. In this regard, I have supervised the preparation of rate of return studies, which were employed, in connection with my testimony and in the past for other individuals. I have presented direct testimony on the subject of fair rate of return, evaluated rate of return testimony of other witnesses, and presented rebuttal testimony.

My studies and prepared direct testimony have been presented before thirty-seven (37) federal, state and municipal regulatory commissions, consisting of: the Federal Energy Regulatory Commission; state public utility commissions in Alabama, Alaska, California, Colorado, Connecticut, Delaware, Florida, Georgia, Hawaii, Illinois, Indiana, Iowa, Kentucky, Louisiana, Maine, Maryland, Massachusetts, Michigan, Minnesota, Missouri, New Hampshire, New Jersey, New York, North Carolina, Ohio, Oklahoma, Pennsylvania, Rhode Island, South Carolina, Tennessee, Texas, Virginia, West Virginia, Wisconsin, and the Philadelphia Gas Commission, and the Texas Commission on Environmental Quality. My testimony has been offered in over 200 rate cases involving electric power, natural gas distribution and transmission, resource recovery, solid waste collection and disposal, telephone, wastewater, and water service utility companies. While my testimony has involved principally fair rate of return and financial matters, I have also testified on capital allocations, capital recovery, cash working capital, income taxes, factoring of accounts receivable, and take-or-pay expense recovery. My testimony has been offered on behalf of municipal and investor-owned public utilities and for the staff of a regulatory commission. I have also testified at an Executive Session of the State of New Jersey Commission of Investigation concerning the BPU regulation of solid waste collection and disposal.

I was a co-author of a verified statement submitted to the Interstate Commerce Commission concerning the 1983 Railroad Cost of Capital (Ex Parte No. 452). I was also co-author of comments submitted to the Federal Energy Regulatory Commission regarding the Generic Determination of Rate of Return on Common Equity for Public Utilities in 1985, 1986 and 1987 (Docket Nos. RM85-19-000, RM86-12-000, RM87-35-000 and RM88-25-000). Further, I have been the consultant to the New York Chapter of the National Association of Water Companies, which represented the water utility group in the Proceeding on Motion of the Commission to Consider Financial Regulatory Policies for New York Utilities (Case 91-M-0509). I have also submitted comments to the Federal Energy Regulatory Commission in its Notice of Proposed Rulemaking (Docket No. RM99-2-000) concerning Regional Transmission Organizations and on behalf of the Edison Electric Institute in its intervention in the case of Southern California Edison Company (Docket No. ER97-2355-000). Also, I was a member of the panel of participants at the Technical Conference in Docket No. PL07-2 on the Composition of Proxy Groups for Determining Gas and Oil Pipeline Return on Equity.

In late 1978, I arranged for the private placement of bonds on behalf of an investor-owned public utility. I have assisted in the preparation of a report to the Delaware Public Service Commission relative to the operations of the Lincoln and Ellendale Electric Company. I was also engaged by the Delaware P.S.C. to review and report on the proposed financing and disposition of certain assets of Sussex Shores Water Company (P.S.C. Docket Nos. 24-79 and 47-79). I was a co-author of a Report on Proposed Mandatory Solid Waste Collection Ordinance prepared for the Board of County Commissioners of Collier County, Florida.

I have been a consultant to the Bucks County Water and Sewer Authority concerning rates and charges for wholesale contract service with the City of Philadelphia. My municipal consulting experience also included an assignment for Baltimore County, Maryland, regarding the City/County Water Agreement for Metropolitan District customers (Circuit Court for Baltimore County in Case 34/153/87-CSP-2636).

STATE OF NEW JERSEY

BOARD OF PUBLIC UTILITIES

IN THE MATTER OF THE PETITION OF

ELIZABETHTOWN GAS COMPANY

FOR APPROVAL OF INCREASED BASE TARIFF RATES AND CHARGES
FOR GAS SERVICE AND OTHER TARIFF REVISIONS

BPU Docket No.

OAL Docket No.

Schedules to Accompany the

Direct Testimony

of

Paul R. Moul, Managing Consultant
P. Moul & Associates

Concerning

Cost of Equity and Fair Rate of Return

Elizabethtown Gas Company
Index of Schedules

Elizabethtown Gas Company
Summary Cost of Capital
Estimated at March 31, 2022

Type of Capital	Ratios	Cost Rate Range Low	Cost Rate Range Midpoint	Cost Rate Range High	Weighted Cost Rate Low	Weighted Cost Rate Midpoint	Weighted Cost Rate High
Long-Term Debt	45.11%	3.83%	3.83%	3.83%	1.73%	1.73%	1.73%
Common Equity	54.89%	10.75%	11.25%	11.75%	5.90%	6.18%	6.45%
Total	100.00%				7.63%	7.90%	8.18%

Indicated levels of fixed charge coverage assuming that the Company could actually achieve its overall cost of capital:

	Low	Midpoint	High
Pre-tax coverage of interest expense based upon a 28.11% composite federal and state income tax rate			
(9.94% ÷ 1.73%)	5.75 x		
(10.32% ÷ 1.73%)		5.97 x	
(10.70% ÷ 1.73%)			6.19 x
Post-tax coverage of interest expense			
(7.63% ÷ 1.73%)	4.41 x		
(7.90% ÷ 1.73%)		4.57 x	
(8.18% ÷ 1.73%)			4.73 x

Elizabethtown Gas Company
Cost of Equity
as of September 30, 2021

Discounted Cash Flow (DCF)				***D_1/P_0*** [1]	**+**	***g*** [2]	**+**	***lev.*** [3]	**=**	***k***
Gas Group				3.51%	+	6.75%	+	0.95%	=	11.21%
Risk Premium (RP)						***I*** [4]	**+**	***RP*** [5]	=	***k***
Gas Group						3.75%	+	6.75%	=	10.50%
Capital Asset Pricing Model (CAPM)	***Rf*** [6]	**+**	***ß*** [7]	***x (***		***Rm-Rf*** [8]	***) +***	***size*** [9]	**=**	***k***
Gas Group	2.75%	+	1.00	x (		9.78%	) +	1.02%	=	13.55%
Comparable Earnings (CE) [10]						***Historical***		***Forecast***		***Average***
Comparable Earnings Group						12.5%		12.9%		12.70%

References:
(1) Schedule 07
(2) Schedule 09
(3) Schedule 10
(4) A-rated public utility bond yield comprised of a 2.75% risk-free rate of return (Schedule 14 page 2) and a yield spread of 1.00% (Schedule 12 page 3)
(5) Schedule 12 page 1
(6) Schedule 13 page 2
(7) Schedule 10
(8) Schedule 13 page 2
(9) Schedule 13 page 3
(10) Schedule 14 page 2

Elizabethtown Gas Company
Capitalization and Financial Statistics
2016-2020, Inclusive

	2020	2019	2018	2017	2016	
			(Millions of Dollars)			
Amount of Capital Employed						
Permanent Capital	$ 2,060.7	$ 1,888.0	$ 1,724.4	$ 883.1	$ 740.0	
Short-Term Debt	$ 73.9	$ 103.7	$ 86.0	$ -	$ -	
Total Capital	$ 2,134.6	$ 1,991.7	$ 1,810.4	$ 883.1	$ 740.0	
Capital Structure Ratios						
Based on Permanent Captial:						Average
Long-Term Debt	38.8%	35.8%	30.7%	50.8%	47.0%	40.6%
Common Equity (1)	61.2%	64.2%	69.3%	49.2%	53.0%	59.4%
	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%
Based on Total Capital:						
Total Debt incl. Short Term	40.9%	39.1%	34.0%	50.8%	47.0%	42.4%
Common Equity (1)	59.1%	60.9%	66.0%	49.2%	53.0%	57.6%
	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%
Rate of Return on Book Common Equity (1)	3.9%	2.8%	2.4%	8.0%	6.2%	4.7%
Operating Ratio (2)	74.3%	78.9%	84.9%	76.9%	82.2%	79.4%
Coverage incl. AFUDC (3)						
Pre-tax: All Interest Charges	2.93 x	2.45 x	2.24 x	4.29 x	3.43 x	3.07 x
Post-tax: All Interest Charges	2.53 x	2.18 x	1.92 x	3.03 x	2.47 x	2.43 x
Coverage excl. AFUDC (3)						
Pre-tax: All Interest Charges	2.88 x	2.40 x	2.21 x	4.26 x	3.41 x	3.03 x
Post-tax: All Interest Charges	2.48 x	2.13 x	1.88 x	3.00 x	2.45 x	2.39 x
Quality of Earnings & Cash Flow						
AFC/Income Avail. for Common Equity	3.1%	4.5%	4.1%	1.3%	1.5%	2.9%
Effective Income Tax Rate	20.7%	18.5%	25.9%	38.4%	39.6%	28.6%
Internal Cash Generation/Construction (4)	62.4%	36.8%	6.4%	36.4%	23.9%	33.2%
Gross Cash Flow/ Avg. Total Debt (5)	15.2%	11.2%	6.9%	20.5%	15.8%	13.9%
Gross Cash Flow Interest Coverage (6)	4.98 x	3.62 x	2.54 x	5.96 x	4.41 x	4.30 x
Common Dividend Coverage (7)	x	x	1.28 x	3.23 x	2.17 x	2.23 x

See Page 2 for Notes.

Elizabethtown Gas Company
Capitalization and Financial Statistics
2019-2015, Inclusive

Notes:

(1) Excluding Accumulated Other Comprehensive Income ("OCI") from the equity account.

(2) Total operating expenses, maintenance, depreciation and taxes other than income as a percentage of operating revenues.

(3) Coverage calculations represent the number of times available earnings, both including and excluding AFUDC (allowance for funds used during construction) as reported in its entirety, cover fixed charges.

(4) Internal cash generation/gross construction is the percentage of gross construction expenditures provided by internally-generated funds from operations after payment of all cash dividends divided by gross construction expenditures.

(5) Gross Cash Flow (sum of net income, depreciation, amortization, net deferred income taxes and investment tax credits, less AFUDC) as a percentage of average total debt.

(6) Gross Cash Flow (sum of net income, depreciation, amortization, net deferred income taxes and investment tax credits, less total AFUDC) plus interest charges, divided by interest charges.

(7) Common dividend coverage is the relationship of internally generated funds from operations after payment of preferred stock dividends to common dividends paid.

Source of Information: FERC Form No. 2

Gas Group
Capitalization and Financial Statistics [1]
2016-2020, Inclusive

	2020	2019	2018	2017	2016	Average
			(Millions of Dollars)			
Amount of Capital Employed						
Permanent Capital	$ 5,894.0	$ 5,169.4	$ 4,698.4	$ 4,133.8	$ 3,746.8	
Short-Term Debt	$ 319.8	$ 553.3	$ 499.2	$ 402.2	$ 393.6	
Total Capital	$ 6,213.8	$ 5,722.7	$ 5,197.6	$ 4,536.0	$ 4,140.4	
Market-Based Financial Ratios						
Price-Earnings Multiple	23 x	26 x	20 x	22 x	22 x	23 x
Market/Book Ratio	185.6%	222.5%	217.6%	224.2%	201.9%	210.4%
Dividend Yield	3.2%	2.7%	2.8%	2.6%	2.8%	2.8%
Dividend Payout Ratio	74.5%	71.9%	52.4%	53.3%	60.7%	62.6%
Capital Structure Ratios						
Based on Permanent Capital:						
Long-Term Debt	50.2%	48.3%	47.9%	47.1%	45.0%	47.7%
Preferred Stock	1.6%	1.5%	1.0%	0.0%	0.1%	0.8%
Common Equity [2]	48.2%	50.3%	51.1%	52.9%	54.9%	51.5%
	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%
Based on Total Capital:						
Total Debt incl. Short Term	53.9%	53.4%	53.4%	53.0%	50.5%	52.8%
Preferred Stock	1.5%	1.3%	0.9%	0.0%	0.1%	0.7%
Common Equity [2]	44.6%	45.3%	45.7%	47.0%	49.5%	46.4%
	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%
Rate of Return on Book Common Equity [2]	8.8%	8.7%	10.0%	8.0%	9.2%	8.9%
Operating Ratio [3]	82.6%	83.6%	84.6%	84.1%	83.0%	83.6%
Coverage incl. AFUDC [4]						
Pre-tax: All Interest Charges	3.99 x	3.80 x	3.65 x	4.22 x	4.88 x	4.11 x
Post-tax: All Interest Charges	3.47 x	3.38 x	3.47 x	3.31 x	3.58 x	3.44 x
Overall Coverage: All Int. & Pfd. Div.	3.43 x	3.34 x	3.47 x	3.31 x	3.58 x	3.43 x
Coverage excl. AFUDC [4]						
Pre-tax: All Interest Charges	3.89 x	3.74 x	3.60 x	4.19 x	4.82 x	4.05 x
Post-tax: All Interest Charges	3.36 x	3.31 x	3.42 x	3.27 x	3.52 x	3.38 x
Overall Coverage: All Int. & Pfd. Div.	3.32 x	3.27 x	3.42 x	3.27 x	3.52 x	3.36 x
Quality of Earnings & Cash Flow						
AFC/Income Avail. for Common Equity	3.3%	3.0%	3.2%	-5.2%	2.3%	1.3%
Effective Income Tax Rate	19.7%	14.9%	15.6%	39.7%	33.6%	24.7%
Internal Cash Generation/Construction [5]	53.5%	48.7%	46.7%	59.5%	71.6%	56.0%
Gross Cash Flow/ Avg. Total Debt [6]	18.0%	18.3%	18.4%	21.4%	23.7%	20.0%
Gross Cash Flow Interest Coverage [7]	6.95 x	6.25 x	6.05 x	6.69 x	7.35 x	6.66 x
Common Dividend Coverage [8]	3.84 x	3.86 x	3.63 x	4.21 x	4.60 x	4.03 x

See Page 2 for Notes.

Gas Group
Capitalization and Financial Statistics
2016-2020, Inclusive

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.
(2) Excluding Accumulated Other Comprehensive Income ("OCI") from the equity account.
(3) Total operating expenses, maintenance, depreciation and taxes other than income taxes as a percent of operating revenues.
(4) Coverage calculations represent the number of times available earnings, both including and excluding AFUDC (allowance for funds used during construction) as reported in its entirety, cover fixed charges.
(5) Internal cash generation/gross construction is the percentage of gross construction expenditures provided by internally-generated funds from operations after payment of all cash dividends divided by gross construction expenditures.
(6) Gross Cash Flow (sum of net income, depreciation, amortization, net deferred income taxes and investment tax credits, less total AFUDC) plus interest charges, divided by interest charges.
(7) Gross Cash Flow plus interest charges divided by interest charges.
(8) Common dividend coverage is the relationship of internally-generated funds from operations after payment of preferred stock dividends to common dividends paid.

Basis of Selection:
The Gas Group includes companies that are contained in The Value Line Investment Survey within the industry group "Natural Gas Utility," they are not currently the target of a publicly-announced merger or acquisition, and after eliminating UGI Corp. due to its highly diversified businesses.

		Corporate Credit Ratings		Stock	Value Line
Ticker	Company	Moody's	S&P	Traded	Beta
ATO	Atmos Energy Corp.	A1	A-	NYSE	0.80
CPK	Chesapeake Utilities Corp.	NAIC "1"		NYSE	0.80
NJR	New Jersey Resources Corp.	A1	-	NYSE	1.00
NI	NiSource Inc.	Baa2	BBB+	NYSE	0.85
NWN	Northwest Natural Holding Compa	Baa1	A+	NYSE	0.85
OGS	ONE Gas, Inc.	A3	BBB+	NYSE	0.80
SJI	South Jersey Industries, Inc.	A3	BBB	NYSE	1.05
SWX	Southwest Gas Holdings, Inc.	Baa1	A-	NYSE	0.95
SR	Spire, Inc.	A1	A-	NYSE	0.85
	Average	A3	A-		0.88

Note: Ratings are those of utility subsidiaries

Source of Information: Annual Reports to Shareholders
Utility COMPUSTAT
Moody's Investors Service
Standard & Poor's Corporation

Standard & Poor's Public Utilities
Capitalization and Financial Statistics [1]
2016-2020, Inclusive

	2020	2019	2018	2017	2016	
			(Millions of Dollars)			
Amount of Capital Employed						
Permanent Capital	$ 38,743.7	$ 36,461.6	$ 32,871.6	$ 30,827.6	$ 29,173.1	
Short-Term Debt	$ 1,154.5	$ 1,221.9	$ 1,420.3	$ 1,076.1	$ 1,032.2	
Total Capital	$ 39,898.2	$ 37,683.5	$ 34,291.9	$ 31,903.7	$ 30,205.3	
Market-Based Financial Ratios						Average
Price-Earnings Multiple	22 x	20 x	21 x	20 x	21 x	21 x
Market/Book Ratio	218.5%	221.3%	204.7%	214.4%	196.0%	211.0%
Dividend Yield	3.6%	3.2%	3.5%	3.3%	3.5%	3.4%
Dividend Payout Ratio	77.8%	62.7%	68.7%	65.2%	74.6%	69.8%
Capital Structure Ratios						
Based on Permanent Captial:						
Long-Term Debt	58.1%	56.7%	55.0%	56.8%	56.6%	56.6%
Preferred Stock	2.6%	2.4%	2.5%	1.4%	1.9%	2.1%
Common Equity [2]	39.4%	41.0%	42.5%	41.8%	41.6%	41.3%
	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%
Based on Total Capital:						
Total Debt incl. Short Term	59.4%	58.1%	57.0%	58.4%	58.2%	58.2%
Preferred Stock	2.5%	2.3%	2.4%	1.4%	1.8%	2.1%
Common Equity [2]	38.1%	39.6%	40.7%	40.3%	40.1%	39.7%
	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%
Rate of Return on Book Common Equity [2]	10.2%	10.3%	10.3%	10.8%	9.7%	10.3%
Operating Ratio [3]	79.8%	79.3%	79.8%	77.0%	78.2%	78.8%
Coverage incl. AFUDC [4]						
Pre-tax: All Interest Charges	2.80 x	3.05 x	2.94 x	3.42 x	3.38 x	3.12 x
Post-tax: All Interest Charges	2.60 x	3.10 x	2.59 x	2.86 x	2.55 x	2.74 x
Overall Coverage: All Int. & Pfd. Div.	2.56 x	3.04 x	2.55 x	2.84 x	2.52 x	2.70 x
Coverage excl. AFUDC [4]						
Pre-tax: All Interest Charges	2.70 x	2.95 x	2.84 x	3.31 x	3.28 x	3.02 x
Post-tax: All Interest Charges	2.50 x	3.00 x	2.48 x	2.75 x	2.44 x	2.63 x
Overall Coverage: All Int. & Pfd. Div.	2.46 x	2.94 x	2.44 x	2.73 x	2.41 x	2.60 x
Quality of Earnings & Cash Flow						
AFC/Income Avail. for Common Equity	6.8%	6.0%	7.3%	7.3%	6.5%	6.8%
Effective Income Tax Rate	10.2%	12.2%	19.0%	28.2%	29.0%	19.7%
Internal Cash Generation/Construction [5]	58.6%	65.9%	66.2%	78.7%	78.0%	69.5%
Gross Cash Flow/ Avg. Total Debt [6]	15.9%	17.5%	17.4%	19.9%	20.5%	18.2%
Gross Cash Flow Interest Coverage [7]	4.90 x	4.97 x	4.98 x	5.57 x	5.54 x	5.19 x
Common Dividend Coverage [8]	3.52 x	5.56 x	4.80 x	4.33 x	4.31 x	4.50 x

See Page 2 for Notes.

Standard & Poor's Public Utilities
Capitalization and Financial Statistics
2016-2020, Inclusive

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.
(2) Excluding Accumulated Other Comprehensive Income ("OCI") from the equity account
(3) Total operating expenses, maintenance, depreciation and taxes other than income taxes as a percent of operating revenues.
(4) Coverage calculations represent the number of times available earnings, both including and excluding AFUDC (allowance for funds used during construction) as reported in its entirety, cover fixed charges.
(5) Internal cash generation/gross construction is the percentage of gross construction expenditures provided by internally-generated funds from operations after payment of all cash dividends divided by gross construction expenditures.
(6) Gross Cash Flow (sum of net income, depreciation, amortization, net deferred income taxes and investment tax credits, less total AFUDC) as a percentage of average total debt.
(7) Gross Cash Flow (sum of net income, depreciation, amortization, net deferred income taxes and investment tax credits, less total AFUDC) plus interest charges, divided by interest charges.
(8) Common dividend coverage is the relationship of internally-generated funds from operations after payment of preferred stock dividends to common dividends paid.

Source of Information: Annual Reports to Shareholders
Utility COMPUSTAT

Standard & Poor's Public Utilities

Company Identities

	Ticker	Credit Rating (1) Moody's	S&P	Common Stock Traded	Value Line Beta
Alliant Energy Corporation	LNT	Baa1	A-	NYSE	0.85
Ameren Corporation	AEE	Baa1	BBB+	NYSE	0.85
American Electric Power	AEP	Baa1	A-	NYSE	0.75
American Water Works	AWK	Baa1	A	NYSE	0.85
CenterPoint Energy	CNP	Baa1	BBB+	NYSE	1.15
CMS Energy	CMS	A3	A-	NYSE	0.80
Consolidated Edison	ED	Baa1	A-	NYSE	0.75
Dominion Energy	D	A2	BBB+	NYSE	0.80
DTE Energy Co.	DTE	A2	A-	NYSE	0.95
Duke Energy	DUK	A1	BBB+	NYSE	0.85
Edison Int'l	EIX	Baa2	BBB	NYSE	0.95
Entergy Corp.	ETR	Baa1	A-	NYSE	0.95
Evergy, Inc.	EVRG	Baa1	A-	NYSE	1.00
Eversource	ES	A3	A	NYSE	0.90
Exelon Corp.	EXC	A2	BBB+	NYSE	0.95
FirstEnergy Corp.	FE	A3	BB+	NYSE	0.85
NextEra Energy Inc.	NEE	A1	A	NYSE	0.90
NiSource Inc.	NI	Baa2	BBB+	NYSE	0.85
NRG Energy Inc.	NRG	Ba1	BB+	NYSE	1.25
Pinnacle West Capital	PNW	A2	A-	NYSE	0.90
PPL Corp.	PPL	A3	A-	NYSE	1.15
Public Serv. Enterprise Inc.	PEG	A2	A-	NYSE	0.90
Sempra Energy	SRE	Baa1	BBB+	NYSE	1.00
Southern Co.	SO	Baa1	A-	NYSE	0.90
WEC Energy Corp.	WEC	A2	A-	NYSE	0.80
Xcel Energy Inc	XEL	A2	A-	NYSE	0.80
Average for S&P Utilities		A3	BBB+		0.91

Note: (1) Ratings are those of utility subsidiaries

Source of Information: SNL Financial LLC
Standard & Poor's Stock Guide
Value Line Investment Survey for Windows

Elizabethtown Gas Company
Capitalization and Related Capital Structure Ratios
Actual at September 30, 2021 and Estimated at March 31 2022

	Actual at September 30, 2021		Estimated at March 31 2022	
	Amount Outstanding	Ratios	Amount Outstanding	Ratios
Long-Term Debt	$ 922,249,299	41.62%	$ 922,504,338	40.64%
Common Equity				
Premium on Capital Stock	1,183,797,343		1,183,797,343	
Retained earnings	109,869,954		163,369,954	
Total Common Equity	1,293,667,297	58.38%	$ 1,347,167,297	59.36%
Total Capital	$ 2,215,916,596	100.00%	$ 2,269,671,635	100.00%
Goodwill				
Debt portion	$ 214,595,022	30.65% (1)	$ 214,595,022	30.65% (1)
Equity portion	485,631,507	69.35% (1)	485,631,507	69.35% (1)
	$ 700,226,529	100.00%	$ 700,226,529	100.00%
Ratesetting				
Long-Term Debt	$ 707,654,277	46.69%	$ 707,909,316	45.11%
Common Equity	808,035,790	53.31%	861,535,790	54.89%
Total Capital	$ 1,515,690,067	100.00%	$ 1,569,445,106	100.00%

Note: (1) Based on initial capitalization of ETG consisting of $530.000 million of Variable Rate Debt and $1,199.397 million Equity Conbtribution

Source of Information: Company provided data

Elizabethtown Gas Company
Calculation of the Embedded Cost of Long-Term Debt
Estimated at September 30, 2021

Series	Principal Amount Outstanding	Percent to Total	Effective Cost Rate (1)	Weighted Cost Rate
4.02% Series 2018A due 2028	$ 50,000,000	5.41%	4.16%	0.22%
4.22% Series 2018A due 2033	55,000,000	5.95%	4.32%	0.26%
4.29% Series 2018A due 2038	150,000,000	16.22%	4.37%	0.71%
4.37% Series 2018A due 2048	200,000,000	21.62%	4.44%	0.96%
4.52% Series 2018A due 2058	75,000,000	8.11%	4.58%	0.37%
2.84% Series 2019A due 2029	40,000,000	4.32%	2.92%	0.13%
2.84% Series 2019A due 2029	35,000,000	3.78%	2.91%	0.11%
2.94% Series 2019A due 2031	25,000,000	2.70%	3.00%	0.08%
2.94% Series 2019A due 2031	45,000,000	4.86%	2.98%	0.14%
3.28% Series 2020A due 2050	75,000,000	8.11%	3.34%	0.27%
3.38% Series 2020B due 2060	50,000,000	5.41%	3.42%	0.18%
Series 2020A-1, Tranche A due 2031	50,000,000	5.41%	2.33%	0.13%
Series 2020A-1, Tranche B due 2041	25,000,000	2.70%	3.12%	0.08%
Series 2020A-1, Tranche C due 2051	50,000,000	5.41%	3.39%	0.18%
Total Long-Term Debt	$ 925,000,000	100.00%		3.83%
Adjustment for Tenders and Calls	(2,750,701)			
Long-Term Debt	$ 922,249,299			
Annualized Cost	$ 35,458,500			
Adjustment for Tenders and Calls on Reacquired Debt	510,077			
Total Cost	$ 35,968,577			3.90%

Note: (1) As calculated on page 3 of this schedule.

Source of Information: Company provided data

Elizabethtown Gas Company
Calculation of the Embedded Cost of Long-Term Debt
Estimated at March 31 2022

Series	Principal Amount Outstanding	Percent to Total	Effective Cost Rate (1)	Weighted Cost Rate
4.02% Series 2018A due 2028	$ 50,000,000	5.41%	4.16%	0.22%
4.22% Series 2018A due 2033	55,000,000	5.95%	4.32%	0.26%
4.29% Series 2018A due 2038	150,000,000	16.22%	4.37%	0.71%
4.37% Series 2018A due 2048	200,000,000	21.62%	4.44%	0.96%
4.52% Series 2018A due 2058	75,000,000	8.11%	4.58%	0.37%
2.84% Series 2019A due 2029	40,000,000	4.32%	2.92%	0.13%
2.84% Series 2019A due 2029	35,000,000	3.78%	2.91%	0.11%
2.94% Series 2019A due 2031	25,000,000	2.70%	3.00%	0.08%
2.94% Series 2019A due 2031	45,000,000	4.86%	2.98%	0.14%
3.28% Series 2020A due 2050	75,000,000	8.11%	3.34%	0.27%
3.38% Series 2020B due 2060	50,000,000	5.41%	3.42%	0.18%
Series 2020A-1, Tranche A due 2031	50,000,000	5.41%	2.33%	0.13%
Series 2020A-1, Tranche B due 2041	25,000,000	2.70%	3.12%	0.08%
Series 2020A-1, Tranche C due 2051	50,000,000	5.41%	3.39%	0.18%
Total Long-Term Debt	$ 925,000,000	100.00%		3.83%
Adjustment for Tenders and Calls	(2,495,663)			
Long-Term Debt	$ 922,504,338			
Annualized Cost	$ 35,458,500			
Adjustment for Tenders and Calls on Reacquired Debt	510,077			
Total Cost	$ 35,968,577			3.90%

Note: (1) As calculated on page 3 of this schedule.

Source of Information: Company provided data

Elizabethtown Gas Company

Calculation of the Effective Cost of Long-Term Debt by Series

Series	Coupon Rate	Date of Issue	Date of Maturity	Average Term in Years (1)	Principal Amount Issued	Discount and Expense	Net Proceeds	Net Proceeds Ratio	Effective Cost Rate (2)
4.02% Series 2018A due 2028	4.02%	12/20/18	12/20/28	10	$ 50,000,000	$ 554,812	$ 49,445,188	98.89%	4.16%
4.22% Series 2018A due 2033	4.22%	12/20/18	12/20/33	15	55,000,000	610,294	54,389,706	98.89%	4.32%
4.29% Series 2018A due 2038	4.29%	12/20/18	12/20/38	20	150,000,000	1,665,746	148,334,254	98.89%	4.37%
4.37% Series 2018A due 2048	4.37%	12/20/18	12/20/48	30	200,000,000	2,219,250	197,780,750	98.89%	4.44%
4.52% Series 2018A due 2058	4.52%	12/20/18	12/20/58	40	75,000,000	832,219	74,167,781	98.89%	4.58%
2.84% Series 2019A due 2029	2.84%	09/27/19	09/27/29	10	40,000,000	263,492	39,736,508	99.34%	2.92%
2.84% Series 2019A due 2029	2.84%	10/29/19	10/29/29	10	35,000,000	210,851	34,789,149	99.40%	2.91%
2.94% Series 2019A due 2031	2.94%	11/26/19	11/26/31	12	25,000,000	156,114	24,843,886	99.38%	3.00%
2.94% Series 2019A due 2031	2.94%	12/27/19	12/27/31	23	45,000,000	275,112	44,724,888	99.39%	2.98%
3.28% Series 2020A due 2050	3.28%	11/10/20	11/10/50	19	75,000,000	621,080	74,378,920	99.17%	3.34%
3.38% Series 2020B due 2060	3.38%	11/10/20	11/10/60	40	50,000,000	414,053	49,585,947	99.17%	3.42%
Series 2020A-1, Tranche A due 2031	2.26%	06/15/21	06/15/31	10	50,000,000	324,758	49,675,242	99.35%	2.33%
Series 2020A-1, Tranche B due 2041	3.08%	06/15/21	06/15/41	20	25,000,000	162,379	24,837,621	99.35%	3.12%
Series 2020A-1, Tranche C due 2051	3.36%	06/15/21	06/15/51	30	50,000,000	324,758	49,675,242	99.35%	3.39%

Notes: (1) Determined by taking into account the effect the annual sinking fund requirements, which are met by the payment of principal that reduces the term of each issue.

(2) The effective cost for each issue is the yield to maturity ("ytm") using as inputs the average term of the issue, the coupon rate, and the net proceeds ratio.

Source of Information: Company provided data

Exhibit P-7
Schedule PRM-7

Monthly Dividend Yields for
Natural Gas Group
for the Twelve Months Ending September 2021

Company	Oct-20	Nov-20	Dec-20	Jan-21	Feb-21	Mar-21	Apr-21	May-21	Jun-21	Jul-21	Aug-21	Sep-21	12-Month Average	6-Month Average	3-Month Average
Atmos Energy Corp (ATO)	2.74%	2.61%	2.63%	2.82%	2.96%	2.54%	2.42%	2.52%	2.61%	2.55%	2.57%	2.84%			
Chesapeake Utilities Corp (CPK)	1.81%	1.70%	1.63%	1.74%	1.67%	1.52%	1.62%	1.68%	1.60%	1.54%	1.47%	1.60%			
New Jersey Resources Corporation (NJR)	4.58%	4.06%	3.75%	3.82%	3.41%	3.34%	3.18%	3.13%	3.37%	3.78%	3.92%	4.17%			
NiSource Inc (NI)	3.66%	3.48%	3.69%	4.01%	4.08%	3.67%	3.38%	3.46%	3.61%	3.55%	3.58%	3.65%			
Northwest Natural Holding Company (NWN)	4.32%	4.02%	4.21%	4.11%	4.01%	3.58%	3.56%	3.64%	3.68%	3.67%	3.74%	4.21%			
ONE Gas Inc (OGS)	3.15%	2.73%	2.82%	3.19%	3.47%	3.03%	2.90%	3.13%	3.14%	3.17%	3.24%	3.68%			
South Jersey Industries Inc (SJI)	6.34%	5.32%	5.63%	5.28%	4.87%	5.37%	4.92%	4.58%	4.68%	4.84%	4.93%	5.71%			
Southwest Gas Holdings Inc (SWX)	3.50%	3.55%	3.77%	3.83%	3.66%	3.33%	3.44%	3.61%	3.61%	3.43%	3.39%	3.58%			
Spire Inc. (SR)	4.67%	4.10%	4.07%	4.27%	3.95%	3.53%	3.47%	3.66%	3.60%	3.68%	3.93%	4.26%			
Average	**3.86%**	**3.51%**	**3.58%**	**3.67%**	**3.56%**	**3.32%**	**3.21%**	**3.27%**	**3.32%**	**3.36%**	**3.42%**	**3.74%**	**3.49%**	**3.39%**	**3.51%**

Note: Monthly dividend yields are calculated by dividing the annualized quarterly dividend by the month-end closing stock price adjusted by the fraction of the ex-dividend.

Source of Information: https://finance.yahoo.com/quote
https://www.nasdaq.com/market-activity/stocks

Forward-looking Dividend Yield				
	1/2 Growth	D_0/P_0	(.5g)	D_1/P_0
		3.39%	1.033750	3.50%
	Discrete	D_0/P_0	Adj.	D_1/P_0
		3.39%	1.041843	3.53%
	Quarterly	D_0/P_0	Adj.	D_1/P_0
		0.8467%	1.016464	3.49%
	Average			3.51%
	Growth rate			6.75%
	K			10.26%

$$K = \frac{D_0(1+g)^0 + D_0(1+g)^0 + D_0(1+g)^1 + D_0(1+g)^1}{P_0} + g$$

$$K = \frac{D_0(1+g)^{.25} + D_0(1+g)^{.50} + D_0(1+g)^{.75} + D_0(1+g)^{1.00}}{P_0} + g$$

$$K = \left[\left(1 + \frac{D_0(1+g)^{.25}}{P_0}\right)^4 - 1\right] + g$$

Historical Growth Rates
Earnings Per Share, Dividends Per Share,
Book Value Per Share, and Cash Flow Per Share

Gas Group	Earnings per Share Value Line 5 Year	Earnings per Share Value Line 10 Year	Dividends per Share Value Line 5 Year	Dividends per Share Value Line 10 Year	Book Value per Share Value Line 5 Year	Book Value per Share Value Line 10 Year	Cash Flow per Share Value Line 5 Year	Cash Flow per Share Value Line 10 Year
Atmos Energy Corp.	9.00%	8.00%	7.50%	5.00%	10.00%	7.50%	7.00%	5.50%
Chesapeake Utilities Corp.	9.00%	9.50%	7.50%	6.50%	11.00%	9.50%	7.50%	9.50%
New Jersey Resources Corp.	5.50%	6.00%	6.50%	7.00%	8.50%	7.50%	7.00%	7.00%
Nisource Inc.	0.50%	2.00%	-3.00%	-1.50%	-5.00%	-3.00%	-	-0.50%
Northwest Natural Gas	1.50%	-1.50%	0.50%	1.50%	-	1.00%	1.50%	0.50%
One Gas, Inc.	10.00%	-	14.50%	-	3.00%	1.00%	8.00%	-
South Jersey Industries, Inc.	-1.50%	1.50%	4.00%	6.50%	2.50%	5.50%	3.00%	4.50%
Southwest Gas Corp.	5.50%	7.50%	8.00%	8.50%	7.00%	6.00%	1.50%	4.00%
Spire, Inc.	4.50%	1.50%	6.00%	4.50%	5.50%	7.00%	8.50%	4.50%
Average	4.89%	4.31%	5.72%	4.75%	5.31%	4.67%	5.50%	4.38%

Source of Information: Value Line Investment Survey, August 27, 2021

Analysts' Five-Year Projected Growth Rates
Earnings Per Share, Dividends Per Share,
Book Value Per Share, and Cash Flow Per Share

Gas Group	I/B/E/S First Call	Zacks	Value Line Earnings Per Share	Value Line Dividends Per Share	Value Line Book Value Per Share	Value Line Cash Flow Per Share	Value Line Percent Retained to Common Equity
Atmos Energy Corp (ATO)	7.80%	7.40%	7.00%	7.50%	10.50%	5.00%	3.50%
Chesapeake Utilities Corp (CPK)	4.74%	NA	8.50%	8.00%	6.50%	9.50%	7.50%
New Jersey Resources Corporation	6.00%	7.10%	2.00%	5.50%	6.00%	3.00%	3.50%
NiSource Inc (NI)	3.52%	6.20%	9.50%	4.50%	4.50%	6.00%	5.50%
Northwest Natural Holding Compan	5.50%	4.90%	5.50%	0.50%	8.50%	4.00%	2.50%
ONE Gas Inc (OGS)	5.00%	5.00%	6.50%	7.00%	10.50%	6.00%	3.00%
South Jersey Industries Inc (SJI)	4.80%	5.40%	11.50%	4.50%	5.00%	6.00%	5.50%
Southwest Gas Holdings Inc (SWX)	4.00%	5.50%	8.00%	4.50%	7.00%	7.00%	5.00%
Spire Inc. (SR)	7.31%	5.50%	10.00%	4.50%	7.50%	8.00%	3.00%
Average	5.41%	5.88%	7.61%	5.17%	7.33%	6.06%	4.33%

Source of Information : Yahoo Finance, September 29, 2021
Zacks, September 29, 2021
Value Line Investment Survey, August 27, 2021

Gas Group
Financial Risk Adjustment

	ATMOS Energy (NYSE:ATO)	Chesapeake Utilities (NYSE:CPK)	New Jersey Resources (NYSE:NJR)	NiSource, Inc (NYSE:NI)	Northwest Natural Gas (NYSE:NWN)	ONE Gas Inc (NYSE:OGS)	South Jersey Industries (NYSE:SJI)	Southwest Gas (SWX)	Spire Inc. (NYSESR)	Average
Fiscal Year	09/30/20	12/31/20	09/30/20	12/31/20	12/31/20	12/31/20	12/31/20	12/31/20	09/30/20	
Capitalization at Fair Values										
Debt(D)	5,597,183	548,500	2,417,748	11,034,200	1,136,311	2,000,000	3,152,224	3,148,818	2,908,600	3,549,287
Preferred(P)	0	0	0	0	0	0	0	0	242,000	26,889
Equity(E)	12,033,105	1,889,546	2,588,540	8,986,976	1,406,788	4,081,610	2,162,231	3,474,470	2,745,747	4,374,335
Total	17,630,288	2,438,046	5,006,288	20,021,176	2,543,099	6,081,610	5,314,455	6,623,288	5,896,347	7,950,511
Capital Structure Ratios										
Debt(D)	31.75%	22.50%	48.29%	55.11%	44.68%	32.89%	59.31%	47.54%	49.33%	43.49%
Preferred(P)	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	4.10%	0.46%
Equity(E)	68.25%	77.50%	51.71%	44.89%	55.32%	67.11%	40.69%	52.46%	46.57%	56.06%
Total	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.01%
Common Stock										
Issued	125,882.477	17,461.841	95,949.183	391,760.051	30,589.000	53,166.733	100,591.940	57,192.925	51,611.789	
Treasury	0.000	0.000	148.310	0.000	0.000	0.000	256.372	0.000	0.000	
Outstanding	125,882.477	17,461.841	95,800.873	391,760.051	30,589.000	53,166.733	100,335.568	57,192.925	51,611.789	
Market Price	$ 95.59	$ 108.21	$ 27.02	$ 22.94	$ 45.99	$ 76.77	$ 21.55	$ 60.75	$ 53.20	
Capitalization at Carrying Amounts										
Debt(D)	4,560,000	523,000	2,102,845	9,243,100	955,425	1,600,000	2,919,201	2,772,633	2,484,100	3,017,812
Preferred(P)	0	0	0	0	0	0	0	0	242,000	26,889
Equity(E)	6,791,203	697,085	1,844,692	4,872,200	888,733	2,233,311	1,660,881	2,674,953	2,280,300	2,660,373
Total	11,351,203	1,220,085	3,947,537	14,115,300	1,844,158	3,833,311	4,580,082	5,447,586	5,006,400	5,705,074
Capital Structure Ratios	53.95	39.92	19.26	12.44	29.05	42.01	16.55	46.77	44.18	
Debt(D)	40.17%	42.87%	53.27%	65.48%	51.81%	41.74%	63.74%	50.90%	49.62%	51.07%
Preferred(P)	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	4.83%	0.54%
Equity(E)	59.83%	57.13%	46.73%	34.52%	48.19%	58.26%	36.26%	49.10%	45.55%	48.40%
Total	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%
Betas Value Line	0.80	0.80	1.00	0.85	0.85	0.80	1.05	0.95	0.85	0.88

Hamada	Bl	=	Bu	[1+	(1 - t)	D/E	+	P/E	]
	0.88	=	Bu	[1+	(1-0.21)	0.7758	+	0.0082	]
	0.88	=	Bu	[1+	0.79	0.7758	+	0.0082	]
	0.88	=	Bu	1.6211					
	0.54	=	Bu						
Hamada	Bl	=	0.54	[1+	(1 - t)	D/E	+	P/E	]
	Bl	=	0.54	[1+	0.79	1.0552	+	0.0111	]
	Bl	=	0.54	1.8447					
	Bl	=	1.00						

M&M	ku	=	ke	-	(((	ku	-	i	)	1-t	)	D	/	E	-	(ku	-	d	)	P	/	E
	7.52%	=	10.26%	-	(((	7.52%	-	3.11%	)	0.79	)	43.49%	/	56.06%	-	7.52%	-	5.68%	)	0.46%	/	56.06%
	7.52%	=	10.26%	-	(((	4.41%			)	0.79	)	0.7758			-	1.84%			)	0.0082		
	7.52%	=	10.26%	-	((	3.48%					)	0.7758			-	1.84%			)	0.0082		
	7.52%	=	10.26%	-		2.70%									-	0.02%						
M&M	ke	=	ku	+	(((	ku	-	i	)	1-t	)	D	/	E	+	(ku	-	d	)	P	/	E
	11.21%	=	7.52%	+	(((	7.52%	-	3.11%	)	0.79	)	51.07%	/	48.40%	+	7.52%	-	5.68%	)	0.54%	/	48.40%
	11.21%	=	7.52%	+	(((	4.41%			)	0.79	)	1.0552			+	1.84%			)	0.0111		
	11.21%	=	7.52%	+	((	3.48%					)	1.0552			+	1.84%			)	0.0111		
	11.21%	=	7.52%	+		3.67%									+	0.02%						

Analysis of Public Offerings of Gas Distribution Company Common Stock

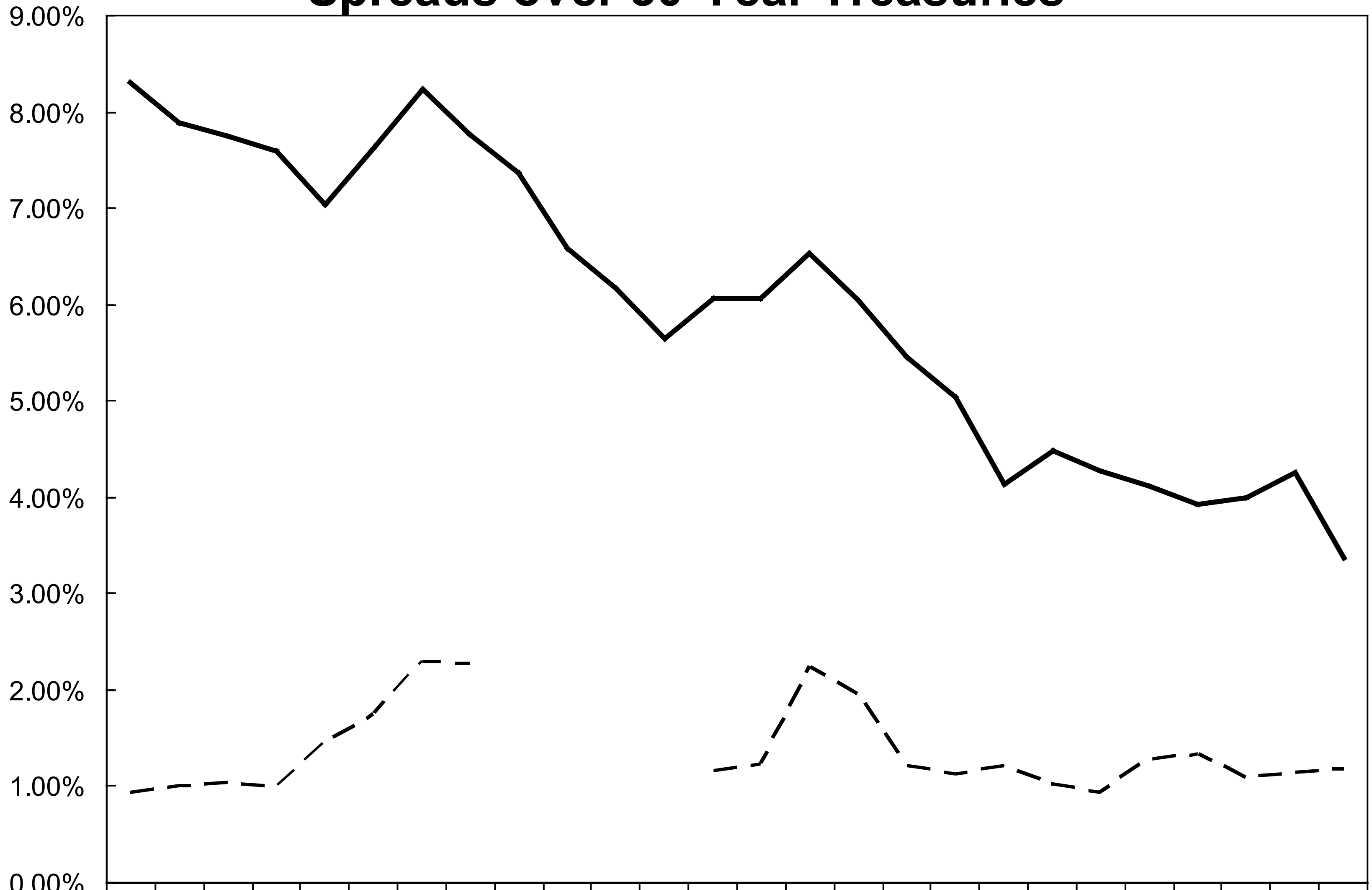
Company	Date of Offering	No. of shares offered	Dollar amount of offering	Price to public	Underwriters' discount and commission	Gross Proceeds per share	Estimated company issuance expenses	Net proceeds per share	Percent of offering price: Underwriters' discount and commission	Percent of offering price: Estimated company issuance expenses	Percent of offering price: Total Issuance and selling expense
Piedmont Natural Gas Company, Inc.	01/29/13	4,000,000	$ 128,000,000	$32.00	1.120	$30.880	$0.088	$30.792	3.5%	0.3%	3.8%
Atmos Energy Corporation	12/07/06	5,500,000	$ 173,250,000	$31.50	1.103	$30.398	$0.073	$30.325	3.5%	0.2%	3.7%
AGL Resources Inc.	11/19/04	9,600,000	$ 297,696,000	$31.01	0.930	$30.080	$0.042	$30.038	3.0%	0.1%	3.1%
Atmos Energy Corporation	10/21/04	14,000,000	$ 346,500,000	$24.75	0.990	$23.760	$0.029	$23.731	4.0%	0.1%	4.1%
Atmos Energy Corporation	07/19/04	8,650,000	$ 214,087,500	$24.75	0.990	$23.760	$0.046	$23.714	4.0%	0.2%	4.2%
The Laclede Group, Inc.	05/25/04	1,500,000	$ 40,200,000	$26.80	0.871	$25.929	$0.067	$25.862	3.3%	0.3%	3.6%
Northwest Natural Gas Company	03/30/04	1,200,000	$ 37,200,000	$31.00	1.010	$29.990	$0.146	$29.844	3.3%	0.5%	3.8%
Piedmont Natural Gas Company, Inc.	01/23/04	4,250,000	$ 180,625,000	$42.50	1.490	$41.010	$0.082	$40.928	3.5%	0.2%	3.7%
Atmos Energy Corporation	06/18/03	4,000,000	$ 101,240,000	$25.31	1.012	$24.298	$0.095	$24.203	4.0%	0.4%	4.4%
AGL Resources Inc.	02/11/03	5,600,000	$ 123,200,000	$22.00	0.770	$21.230	$0.045	$21.185	3.5%	0.2%	3.7%
WGL Holdings, Inc	06/26/01	1,790,000	$ 47,846,700	$26.73	0.895	$25.835	$0.031	$25.804	3.3%	0.1%	3.4%
Atmos Energy Corporation	11/07/00	6,000,000	$ 133,500,000	$22.25	1.110	$21.140	$0.058	$21.082	5.0%	0.3%	5.3%
Average									3.7%	0.2%	3.9%

Source of Information: SNL Financial and SEC filings

Interest Rates for Investment Grade Public Utility Bonds
Yearly for 2016-2020
and the Twelve Months Ended September 2021

Years	Aa Rated	A Rated	Baa Rated	Average
2016	3.73%	3.93%	4.68%	4.11%
2017	3.82%	4.00%	4.38%	4.07%
2018	4.09%	4.25%	4.67%	4.34%
2019	3.61%	3.77%	4.19%	3.86%
2020	2.79%	3.02%	3.39%	3.07%
Five-Year Average	3.61%	3.79%	4.26%	3.89%
Months				
Oct-20	2.72%	2.95%	3.27%	2.98%
Nov-20	2.63%	2.85%	3.17%	2.89%
Dec-20	2.57%	2.77%	3.05%	2.80%
Jan-21	2.73%	2.91%	3.18%	2.94%
Feb-21	2.93%	3.09%	3.37%	3.13%
Mar-21	3.27%	3.44%	3.72%	3.48%
Apr-21	3.13%	3.30%	3.57%	3.33%
May-21	3.17%	3.33%	3.58%	3.36%
Jun-21	3.01%	3.16%	3.41%	3.19%
Jul-21	2.80%	2.95%	3.20%	2.99%
Aug-21	2.82%	2.95%	3.19%	2.99%
Sep-21	2.84%	2.96%	3.19%	3.00%
Twelve-Month Average	2.89%	3.06%	3.33%	3.09%
Six-Month Average	2.96%	3.11%	3.36%	3.14%
Three-Month Average	2.82%	2.95%	3.19%	2.99%

Yields on
A-rated Public Utility Bonds and
Spreads over 30-Year Treasuries



	1994	1995	1996	1997	1998	1999	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019
A-rated Public Utility	8.31	7.89	7.75	7.60	7.04	7.62	8.24	7.76	7.37	6.58	6.16	5.65	6.07	6.07	6.53	6.04	5.46	5.04	4.13	4.48	4.28	4.12	3.93	4.00	4.25	3.37
Spread vs. 30-year	0.94	1.01	1.04	0.99	1.46	1.75	2.30	2.27					1.16	1.23	2.25	1.96	1.21	1.13	1.21	1.03	0.94	1.28	1.34	1.10	1.14	1.19

A rated Public Utility Bonds over 30-Year Treasuries

Year	A-rated Public Utility	30-Year Treasuries Yield	Spread
Jan-99	6.97%	5.16%	1.81%
Feb-99	7.09%	5.37%	1.72%
Mar-99	7.26%	5.58%	1.68%
Apr-99	7.22%	5.55%	1.67%
May-99	7.47%	5.81%	1.66%
Jun-99	7.74%	6.04%	1.70%
Jul-99	7.71%	5.98%	1.73%
Aug-99	7.91%	6.07%	1.84%
Sep-99	7.93%	6.07%	1.86%
Oct-99	8.06%	6.26%	1.80%
Nov-99	7.94%	6.15%	1.79%
Dec-99	8.14%	6.35%	1.79%
Jan-00	8.35%	6.63%	1.72%
Feb-00	8.25%	6.23%	2.02%
Mar-00	8.28%	6.05%	2.23%
Apr-00	8.29%	5.85%	2.44%
May-00	8.70%	6.15%	2.55%
Jun-00	8.36%	5.93%	2.43%
Jul-00	8.25%	5.85%	2.40%
Aug-00	8.13%	5.72%	2.41%
Sep-00	8.23%	5.83%	2.40%
Oct-00	8.14%	5.80%	2.34%
Nov-00	8.11%	5.78%	2.33%
Dec-00	7.84%	5.49%	2.35%
Jan-01	7.80%	5.54%	2.26%
Feb-01	7.74%	5.45%	2.29%
Mar-01	7.68%	5.34%	2.34%
Apr-01	7.94%	5.65%	2.29%
May-01	7.99%	5.78%	2.21%
Jun-01	7.85%	5.67%	2.18%
Jul-01	7.78%	5.61%	2.17%
Aug-01	7.59%	5.48%	2.11%
Sep-01	7.75%	5.48%	2.27%
Oct-01	7.63%	5.32%	2.31%
Nov-01	7.57%	5.12%	2.45%
Dec-01	7.83%	5.48%	2.35%
Jan-02	7.66%	5.45%	2.21%
Feb-02	7.54%	5.40%	2.14%
Mar-02	7.76%		
Apr-02	7.57%		
May-02	7.52%		
Jun-02	7.42%		
Jul-02	7.31%		
Aug-02	7.17%		
Sep-02	7.08%		
Oct-02	7.23%		
Nov-02	7.14%		
Dec-02	7.07%		
Jan-03	7.07%		
Feb-03	6.93%		
Mar-03	6.79%		
Apr-03	6.64%		
May-03	6.36%		
Jun-03	6.21%		
Jul-03	6.57%		
Aug-03	6.78%		
Sep-03	6.56%		
Oct-03	6.43%		
Nov-03	6.37%		
Dec-03	6.27%		
Jan-04	6.15%		
Feb-04	6.15%		
Mar-04	5.97%		
Apr-04	6.35%		
May-04	6.62%		
Jun-04	6.46%		
Jul-04	6.27%		
Aug-04	6.14%		
Sep-04	5.98%		
Oct-04	5.94%		
Nov-04	5.97%		
Dec-04	5.92%		

Year	A-rated Public Utility	30-Year Treasuries Yield	Spread
Jan-05	5.78%		
Feb-05	5.61%		
Mar-05	5.83%		
Apr-05	5.64%		
May-05	5.53%		
Jun-05	5.40%		
Jul-05	5.51%		
Aug-05	5.50%		
Sep-05	5.52%		
Oct-05	5.79%		
Nov-05	5.88%		
Dec-05	5.80%		
Jan-06	5.75%		
Feb-06	5.82%	4.54%	1.28%
Mar-06	5.98%	4.73%	1.25%
Apr-06	6.29%	5.06%	1.23%
May-06	6.42%	5.20%	1.22%
Jun-06	6.40%	5.15%	1.25%
Jul-06	6.37%	5.13%	1.24%
Aug-06	6.20%	5.00%	1.20%
Sep-06	6.00%	4.85%	1.15%
Oct-06	5.98%	4.85%	1.13%
Nov-06	5.80%	4.69%	1.11%
Dec-06	5.81%	4.68%	1.13%
Jan-07	5.96%	4.85%	1.11%
Feb-07	5.90%	4.82%	1.08%
Mar-07	5.85%	4.72%	1.13%
Apr-07	5.97%	4.87%	1.10%
May-07	5.99%	4.90%	1.09%
Jun-07	6.30%	5.20%	1.10%
Jul-07	6.25%	5.11%	1.14%
Aug-07	6.24%	4.93%	1.31%
Sep-07	6.18%	4.79%	1.39%
Oct-07	6.11%	4.77%	1.34%
Nov-07	5.97%	4.52%	1.45%
Dec-07	6.16%	4.53%	1.63%
Jan-08	6.02%	4.33%	1.69%
Feb-08	6.21%	4.52%	1.69%
Mar-08	6.21%	4.39%	1.82%
Apr-08	6.29%	4.44%	1.85%
May-08	6.28%	4.60%	1.68%
Jun-08	6.38%	4.69%	1.69%
Jul-08	6.40%	4.57%	1.83%
Aug-08	6.37%	4.50%	1.87%
Sep-08	6.49%	4.27%	2.22%
Oct-08	7.56%	4.17%	3.39%
Nov-08	7.60%	4.00%	3.60%
Dec-08	6.52%	2.87%	3.65%
Jan-09	6.39%	3.13%	3.26%
Feb-09	6.30%	3.59%	2.71%
Mar-09	6.42%	3.64%	2.78%
Apr-09	6.48%	3.76%	2.72%
May-09	6.49%	4.23%	2.26%
Jun-09	6.20%	4.52%	1.68%
Jul-09	5.97%	4.41%	1.56%
Aug-09	5.71%	4.37%	1.34%
Sep-09	5.53%	4.19%	1.34%
Oct-09	5.55%	4.19%	1.36%
Nov-09	5.64%	4.31%	1.33%
Dec-09	5.79%	4.49%	1.30%
Jan-10	5.77%	4.60%	1.17%
Feb-10	5.87%	4.62%	1.25%
Mar-10	5.84%	4.64%	1.20%
Apr-10	5.81%	4.69%	1.12%
May-10	5.50%	4.29%	1.21%
Jun-10	5.46%	4.13%	1.33%
Jul-10	5.26%	3.99%	1.27%
Aug-10	5.01%	3.80%	1.21%
Sep-10	5.01%	3.77%	1.24%
Oct-10	5.10%	3.87%	1.23%
Nov-10	5.37%	4.19%	1.18%
Dec-10	5.56%	4.42%	1.14%

Year	A-rated Public Utility	30-Year Treasuries Yield	Spread
Jan-11	5.57%	4.52%	1.05%
Feb-11	5.68%	4.65%	1.03%
Mar-11	5.56%	4.51%	1.05%
Apr-11	5.55%	4.50%	1.05%
May-11	5.32%	4.29%	1.03%
Jun-11	5.26%	4.23%	1.03%
Jul-11	5.27%	4.27%	1.00%
Aug-11	4.69%	3.65%	1.04%
Sep-11	4.48%	3.18%	1.30%
Oct-11	4.52%	3.13%	1.39%
Nov-11	4.25%	3.02%	1.23%
Dec-11	4.33%	2.98%	1.35%
Jan-12	4.34%	3.03%	1.31%
Feb-12	4.36%	3.11%	1.25%
Mar-12	4.48%	3.28%	1.20%
Apr-12	4.40%	3.18%	1.22%
May-12	4.20%	2.93%	1.27%
Jun-12	4.08%	2.70%	1.38%
Jul-12	3.93%	2.59%	1.34%
Aug-12	4.00%	2.77%	1.23%
Sep-12	4.02%	2.88%	1.14%
Oct-12	3.91%	2.90%	1.01%
Nov-12	3.84%	2.80%	1.04%
Dec-12	4.00%	2.88%	1.12%
Jan-13	4.15%	3.08%	1.07%
Feb-13	4.18%	3.17%	1.01%
Mar-13	4.20%	3.16%	1.04%
Apr-13	4.00%	2.93%	1.07%
May-13	4.17%	3.11%	1.06%
Jun-13	4.53%	3.40%	1.13%
Jul-13	4.68%	3.61%	1.07%
Aug-13	4.73%	3.76%	0.97%
Sep-13	4.80%	3.79%	1.01%
Oct-13	4.70%	3.68%	1.02%
Nov-13	4.77%	3.80%	0.97%
Dec-13	4.81%	3.89%	0.92%
Jan-14	4.63%	3.77%	0.86%
Feb-14	4.53%	3.66%	0.87%
Mar-14	4.51%	3.62%	0.89%
Apr-14	4.41%	3.52%	0.89%
May-14	4.26%	3.39%	0.87%
Jun-14	4.29%	3.42%	0.87%
Jul-14	4.23%	3.33%	0.90%
Aug-14	4.13%	3.20%	0.93%
Sep-14	4.24%	3.26%	0.98%
Oct-14	4.06%	3.04%	1.02%
Nov-14	4.09%	3.04%	1.05%
Dec-14	3.95%	2.83%	1.12%
Jan-15	3.58%	2.46%	1.12%
Feb-15	3.67%	2.57%	1.10%
Mar-15	3.74%	2.63%	1.11%
Apr-15	3.75%	2.59%	1.16%
May-15	4.17%	2.96%	1.21%
Jun-15	4.39%	3.11%	1.28%
Jul-15	4.40%	3.07%	1.33%
Aug-15	4.25%	2.86%	1.39%
Sep-15	4.39%	2.95%	1.44%
Oct-15	4.29%	2.89%	1.40%
Nov-15	4.40%	3.03%	1.37%
Dec-15	4.35%	2.97%	1.38%
Jan-16	4.27%	2.86%	1.41%
Feb-16	4.11%	2.62%	1.49%
Mar-16	4.16%	2.68%	1.48%
Apr-16	4.00%	2.62%	1.38%
May-16	3.93%	2.63%	1.30%
Jun-16	3.78%	2.45%	1.33%
Jul-16	3.57%	2.23%	1.34%
Aug-16	3.59%	2.26%	1.33%
Sep-16	3.66%	2.35%	1.31%
Oct-16	3.77%	2.50%	1.27%
Nov-16	4.08%	2.86%	1.22%
Dec-16	4.27%	3.11%	1.16%

Year	A-rated Public Utility	30-Year Treasuries Yield	Spread
Jan-17	4.14%	3.02%	1.12%
Feb-17	4.18%	3.03%	1.15%
Mar-17	4.23%	3.08%	1.15%
Apr-17	4.12%	2.94%	1.18%
May-17	4.12%	2.96%	1.16%
Jun-17	3.94%	2.80%	1.14%
Jul-17	3.99%	2.88%	1.11%
Aug-17	3.86%	2.80%	1.06%
Sep-17	3.87%	2.78%	1.09%
Oct-17	3.91%	2.88%	1.03%
Nov-17	3.83%	2.80%	1.03%
Dec-17	3.79%	2.77%	1.02%
Jan-18	3.86%	2.88%	0.98%
Feb-18	4.09%	3.13%	0.96%
Mar-18	4.13%	3.09%	1.04%
Apr-18	4.17%	3.07%	1.10%
May-18	4.28%	3.13%	1.15%
Jun-18	4.27%	3.05%	1.22%
Jul-18	4.27%	3.01%	1.26%
Aug-18	4.26%	3.04%	1.22%
Sep-18	4.32%	3.15%	1.17%
Oct-18	4.45%	3.34%	1.11%
Nov-18	4.52%	3.36%	1.16%
Dec-18	4.37%	3.10%	1.27%
Jan-19	4.35%	3.04%	1.31%
Feb-19	4.25%	3.02%	1.23%
Mar-19	4.16%	2.98%	1.18%
Apr-19	4.08%	2.94%	1.14%
May-19	3.98%	2.82%	1.16%
Jun-19	3.82%	2.57%	1.25%
Jul-19	3.69%	2.57%	1.12%
Aug-19	3.29%	2.12%	1.17%
Sep-19	3.37%	2.16%	1.21%
Oct-19	3.39%	2.19%	1.20%
Nov-19	3.43%	2.28%	1.15%
Dec-19	3.40%	2.30%	1.10%
Jan-20	3.29%	2.22%	1.07%
Feb-20	3.11%	1.97%	1.14%
Mar-20	3.50%	1.46%	2.04%
Apr-20	3.19%	1.27%	1.92%
May-20	3.14%	1.38%	1.76%
Jun-20	3.07%	1.49%	1.58%
Jul-20	2.74%	1.31%	1.43%
Aug-20	2.73%	1.36%	1.37%
Sep-20	2.84%	1.42%	1.42%
Oct-20	2.95%	1.57%	1.38%
Nov-20	2.85%	1.62%	1.23%
Dec-20	2.77%	1.67%	1.10%
Jan-21	2.91%	1.82%	1.09%
Feb-21	3.09%	2.04%	1.05%
Mar-21	3.44%	2.34%	1.10%
Apr-21	3.30%	2.30%	1.00%
May-21	3.33%	2.32%	1.01%
Jun-21	3.16%	2.16%	1.00%
Jul-21	2.95%	1.94%	1.01%
Aug-21	2.95%	1.92%	1.03%
Sep-21	2.96%	1.94%	1.02%
Average:	12-months		1.09%
	6-months		1.01%
	3-months		1.02%

Common Equity Risk Premiums
Years 1926-2020

	Large Common Stocks	Long-Term Corp. Bonds	Equity Risk Premium	Long-Term Govt. Bonds Yields
Low Interest Rates	12.06%	5.43%	6.63%	2.85%
Average Across All Interest Rates	12.16%	6.49%	5.67%	4.95%
High Interest Rates	12.26%	7.57%	4.69%	7.09%

Source of Information: 2021 SBBI Yearbook Stocks, Bonds, Bills, and Inflation

Basic Series
Annual Total Returns (except yields)

Year	Large Common Stocks	Long-Term Corp. Bonds	Long-Term Govt. Bonds Yields
2020	18.40%	15.40%	1.37%
1940	-9.78%	3.39%	1.94%
1945	36.44%	4.08%	1.99%
1941	-11.59%	2.73%	2.04%
1949	18.79%	3.31%	2.09%
1946	-8.07%	1.72%	2.12%
1950	31.71%	2.12%	2.24%
2019	31.49%	19.95%	2.25%
1939	-0.41%	3.97%	2.26%
1948	5.50%	4.14%	2.37%
1947	5.71%	-2.34%	2.43%
1942	20.34%	2.60%	2.46%
1944	19.75%	4.73%	2.46%
2012	16.00%	10.68%	2.46%
2014	13.69%	17.28%	2.46%
1943	25.90%	2.83%	2.48%
1938	31.12%	6.13%	2.52%
2017	21.83%	12.25%	2.54%
1936	33.92%	6.74%	2.55%
2011	2.11%	17.95%	2.55%
2015	1.38%	-1.02%	2.68%
1951	24.02%	-2.69%	2.69%
1954	52.62%	5.39%	2.72%
2016	11.96%	6.70%	2.72%
1937	-35.03%	2.75%	2.73%
1953	-0.99%	3.41%	2.74%
1935	47.67%	9.61%	2.76%
1952	18.37%	3.52%	2.79%
2018	-4.38%	-4.73%	2.84%
1934	-1.44%	13.84%	2.93%
1955	31.56%	0.48%	2.95%
2008	-37.00%	8.78%	3.03%
1932	-8.19%	10.82%	3.15%
1927	37.49%	7.44%	3.17%
1957	-10.78%	8.71%	3.23%
1930	-24.90%	7.98%	3.30%
1933	53.99%	10.38%	3.36%
1928	43.61%	2.84%	3.40%
1929	-8.42%	3.27%	3.40%
1956	6.56%	-6.81%	3.45%
1926	11.62%	7.37%	3.54%
2013	32.39%	-7.07%	3.78%
1960	0.47%	9.07%	3.80%
1958	43.36%	-2.22%	3.82%
1962	-8.73%	7.95%	3.95%
1931	-43.34%	-1.85%	4.07%
2010	15.06%	12.44%	4.14%
1961	26.89%	4.82%	4.15%
1963	22.80%	2.19%	4.17%
1964	16.48%	4.77%	4.23%
1959	11.96%	-0.97%	4.47%
1965	12.45%	-0.46%	4.50%
2007	5.49%	2.60%	4.50%
1966	-10.06%	0.20%	4.55%
2009	26.46%	3.02%	4.58%
2005	4.91%	5.87%	4.61%
2002	-22.10%	16.33%	4.84%
2004	10.88%	8.72%	4.84%
2006	15.79%	3.24%	4.91%
2003	28.68%	5.27%	5.11%
1998	28.58%	10.76%	5.42%
1967	23.98%	-4.95%	5.56%
2000	-9.10%	12.87%	5.58%
2001	-11.89%	10.65%	5.75%
1971	14.30%	11.01%	5.97%
1968	11.06%	2.57%	5.98%
1972	18.99%	7.26%	5.99%
1997	33.36%	12.95%	6.02%
1995	37.58%	27.20%	6.03%
1970	3.86%	18.37%	6.48%
1993	10.08%	13.19%	6.54%
1996	22.96%	1.40%	6.73%
1999	21.04%	-7.45%	6.82%
1969	-8.50%	-8.09%	6.87%
1976	23.93%	18.65%	7.21%
1973	-14.69%	1.14%	7.26%
1992	7.62%	9.39%	7.26%
1991	30.47%	19.89%	7.30%
1974	-26.47%	-3.06%	7.60%
1986	18.67%	19.85%	7.89%
1994	1.32%	-5.76%	7.99%
1977	-7.16%	1.71%	8.03%
1975	37.23%	14.64%	8.05%
1989	31.69%	16.23%	8.16%
1990	-3.10%	6.78%	8.44%
1978	6.57%	-0.07%	8.98%
1988	16.61%	10.70%	9.19%
1987	5.25%	-0.27%	9.20%
1985	31.73%	30.09%	9.56%
1979	18.61%	-4.18%	10.12%
1982	21.55%	42.56%	10.95%
1984	6.27%	16.86%	11.70%
1983	22.56%	6.26%	11.97%
1980	32.50%	-2.76%	11.99%
1981	-4.92%	-1.24%	13.34%

Yields for Treasury Constant Maturities
Yearly for 2016-2020
and the Twelve Months Ended September 2021

Years	1-Year	2-Year	3-Year	5-Year	7-Year	10-Year	20-Year	30-Year
2016	0.61%	0.84%	1.01%	1.34%	1.64%	1.84%	2.23%	2.60%
2017	1.20%	1.40%	1.58%	1.91%	2.16%	2.33%	2.65%	2.90%
2018	2.33%	2.53%	2.63%	2.75%	2.85%	2.91%	3.02%	3.11%
2019	2.05%	1.97%	1.94%	1.96%	2.05%	2.14%	2.40%	2.58%
2020	0.38%	0.40%	0.43%	0.54%	0.73%	0.89%	1.35%	1.56%
Five-Year Average	1.31%	1.43%	1.52%	1.70%	1.89%	2.02%	2.33%	2.55%
Months								
Oct-20	0.13%	0.15%	0.19%	0.34%	0.55%	0.79%	1.34%	1.57%
Nov-20	0.12%	0.17%	0.22%	0.39%	0.63%	0.87%	1.40%	1.62%
Dec-20	0.10%	0.14%	0.19%	0.39%	0.66%	0.93%	1.47%	1.67%
Jan-21	0.10%	0.13%	0.20%	0.45%	0.77%	1.08%	1.63%	1.82%
Feb-21	0.07%	0.12%	0.21%	0.54%	0.91%	1.26%	1.88%	2.04%
Mar-21	0.08%	0.15%	0.32%	0.82%	1.27%	1.61%	2.24%	2.34%
Apr-21	0.06%	0.16%	0.35%	0.86%	1.31%	1.64%	2.20%	2.30%
May-21	0.05%	0.16%	0.32%	0.82%	1.28%	1.62%	2.22%	2.32%
Jun-21	0.07%	0.20%	0.39%	0.84%	1.23%	1.52%	2.09%	2.16%
Jul-21	0.08%	0.22%	0.40%	0.76%	1.07%	1.32%	1.87%	1.94%
Aug-21	0.07%	0.22%	0.42%	0.77%	1.06%	1.28%	1.83%	1.92%
Sep-21	0.08%	0.24%	0.47%	0.86%	1.16%	1.37%	1.87%	1.94%
Twelve-Month Average	0.08%	0.17%	0.31%	0.65%	0.99%	1.27%	1.84%	1.97%
Six-Month Average	0.07%	0.20%	0.39%	0.82%	1.19%	1.46%	2.01%	2.10%
Three-Month Average	0.08%	0.23%	0.43%	0.80%	1.10%	1.32%	1.86%	1.93%

Measures of the Risk-Free Rate & Corporate Bond Yields

The forecast of Treasury and Corporate yields
per the consensus of nearly 50 economists
reported in the Blue Chip Financial Forecasts dated June 1, 2021 and October 1, 2021

		Treasury					Corporate	
Year	Quarter	1-Year Bill	2-Year Note	5-Year Note	10-Year Note	30-Year Bond	Aaa Bond	Baa Bond
2021	Fourth	0.1%	0.3%	1.0%	1.5%	2.2%	2.9%	3.6%
2022	First	0.2%	0.4%	1.1%	1.7%	2.3%	3.0%	3.8%
2022	Second	0.2%	0.5%	1.2%	1.8%	2.4%	3.1%	4.0%
2022	Third	0.3%	0.5%	1.3%	1.9%	2.5%	3.2%	4.1%
2022	Fourth	0.4%	0.7%	1.4%	2.0%	2.6%	3.3%	4.2%
2023	First	0.5%	0.8%	1.5%	2.1%	2.7%	3.4%	4.3%
Long-range CONSENSUS								
2022		0.3%	0.5%	1.2%	2.0%	2.6%	3.3%	4.3%
2023		0.7%	0.9%	1.6%	2.4%	2.9%	3.7%	4.7%
2024		1.2%	1.5%	2.1%	2.7%	3.3%	4.1%	5.1%
2025		1.8%	2.0%	2.5%	3.0%	3.6%	4.5%	5.4%
2026		2.1%	2.3%	2.8%	3.2%	3.8%	4.7%	5.6%
2027		2.3%	2.5%	2.8%	3.3%	3.8%	4.7%	5.7%
Averages:								
	2023-2027	1.6%	1.8%	2.4%	2.9%	3.5%	4.3%	5.3%
	2028-2032	2.4%	2.6%	3.0%	3.3%	3.9%	4.8%	5.8%

Measures of the Market Premium

Value Line Return					
As of:	Dividend Yield		Median Appreciation Potential		Median Total Return
1-Oct-21	1.9%	+	8.78%	=	10.68%

DCF Result for the S&P 500 Composite								
D/P	(	1+.5g	)	+	g	=	k
1.41%	(	1.070	)	+	14.0%	=	15.51%

Summary			
Value Line			10.68%
S&P 500			15.51%
Average			13.10%
Risk-free Rate of Return (Rf)			2.75%
Forecast Market Premium			10.35%
Historical Market Premium			
Low Interest Rates	(Rm)	(Rf)	
1926-2020 Arith. mean	12.06%	2.85%	9.21%
Average - Forecast/Historical			9.78%

Exhibit 7.8: Size-Decile Portfolios of the NYSE/NYSE MKT/NASDAQ Long-Term Returns in Excess of CAPM
1926–2016

Size Grouping	OLS Beta	Arithmetic Mean	Return in Excess of Risk-free Rate (actual)	Return in Excess of Risk-free Rate (as predicted by CAPM)	Size Premium
Mid-Cap (3–5)	1.12	13.82%	8.80%	7.79%	1.02%
Low-Cap (6–8)	1.22	15.26%	10.24%	8.49%	1.75%
Micro-Cap (9–10)	1.35	18.04%	13.02%	9.35%	3.67%
Breakdown of Deciles 1–10					
1-Largest	0.92	11.05%	6.04%	6.38%	-0.35%
2	1.04	12.82%	7.81%	7.19%	0.61%
3	1.11	13.57%	8.55%	7.66%	0.89%
4	1.13	13.80%	8.78%	7.80%	0.98%
5	1.17	14.62%	9.60%	8.09%	1.51%
6	1.17	14.81%	9.79%	8.14%	1.66%
7	1.25	15.41%	10.39%	8.67%	1.72%
8	1.30	16.14%	11.12%	9.04%	2.08%
9	1.34	16.97%	11.96%	9.28%	2.68%
10-Smallest	1.39	20.27%	15.25%	9.66%	5.59%

Betas are estimated from monthly returns in excess of the 30-day U.S. Treasury bill total return, January 1926–December 2016. Historical riskless rate measured by the 91-year arithmetic mean income return component of 20-year government bonds (5.02%). Calculated in the context of the CAPM by multiplying the equity risk premium by beta. The equity risk premium is estimated by the arithmetic mean total return of the S&P 500 (11.95%) minus the arithmetic mean income return component of 20-year government bonds (5.02%) from 1926–2016. Source: Morningstar *Direct* and CRSP. Calculated based on data from CRSP US Stock Database and CRSP US Indices Database ©2017 Center for Research. Used with permission. All calculations performed by Duff & Phelps, LLC.

Comparable Earnings Approach
Using Non-Utility Companies with
Timeliness of 2,3,4 & 5; Safety Rank of 1,2 & 3; Financial Strength of B+, B++, A & A+;
Price Stability of 70 to 95; Betas of .80 to 1.05; and Technical Rank of 2,3,4 & 5

Company	Industry	Timeliness Rank	Safety Rank	Financial Strength	Price Stability	Beta	Technical Rank
AAON Inc	Machinery	3	3	B+	75	0.85	3
AbbVie Inc	Drug	3	3	A	75	1.00	3
ACI Worldwide Inc	IT Services	2	3	B+	70	1.00	4
Agilent Technologies	Precision Instrument	2	2	A	95	0.90	4
Alamo Group	Machinery	2	3	B+	75	1.05	3
Altria Group Inc	Tobacco	4	3	B++	85	0.95	3
AMERCO	Trucking	3	2	B++	90	0.95	3
AmerisourceBergen Corp	Med Supp Non-Invasive	2	2	A	75	0.90	3
Amphenol Corp	Electronics	3	1	A	95	1.00	4
Analog Devices Inc	Semiconductor	2	1	A+	90	0.95	3
AO Smith Corp	Machinery	3	2	B++	95	0.85	2
Archer Daniels Midland Company	Food Processing	4	1	A+	90	1.00	3
Assurant Inc	Financial Svcs. (Div.)	3	2	A	90	0.90	3
Ball Corp	Packaging & Container	3	2	B++	85	1.00	4
Bio-Techne Corp.	Biotechnology	3	2	A	75	0.85	4
Booz Allen Hamilton Holding Corporatio	Industrial Services	3	3	B++	80	0.90	3
Brady Corp	Diversified Co.	4	3	B++	85	0.95	3
Broadridge Fin'l	Information Services	3	2	B++	95	0.85	2
Brown Forman Corp (Class B)	Beverage	5	1	A	90	0.90	4
BWX Technologies	Power	3	3	B++	75	0.90	5
CACI International Inc	IT Services	3	3	B+	85	0.95	2
Caseys General Stores Inc	Retail/Wholesale Food	3	3	B+	80	0.90	4
Cboe Global Markets	Brokers & Exchanges	3	2	A	85	0.90	2
CDW Corp.	IT Services	2	3	B+	85	1.05	3
Chemed Corporation	Diversified Co.	3	2	A	95	0.85	4
Cognizant Technology Solutions Corp	IT Services	5	2	A+	80	1.00	3
Commerce Bancshares Inc	Bank (Midwest)	4	1	A	90	0.90	2
Cooper Companies Inc	Med Supp Non-Invasive	4	2	A	90	0.95	3
Copart Inc	Retail Automotive	2	2	A	75	1.00	4
CoStar Group Inc	Information Services	3	2	A+	80	0.85	4
Crown Castle International Corporation	Wireless Networking	3	2	A	90	0.85	3
CVS Caremark Corporation	Retail Store	3	2	A+	70	0.95	3
Dolby Laboratories Inc	Entertainment Tech	2	2	A	90	0.95	2
Encore Wire	Electronics	3	3	A	75	0.95	3
ESCO Technologies Inc	Diversified Co.	3	3	B+	85	1.00	3
Estee Lauder Companies Inc	Toiletries/Cosmetics	3	2	A	85	0.95	2
Expeditors International of Washington I	Industrial Services	3	1	A+	95	0.95	3
Exponent Inc.	Information Services	3	3	B+	90	0.90	4
F5 Networks	Telecom. Equipment	4	3	A	75	0.95	3
FactSet Research Systems Inc	Information Services	5	1	A+	90	1.00	4
Fastenal Co	Retail Building Supply	5	2	A+	80	0.95	3
Federal Signal Corp	Heavy Truck & Equip	3	3	B+	75	1.00	3
FirstCash Inc.	Financial Svcs. (Div.)	4	3	B++	80	0.90	4
FleetCor Technologies Inc	Financial Svcs. (Div.)	2	3	B++	70	1.05	4
Forward Air Corp	Trucking	2	3	B++	80	1.00	2
Franklin Electric Co Inc	Electrical Equipment	2	2	A	80	0.95	3
GATX Corp	Railroad	3	3	B+	80	0.95	3
Gentex Corp	Auto Parts	3	2	B++	90	0.95	3
Globus Medical Inc	Med Supp Invasive	3	3	B++	70	0.80	3
Graphic Packaging	Packaging & Container	3	3	B+	80	1.00	3
Harris Corp.	Aerospace/Defense	3	2	A+	75	0.95	2
Hershey Company	Food Processing	3	1	A+	95	0.85	3
IDEX Corporation	Machinery	2	2	B++	95	1.05	2
IDEXX Laboratories Inc	Med Supp Non-Invasive	3	3	A	75	1.00	3
Ingredion Incorporated	Food Processing	4	2	B++	90	0.95	3
Innospec Inc	Chemical (Specialty)	4	3	B++	75	1.05	2
Intuit Inc	Computer Software	2	2	A+	80	1.00	4
Iron Mountain Inc	Industrial Services	4	3	B+	80	0.90	2
J B Hunt Transport Services Inc	Trucking	3	1	A+	85	0.95	3
Jack Henry and Associates Inc	IT Services	3	1	A+	90	0.85	2
Juniper Networks Inc	Telecom. Equipment	4	2	A	85	1.00	3
Lennox International Inc	Machinery	3	3	B+	90	1.00	2
Lindsay Corporation	Machinery	2	3	B++	80	0.85	2
ManTech International Corporation	IT Services	3	3	B++	85	0.85	3
Masimo Corporation	Med Supp Non-Invasive	4	2	A	70	0.80	3
McCormick and Co	Food Processing	3	1	A+	95	0.80	5
Mercury General Corp	Insurance (Prop/Cas.)	4	3	B++	75	0.90	3
Monster Beverage Corporation	Beverage	2	2	A+	90	0.85	3
Motorola Solutions Inc	Telecom. Equipment	3	2	B++	90	0.90	3
MSA Safety	Machinery	3	2	A	80	1.00	3
MSC Industrial Direct Co Inc	Machinery	3	2	A	75	0.95	2
MSCI Inc	Information Services	2	3	B+	85	0.95	4
Nasdaq Inc.	Brokers & Exchanges	3	1	A+	90	1.05	4
Neogen Corp	Med Supp Non-Invasive	3	3	B++	70	0.80	3
Northwest Bancshares Inc	Thrift	3	3	B+	95	0.95	3
O Reilly Automotive Inc	Retail Automotive	3	3	B++	75	0.95	3
Old National Bancorp	Bank (Midwest)	4	3	B+	80	1.00	3
Omnicom Group Inc	Advertising	4	3	B+	85	1.00	3
Packaging Corp	Packaging & Container	2	2	A	85	0.95	2
Park National Corp	Bank (Midwest)	3	3	B++	80	0.80	3
PerkinElmer Inc	Precision Instrument	2	2	B++	85	0.90	3
Philip Morris International Inc	Tobacco	3	3	B++	75	0.95	3
Plexus Corp	Electronics	4	3	B+	80	1.05	4
Pool Corporation	Recreation	2	2	A	80	0.85	3
Progressive Corp.	Insurance (Prop/Cas.)	2	1	A	95	0.80	3
Quest Diagnostics Inc	Medical Services	4	2	B++	90	0.85	3
Rayonier Inc	Paper/Forest Products	3	3	B+	90	1.05	3
RLI Corp	Insurance (Prop/Cas.)	2	2	A	90	0.80	3
Rollins Inc	Industrial Services	3	2	A	90	0.85	3
Roper Tech.	Machinery	2	1	A+	95	1.00	3
Scholastic Corporation	Publishing	4	3	B++	70	1.00	3
Sensient Technologies Corp	Food Processing	3	2	B++	95	0.90	3
Sherwin Williams	Retail Building Supply	4	1	A+	90	0.95	3
Sonoco Products	Packaging & Container	4	2	A	95	1.00	2
Standard Motor Products Inc	Auto Parts	3	3	B++	75	0.85	4
Stepan Company	Chemical (Specialty)	3	3	B++	75	0.80	3
Synopsys Inc	Computer Software	2	1	A+	85	0.95	4
T Rowe Price Group Inc	Asset Management	2	1	A+	85	1.05	2
Tetra Tech	Environmental	3	3	B++	80	0.95	4
Thermo Fisher Scientific Inc	Precision Instrument	2	1	A	95	0.85	4
Toro Co	Machinery	3	2	B++	90	1.05	2
Trimas Corporation	Diversified Co.	4	3	B+	80	0.85	3
UniFirst Corp	Industrial Services	4	2	A	85	0.95	3
United Parcel Service	Air Transport	3	1	A+	85	0.80	3
Vail Resorts	Hotel/Gaming	2	3	B+	75	0.95	3
Valmont Industries	Diversified Co.	2	2	A	80	1.05	3
Viavi Solutions	Electronics	4	3	B+	70	0.95	3
Walgreens Boots	Retail Store	3	3	A	75	0.85	3
Washington Federal Inc	Thrift	3	3	B+	75	1.05	3
Waters Corp	Precision Instrument	3	2	A	90	0.95	3
Watsco Inc	Retail Building Supply	3	1	A+	95	0.85	3
West Pharmaceutical Services Inc	Med Supp Non-Invasive	4	2	A	85	0.80	4
Western Union Company	Financial Svcs. (Div.)	5	3	B+	95	0.80	3
Wiley John and Sons Inc (Class A)	Publishing	3	3	B+	75	0.85	3
Xylem Inc	Machinery	2	2	B++	85	1.05	3
Yum Brands Inc	Restaurant	4	2	B++	90	1.05	2
Zoetis Inc	Drug	3	2	B++	90	1.00	3
Average		3	2	B++	84	0.93	3
Gas Group	Average	4	2	A	87	0.88	3

Source of Information: Value Line Investment Survey for Windows, January 2021

Comparable Earnings Approach
Five -Year Average Historical Earned Returns
for Years 2016-2020 and
Projected 3-5 Year Returns

Company	2016	2017	2018	2019	2020	Average	Projected 2024-26
AAON Inc	25.9%	21.1%	17.2%	18.5%	22.5%	21.0%	22.5%
AbbVie Inc	NMF	NMF	NMF	NMF	NMF	-	NMF
ACI Worldwide Inc	17.2%	0.7%	6.6%	5.9%	6.0%	7.3%	10.0%
Agilent Technologies	15.4%	15.9%	19.9%	20.8%	21.0%	18.6%	20.0%
Alamo Group	10.3%	12.1%	14.5%	11.0%	9.1%	11.4%	13.0%
Altria Group Inc	46.4%	42.5%	51.0%	NMF	NMF	46.6%	NMF
AMERCO	15.2%	9.0%	10.0%	7.0%	12.6%	10.8%	9.0%
AmerisourceBergen Corp	60.4%	63.2%	48.8%	52.2%	NMF	56.2%	NMF
Amphenol Corp	23.3%	24.7%	30.0%	25.5%	22.3%	25.2%	26.5%
Analog Devices Inc	18.6%	16.6%	20.4%	16.3%	15.2%	17.4%	19.0%
AO Smith Corp	21.5%	22.9%	26.2%	22.2%	18.7%	22.3%	28.0%
Archer Daniels Midland Company	7.4%	6.6%	9.5%	7.2%	8.9%	7.9%	9.5%
Assurant Inc	13.8%	12.2%	4.9%	6.8%	7.4%	9.0%	7.5%
Ball Corp	7.7%	7.7%	13.1%	19.2%	17.9%	13.1%	20.5%
Bio-Techne Corp.	11.9%	9.2%	9.8%	8.2%	11.0%	10.0%	15.5%
Booz Allen Hamilton Holding Corporation	44.0%	55.0%	58.8%	56.4%	50.8%	53.0%	30.0%
Brady Corp	13.3%	13.7%	14.9%	15.4%	13.0%	14.1%	12.5%
Broadridge Fin'l	29.4%	32.6%	46.1%	49.1%	43.7%	40.2%	34.0%
Brown Forman Corp (Class B)	48.8%	56.7%	50.7%	41.9%	29.1%	45.4%	53.0%
BWX Technologies	NMF	71.1%	96.3%	60.4%	45.1%	68.2%	38.0%
CACI International Inc	8.9%	9.1%	9.4%	11.2%	12.1%	10.1%	12.0%
Caseys General Stores Inc	14.9%	11.2%	14.5%	16.1%	16.2%	14.6%	15.5%
Cboe Global Markets	58.4%	12.9%	13.1%	11.1%	13.9%	21.9%	12.0%
CDW Corp.	40.6%	53.2%	65.9%	76.7%	60.8%	59.4%	64.5%
Chemed Corporation	20.7%	26.1%	33.9%	31.7%	32.9%	29.1%	27.0%
Cognizant Technology Solutions Corp	19.3%	21.0%	23.4%	20.3%	17.0%	20.2%	17.5%
Commerce Bancshares Inc	11.0%	11.8%	14.8%	13.4%	10.4%	12.3%	12.0%
Cooper Companies Inc	10.1%	11.7%	10.3%	12.9%	6.2%	10.2%	12.5%
Copart Inc	33.0%	27.6%	26.3%	30.1%	24.5%	28.3%	32.0%
CoStar Group Inc	8.3%	5.8%	10.0%	11.0%	7.1%	8.4%	11.0%
Crown Castle International Corporation	21.5%	3.6%	5.6%	8.2%	11.2%	10.0%	9.5%
CVS Caremark Corporation	17.2%	16.1%	12.7%	14.5%	14.2%	14.9%	12.5%
Dolby Laboratories Inc	9.4%	9.4%	12.6%	11.1%	9.5%	10.4%	13.0%
Encore Wire	5.9%	10.5%	10.8%	7.5%	9.1%	8.8%	9.5%
ESCO Technologies Inc	8.3%	8.6%	9.0%	9.9%	7.5%	8.7%	10.0%
Estee Lauder Companies Inc	31.2%	28.5%	36.2%	45.1%	38.4%	35.9%	54.0%
Expeditors International of Washington Inc	23.4%	22.7%	31.1%	26.9%	26.2%	26.1%	32.0%
Exponent Inc.	17.4%	14.3%	23.0%	23.5%	22.8%	20.2%	29.5%
F5 Networks	30.9%	34.2%	35.3%	24.3%	13.8%	27.7%	16.0%
FactSet Research Systems Inc	49.7%	46.1%	50.8%	52.5%	41.6%	48.1%	42.5%
Fastenal Co	25.8%	27.6%	32.7%	29.7%	31.4%	29.4%	41.0%
Federal Signal Corp	10.8%	11.2%	16.5%	17.2%	14.7%	14.1%	14.5%
FirstCash Inc.	4.1%	7.9%	11.6%	12.2%	8.3%	8.8%	12.0%
FleetCor Technologies Inc	21.4%	21.7%	24.3%	24.1%	21.0%	22.5%	32.5%
Forward Air Corp	13.0%	13.4%	16.6%	15.1%	9.4%	13.5%	13.5%
Franklin Electric Co Inc	12.8%	12.5%	14.6%	12.3%	12.1%	12.9%	14.5%
GATX Corp	17.6%	10.4%	11.2%	10.9%	6.5%	11.3%	9.0%
Gentex Corp	18.2%	18.0%	23.5%	21.9%	17.7%	19.9%	28.5%
Globus Medical Inc	12.5%	12.2%	13.2%	11.1%	6.8%	11.2%	12.0%
Graphic Packaging	21.6%	23.2%	11.9%	13.2%	11.7%	16.3%	22.5%
Harris Corp.	-	-	-	NMF	5.4%	5.4%	13.0%
Hershey Company	NMF	NMF	80.8%	70.1%	57.2%	69.4%	29.0%
IDEX Corporation	18.5%	17.9%	21.1%	19.6%	15.6%	18.5%	20.0%
IDEXX Laboratories Inc	-	-	-	NMF	92.0%	92.0%	38.5%
Ingredion Incorporated	20.5%	19.5%	20.8%	16.4%	13.6%	18.2%	17.0%
Innospec Inc	12.4%	7.8%	10.3%	12.2%	3.0%	9.1%	13.0%
Intuit Inc	86.5%	84.9%	62.2%	47.5%	40.6%	64.3%	21.0%
Iron Mountain Inc	13.7%	13.3%	16.8%	20.0%	30.1%	18.8%	NMF
J B Hunt Transport Services Inc	30.6%	22.6%	29.7%	24.9%	19.5%	25.5%	16.0%
Jack Henry and Associates Inc	25.0%	23.8%	22.3%	19.0%	19.1%	21.8%	23.5%
Juniper Networks Inc	12.9%	17.3%	13.8%	13.0%	11.4%	13.7%	31.0%
Lennox International Inc	812.8%	674.5%	-	NMF	NMF	743.7%	NMF
Lindsay Corporation	11.4%	8.6%	11.4%	5.8%	12.9%	10.0%	12.5%
ManTech International Corporation	4.5%	4.7%	5.9%	7.6%	7.6%	6.1%	9.0%
Masimo Corporation	21.5%	24.2%	20.0%	16.8%	17.1%	19.9%	15.5%
McCormick and Co	29.7%	21.4%	20.9%	20.8%	19.4%	22.4%	16.5%
Mercury General Corp	5.4%	5.1%	6.2%	8.0%	15.1%	8.0%	14.0%
Monster Beverage Corporation	21.4%	20.0%	27.5%	26.6%	24.6%	24.0%	23.0%
Motorola Solutions Inc	-	-	-	-	-	-	NMF
MSA Safety	18.8%	23.6%	27.7%	25.9%	22.4%	23.7%	24.5%
MSC Industrial Direct Co Inc	21.1%	18.7%	20.8%	20.0%	20.1%	79.0%	22.0%
MSCI Inc	82.1%	75.8%	-	NMF	NMF	13.8%	NMF
Nasdaq Inc.	11.4%	11.7%	14.9%	14.8%	16.0%	13.8%	10.5%
Neogen Corp	9.0%	9.3%	10.3%	9.4%	8.2%	9.2%	8.0%
Northwest Bancshares Inc	4.2%	7.6%	8.4%	8.2%	4.9%	6.7%	9.5%
O Reilly Automotive Inc	63.8%	NMF	NMF	NMF	NMF	63.8%	NMF
Old National Bancorp	7.4%	6.0%	7.1%	8.4%	7.6%	7.3%	8.0%
Omnicom Group Inc	53.1%	46.0%	52.1%	46.9%	30.7%	45.8%	28.5%
Packaging Corp	25.5%	25.0%	27.6%	22.7%	16.9%	23.5%	17.0%
Park National Corp	11.6%	11.3%	13.3%	10.6%	12.3%	11.8%	10.5%
PerkinElmer Inc	13.3%	12.9%	15.6%	16.3%	24.9%	16.6%	14.5%
Philip Morris International Inc	NMF	NMF	NMF	NMF	NMF	-	NMF
Plexus Corp	9.9%	10.9%	11.9%	12.3%	12.5%	11.5%	12.5%
Pool Corporation	72.6%	74.9%	104.9%	63.8%	57.4%	74.7%	45.0%
Progressive Corp.	11.8%	16.7%	27.2%	23.1%	26.0%	21.0%	19.5%
Quest Diagnostics Inc	15.9%	16.2%	16.8%	15.9%	22.6%	17.5%	16.5%
Rayonier Inc	15.0%	9.3%	6.6%	4.1%	2.3%	7.5%	13.5%
RLI Corp	11.3%	8.7%	11.4%	11.8%	10.4%	10.7%	11.0%
Rollins Inc	29.4%	29.2%	32.5%	24.9%	27.7%	28.7%	34.0%
Roper Tech.	11.4%	11.0%	15.9%	14.4%	12.9%	13.1%	12.0%
Scholastic Corporation	4.7%	5.0%	3.9%	2.6%	NMF	4.1%	5.5%
Sensient Technologies Corp	17.2%	17.7%	18.3%	14.2%	11.7%	15.8%	13.0%
Sherwin Williams	60.3%	38.7%	47.1%	47.9%	62.6%	51.3%	40.0%
Sonoco Products	18.1%	16.5%	19.4%	19.8%	18.2%	18.4%	17.0%
Standard Motor Products Inc	14.2%	13.5%	12.2%	13.7%	14.6%	13.6%	14.0%
Stepan Company	13.6%	12.4%	14.4%	11.6%	12.9%	13.0%	13.0%
Synopsys Inc	14.6%	16.4%	17.2%	17.2%	17.6%	16.6%	24.5%
T Rowe Price Group Inc	24.6%	26.4%	29.0%	30.0%	31.0%	28.2%	32.5%
Tetra Tech	12.8%	13.3%	15.4%	17.8%	17.0%	15.3%	22.0%
Thermo Fisher Scientific Inc	9.4%	8.8%	10.7%	11.5%	18.5%	11.8%	16.5%
Toro Co	42.0%	43.4%	40.7%	31.9%	29.6%	37.5%	40.5%
Trimas Corporation	11.6%	11.8%	13.1%	9.5%	11.8%	11.6%	14.5%
UniFirst Corp	8.5%	7.4%	10.2%	10.0%	7.8%	8.8%	8.5%
United Parcel Service	NMF	NMF	NMF	NMF	NMF	-	NMF
Vail Resorts	17.1%	13.4%	23.9%	20.1%	7.5%	16.4%	18.5%
Valmont Industries	18.4%	14.2%	16.1%	13.8%	14.8%	15.5%	14.5%
Viavi Solutions	13.1%	11.8%	14.8%	21.5%	24.1%	17.1%	15.5%
Walgreens Boots	16.8%	20.0%	23.0%	23.5%	20.2%	20.7%	21.5%
Washington Federal Inc	8.3%	8.7%	10.2%	10.3%	8.6%	9.2%	8.0%
Waters Corp	22.7%	27.0%	39.9%	39.9%	NMF	32.4%	24.0%
Watsco Inc	18.2%	15.3%	18.0%	17.1%	18.1%	17.3%	24.0%
West Pharmaceutical Services Inc	12.9%	11.8%	14.8%	15.4%	18.7%	14.7%	20.0%
Western Union Company	91.4%	-	-	NMF	416.8%	254.1%	NMF
Wiley John and Sons Inc (Class A)	17.4%	16.6%	14.2%	NMF	13.6%	15.5%	14.0%
Xylem Inc	11.9%	17.1%	18.9%	18.5%	12.6%	15.8%	13.5%
Yum Brands Inc	-	-	-	-	-	-	NMF
Zoetis Inc	65.4%	66.8%	69.8%	64.8%	48.9%	63.1%	44.5%
Average						31.3%	20.2%
Median						16.6%	16.0%
Average (excluding companies with values >20%)						12.5%	12.9%

Comparable Earnings Approach

Screening Parameters

Timeliness Rank

The rank for a stock's probable relative market performance in the year ahead. Stocks ranked 1 (Highest) or 2 (Above Average) are likely to outpace the year-ahead market. Those ranked 4 (Below Average) or 5 (Lowest) are not expected to outperform most stocks over the next 12 months. Stocks ranked 3 (Average) will probably advance or decline with the market in the year ahead. Investors should try to limit purchases to stocks ranked 1 (Highest) or 2 (Above Average) for Timeliness.

Safety Rank

A measure of potential risk associated with individual common stocks rather than large diversified portfolios (for which Beta is good risk measure). Safety is based on the stability of price, which includes sensitivity to the market (see Beta) as well as the stock's inherent volatility, adjusted for trend and other factors including company size, the penetration of its markets, product market volatility, the degree of financial leverage, the earnings quality, and the overall condition of the balance sheet. Safety Ranks range from 1 (Highest) to 5 (Lowest). Conservative investors should try to limit purchases to equities ranked 1 (Highest) or 2 (Above Average) for Safety.

Financial Strength

The financial strength of each of the more than 1,600 companies in the VS II data base is rated relative to all the others. The ratings range from A++ to C in nine steps. (For screening purposes, think of an A rating as "greater than" a B). Companies that have the best relative financial strength are given an A++ rating, indicating ability to weather hard times better than the vast majority of other companies. Those who don't quite merit the top rating are given an A+ grade, and so on. A rating as low as C++ is considered satisfactory. A rating of C+ is well below average, and C is reserved for companies with very serious financial problems. The ratings are based upon a computer analysis of a number of key variables that determine (a) financial leverage, (b) business risk, and (c) company size, plus the judgment of Value Line's analysts and senior editors regarding factors that cannot be quantified across-the-board for companies. The primary variables that are indexed and studied include equity coverage of debt, equity coverage of intangibles, "quick ratio", accounting methods, variability of return, fixed charge coverage, stock price stability, and company size.

Price Stability Index

An index based upon a ranking of the weekly percent changes in the price of the stock over the last five years. The lower the standard deviation of the changes, the more stable the stock. Stocks ranking in the top 5% (lowest standard deviations) carry a Price Stability Index of 100; the next 5%, 95; and so on down to 5. One standard deviation is the range around the average weekly percent change in the price that encompasses about two thirds of all the weekly percent change figures over the last five years. When the range is wide, the standard deviation is high and the stock's Price Stability Index is low.

Beta

A measure of the sensitivity of the stock's price to overall fluctuations in the New York Stock Exchange Composite Average. A Beta of 1.50 indicates that a stock tends to rise (or fall) 50% more than the New York Stock Exchange Composite Average. Use Beta to measure the stock market risk inherent in any diversified portfolio of, say, 15 or more companies. Otherwise, use the Safety Rank, which measures total risk inherent in an equity, including that portion attributable to market fluctuations. Beta is derived from a least squares regression analysis between weekly percent changes in the price of a stock and weekly percent changes in the NYSE Average over a period of five years. In the case of shorter price histories, a smaller time period is used, but two years is the minimum. The Betas are periodically adjusted for their long-term tendency to regress toward 1.00.

Technical Rank

A prediction of relative price movement, primarily over the next three to six months. It is a function of price action relative to all stocks followed by Value Line. Stocks ranked 1 (Highest) or 2 (Above Average) are likely to outpace the market. Those ranked 4 (Below Average) or 5 (Lowest) are not expected to outperform most stocks over the next six months. Stocks ranked 3 (Average) will probably advance or decline with the market. Investors should use the Technical and Timeliness Ranks as complements to one another.

IN THE MATTER OF THE PETITION OF ELIZABETHTOWN GAS COMPANY FOR APPROVAL OF INCREASED BASE TARIFF RATES AND CHARGES FOR GAS SERVICE, CHANGES TO DEPRECIATION RATES AND OTHER TARIFF REVISIONS

BPU DOCKET NO. GR21__________

DIRECT TESTIMONY

OF

TIMOTHY S. LYONS

Cash Working Capital

On Behalf Of
Elizabethtown Gas Company

Exhibit P-8

December 28, 2021

TABLE OF CONTENTS

ELIZABETHTOWN GAS COMPANY
DIRECT TESTIMONY OF
TIMOTHY S. LYONS

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

Q. PLEASE STATE YOUR NAME AND BUSINESS ADDRESS.

A. My name is Timothy S. Lyons. My business address is 1900 West Park Drive, Suite 250, Westborough, Massachusetts 01581.

Q. PLEASE DESCRIBE YOUR CURRENT POSITION.

A. I am a Partner at ScottMadden, Inc. ("ScottMadden").

Q. PLEASE DESCRIBE YOUR WORK EXPERIENCE AND QUALIFICATIONS.

A. I have more than 30 years of experience in the energy industry. I started my career in 1985 at Boston Gas Company, eventually becoming Director of Rates and Revenue Analysis. In 1993, I moved to Providence Gas Company, eventually becoming Vice President of Marketing and Regulatory Affairs. Starting in 2001, I held a number of management consulting positions in the energy industry first at KEMA and then at Quantec, LLC. In 2005, I became Vice President of Sales and Marketing at Vermont Gas Systems, Inc. before joining Sussex Economic Advisors, LLC ("Sussex") in 2013. Sussex was acquired by ScottMadden in 2016.

Q. PLEASE DESCRIBE YOUR EDUCATIONAL BACKGROUND.

A. I hold a bachelor's degree from St. Anselm College, a master's degree in Economics from The Pennsylvania State University, and a master's degree in Business Administration from Babson College.

Q. HAVE YOU PREVIOUSLY SPONSORED TESTIMONY BEFORE THE NEW JERSEY BOARD OF PUBLIC UTILITIES ("BPU" OR "BOARD")?

A. Yes, I previously sponsored testimony before the Board. A summary of my testimony experience along with my professional and educational experience is included in Schedule TSL-1.

Q. WHAT IS THE PURPOSE OF YOUR TESTIMONY?

A. The purpose of my testimony is to sponsor the results of the lead-lag study conducted on behalf of Elizabethtown Gas Company ("Elizabethtown" or "Company"), a subsidiary of South Jersey Industries, Inc. ("SJI"). The Company submits the lead-lag study as part of its base rate filing before the Board. The lead-lag study was used to determine the Company's Cash Working Capital ("CWC") requirement, which is included in the Company's rate base.

Q. ARE YOU SPONSORING ANY SCHEDULES IN CONNECTION WITH YOUR TESTIMONY?

A. Yes. I am sponsoring the following schedules that were prepared by me or under my direction:

- Schedule TSL-1 – Qualifications;
- Schedule TSL-2 – Elizabethtown Gas Company – Summary of the Cash Working Capital Requirement; and
- Schedule TSL-3 – Elizabethtown Gas Company – Workpapers supporting the Lead-Lag Study.

II. OVERVIEW OF TESTIMONY

Q. PLEASE DEFINE THE TERM "WORKING CAPITAL" AS A RATE BASE COMPONENT.

A. The term "working capital" refers to the net funds required by the Company to finance goods and services used to provide service to customers from the time those goods and services are paid for by the Company to the time that payment is received from customers. Goods and services considered in the lead-lag study include: operations and maintenance ("O&M") expenses, including labor and non-labor expenses; federal, state, and local taxes; and employment taxes.

Q. HOW WAS THE COMPANY'S CASH WORKING CAPITAL REQUIREMENT DETERMINED?

A. The Company's cash working capital requirement was determined by applying the results of the lead-lag study to forecasted post-test year adjusted expenses. The lead-lag study compares differences between the Company's revenue lag and expense leads. The revenue lag represents the number of days from the time customers receive their natural gas service to the time customers pay for their natural gas service, *i.e.*, when the funds are available to the Company. The longer the revenue lag, the more cash the Company needs to finance its day-to-day operations. The expense lead represents the number of days from the time the Company receives goods and services used to provide natural gas service to the time payments are made for those goods and services, *i.e.*, when the funds are no longer available to the Company. The longer the expense lead, the less cash the Company needs to fund its day-to-day operations. Together, the revenue lag and expense leads are used to measure the lead-lag days. The lead-lag days are then applied to the Company's forecasted post-test year adjusted expenses to derive the CWC requirement, which is included in the Company's rate base.

III. LEAD-LAG STUDY APPROACH

Q. PLEASE DESCRIBE THE DATA USED IN THE LEAD-LAG STUDY.

A. The lead-lag study was based on data from the period July 1, 2020 through June 30, 2021. The data included customer meter reading and billing schedules, O&M expenses, and federal, state, local and employment taxes. The data generally included service periods, payment dates, and payment amounts.

A. Revenue Lag

Q. PLEASE DESCRIBE DEVELOPMENT OF THE REVENUE LAG.

A. The revenue lag was measured as the sum of three components: (1) the service lag; (2) the billing lag; and (3) the collection lag.

Q. WHAT IS THE SERVICE LAG?

A. The service lag measures the average number of days in the service period; *i.e.*, the time between the start and end of the billing month. Meters are read at the end of the billing month. The service lag in this lead-lag study was based on the midpoint of the service period, which reflects that natural gas is delivered evenly over the service period.

Q. WHAT IS THE BILLING LAG?

A. The billing lag measures the number of days from the time meters are read to the time bills are recorded and sent to customers. The billing lag includes time for review and validation of billed usage and dollars. The billing lag in this lead-lag study was based on the Company's meter reading schedule.

Q. WHAT IS THE COLLECTION LAG?

A. The collection lag measures the number of days from the time bills are recorded and sent to customers to the time customer payments are received (i.e., funds are available to the Company). The collection lag in this lead-lag study was based on monthly accounts receivable balances and billed revenue data. The data were used to calculate the average number of days to receive customer payments. The monthly accounts receivable balances reflect an adjustment to remove the amounts related to bad debt created by COVID-19 because recovery of those amounts will be addressed in a separate filing to be made with the Board no later than 60 days after December 31, 2022 pursuant to the Board's Order dated September 21, 2021 in BPU Docket No. AO20060471.

Q. WHAT IS THE TOTAL REVENUE LAG USED IN THE LEAD-LAG STUDY?

A. The total revenue lag used in the lead-lag study is 57.23 days based on the sum of the three components described above and as shown in Schedule TSL-3, page 1 of 6.

B. Expense Leads

1. Operation and Maintenance Expenses

Q. PLEASE DESCRIBE DEVELOPMENT OF LEAD DAYS FOR O&M EXPENSES.

A. Lead days for O&M expenses were measured separately for the following categories: (1) purchased gas costs; (2) salaries and wages; (3) retirement savings plan expenses; (4) group insurance; (5) uncollectible expenses; (6) service company charges; and (7) other O&M expenses.

Q. HOW WERE LEAD DAYS DETERMINED FOR PURCHASED GAS EXPENSES?

A. Lead days for purchased gas costs were based on a review of the Company's payment schedules. Lead days were measured as the number of days from the midpoint of the service period to the payment date, converted to "dollar days" to reflect a weighting of expense amounts and then summed across the months.

Q. HOW WERE LEAD DAYS DETERMINED FOR REGULAR PAYROLL EXPENSES?

A. Lead days for regular payroll expenses were based on the Company's payroll process, which pays employees on a bi-weekly or weekly basis. Lead days were measured as the number of days from the midpoint of each pay period to the payment date. Bi-weekly and weekly lead days were then converted to "dollar days" to reflect a weighting of expense amounts and then summed across payroll expenses.

Q. DID THE STUDY ADJUST FOR VARIABLE COMPENSATION EXPENSES?

A. Yes. Lead days for the Company's variable compensation expenses were based on the number of days from the midpoint of the performance period to the payment date. Specifically, lead days for the Company's variable compensation expenses were measured as the number of days from the midpoint of the January 2020 through December 2020 performance period to the March 11, 2021 payment date.

Q. HOW WERE LEAD DAYS DETERMINED FOR RETIREMENT SAVINGS PLAN EXPENSES?

A. Lead days for retirement savings plan expenses were based on the timing of the Company's matching payments of employees' retirement contributions to their retirement savings plan. Lead days were measured as the number of days from the midpoint of the payroll period to the contribution date.

Q. HOW WERE LEAD DAYS DETERMINED FOR GROUP INSURANCE EXPENSES?

A. Lead days for group insurance expenses were based on a review of insurance expenses. Lead days were measured as the number of days from the midpoint of the service period to the payment date.

Q. HOW WERE LEAD DAYS DETERMINED FOR UNCOLLECTIBLE EXPENSES?

A. Lead days for uncollectible expenses were based on the Company's accounting process, which creates a reserve account for uncollectible expenses prior to the actual write-off. Lead days for uncollectible expenses were measured as the average balance of the reserve account over the period June 1, 2020 through June 30, 2021 divided by uncollectible expenses over the period July 1, 2020 through June 30, 2021. The approach reflects a change to the most recent lead-lag study in Docket No. GR19040486 to better align with the Company's accounting process.

Q. HOW WERE LEAD DAYS DETERMINED FOR SJI SERVICES COMPANY (AFFILIATE) EXPENSES?

A. Lead days for the SJI Services Company (affiliate) expenses were based on the payment schedule. SJI Services Company payments are made in the month following the service period. Lead days for SJI Service Company expenses were measured as the number of days from the midpoint of the service period to the payment date.

Q. HOW WERE LEAD DAYS DETERMINED FOR OTHER O&M EXPENSES?

A. Lead days for Other O&M expenses were based on the sum of two components: (1) lead days from the service period to the invoice date; and (2) lead days from the invoice date to the payment date.

Lead days from the service period to the invoice date were based on a stratified sample of invoices paid by the Company over the period July 1, 2020 through June 30, 2021. Lead days were measured for each invoice in the sample as the number of days from the midpoint of the service period to the invoice date. Invoices were then converted to "dollar days" to reflect a weighting by expense amount and then summed by invoice amounts to determine the lead days. The approach is consistent with the approach used in the Company's most recent lead-lag study in Docket No. GR19040486. The study relies on a sample of invoices to measure the lead days because the service periods were not readily available electronically and required detailed inspection of individual invoices.

Lead days from the invoice date to the payment date were based on the full population of invoices paid by the Company over the period July 1, 2020 through June 30, 2021. Lead days were measured for each invoice as the number of days from the invoice date to the payment date. Invoices were then converted to "dollar days" to reflect a weighting by expense amount and then summed by invoice amounts to determine the lead days. The approach is a change from the approach used in the Company's most recent lead-lag study in Docket No. GR 19040486. The prior approach relied on the sample of invoices to calculate the lead days from invoice date to payment date while the current approach relies on the full population of invoices because the invoice dates and payment dates were readily available electronically for the full population of invoices.

2. Current Income Tax Expense

Q. HOW WERE LEAD DAYS DETERMINED FOR FEDERAL INCOME TAXES?

A. Lead days for federal income taxes were based on due dates for tax payments: September 15, December 15, April 15, and June 15. Lead days for federal income taxes were measured as the number of days from the midpoint of the taxing period (*i.e.*, the calendar year) to the due dates.

Q. HOW WERE LEAD DAYS DETERMINED FOR CORPORATE BUSINESS TAXES?

A. Lead days for corporate business taxes were based on due dates for tax payments: September 15, December 15, April 15, and June 15. Lead days for corporate business taxes were measured as the number of days from the midpoint of the taxing period (*i.e.*, the calendar year) to the due dates.

3. Taxes Other than Income Taxes

Q. PLEASE DESCRIBE DEVELOPMENT OF LEAD DAYS FOR TAXES OTHER THAN INCOME TAXES?

A. Lead days for Taxes Other Than Income Taxes were measured separately for the following categories: (1) payroll-related taxes (FICA, federal unemployment, and state unemployment); and (2) property taxes.

Q. HOW WERE LEAD DAYS DETERMINED FOR EACH OF THESE TAXES?

A. Lead days for FICA taxes were measured as the number of days from the midpoint of the pay period to the payment date. Lead days for federal unemployment taxes were measured as the number of days from the liability date at the end of each quarter to the due date. Lead days for state unemployment taxes were measured as the number of days from the liability date at the end of each quarter to the due date. Lead days for property taxes were measured as the number of days from the midpoint of the taxing period to the payment date.

4. Return on Invested Capital and Interest Expenses

Q. DID YOU CALCULATE AN EXPENSE LEAD ASSOCIATED WITH RETURN ON INVESTED CAPITAL AND INTEREST PAYMENTS?

A. Yes. Consistent with the Board's practice, the return on invested capital is included in the lead-lag study.[1] A zero expense lead was assigned to the return on common equity, recognizing returns are earned and become the property of the utility's investors at the time services are rendered.

Based on available data, lead days for interest payments related to long-term borrowings, short-term commercial paper borrowings, and customer deposits were measured as the number of days from the midpoint of the service period to the payment date for the period July 1, 2020 through June 30, 2021.

5. Deferred Income Taxes

Q. DID YOU INCLUDE DEFERRED INCOME TAXES IN THE LEAD-LAG STUDY?

A. No. It has been the Board's practice to exclude deferred taxes from lead-lag studies.[2] As such, no deferred income taxes are included in the analysis. However, the Company has included its excess deferred tax amortization with a zero-expense lead because this item is deducted from rate base when the amortization amount is recognized.

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[1] *See* "Order Adopting Initial Decision with Modifications and Clarifications," BPU Docket No. ER12111052, March 26, 2015, at 14.

[2] *See* "Order Adopting Initial Decision with Modifications and Clarifications," BPU Docket No. ER12111052, March 26, 2015, at 13-14.

6. Depreciation and Other Expense Items

Q. PLEASE DESCRIBE HOW YOU CALCULATED THE EXPENSE LEAD ASSOCIATED WITH DEPRECIATION AND AMORTIZATION, PENSION, AND OTHER POST EMPLOYMENT BENEFITS ("OPEB") EXPENSES.

A. Depreciation and amortization expenses, pension expenses, and OPEB expenses are included with a zero-expense lead because these items are deducted from rate base when the expenses are recorded. This is consistent with the prior practice of the Board.[3]

C. Other Adjustments

Q. PLEASE DESCRIBE ANY ADDITIONAL ADJUSTMENTS MADE TO THE CASH WORKING CAPITAL REQUIREMENT.

A. There was an adjustment for sales and use tax balances. The Company collects these taxes from customers, outside of base rates, and pays the tax to the State. The tax is not a Company expense because the Company only transmits the payments from customers to the State. However, the Company is required to make a substantial prepayment on sales tax, so it has an average prepayment balance on its books. There is a similar adjustment for Universal Service Fund and Lifeline funds, which are also recovered outside base rates.

Q. PLEASE EXPLAIN THE TREATMENT OF EMPLOYEE DEDUCTIONS IN THE CALCULATION OF THE CASH WORKING CAPITAL REQUIREMENT.

A. Employee deductions associated with the employee portion of payroll withholdings are a source of cash working capital to the Company from the time the employee deductions are withheld from employee payroll to the time employee deductions are used to pay for the

[3] *See* "Order Adopting Initial Decision with Modifications and Clarifications," BPU Docket No. ER12111052, March 26, 2015, at 13.

items for which they were withheld. Therefore, miscellaneous employee deductions are deducted from the cash working capital requirement.

IV. CONCLUSION

Q. WHAT WERE THE RESULTS OF THE LEAD-LAG STUDY?

A. The results of the lead-lag study are included in Schedule TSL-2. As shown therein, the Company's CWC requirement is $31,959,285.

Q. ARE THE RESULTS OF THIS LEAD-LAG STUDY REASONABLE?

A. Yes, the study provides an accurate assessment of the Company's actual cash working capital requirements. The resulting cash working capital requirement should be included in the Company's rate base.

Q. DOES THIS CONCLUDE YOUR TESTIMONY?

A. Yes, it does.

scottmadden
MANAGEMENT CONSULTANTS

Summary of Qualifications

Tim Lyons is a partner with ScottMadden with more than 30 years of experience in the energy industry. Tim has held senior positions at several gas utilities and energy consulting firms. His experience includes rates and regulatory support, sales and marketing, customer service and strategy development. Prior to joining ScottMadden, Tim served as Vice President of Sales and Marketing for Vermont Gas. He has also served as Vice President of Marketing and Regulatory Affairs for Providence Gas Company, Director of Rates at Boston Gas Company, and Project Director at Quantec, LLC, an energy consulting firm.

Tim has sponsored testimony before 20 state regulatory commissions. Tim holds a B.A. from St. Anselm College, an M.A. in Economics from The Pennsylvania State University, and an M.B.A. from Babson College.

Areas of Specialization

- Regulation and Rates
- Retail Energy
- Utilities
- Natural Gas

Capabilities

- Regulatory Strategy and Rate Case Support
- Strategic and Business Planning
- Capital Project Planning
- Process Improvements

Articles and Speeches

- "Country Strong: Vermont Gas shares its comprehensive effort to expand natural gas service into rural communities." ***American Gas Association***, June 2011 (with Don Gilbert).
- "Talking Safety With Vermont Gas." ***American Gas Association***, February 2009 (with Dave Attig).
- "Consumers Say 'Act Now' To Stabilize Prices." ***Power & Gas Marketing***, September/ October 2001 (with Jim DeMetro and Gerry Yurkevicz).
- "Rate Reclassification: Who Buys What and When." ***Public Utilities Fortnightly***, October 15, 1991 (with John Martin).

Sponsor	Date	Docket No.	Subject
Regulatory Commission of Alaska			
ENSTAR Natural Gas Company	06/16	Docket No. U-16-066	Adopted and sponsored testimony supporting a lead-lag study for a general rate case proceeding.
Arkansas Public Service Commission			
Liberty Utilities (Pine Bluff Water)	10/18	Docket No. 18-027-U	Sponsored testimony supporting the cost of service, rate design and bill impact studies for a general rate case proceeding.
California Public Utilities Commission			
Liberty Utilities (CalPeco Electric)	5/21	Docket No. A 21-05-017	Sponsored testimony supporting the lead-lag study/cash working capital, marginal cost study, rate design and bill impact analysis for a general rate case proceeding.
Southwest Gas Corporation (Southern California, Northern California and South Lake Tahoe jurisdictions)	8/19	Docket No. A.19-08-015	Sponsored testimony on behalf of three separate rate jurisdictions supporting revenue requirements, lead-lag/ cash working capital, and class cost of service, rate design and bill impact analysis for a general rate case proceeding.
Connecticut Public Utilities Regulatory Authority			
Yankee Gas Company	07/14	Docket No. 13-06-02	Sponsored report and testimony supporting the review and evaluation of gas expansion policies, procedures and analysis.
Illinois Commerce Commission			
Liberty Utilities (Midstates Natural Gas)	07/16	Docket No. 16-0401	Sponsored testimony supporting the cost of service, rate design and bill impact studies for a general rate case proceeding. The testimony includes proposal for new commercial classes and a decoupling mechanism.
Iowa Utilities Board			
Liberty Utilities (Midstates Natural Gas)	07/16	Docket No. RPU-2016-0003	Sponsored testimony supporting the cost of service, rate design and bill impact studies for a general rate case proceeding. The testimony includes proposal for new commercial classes.
Kansas Corporation Commission			
The Empire District Electric Company	12/18	Docket No. 19-EPDE-223-RTS	Sponsored testimony supporting cost of service, rate design, bill impact and lead-lag studies for a general rate case proceeding.
Maine Public Utilities Commission			
Maine Water Company	03/21	Docket No. 2021-00053	Sponsored testimony supporting a proposed rate smoothing mechanism.
Northern Utilities, Inc. d/b/a Unitil	06/19	Docket No. 2019-00092	Sponsored testimony supporting a proposed capital investment cost recovery mechanism.
Northern Utilities, Inc. d/b/a Unitil	06/15	Docket No. 2015-00146	Sponsored testimony supporting the proposed gas expansion program, including a zone area surcharge.
Maryland Public Service Commission			
Sandpiper Energy, a Chesapeake Utilities company	12/15	Case No. 9410	Sponsored testimony supporting the cost of service, rate design and bill impact studies for a general rate case proceeding. The testimony includes proposal for new residential and commercial classes.

Sponsor	Date	Docket No.	Subject
Massachusetts Department of Public Utilities			
Liberty Utilities (New England Gas Company)	08/20	Docket No. DPU 20-92	Sponsored the Long-Range Forecast and Supply Plan filing for the five-year forecast period 2020/2021 through 2024/2025.
Liberty Utilities (New England Gas Company)	07/18	Docket No. DPU 18-68	Sponsored the Long-Range Forecast and Supply Plan filing for the five-year forecast period 2018/2019 through 2022/2023.
Liberty Utilities (New England Gas Company)	07/16	Docket No. DPU 16-109	Sponsored the Long-Range Forecast and Supply Plan filing for the five-year forecast period 2016/2017 through 2020/2021.
Boston Gas	10/93	Docket No. DPU 92-230	Sponsored testimony describing the Company's position regarding rate treatment of vehicular natural gas investments and expenses.
Boston Gas	03/90	Docket No. DPU 90-55	Sponsored testimony supporting the weather and other cost of service adjustments, rate design and customer bill impact studies for a general rate case proceeding.
Boston Gas	03/88	Docket No. DPU 88-67-II	Sponsored testimony supporting the rate reclassification of commercial and industrial customers for a rate design proceeding.
Michigan Public Service Commission			
Lansing Board of Water & Light and Michigan State University	04/20	Docket No. U-20650	Sponsored testimony evaluating Consumer Energy's cost of service and rate design proposals.
Lansing Board of Water & Light and Michigan State University	04/19	Docket No. U-20322	Sponsored testimony evaluating Consumer Energy's cost of service and rate design proposals.
Midland Cogeneration Ventures, LLC	09/18	Docket No. U-18010	Sponsored testimony evaluating Consumer Energy's cost of service and rate design proposals.
Missouri Public Service Commission			
The Empire District Gas Company	08/21	Docket No. GR-2021-0320	Sponsored testimony supporting the cost of service, rate design, bill impact and lead-lag studies for a general rate case proceeding.
The Empire District Electric Company	05/21	Docket No. ER-2021-0312	Sponsored testimony supporting the cost of service, rate design, bill impact and lead-lag studies for a general rate case proceeding.
Spire Missouri, Inc.	12/20	Docket No. GR-2021-0108	Sponsored testimony supporting class cost of service, rate design, and lead-lag study proposals for a general rate case proceeding. The testimony also included support for a proposed revenue adjustment mechanism.
The Empire District Electric Company	08/19	Docket No. ER-2019-0374	Sponsored testimony supporting the cost of service, rate design, bill impact and lead-lag studies for a general rate case proceeding. The testimony also included proposals for a weather normalization mechanism.

Sponsor	Date	Docket No.	Subject
Liberty Utilities (Midstates Natural Gas)	09/17	Docket No. GR-2018-0013	Sponsored testimony supporting the cost of service, rate design, bill impact and lead-lag studies for a general rate case proceeding. The testimony also included proposals for a revenue decoupling/ weather normalization mechanism as well as tracker accounts for certain O&M expenses and capital costs.
Missouri Gas Energy	04/17	Docket No. GR-2017-0216	Sponsored testimony supporting the cost of service, rate design, bill impact and Lead/Lag studies for a general rate case proceeding. The testimony included support for a decoupling mechanism.
Laclede Gas Company	04/17	Docket No. GR-2017-0215	Sponsored testimony supporting the cost of service, rate design, bill impact and Lead/Lag studies for a general rate case proceeding. The testimony included support for a decoupling mechanism.
New Hampshire Public Utilities Commission			
Unitil (Northern Utilities, Inc.)	8/21	Docket No. DG 21-104	Sponsored testimony supporting a revenue decoupling mechanism.
Unitil Energy Systems, Inc.	4/21	Docket No. DE 21-030	Sponsored testimony supporting a revenue decoupling mechanism.
Liberty Utilities (EnergyNorth Natural Gas) Corp. d/b/a Liberty Utilities	11/17	Docket No. DG 17-198	Sponsored testimony supporting a levelized cost analysis for approval of firm supply and transportation agreements.
Liberty Utilities d/b/a Granite State Electric Company	04/16	Docket No. DE 16-383	Adopted testimony and sponsored Lead/Lag study for a general rate case proceeding.
Nevada Public Utilities Commission			
Southwest Gas Corporation	08/21	Docket No. 21-09001	Sponsored testimony supporting the class cost of service, rate design, bill impact and Lead/Lag studies for a general rate case proceeding.
Southwest Gas Corporation	02/20	Docket No. 20-02023	Sponsored testimony supporting the class cost of service, rate design, bill impact and Lead/Lag studies for a general rate case proceeding.
New Jersey Board of Public Utilities			
South Jersey Gas Company	03/20	Docket No. GR20030243	Sponsored testimony supporting the Lead/Lag study for a general rate case proceeding.
Elizabethtown Gas Company	04/19	Docket No. GR19040486	Sponsored testimony supporting the Lead/Lag study for a general rate case proceeding.
Pivotal Utility Holdings, Inc. d/b/a Elizabethtown Gas Company	08/16	Docket No. GR16090826	Sponsored testimony supporting the Lead/Lag study for a general rate case proceeding.
Corporation Commission of Oklahoma			
The Empire District Electric Company	03/19	Cause No. PUD 201800133	Sponsored testimony supporting the cost of service, rate design, bill impact and Lead/Lag studies for a general rate case proceeding.
The Empire District Electric Company	04/17	Cause No. PUD 201600468	Adopted direct testimony and sponsored rebuttal testimony supporting the revenue requirements for a general rate case proceeding. The

Sponsor	Date	Docket No.	Subject
			testimony included proposals for alternative ratemaking mechanisms.
Rhode Island Public Utilities Commission			
Providence Gas Company	08/01 09/00 08/96	Docket No. 1673	Sponsored testimony supporting the changes in cost of gas adjustment factor related to projected under-recovery of gas costs; Filed testimony and witness for pilot hedging program to mitigate price risks to customers; Filed testimony and witness for changes in cost of gas adjustment factor related to extension of rate plan.
Providence Gas Company	08/00	Docket No. 2581	Sponsored testimony supporting the extension of a rate plan that began in 1997 and included certain modifications, including a weather normalization clause.
Providence Gas Company	03/00	Docket No. 3100	Sponsored testimony supporting the de-tariff and deregulation of appliance repair service, enabling the Company to have needed pricing flexibility.
Providence Gas Company	06/97	Docket No. 2581	Sponsored testimony supporting a rate plan that fixed all billing rates for three-year period; included funding for critical infrastructure investments in accelerated replacement of mains and services, digitized records system, and economic development projects.
Providence Gas Company	04/97	Docket No. 2552	Sponsored testimony supporting the rate design, customer bill impact studies and retail access tariffs for commercial and industrial customers, including redesign of cost of gas adjustment clause, for a rate design proceeding.
Providence Gas Company	02/96	Docket No. 2374	Sponsored testimony supporting the rate design, customer bill impact studies and retail access tariffs for largest commercial and industrial customers for a rate design proceeding.
Providence Gas Company	01/96	Docket No. 2076	Sponsored testimony supporting the rate reclassification of customers into new rate classes, rate design (including introduction of demand charges), and customer bill impact studies for a rate design proceeding.
Providence Gas Company	11/92	Docket No. 2025	Sponsored testimony supporting the Integrated Resource Plan filing, including a performance-based incentive mechanism.
Railroad Commission of Texas			
Texas Gas Service Company – Central Texas and Gulf Coast Service Areas	12/19	GUD No. 10928	Sponsored testimony supporting the Lead/Lag study for a general rate case proceeding.
CenterPoint Energy – Beaumont/ East Texas Division	11/19	GUD No. 10920	Sponsored testimony supporting the Lead/Lag study for a general rate case proceeding.
Texas Gas Service Company – Borger/ Skellytown Service Area	08/18	GUD No. 10766	Sponsored testimony supporting the Lead/Lag study for a general rate case proceeding.

Sponsor	Date	Docket No.	Subject
Texas Gas Service Company – North Texas Service Area	06/18	GUD No. 10739	Sponsored testimony supporting the Lead/Lag study for a general rate case proceeding.
CenterPoint Energy – South Texas Division	11/17	GUD No. 10669	Sponsored testimony supporting the Lead/Lag study for a general rate case proceeding.
Texas Gas Service Company – Rio Grande Valley Service Area	06/17	GUD No. 10656	Sponsored testimony supporting the Lead/Lag study for a general rate case proceeding.
Atmos Pipeline – Texas	01/17	GUD No. 10580	Sponsored testimony supporting the Lead/Lag study for a general rate case proceeding.
CenterPoint Energy – Texas Gulf Division	11/16	GUD No. 10567	Sponsored testimony supporting the Lead/Lag study for a general rate case proceeding.
Public Utility Commission of Texas			
CenterPoint Energy Houston Electric, LLC	04/19	Docket No. 49421	Sponsored testimony supporting the Lead/Lag study for a general rate case proceeding.
Vermont Public Utilities Commission			
Vermont Gas Systems	12/12	Docket No. 7970	Sponsored testimony describing the market served by $90 million natural gas expansion project to Addison County, VT. Also described the terms and economic benefits of a special contract with International Paper.
Vermont Gas Systems	02/11	Docket No. 7712	Sponsored testimony supporting the market evaluation and analysis for a system expansion and reliability regulatory fund.
Virginia State Corporation Commission			
American Electric Power - Appalachian Power Company	3/20	Case No. PUR-2020-00015	Sponsored testimony supporting the Lead/Lag study for the 2020 triennial review of base rates, terms and conditions.

Elizabethtown Gas Company
Lead-Lag Study
Working Capital Requirement

Line	Description	Adjusted Test Year to Post Test Year Expenses	Average Daily Expenses	Revenue Lag	Ref.	Expense Lead	Ref.	Net (Lead)/Lag Days	Working Capital Requirement
1	**Operations and Maintenance Expenses**								
2	Purchased Gas Costs and Other Riders	$ 199,139,696	$ 545,588	57.23	A	(40.24)	B	16.99	$ 9,269,540
3	Regular Payroll	26,371,049	72,249	57.23	A	(9.77)	C	47.46	3,428,938
4	Variable Compensation	1,228,381	3,365	57.23	A	(253.42)	C	(196.19)	(660,179)
5	Pension/ OPEB	5,110,817	14,002	57.23	A	-		57.23	801,334
6	Retirement Savings Plan	985,309	2,699	57.23	A	(19.63)	C	37.60	101,482
7	Group Insurance	4,157,210	11,390	57.23	A	(40.16)	C	17.07	194,427
8	Uncollectible Expense	2,877,768	7,884	57.23	A	(990.73)	C	(933.50)	(7,359,714)
9	Service Company Charges	24,183,271	66,256	57.23	A	(37.86)	C	19.37	1,283,379
10	Other Third-Party O&M Expenses	22,487,573	61,610	57.23	A	(37.88)	C	19.35	1,192,154
11	Total O&M Expenses	$ 286,541,074				.			$ 8,251,361
12	**Income Taxes**								
13	Excess Deferred Tax Amortization	$ (2,227,894)	$ (6,104)	57.23		-		57.23	$ (349,332)
14	Federal Income Taxes	20,270,701	55,536	57.23	A	(37.24)	D	19.99	1,110,165
15	State Income Tax	9,546,641	26,155	57.23	A	(37.24)	D	19.99	522,838
16	Total Federal Income Taxes	$ 27,589,448							$ 1,283,671
17	**Taxes Other Than Income Taxes**	$ 5,348,723	$ 14,654	57.23	A	(10.58)	E	46.65	$ 683,609
18	**Depreciation and Amortization Expense**	$ 60,832,003	$ 166,663	57.23	A	-		57.23	$ 9,538,123
19	**Interest Expense**								
20	Interest on Long-Term Debt	$ 24,082,760	$ 65,980	57.23	A	(90.00)	F	(32.77)	$ (2,162,165)
21	Interest on Short-Term Debt	-	-	57.23	A	(3.94)	F	53.29	-
22	Interest on Customer Deposits	2,703	7	57.23	A	(234.62)	F	(177.39)	(1,242)
23	Total Interest Expense	$ 24,085,463							$ (2,163,407)
24	**Return**	$ 82,131,955	$ 225,019	57.23	A	-		57.23	$ 12,877,837
25	**Other Adjustments**								
26	Incidental collections								$ 1,985,982
27	Employee deductions								(497,891)
28	Total Other Adjustments								$ 1,488,091
29	Total	$ 486,528,666	$ 406,336						$ 31,959,285

Elizabethtown Gas Company
Lead-Lag Study
Revenue and Collection Lag

Revenue Lag

Line	Description	Revenue Lag	Reference
1	Service Lag	15.21	
2	Billing Lag	1.37	WP A-1
3	Collection Lag	40.66	WP A-2
4	Composite Revenue Lag	57.23	

Elizabethtown Gas Company
Lead-Lag Study
Purchased Gas

Line	Month	Production Period Begin	Production Period End	Invoice	Settlement	Expense	Midpoint	(Lead)/Lag Days	Dollar Days	Composite (Lead)/Lag Days
1	June 2020	06/01/20	06/30/20	07/15/20	07/25/20	$ 15,259,349	(15.00)	(40.00)	$ (610,373,940)	
2	July 2020	07/01/20	07/31/20	08/15/20	08/25/20	15,615,151	(15.50)	(40.50)	(632,413,623)	
3	August 2020	08/01/20	08/31/20	09/15/20	09/25/20	23,376,303	(15.50)	(40.50)	(946,740,253)	
4	September 2020	09/01/20	09/30/20	10/15/20	10/25/20	11,358,794	(15.00)	(40.00)	(454,351,751)	
5	October 2020	10/01/20	10/31/20	11/15/20	11/25/20	10,842,689	(15.50)	(40.50)	(439,128,906)	
6	November 2020	11/01/20	11/30/20	12/15/20	12/25/20	8,635,235	(15.00)	(40.00)	(345,409,395)	
7	December 2020	12/01/20	12/31/20	01/15/21	01/25/21	1,189,997	(15.50)	(40.50)	(48,194,879)	
8	January 2021	01/01/21	01/31/21	02/15/21	02/25/21	7,723,494	(15.50)	(40.50)	(312,801,518)	
9	February 2021	02/01/21	02/28/21	03/15/21	03/25/21	7,007,519	(14.00)	(39.00)	(273,293,240)	
10	March 2021	03/01/21	03/31/21	04/15/21	04/25/21	7,686,323	(15.50)	(40.50)	(311,296,080)	
11	April 2021	04/01/21	04/30/21	05/15/21	05/25/21	7,822,510	(15.00)	(40.00)	(312,900,418)	
12	May 2021	05/01/21	05/31/21	06/15/21	06/25/21	8,511,224	(15.50)	(40.50)	(344,704,585)	
13	Total		Total			$ 125,028,588			$ (5,031,608,586)	(40.24)

Elizabethtown Gas Company
Lead-Lag Study
O&M Expenses

Line	Description	(Lead)/Lag Days	Ref.
1	Operations and Maintenance Expenses		
2	Regular Payroll	(9.77)	C-1
3	Variable Compensation	(253.42)	C-4
4	Retirement Savings Plan	(19.63)	C-5
5	Group Insurance	(40.16)	C-6
6	Uncollectible Expenses	(990.73)	C-7
7	Service Company Charges	(37.86)	C-8
8	Other Third-Party O&M Expenses	(37.88)	C-9
	Total O&M Expenses		

Elizabethtown Gas Company
Lead-Lag Study
Income Taxes

Line	Description	(Lead)/Lag Days	Ref.
1	Current Federal Income Taxes	(37.24)	D-1
2	State Income Tax	(37.24)	D-2
3	Total Federal Income Taxes		

Elizabethtown Gas Company
Lead-Lag Study
Taxes Other Than Income Taxes

Line	Description	Expense	Percent	(Lead)/Lag Days	Reference	Dollar Days
1	Payroll Taxes - Regular Payroll					
2	FICA	$ 2,636,844	95.09%	(19.70)	E-1	$ (51,935,695)
3	Federal Unemployment	17,584	0.63%	(30.08)	E-2	(528,926)
4	State Unemployment	118,535	4.27%	(30.30)	E-3	(3,592,016)
5	Total Payroll Taxes - Regular Payroll	$ 2,772,963	100.00%	(20.22)		$ (56,056,636)
6	Property Taxes	$ 959,076		17.27	E-4	$ 16,564,340
7	Taxes Other Than Income Taxes (Lead)/Lag Days	$ 3,732,039		(10.58)		$ (39,492,296)

Elizabethtown Gas Company
Lead-Lag Study
Interest Expense

Line	Description	(Lead)/Lag Days	Ref.
1	Interest Expense		
2	Interest on Long-Term Debt	(90.00)	F-1
3	Interest on Short-Term Debt	(3.94)	F-2
4	Interest on Customer Deposits	(234.62)	F-3

IN THE MATTER OF THE PETITION OF ELIZABETHTOWN GAS COMPANY FOR APPROVAL OF INCREASED BASE TARIFF RATES AND CHARGES FOR GAS SERVICE, CHANGES TO DEPRECIATION RATES AND OTHER TARIFF REVISIONS

BPU DOCKET NO. GR21__________

DIRECT TESTIMONY

OF

DANE A. WATSON, PE CDP

On Behalf Of
Elizabethtown Gas Company

Exhibit P-9

December 28, 2021

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LIST OF SCHEDULES

Exhibit P-9

ELIZABETHTOWN GAS COMPANY
DIRECT TESTIMONY OF
DANE A. WATSON

I. <u>INTRODUCTION</u>

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

A. My name is Dane A. Watson, and my business address is 101 E. Park Blvd, Plano, Texas 75074. I am a Partner of Alliance Consulting Group. Alliance Consulting Group provides consulting and expert services to the utility industry.

Q. WHAT IS YOUR EDUCATIONAL BACKGROUND?

A. I hold a Bachelor of Science degree in Electrical Engineering from the University of Arkansas at Fayetteville and a Master's Degree in Business Administration from Amberton University.

Q. DO YOU HOLD ANY SPECIAL CERTIFICATION AS A DEPRECIATION EXPERT?

A. Yes. The Society of Depreciation Professionals ("the Society") has established national standards for depreciation professionals. The Society administers an examination and has certain required qualifications to become certified in this field. I met all requirements and have become a Certified Depreciation Professional ("CDP"). A list of depreciation studies that I have prepared is provided in Schedule DAW-2.

Q. PLEASE OUTLINE YOUR EXPERIENCE IN THE FIELD OF DEPRECIATION.

A. Since graduation from college in 1985, I have worked in the area of depreciation and valuation. I founded Alliance Consulting Group in 2004 and am responsible for conducting depreciation, valuation, and certain accounting-related studies for utilities in various industries. My duties related to depreciation studies include the assembly and analysis of historical and simulated data, conducting field reviews, determining service life and net salvage estimates, calculating annual depreciation, presenting recommended depreciation rates to utility management and supporting such rates before regulatory bodies.

My prior employment from 1985 to 2004 was with Texas Utilities ("TXU"). During my tenure with TXU, I was responsible for, among other things, conducting valuation and depreciation studies for the domestic TXU companies. During that time, I served as Manager of Property Accounting Services and Records Management in addition to my depreciation responsibilities.

I have twice been Chair of the Edison Electric Institute ("EEI") Property Accounting and Valuation Committee and have been Chairman of EEI's Depreciation and Economic Issues Subcommittee. I was the Industry Project Manager for the EEI/American Gas Association ("AGA") effort around the electric and gas industry adoption of FERC Accounting Standard ("FAS") 143 and testified before the Federal Energy Regulatory Commission ("FERC") in the hearings leading up to the release of FERC Order 631.[1] I was also the Project Leader for the EEI/AGA *Introduction to Depreciation* textbook update. I am a Registered Professional Engineer ("PE") in the State of Texas and a CDP. I am a Senior Member of the Institute of Electrical and Electronics Engineers ("IEEE") and have held various local, regional and world-wide offices in IEEE. I am also a twice past President of the Society. As part of the annual training program for the Society, I serve as a faculty member. I also teach depreciation in multiple venues for EEI/AGA and other entities.

[1] FERC Order 631 was issued by FERC in 2003 to update uniform accounting and financial reporting standards for the recognition and measurement of liabilities arising from retirement and decommissioning obligations of tangible long-lived assets, and related costs.

Q. HAVE YOU PREVIOUSLY TESTIFIED BEFORE THE NEW JERSEY BOARD OF PUBLIC UTILITIES?

A. Yes. I have previously provided testimony in numerous proceedings before the New Jersey Board of Public Utilities ("BPU"). I have provided testimony on behalf of South Jersey Gas Company and Elizabethtown Gas Company ("Elizabethtown" or "Company") in their prior base rate cases. Additionally, I have testified before thirty-five regulatory commissions across the United States and have performed more than 275 depreciation studies over the course of my career. Schedule DAW-2 contains a complete listing of the various proceedings in which I have been involved.

II. PURPOSE OF DIRECT TESTIMONY

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

A. I sponsor and support the depreciation study performed for Elizabethtown, a wholly owned subsidiary of South Jersey Industries, that calculated the depreciation rates that were used to determine the depreciation expense in this proceeding. My testimony explains the analysis I undertook to determine reasonable and necessary depreciation rates based on the Company's total capital investment, and it provides detailed calculations and comparisons of my proposed rates to existing depreciation rates, which were approved by the BPU in 2019.

Specifically, my testimony:

- addresses recommended changes in the service lives and net salvage costs for certain accounts;
- addresses the depreciation reserve; and
- addresses the depreciation rate system (method, procedure, and technique).

Q. DO YOU SPONSOR ANY SCHEDULES AS PART OF YOUR DIRECT TESTIMONY?

A. Yes. I sponsor Schedules DAW-1 and DAW-2 which were prepared by me or under my supervision and direction. Schedule DAW-1 is the depreciation study performed for Elizabethtown that resulted in depreciation rates that were used to determine the depreciation expense in this proceeding. Schedule DAW-2 contains a complete listing of various proceedings in which I have been involved.

Q. WHAT DEPRECIATION RATES ARE YOU PROPOSING, AND HOW DO THEY COMPARE WITH THE CURRENT RATES?

A. My depreciation rate recommendations as compared to current depreciation rates result in an increase in depreciation expense and can be found in Appendix B of Schedule DAW-1. Detailed calculations of the proposed rates are found in Appendix A of Schedule DAW–1. Appendix B of Schedule DAW-1 provides a comparison.

Q. WHAT DEPRECIATION EXPENSE ARE YOU RECOMMENDING IN THIS PROCEEDING?

A. Based on the depreciation study, which analyzed the Company's depreciable plant in service at December 31, 2020, I recommend an annualized depreciation expense for Elizabethtown of approximately $53.0 million. This represents an increase of approximately $9.3 million over the annualized depreciation expense calculated on year-end 2020 investment using the Company's current depreciation rates. This amount was determined by comparing the depreciation expense difference between the current rates and the proposed rates as of December 31, 2020, as shown in Schedule DAW-1, Appendix B.

Q. WHAT ARE THE PRIMARY FACTORS THAT HAVE INFLUENCED THE CHANGE IN THE COMPANY'S DEPRECIATION RATES?

A. First, Elizabethtown has increased its depreciable plant investment significantly since the previous depreciation study, which was conducted in in 2018 and used to develop the existing approved depreciation rates. Specifically, the Distribution function has seen the most dramatic increase, which correlates with the focus of the Company's Infrastructure Investment Program (or "IIP"). Second, Elizabethtown is also experiencing different service lives for some of its assets as compared to the service lives reflected in its current depreciation rates. As a result, I am recommending a change in the service life for certain accounts in the Other Storage, Transmission, Distribution, and General Plant functional groups to more accurately reflect the Company's recent and specific retirement experience for assets. Lastly, both the Company's statistical data and field experience indicate that the accounts in Distribution plant continue to demonstrate a change in removal costs, resulting in updated net salvage. The depreciation rates and resulting accrual amounts I recommend for adoption in this case reflect the factors I described above.

Q. DOES THE DEPRECIATION STUDY YOU SPONSOR IN THIS CASE REFLECT THE MOST CURRENT DATA AVAILABLE FOR ELIZABETHTOWN'S ASSETS?

A. Yes. The data used reflects the most recent experience and future expectations for life and net salvage characteristics for Elizabethtown.

III. <u>ELIZABETHTOWN DEPRECIATION STUDY</u>

Q. WHAT DOES THE DEPRECIATION STUDY ANALYZE?

A. The depreciation study analyzes the life and net salvage for the Elizabethtown property groups associated with Manufactured Gas, Other Storage, Transmission, Distribution and General plant assets as of December 31, 2020.

Q., PLEASE DESCRIBE THE ASSETS OF ELIZABETHTOWN.

A. There are five general classes, or functional groups, of depreciable property: Manufactured Gas, Other Storage, Transmission, Distribution and General. The Manufactured Gas Plant functional group consists of only land rights at this point in time. Assets in this function have been retired or transferred to other functions. The Company is no longer using assets to manufacture gas from petroleum products. The Other Storage Plant functional group primarily consists of liquefied natural gas storage facilities and related processing equipment. The Transmission Plant functional group consists of land rights, mains and regulating equipment to move the gas to its distribution system. The Distribution Plant functional group primarily consists of lines and associated facilities used to distribute gas to the customers served by Elizabethtown. General Plant property is not location-specific but is used to support the overall distribution of gas to customers.

Q. WHAT DEFINITION OF DEPRECIATION HAVE YOU USED FOR THE PURPOSE OF CONDUCTING THE DEPRECIATION STUDY AND PREPARING YOUR TESTIMONY?

A. The term “depreciation,” as used herein, is considered in the accounting sense; that is, it is a system of accounting that distributes the cost of assets, less net salvage (if any), over the estimated useful life of the assets in a systematic and rational manner. Depreciation is a process of allocation, not valuation. Depreciation expense is systematically allocated to accounting periods over the life of the properties. The amount allocated to any one accounting period does not necessarily represent the loss or decrease in value that will occur during that particular period. Thus, depreciation is considered an expense or cost, rather than a loss or decrease in value. The Company accrues depreciation based on the original cost of all property included in each depreciable plant account. On retirement, the full cost of depreciable property, less the net salvage amount, if any, is charged to the depreciation reserve.

Q. PLEASE DESCRIBE YOUR DEPRECIATION STUDY APPROACH.

A. I conducted the depreciation studies in four phases as shown in my Schedule DAW-1. The four phases are: Data Collection, Analysis, Evaluation, and Calculation. During the Data Collection phase of the study, I collected historical data to be used in the analysis. After the data was assembled, I performed analyses to determine the life and net salvage percentage for the different property groups being studied. As part of this process, I conferred with field personnel, engineers, and managers responsible for the installation, operation, and removal of the assets to gain their input into the operation, maintenance, and salvage of the assets. The information obtained from field personnel, engineers, and managerial personnel, combined with the study results, was then evaluated to determine how the results of the historical asset activity analysis, in conjunction with the Company's expected future plans, should be applied to develop depreciation rates that will allow the recovery of the plant investment. I used all of these resources to calculate the depreciation rate for each account and function.

Q. WHAT DEPRECIATION METHODOLOGY DID YOU USE?

A. The straight-line, average life group, remaining-life depreciation system was employed to calculate annual and accrued depreciation in this study. This is the same methodology used to develop the Company's current depreciation rates, which were approved, through a stipulated agreement, by the BPU in the Company's last base rate case in 2019 in Docket No. GR19040486.

Q. HOW WERE THE DEPRECIATION RATES DETERMINED USING THE AVERAGE LIFE GROUP PROCEDURE?

A. In this system, the annual depreciation expense for each group was computed by dividing the original cost of the asset, less allocated book depreciation reserve, less estimated net salvage, by its respective average life group remaining life. The resulting annual accrual amounts of all depreciable property within an account were accumulated and divided by the original cost of all depreciable property in the account to determine the depreciation rate. The calculated remaining lives and annual depreciation accrual rates were based on attained ages of plant in service and the estimated service life and salvage characteristics of each depreciable group. The computations of the annual depreciation rates are shown in Appendix A of Schedule DAW-1. The remaining life calculations are discussed below and are also shown in Appendix A of Schedule DAW-1.

Q. WHAT TIME PERIOD DID YOU USE TO DEVELOP THE PROPOSED DEPRECIATION RATES?

A. The account level depreciation rates were developed based on the depreciable property recorded on the Company's books at December 31, 2020.

Q. IN DEVELOPING THE PROPOSED DEPRECIATION RATES, DID YOU CONSIDER THE COMPANY'S CURRENT ASSET ACCOUNTING PRACTICES?

A. Yes. In developing the proposed depreciation rates, the depreciation study analysis focused not only on historical data, but also on the field experience noted by the Company's operations personnel.

Q., PLEASE SUMMARIZE THE DEPRECIATION STUDY RESULTS WITH RESPECT TO THE DEPRECIATION RATES.

A. Overall, depreciation expense is increasing and is primarily influenced by the continued focus of Elizabethtown on addressing its aging infrastructure and the increased cost of performing this work resulting in increased depreciable plant balances. Regulatory and environmental requirements all have increased and added additional cost when adding and retiring assets. As shown in Schedule DAW-1, Appendix B, overall depreciation expense is increasing by approximately $9.3 million annually. This increase is computed by applying the existing account rates to the investment balances at the study date of December 31, 2020 to determine the annual depreciation expense accrual and comparing that accrual to the application of the proposed depreciation rates to the same investment balances to determine the proposed annual depreciation expense accrual amounts, which are shown on Appendix B of Schedule DAW-1. Table 1 below summarizes the change in annual depreciation expense.

TABLE 1

Description	Plant Balance 12/31/2020	Existing Annual Accrual		Proposed Annual Accrual		Change in Depreciation Expense
		Rate	Amount	Rate	Amount	
Manufactured Gas	61,423	4.37%	2,684	4.39%	2,696	12
Other Storage	18,119,408	2.19%	397,357	2.05%	371,908	(25,449)
Transmission	22,819,165	1.96%	448,112	2.21%	503,892	55,779
Distribution	1,511,503,564	2.10%	31,792,689	2.40%	36,275,449	4,482,760
General Depreciated	147,895,799	6.40%	9,470,377	9.59%	14,186,265	4,715,888
General Amortized	15,179,504	10.57%	1,604,882	11.03%	1,674,629	69,747
Total Plant in Study (excl Intangibles & Land)	$1,715,578,863	2.55%	$43,716,103	3.09%	$53,014,840	$9,298,737

Q. WHAT FACTORS INFLUENCE THE DEPRECIATION RATES FOR AN ACCOUNT?

A. The primary factors that influence the depreciation rate for an account are (1) the remaining investment to be recovered in the account, (2) the depreciable life of the assets in the account, and (3) the net salvage of the assets in the account.

Q. HAS THE REMAINING INVESTMENT TO BE RECOVERED INCREASED?

A. Yes. Elizabethtown has been engaged in replacing its aging infrastructure and plans to continue addressing various aspects of its system in the coming years.

Q. DID YOU USE PER BOOK DATA FOR THE DEPRECIATION STUDY?

A. Yes. As previously stated, the study reflects Company data as of December 31, 2020. During the study it was determined that some assets needed to be retired and/or transferred to other accounts. Those have been included in our study as *pro forma* adjustments. Schedule DAW-1 contains more detailed information for those *pro forma* adjustments.

Q. DID YOU INCORPORATE A RESERVE REALLOCATION WITHIN EACH OF THE FUNCTIONAL GROUPS IN THE DEPRECIATION STUDY?

A. Yes. The reserve of each functional group was allocated among the accounts in that function.

Q. WAS THERE AN IMPACT AS A RESULT OF THE RESERVE ALLOCATION?

A. Yes. The impact of the reserve allocation reduced the overall accrual expense by approximately $407 thousand when compared to the results using the actual book reserves by account.

Q. WHAT IS THE REASON FOR PERFORMING A RESERVE ALLOCATION?

A. The reserve allocation realigns the company's depreciation reserves by account within a function to more accurately reflect the life characteristics, proposed in the study, of the underlying assets going forward. This reallocation of the depreciation reserves applies to all accounts within each function. A detailed discussion on the theoretical reserve calculation and reallocation is provided in Exhibit DAW-1, pages 13 - 14.

Q. WILL THE COMPANY ADOPT THESE REALLOCATED RESERVES?

A. Yes. Once the BPU approves depreciation rates and the underlying life and net salvage parameters, the Company will use the approved parameters, at the time new rates will be implemented, to update the reserves, as reallocated, on its books and records.

A. <u>Service Lives</u>

Q. WHAT IS THE SIGNIFICANCE OF AN ASSET'S USEFUL LIFE IN YOUR DEPRECIATION STUDY?

A. An asset's useful life was used to determine the remaining life over which the remaining cost (original cost, plus or minus net salvage, minus accumulated depreciation) can be allocated to normalize the asset's cost and spread it ratably over future periods.

Q. HOW DID YOU DETERMINE THE AVERAGE SERVICE LIVES FOR EACH ACCOUNT?

A. All accounts were analyzed using the well-accepted actuarial analysis method (retirement rate method) to estimate the life of property. In much the same manner as human mortality is analyzed by actuaries, depreciation analysts use models of property mortality characteristics that have been validated in research and empirical applications. Further detail is found in the life analysis section of Schedule DAW-1.

Q. IN ADDITION TO STATISTICAL MODELING, DID YOU ALSO CONSIDER COMPANY-SPECIFIC EXPECTATIONS IN DEVELOPING YOUR SERVICE LIFE RECOMMENDATIONS?

A. Yes. Both statistical modeling of historical data and Company-specific expectations are critical to any depreciation analysis. In order to achieve a reasonable balance between these critical components of the life analysis, I evaluated the statistical historical data and then applied informed judgment to make the most appropriate service life selections. The objective in any depreciation study is to project the remaining cost (installation, material, and removal cost) to be recovered and the remaining periods in which to recover the costs. This requires that the service life selections reflect both the Company's historical experience and its current expectations of asset lives. In order to understand the Company's expectations regarding asset lives, I interviewed Company engineers working in both operations and maintenance to confirm the historical activity and indications, current and future plans, expectations, and the applicability of those plans to the future surviving assets. The interview process provides important information regarding changes in materials, operation, and maintenance, as well as the Company's current expectation regarding the service life of the assets currently in use. This information is then considered along with the historical statistical data to develop the most reasonable and representative expected service lives for the Company's assets. The result of all of this analysis is reflected in the service life recommendations set forth in the depreciation study and accompanying workpapers.

Q. CAN YOU PROVIDE AN EXAMPLE OF THE IMPORTANT INFORMATION YOU OBTAINED FROM COMPANY PERSONNEL?

A. Yes. The current service life for the Company's storage plant, specifically the vaporizing equipment, is 35 years. In the 1990s and 2000s, Elizabethtown updated most of the vaporization assets on its system but noted that due to the age of existing assets, replacement parts now are harder to find. The Company plans to update the existing equipment in the future but stated that the vaporizers should continue to serve their purpose for the next five years. As a result, this study recommends retaining the existing life of 35 years for the Company's vaporizing equipment.

Q. HAVE YOU PREPARED A SUMMARY OF THE LIFE CHANGES BY ACCOUNT?

A. Yes. In my depreciation study, the remaining life for each account is shown in Appendix A of my Schedule DAW-1. Graphs and tables supporting the actuarial analysis and the chosen Iowa Curves used to determine the average service lives for analyzed accounts are found in the Life Analysis section of Schedule DAW-1. A comparison of the depreciable life for each account is shown in Schedule DAW-1, Appendix C.

Q. WHAT ARE THE KEY FACTORS DRIVING THE NEED TO REVISE THE AVERAGE SERVICE LIVES FOR THE VARIOUS ACCOUNTS?

A. The key factor driving the need to change the average service lives was incorporation of updated information about the Company's assets since the last depreciation study, including an additional two years of Company-specific retirement information and input from operations personnel. In addition, the Company's IIP is in place and infrastructure replacements under that program will continue for at least another 2.5 years from the study date, which is expected to eventually extend the life of the assets by replacing equipment with a lower expected remaining life with longer-lasting equipment resulting in an overall longer remaining life. The detailed analysis of each account is described fully in Schedule DAW-1. Overall, 4 accounts had an increase in life, 11 accounts had a decrease in life, and 28 accounts remained the same.

Q. ARE YOU RECOMMENDING THE CONTINUATION OF FIXED LIFE AMORTIZATION FOR CERTAIN ACCOUNTS?

A. Yes. The BPU approved the use of fixed-life amortization for certain Elizabethtown accounts in the depreciation rates approved in the Company's 2009, 2016, and 2019 base rate cases. Specifically, the Company has amortized Accounts 391X, 393, 394, 395, 397 and 398. I recommend this practice be continued. The fixed life amortization calculations are shown in detail in Schedule DAW-1, Appendix A.

B. <u>Net Salvage</u>

Q. WHAT IS NET SALVAGE?

A. Net salvage is the difference between the gross salvage (what the asset was sold for upon removal) and the removal cost (cost to remove and dispose of the asset). Salvage and removal cost percentages are calculated by dividing the current cost of salvage or removal by the original installed cost of the asset. When salvage exceeds removal (positive net salvage), the net salvage reduces the amount to be depreciated over time. When removal exceeds salvage (negative net salvage), the negative net salvage increases the amount to be depreciated. Plant assets can experience significant negative removal cost percentages.

Q. CAN YOU PROVIDE AN EXAMPLE OF THE NET SALVAGE CALCULATION?

A. The correct calculation of a net salvage percentage is to divide the difference between the gross salvage and the removal cost by the retirement dollars. Salvage and removal cost represent the current cost of salvage or removal whereas the retirement amount is the original installed cost of the asset as of the date of its installation. For example, a distribution asset in FERC Account 376 with a current installed cost of $500 (2020) would have had an installed cost of $15.78 in 1950[2] (which is the proposed average life of the account). A removal cost of $50 for the asset calculated (incorrectly) on current installed cost would only have a negative 10 percent removal cost ($50/$500), thus ignoring the significant inflation that occurred between installation and removal. However, a correct removal cost calculation would show a negative 317 percent removal cost for that asset ($50/$15.78).

Some plant assets can experience significant negative removal cost percentages due to the timing of the addition versus the retirement. In the example above, a -317% removal cost rate accurately reflects the cost necessary to remove the asset 71 years after it was originally installed. A rate of -10% clearly would not. Inflation from the time of installation of the asset until the time of its removal must be included in the calculation of the removal cost percentage because the depreciation rate, which includes the removal cost percentage, will be applied to the original installed cost of assets. However, regulators in New Jersey have chosen an alternative net salvage calculation methodology, which has

[2] Using the Handy-Whitman Bulletin No. 194, G-1, line 44, $15.78 = $500 x 32/1014.

typically consisted of determining the net salvage amount based on recent actual expenditures.[3]

Q. WHAT ARE THE MAIN FACTORS IMPACTING THE NET SALVAGE THE COMPANY IS EXPERIENCING?

A. The activities related to retirement costs (generally including cutting, capping, and purging of gas for the abandonment of pipe) affect the costs that the Company incurs. The Company has recently experienced higher removal costs for many of its assets.

Q. HOW DID YOU DETERMINE THE NET SALVAGE FOR EACH ASSET GROUP?

A. The historical retirement, salvage, and cost of removal for each account have been maintained and analyzed from 1999 to 2020. In that analysis, 2- through 10-year averages were calculated and evaluated. A 3-year average and 5-year average amount was calculated for salvage and cost of removal. The Company has included the 3-year average amount in the annual accrual amount to determine the total depreciation rate for accounts where net salvage is present. The use of an average amount is the same approach approved by the BPU in the Company's prior base rate case. These amounts are shown in Schedule DAW-1, Appendix A. The net salvage analysis and the 3- and 5-year average calculations are shown in Schedule DAW-1, Appendix D.

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[3] *See, e.g., In the Matter of the Petition of South Jersey Gas Co. for Approval of Increased Base Tariff Rates and Charges for Gas Service and Other Tariff* Revisions, BPU Docket No. GR13111137, Decision and Order Approving Stipulations (September 30, 2014), *and see, In the Matter of Jersey Central Power and Light Co. for Review and Approval of Increases in and Other Adjustments to its Rates and Charges for Electric Service, and for Approval of Other Proposed Tariff Revisions in Connection Therewith; and for Approval of an Accelerated Reliability Enhancement Program ("2012 Base Rate Filing")*, Order Adopting Initial Decision with Modifications and Clarifications (March 18, 2015).

Q. IS THIS A PREFERRED METHOD IN THE INDUSTRY FOR DETERMINING NET SALVAGE RATES?

A. No. In fact, New Jersey is one of only a handful of jurisdictions that adopted an alternative methodology for determining net salvage in rates. This method is considered to be non-traditional. However, it does include amounts for recovery based on recent experience until depreciation rates are revised by the BPU. This method is not the methodology that is utilized by the majority of the industry and it is not the method recommended in authoritative texts such as *Depreciation Systems*, by Drs. Fitch and Wolf[4] and the National Association of Regulatory Utility Commissioners' ("NARUC") *Public Utility Depreciation Practices*.[5]

Q. WHAT IS THE IMPACT TO THE COMPANY AND THE CUSTOMER OF USING THIS ALTERNATIVE METHODOLOGY?

A. It hurts both over the long run. As an example, if you look at Account 380 Services, which is one of the accounts that routinely has higher levels of cost of removal with little or no salvage, you can see that in the last case the amount of net salvage approved was a negative $3,894,584 and, in this case, it has grown to a negative $5,903,383, using the 3-year average amount. The Company will always be behind in the recovery of removal cost as total expenditures are increasing and in times where there is a focus on infrastructure, such as under the Company's IIP, the disparity of what the Company is incurring and what it is authorized to collect will grow. This approach is a cash basis approach, the Company's recovery is always lagging and not accruing for future removal activities, and the

[4] F.K. Wolf and W.C. Fitch, *Depreciation Systems*, pp. 260-267 (1994).
[5] NARUC, *Public Utility Depreciation Practices,* pp. 157-164 (1996).

significantly lower removal cost accrual (which increases rate base over time as compared to the traditional approach) will increase the overall cost to customers.

Q. WHEN WERE THE COMPANY'S CURRENT NET SALVAGE RATES ESTABLISHED?

A. Net salvage amounts for the Company were most recently established in its last base rate case in 2019 in BPU Docket No. GR19040486. However, it is important to note that the amounts were established pursuant to a settlement agreement.

Q. HAVE ANY PLANT ACCOUNTS EXPERIENCED A CHANGE IN NET SALVAGE?

A. Yes. Several of the accounts reflect significant increases in removal costs. Eight accounts generally show large amounts of negative net salvage: Mains (Transmission 367 and Distribution 376), Measuring and Regulating Stations (Transmission 369, Distribution 378 and 379) and Services (380). These accounts constitute most of the Company's plant from a dollar perspective, and the efforts associated with removing underground assets from service make up the majority of the Company's removal cost expense. These accounts are a primary focus in the ongoing infrastructure replacement program.

Q. HOW IS REMOVAL COST CHARGED TO ACCUMULATED DEPRECIATION?

A. Removal cost is tracked and recorded through the Company's work order system. The work order costs (retirement, salvage, and cost of removal) are recorded to accumulated depreciation on a project level through the accounting system.

Q. BASED ON YOUR ANALYSIS, WHAT ARE YOUR NET SALVAGE RECOMMENDATIONS FOR MAINS AND SERVICES?

A. Based on a 3-year average, for Transmission Mains, I recommend including $21,163 in the annual accrual amount; Distribution Mains, I recommend including $2,659,609 in the annual accrual amount; and for Distribution Services, I recommend including $5,903,383 in the annual accrual amount. These amounts are based on the most recent 3-year average of net salvage costs and most reflective of what Elizabethtown is expected to incur in the future. These are the accounts where the most significant cost of removal has been and is expected to be recorded in the future. The detailed amounts for all accounts are shown in Schedule DAW-1, Appendix A and were derived from the net salvage analysis in Schedule DAW-1, Appendix D.

Q. PLEASE SUMMARIZE YOUR NET SALVAGE RECOMMENDATIONS?

A. The total amount of negative net salvage (salvage less cost of removal) included in the depreciation rate accrual in Transmission and Distribution functions is $8,810,942. General Plant Transportation and Power Operated Equipment Accounts exhibit positive net salvage of $66,868. The total amount of net salvage (salvage less cost of removal) included in the depreciation rate accrual is a negative $8,744,073. Both positive and negative net salvage amounts have been included in the depreciation accrual calculations and are shown on Schedule DAW-1, Appendix A.

IV. <u>CONCLUSION</u>

Q. PLEASE SUMMARIZE THE CONCLUSIONS YOU HAVE REACHED AS A RESULT OF YOUR ANALYSIS.

A. The depreciation study and analysis performed under my supervision fully support setting depreciation rates at the levels I have indicated in my testimony. The depreciation study describes the extensive analysis performed and the resulting rates that are now appropriate for Company property. The Company's depreciation rates should be set at my recommended amounts to permit recovery of the Company's total investment in property over the estimated remaining life of the assets

Q. DOES THIS CONCLUDE YOUR DIRECT TESTIMONY?

A. Yes, it does.

ELIZABETHTOWN GAS COMPANY

A SOUTH JERSEY INDUSTRIES WHOLLY OWNED SUBSIDIARY

GAS UTILITY PLANT

DEPRECIATION RATE STUDY

AT DECEMBER 31, 2020

ALLIANCE CONSULTING GROUP

http://www.utilityalliance.com

ELIZABETHTOWN GAS COMPANY

GAS UTILITY PLANT

DEPRECIATION RATE STUDY

EXECUTIVE SUMMARY

Elizabethtown Gas Company ("Elizabethtown" or "Company"), a wholly owned subsidiary of South Jersey Industries, engaged Alliance Consulting Group to conduct a depreciation study of the Company's Gas utility plant depreciable assets using actual plant asset balances and depreciation reserve balances as of December 31, 2020 ("Study"). To determine depreciation rates, the following process occurred: 1) historic data through December 31, 2020 and judgment are used to estimate life and net salvage amounts based on a 3-year average; 2) discussions with Company operations and accounting personnel are used to validate the life and net salvage parameters shown in the historical data; and 3) the vintage balances and allocated reserves at December 31, 2020 are used to compute the proposed depreciation accrual. The total proposed increase that results from depreciation expense in this Study is approximately $9.3 million based on plant balances as of December 31, 2020.

This Study uses the straight-line, broad (average life) group, remaining life depreciation system. The net salvage proposal in this Study, 3-year average, is similar to what was adopted by the New Jersey Board of Public Utilities ("BPU") in the Stipulated Agreement in Elizabethtown's last gas rate case in Docket No. GR19040486. In accounts where net salvage is expected to occur, a three-year average amount of net salvage has been included for the calculation of the annual depreciation accrual and rates.

For Manufactured Gas, Other Storage, Transmission, Distribution, and General accounts, the lives of the accounts and net salvage parameters are reviewed in this Study. This Study recommends changes in depreciation for each function based on account balances as of December 31, 2020 as follows: no change for Manufactured Gas, a decrease of $25 thousand for Other Storage, an increase of $56 thousand for Transmission, an increase of $4.5 million for Distribution, and an increase of $4.8 million for General. The total proposed change in depreciation expense is an increase of $9.3 million.

For Manufactured Gas, Storage, Transmission, Distribution, and General accounts (excluding Intangibles), there are 4 accounts that have increasing lives and 11 accounts that have decreasing lives, while all others remain unchanged or permit no comparison. Based on the BPU precedent for using a historical average amount for net salvage calculations, 9 accounts experienced negative net salvage (removal cost) charges, for a total of $8,810,942. This experience is included in the total accrual amount used to calculate annual depreciation accrual rates. The negative net salvage amounts (COR) added to the accrual can be found in Appendix A. For Transportation and Power Operated Equipment accounts the positive net salvage (Gross Salvage) amounts, $66,868 are subtracted from the accrual, which can also be found in Appendix A.

ELIZABETHTOWN GAS COMPANY
GAS UTILITY PLANT
DEPRECIATION RATE STUDY
AT DECEMBER 31, 2020
Table of Contents

I. PURPOSE OF THE STUDY

The purpose of this Study is to develop depreciation rates for the depreciable property of Elizabethtown based on plant and reserve balances at December 31, 2020. Historical data at December 31, 2020 and judgment are used to estimate life and net salvage. The account-based depreciation rates are designed to recover the total remaining undepreciated investment, adjusted for net salvage, over the remaining life of Elizabethtown's property on a straight-line basis. This Study includes the Company's depreciable gas plant assets. Non-depreciable property and property that is amortized, such as intangibles, are excluded from the analysis of this Study but are reported in the total plant and reserve data for a complete report of plant assets at the Study date. The study has included "proforma" adjustments, which reflect known retirements and/or transfers of plant.

Elizabethtown is now a wholly owned subsidiary of South Jersey Industries and is dedicated to delivering safe and reliable natural gas in New Jersey. Regulated by the New Jersey Board of Public Utilities, Elizabethtown is principally engaged in the storage, transmission, and distribution of gas. Elizabethtown provides the essential service of efficiently delivering abundant and affordable natural gas to more than 292,000 end-use customers across seven counties through its transmission and distribution systems.

II. STUDY RESULTS

Overall depreciation rates for all Elizabethtown depreciable property are shown in Appendix B. As shown in Appendix B, these rates translate into an annual depreciation expense of $53.0 million based on Elizabethtown's depreciable investment for the plant balances as of December 31, 2020. This reflects an increase of $9.3 million as compared to the equivalent annual depreciation expense of $43.7 million calculated using the currently approved rates. The proposed depreciation rates for Manufactured Gas translate into an annual depreciation accrual of nearly $3 thousand. Other Storage translates into an annual depreciation accrual of $372 thousand. The proposed depreciation rates for Transmission translate into an annual depreciation expense of $504 thousand. The proposed depreciation rates for Distribution translate into an annual depreciation expense of $36.3 million. The proposed depreciation rates for General Plant translate into an annual depreciation expense of $15.9 million. The changes in proposed depreciation expense are primarily due to increased investment, increases in cost of removal in the Distribution Plant function, in General Plant the reduction in life for Account 391.20, and the reserve position.

Appendix A shows the development of the annual depreciation rates and accruals. Appendix B presents a comparison of approved rates versus proposed rates by account. Appendix C presents a summary of average service lives and net salvage estimates by account. Appendix D presents the net salvage analysis for all accounts.

III. GENERAL DISCUSSION OF THE DEPRECIATION RATE STUDY PROCESS

A. Definition of Depreciation

The term "depreciation" as used in this Study is considered in the accounting sense; that is, depreciation is a system of accounting that distributes the cost of assets, less net salvage (if any), over the estimated useful life of the assets in a systematic and rational manner. It is a process of allocation, not valuation. This expense is systematically allocated to accounting periods over the life of the properties. The amount allocated to any one accounting period does not necessarily represent the loss or decrease in value that will occur during that particular period. The Company accrues depreciation on the basis of the original cost of all depreciable property included in each functional property group. On retirement, the full cost of depreciable property, less the net salvage value, is charged to the depreciation reserve.

B. Basis of Depreciation Estimates

1. Overview of the Depreciation Method, Procedure and Technique

The Straight-Line, Broad (Average) Life Group, Remaining Life depreciation system is employed to calculate annual and accrued depreciation in this Study. In this system, the annual depreciation accrual for each plant account or sub-account is computed by dividing the original cost of the asset, less allocated depreciation reserve less estimated net salvage, by its respective average life group remaining life. The resulting annual accrual amounts of all depreciable property within a functional group[1] are accumulated, and that total is divided by the original cost of all functional depreciable property to determine the depreciation rate. The calculated remaining lives and annual depreciation accrual rates are based on

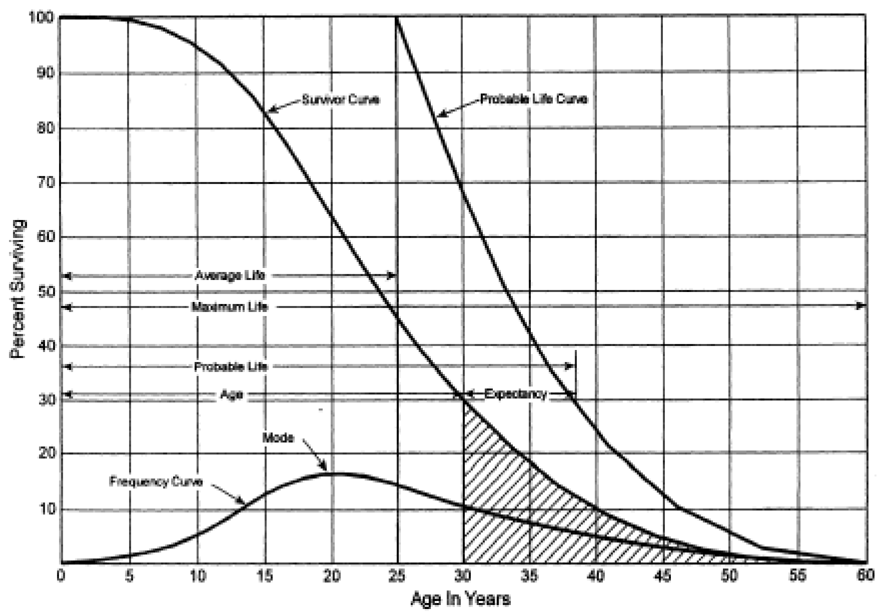
[1] Function or function group refers to different categories of plant. Specifically, the functions analyzed in this study are: Manufactured Gas Production, Other Storage, Transmission, Distribution, and General.

attained ages of plant in service and the estimated service life and salvage characteristics of each depreciable group. The computations of the annual depreciation rates are shown in Appendix A.

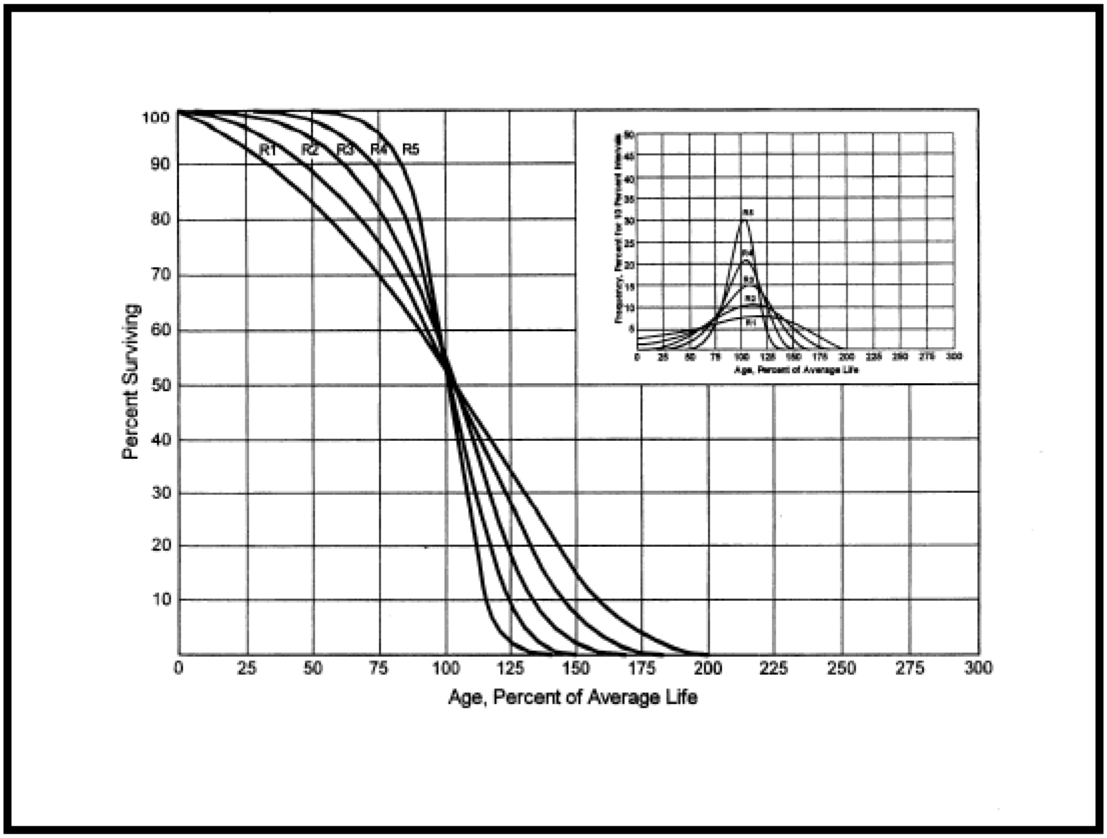
The actuarial analysis is used for each account within a functional group where sufficient data is available. Judgment is used to some degree on all accounts.

2. Survivor Curves

To fully understand depreciation projections in a regulated utility setting, there must be a basic understanding of survivor curves. Individual property units within a group do not normally have identical lives or investment amounts. The average life of a group can be determined by first constructing a survivor curve, which is plotted as a percentage of the units surviving at each age. A survivor curve represents the percentage of property remaining in service at various age intervals. The Iowa Curves are the result of an extensive investigation of life characteristics of physical property made at Iowa State College Engineering Experiment Station in the first half of the prior century. Through common usage, revalidation and regulatory acceptance, the Iowa Curves have become a descriptive standard for the life characteristics of industrial property. An example of an Iowa Curve is shown below.



There are four families in the Iowa Curves that are distinguished by the relation of the age at the retirement mode (largest annual retirement frequency) and the average life. For distributions with the mode age greater than the average life, an "R" designation (*i.e.*, Right modal) is used. The family of "R" moded curves is shown below.



Similarly, an “S” designation (*i.e.*, Symmetric modal) is used for the family of curves whose mode age is symmetric about the average life. An “L” designation (*i.e.*, Left modal) is used for the family of curves whose mode age is less than the average life. A special case of left modal dispersion is the “O” or origin modal curve family. Within each curve family, numerical designations are used to describe the relative magnitude of the retirement frequencies at the mode. A “6” indicates that the retirements are not greatly dispersed from the mode (*i.e.*, high mode frequency), while a “1” indicates a large dispersion about the mode (*i.e.*, low mode frequency). For example, a curve with an average life of 30 years and an “L3” dispersion is a moderately dispersed, left modal curve that can be designated as a 30 L3 Curve. An SQ, or square, survivor curve occurs where no dispersion is present (*i.e.*, units of common age retire simultaneously).

Most property groups can be closely fitted to one Iowa Curve with a unique average service life. The blending of judgment concerning current conditions and future trends along with the matching of historical data permits the depreciation analyst to make an informed selection of an account's average life and retirement dispersion pattern.

3. Actuarial Analysis

For all functions, the actuarial analysis ("Retirement Rate") method is used in evaluating historical asset retirement experience where vintage data are available and sufficient retirement activity is present. In actuarial analysis, interval exposures (total property subject to retirement at the beginning of the age interval, regardless of vintage) and age interval retirements are calculated. The complement of the ratio of interval retirements to interval exposures establishes a survivor ratio. The survivor ratio is the fraction of property surviving to the end of the selected age interval, given that it has survived to the beginning of that age interval. Survivor ratios for all of the available age intervals are computed by successive multiplications to establish a series of survivor factors, collectively known as an observed life table. The observed life table shows the experienced mortality characteristic of the account and may be compared to standard mortality curves, such as the Iowa Curves. Where data is available, accounts are analyzed using this method. Placement bands are used to illustrate the composite history over a specific era, and experience bands are used to focus on retirement history for all vintages during a set period. The results from the analyses for the accounts having data sufficient to be analyzed using this method are shown in the Life Analysis section of this Study.

4. Judgment

Any depreciation study requires informed judgment by the analyst conducting the study. A knowledge of the property being studied, company policies and procedures, general trends in technology and industry practice, and a sound basis of understanding in depreciation theory are needed to apply this informed judgment. Judgment is used in areas such as survivor curve modeling and selection, depreciation method selection, simulated plant record method analysis, and actuarial analysis.

Judgment is not used in cases where there are specific, significant pieces of information that influence the choice of a life or curve. Those cases would simply be a reflection of applying specific facts to the relevant analysis. Where there are multiple factors, activities, actions, property characteristics, statistical inconsistencies, implications of applying certain curves, property mix in accounts or a multitude of other considerations that impact the analysis (potentially in various directions), judgment is used to take all of these factors and synthesize them into a general direction or understanding of the characteristics of the property. Individually, no one factor in these cases may have a substantial impact on the analysis, but overall, may shed light on the utilization and characteristics of assets. Judgment also may include deduction, inference, wisdom, common sense, or the ability to make sensible decisions. Statistical analysis is a tool in life estimation; and all facets of selecting a life estimate require judgment. At the very least, as an example, any analysis requires choosing upon which bands to place more emphasis.

The establishment of appropriate average service lives and retirement dispersions for the Transmission, Distribution, and General Plant accounts requires judgment to incorporate the understanding of the operation of the system with the available accounting information analyzed using the Retirement Rate actuarial methods. The appropriateness of lives and curves depends not only on statistical analyses, but also on how well future retirement patterns will match past retirements.

Current applications and trends in use of the equipment also need to be factored into life and survivor curve choices in order for appropriate mortality characteristics to be chosen.

5. Broad (Average Life) Group Depreciation Procedure

Elizabethtown's current depreciation rates, as stipulated to and authorized by the BPU in Docket No. GR19040486, were developed using the Average Life Group ("ALG") depreciation procedure. After discussion with Elizabethtown, the ALG procedure has been retained in this Study. After an average service life and dispersion are selected for each account, those parameters are used to estimate what portion of the surviving investment of each vintage is expected to retire. The depreciation of the group continues until all investment in the vintage group is retired. ALG is defined by each group's respective account dispersion, life, and salvage estimates. A straight-line rate for each ALG is calculated by computing a composite remaining life for each group across all vintages within the group, dividing the remaining investment to be recovered by the remaining life to find the annual depreciation expense and then dividing the annual depreciation expense by the surviving investment. The resulting rate for each account using the ALG procedure is designed to recover all retirements less net salvage when the last unit retires. The ALG procedure recovers net estimated book cost over the life of each account by averaging many components. The ALG procedure is a standard methodology and is used by other South Jersey Industries regulated utility companies.

6. Theoretical Depreciation Reserve

The book depreciation reserve was derived from Company records. A theoretical depreciation reserve model was computed for each account and the existing functional book reserve was allocated, based on the computed theoretical depreciation reserve, to each account within that function. The book accumulated provision for depreciation within each Production, Storage, Transmission, Distribution, and General Property function was allocated among the accounts through the use of the theoretical depreciation reserve model.

This reserve model relies on a prospective concept relating future retirement and accrual patterns for property, given current life and net salvage estimates. The theoretical reserve of a property group is developed from the estimated remaining life of the group, the total life of the group, and estimated net salvage. The theoretical reserve represents the portion of the group cost that would have been accrued if current forecasts were used throughout the life of the group for future depreciation accruals. The computation involves multiplying the vintage balances within the group by the theoretical reserve ratio for each vintage. The straight-line remaining-life theoretical reserve ratio (“RR”) at any given age is calculated as:

$$RR = 1 - \frac{(\text{Average Remaining Life})}{(\text{Average Service Life})} * (1 - \text{Net Salvage Ratio})$$

In the workpapers, a theoretical reserve is computed for each account as of December 31, 2020, using the proposed life.

IV. THE DETAILS OF THIS DEPRECIATION RATE STUDY

A. The Four Phases of the Depreciation Study Process

This Study encompasses four distinct phases. The first phase involves data collection and field interviews. The second phase is where the initial data analysis occurs. The third phase is where the information and analysis are evaluated. Once the first three stages are complete, the fourth phase begins. This fourth phase involves the calculation of depreciation rates and documentation of the corresponding recommendations.

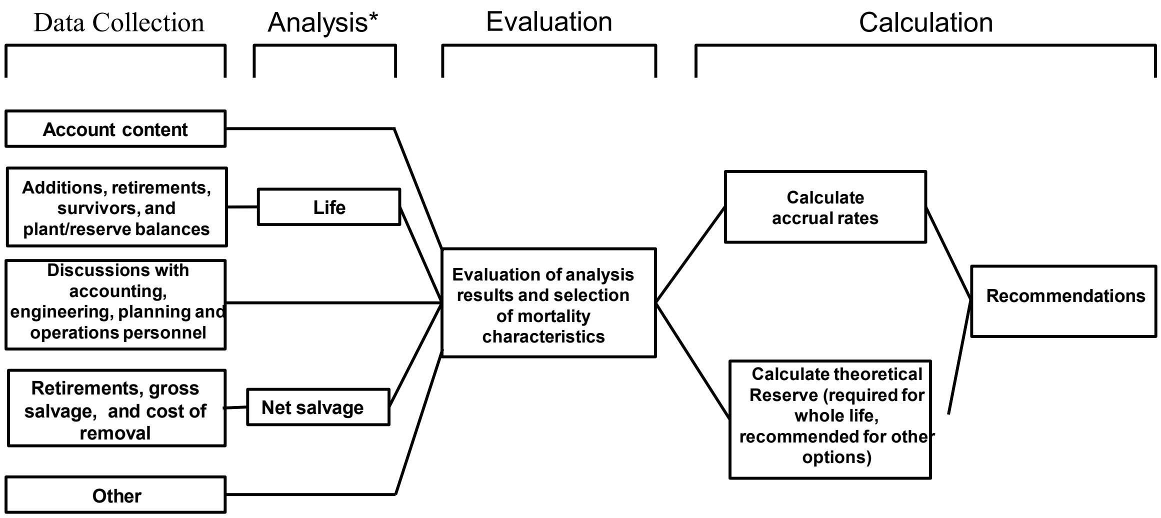
During the Phase I data collection process, historical data is compiled from property records and general ledger systems. Data is validated for accuracy by extracting and comparing to multiple financial system sources. Audit of this data is validated against historical data from prior periods, historical general ledger sources, and field personnel discussions. This data is reviewed extensively to put it in the proper format for the Study. Further discussion on data review and adjustment is found in the Salvage Considerations section of this Study. Also, as part of the Phase I data collection process, numerous discussions are conducted with engineers and field operations personnel to obtain information that will assist in formulating life and salvage recommendations in this Study. One of the most important elements of performing a proper depreciation study is to understand how the Company utilizes assets and the environment of those assets. Interviews with engineering and operations personnel are important ways to allow the analyst to obtain information that is beneficial when evaluating the output from the life and net salvage programs in relation to the Company's actual asset utilization and environment. Information regarding these discussions is found in the life analysis and salvage analysis discussions below in this Section IV of the Study and also in workpapers.

Phase 2 is where the actuarial analysis is performed. Phase 2 and 3 overlap to a significant degree. The detailed property records information is used in Phase 2 to develop observed life tables for life analysis. These tables are visually compared to industry standard tables to determine historical life characteristics. It is possible that the analyst will cycle back to this Phase 2 based on the evaluation process performed in Phase 3. Net salvage analysis consists of compiling historical salvage and removal data by functional group to determine values and trends in gross salvage and removal cost. This information is then carried forward into Phase 3 for the evaluation process.

Phase 3 is the evaluation process, which synthesizes analyses, interviews, and operational characteristics into a final selection of asset lives and net salvage parameters. The historical analysis from Phase 2 is further enhanced by the incorporation of recent or future changes in the characteristics or operations of assets that were revealed in Phase 1. Phases 2 and 3 allow the depreciation analyst to validate the asset characteristics as seen in the accounting transactions with actual Company operational experience.

Finally, Phase 4 involves the calculation of accrual rates, making recommendations and documenting the conclusions in the Study. The calculation of accrual rates is found in Appendix A. Recommendations for the various accounts are contained within this Section IV of this Study. The depreciation study flow diagram shown as Figure 1[2] below also documents the steps used in conducting this Study. DEPRECIATION SYSTEMS[3], at page 289, documents the same basic processes in performing a depreciation study which are: statistical analysis, evaluation of statistical analysis, discussions with management, forecast assumptions, and document recommendations.

[2] INTRODUCTION TO DEPRECIATION FOR PUBLIC UTILITIES & OTHER INDUSTRIES, AGA EEI (2013).
[3] W. C. Fitch and F.K.Wolf, DEPRECIATION SYSTEMS, Iowa State Press, at page 289 (1994).



Source: Introduction to Depreciation for Public Utilities and Other Industries, AGA EEI , 2013.

*Although not specifically noted, the mathematical analysis may need some level of input from other sources (for example, to determine analysis bands for life and adjustments to data used in all analysis).

Figure 1

ELIZABETHTOWN DEPRECIATION STUDY PROCESS

B. Depreciation Rate Calculation

1. Overview of Calculation

Annual depreciation expense amounts for all accounts are calculated by the Broad (Average Life) Group, Straight-Line, Remaining Life system.

In a whole-life representation, the annual accrual rate is computed by the following equation:

$$\text{Annual Accrual Rate} = \frac{(100\% - \text{Net Salvage Percent})}{\text{Average Service Life}}$$

Use of the remaining life depreciation system adds a self-correcting mechanism, which accounts for any differences between theoretical and book depreciation reserve over the remaining life of the group. With the straight-line, remaining life, system using Iowa Curves, composite remaining lives are calculated according to standard broad group expectancy techniques, noted in the formula below:

$$\text{Composite Remaining Life} = \frac{\sum \text{Original Cost} - \text{Theoretical Reserve}}{\sum \text{Whole Life Annual Accrual}}$$

For each FERC plant account, the difference between the surviving investment, adjusted for estimated net salvage, and the allocated book depreciation reserve as of December 31, 2020, is divided by the composite remaining life to yield the annual depreciation expense as noted in this equation. In the equation, the Net Salvage % represents future net salvage.

$$\textit{Annual Depreciation Expense} = \frac{\textit{Original Cost} - \textit{Allocated Book Reserve} - (\textit{Original Cost} * \textit{Net Salvage \%})}{\textit{Average Remaining Life}}$$

Within a group, the sum of the group annual depreciation expense amounts, as a percentage of the depreciable original cost investment summed, gives the annual depreciation rate as shown below:

$$\text{Annual Depreciation Rate} = \frac{\sum \text{Annual Depreciation Expense}}{\sum \text{Original Cost}}$$

These calculations are shown in Appendix A. The calculations of the theoretical depreciation reserve values and the corresponding remaining life calculations are shown in workpapers. The book depreciation reserve, as of December 31, 2020, is allocated by account from each functional reserve. The theoretical reserve computation and the average remaining life for each account is provided in the study workpapers. The calculation of the accrual rates is shown in Appendix A.

2. Remaining Life Calculation

The establishment of appropriate average service lives and retirement dispersions for each account within a functional group is based on engineering judgment that incorporates available accounting information analyzed using the Retirement Rate actuarial methods. After establishment of appropriate average service lives and retirement dispersion, remaining life is computed for each account. The theoretical depreciation reserve is calculated using theoretical reserve ratios as defined in the theoretical reserve portion of Section III of this Study. The difference between plant balance and theoretical reserve is then spread over the ALG depreciation accruals for each plant account. Remaining life computations are found for each account in the study workpapers.

3. Life Analysis

The Retirement Rate actuarial analysis method is applied to all accounts, where sufficient data exists, for Elizabethtown. For each account, an actuarial retirement rate analysis is made with placement and experience bands of varying width. The historical observed life table is plotted and compared with various Iowa Curves to obtain the most appropriate match. A selected Iowa Curve for each account is shown in Section IV (Determination of the Lives) below. The observed life tables for all analyzed placement and experience bands are provided in workpapers.

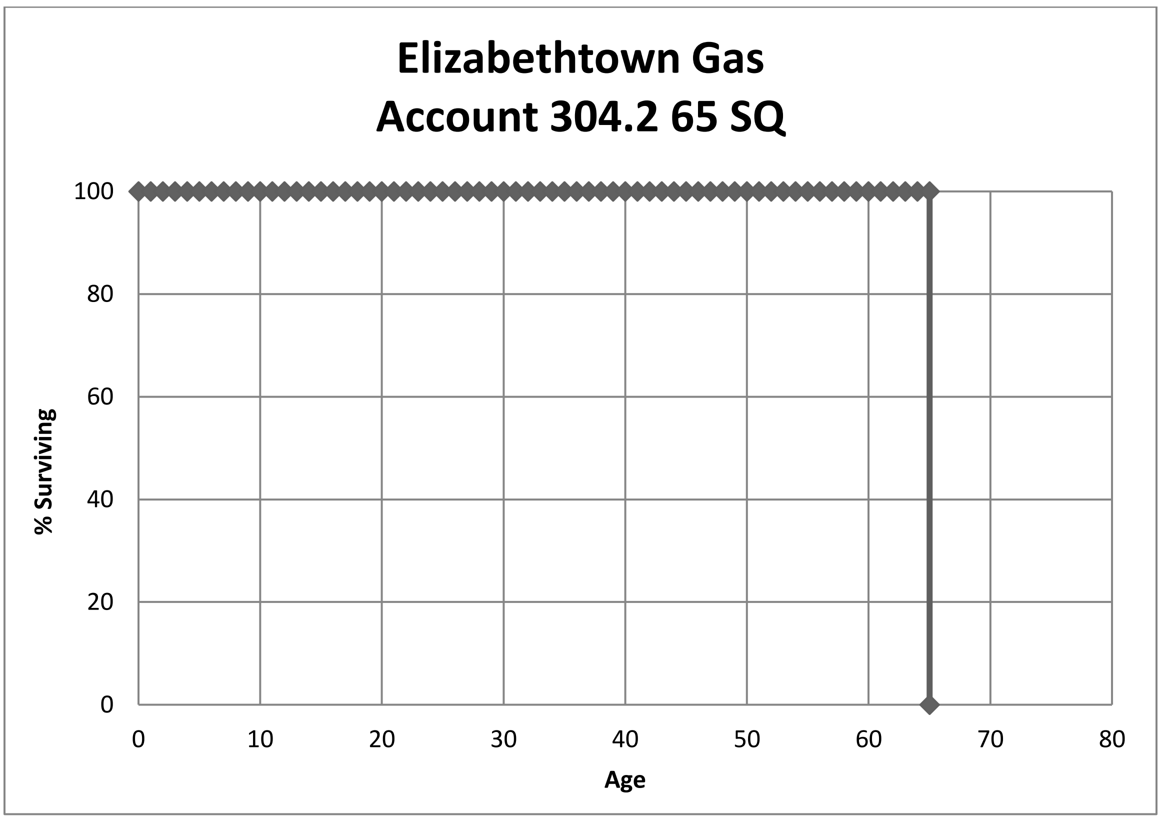
For each account on the overall band (*i.e.*, placement from earliest vintage year available for each account through 2020), the survivor curves underlying the depreciation rates stipulated and approved in Docket No. GR19040486 were used as a starting point. Using the same average life, various dispersion curves are then plotted. Frequently, visual matching confirms one specific dispersion pattern (*e.g.*, L, S., or R) as an obviously better match than others. The next step is to determine the most appropriate life using that dispersion pattern. After looking at the overall experience band, different experience bands are then plotted and analyzed as follows: in increments from the overall band to a middle-range band, then the most recent bands. Next, placement bands of varying width are plotted within each experience band discussed above. Repeating the process across the various bands usually points to a focus on one dispersion family and small range of service lives. The goal of visual matching is to minimize the differential between the observed life table and Iowa Curve in the top- and mid-range of the plots. These results are used in conjunction with all other factors that may influence asset lives.

V. DETERMINATION OF THE LIVES

A. Manufactured Gas Plant

<u>FERC Account 304.20 Land Rights 65 SQ</u>

This account includes the cost of land rights associated with manufactured gas production plant. At December 31, 2020, there was approximately $61 thousand in this account. The current approved life is 65 SQ. There is not enough retirement activity for a meaningful analysis. Based on the type of assets and judgment, this Study recommends retention of the existing service life. A representative graph of the life of the account is shown in the curve below.



FERC Account 311.00 Liquefied Petroleum Gas Equipment 35 S3

This account contains vaporizer valves but would generally have other types of equipment used in the production of gas from petroleum derivatives. At December 31, 2020, there was approximately $809 thousand in this account. The existing parameter is 35 S3. Discussions with Company personnel indicated they no longer operate this equipment, and it was determined $155,623.76 would be transferred to Account 363.20 Vaporizing Equipment and $652,908.59 would be retired, leaving a zero balance in this account. This proforma adjustment has been reflected in the study. No future activity is expected.

FERC Account 320.40 Other Equipment 12 L2.5

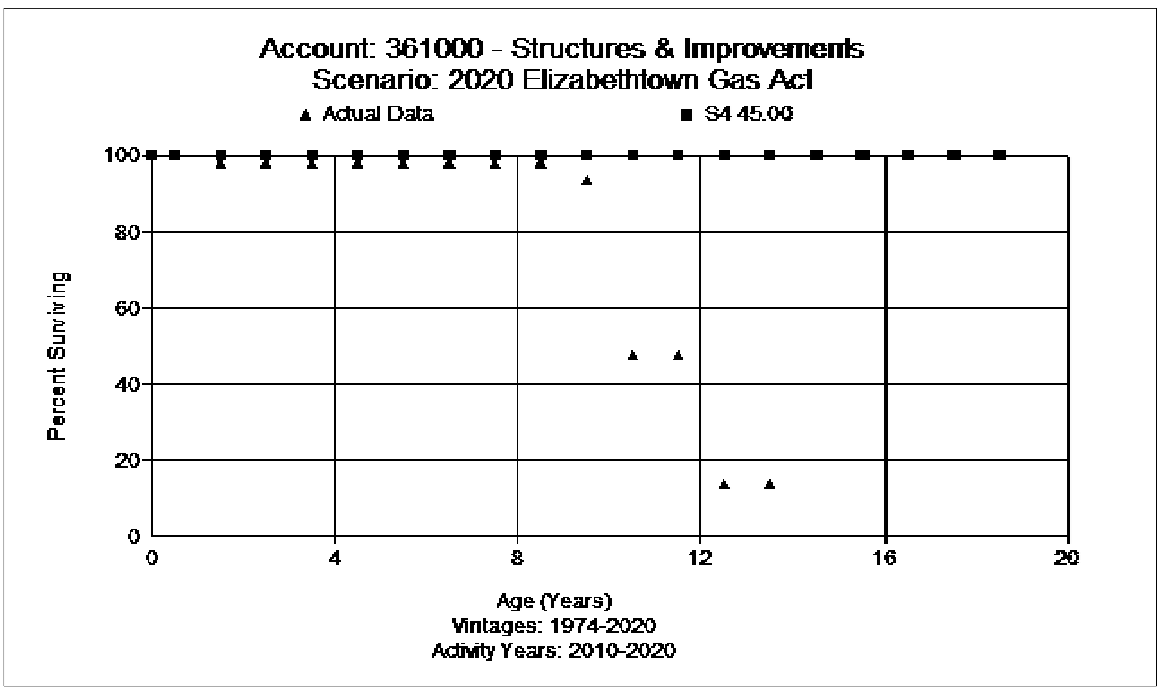
This account contains gas detection, fire detection, and other miscellaneous equipment associated with manufactured gas production plant. At December 31, 2020, there was approximately $440 thousand in this account. The current approved life is 15 years with the L1 dispersion. Based on the analysis the life is decreasing and we would recommend moving to 12 L2.5. However, discussions with Company personnel indicated they no longer operate this equipment, and it was determined $266,121.78 would be transferred to Account 391.00 Office Furniture and Equipment and $173,509.18 would be retired, leaving a zero balance in this account. This proforma adjustment has been reflected in the study. No future activity is expected.

B. Other Storage Plant

Storage Accounts, FERC Accounts 361.00–363.40

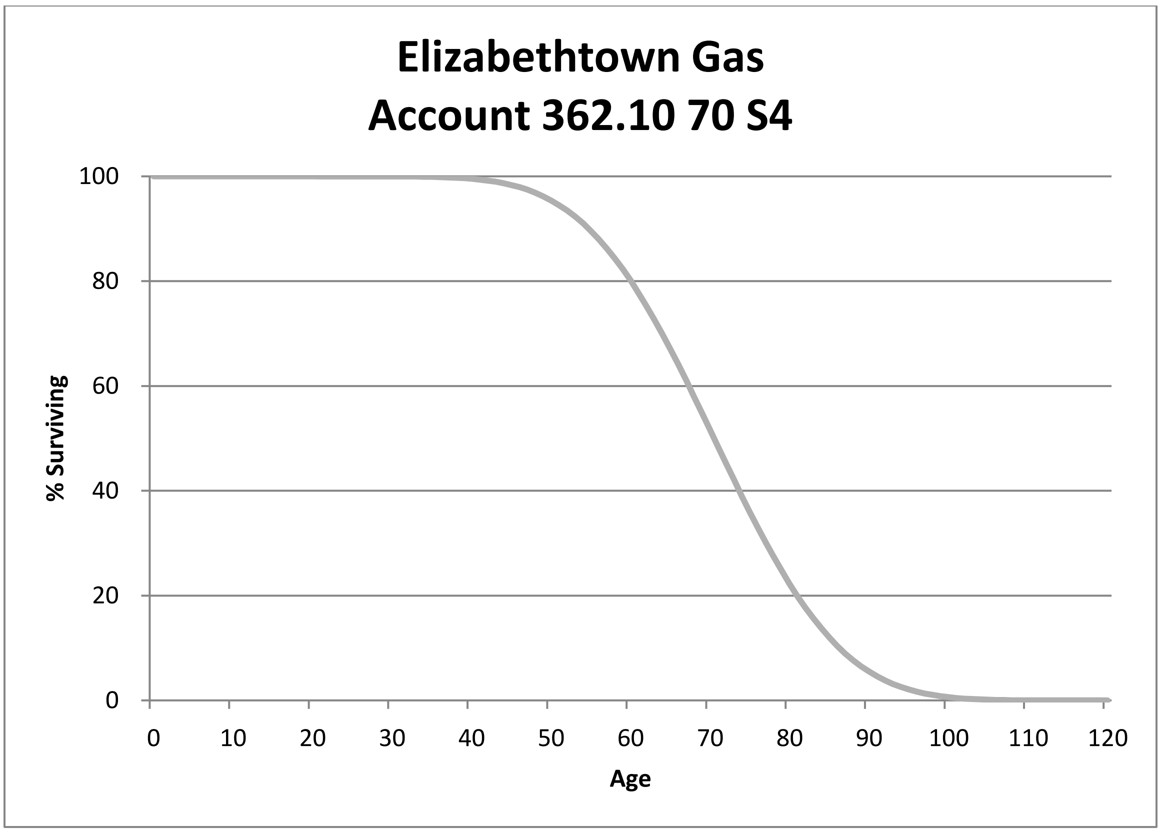
FERC Account 361.00 Structures and Improvements 45 S4

This account includes the cost of structures and improvements in connection with building station control, security systems, yard improvements, protective fencing, and other structures for other storage plant. At December 31, 2020, there was approximately $4.6 million in this account. The current approved life for this account is 45 years with the S4 dispersion. Discussions with Company personnel indicated the buildings are concrete, metal, and steel, and the existing life remains appropriate for the assets. However, the life analysis suggests a life much shorter than the existing life parameters. Best fits in the analysis are around 11 years. Based on the analysis, discussions with Company personnel, the type of assets in the account, and judgment, this Study recommends retention of the existing 45 S4 at this time. A graph of the observed life table versus the proposed curve is shown below.



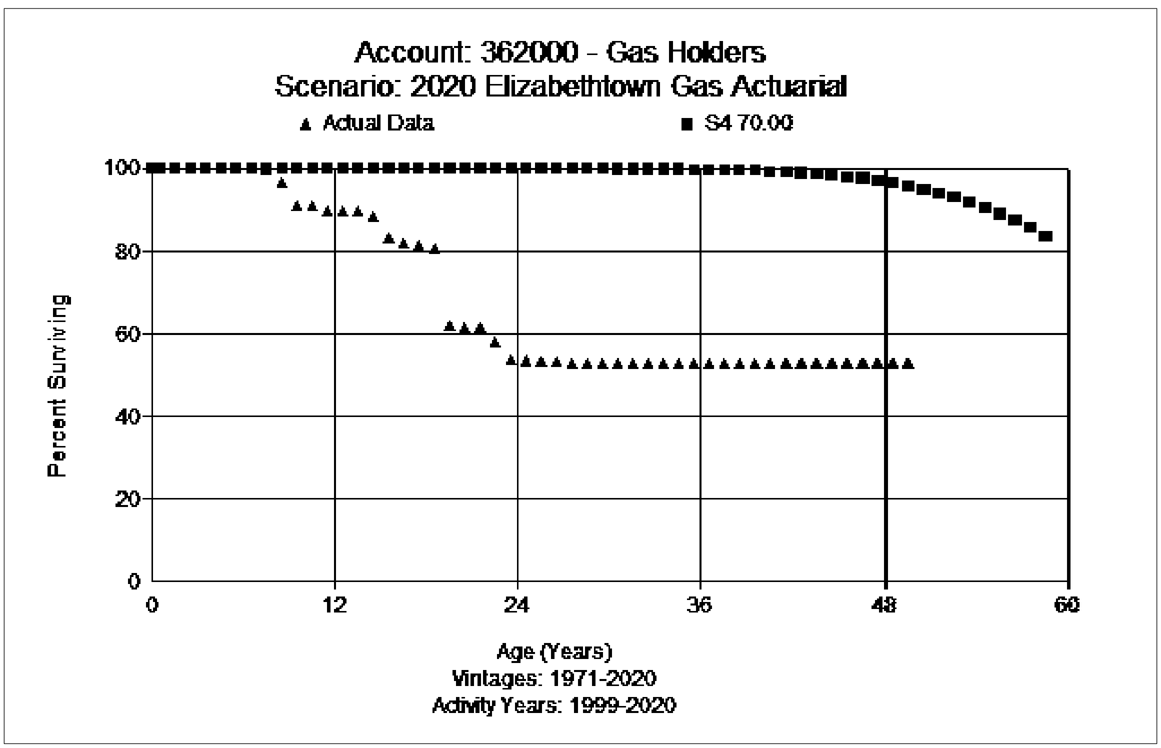
FERC Account 362.00 Gas Holders – Natural Gas 70 S4

This account includes the cost of natural gas holders (tanks) used in the storage function. At December 31, 2020, the balance is $3.6 million. However, it was determined that these assets are LNG related and should be transferred to 36210, which is reflected as a proforma adjustment in the study. The current approved life for this account is 65 years with the S4. The life analysis that was performed is shown below in Account 362.10. If assets are added to this account, the same life used for Account 362.10, 70 S4 is proposed along with a whole life rate.



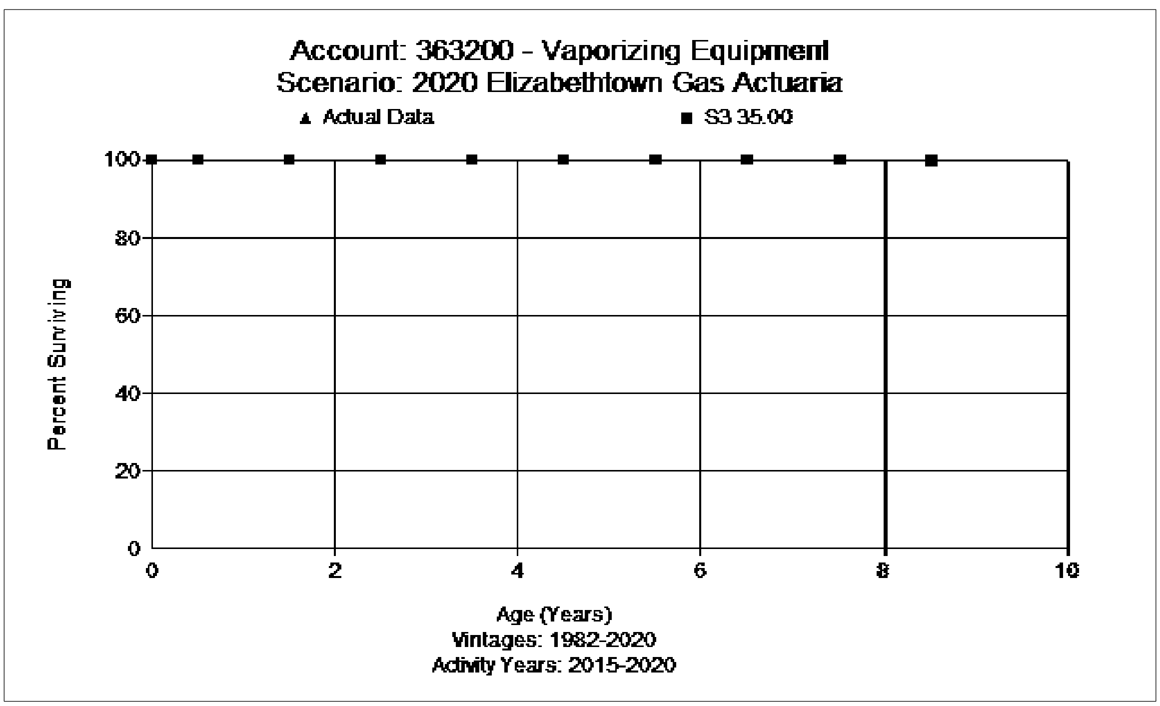
FERC Account 362.10 Gas Holders – LNG 65 S4

This account includes the cost of LNG holders (tanks), piping, valves, and other miscellaneous equipment used in the storage function. At December 31, 2020, there was no balance. However, it was determined that Account 362.00 assets are LNG related and should be transferred to 36210, which is reflected as a proforma adjustment in the study. The current approved life for this account is 65 years with the S4 dispersion. Discussions with Company personnel indicated the tank is original equipment (1972 vintage). Carbon steel outer, painted, with a nickel steel alloy interior, which sits off the ground. The facility is well maintained, the tank is wearing well, and maintenance is constant. The life analysis indicates a much shorter life, but it is not reasonable for the type of assets and expectations. This study recommends increasing the life to 70 years and retaining the S4 curve. A graph of the observed life table versus the proposed curve is shown below.



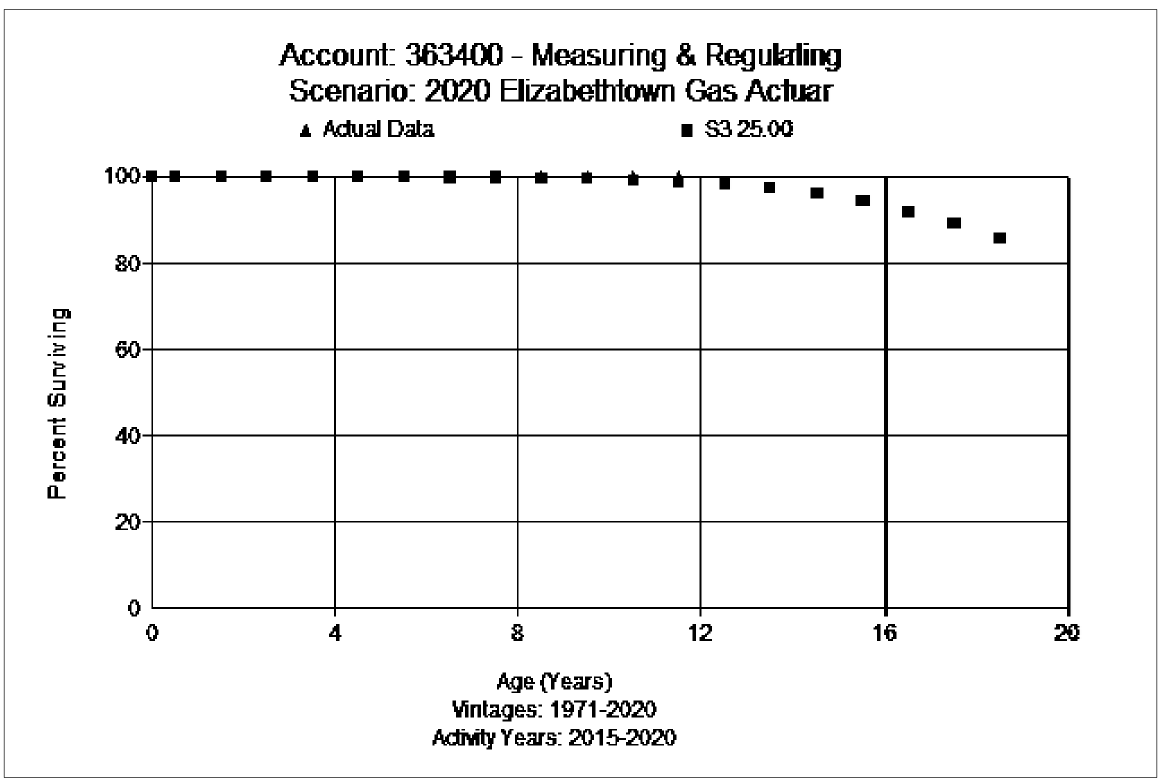
FERC Account 363.20 Vaporizing Equipment 35 S3

This account consists of vaporizers, liquefaction equipment, boiler, piping, and pump equipment associated with the LNG plant. There is approximately $16.9 million in this account at December 31, 2020. However, during the study it was determined that $155, 623.76 in vaporizer valves from Account 311 would be transferred to this account. Additionally, a retirement, $10.1 million, for vaporizer equipment related to Erie Street was included as a proforma adjustment. The study balance is now $7.0 million. The approved life for this account is 35 years with the S3 dispersion. Discussions with Company personnel indicated that in 2015 the Company started building liquefaction assets for two units at Erie Street. The equipment in this account (other than the liquefaction equipment) is now outdated and replacement parts are getting harder to find. Company personnel expect to have to replace much of the equipment within the next 10 years. Company personnel indicated a 35-year life is still reasonable. Based on the type of assets, discussion with Company personnel, and expectations, the Study recommends retention of the 35 S3 dispersion pattern. The observed life table versus the proposed is graphed for this account below.



FERC Account 363.40 Measuring & Regulating Equipment 25 S3

This account consists of measuring and regulating station equipment used for LNG storage operations. There is approximately $2.9 million in this account. The approved life for this account is 25 years with the S3 dispersion. The average age of retirements is 29 years, and the average age of surviving assets is about 5 years. Discussions with Company personnel indicated most of the current investment is related to the control systems, which are expected to last, even without obsolescence, for only 20 years. Some of the control system assets, like the computers, monitors, and network equipment, will only last 5 years. Mixed with the other assets, the overall life for the account is expected to be around 25 years. Current assets are young, so based on type of assets and discussions with Company, the Study retains the 25 S3 dispersion pattern. The observed life table versus the proposed is graphed for this account below.

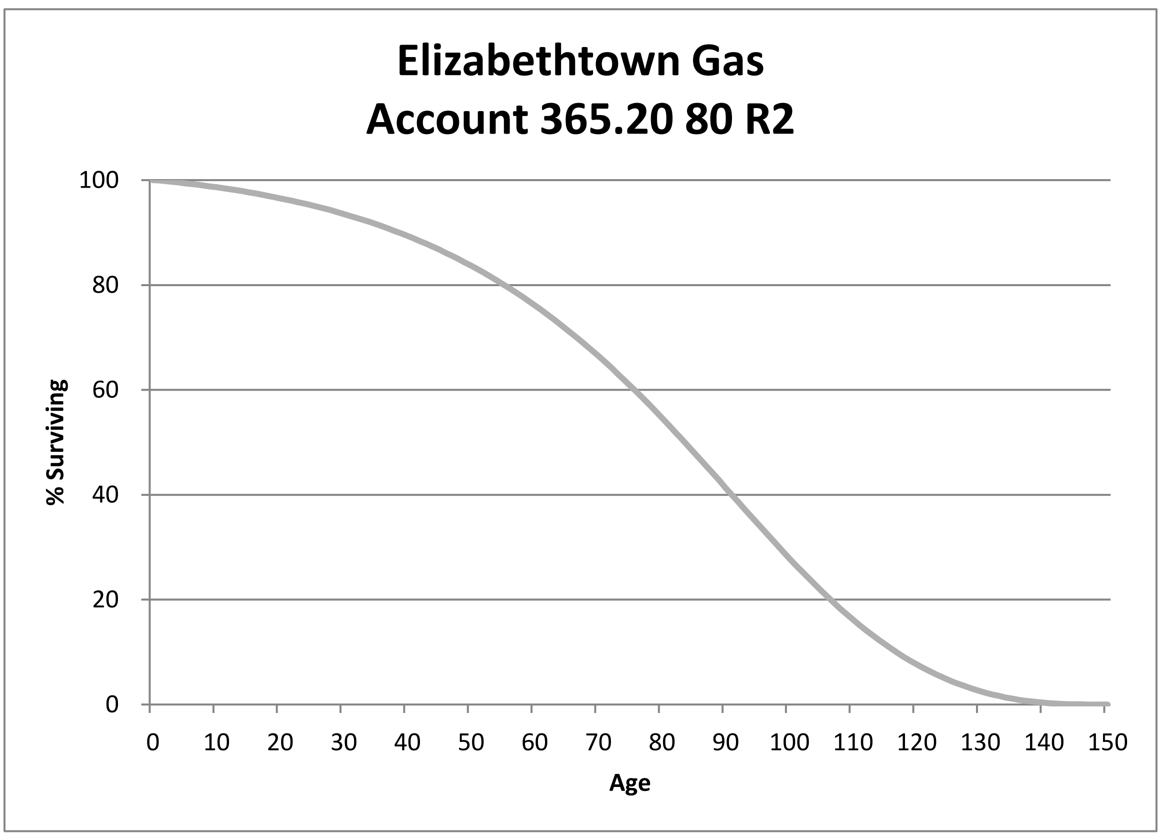


C. Transmission Plant

Transmission Accounts, FERC Accounts 365.20–371.0

FERC Account 365.20 Rights of Way 80 R2

This account includes the cost of rights of way, legal fees, and recording costs associated with transmission assets and operations. There is approximately $367 thousand in this account. The approved life for this account is 80 years with the R2 dispersion. There have been no retirements recorded and few are expected in the intermediate future. These land rights are generally used in conjunction with the installation of mains so a reasonable expectation is the life would at least equal or exceed the life of mains. Based on the 71 year life recommendation for Account 367, Mains in this Study, the Study retaining the 80-year life and R2 dispersion. A representative graph of the life of the account is shown in the curve below.

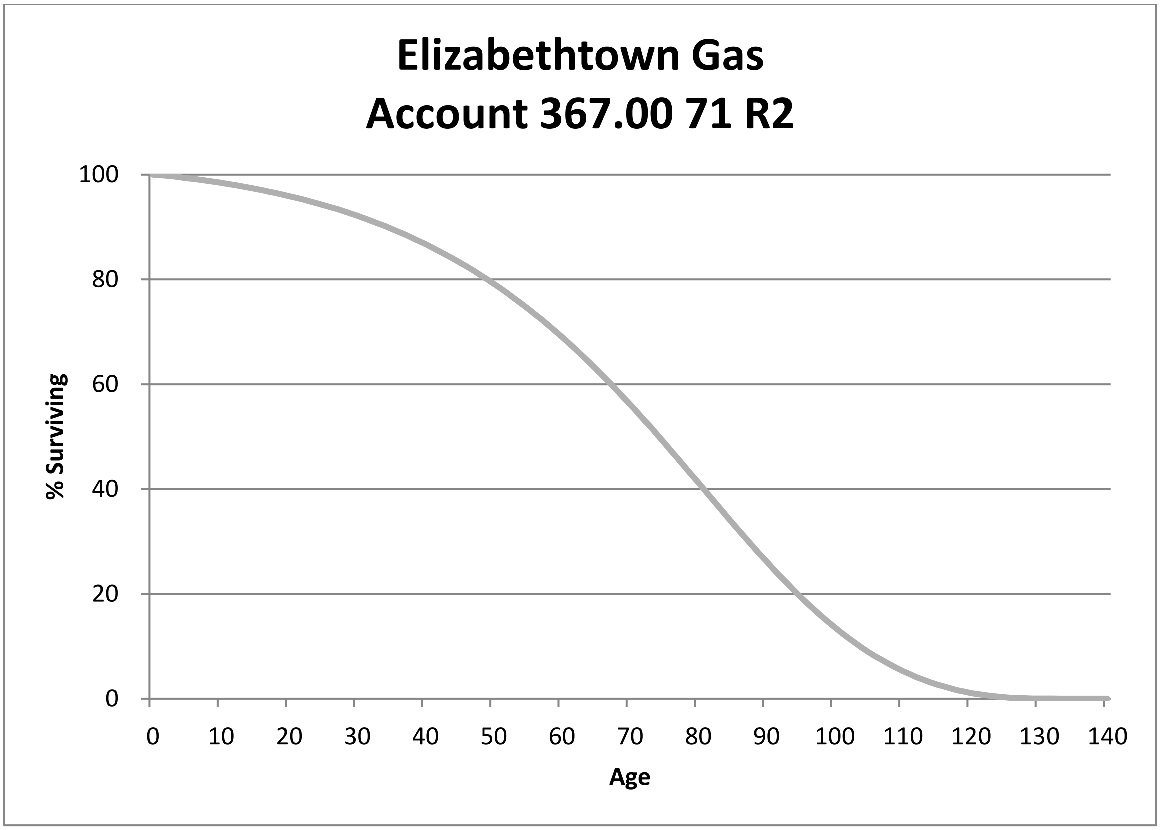


<u>FERC Account 367.00 Mains - All 71 R2</u>

This account includes transmission mains of all sizes, rectifiers and ground beds used for cathodic protection, valves and leak clamps associated with pipe. There is approximately $18.3 million as of December 31, 2020. However, during the discussions with Company personnel they indicated 1.5 miles of main had been retired in 2020. The study has reflected this retirement of $4,435,634.11 as a proforma adjustment, which reduces the study depreciable balance for this account to $13.9 million. The approved life is 71 R2.

Discussions with Company personnel indicated there is currently about 12.5 miles of transmission pipe on the system. The oldest transmission mains, which were installed in the 1970's, consist of 3.5 miles of 10" diameter pipe. There are also 9 miles of 12" diameter pipe from the 1980's. Recently, a third main was down rated to distribution operationally. They expect transmission mains to last at least as long as distribution mains. Assessments of the transmission mains in recent years make the Company comfortable with retention of the existing life.

The current average age of survivors, almost 7.5 years, is relatively young for this type of asset. Retirement activity has been limited, so no life analysis was performed. Based on type of assets and expectations, this Study retains the existing 71 R2. A representative graph of the life of the account is shown in the curve below.

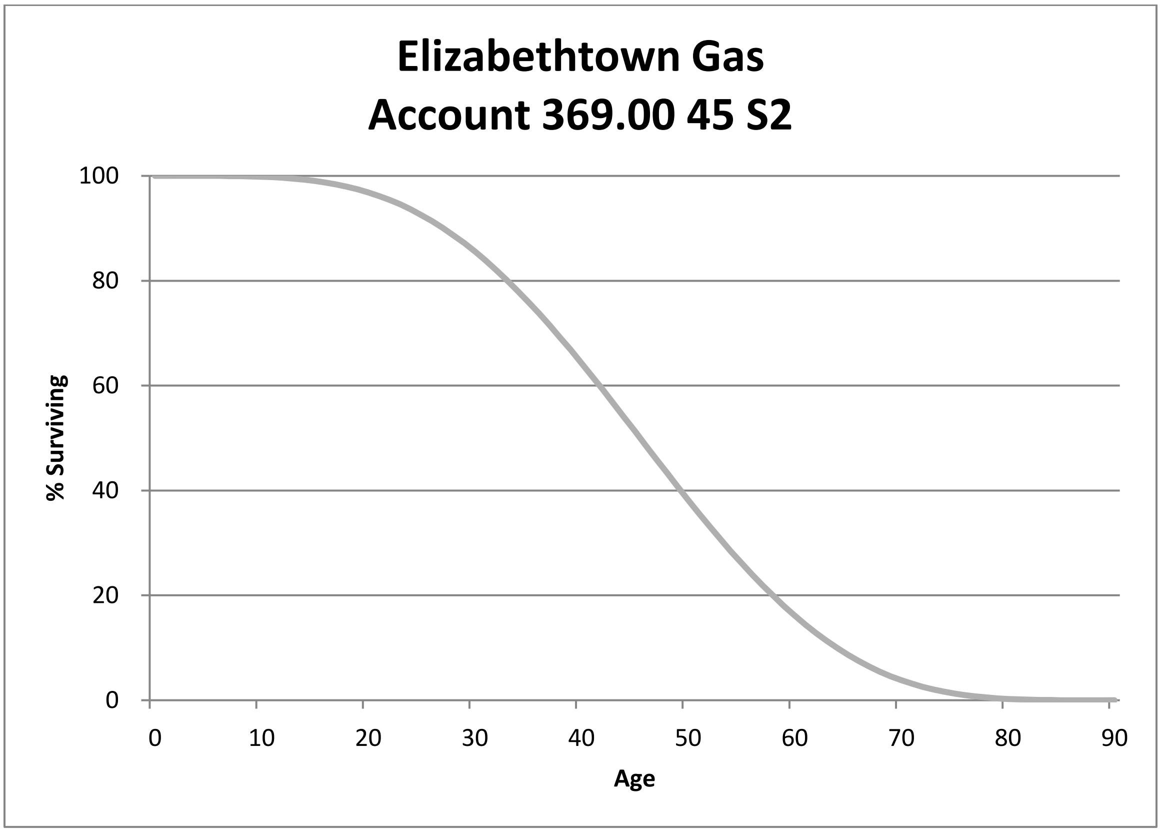


<u>FERC Account 369.00 M&R Station Equipment 45 S2</u>

This account includes measuring equipment, gauges, piping, and valves associated with the transmission system. There is approximately $8.5 million in this account. The approved life for this account is 45 S2. Only $8 thousand of the $8.5 million in assets has a vintage before 2008.

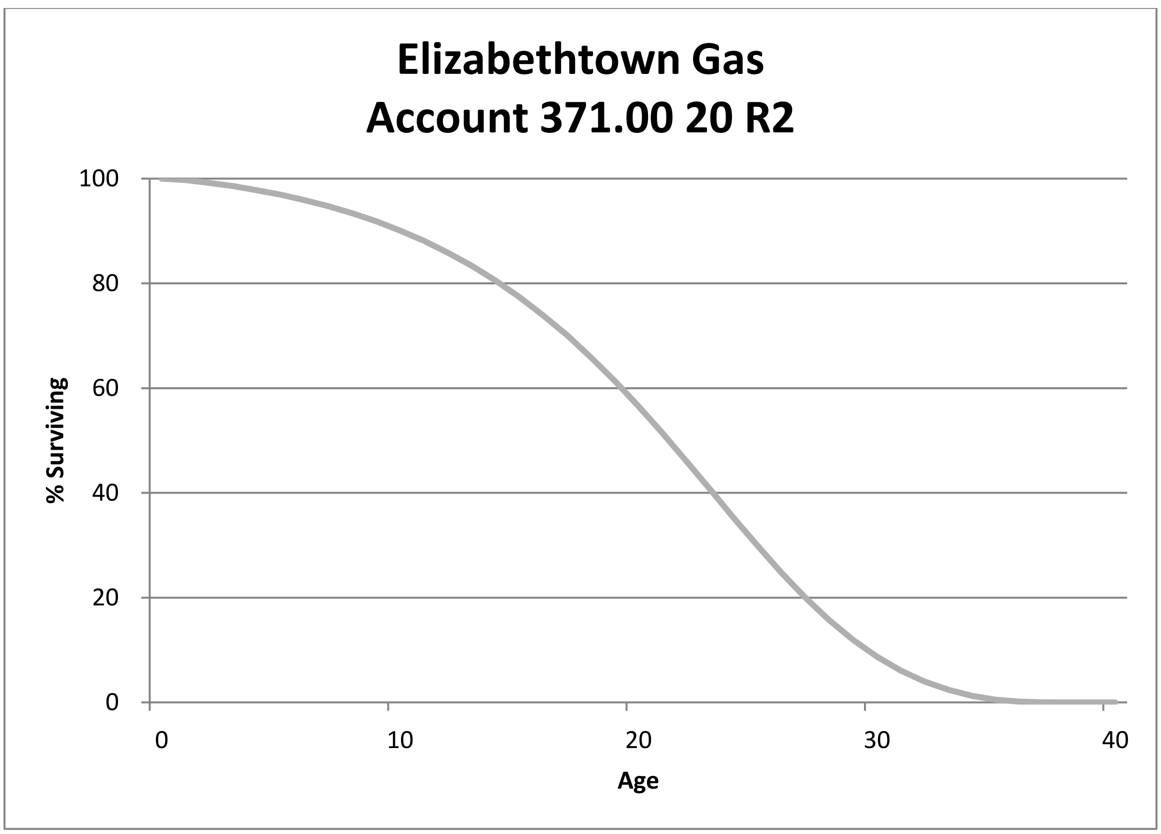
Discussions with Company personnel indicated there are two transmission stations, which connect the 3rd party take points to the Company's transmission system: Warren Glen and New Village. The Company has just started to replace SCADA equipment and electronics, but it has not yet been moved through to accounting.

Overall, there has not been enough retirement activity for life analysis. These stations have basically the same equipment as 379 City Gates and are expected to have the same life. Based on the type of assets, the life of Account 379 City Gates and Company expectations, this study recommends retention of the 45 S2. A representative graph of the life of the account is shown in the curve below.



FERC Account 371.00 Other Equipment 20 R2

This account includes miscellaneous equipment associated with the transmission system. There is approximately $56 thousand in this account. The approved life for this account is 20 R2. Current surviving assets were recorded in the account in 2011 and 2019 and have an average age of 2 years. There has been limited retirement activity in this account, so no life analysis was performed. The average age of the few retirements that have been recorded is nearly 7 years. Based on judgment, the Study recommends retention of the life of 20 years with the R2 dispersion. A representative graph of the life of the account is shown in the curve below.

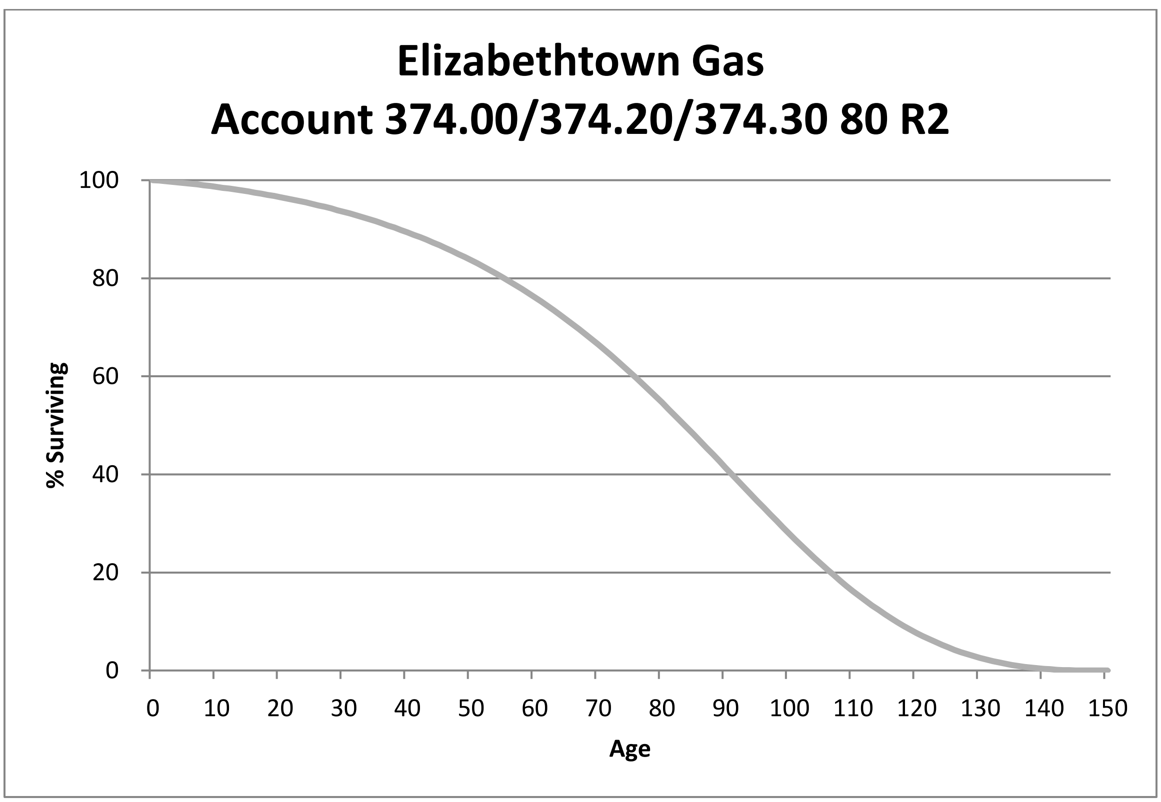


D. Distribution Plant

Distribution Plant Accounts, FERC Accounts 374.10–387.00

FERC Account 374.00/374.20/374.30 Land Rights and Right of Way 80 R2

This account includes the cost of land rights used in connection with distribution operations. There is approximately $2.9 million in this account. The approved life for this account is 80 R2. There have been very limited retirements recorded and few are expected in the future. These land rights are generally used in conjunction with the installation of mains and other distribution property so a reasonable expectation is that the life would equal or exceed the life of mains. Based on the proposed life, 71 years, for Account 376, Mains, this Study recommends retention of the 80 R2. A representative graph of the life of the account is shown in the curve below.

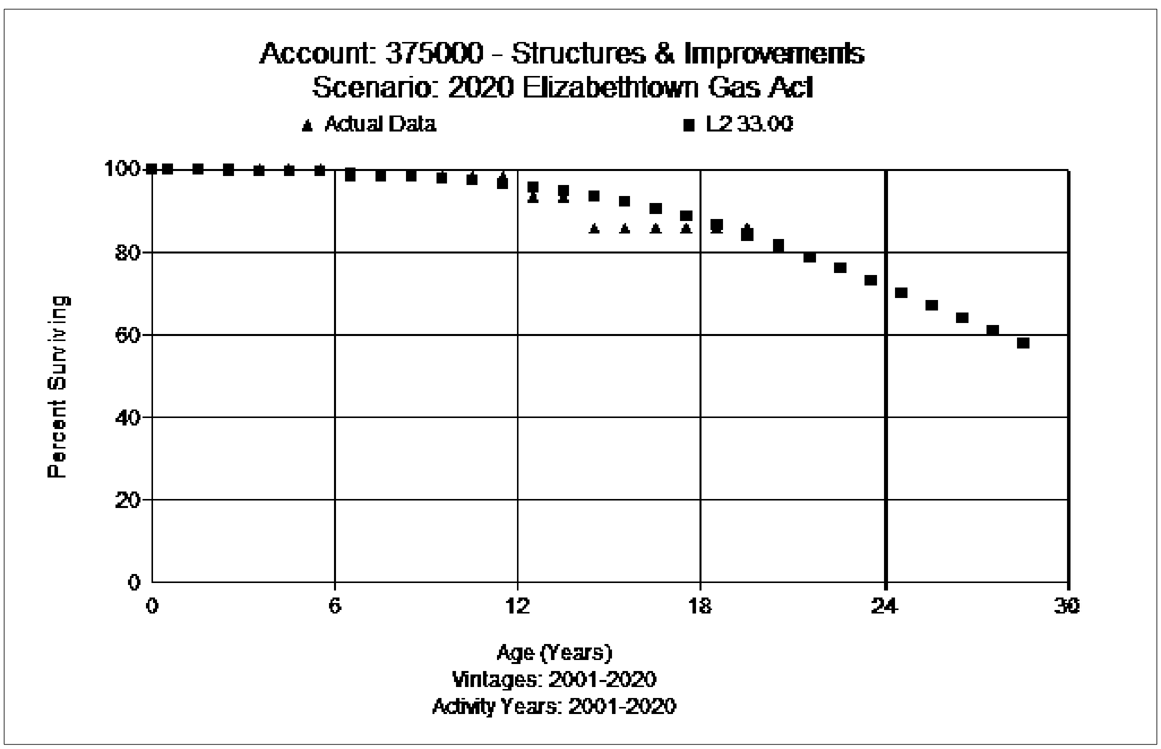


FERC Account 375.00 Structures and Improvements 33 L2

This account includes Erie Street structures, Green Lane training center along with two portable steel buildings and other miscellaneous structures and improvements associated with the gas distribution system. There is approximately $5.8 million in this account. The approved life for this account is 33 years with the L0.5 dispersion. Currently there are no assets with a vintage older than 2001 and $4.8 million of the total balance is from 2017 or newer.

Discussions with Company indicated there are some longer lived assets as well as shorter lived assets (e.g., instrumentation would have a life of 10 years).

The life analysis is limited but suggests a lower life than the existing life. Based on the type of assets, recent activity, and discussions with Company personnel, this study proposes retaining the 33-year life and changing to an L2 dispersion pattern. The observed life table versus the proposed is graphed for this account below.



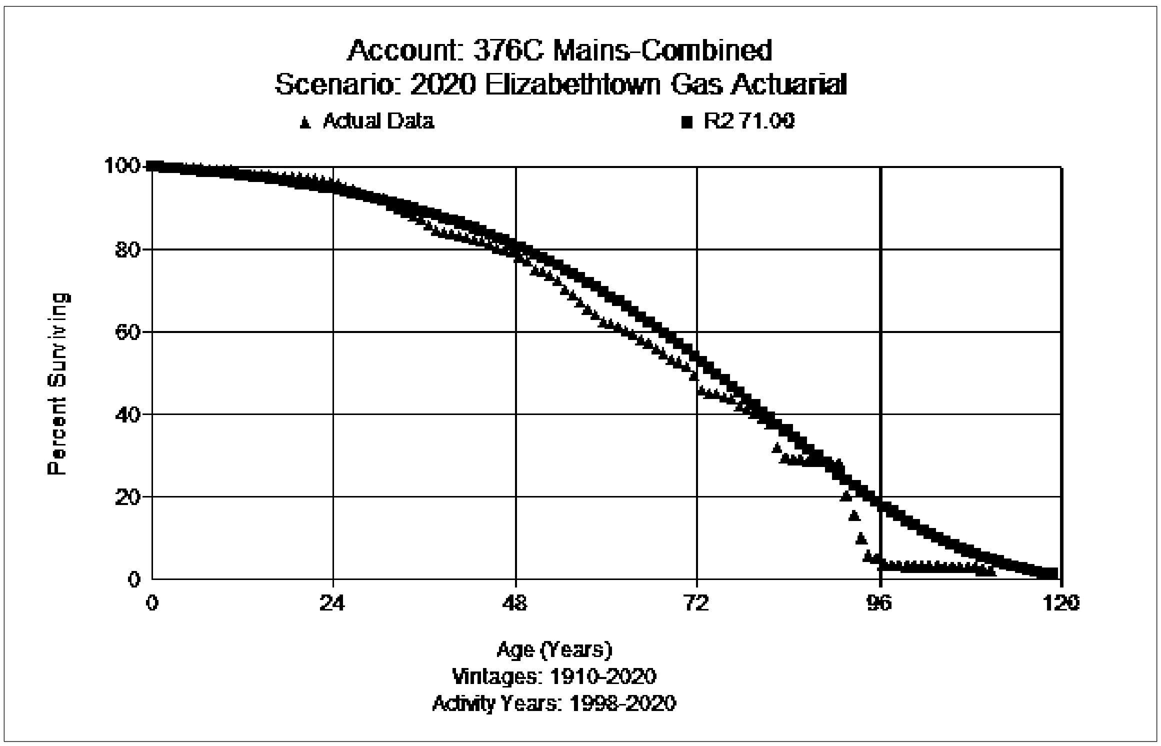
FERC Account 376.00 Mains – All 71 R2

This account consists of all distribution mains, which comprise cast iron, steel, and plastic. There is approximately $660 million of investment in this account. The approved curve for this account is the 71 R2. The Company has been replacing cast iron over the years. Of the 3,200 miles of main, a third is steel and all are cathodically protected. The Company mostly uses anodes, which are capitalized with original installation, but replacement of anodes will be expensed.

Discussions with Company personnel indicated a lot of the historical retirement experience would be related to the cast iron mains and some DOT relocations. There is not a lot of vintage plastic (defined as plastic installed prior to approximately 1983). In the 1990s, they increased their pipeline replacement initiatives targeting vintage pipe replacements (e.g., cast iron). Since 2005, they have had various vintage pipe replacement programs in place during various time periods. There is a program approved by the Board of Public Utilities called IIP (Infrastructure Investment Program), which will replace 50-75 miles of pipe per year for 5 years. The replacements are consistent with replacement over the last few years and the plan contemplates a continuation of the replacements at that level. The program started in 2019 and goes through 2024. The vast majority of new pipe installed is plastic. The IIP program will also target replacing low-pressure pipe with medium pressure systems. The Company also is planning to replace its early generation plastic – Aldel-A but there is not a lot of the early generation plastic on the system. Company personnel believe the current life of 71 years is reasonable.

In the life analysis, the full band observed life table continues to indicate a lower life. The 68 R2 is a better fit than the approved 71 R2. A mid-placement band of 1951-2020, which drops to around 40 percent surviving has a great fit at 65 R2. This shorter life is influenced by the past infrastructure replacement activity that was occurring and now with the approved five-year IIP activity that is expected to occur through 2024. However, as the older pipe is replaced with newer pipe, the shorter life indication is expected to move back to the existing life. The existing 71 R2 in the full band, is a reasonably good fit at this time and drops to nearly zero percent, providing a full curve.

Based on the analysis, along with the Company's plans to finish replacing cast iron pipe, as well as any early vintage plastic on the system, the Study recommends retention of the 71 R2 dispersion pattern at this time. The observed life table versus the proposed is graphed for this account below.



FERC Account 378.00 Measuring & Regulating Equipment 35 S2

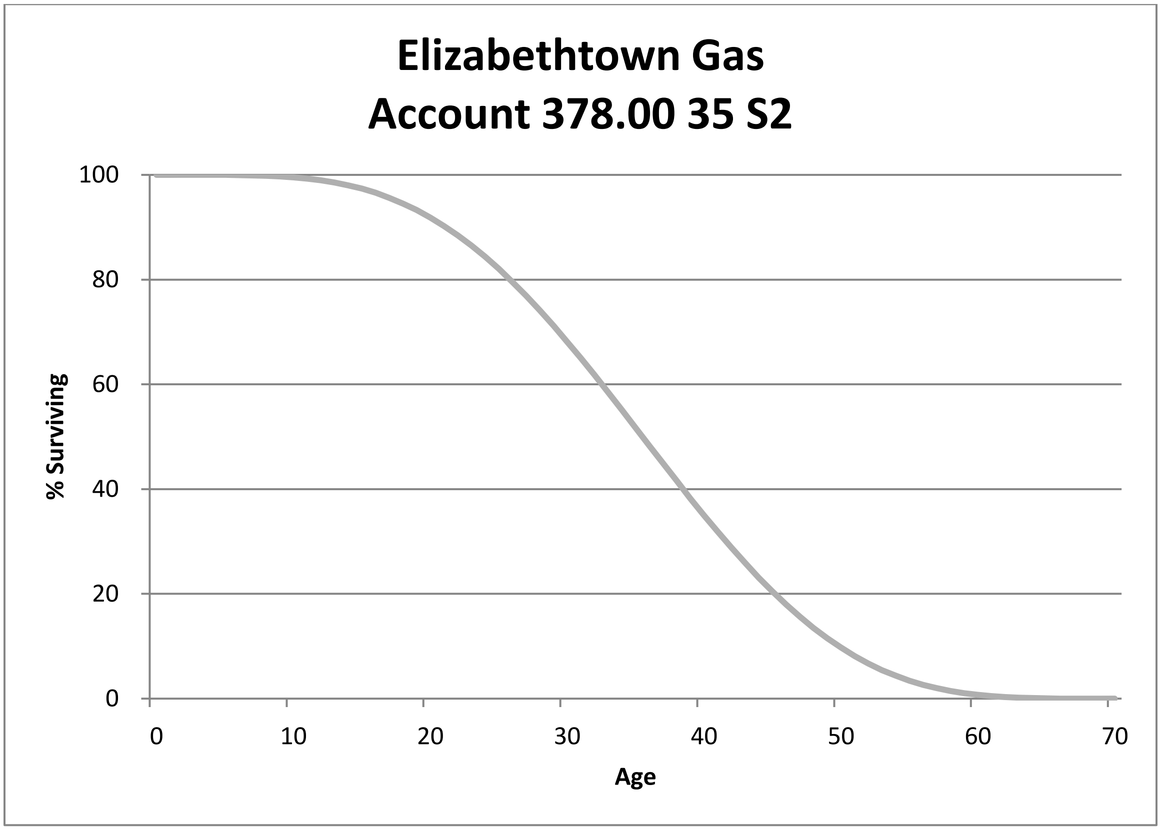
This account consists primarily of valves, regulators, and heaters. There is approximately $20 million of investment in this account at December 31, 2020. The approved curve for this account is the 35 S2. There is a proforma retirement adjustment of nearly $2 million that has been reflected in the study making the study balance for this account $17.9 million.

Discussions with Company personnel indicated there are approximately 270 district regulator stations ("DRS") that change higher pressure distribution to lower pressure distribution. There is a total of 180 DRS that have been targeted for retirement due to low pressure. The Company indicated they have already retired around 15 stations in the last couple years (2020-2021). The remaining 165 low pressure DRS are expected to be retied in the near future.

Drivers of retirements for DRS is due to capacity changes, which does not affect City Gates but does create a shorter life. The DRS boxes are galvanized steel and may have to be replaced in 20 years, as 99% of the DRS are below grade. Salt is an issue creating corrosion on the pipe and regulators. After the labor to install the station, the regulator is the next most expensive part of a station. The regulator life would be around 30 years or more – the oldest regulator on the system may be 35-40 years old. The Company believes leaving the DRS account at 35 years is reasonable.

The historical retirement data included about $5 thousand of retirements recorded to date. This level of retirement activity is not conducive to a meaningful life analysis, as indicated by a 98 percent surviving in the full band. However, as noted above, during interview discussions with Company operations personnel the assets related to the 15 DRS retirements had not been received into property accounting records for processing. As a result, the study balance used to calculate the annual depreciation expense accrual and rate reflects a proforma retirement adjustment of nearly $2 million.

Giving consideration to the life analysis, the proforma retirement activity along with Company plans to retire another 165 low pressure DRS in the near future, this study recommends retention of the existing 35 S2 at this time. A representative graph of the life of the account is shown in the curve below.



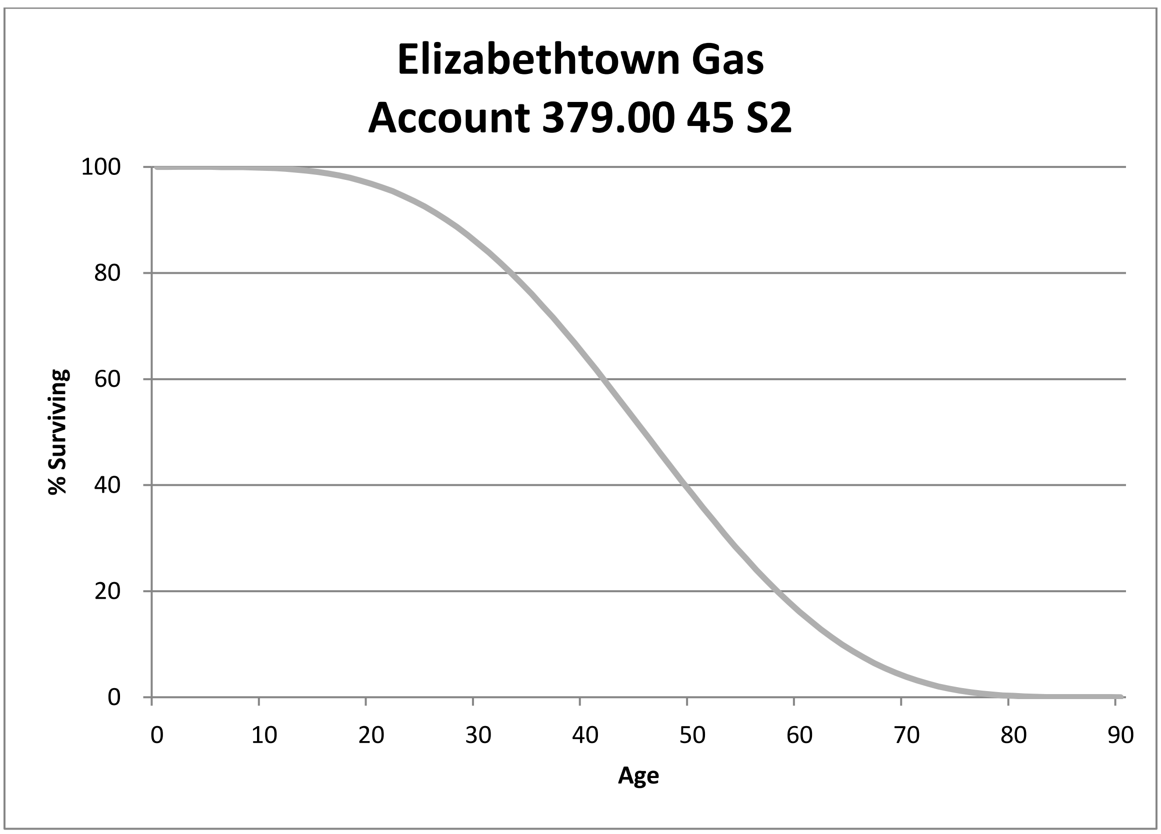
<u>FERC Account 379.00 M&R - City Gate Equipment 45 S2</u>

This account consists primarily of valves, regulators, and heaters used at receipt points on the distribution system. There is approximately $21.3 million of investment in this account. The approved curve for this account is the 45 S2. City gate stations connect 3rd party suppliers to the distribution system.

Discussions with Company personnel indicated the city gates are above ground and are inspected much more often. They are also less exposed to salt.

They would expect city gates to have a longer life than DRS. Capacity is a driver of retirement/replacement. Many components are expected to last up to 50 years. Heaters would have a shorter life in many cases. SCADA systems would also have a shorter life (10-15 years on electronics). Orifice plate would have a life of pipe. For the turbine meters, the modules are changed out every two years under O&M but otherwise would have a life of pipe as well. The Company believes the existing 45-year life is reasonable.

No retirements have been recorded. The average age of the surviving balance is nearing 27 years. There were no retirements recorded to this account. Based on type of assets, similarity in form and operation with other M&R accounts, and Company input, this Study recommends retention of the 45 S2 dispersion pattern. A representative graph of the life of the account is shown in the curve below.

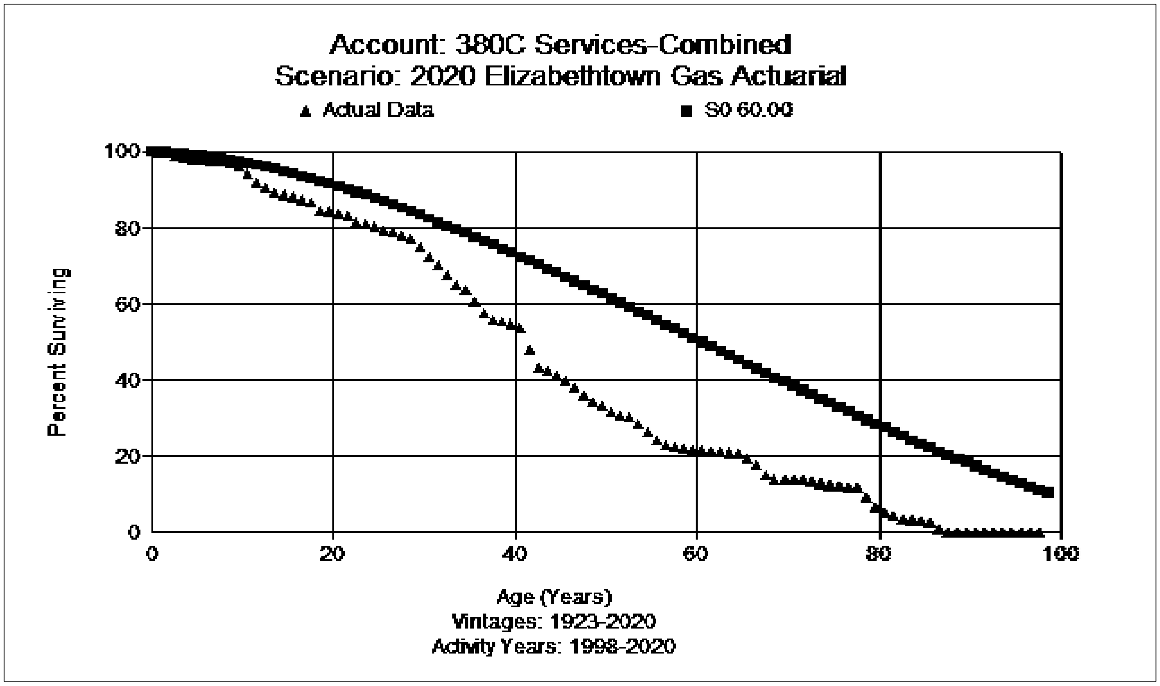


FERC Account 380.00 Services - All 60 S0

This account consists of steel, plastic, and some copper services. There is approximately $460 million of investment in this account. The approved curve for this account is the 60 S0. As mentioned above for Mains, the Company has been engaged in replacing aging infrastructure. Current average age of surviving assets is approximately 13 years.

Discussions with Company personnel indicated there are approximately 227 thousand services, with around 44 thousand services targeted in the BPU approved IIP. They expect services historically to have a shorter life than mains. If a main is replaced, the service will be replaced. Capacity on services will also result in retirement of services. If a service is leaking or undersized, it could be replaced without other components being replaced, but this is rare. It will also replace the meter set and regulator at that time, especially as related to the IIP program. There is a meter move out component to the program which was also being performed before the IIP started. When replacing a main, the Company will replace a service, meter loop, and regulator at that time, so they are all expected to have a similar life.

The analysis indicates a shorter life than existing. In the full band 43 L1.5 is a great fit. In a more recent placement band, a 38 R1.5 is a good fit. As mentioned above, as the IIP is completed and older services are replaced with newer ones, the shorter life indication is expected to move back to the existing life. Factoring in IIP, the type of assets, the analysis, and Company expectations, this Study proposes retention of the 60 S0 dispersion pattern at this time. The observed life table versus the proposed is graphed for this account below.

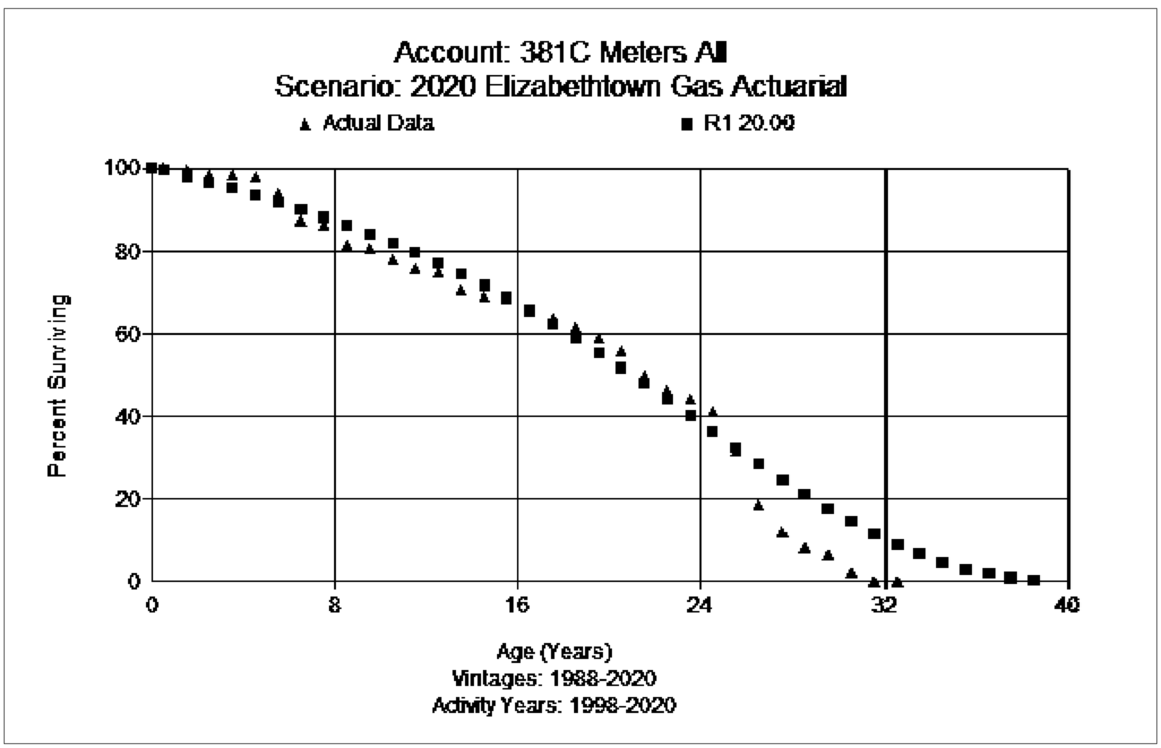


FERC Account 381.00 Meters – All 20 R1

This account includes the cost of meters and related equipment used in measuring gas to customers. The current investment is approximately $123 million. The approved curve for this account is the 28 R1.5. The Company currently uses Itron ERTs (100G).

Discussions with Company personnel indicated that the Company is using 100G and will be moving to 500G. It will replace the ERT when replacing the meter and they will replace the meter if the ERT fails for residential customers. For industrial customer, the Company might only replace the ERT. The Company no longer will repair or refurbished meters. They expect a 15-year life on the ERTs but only really seeing around 10 years. The Company believes the weather is having some impact. The Company capitalizes meters on purchase. There has been no material change in the sampling technique over time. When a residential meter comes into the shop for sampling, it will be retired after testing on a prover. If an industrial meter is 30 years old or older and fails, it will be retired. In the field, the Company will only replace an existing residential meter if the existing meter is 10 years old or older, 30 years for large industrial, 6 years on rotary, and 2 years on turbine. The Company believes a shorter life than the existing 28 years is reasonable due to policy of changing meters with ERTs.

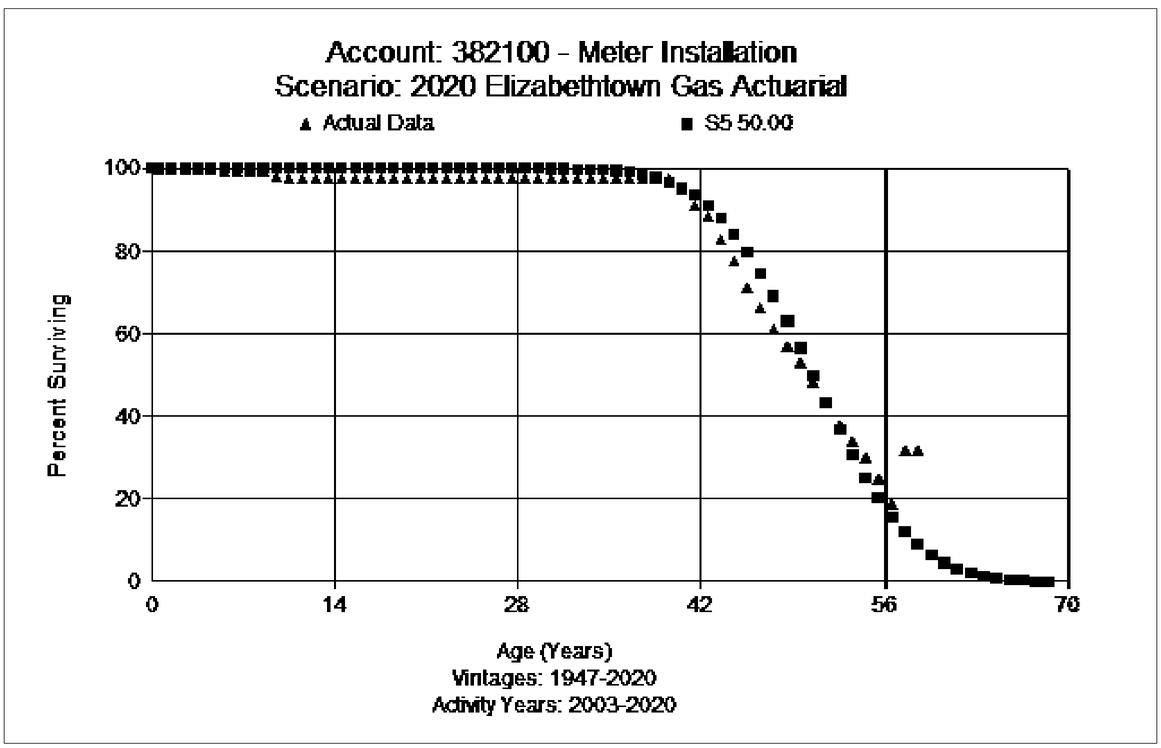
The life analysis supports the Company's expectations of a shorter life. This is not surprising with the move to more technological assets and the life of the batteries associated with these assets. Indications across the bands support a decrease from the existing and a slightly different, flatter, dispersion. For now, this Study recommends decreasing the life to 20 years and moving to the R1 dispersion pattern. The observed life table versus the proposed is graphed for this account below.



FERC Account 382.10 Meter Installations 50 S5

This account includes the cost of installation of meters. There is approximately $38 million of investment in this account. The approved life is 50 years with the S5 dispersion.

Discussions with Company personnel indicated that meter sets may last up to 45-50 years. They are moving to a majority of premanufactured meter sets as the inside meters are moved outside. The meter can be changed out without replacing the meter set (outside the IIP program). In many cases, the regulator would be replaced without replacing the meter set. Based on the analysis and Company input, this Study recommends retention of the 50-year life and S5 dispersion. The observed life table versus the proposed is graphed for this account below.

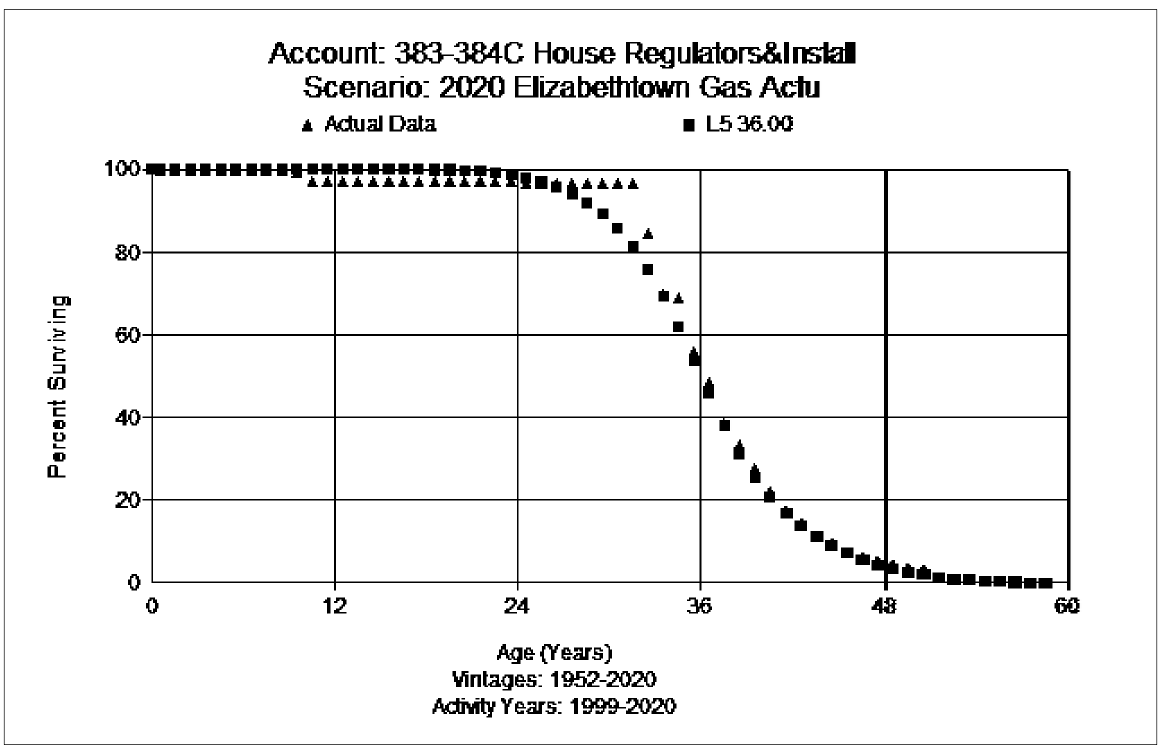


FERC Account 383.00 House Regulators 36 L5

This account includes the cost of house regulators. There is approximately $7.4 million of investment in this account. The approved life is 42 years with the L5 dispersion. Consistent with the prior study, a combined life analysis of Accounts 383 and 384 was performed.

Discussions with Company personnel indicated that in many cases, the regulator would be replaced without replacing the meter set. The regulators are changed much more frequently than the meter loops. This is exhibited in the shorter life seen for regulators and regulator installations as compared to meter installations.

The combined analysis is consistently fitting a 36-year life with a steep L5 dispersion pattern. Based on the analysis and Company input, the Study recommends moving to the 36 L5 dispersion pattern. The observed life table versus the proposed is graphed for this account below.

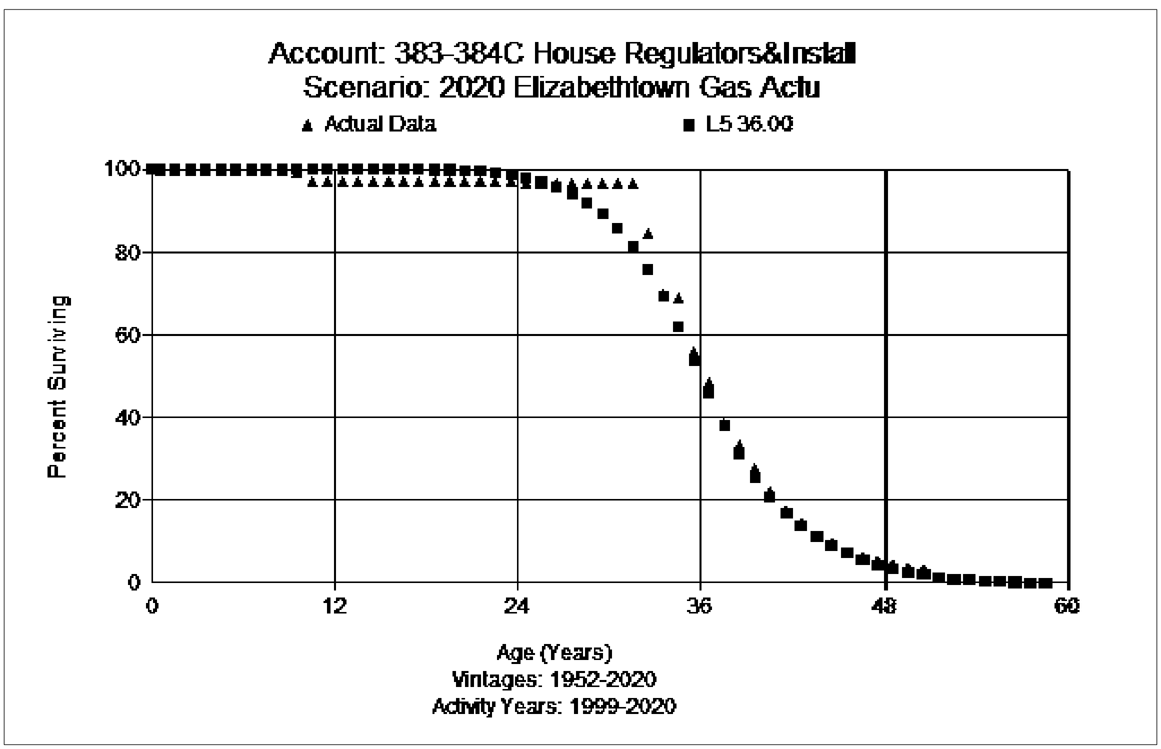


FERC Account 384.00 House Regulator Installations (36 L5)

This account includes the cost of installing house regulating equipment. The current balance is $2.3 million. The approved life is 42 L5. Consistent with the prior study, a combined life analysis of Accounts 383 and 384 was performed.

Discussions with Company personnel indicated that in many cases, the regulator would be replaced without replacing the meter set. The regulators are changed much more frequently than the meter loops. This is exhibited in the shorter life seen for regulators and regulator installations as compared to meter installations.

The analysis is consistently fitting a 36-year life with a steep L5 dispersion pattern. Based on the analysis and Company input, this Study recommends moving to the 36 L5 dispersion pattern. The observed life table versus the proposed is graphed for this account below.

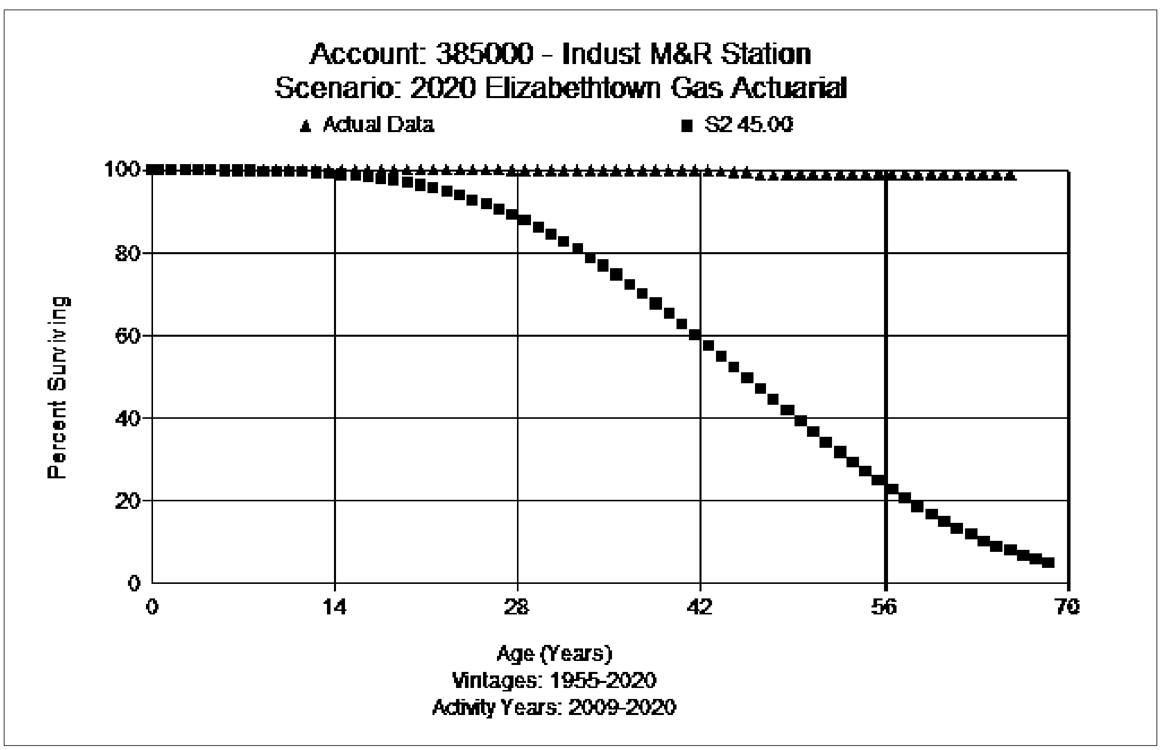


FERC Account 385.00 Industrial Meter & Regulator Equipment (45 S2)

This account includes the cost of measuring and regulating equipment used in industrial stations. The current balance is $15.8 million. The approved life is 45 years with the S2 dispersion. The analysis shows only $4 thousand has been retired at an average age of 34 years. The current average age of survivors is 26 years.

Discussions with Company personnel indicated that the equipment in this account is similar to equipment found at the city gates. There is very little movement in loads for customers served by this equipment and the Company would expect to see the life of the equipment in this account similar to the life of city gates.

There have not been many retirements, so the percent surviving is still close to 100%. Based on the type of assets, similarity to the city gate equipment, and expectations of the Company, this Study retains the approved 45 S2. The observed life table versus the proposed is graphed for this account below.

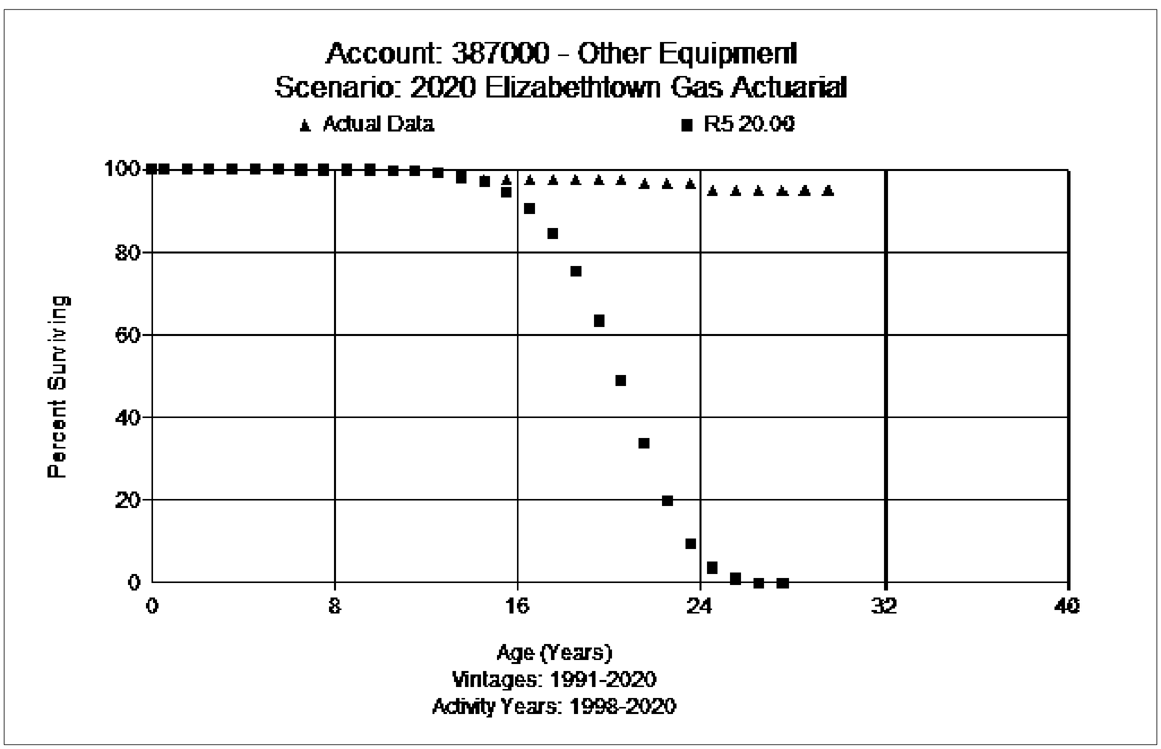


FERC Account 387.00 Other Equipment (20 R5)

This account includes the cost of equipment used in conjunction with providing distribution service. The current balance is $3.8 million. The approved life is a 17 R5.

Discussions with Company personnel indicated that many of the existing assets are much older than would be expected. Current average age of surviving investment is around 15 years and the average age of retirements is around 20 years. The Company indicated it will be sending an inventory request to determine what is still being used and what should be retired.

The analysis in the full band produces a good fit with 62 R5, which is beyond the range of reasonableness for these assets. Based on the type of assets, giving consideration to the currently approved life, the average age of the surviving investment, and judgment, the Study proposes increasing the life to 20 years and retaining the R5 curve. The observed life table versus the proposed is graphed for this account below.



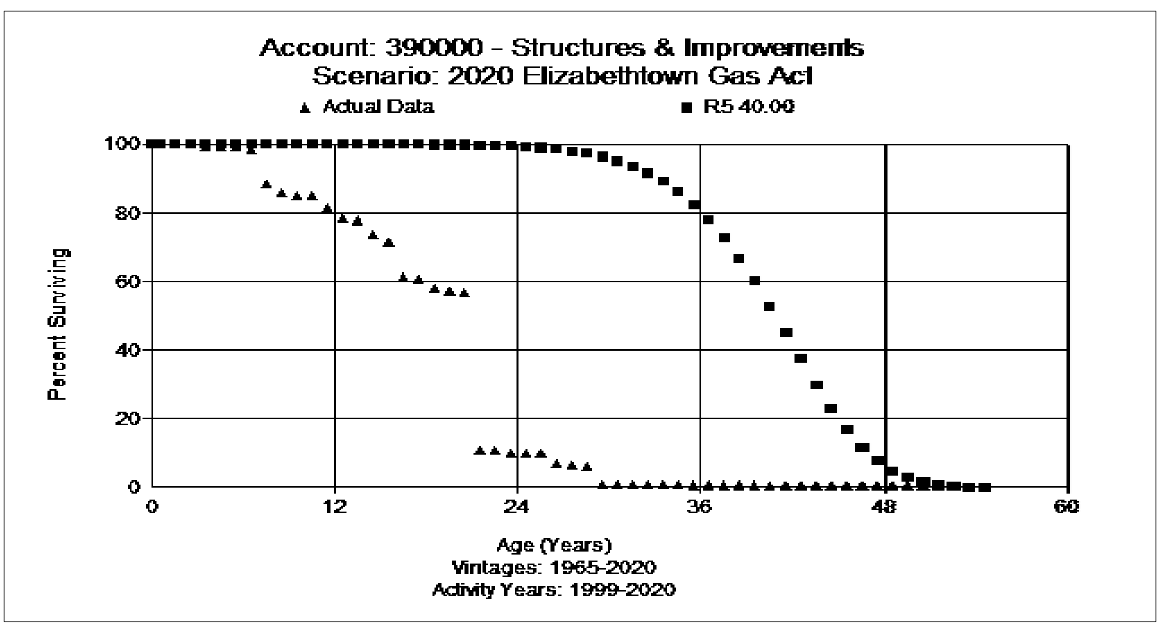
E. General Plant

General Plant Accounts, FERC Accounts 390.00–398.00
GENERAL PLANT DEPRECIATED
FERC Account 390.00 Structures & Improvements (40 R5)

This account generally includes the cost of structures and improvements used for utility service. Currently, there is about $24.7 million in this account. The approved life for this account is a 40 R5.

Discussions with Company personnel indicate the headquarters building dates back to 1945 and has been renovated a number of times. It was last gutted and rebuilt in 2014. Green Lane is now Elizabethtown's headquarters. In addition, in recent years, there have been a number of renovations (e.g., added training center, added dispatch center, renovation of interior office and renovation of call center). These were needed to move support from Southern Company (prior owner) to internal. The Company believes a 40-year life is reasonable.

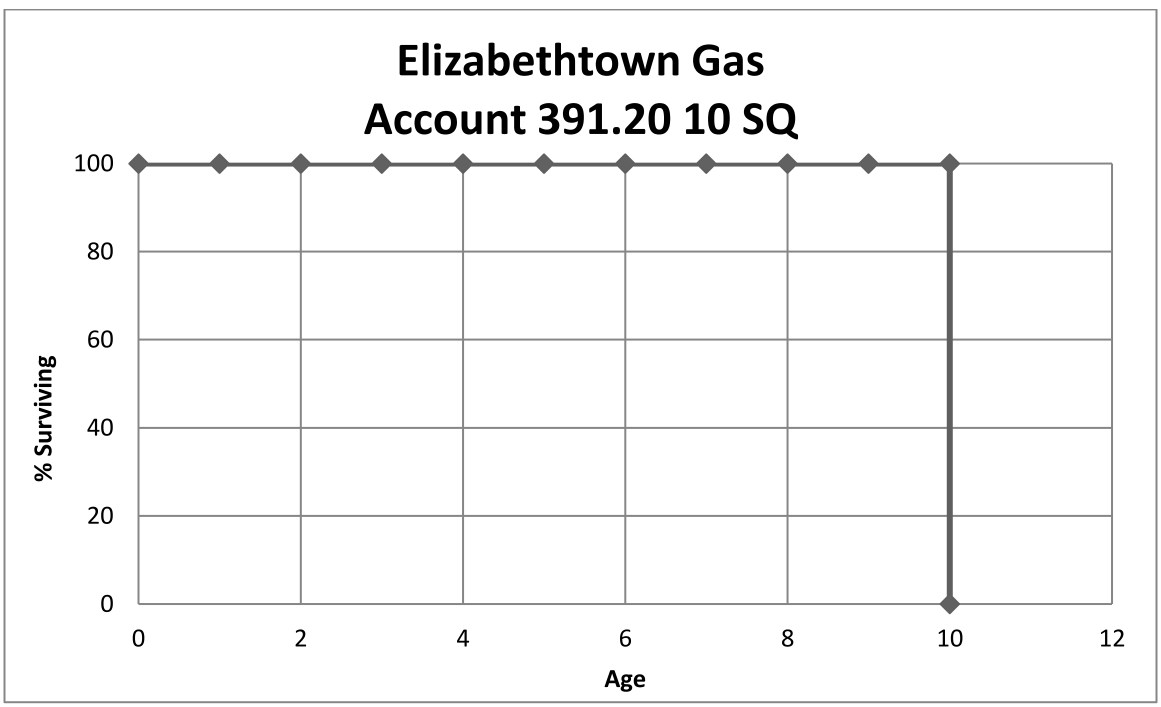
The life analysis indicates early age retirements. The best fits across the bands analyzed are from 10 to 21 years. Based on the type of surviving assets and future expectations, this Study proposes retaining the 40 R5. The observed life table versus the proposed is graphed for this account below.



FERC Account 391.20 Enterprises Systems 10 SQ

This account consists of enterprise (large software applications) system software. There is approximately $100 thousand in this account. The approved curve for this account is the 15 SQ.

Discussions with Company personnel indicated they moved to their own systems in 2020 at which time around 34 systems went live. The Company believes 15 years is too long for any platform like Oracle. For example, they will upgrade every couple of years and will capitalize CC&B upgrades but will likely not retire original investment. They currently don't have any evidence that they would move off Oracle CC&B (or Maximo or GIS, etc.) at any point in time. The increasing speed of technology change and the cloud base system being considered, 15 years would be too long. The possibility of moving to a cloud platform could necessitate a life considerably shorter than 10 years. The Company believes the software life is between 7-10 years depending on the specific system. Based on type of assets, Company plans and expectations, this Study recommends moving the life to 10 years while retaining the SQ dispersion. A representative graph of the life of the account is shown in the curve below.

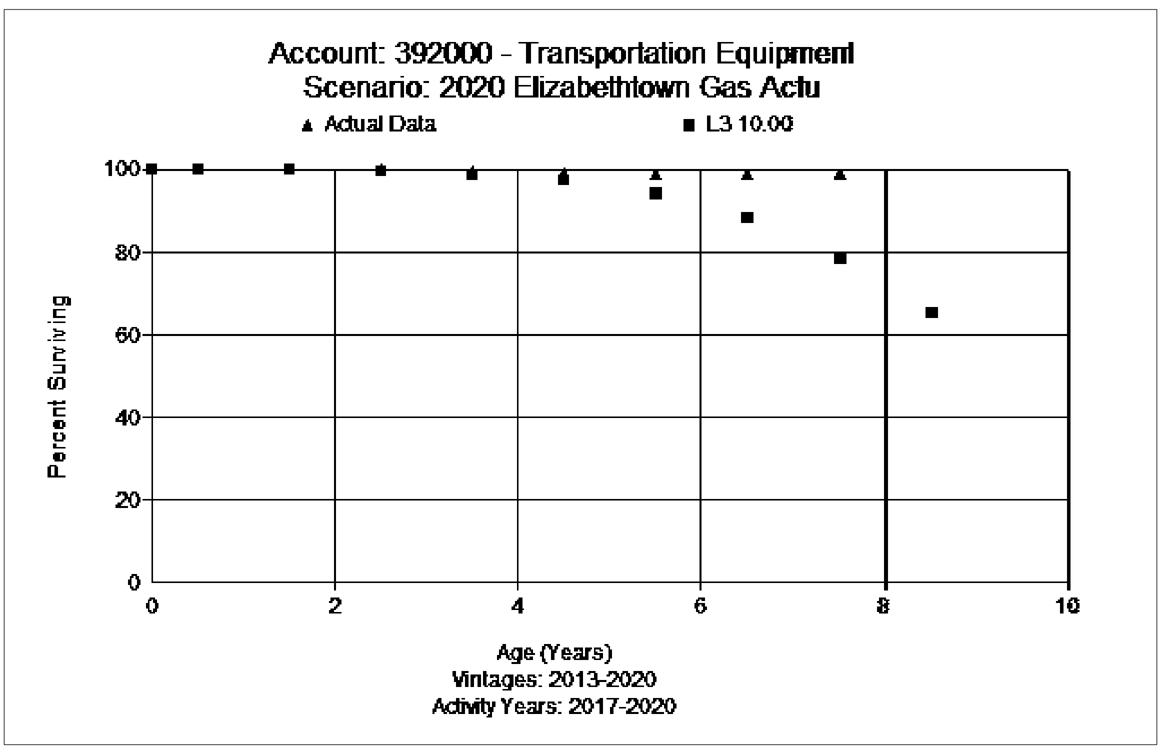


FERC Account 392.00 Transportation Equipment 10 L3

This account consists of street trucks, excavation equipment, trailers, and other related equipment used with transportation equipment in performing various distribution and general company operations. Based on the existing rate, the life parameter is 15 L3. There is approximately $5.6 million in this account. There have been few retirements and all assets have been added since 2013 and the average age of the investment is nearing 3 years.

Discussions with Company personnel indicated they have a “new fleet” policy, which means they replace quicker to maintain a reliable fleet. For this particular class they expect a life between 10-12 years.

The life analysis does not produce meaningful results due to limited retirement history and current young age of the assets. Considering the type of assets and use, Company policy and expectations, and judgment, the Study recommends decreasing the life to 10 years and retaining the L3 curve. The observed life table versus the proposed is graphed below for this account.

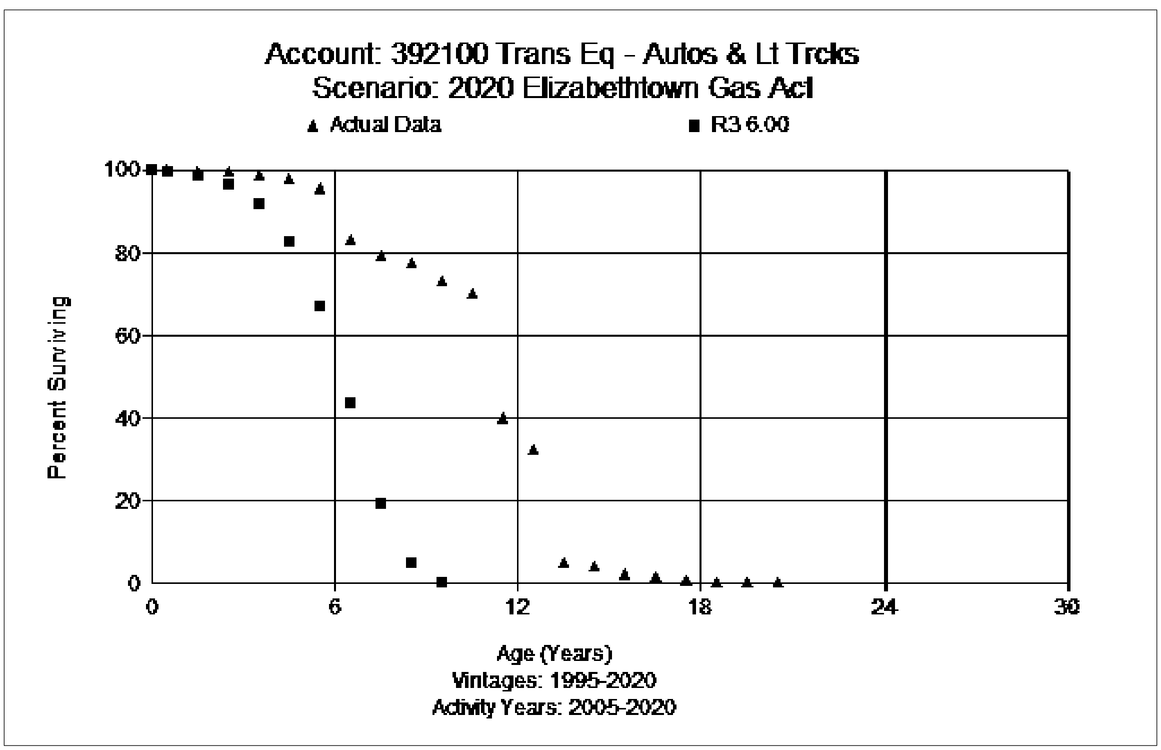


FERC Account 392.10 Autos & Light Trucks 6 R3

This account consists of autos and light duty trucks, meter reading trucks, CNG vehicles, and other related equipment used in performing various distribution and general company operations. The approved curve for this account is the 11 R3. There is approximately $4.5 million in this account.

Discussions with Company personnel indicated they have a "new fleet" policy, which means they replace quicker to maintain a reliable fleet. For this particular class they expect a life between 5-7 years and for CNG vehicles 7-10 years. History might show a longer life based on the earlier "old fleet" practice so it would not be unreasonable if a slightly longer life was indicated in the analysis.

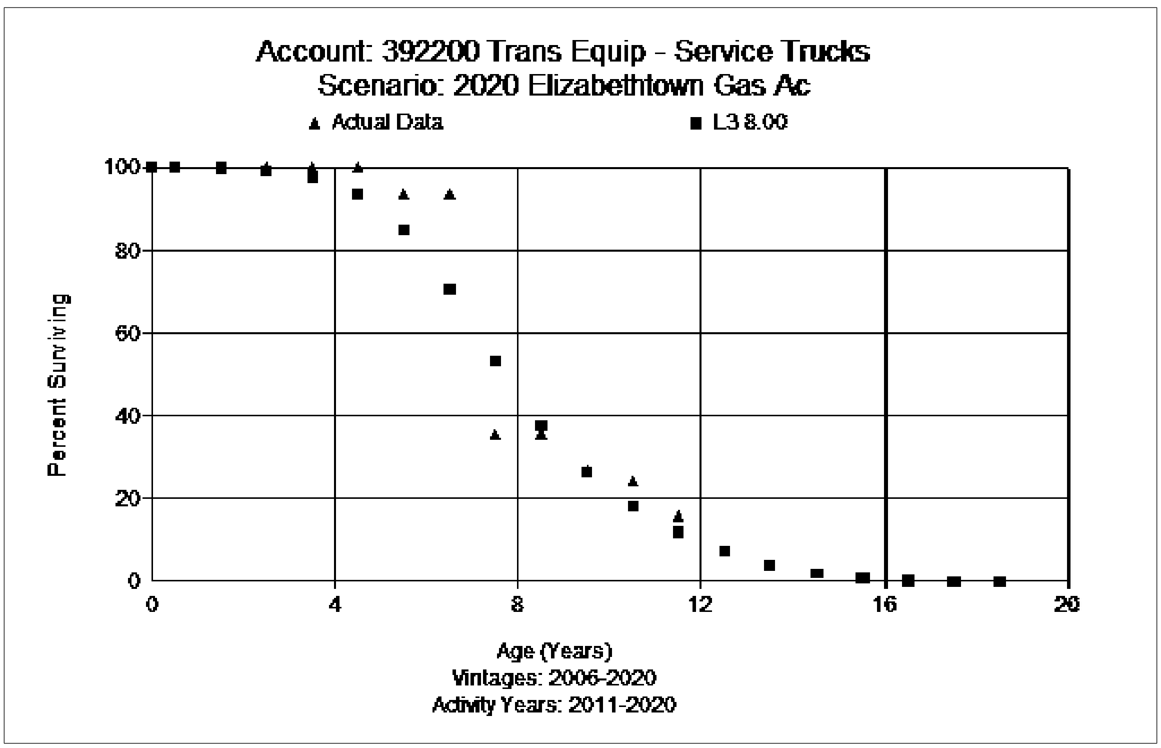
The analysis does indicate a longer life than what Company expectations are for this type of vehicles. The best fits across the bands analyzed are 9-12 years. However, considering past delays, Company policy and expectations, type of assets and use, the Study recommends decreasing the life to 6 years with the R3 curve. The observed life table versus the proposed is graphed for this account below.



FERC Account 392.20 Transportation Equipment – Service Trucks 8 L3

This account consists of service trucks and related equipment used in performing operations and maintenance on the distribution system. The approved curve for this account is the 8 L3. There is approximately $2.5 million in this account.

Discussions with Company personnel indicated they have a "new fleet" policy, which means they replace quicker to maintain a reliable fleet. For this particular class they expect a life between 7-8 years. The analysis indicated consistent life of 8 years. The Study recommendation is to retain the life of 8 years and L3 dispersion pattern. The observed life table versus the proposed is graphed for this account below.

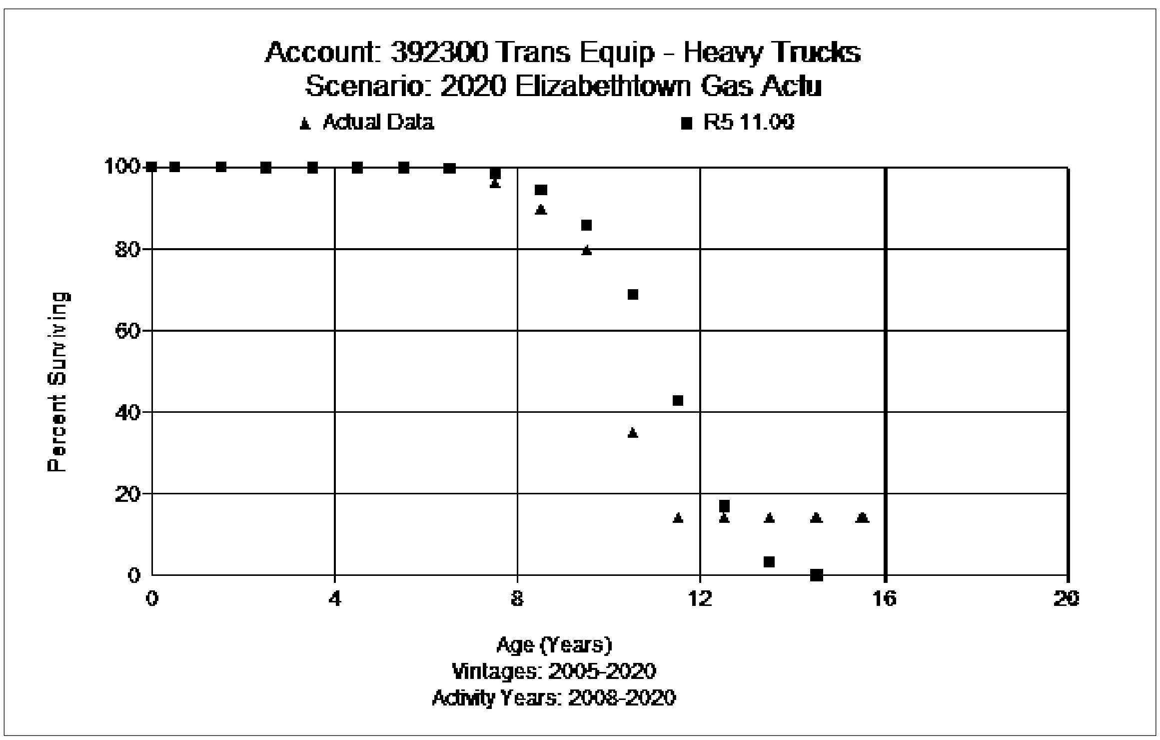


FERC Account 392.30 Heavy Trucks 11 R5

This account consists of heavy duty trucks and related equipment used by service center crews performing operations and maintenance on the transmission and distribution system. The approved curve for this account is the 10 R5. There is approximately $4.1 million in this account.

The current average age of surviving assets is 6 years. Discussions with Company personnel indicated they have a "new fleet" policy, which means they replace quicker to maintain a reliable fleet. History might show a longer life based on the earlier "old fleet" practice. For this particular class they expect a life between 10-12 years.

The life analysis indications show a good fit with a 10-year R5 dispersion pattern. This supports the Company's lower life cycle target replacement and "new fleet" policy. However, based on the type of assets, expected use, the target range for replacement, and judgment, the study recommendation is to increase the life from 10 to 11 years and retain the R5 dispersion pattern. The observed life table versus the proposed is graphed for this account below.

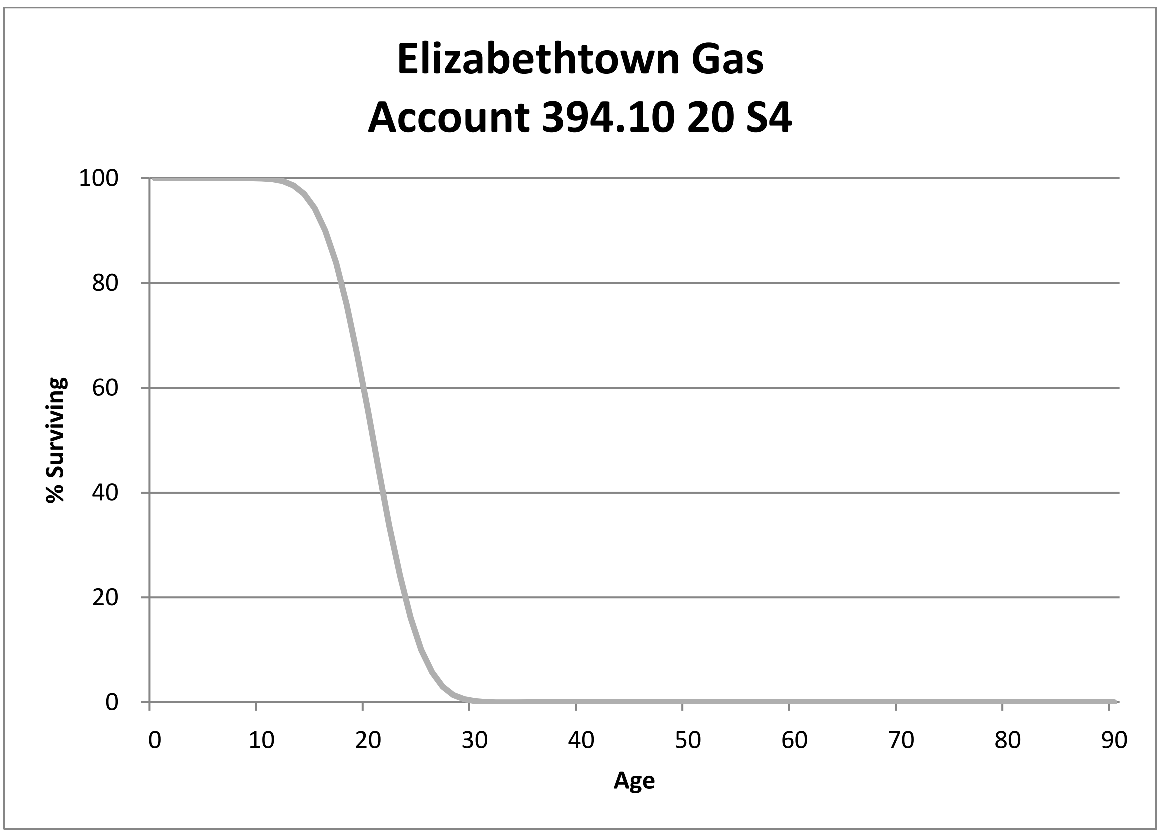


FERC Account 394.10 Natural Gas Vehicle Stations 20 S4

This account consists of natural gas vehicle stations used by service center crews performing operations and maintenance on the transmission and distribution system. The approved curve for this account is the 20 S4. There is approximately $2.7 million in this account.

Discussions with Company personnel indicated that readers and dispersers would have a shorter life than the existing 20 years. The tanks would have a longer life and compressors are expected to live to around 20 years too.

There have been no retirements, so no life analysis was performed. Based on the approved life, types of assets, input from Company personnel, and judgment, this study recommends retention of the 20 S4 curve. A representative graph of the life of the account is shown in the curve below.

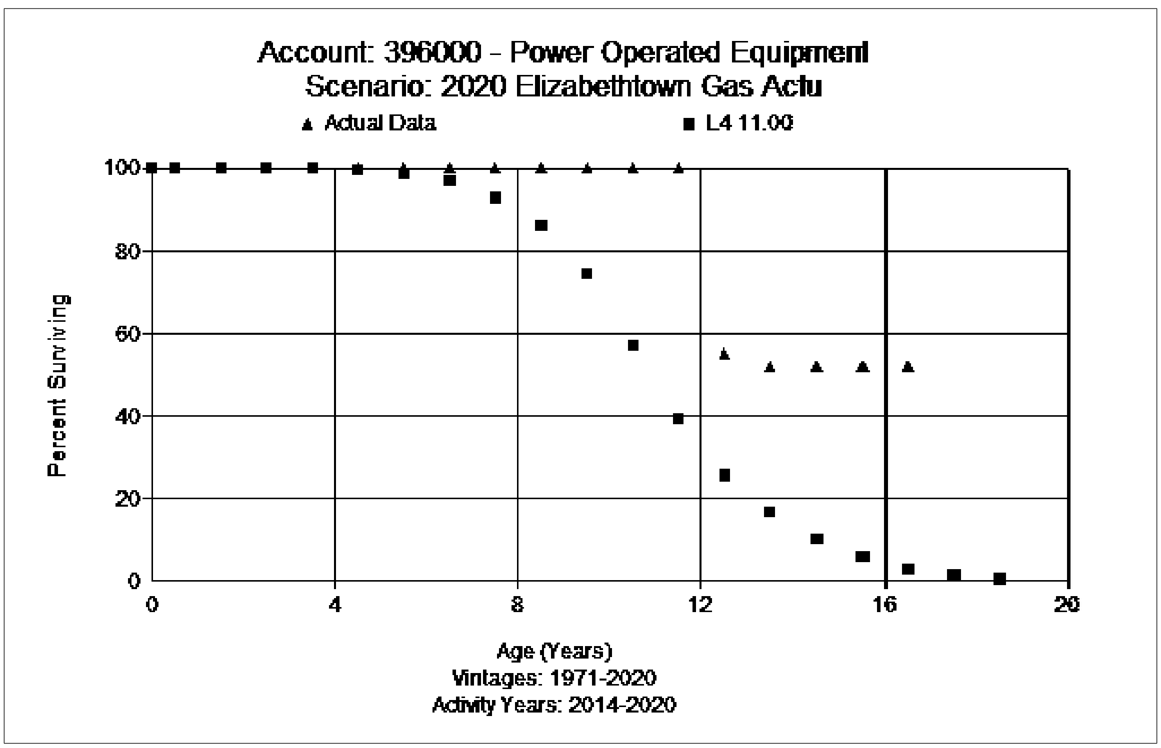


FERC Account 396.00 Power Operated Equipment 11 L4

This account consists primarily of forklifts, backhoes, and other miscellaneous equipment. Based on the existing rate, the life parameter is 14 L4. There is approximately $1.9 million in this account.

Discussions with Company personnel indicated a life between 10-12 years for a backhoe and around 12-14 years for generators.

Based on type of assets, the analysis indications, and Company expectations, this study recommends decreasing the life to 11 years and retaining the L4 dispersion pattern. The observed life table versus the proposed is graphed for this account below.

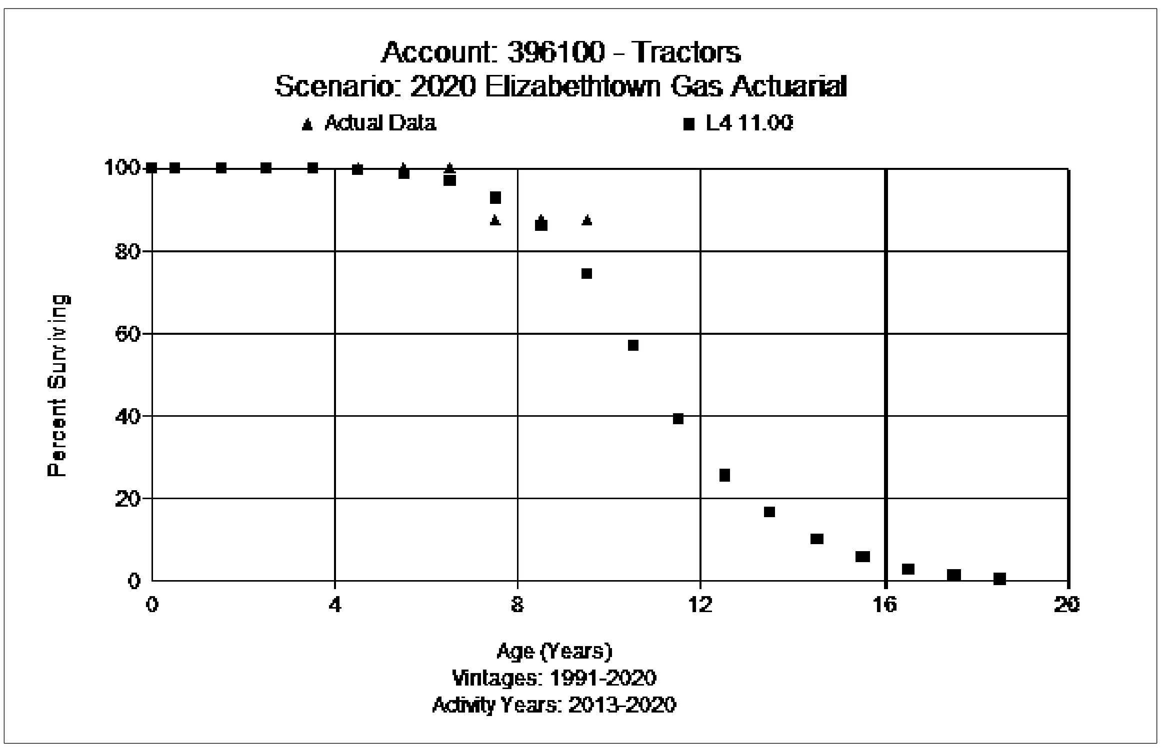


FERC Account 396.10 Power Operated – Tractors 11 L4

This account consists of tractors and other related power operated equipment that cannot be licensed on roadways. The approved curve for this account is the 12 L3. There is approximately $1.9 million in this account.

Discussions with Company personnel indicated they would expect a life of 10-12 years for the nature of the equipment and use.

The life analysis indicates a life of 11 years, which is right in the middle of the Company expected life range. Based on type of assets, analysis indications, and Company expectations, this Study recommends decreasing the life to 11 years and changing the dispersion to the L4. The observed life table versus the proposed is graphed for this account below.



GENERAL PLANT AMORTIZED (391X, 393-395, 397-398)

Assets in these accounts have a fixed life amortization. The dispersion pattern used is the SQ. The lives of each account were confirmed, and some changes were noted, but most of the accounts retained the existing life parameter. No graphs are provided for these accounts.

FERC Account 391.00 Office Furniture and Equipment 20 SQ

This account consists of office furniture and equipment used for general utility service. There is approximately $563 thousand in this account. The approved curve for this account is the 20 SQ and is retained.

FERC Account 391.10 Computer Equipment 5 SQ

This account consists of personal computer ("PC") equipment, printers, and peripherals used for general utility service. There is approximately $1.3 million in this account. The approved curve for this account is the 3 SQ. This account is an amortized account and reflects an SQ dispersion. Discussions with Company personnel indicated the Company refresh cycle is closer to 4 years and can get delayed at times. This Study recommends moving to 5 years based on the Company refresh cycle and expectations, but retains the SQ dispersion reflective of amortization accounting

FERC Account 391.11 Computer Equipment and Software 5 SQ

This account consists of personal computer software used for general utility service. There is approximately $715 thousand in this account. The existing parameter is 7 SQ. Discussions with Company personnel indicated the refresh cycle for this group is similar to Account 391.10 above. Target PC/Laptop equipment and software is closer to 4 years but can get delayed at times. Based on judgment, this Study recommends moving to a 5-year life but retains the SQ dispersion reflective of amortization accounting.

FERC Account 391.12 Computer Hardware 6 SQ

This account consists of servers, copier, and other computer related hardware used for general utility service. There is approximately $5.1 million in this account. The existing parameter is 7 SQ. Discussions with Company personnel indicated the lifecycle of servers is between 5-7 years. Based on judgment, this Study recommends using a 6-year life and retaining the SQ dispersion reflective of amortization accounting.

FERC Account 391.50 Individual Equipment 3 SQ

This account consists primarily of laptops. There is no balance in this account. The approved curve for this account is the 3 SQ.

FERC Account 393.00 Stores Equipment 25 SQ

This account contains forklifts, shelves, and bins used for general utility service. There is approximately $60 thousand in this account. The approved life and curve for this account is the 25 SQ and is retained.

FERC Account 394.00 Tools, Shop & Garage Equipment 18 SQ

This account consists of vacuum excavation machine, tapping machines, electro fusion unit, pipe horn & pipe horn valve locators, mustang squeezer, roots transfer prover, air tools, various pipe squeezers, and other miscellaneous tools and equipment used in shop and garages. There is approximately $4.2 million in this account. The approved life and curve for this account is the 18 SQ and is retained.

FERC Account 395.00 Laboratory Equipment 20 SQ

This account generally consists of balances, scales, gauges, glassware, piping, and various other tools and equipment used in a general laboratory department. There currently is no investment in this account. The approved life is 20 SQ.

FERC Account 397.00 Communication Equipment 10 SQ

This account consists of mobile radios, dispatch equipment and other miscellaneous communication equipment used in general utility service. There is approximately $2.5 million in this account. The approved life and curve are an 18 SQ. Discussions with Company personnel indicated the existing 18-year life is too long. The system was refreshed after purchase from Southern Company. They expect most of the equipment in the account would likely be retired, such as cellular modems, between 7-10 years. Technology is a big driver and forces accelerated changes in electronic assets in the account. Based on type of assets and Company input, this study recommends moving to 10 SQ.

FERC Account 398.00 Miscellaneous Equipment 20 SQ

This account consists of exercise equipment, kitchen equipment, camera, and other miscellaneous equipment used in general utility service. There is approximately $1.6 million in this account. This account currently has a 20 SQ and is retained.

VI. DETERMINATION OF NET SALVAGE

When a capital asset is retired, physically removed from service, and finally disposed of, terminal retirement is said to have occurred. The residual value of a terminal retirement is called gross salvage. Net salvage is the difference between the gross salvage (what the asset was sold for) and the removal cost (cost to remove and dispose of the asset).

Gross salvage and cost of removal related to retirements are recorded to the general ledger in the accumulated provision for depreciation at the time retirements occur within the system.

Removal cost percentages are calculated by dividing the current cost of removal by the original installed cost of the asset. Some plant assets can experience significant negative removal cost percentages due to the timing of the addition versus the retirement. For example, a distribution asset in FERC Account 376 with a current installed cost of $500 (2020) would have had an installed cost of $15.78 in 1950[4] (which is the proposed average life of the account). A removal cost of $50 for the asset calculated (incorrectly) on current installed cost would only have a negative 10 percent removal cost ($50/$500). However, a correct removal cost calculation would show a negative 317 percent removal cost for that asset ($50/$15.78). Inflation from the time of installation of the asset until the time of its removal must be considered in the calculation of the removal cost percentage because the depreciation rate, which includes the removal cost percentage, will be applied to the original installed cost of assets.

A. Discussion

For most accounts, the data for retirements, gross salvage, and cost of removal for each account ranges from 1999-2020. Moving averages, which remove timing differences between retirement and salvage and removal cost, were analyzed over periods varying from one to 10 years. These calculations are found

4 Using the Handy-Whitman Bulletin No. 194, G-1, line 44, $15.78 = $500 x 32/1014.

in Appendix D. The BPU, in the recent past, has indicated a desire to use a recent historical average amount. The Stipulation Agreement in Elizabethtown's last BPU Docket No. GR19040486 was a 5-year average. While Alliance continues to believe the traditional approach to net salvage is the most appropriate, the Company has requested our study recommendation to reflect a 3-year average removal cost amount. While the general approach is consistent with the existing rates, the Study recommendation reflects more recent activity and future expectations for the accounts experiencing cost of removal by using the past three years. This 3-year average is the basis for the recommendations in this Study as discussed further below.

Manufactured Gas Production Plant

FERC Account 304.20 Land Rights

This account includes any salvage and removal cost related to structures used in connection with production of gas derived from petroleum based products. The approved net salvage is zero. This study does not reflect any net salvage amount for this account.

FERC Account 311.00 Liquefied Petroleum Gas Equipment

This account includes any salvage and removal cost related to structures used in the production of gas derived from petroleum based products. The approved net salvage is zero. This study now reflects a zero balance and there is not any net salvage amount for this account.

FERC Account 320.40 Other Equip

This account includes any salvage and removal cost related to structures used in the production of gas derived from petroleum based products. The approved net salvage is zero. This study now reflects a zero balance and there is not any net salvage amount for this account.

B. Other Storage Plant

FERC Account 361.00 Structures and Improvements

This account includes any salvage and removal cost related to structures used in connection with storage operations. The approved net salvage is zero. This study does not reflect any net salvage amount for this account.

FERC Account 362.00 Storage Tanks – Natural Gas

This account consists of salvage and removal costs associated with the storage tanks for natural gas. No salvage or cost of removal has been recorded. The approved net salvage is zero. This study does not reflect any net salvage amount for this account.

FERC Account 362.10 Storage Tanks - LNG

This account consists of salvage and removal costs associated with the storage tanks for liquefied natural gas. There currently is no investment. The approved net salvage is zero. This study does not reflect any net salvage amount for this account.

FERC Account 363.20 Vaporizing Equipment

This account includes any salvage and removal cost related to vaporizing equipment used in connection with LNG storage operations. The approved net salvage is zero. This study does not reflect any net salvage amount for this account.

FERC Account 363.40 Measuring & Regulating Equipment

This account includes any salvage and removal cost related to measuring and regulating equipment used in connection with LNG storage operations. The approved net salvage is zero. This study does not reflect any net salvage amount for this account.

C. Transmission Plant

FERC Account 365.20 Land Rights

This account includes any salvage and removal cost related to land rights used in conjunction with the Transmission function. The approved net salvage is zero. This study does not reflect any net salvage amount for this account.

FERC Account 367.00 Mains

This account consists of any salvage and removal cost related to Mains of all material types. The approved net salvage amount is negative $46,404. This study recommends adding $21,163 to the annual accrual for negative net salvage (cost of removal expenditures) based on a three-year average for this account.

FERC Account 369.00 M&R Equipment

This account consists of any salvage and removal cost related to M&R Equipment related to transmission. The approved net salvage amount is negative $17,7873. This study recommends adding $33,475 to the annual accrual for negative net salvage (cost of removal expenditures) based on a three-year average for this account.

FERC Account 371.00 Other Equipment

This account consists of any salvage and removal cost related to M&R Equipment related to transmission. The approved net salvage is zero. This study does not reflect any net salvage amount for this account.

D. Distribution Plant

FERC Account 374.00/374.20/374.30 Land Rights and Rights of Way

This account includes any salvage and removal cost related to land rights or rights of way used in connection with distribution operations. Generally, little or no removal cost is incurred and no salvage is received at the retirement of land rights. The approved net salvage is zero. This study does not reflect any net salvage amount for this account.

FERC Account 375.00 Structures and Improvements

This account consists of any salvage and removal cost related to small structures and associated assets on the distribution system. Some salvage and cost of removal may be realized at time of retirement but recent experience continues to support zero. The approved net salvage is zero. This study does not reflect any net salvage amount for this account.

FERC Account 376.00 Mains

This account consists of any salvage and removal cost related to Mains of all material types. The approved net salvage amount is negative $1,754,567. This study recommends adding $2,659,609 to the annual accrual for negative net salvage (cost of removal expenditures) based on a three-year average for this account.

FERC Account 378.00 Measuring & Regulating Station Equipment

This account includes any salvage and removal cost related to installed equipment used in regulating gas at entry points to the distribution system. The approved negative net salvage amount is $51,175. This study recommends adding $65,124 to the annual accrual for negative net salvage (cost of removal expenditures) based on a three-year average for this account.

FERC Account 379.00 City Gate Equipment

This account includes any salvage and removal cost related to installed equipment used in regulating gas at city gate entry points to the distribution system. The approved negative net salvage amount is $13,902. This study recommends adding $12,255 to the annual accrual for negative net salvage (cost of removal expenditures) based on a three-year average for this account.

FERC Account 380.00 Services

This account includes any salvage and removal cost related to service lines on the distribution system. Service lines are the pipes and accessories leading from the main to the customers' premises. Generally, pipe is abandoned in place. However, removal cost is still incurred even when abandoning the pipe in place. For pipe that is being replaced, activities such as isolating the old pipe, cutting the old pipe, purging, or foaming the old pipe and capping the old pipe are charged as removal costs. When the pipe is not being replaced, in addition to the above activities, dispatching a crew, uncovering the pipe, recovering the hole, and repairing the surface are additional activities charged to removal cost. The approved negative net salvage amount is $3,894,584. This Study recommends adding $5,903,383 to the annual accrual for negative net salvage (cost of removal expenditures) based on a three-year average for this account.

FERC Account 381.00 Meters

This account includes any salvage and removal cost related to meters used in measuring gas to residential customers. The approved negative net salvage amount is $400. This study recommends adding $31,881 to the annual accrual for negative net salvage (cost of removal expenditures) based on a three-year average for this account.

FERC Account 382.10 Meter Installations

This account includes any salvage and removal cost related to meter installations used in measuring gas to customers. The approved negative net salvage amount is $72. This study recommends adding $0 to the annual accrual for negative net salvage (cost of removal expenditures) based on a three-year average for this account.

FERC Account 383.00 House Regulators

This account includes any salvage and removal cost related to house regulators. The approved net salvage is zero. This study recommends adding $112 to the annual accrual for negative net salvage (cost of removal expenditures) based on a three-year average for this account.

FERC Account 384.00 House Regulator Installations

This account includes any salvage and removal cost related to house regulator installations. The approved net salvage is zero. This study recommends adding $83,939 to the annual accrual for negative net salvage (cost of removal expenditures) based on a three-year average for this account.

FERC Account 385.00 Industrial Meter & Regulator Equipment

This account includes the salvage and removal costs related to measuring and regulating equipment used in industrial stations. The existing removal cost amount is zero. There has not been any cost of removal recorded over the last three years. Therefore, this study does not reflect any net salvage amount for this account.

FERC Account 387.00 Other Equipment

This account includes the salvage and removal costs related to miscellaneous distribution equipment used in distribution operations. The approved net salvage is zero. This study does not reflect any net salvage for this account.

GENERAL PLANT DEPRECIATED

FERC Account 390.00 Structures and Improvements

This account includes any salvage and removal cost related to structures and improvements used for general utility operations. The approved net salvage is zero. This study does not reflect any net salvage amount for this account.

FERC Account 391.20 Enterprise Systems

This account includes any salvage and removal cost related to enterprise system software. The approved net salvage is zero. This study does not reflect any net salvage amount for this account.

FERC Account 392.00 Transportation Equipment

This account consists of salvage and removal costs associated with trailers, some heavy trucks, and other miscellaneous related equipment. This study reflects a segregated analysis of the accounts. The approved positive net salvage is $5,622. This study recommends an amount of $183, based on a three-year average, be included as positive net salvage for this account.

FERC Account 392.10 Autos and Light Trucks

This account consists of salvage and removal costs associated with automobiles and some trucks. This study reflects a segregated analysis of the accounts. The approved positive net salvage is $96,453. This study recommends an amount of $41,919, based on a three-year average, be included as positive net salvage for this account.

FERC Account 392.20 Service Trucks

This account consists of salvage and removal costs associated with service trucks and associated equipment. This study reflects a segregated analysis of the accounts. The approved positive net salvage is $15,741. This study recommends an amount of $13,616, based on a three-year average, be included as positive net salvage for this account.

FERC Account 392.30 Heavy Trucks

This account consists of salvage and removal costs associated with heavy trucks and associated equipment. This study reflects a segregated analysis of the accounts. The approved positive net salvage is $67,811. This study recommends an amount of $11,150, based on a three year-average, be included as positive net salvage for this account.

FERC Account 394.10 Natural Gas Vehicles

This account includes any salvage and removal cost related to various structures and equipment related to the natural gas vehicles stations. This is a new account with no historical experience. This study does not reflect any net salvage amount for this account.

FERC Account 396.00 Power Operated Equipment

This account includes any salvage and removal cost related to backhoes, forklifts, trenchers, and other power operated equipment that cannot be licensed on roadways. The approved net salvage is zero. This study does not reflect any net salvage amount for this account.

<u>FERC Account 396.10 Power Operated - Tractors</u>

This account includes any salvage and removal cost related to tractors and other power operated equipment that cannot be licensed on roadways. The approved net salvage is $8,515. This study does not reflect any net salvage amount for this account.

GENERAL PLANT AMORTIZED

<u>FERC Account 391.00 Office Furniture and Equipment</u>

This account includes any salvage and removal cost related to office furniture and equipment. This study does not reflect any net salvage amount for this account.

<u>FERC Account 391.10 Computer Equipment</u>

This account includes any salvage and removal cost related to personal computers, printers, peripherals, and related software. The approved net salvage is zero. This study does not reflect any net salvage amount for this account.

<u>FERC Account 391.11 Computer Equipment and Software</u>

This account includes any salvage and removal cost related to personal computers software. The approved net salvage is zero. This study does not reflect any net salvage amount for this account.

FERC Account 391.12 Computer Hardware

This account includes any salvage and removal cost related to computer hardware. The approved net salvage is zero. This study does not reflect any net salvage amount for this account.

FERC Account 391.50 Individual Equipment

This account includes any salvage and removal cost related to computer laptops. The approved net salvage is zero. This account does not have a balance. This study does not reflect any net salvage amount for this account.

FERC Account 393.00 Stores Equipment

This account consists of salvage and removal costs associated with forklifts, shelves, and bins. The approved net salvage is zero. This study does not reflect any net salvage amount for this account.

FERC Account 394.00 Tools, Shop & Garage Equipment

This account consists of salvage and removal costs associated with air compressors, grinders, mixers, hoists, and cranes. The approved net salvage is zero. This study does not reflect any net salvage amount for this account.

FERC Account 395.00 Laboratory Equipment

This account consists of laboratory equipment used in general utility service. The approved net salvage is zero. This study does not reflect any net salvage amount for this account.

FERC Account 397.00 Communication Equipment

This account consists of miscellaneous communication equipment used in general utility service. The approved net salvage is zero. This study does not reflect any net salvage amount for this account.

FERC Account 398.00 Miscellaneous Equipment

This account consists of miscellaneous equipment used in general utility service. The approved net salvage is $0. Based on the most recent three-year average, the negative net salvage (cost of removal expenditures) is $19,112. However, this activity is not representative of the future and this study does not reflect any net salvage amount for this account.

APPENDIX A - Depreciation Rate Calculations

ELIZABETHTOWN GAS COMPANY
COMPUTATION OF DEPRECIATION ACCRUAL RATES
BASED ON DEPRECIABLE INVESTMENT AT DECEMBER 31,2020

Account Description	Plant In Service 12/31/2020	Allocated Book Depreciation 12/31/2020	Net Salvage %	3-year Gross Salvage Amount	Unaccrued Balance	Remaining Life	Life Accrual Amount	Life Accrual Rate	3-Year COR Accrual Amount	Total (Life and COR) Accrual Amount	Total (Life and COR) Accrual Rate
PRODUCTION PLANT											
304.2 Land Rights	61,423	28,453	0%		32,970	12.24	2,694	4.39%	0	2,694	4.39%
311.0 Liquefied Petroleum Gas Equipment	0		0%		0	0.00			0	0	0.00%
320.0 Other Equipment	0	0	0%		0	0.00	0	0.00%	0	0	0.00%
Total Production	**61,423**	**28,453**			**32,970**		**2,694**	**4.39%**	**0**	**2,694**	**4.39%**
STORAGE PLANT											
361.00 Structures & Improvements	4,615,995	749,198	0%		3,866,796	42.01	92,056	1.99%	0	92,056	1.99%
362.00 Gas Holders - Natural Gas	0	0	0%		0	0.00	0	0.00% *	0	0	0.00% *
362.10 Gas Holders - LNG	3,615,393	3,133,248	0%		482,146	28.08	17,170	0.47%	0	17,170	0.47%
363.20 Vaporization	6,958,069	973,044	0%		5,985,025	31.95	187,354	2.69%	0	187,354	2.69%
363.40 M&R Equipment	2,929,952	1,412,465	0%		1,517,486	20.01	75,821	2.59%	0	75,821	2.59%
Total Storage	**18,119,408**	**6,267,956**			**11,851,452**		**372,400**	**2.06%**	**0**	**372,400**	**2.06%**
TRANSMISSION PLANT											
365.20 Rights Of Way	367,325	(46,553)	0%	0	413,878	43.97	9,412	2.56%	0	9,412	2.56%
367.00 Mains	13,880,278	(335,239)	0%	0	14,215,517	64.91	219,015	1.58%	21,163	240,178	1.73%
369.00 Measuring And Regulating St	8,515,865	(252,522)	0%	0	8,768,387	40.26	217,803	2.56%	33,475	251,277	2.95%
371.00 Other Equipment	55,697	(1,414)	0%	0	57,111	18.20	3,139	5.64%	0	3,139	5.64%
Total Transmission	**22,819,165**	**(635,728)**		**0**	**23,454,892**		**449,368**	**1.97%**	**54,637**	**504,006**	**2.21%**
DISTRIBUTION PLANT											
374.00 Land Right and Rights of Way	2,935,307	779,882	0%	0	2,155,425	60.26	35,770	1.22%	0	35,770	1.22%
375.00 Structures & Improvements	5,795,115	789,637	0%	0	5,005,478	28.82	173,659	3.00%	0	173,659	3.00%
376.00 Mains - All	813,561,527	141,392,722	0%	0	672,168,805	59.54	11,289,556	1.39%	2,659,609	13,949,166	1.71%
378.00 M&R Stations General	17,938,513	11,366,867	0%	0	6,571,646	14.39	456,684	2.55%	65,124	521,808	2.91%
379.00 M&R Stations City Gate	21,293,673	11,788,979	0%	0	9,504,694	21.86	434,801	2.04%	12,255	447,056	2.10%
380.00 Services - All	460,062,192	69,684,790	0%	0	390,377,401	51.56	7,571,488	1.65%	5,903,383	13,474,872	2.93%
381.00 Meters - All	123,125,945	28,421,430	0%	0	94,704,514	15.71	6,027,525	4.90%	31,881	6,059,407	4.92%
382.00 Meter Installation	37,556,913	13,275,983	0%	0	24,280,930	33.58	723,060	1.93%	0	723,060	1.93%
383-384 House Regulators and Installation	9,724,065	2,192,156	0%	0	7,531,909	28.46	264,630	2.72%	84,051	348,681	3.59%
385.00 Industrial M&R Equipment	15,751,970	10,379,060	0%	0	5,372,910	13.58	395,676	2.51%	0	395,676	2.51%
387.00 Other Equipment	3,758,345	2,269,552	0%	0	1,488,793	8.38	177,742	4.73%	0	177,742	4.73%
Total Distribution	**1,511,503,564**	**292,341,058**		**0**	**1,219,162,506**		**27,550,593**	**1.82%**	**8,756,304**	**36,306,897**	**2.40%**
GENERAL PLANT - DEPRECIATED											
390.00 Structures & Improvements	24,733,652	2,985,115	0%		21,748,536	32.66	665,896	2.69%	0	665,896	2.69%
391.20 Enterprise Systems	99,961,209	4,473,242	0%		95,487,968	9.32	10,245,857	10.25%	0	10,245,857	10.25%
392.00 Transportation Equipment	5,586,900	955,911	0%	183	4,630,806	7.40	625,888	11.20%	0	625,888	11.20%
392.10 Auto & Light Trucks	4,508,198	1,921,644	0%	41,919	2,544,635	2.11	1,204,979	26.73%	0	1,204,979	26.73%
392.20 Service Trucks	2,471,544	804,159	0%	13,616	1,653,768	4.04	409,072	16.55%	0	409,072	16.55%
392.30 Heavy Trucks	4,120,912	1,381,383	0%	11,150	2,728,379	5.39	505,807	12.27%	0	505,807	12.27%
394.10 Natural Gas Vehicle Stations	2,721,905	450,523	0%	0	2,271,382	14.97	151,757	5.58%	0	151,757	5.58%
396.00 Power Operated Equipment	1,860,485	398,097	0%	0	1,462,388	7.42	197,044	10.59%	0	197,044	10.59%
396.10 Power Operated - Tractors	1,930,995	97,424	0%	0	1,833,571	10.16	180,536	9.35%	0	180,536	9.35%
Total General Depreciated	**147,895,799**	**13,467,498**		**66,868**	**134,361,432**		**14,186,837**	**9.59%**	**0**	**14,186,837**	**9.59%**

ELIZABETHTOWN GAS COMPANY
COMPUTATION OF DEPRECIATION ACCRUAL RATES
BASED ON DEPRECIABLE INVESTMENT AT DECEMBER 31,2020

Account Description	Plant In Service 12/31/2020	Allocated Book Depreciation 12/31/2020	Net Salvage %	3-year Gross Salvage Amount	Unaccrued Balance	Remaining Life	Life Accrual Amount	Life Accrual Rate	3-Year COR Accrual Amount	Total (Life and COR) Accrual Amount	Total (Life and COR) Accrual Rate
GENERAL PLANT - AMORTIZED											
391.00 Office Furniture And Equipment	828,990	187,066	0%	0	641,924		41,450	5.00%	0	41,450	5.00% *
391.10 Computer Equipment	1,318,616	554,361	0%	0	764,255		263,723	20.00%	0	263,723	20.00% *
391.11 Computer Equipment and Software	714,729	357,364	0%	0	357,364		142,946	20.00%	0	142,946	20.00% *
391.12 Computer Hardware	3,974,880	1,860,865	0%	0	2,114,015		662,480	16.67%	0	662,480	16.67% *
391.50 Individual Equipment	0	0	0%	0	0		0	33.33%	0	0	33.33% *
393.00 Stores Equipment	60,377	15,698	0%	0	44,679		2,415	4.00%	0	2,415	4.00% *
394.00 Tools Shop And Garage Equip	4,177,710	1,879,265	0%	0	2,298,445		232,095	5.56%	0	232,095	5.56% *
395.00 Laboratory Equipment	0	0	0%	0	0		0	5.00%	0	0	5.00% *
397.00 Communication Equipment	2,479,844	1,084,869	0%	0	1,394,974		247,984	10.00%	0	247,984	10.00% *
398.00 Miscellaneous Equipment	1,624,358	709,252	0%	0	915,106		81,218	5.00%	0	81,218	5.00% *
Total General Amortized	**15,179,504**	**6,648,740**		**0**	**8,530,764**		**1,674,311**	**11.03%**	**0**	**1,674,311**	**11.03%**
Total General Depreciated & Amortized	**163,075,303**	**20,116,239**		**66,868**	**142,892,196**		**15,861,147**	**9.73%**	**0**	**15,861,147**	**9.73%**
Total Plant Depreciated and Amortized	**$ 1,715,578,863**	**$ 318,117,978**		**$ 66,868**	**$ 1,397,394,017**		**$ 44,236,203**	**2.58%**	**$ 8,810,942**	**$ 53,047,145**	**3.09%**
Total Net Salvage in Rates									**$ (8,744,073)**		

*Denotes a whole life rate is proposed.

Study Adjustments		
Amortized Retirements	1,137,594	1,137,594
Proforma Retirements 311&320.4	826,418	826,418
Proforma Retirement 363.20	10,060,650	1,458,431
Proforma Retirements 367	4,435,634	4,435,634
Proforma Retirements 378	1,994,846	1,994,846
Total Study Adjustments	18,455,142	9,852,923
Land - Non Depreciable	1,252,071	
Intangible Plant	98,841	
Total Plant In Service	$ 1,735,384,917	$ 327,970,900

ELIZABETHTOWN GAS COMPANY
COMPUTATION OF DEPRECIATION ACCRUAL RATE - AMORTIZED ACCOUNTS
AT DECEMBER 31, 2020

GENERAL PLANT - AMORTIZED Account	Description	Plant Balance 12/31/2020	Allocated Book Reserve 12/31/2020	Theoretical Reserve 12/31/2020	Reserve (Deficit)/Surplus	Reserve Recovery Period (Yrs.)	Amortize Reserve Deficit/Surplus	Assets to Retire Greater Than ASL
391.00	Office Furniture And Equipment	$ 828,990	$ 187,066	$ 187,066	$ -	5	$ -	$ -
391.10	Computer Equipment	1,318,616	554,361	554,361	-	5	-	-
391.11	Computer Equipment and Software	714,729	357,364	357,364	-	5	-	
391.12	Computer Hardware	5,089,630	2,975,615	2,975,615	-	5	-	1,114,750
391.50	Individual Equipment	-	-	-	-	5	-	-
393.00	Stores Equipment	60,377	15,698	15,698	-	5	-	-
394.00	Tools Shop And Garage Equip	4,177,710	1,879,265	1,879,265	-	5	-	-
397.00	Communication Equipment	2,502,688	1,107,714	1,107,714	-	5	-	22,844
398.00	Miscellaneous Equipment	1,624,358	709,252	709,252	-	5	-	-
	Total General Amortized	16,317,098	7,786,335	7,786,335	-		-	1,137,594

After Retirements of Assets With Age > Average Service Life

Account	Description	Plant Balance 12/31/2020	Allocated Reserve 12/31/2020	Proposed Life	Annual Amortization	Accrual For Reserve Deficit/Surplus	Total Amortization	Annual Amortization %
391.00	Office Furniture And Equipment	828,990	187,066	20	41,450			5.00%
391.00	Office Furniture And Equipment					-		
391.00	Total						41,450	
391.10	Computer Equipment	1,318,616	554,361	5	263,723			20.00%
391.10	Computer Equipment					-		
391.10	Total						263,723	
391.11	Computer Equipment and Software	714,729	357,364	5	142,946			20.00%
391.11	Computer Equipment and Software					-		
391.11	Total						142,946	
391.12	Computer Hardware	3,974,880	1,860,865	6	662,480			16.67%
391.12	Computer Hardware					-		
391.12	Total						662,480	
391.50	Individual Equipment	-	-	3	-			33.33%
391.50	Individual Equipment					-		
391.50	Total						-	
393.00	Stores Equipment	60,377	15,698	25	2,415			4.00%
393.00	Stores Equipment					-		
393.00	Total						2,415	
394.00	Tools, Shop, and Garage Equipment	4,177,710	1,879,265	18	232,095			5.56%
394.00	Tools, Shop, and Garage Equipment					-		
394.00	Total						232,095	
397.00	Communication Equipment	2,479,844	1,084,869	10	247,984			10.00%
397.00	Communication Equipment					-		
397.00	Total						247,984	
398.00	Miscellaneous Equipment	1,624,358.03	709,251.63	20	81,218			5.00%
398.00	Miscellaneous Equipment					-		
398.00	Total						81,218	
	Total General Amortized After Ret	$ 15,179,504	$ 6,648,740		$ 1,674,311	$ -	$ 1,674,311	
	Assets retired > ASL	$ 1,137,594	$ 1,137,594					

APPENDIX B - Depreciation Expense Comparison

Elizabethtown Gas Company
Comparison of Depreciation Expense
Comparison of Existing and Proposed Depreciation Accrual Rates
Depreciation Study as of December 31, 2020

Account	Description	Plant Balance	Existing Annual Accrual Rate	Existing Annual Accrual Amount	Proposed Annual Accrual Rate	Proposed Annual Accrual Amount	Change in Depreciation Expense
(a)	(b)	(c)	(d)	(e)	[f]	[g]	[h]
	INTANGIBLE PLANT						
301.00	Organization	$ 77,895	0.00%	$ -	0.00%	$ -	$ -
302.00	Franchises and Consents	$ 20,947	0.00%	-	0.00%	-	-
	Total Intangible	98,841		-		-	-
	PRODUCTION PLANT						
304.20	Land Rights	61,423	4.37%	2,684	4.39%	2,696	12
305.00	Structures and Improvements	-	0.00%	-	0.00%	-	-
311.00	Liquefied Petroleum Gas Equip	-	2.87%	-	0.00%	-	-
320.00	Other Equipment	-	2.58%	-	0.00%	-	-
	Total Production	61,423	4.37%	2,684	4.39%	2,696	12
	STORAGE PLANT						
360.00	Land and Land Rights	68,417	0.00%	-	0.00%	-	-
361.00	Structures and Improvements	4,615,995	1.52%	70,163	1.99%	91,858	21,695
362.00	Gas Holders-Natural Gas	-	1.54%	-	1.43%	- *	-
362.10	Gas Holders-LNG	3,615,393	1.54%	55,677	0.47%	16,992	(38,685)
363.20	Vaporizing Equipment	6,958,069	2.82%	196,218	2.69%	187,172	(9,045)
363.40	Measuring & Regulating Equip	2,929,952	2.57%	75,300	2.59%	75,886	586
	Total Storage (Excl Land Rights)	18,119,408	2.19%	397,357	2.05%	371,908	(25,449)
	TRANSMISSION PLANT						
365.11	Land	263,454	0.00%	-	0.00%	-	-
365.20	Rights of Way	367,325	0.94%	3,453	2.56%	9,404	5,951
367.00	Transmission-Mains	13,880,278	1.72%	238,741	1.73%	240,129	1,388
369.00	Measuring & Regulating Equip	8,515,865	2.39%	203,529	2.95%	251,218	47,689
371.00	Other Equipment	55,697	4.29%	2,389	5.64%	3,141	752
	Total Transmission (Excl Land)	22,819,165	1.96%	448,112	2.21%	503,892	55,779

Elizabethtown Gas Company
Comparison of Depreciation Expense
Comparison of Existing and Proposed Depreciation Accrual Rates
Depreciation Study as of December 31, 2020

			Existing Annual Accrual		Proposed Annual Accrual		Change in Depreciation Expense
Account	**Description**	**Plant Balance**	**Rate**	**Amount**	**Rate**	**Amount**	**Expense**
(a)	**(b)**	**(c)**	**(d)**	**(e)**	**[f]**	**[g]**	**[h]**
	DISTRIBUTION PLANT						
374.00	Land and Land Rights	1,352,356	1.13%	15,282	1.22%	16,499	1,217
374.10	Land	895,051	0.00%	-	0.00%	-	-
374.20	Land Rights	880,548	1.13%	9,950	1.22%	10,743	792
374.30	Rights of Way	702,404	1.13%	7,937	1.22%	8,569	632
375.00	Structures & Improvements	5,795,115	2.78%	161,104	3.00%	173,853	12,749
376.00	Mains	813,561,527	1.60%	13,016,984	1.71%	13,911,902	894,918
378.00	M&R Station Equip - General	17,938,513	2.09%	374,915	2.91%	522,011	147,096
379.00	M&R Equipment - City Gate	21,293,673	1.47%	313,017	2.10%	447,167	134,150
380.00	Services	460,062,192	2.70%	12,421,679	2.93%	13,479,822	1,058,143
381.00	Meters	123,125,945	3.55%	4,370,971	4.92%	6,057,796	1,686,825
382.00	Meter Installations	37,556,913	1.32%	495,751	1.93%	724,848	229,097
383.00	House Regulators	7,434,854	2.16%	160,593	3.59%	266,911	106,318
384.00	Regulator Installations	2,289,211	2.16%	49,447	3.59%	82,183	32,736
385.00	Industrial M&R Station Equipment	15,751,970	1.42%	223,678	2.51%	395,374	171,696
386.00	Other Property On Customer Premises	-	0.00%	-	0.00%	-	-
387.00	Other Equipment	3,758,345	4.56%	171,381	4.73%	177,770	6,389
	Total Distribution (Excl Land)	1,511,503,564	2.10%	31,792,689	2.40%	36,275,449	4,482,760
	GENERAL PLANT - DEPRECIATED						
389.00	Land and Land Rights	25,149	0.00%	-	0.00%	-	-
390.00	Structures & Improvements	24,733,652	2.60%	643,075	2.69%	665,335	22,260
391.20	Enterprise Systems	99,961,209	6.67%	6,667,413	10.25%	10,246,024	3,578,611
392.00	Transportation Equip	5,586,900	7.06%	394,435	11.20%	625,733	231,298
392.10	Autos & Light Trucks	4,508,198	9.98%	449,918	26.73%	1,205,041	755,123
392.20	Service Trucks	2,471,544	13.35%	329,951	16.55%	409,040	79,089
392.30	Heavy Trucks	4,120,912	13.21%	544,372	12.27%	505,636	(38,737)
394.10	Natural Gas Vehicle Stations	2,721,905	5.14%	139,906	5.58%	151,882	11,976
396.00	Power Operated Equip	1,860,485	7.84%	145,862	10.59%	197,025	51,163
396.10	Power Operated Equip Tractors	1,930,995	8.05%	155,445	9.35%	180,548	25,103
	Total General Depreciated (excl Land)	147,895,799	6.40%	9,470,377	9.59%	14,186,265	4,715,888

Elizabethtown Gas Company
Comparison of Depreciation Expense
Comparison of Existing and Proposed Depreciation Accrual Rates
Depreciation Study as of December 31, 2020

Account	Description	Plant Balance	Existing Annual Accrual Rate	Existing Annual Accrual Amount	Proposed Annual Accrual Rate	Proposed Annual Accrual Amount	Change in Depreciation Expense
(a)	(b)	(c)	(d)	(e)	[f]	[g]	[h]
	GENERAL PLANT - AMORTIZED						
391.00	Office Furniture and Equipment	828,990	5.00%	41,450	5.00%	41,450	-
391.10	Computer Equipment	1,318,616	33.33%	439,495	20.00%	263,723	(175,772)
391.11	Computer Equipment and Software	714,729	14.29%	102,135	20.00%	142,946	40,811
391.12	Computer Hardware	3,974,880	14.29%	568,010	16.67%	662,612	94,602
391.50	Individual Equipment	-	33.33%	-	33.33%	-	-
393.00	Stores Equipment	60,377	4.00%	2,415	4.00%	2,415	-
394.00	Tools, Shop, Garage Equipment	4,177,710	5.56%	232,281	5.56%	232,281	-
395.00	Laboratory Equipment	-	5.00%	-	5.00%	-	-
397.00	Communication Equipment	2,479,844	5.56%	137,879	10.00%	247,984	110,105
398.00	Misc. Equipment	1,624,358	5.00%	81,218	5.00%	81,218	-
	Total General Amortized (after retirements)	15,179,504	10.57%	1,604,882	11.03%	1,674,629	69,747
	Total General Plant	163,075,303	6.79%	11,075,260	9.73%	15,860,894	4,785,635
	TOTAL DEPRECIABLE AND AMORTIZED PLANT IN SERVICE	$ 1,715,578,863	2.55%	$ 43,716,103	3.09%	$ 53,014,840	$ 9,298,737
	(excludes Intangibles and Land)						
	TOTAL STUDY PLANT IN SERVICE	$ 1,716,929,775					

* Denotes a whole life rate is being proposed for new additions.

Study Adjustments	
Amortized Retirements (assets with life > ASL)	1,137,594.25
Proforma Retirements 311-320.4	826,417.72
Proforma Retirement 363.20	10,060,649.71
Proforma Retirements 367	4,435,634.11
Proforma Retirements 378	1,994,845.93
Total Study Adjustments	18,455,141.72
TOTAL BOOK PLANT IN SERVICE	$ 1,735,384,916.74
GL	1,735,384,916.74
Unreconciled Difference	$ -

APPENDIX C - Depreciation Parameter Comparison

Elizabethtown Gas Company
Depreciation Study as of December 31, 2020
Comparison of Existing and Proposed Parameters

		Docket No. GR19040486 Approved Parameters			Proposed Parameters		
Account	**Description**	**Life**	**Curve**	**Net Salvage Amount $**	**Life**	**Curve**	**Net Salvage Amount $**
MANUFACTURED GAS PLANT							
304.20	Land Rights	65	SQ	-	65	SQ	-
311.00	Liquefied Petroleum Gas Equipment	35	S3	-	35	S3	-
320.00	Other Equipment	15	L1	-	12	L2.5	-
	Total Manufactured Gas Plant			**-**			**-**
OTHER STORAGE PLANT							
361.00	Structures & Improvements	45	S4	-	45	S4	-
362.00	Gas Holders-Natural Gas	65	S4	-	70	S4	-
362.10	Gas Holders-LNG	65	S4	-	70	S4	-
363.20	Vaporizing Equipment	35	S3	-	35	S3	-
363.40	M&R Equipment	25	S3	-	25	S3	-
	Total Other Storage Plant			**-**			**-**
TRANSMISSION PLANT							
365.20	Rights of Way	80	R2	-	80	R2	-
367.00	Mains	71	R2	(46,404)	71	R2	(21,163)
369.00	M&R Equipment	45	S2	(17,873)	45	S2	(33,475)
371.00	Other Equipment	20	R2	-	20	R2	-
	Total Transmission Plant			**(64,277)**			**(54,637)**
DISTRIBUTION PLANT							
374.00	Land and Land Rights	80	R2	-	80	R2	-
374.20	Land Rights	80	R2	-	80	R2	-
374.30	Rights of Way	80	R2	-	80	R2	-
375.00	Structures & Improvements	33	L0.5	-	33	L2	-
376 All	Mains	71	R2	(1,754,567)	71	R2	(2,659,609)
378.00	M&R Station Equipment - General	35	S2	(51,175)	35	S2	(65,124)
379.00	M&R Equipment - City Gate	45	S2	(13,902)	45	S2	(12,255)
380 All	Services	60	S0	(3,894,584)	60	S0	(5,903,383)
381.00	Meters	28	R1.5	(400)	20	R1	(31,881)
382.00	Meter Installations	50	S5	(72)	50	S5	0
383.00	House Regulators	42	L5	-	36	L5	(112.47)
384.00	Regulator Installations	42	L5	-	36	L5	(83,938.54)
385.00	Industrial M&R Station Equipment	45	S2	-	45	S2	-
387.00	Other Equipment	17	R5	(22,974)			-
	Total Distribution Plant			**(5,737,674)**			**(8,756,304)**

Elizabethtown Gas Company
Depreciation Study as of December 31, 2020
Comparison of Existing and Proposed Parameters

		Docket No. GR19040486 Approved Parameters			Proposed Parameters		
Account	**Description**	**Life**	**Curve**	**Net Salvage Amount $**	**Life**	**Curve**	**Net Salvage Amount $**
GENERAL PLANT							
390.00	Structures & Improvements	40	R5	-	40	R5	-
391.00	Office Furniture & Equipment	20	SQ	-	20	SQ	-
391.10	Computer Equipment & Software	3	SQ	-	5	SQ	-
391.11	Computer Software	7	SQ	-	5	SQ	-
391.12	Computer Hardware	7	SQ	-	6	SQ	-
391.20	Enterprise Systems	15	SQ	-	10	SQ	-
391.50	Individual Equipment	3	SQ	-	3	SQ	-
392.00	Transportation Equipment	15	L3	5,622	10	L3	183
392.10	Transporttion - Auto & Light Trucks	11	R3	96,453	6	R3	41,919
392.20	Transportation - Service Trucks	8	L3	15,741	8	L3	13,616
392.30	Transportation - Heavy Trucks	10	R5	67,811	11	R5	11,150
393.00	Stores Equipment	25	SQ	-	25	SQ	-
394.00	Tools, Shop, & Garage Equipment	18	SQ	Salvage not included	18	SQ	-
394.10	Natural Gas Vehicle Equipment	20	S4	-	20	S4	-
395.00	Laboratory Equipment	20	SQ	-	20	SQ	-
396.00	Power Operated Equipment	14	L4	-	11	L4	-
396.10	Power Operated Equipment Tractors	12	L3	8,515	11	L4	0
397.00	Communication Equipment	18	SQ	-	10	SQ	-
398.00	Miscellaneous Equipment	20	SQ	COR not included	20	SQ	COR not included
	Total General Plant			**194,142**			**66,868**
Total Net Salvage Amount Included in Annual Accrual				**$ (5,607,809)**			**$ (8,744,073)**

APPENDIX D - Net Salvage Analysis

Exhibit P-9

Elizabethtown Gas Company
Depreciation Study at December 31, 2020
Net Salvage As Adjusted

Account	TransYear	Retirement	Salvage	Removal Cost	Net Salvage	Net Salvage %	2-Yr Net Salvage %	3-Yr Net Salvage %	4-Yr Net Salvage %	5-Yr Net Salvage %	6-Yr Net Salvage %	7-Yr Net Salvage %	8-Yr Net Salvage %	9-Yr Net Salvage %	10-Yr Net Salvage %
304	1999	-	0	0	0	NA									
304	2000	-	0	0	0	NA	NA								
304	2001	-	0	0	0	NA	NA	NA							
304	2002	1,113	0	0	0	0.00%	0.00%	0.00%	0.00%						
304	2003	-	0	0	0	NA	0.00%	0.00%	0.00%	0.00%					
304	2004	-	0	0	0	NA	NA	0.00%	0.00%	0.00%	0.00%				
304	2005	-	0	0	0	NA	NA	NA	0.00%	0.00%	0.00%	0.00%			
304	2006	-	0	0	0	NA	NA	NA	NA	0.00%	0.00%	0.00%	0.00%		
304	2007	6,217	0	0	0	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	
304	2008	-	0	0	0	NA	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
304	2009	-	0	0	0	NA	NA	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
304	2010	-	0	0	0	NA	NA	NA	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
304	2011	-	0	0	0	NA	NA	NA	NA	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
304	2012	-	0	0	0	NA	NA	NA	NA	NA	0.00%	0.00%	0.00%	0.00%	0.00%
304	2013	-	0	0	0	NA	NA	NA	NA	NA	NA	0.00%	0.00%	0.00%	0.00%
304	2014	-	0	0	0	NA	NA	NA	NA	NA	NA	NA	0.00%	0.00%	0.00%
304	2015	-	0	0	0	NA	NA	NA	NA	NA	NA	NA	NA	0.00%	0.00%
304	2016	-	0	0	0	NA	NA	NA	NA	NA	NA	NA	NA	NA	0.00%
304	2017	-	0	0	0	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA
304	2018	-	0	0	0	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA
304	2019	-	0	0	0	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA
304	2020	-	0	0	0	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA
305	1999	-	0	0	0	NA									
305	2000	-	0	0	0	NA	NA								
305	2001	-	0	0	0	NA	NA	NA							
305	2002	860,334	0	0	0	0.00%	0.00%	0.00%	0.00%						
305	2003	-	0	0	0	NA	0.00%	0.00%	0.00%	0.00%					
305	2004	-	0	0	0	NA	NA	0.00%	0.00%	0.00%	0.00%				
305	2005	-	0	0	0	NA	NA	NA	0.00%	0.00%	0.00%	0.00%			
305	2006	-	0	0	0	NA	NA	NA	NA	0.00%	0.00%	0.00%	0.00%		
305	2007	-	0	0	0	NA	NA	NA	NA	NA	0.00%	0.00%	0.00%	0.00%	
305	2008	-	0	0	0	NA	NA	NA	NA	NA	NA	0.00%	0.00%	0.00%	0.00%
305	2009	-	0	0	0	NA	NA	NA	NA	NA	NA	NA	0.00%	0.00%	0.00%
305	2010	-	0	0	0	NA	NA	NA	NA	NA	NA	NA	NA	0.00%	0.00%
305	2011	-	0	0	0	NA	NA	NA	NA	NA	NA	NA	NA	NA	0.00%
305	2012	-	0	0	0	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA
305	2013	-	0	0	0	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA
305	2014	-	0	0	0	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA
305	2015	-	0	0	0	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA
305	2016	-	0	0	0	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA
305	2017	-	0	0	0	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA
305	2018	-	0	0	0	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA
305	2019	-	0	0	0	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA
305	2020	-	0	0	0	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA

Elizabethtown Gas Company
Depreciation Study at December 31, 2020
Net Salvage As Adjusted

Account	TransYear	Retirement	Salvage	Removal Cost	Net Salvage	Net Salvage %	2-Yr Net Salvage %	3-Yr Net Salvage %	4-Yr Net Salvage %	5-Yr Net Salvage %	6-Yr Net Salvage %	7-Yr Net Salvage %	8-Yr Net Salvage %	9-Yr Net Salvage %	10-Yr Net Salvage %
311	1999	5,934,489	0	0	0	0.00%									
311	2000	-	0	0	0	NA	0.00%								
311	2001	-	0	0	0	NA	NA	0.00%							
311	2002	529,682	0	0	0	0.00%	0.00%	0.00%	0.00%						
311	2003	-	0	0	0	NA	0.00%	0.00%	0.00%	0.00%					
311	2004	-	0	0	0	NA	NA	0.00%	0.00%	0.00%	0.00%				
311	2005	-	0	0	0	NA	NA	NA	0.00%	0.00%	0.00%	0.00%			
311	2006	-	0	0	0	NA	NA	NA	NA	0.00%	0.00%	0.00%	0.00%		
311	2007	-	0	0	0	NA	NA	NA	NA	NA	0.00%	0.00%	0.00%	0.00%	
311	2008	-	0	0	0	NA	NA	NA	NA	NA	NA	0.00%	0.00%	0.00%	0.00%
311	2009	-	0	0	0	NA	NA	NA	NA	NA	NA	NA	0.00%	0.00%	0.00%
311	2010	-	0	0	0	NA	NA	NA	NA	NA	NA	NA	NA	0.00%	0.00%
311	2011	-	0	0	0	NA	NA	NA	NA	NA	NA	NA	NA	NA	0.00%
311	2012	-	0	0	0	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA
311	2013	-	0	0	0	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA
311	2014	-	0	0	0	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA
311	2015	-	0	0	0	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA
311	2016	-	0	0	0	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA
311	2017	-	0	0	0	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA
311	2018	-	0	0	0	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA
311	2019	-	0	0	0	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA
311	2020	-	-	0	0	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA
320	1999	-	0	0	0	NA									
320	2000	-	0	0	0	NA	NA								
320	2001	-	0	0	0	NA	NA	NA							
320	2002	577,745	0	0	0	0.00%	0.00%	0.00%	0.00%						
320	2003	-	0	0	0	NA	0.00%	0.00%	0.00%	0.00%					
320	2004	-	0	0	0	NA	NA	0.00%	0.00%	0.00%	0.00%				
320	2005	-	0	0	0	NA	NA	NA	0.00%	0.00%	0.00%	0.00%			
320	2006	-	0	0	0	NA	NA	NA	NA	0.00%	0.00%	0.00%	0.00%		
320	2007	-	0	0	0	NA	NA	NA	NA	NA	0.00%	0.00%	0.00%	0.00%	
320	2008	-	0	0	0	NA	NA	NA	NA	NA	NA	0.00%	0.00%	0.00%	0.00%
320	2009	-	0	0	0	NA	NA	NA	NA	NA	NA	NA	0.00%	0.00%	0.00%
320	2010	-	0	0	0	NA	NA	NA	NA	NA	NA	NA	NA	0.00%	0.00%
320	2011	-	0	0	0	NA	NA	NA	NA	NA	NA	NA	NA	NA	0.00%
320	2012	-	0	0	0	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA
320	2013	-	0	0	0	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA
320	2014	-	0	0	0	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA
320	2015	9,380	0	0	0	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
320	2016	-	0	0	0	NA	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
320	2017	-	0	0	0	NA	NA	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%

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320	2018	-	0	0	0	NA	NA	NA	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
320	2019	-	0	0	0	NA	NA	NA	NA	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
320	2020	-	0	0	0	NA	NA	NA	NA	NA	0.00%	0.00%	0.00%	0.00%	0.00%
361	1999	-	0	0	0	NA									
361	2000	-	0	0	0	NA	NA								
361	2001	-	0	0	0	NA	NA	NA							
361	2002	-	0	0	0	NA	NA	NA	NA						
361	2003	-	0	0	0	NA	NA	NA	NA	NA					
361	2004	-	0	0	0	NA	NA	NA	NA	NA	NA				
361	2005	-	0	0	0	NA	NA	NA	NA	NA	NA	NA			
361	2006	-	0	0	0	NA	NA	NA	NA	NA	NA	NA	NA		
361	2007	-	0	0	0	NA	NA	NA	NA	NA	NA	NA	NA	NA	
361	2008	-	0	0	0	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA
361	2009	-	0	0	0	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA
361	2010	9,033	0	0	0	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
361	2011	-	0	0	0	NA	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
361	2012	-	0	0	0	NA	NA	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
361	2013	274,823	0	0	0	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
361	2014	-	0	0	0	NA	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
361	2015	193,586	0	0	0	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
361	2016	-	0	0	0	NA	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
361	2017	-	0	0	0	NA	NA	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
361	2018	-	0	0	0	NA	NA	NA	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
361	2019	-	0	0	0	NA	NA	NA	NA	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
361	2020	-	0	0	0	NA	NA	NA	NA	NA	0.00%	0.00%	0.00%	0.00%	0.00%
362	1999	456,331	0	104,703	(104,703)	-22.94%									
362	2000	-	0	0	0	NA	-22.94%								
362	2001	-	0	0	0	NA	NA	-22.94%							
362	2002	-	0	0	0	NA	NA	NA	-22.94%						
362	2003	-	0	0	0	NA	NA	NA	NA	-22.94%					
362	2004	-	0	0	0	NA	NA	NA	NA	NA	-22.94%				
362	2005	-	0	0	0	NA	NA	NA	NA	NA	NA	-22.94%			
362	2006	-	0	0	0	NA	NA	NA	NA	NA	NA	NA	-22.94%		
362	2007	-	0	0	0	NA	NA	NA	NA	NA	NA	NA	NA	-22.94%	
362	2008	-	0	0	0	NA	NA	NA	NA	NA	NA	NA	NA	NA	-22.94%
362	2009	2,186,647	0	0	0	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
362	2010	-	0	0	0	NA	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
362	2011	-	0	0	0	NA	NA	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
362	2012	-	0	0	0	NA	NA	NA	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
362	2013	-	0	0	0	NA	NA	NA	NA	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
362	2014	-	0	0	0	NA	NA	NA	NA	NA	0.00%	0.00%	0.00%	0.00%	0.00%

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362	2015	-	0	0	0	NA	NA	NA	NA	NA	NA	0.00%	0.00%	0.00%	0.00%
362	2016	-	0	0	0	NA	NA	NA	NA	NA	NA	NA	0.00%	0.00%	0.00%
362	2017	-	0	0	0	NA	NA	NA	NA	NA	NA	NA	NA	0.00%	0.00%
362	2018	-	0	0	0	NA	NA	NA	NA	NA	NA	NA	NA	NA	0.00%
362	2019	-	0	0	0	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA
362	2020	-	0	0	0	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA
362.1	1999	56,123	0	0	0	0.00%									
362.1	2000	-	0	0	0	NA	0.00%								
362.1	2001	-	0	0	0	NA	NA	0.00%							
362.1	2002	-	0	0	0	NA	NA	NA	0.00%						
362.1	2003	-	0	0	0	NA	NA	NA	NA	0.00%					
362.1	2004	-	0	0	0	NA	NA	NA	NA	NA	0.00%				
362.1	2005	-	0	0	0	NA	NA	NA	NA	NA	NA	0.00%			
362.1	2006	-	0	0	0	NA	NA	NA	NA	NA	NA	NA	0.00%		
362.1	2007	-	0	0	0	NA	NA	NA	NA	NA	NA	NA	NA	0.00%	
362.1	2008	-	0	0	0	NA	NA	NA	NA	NA	NA	NA	NA	NA	0.00%
362.1	2009	-	0	0	0	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA
362.1	2010	-	0	0	0	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA
362.1	2011	-	0	0	0	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA
362.1	2012	-	0	0	0	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA
362.1	2013	-	0	0	0	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA
362.1	2014	-	0	0	0	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA
362.1	2015	1,102,044	0	0	0	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
362.1	2016	-	0	0	0	NA	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
362.1	2017	-	0	0	0	NA	NA	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
362.1	2018	-	0	0	0	NA	NA	NA	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
362.1	2019	-	0	0	0	NA	NA	NA	NA	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
362.1	2020	-	0	0	0	NA	NA	NA	NA	NA	0.00%	0.00%	0.00%	0.00%	0.00%
362 Combined	1999	512,454	0	104,703	(104,703)	-20.43%									
362 Combined	2000	-	0	0	0	NA	-20.43%								
362 Combined	2001	-	0	0	0	NA	NA	-20.43%							
362 Combined	2002	-	0	0	0	NA	NA	NA	-20.43%						
362 Combined	2003	-	0	0	0	NA	NA	NA	NA	-20.43%					
362 Combined	2004	-	0	0	0	NA	NA	NA	NA	NA	-20.43%				
362 Combined	2005	-	0	0	0	NA	NA	NA	NA	NA	NA	-20.43%			
362 Combined	2006	-	0	0	0	NA	NA	NA	NA	NA	NA	NA	-20.43%		
362 Combined	2007	-	0	0	0	NA	NA	NA	NA	NA	NA	NA	NA	-20.43%	
362 Combined	2008	-	0	0	0	NA	NA	NA	NA	NA	NA	NA	NA	NA	-20.43%
362 Combined	2009	2,186,647	0	0	0	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
362 Combined	2010	-	0	0	0	NA	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
362 Combined	2011	-	0	0	0	NA	NA	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%

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362 Combined	2012	-	0	0	0	NA	NA	NA	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
362 Combined	2013	-	0	0	0	NA	NA	NA	NA	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
362 Combined	2014	-	0	0	0	NA	NA	NA	NA	NA	0.00%	0.00%	0.00%	0.00%	0.00%
362 Combined	2015	1,102,044	0	0	0	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
362 Combined	2016	-	0	0	0	NA	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
362 Combined	2017	-	0	0	0	NA	NA	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
362 Combined	2018	-	0	0	0	NA	NA	NA	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
362 Combined	2019	-	0	0	0	NA	NA	NA	NA	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
362 Combined	2020	-	0	0	0	NA	NA	NA	NA	NA	0.00%	0.00%	0.00%	0.00%	0.00%
363.2	1999	-	0	0	0	NA									
363.2	2000	-	0	0	0	NA	NA								
363.2	2001	-	0	0	0	NA	NA	NA							
363.2	2002	-	0	0	0	NA	NA	NA	NA						
363.2	2003	-	0	0	0	NA	NA	NA	NA	NA					
363.2	2004	-	0	0	0	NA	NA	NA	NA	NA	NA				
363.2	2005	-	0	0	0	NA	NA	NA	NA	NA	NA	NA			
363.2	2006	-	0	0	0	NA	NA	NA	NA	NA	NA	NA	NA		
363.2	2007	-	0	0	0	NA	NA	NA	NA	NA	NA	NA	NA	NA	
363.2	2008	-	0	0	0	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA
363.2	2009	-	0	0	0	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA
363.2	2010	-	0	0	0	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA
363.2	2011	-	0	0	0	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA
363.2	2012	-	0	0	0	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA
363.2	2013	-	0	0	0	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA
363.2	2014	-	0	0	0	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA
363.2	2015	446,836	0	0	0	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
363.2	2016	-	0	0	0	NA	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
363.2	2017	-	0	0	0	NA	NA	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
363.2	2018	-	0	0	0	NA	NA	NA	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
363.2	2019	-	0	0	0	NA	NA	NA	NA	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
363.2	2020	-	0	0	0	NA	NA	NA	NA	NA	0.00%	0.00%	0.00%	0.00%	0.00%
363.4	1999	-	0	0	0	NA									
363.4	2000	-	0	0	0	NA	NA								
363.4	2001	-	0	0	0	NA	NA	NA							
363.4	2002	-	0	0	0	NA	NA	NA	NA						
363.4	2003	-	0	0	0	NA	NA	NA	NA	NA					
363.4	2004	-	0	0	0	NA	NA	NA	NA	NA	NA				
363.4	2005	-	0	0	0	NA	NA	NA	NA	NA	NA	NA			
363.4	2006	-	0	0	0	NA	NA	NA	NA	NA	NA	NA	NA		
363.4	2007	-	0	0	0	NA	NA	NA	NA	NA	NA	NA	NA	NA	
363.4	2008	-	0	0	0	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA

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363.4	2009	-	0	0	0	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA
363.4	2010	-	0	0	0	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA
363.4	2011	-	0	0	0	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA
363.4	2012	-	0	0	0	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA
363.4	2013	-	0	0	0	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA
363.4	2014	-	0	0	0	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA
363.4	2015	1,046,192	0	0	0	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
363.4	2016	-	0	0	0	NA	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
363.4	2017	-	0	0	0	NA	NA	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
363.4	2018	-	0	0	0	NA	NA	NA	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
363.4	2019	-	0	0	0	NA	NA	NA	NA	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
363.4	2020	-	0	0	0	NA	NA	NA	NA	NA	0.00%	0.00%	0.00%	0.00%	0.00%
367C	1999	-	0	0	0	NA									
367C	2000	-	0	0	0	NA	NA								
367C	2001	-	0	0	0	NA	NA	NA							
367C	2002	-	0	0	0	NA	NA	NA	NA						
367C	2003	-	0	0	0	NA	NA	NA	NA	NA					
367C	2004	-	0	0	0	NA	NA	NA	NA	NA	NA				
367C	2005	-	0	0	0	NA	NA	NA	NA	NA	NA	NA			
367C	2006	-	0	0	0	NA	NA	NA	NA	NA	NA	NA	NA		
367C	2007	-	0	0	0	NA	NA	NA	NA	NA	NA	NA	NA	NA	
367C	2008	-	0	0	0	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA
367C	2009	-	0	0	0	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA
367C	2010	-	0	0	0	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA
367C	2011	-	0	0	0	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA
367C	2012	-	0	0	0	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA
367C	2013	-	0	0	0	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA
367C	2014	-	0	154,600	(154,600)	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA
367C	2015	-	0	12,232	(12,232)	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA
367C	2016	-	0	1,697	(1,697)	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA
367C	2017	-	0	0	0	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA
367C	2018	-	0	63,488	(63,488)	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA
367C	2019	-	0	0	0	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA
367C	2020 *	4,435,634	0	0	0	0.00%	0.00%	-1.43%	-1.43%	-1.47%	-1.75%	-5.23%	-5.23%	-5.23%	-5.23%
5 year		887,127	0	13,037	(13,037)										
3 year		1,478,545	0	21,163	(21,163)										

*Denotes Proforma Retirement

369	2018	-	0	89,367	(89,367)	NA		
369	2019	-	0	11,057	(11,057)	NA	NA	
369	2020	-	0	0	0	NA	NA	NA
3 year		0	0	33,475	(33,475)			

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371	1999	-	0	0	0	NA									
371	2000	-	0	0	0	NA	NA								
371	2001	-	0	0	0	NA	NA	NA							
371	2002	-	0	0	0	NA	NA	NA	NA						
371	2003	-	0	0	0	NA	NA	NA	NA	NA					
371	2004	-	0	0	0	NA	NA	NA	NA	NA	NA				
371	2005	-	0	0	0	NA	NA	NA	NA	NA	NA	NA			
371	2006	-	0	0	0	NA	NA	NA	NA	NA	NA	NA	NA		
371	2007	-	0	0	0	NA	NA	NA	NA	NA	NA	NA	NA	NA	
371	2008	-	0	0	0	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA
371	2009	-	0	0	0	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA
371	2010	-	0	0	0	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA
371	2011	-	0	0	0	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA
371	2012	-	0	0	0	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA
371	2013	-	0	0	0	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA
371	2014	-	0	0	0	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA
371	2015	4,775	0	0	0	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
371	2016	-	0	0	0	NA	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
371	2017	-	0	0	0	NA	NA	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
371	2018	-	0	0	0	NA	NA	NA	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
371	2019	-	0	0	0	NA	NA	NA	NA	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
371	2020	-	0	0	0	NA	NA	NA	NA	NA	0.00%	0.00%	0.00%	0.00%	0.00%
374 C	1999	-	0	0	0	NA									
374 C	2000	-	0	0	0	NA	NA								
374 C	2001	-	0	0	0	NA	NA	NA							
374 C	2002	61,317	0	0	0	0.00%	0.00%	0.00%	0.00%						
374 C	2003	-	0	0	0	NA	0.00%	0.00%	0.00%	0.00%					
374 C	2004	-	0	0	0	NA	NA	0.00%	0.00%	0.00%	0.00%				
374 C	2005	-	0	0	0	NA	NA	NA	0.00%	0.00%	0.00%	0.00%			
374 C	2006	-	0	0	0	NA	NA	NA	NA	0.00%	0.00%	0.00%	0.00%		
374 C	2007	-	0	0	0	NA	NA	NA	NA	NA	0.00%	0.00%	0.00%	0.00%	
374 C	2008	-	0	0	0	NA	NA	NA	NA	NA	NA	0.00%	0.00%	0.00%	0.00%
374 C	2009	-	0	0	0	NA	NA	NA	NA	NA	NA	NA	0.00%	0.00%	0.00%
374 C	2010	-	0	0	0	NA	NA	NA	NA	NA	NA	NA	NA	0.00%	0.00%
374 C	2011	-	0	0	0	NA	NA	NA	NA	NA	NA	NA	NA	NA	0.00%
374 C	2012	-	0	0	0	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA
374 C	2013	-	0	0	0	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA
374 C	2014	-	0	0	0	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA
374 C	2015	-	0	0	0	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA
374 C	2016	-	0	0	0	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA
374 C	2017	-	0	0	0	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA
374 C	2018	-	0	0	0	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA
374 C	2019	-	0	0	0	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA
374 C	2020	-	0	0	0	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA

Elizabethtown Gas Company
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Net Salvage As Adjusted

Account	TransYear	Retirement	Salvage	Removal Cost	Net Salvage	Net Salvage %	2-Yr Net Salvage %	3-Yr Net Salvage %	4-Yr Net Salvage %	5-Yr Net Salvage %	6-Yr Net Salvage %	7-Yr Net Salvage %	8-Yr Net Salvage %	9-Yr Net Salvage %	10-Yr Net Salvage %
375	1999	-	0	0	0	NA									
375	2000	-	0	0	0	NA	NA								
375	2001	-	0	9,792	(9,792)	NA	NA	NA							
375	2002	339,248	0	824	(824)	-0.24%	-3.13%	-3.13%	-3.13%						
375	2003	-	0	0	0	NA	-0.24%	-3.13%	-3.13%	-3.13%					
375	2004	-	0	29,080	(29,080)	NA	NA	-8.81%	-11.70%	-11.70%	-11.70%				
375	2005	-	0	0	0	NA	NA	NA	-8.81%	-11.70%	-11.70%	-11.70%			
375	2006	-	0	0	0	NA	NA	NA	NA	-8.81%	-11.70%	-11.70%	-11.70%		
375	2007	242,207	110,351	0	110,351	45.56%	45.56%	45.56%	33.55%	33.55%	13.84%	12.15%	12.15%	12.15%	
375	2008	-	0	0	0	NA	45.56%	45.56%	45.56%	33.55%	33.55%	13.84%	12.15%	12.15%	12.15%
375	2009	-	0	0	0	NA	NA	45.56%	45.56%	45.56%	33.55%	33.55%	13.84%	12.15%	12.15%
375	2010	444,214	0	0	0	0.00%	0.00%	0.00%	16.08%	16.08%	16.08%	11.84%	11.84%	7.84%	6.89%
375	2011	-	0	0	0	NA	0.00%	0.00%	0.00%	16.08%	16.08%	16.08%	11.84%	11.84%	7.84%
375	2012	-	0	0	0	NA	NA	0.00%	0.00%	0.00%	16.08%	16.08%	16.08%	11.84%	11.84%
375	2013	1,563,832	0	0	0	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	4.90%	4.90%	4.90%	3.61%
375	2014	-	0	0	0	NA	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	4.90%	4.90%	4.90%
375	2015	249,748	0	0	0	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	4.41%	4.41%
375	2016	-	0	0	0	NA	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	4.41%
375	2017	-	0	0	0	NA	NA	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
375	2018	-	0	0	0	NA	NA	NA	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
375	2019	-	0	0	0	NA	NA	NA	NA	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
375	2020	-	0	0	0	NA	NA	NA	NA	NA	0.00%	0.00%	0.00%	0.00%	0.00%
376 C	1999	188,587	0	741,866	(741,866)	-393.38%									
376 C	2000	1,363,725	0	609,608	(609,608)	-44.70%	-87.06%								
376 C	2001	173,780	0	267,126	(267,126)	-153.71%	-57.02%	-93.77%							
376 C	2002	848,409	0	514,389	(514,389)	-60.63%	-76.46%	-58.31%	-82.85%						
376 C	2003	329,530	0	443,042	(443,042)	-134.45%	-81.28%	-90.59%	-67.55%	-88.71%					
376 C	2004	417,134	0	508,214	(508,214)	-121.83%	-127.40%	-91.89%	-97.96%	-74.77%	-92.87%				
376 C	2005	71,199	0	98,374	(98,374)	-138.17%	-124.22%	-128.34%	-93.86%	-99.52%	-76.18%	-93.82%			
376 C	2006	-	0	76,625	(76,625)	NA	-245.79%	-139.91%	-137.71%	-98.46%	-103.68%	-78.58%	-96.08%		
376 C	2007	4,480,577	0	(9,863)	9,863	0.22%	-1.49%	-3.63%	-13.55%	-21.07%	-26.53%	-30.03%	-32.63%	-41.27%	
376 C	2008	29,574	0	22,153	(22,153)	-74.91%	-0.27%	-1.97%	-4.09%	-13.91%	-21.37%	-26.76%	-30.24%	-32.79%	-41.40%
376 C	2009	4,352,275	0	638,158	(638,158)	-14.66%	-15.07%	-7.34%	-8.20%	-9.24%	-14.26%	-18.35%	-21.76%	-23.90%	-26.25%
376 C	2010	238,328	0	1,533,288	(1,533,288)	-643.35%	-47.30%	-47.48%	-24.00%	-24.84%	-25.72%	-29.90%	-33.37%	-35.52%	-37.40%
376 C	2011	211,069	0	839,241	(839,241)	-397.61%	-527.94%	-62.70%	-62.78%	-32.46%	-33.29%	-34.08%	-37.82%	-40.96%	-42.48%
376 C	2012	3,586	0	659,597	(659,597)	-18391.91%	-698.25%	-669.37%	-76.38%	-76.37%	-39.53%	-40.35%	-41.10%	-44.53%	-47.46%
376 C	2013	-	0	(1,672,684)	1,672,684	NA	28248.51%	80.99%	-300.11%	-41.57%	-41.78%	-21.58%	-22.40%	-23.28%	-27.47%
376 C	2014	2,625,440	0	1,404,761	(1,404,761)	-53.51%	10.20%	-14.90%	-43.34%	-89.79%	-45.79%	-45.90%	-28.60%	-29.24%	-29.88%
376 C	2015	1,048,684	0	1,523,347	(1,523,347)	-145.26%	-79.70%	-34.17%	-52.07%	-70.83%	-103.89%	-58.09%	-58.15%	-38.02%	-38.61%
376 C	2016	1,125,284	0	2,569,028	(2,569,028)	-228.30%	-188.24%	-114.54%	-79.69%	-93.36%	-106.17%	-130.54%	-78.03%	-78.02%	-53.19%
376 C	2017	1,828,790	0	963,945	(963,945)	-52.71%	-119.60%	-126.32%	-97.48%	-72.24%	-82.15%	-91.88%	-110.44%	-73.98%	-73.98%

Exhibit P-9

Elizabethtown Gas Company
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Account	TransYear	Retirement	Salvage	Removal Cost	Net Salvage	Net Salvage %	2-Yr Net Salvage %	3-Yr Net Salvage %	4-Yr Net Salvage %	5-Yr Net Salvage %	6-Yr Net Salvage %	7-Yr Net Salvage %	8-Yr Net Salvage %	9-Yr Net Salvage %	10-Yr Net Salvage %
376 C	2018	3,166,484	0	2,311,753	(2,311,753)	-73.01%	-65.58%	-95.49%	-102.77%	-89.57%	-72.49%	-79.20%	-85.91%	-98.87%	-73.77%
376 C	2019	3,754,841	0	3,916,184	(3,916,184)	-104.30%	-89.98%	-82.19%	-98.84%	-103.30%	-93.65%	-81.30%	-86.15%	-90.93%	-100.33%
376 C	2020	2,935,602	0	1,750,891	(1,750,891)	-59.64%	-84.70%	-80.95%	-76.53%	-89.86%	-94.05%	-87.59%	-77.45%	-81.43%	-85.43%
5 Year		2,562,200	0	2,302,360	(2,302,360)										
3 Year		3,285,642	0	2,659,609	(2,659,609)										
378	1999	-	0	0	0	NA									
378	2000	-	0	0	0	NA	NA								
378	2001	-	0	0	0	NA	NA	NA							
378	2002	-	0	0	0	NA	NA	NA	NA						
378	2003	-	0	0	0	NA	NA	NA	NA	NA					
378	2004	1,923	0	1,735	(1,735)	-90.22%	-90.22%	-90.22%	-90.22%	-90.22%	-90.22%				
378	2005	-	0	0	0	NA	-90.22%	-90.22%	-90.22%	-90.22%	-90.22%	-90.22%			
378	2006	-	0	0	0	NA	NA	-90.22%	-90.22%	-90.22%	-90.22%	-90.22%	-90.22%		
378	2007	-	0	953	(953)	NA	NA	NA	-139.75%	-139.75%	-139.75%	-139.75%	-139.75%	-139.75%	
378	2008	-	0	8,703	(8,703)	NA	NA	NA	NA	-592.30%	-592.30%	-592.30%	-592.30%	-592.30%	-592.30%
378	2009	-	0	0	0	NA	NA	NA	NA	NA	-592.30%	-592.30%	-592.30%	-592.30%	-592.30%
378	2010	-	0	0	0	NA	NA	NA	NA	NA	NA	-592.30%	-592.30%	-592.30%	-592.30%
378	2011	-	0	0	0	NA	NA	NA	NA	NA	NA	NA	-592.30%	-592.30%	-592.30%
378	2012	-	0	0	0	NA	NA	NA	NA	NA	NA	NA	NA	-592.30%	-592.30%
378	2013	-	0	0	0	NA	NA	NA	NA	NA	NA	NA	NA	NA	-592.30%
378	2014	-	0	0	0	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA
378	2015	-	0	10,089	(10,089)	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA
378	2016 *	106,852	0	89,829	(89,829)	-84.07%	-93.51%	-93.51%	-93.51%	-93.51%	-93.51%	-93.51%	-93.51%	-101.66%	-102.55%
378	2017 *	468,994	0	20,466	(20,466)	-4.36%	-19.15%	-20.91%	-20.91%	-20.91%	-20.91%	-20.91%	-20.91%	-20.91%	-22.42%
378	2018 *	707,397	0	135,492	(135,492)	-19.15%	-13.26%	-19.15%	-19.94%	-19.94%	-19.94%	-19.94%	-19.94%	-19.94%	-19.94%
378	2019 *	312,635	0	59,881	(59,881)	-19.15%	-19.15%	-14.50%	-19.15%	-19.79%	-19.79%	-19.79%	-19.79%	-19.79%	-19.79%
378	2020 *	398,969	0	0	0	0.00%	-8.41%	-13.77%	-11.43%	-15.32%	-15.83%	-15.83%	-15.83%	-15.83%	-15.83%
5 Year		398,969	0	61,134	(61,134)										
3 Year		473,000	0	65,124	(65,124)										

*Denotes Proforma estimated retirement between 2016-2020

Account	TransYear	Retirement	Salvage	Removal Cost	Net Salvage	Net Salvage %	2-Yr Net Salvage %	3-Yr Net Salvage %	4-Yr Net Salvage %	5-Yr Net Salvage %	6-Yr Net Salvage %	7-Yr Net Salvage %	8-Yr Net Salvage %	9-Yr Net Salvage %	10-Yr Net Salvage %
379	1999	-	0	0	0	NA									
379	2000	-	0	0	0	NA	NA								
379	2001	-	0	0	0	NA	NA	NA							
379	2002	-	0	0	0	NA	NA	NA	NA						
379	2003	-	0	0	0	NA	NA	NA	NA	NA					
379	2004	-	0	4,015	(4,015)	NA	NA	NA	NA	NA	NA				
379	2005	-	0	0	0	NA	NA	NA	NA	NA	NA	NA			
379	2006	-	0	0	0	NA	NA	NA	NA	NA	NA	NA	NA		
379	2007	-	0	0	0	NA	NA	NA	NA	NA	NA	NA	NA	NA	
379	2008	-	0	0	0	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA
379	2009	-	0	0	0	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA
379	2010	-	0	0	0	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA

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Account	TransYear	Retirement	Salvage	Removal Cost	Net Salvage	Net Salvage %	2-Yr Net Salvage %	3-Yr Net Salvage %	4-Yr Net Salvage %	5-Yr Net Salvage %	6-Yr Net Salvage %	7-Yr Net Salvage %	8-Yr Net Salvage %	9-Yr Net Salvage %	10-Yr Net Salvage %
379	2011	-	0	0	0	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA
379	2012	-	0	0	0	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA
379	2013	-	0	0	0	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA
379	2014	-	0	32,744	(32,744)	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA
379	2015	-	0	0	0	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA
379	2016	-	0	0	0	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA
379	2017	-	0	0	0	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA
379	2018	-	0	36,764	(36,764)	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA
379	2019	-	0	0	0	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA
379	2020	-	0	0	0	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA
5 Year		0	0	7,353	(7,353)										
3 Year		0	0	12,255	(12,255)										
380 C	1999	865	0	931,002	(931,002)	-107630.29%									
380 C	2000	11,304	0	601,129	(601,129)	-5317.84%	-12590.44%								
380 C	2001	10,970	0	432,820	(432,820)	-3945.49%	-4641.95%	-8491.94%							
380 C	2002	898,459	0	642,687	(642,687)	-71.53%	-118.26%	-182.10%	-282.95%						
380 C	2003	537,415	0	671,918	(671,918)	-125.03%	-91.55%	-120.77%	-161.06%	-224.78%					
380 C	2004	698,025	0	539,122	(539,122)	-77.24%	-98.02%	-86.87%	-106.61%	-133.93%	-177.03%				
380 C	2005	145,743	0	94,180	(94,180)	-64.62%	-75.06%	-94.50%	-85.45%	-103.93%	-129.54%	-169.92%			
380 C	2006	-	0	434,490	(434,490)	NA	-362.74%	-126.55%	-125.96%	-104.51%	-122.90%	-148.41%	-188.79%		
380 C	2007	1,038,341	0	535,372	(535,372)	-51.56%	-93.40%	-89.86%	-85.18%	-94.03%	-87.94%	-100.65%	-118.31%	-146.14%	
380 C	2008	3,036,933	0	481,281	(481,281)	-15.85%	-24.95%	-35.61%	-36.61%	-42.38%	-50.52%	-53.49%	-60.19%	-69.51%	-84.10%
380 C	2009	5,782,368	0	428,637	(428,637)	-7.41%	-10.32%	-14.66%	-19.07%	-19.73%	-23.48%	-28.34%	-31.54%	-35.07%	-39.98%
380 C	2010	3,262,399	0	1,660,527	(1,660,527)	-50.90%	-23.10%	-21.28%	-23.67%	-26.98%	-27.40%	-29.89%	-33.41%	-35.64%	-38.42%
380 C	2011	1,953,987	0	402,823	(402,823)	-20.62%	-39.56%	-22.66%	-21.18%	-23.28%	-26.16%	-26.53%	-28.75%	-31.89%	-33.95%
380 C	2012	1,380,802	0	343,588	(343,588)	-24.88%	-22.38%	-36.48%	-22.91%	-21.51%	-23.41%	-26.05%	-26.39%	-28.44%	-31.35%
380 C	2013	1,612,165	0	969,893	(969,893)	-60.16%	-43.89%	-34.69%	-41.13%	-27.20%	-25.17%	-26.69%	-29.10%	-29.38%	-31.15%
380 C	2014	1,455,837	0	2,322,503	(2,322,503)	-159.53%	-107.31%	-81.73%	-63.08%	-58.97%	-39.67%	-35.76%	-36.60%	-38.82%	-39.01%
380 C	2015	938,044	0	3,480,510	(3,480,510)	-371.04%	-242.41%	-169.07%	-132.11%	-102.43%	-86.58%	-58.64%	-51.95%	-51.93%	-54.05%
380 C	2016	4,348,127	0	6,367,582	(6,367,582)	-146.44%	-186.30%	-180.52%	-157.29%	-138.51%	-118.80%	-103.99%	-77.05%	-69.23%	-68.49%
380 C	2017	3,648,636	0	1,691,678	(1,691,678)	-46.36%	-100.78%	-129.16%	-133.41%	-123.57%	-113.39%	-101.57%	-92.68%	-72.46%	-66.19%
380 C	2018	6,649,000	0	5,610,649	(5,610,649)	-84.38%	-70.91%	-93.34%	-110.05%	-114.28%	-109.60%	-103.76%	-96.37%	-90.50%	-75.02%
380 C	2019	5,445,735	22,850	8,513,556	(8,490,706)	-155.91%	-116.59%	-100.32%	-110.30%	-121.93%	-124.36%	-120.07%	-114.91%	-108.19%	-102.10%
380 C	2020	11,828,784	162,264	3,771,059	(3,608,796)	-30.51%	-70.04%	-74.03%	-70.37%	-80.73%	-89.02%	-92.01%	-90.58%	-88.15%	-84.79%
5 Year		6,384,056	37,023	5,190,905	(5,153,882)										
3 Year		7,974,506	61,705	5,965,088	(5,903,383)										
381 C	1999	-	0	0	0	NA									
381 C	2000	-	0	0	0	NA	NA								
381 C	2001	-	0	0	0	NA	NA	NA							
381 C	2002	1,623,067	0	0	0	0.00%	0.00%	0.00%	0.00%						
381 C	2003	361,471	0	0	0	0.00%	0.00%	0.00%	0.00%	0.00%					

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Account	TransYear	Retirement	Salvage	Removal Cost	Net Salvage	Net Salvage %	2-Yr Net Salvage %	3-Yr Net Salvage %	4-Yr Net Salvage %	5-Yr Net Salvage %	6-Yr Net Salvage %	7-Yr Net Salvage %	8-Yr Net Salvage %	9-Yr Net Salvage %	10-Yr Net Salvage %
381 C	2004	663,636	0	0	0	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%				
381 C	2005	309,546	0	1,495	(1,495)	-0.48%	-0.15%	-0.11%	-0.05%	-0.05%	-0.05%	-0.05%			
381 C	2006	652,142	0	9,858	(9,858)	-1.51%	-1.18%	-0.70%	-0.57%	-0.31%	-0.31%	-0.31%	-0.31%		
381 C	2007	55,957	0	18,018	(18,018)	-32.20%	-3.94%	-2.89%	-1.75%	-1.44%	-0.80%	-0.80%	-0.80%	-0.80%	
381 C	2008	26,248	0	0	0	0.00%	-21.92%	-3.80%	-2.81%	-1.72%	-1.42%	-0.80%	-0.80%	-0.80%	-0.80%
381 C	2009	6,537,860	0	0	0	0.00%	0.00%	-0.27%	-0.38%	-0.39%	-0.36%	-0.34%	-0.29%	-0.29%	-0.29%
381 C	2010	34,224	0	0	0	0.00%	0.00%	0.00%	-0.27%	-0.38%	-0.39%	-0.35%	-0.34%	-0.29%	-0.29%
381 C	2011	119,773	0	0	0	0.00%	0.00%	0.00%	0.00%	-0.27%	-0.38%	-0.38%	-0.35%	-0.34%	-0.28%
381 C	2012	34,287	0	0	0	0.00%	0.00%	0.00%	0.00%	0.00%	-0.26%	-0.37%	-0.38%	-0.35%	-0.33%
381 C	2013	23,236	0	0	0	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	-0.26%	-0.37%	-0.38%	-0.35%
381 C	2014	933,870	0	645	(645)	-0.07%	-0.07%	-0.07%	-0.06%	-0.06%	-0.01%	-0.01%	-0.24%	-0.34%	-0.34%
381 C	2015	3,513,011	0	307	(307)	-0.01%	-0.02%	-0.02%	-0.02%	-0.02%	-0.02%	-0.01%	-0.01%	-0.17%	-0.24%
381 C	2016	1,084,371	0	0	0	0.00%	-0.01%	-0.02%	-0.02%	-0.02%	-0.02%	-0.02%	-0.01%	-0.01%	-0.15%
381 C	2017	4,945,653	0	27	(27)	0.00%	0.00%	0.00%	-0.01%	-0.01%	-0.01%	-0.01%	-0.01%	-0.01%	-0.01%
381 C	2018	3,514,391	0	1,021	(1,021)	-0.03%	-0.01%	-0.01%	-0.01%	-0.01%	-0.01%	-0.01%	-0.01%	-0.01%	-0.01%
381 C	2019	6,477,950	0	7,293	(7,293)	-0.11%	-0.08%	-0.06%	-0.05%	-0.04%	-0.05%	-0.05%	-0.05%	-0.05%	-0.04%
381 C	2020	4,360,619	0	87,331	(87,331)	-2.00%	-0.87%	-0.67%	-0.50%	-0.47%	-0.40%	-0.39%	-0.39%	-0.39%	-0.39%
5 Year		4,076,597	0	19,134	(19,134)										
3 Year		4,784,320	0	31,881	(31,881)										

Account	TransYear	Retirement	Salvage	Removal Cost	Net Salvage	Net Salvage %	2-Yr Net Salvage %	3-Yr Net Salvage %	4-Yr Net Salvage %	5-Yr Net Salvage %	6-Yr Net Salvage %	7-Yr Net Salvage %	8-Yr Net Salvage %	9-Yr Net Salvage %	10-Yr Net Salvage %
382	1999	-	0	3,802	(3,802)	NA									
382	2000	-	0	1,216	(1,216)	NA	NA								
382	2001	-	0	1,420	(1,420)	NA	NA	NA							
382	2002	-	0	4,865	(4,865)	NA	NA	NA	NA						
382	2003	1,018,882	0	39	(39)	0.00%	-0.48%	-0.62%	-0.74%	-1.11%					
382	2004	-	0	0	0	NA	0.00%	-0.48%	-0.62%	-0.74%	-1.11%				
382	2005	-	0	0	0	NA	NA	0.00%	-0.48%	-0.62%	-0.74%	-1.11%			
382	2006	50,092	0	0	0	0.00%	0.00%	0.00%	0.00%	-0.46%	-0.59%	-0.71%	-1.06%		
382	2007	4,774	0	0	0	0.00%	0.00%	0.00%	0.00%	0.00%	-0.46%	-0.59%	-0.70%	-1.06%	
382	2008	-	0	0	0	NA	0.00%	0.00%	0.00%	0.00%	0.00%	-0.46%	-0.59%	-0.70%	-1.06%
382	2009	100,668	0	0	0	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	-0.42%	-0.54%	-0.64%
382	2010	-	0	0	0	NA	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	-0.42%	-0.54%
382	2011	-	0	0	0	NA	NA	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	-0.42%
382	2012	110,828	0	0	0	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
382	2013	-	0	0	0	NA	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
382	2014	-	0	0	0	NA	NA	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
382	2015	-	0	0	0	NA	NA	NA	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
382	2016	237,712	0	0	0	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
382	2017	25,276	0	359	(359)	-1.42%	-0.14%	-0.14%	-0.14%	-0.14%	-0.10%	-0.10%	-0.10%	-0.08%	-0.08%
382	2018	34,561	0	0	0	0.00%	-0.60%	-0.12%	-0.12%	-0.12%	-0.12%	-0.09%	-0.09%	-0.09%	-0.07%
382	2019	13,228	0	0	0	0.00%	0.00%	-0.49%	-0.12%	-0.12%	-0.12%	-0.12%	-0.09%	-0.09%	-0.09%
382	2020	636	0	0	0	0.00%	0.00%	0.00%	-0.49%	-0.12%	-0.12%	-0.12%	-0.12%	-0.09%	-0.09%
5 Year		62,283	0	72	(72)										
3 Year		16,142	0	0	0										

Exhibit P-9

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Account	TransYear	Retirement	Salvage	Removal Cost	Net Salvage	Net Salvage %	2-Yr Net Salvage %	3-Yr Net Salvage %	4-Yr Net Salvage %	5-Yr Net Salvage %	6-Yr Net Salvage %	7-Yr Net Salvage %	8-Yr Net Salvage %	9-Yr Net Salvage %	10-Yr Net Salvage %
383	1999	110	0	14	(14)	-12.73%									
383	2000	-	0	0	0	NA	-12.73%								
383	2001	-	0	0	0	NA	NA	-12.73%							
383	2002	-	0	0	0	NA	NA	NA	-12.73%						
383	2003	529,614	0	0	0	0.00%	0.00%	0.00%	0.00%	0.00%					
383	2004	-	0	23,585	(23,585)	NA	-4.45%	-4.45%	-4.45%	-4.45%	-4.46%				
383	2005	-	0	9,147	(9,147)	NA	NA	-6.18%	-6.18%	-6.18%	-6.18%	-6.18%			
383	2006	-	0	0	0	NA	NA	NA	-6.18%	-6.18%	-6.18%	-6.18%	-6.18%		
383	2007	-	0	0	0	NA	NA	NA	NA	-6.18%	-6.18%	-6.18%	-6.18%	-6.18%	
383	2008	-	0	0	0	NA	NA	NA	NA	NA	-6.18%	-6.18%	-6.18%	-6.18%	-6.18%
383	2009	-	0	0	0	NA	NA	NA	NA	NA	NA	-6.18%	-6.18%	-6.18%	-6.18%
383	2010	2,736	0	0	0	0.00%	0.00%	0.00%	0.00%	0.00%	-334.26%	-1196.16%	-6.15%	-6.15%	-6.15%
383	2011	8	0	0	0	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	-333.25%	-1192.54%	-6.15%	-6.15%
383	2012	15	0	0	0	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	-331.44%	-1186.09%	-6.15%
383	2013	2	0	0	0	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	-331.24%	-1185.38%
383	2014	823	0	0	0	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	-255.21%
383	2015	-	0	0	0	NA	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
383	2016	84,579	0	0	0	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
383	2017	487	0	0	0	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
383	2018	505	0	0	0	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
383	2019	207	0	0	0	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
383	2020	-	0	337	(337)	NA	-163.20%	-47.40%	-28.15%	-0.39%	-0.39%	-0.39%	-0.39%	-0.39%	-0.39%
5 Year		17,156	0	67	(67)										
3 Year		237	0	112	(112)										
384	1999	-	0	0	0	NA	NA	NA	-2.97%	-2.94%	-2.86%	-2.78%	-0.50%	-0.50%	-0.50%
384	2000	-	0	0	0	NA	NA	NA	NA	-2.97%	-2.94%	-2.86%	-2.78%	-0.50%	-0.50%
384	2001	-	0	0	0	NA	NA	NA	NA	NA	-2.97%	-2.94%	-2.86%	-2.78%	-0.50%
384	2002	-	0	0	0	NA	NA	NA	NA	NA	NA	-2.97%	-2.94%	-2.86%	-2.78%
384	2003	-	0	0	0	NA	NA	NA	NA	NA	NA	NA	-2.97%	-2.94%	-2.86%
384	2004	-	0	0	0	NA	NA	NA	NA	NA	NA	NA	NA	-2.97%	-2.94%
384	2005	-	0	0	0	NA	NA	NA	NA	NA	NA	NA	NA	NA	-2.97%
384	2006	-	0	0	0	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA
384	2007	-	0	0	0	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA
384	2008	-	0	0	0	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA
384	2009	-	0	0	0	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA
384	2010	-	0	0	0	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA
384	2011	-	0	0	0	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA
384	2012	-	0	0	0	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA
384	2013	-	0	0	0	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA
384	2014	-	0	0	0	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA
384	2015	-	0	0	0	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA

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Account	TransYear	Retirement	Salvage	Removal Cost	Net Salvage	Net Salvage %	2-Yr Net Salvage %	3-Yr Net Salvage %	4-Yr Net Salvage %	5-Yr Net Salvage %	6-Yr Net Salvage %	7-Yr Net Salvage %	8-Yr Net Salvage %	9-Yr Net Salvage %	10-Yr Net Salvage %
384	2016	-	0	0	0	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA
384	2017	-	0	0	0	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA
384	2018	-	0	0	0	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA
384	2019	-	0	67,229	(67,229)	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA
384	2020	-	0	184,586	(184,586)	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA
5 Year		0	0	50,363	(50,363)										
3 Year		0	0	83,939	(83,939)										
383-384	1999	110	0	14	(14)	-12.78%									
383-384	2000	-	0	0	0	NA	-12.78%								
383-384	2001	-	0	0	0	NA	NA	-12.78%							
383-384	2002	-	0	0	0	NA	NA	NA	-12.78%						
383-384	2003	529,614	0	0	0	0.00%	0.00%	0.00%	0.00%	0.00%					
383-384	2004	-	0	23,585	(23,585)	NA	-4.45%	-4.45%	-4.45%	-4.45%	-4.46%				
383-384	2005	-	0	9,147	(9,147)	NA	NA	-6.18%	-6.18%	-6.18%	-6.18%	-6.18%			
383-384	2006	-	0	0	0	NA	NA	NA	-6.18%	-6.18%	-6.18%	-6.18%	-6.18%		
383-384	2007	-	0	0	0	NA	NA	NA	NA	-6.18%	-6.18%	-6.18%	-6.18%	-6.18%	
383-384	2008	-	0	0	0	NA	NA	NA	NA	NA	-6.18%	-6.18%	-6.18%	-6.18%	-6.18%
383-384	2009	-	0	0	0	NA	NA	NA	NA	NA	NA	-6.18%	-6.18%	-6.18%	-6.18%
383-384	2010	2,736	0	0	0	0.00%	0.00%	0.00%	0.00%	0.00%	-334.26%	-1196.16%	-6.15%	-6.15%	-6.15%
383-384	2011	8	0	0	0	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	-333.25%	-1192.54%	-6.15%	-6.15%
383-384	2012	15	0	0	0	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	-331.44%	-1186.09%	-6.15%
383-384	2013	2	0	0	0	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	-331.24%	-1185.38%
383-384	2014	823	0	0	0	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	-255.21%
383-384	2015	-	0	0	0	NA	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
383-384	2016	84,579	0	0	0	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
383-384	2017	487	0	0	0	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
383-384	2018	505	0	0	0	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
383-384	2019	207	0	67,229	(67,229)	-32517.26%	-9445.12%	-5609.32%	-78.38%	-78.38%	-77.63%	-77.63%	-77.62%	-77.61%	-75.23%
383-384	2020	-	0	184,924	(184,924)	NA	-121960.35%	-35425.20%	-21038.52%	-293.96%	-293.96%	-291.17%	-291.16%	-291.11%	-291.09%
5 Year		17,156	0	50,431	(50,431)										
3 Year		237	0	84,051	(84,051)										
385	1999	-	0	0	0	NA									
385	2000	-	0	0	0	NA	NA								
385	2001	-	0	0	0	NA	NA	NA							
385	2002	-	0	0	0	NA	NA	NA	NA						
385	2003	-	0	0	0	NA	NA	NA	NA	NA					
385	2004	-	0	0	0	NA	NA	NA	NA	NA	NA				
385	2005	-	0	0	0	NA	NA	NA	NA	NA	NA	NA			
385	2006	-	0	0	0	NA	NA	NA	NA	NA	NA	NA	NA		
385	2007	-	0	0	0	NA	NA	NA	NA	NA	NA	NA	NA	NA	
385	2008	-	0	0	0	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA

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385	2009	941	0	0	0	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
385	2010	-	0	0	0	NA	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
385	2011	-	0	0	0	NA	NA	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
385	2012	-	0	0	0	NA	NA	NA	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
385	2013	-	0	0	0	NA	NA	NA	NA	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
385	2014	-	0	0	0	NA	NA	NA	NA	NA	0.00%	0.00%	0.00%	0.00%	0.00%
385	2015	3,291	0	0	0	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
385	2016	-	0	0	0	NA	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
385	2017	-	0	0	0	NA	NA	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
385	2018	-	0	0	0	NA	NA	NA	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
385	2019	-	0	0	0	NA	NA	NA	NA	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
385	2020	-	0	0	0	NA	NA	NA	NA	NA	0.00%	0.00%	0.00%	0.00%	0.00%
387	1999	-	0	0	0	NA									
387	2000	-	0	0	0	NA	NA								
387	2001	-	0	0	0	NA	NA	NA							
387	2002	21,905	0	0	0	0.00%	0.00%	0.00%	0.00%						
387	2003	-	0	0	0	NA	0.00%	0.00%	0.00%	0.00%					
387	2004	-	0	0	0	NA	NA	0.00%	0.00%	0.00%	0.00%				
387	2005	-	0	0	0	NA	NA	NA	0.00%	0.00%	0.00%	0.00%			
387	2006	-	0	0	0	NA	NA	NA	NA	0.00%	0.00%	0.00%	0.00%		
387	2007	-	0	0	0	NA	NA	NA	NA	NA	0.00%	0.00%	0.00%	0.00%	
387	2008	-	0	0	0	NA	NA	NA	NA	NA	NA	0.00%	0.00%	0.00%	0.00%
387	2009	-	0	0	0	NA	NA	NA	NA	NA	NA	NA	0.00%	0.00%	0.00%
387	2010	-	0	0	0	NA	NA	NA	NA	NA	NA	NA	NA	0.00%	0.00%
387	2011	-	0	0	0	NA	NA	NA	NA	NA	NA	NA	NA	NA	0.00%
387	2012	-	0	0	0	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA
387	2013	-	0	0	0	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA
387	2014	-	0	100,088	(100,088)	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA
387	2015	61,531	0	14,782	(14,782)	-24.02%	-186.69%	-186.69%	-186.69%	-186.69%	-186.69%	-186.69%	-186.69%	-186.69%	-186.69%
387	2016	-	0	0	0	NA	-24.02%	-186.69%	-186.69%	-186.69%	-186.69%	-186.69%	-186.69%	-186.69%	-186.69%
387	2017	-	0	0	0	NA	NA	-24.02%	-186.69%	-186.69%	-186.69%	-186.69%	-186.69%	-186.69%	-186.69%
387	2018	-	0	0	0	NA	NA	NA	-24.02%	-186.69%	-186.69%	-186.69%	-186.69%	-186.69%	-186.69%
387	2019	-	0	0	0	NA	NA	NA	NA	-24.02%	-186.69%	-186.69%	-186.69%	-186.69%	-186.69%
387	2020	-	0	0	0	NA	NA	NA	NA	NA	-24.02%	-186.69%	-186.69%	-186.69%	-186.69%
5 Year		0	0	0	0										
3 Year		0	0	0	0										
390	1999	611	0	0	0	0.00%									
390	2000	-	0	0	0	NA	0.00%								
390	2001	-	0	0	0	NA	NA	0.00%							
390	2002	146,641	0	0	0	0.00%	0.00%	0.00%	0.00%						
390	2003	-	0	0	0	NA	0.00%	0.00%	0.00%	0.00%					

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390	2004	-	0	0	0	NA	NA	0.00%	0.00%	0.00%	0.00%				
390	2005	-	0	0	0	NA	NA	NA	0.00%	0.00%	0.00%	0.00%			
390	2006	-	0	0	0	NA	NA	NA	NA	0.00%	0.00%	0.00%	0.00%		
390	2007	53,155	0	0	0	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	
390	2008	-	0	0	0	NA	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
390	2009	-	0	0	0	NA	NA	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
390	2010	13,956,643	0	0	0	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
390	2011	-	0	0	0	NA	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
390	2012	-	0	0	0	NA	NA	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
390	2013	5,022,313	0	0	0	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
390	2014	1,560,149	0	0	0	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
390	2015	3,043,781	0	0	0	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
390	2016	-	0	0	0	NA	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
390	2017	413,256	0	0	0	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
390	2018	5,977	0	0	0	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
390	2019	-	0	0	0	NA	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
390	2020	-	0	0	0	NA	NA	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
39100	1999	-	0	0	0	NA									
39100	2000	-	0	0	0	NA	NA								
39100	2001	-	0	0	0	NA	NA	NA							
39100	2002	-	0	0	0	NA	NA	NA	NA						
39100	2003	-	0	0	0	NA	NA	NA	NA	NA					
39100	2004	-	0	0	0	NA	NA	NA	NA	NA	NA				
39100	2005	-	0	0	0	NA	NA	NA	NA	NA	NA	NA			
39100	2006	1,115,008	0	0	0	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%		
39100	2007	2,109	0	0	0	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	
39100	2008	-	0	0	0	NA	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
39100	2009	-	0	0	0	NA	NA	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
39100	2010	-	0	0	0	NA	NA	NA	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
39100	2011	-	0	0	0	NA	NA	NA	NA	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
39100	2012	-	0	0	0	NA	NA	NA	NA	NA	0.00%	0.00%	0.00%	0.00%	0.00%
39100	2013	531	0	0	0	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
39100	2014	74,135	0	0	0	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
39100	2015	1,615,101	0	0	0	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
39100	2016	-	0	0	0	NA	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
39100	2017	9,272	0	0	0	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
39100	2018	-	0	0	0	NA	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
39100	2019	-	0	0	0	NA	NA	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
39100	2020	-	0	0	0	NA	NA	NA	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
39110	1999	-	0	0	0	NA									
39110	2000	-	0	0	0	NA	NA								

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39110	2001	-	0	0	0	NA	NA	NA							
39110	2002	-	0	0	0	NA	NA	NA	NA						
39110	2003	-	0	0	0	NA	NA	NA	NA	NA					
39110	2004	-	0	0	0	NA	NA	NA	NA	NA	NA				
39110	2005	7,240	0	0	0	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%			
39110	2006	6,802,867	0	0	0	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%		
39110	2007	6,330,625	0	0	0	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	
39110	2008	-	0	0	0	NA	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
39110	2009	416,916	0	0	0	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
39110	2010	81,271	0	0	0	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
39110	2011	-	0	0	0	NA	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
39110	2012	-	0	0	0	NA	NA	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
39110	2013	-	0	0	0	NA	NA	NA	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
39110	2014	0	0	0	0	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
39110	2015	1,259,673	0	0	0	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
39110	2016	25,015	0	0	0	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
39110	2017	-	0	0	0	NA	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
39110	2018	1,229,203	0	0	0	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
39110	2019	-	0	0	0	NA	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
39110	2020	-	0	0	0	NA	NA	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
39111	1999	-	0	0	0	NA									
39111	2000	-	0	0	0	NA	NA								
39111	2001	-	0	0	0	NA	NA	NA							
39111	2002	-	0	0	0	NA	NA	NA	NA						
39111	2003	-	0	0	0	NA	NA	NA	NA	NA					
39111	2004	-	0	0	0	NA	NA	NA	NA	NA	NA				
39111	2005	-	0	0	0	NA	NA	NA	NA	NA	NA	NA			
39111	2006	-	0	0	0	NA	NA	NA	NA	NA	NA	NA	NA		
39111	2007	505,192	0	0	0	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	
39111	2008	-	0	0	0	NA	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
39111	2009	4,712	0	0	0	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
39111	2010	9,924	0	0	0	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
39111	2011	-	0	0	0	NA	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
39111	2012	-	0	0	0	NA	NA	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
39111	2013	-	0	0	0	NA	NA	NA	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
39111	2014	-	0	0	0	NA	NA	NA	NA	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
39111	2015	35,383	0	0	0	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
39111	2016	28,224	0	0	0	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
39111	2017	40,259	0	0	0	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
39111	2018	5,433,319	0	0	0	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
39111	2019	-	0	0	0	NA	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
39111	2020	-	0	0	0	NA	NA	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%

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39112	1999	-	0	0	0	NA									
39112	2000	-	0	0	0	NA	NA								
39112	2001	-	0	0	0	NA	NA	NA							
39112	2002	-	0	0	0	NA	NA	NA	NA						
39112	2003	-	0	0	0	NA	NA	NA	NA	NA					
39112	2004	-	0	0	0	NA	NA	NA	NA	NA	NA				
39112	2005	-	0	0	0	NA	NA	NA	NA	NA	NA	NA			
39112	2006	-	0	0	0	NA	NA	NA	NA	NA	NA	NA	NA		
39112	2007	-	0	0	0	NA	NA	NA	NA	NA	NA	NA	NA	NA	
39112	2008	-	0	0	0	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA
39112	2009	-	0	0	0	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA
39112	2010	-	0	0	0	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA
39112	2011	-	0	0	0	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA
39112	2012	-	0	0	0	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA
39112	2013	-	0	0	0	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA
39112	2014	-	0	0	0	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA
39112	2015	145,834	0	0	0	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
39112	2016	6,571	0	0	0	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
39112	2017	-	0	0	0	NA	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
39112	2018	-	0	0	0	NA	NA	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
39112	2019	-	0	0	0	NA	NA	NA	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
39112	2020	88,237	0	0	0	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
39120	1999	-	0	0	0	NA									
39120	2000	-	0	0	0	NA	NA								
39120	2001	-	0	0	0	NA	NA	NA							
39120	2002	37,708	0	0	0	0.00%	0.00%	0.00%	0.00%						
39120	2003	-	0	0	0	NA	0.00%	0.00%	0.00%	0.00%					
39120	2004	-	0	0	0	NA	NA	0.00%	0.00%	0.00%	0.00%				
39120	2005	-	0	0	0	NA	NA	NA	0.00%	0.00%	0.00%	0.00%			
39120	2006	-	0	0	0	NA	NA	NA	NA	0.00%	0.00%	0.00%	0.00%		
39120	2007	-	0	0	0	NA	NA	NA	NA	NA	0.00%	0.00%	0.00%	0.00%	
39120	2008	-	0	0	0	NA	NA	NA	NA	NA	NA	0.00%	0.00%	0.00%	0.00%
39120	2009	-	0	0	0	NA	NA	NA	NA	NA	NA	NA	0.00%	0.00%	0.00%
39120	2010	-	0	0	0	NA	NA	NA	NA	NA	NA	NA	NA	0.00%	0.00%
39120	2011	-	0	0	0	NA	NA	NA	NA	NA	NA	NA	NA	NA	0.00%
39120	2012	-	0	0	0	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA
39120	2013	-	0	0	0	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA
39120	2014	-	0	0	0	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA
39120	2015	173,549	0	0	0	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
39120	2016	-	0	0	0	NA	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
39120	2017	12,345,327	0	0	0	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
39120	2018	29,285,577	0	0	0	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
39120	2019	-	0	0	0	NA	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
39120	2020	-	0	0	0	NA	NA	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%

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39130	1999	-	0	0	0	NA									
39130	2000	-	0	0	0	NA	NA								
39130	2001	-	0	0	0	NA	NA	NA							
39130	2002	2,497,743	0	0	0	0.00%	0.00%	0.00%	0.00%						
39130	2003	-	0	0	0	NA	0.00%	0.00%	0.00%	0.00%					
39130	2004	-	0	0	0	NA	NA	0.00%	0.00%	0.00%	0.00%				
39130	2005	-	0	0	0	NA	NA	NA	0.00%	0.00%	0.00%	0.00%			
39130	2006	-	0	0	0	NA	NA	NA	NA	0.00%	0.00%	0.00%	0.00%		
39130	2007	-	0	0	0	NA	NA	NA	NA	NA	0.00%	0.00%	0.00%	0.00%	
39130	2008	-	0	0	0	NA	NA	NA	NA	NA	NA	0.00%	0.00%	0.00%	0.00%
39130	2009	-	0	0	0	NA	NA	NA	NA	NA	NA	NA	0.00%	0.00%	0.00%
39130	2010	-	0	0	0	NA	NA	NA	NA	NA	NA	NA	NA	0.00%	0.00%
39130	2011	-	0	0	0	NA	NA	NA	NA	NA	NA	NA	NA	NA	0.00%
39130	2012	-	0	0	0	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA
39130	2013	-	0	0	0	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA
39130	2014	-	0	0	0	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA
39130	2015	-	0	0	0	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA
39130	2016	-	0	0	0	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA
39130	2017	-	0	0	0	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA
39130	2018	-	0	0	0	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA
39130	2019	-	0	0	0	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA
39130	2020	-	0	0	0	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA
39150	1999	-	0	0	0	NA									
39150	2000	-	0	0	0	NA	NA								
39150	2001	-	0	0	0	NA	NA	NA							
39150	2002	-	0	0	0	NA	NA	NA	NA						
39150	2003	-	0	0	0	NA	NA	NA	NA	NA					
39150	2004	-	0	0	0	NA	NA	NA	NA	NA	NA				
39150	2005	-	0	0	0	NA	NA	NA	NA	NA	NA	NA			
39150	2006	-	0	0	0	NA	NA	NA	NA	NA	NA	NA	NA		
39150	2007	-	0	0	0	NA	NA	NA	NA	NA	NA	NA	NA	NA	
39150	2008	-	0	0	0	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA
39150	2009	-	0	0	0	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA
39150	2010	-	0	0	0	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA
39150	2011	-	0	0	0	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA
39150	2012	-	0	0	0	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA
39150	2013	-	0	0	0	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA
39150	2014	-	0	0	0	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA
39150	2015	4,183	0	0	0	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
39150	2016	-	0	0	0	NA	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
39150	2017	-	0	0	0	NA	NA	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%

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39150	2018	-	0	0	0	NA	NA	NA	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
39150	2019	26,623	0	0	0	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
39150	2020	164,898	0	0	0	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
39200	2016	-	16,092	0	16,092	NA									
39200	2017	-	225	0	225	NA	NA								
39200	2018	-	550	0	550	NA	NA	NA							
39200	2019	18,833	0	0	0	0.00%	2.92%	4.12%	89.56%						
39200	2020	-	0	0	0	NA	0.00%	2.92%	4.12%	89.56%					
5 Year		3,767	3,373	0	3,373										
3 Year		6,278	183	0	183										
39210	1999	-	0	0	0	NA									
39210	2000	-	0	0	0	NA	NA								
39210	2001	-	0	0	0	NA	NA	NA							
39210	2002	-	23,991	0	23,991	NA	NA	NA	NA						
39210	2003	-	0	0	0	NA	NA	NA	NA	NA					
39210	2004	-	20,637	0	20,637	NA	NA	NA	NA	NA	NA				
39210	2005	158,460	18,570	0	18,570	11.72%	24.74%	24.74%	39.88%	39.88%	39.88%	39.88%			
39210	2006	657,243	64,311	0	64,311	9.78%	10.16%	12.69%	12.69%	15.63%	15.63%	15.63%	15.63%		
39210	2007	14,647	10,887	0	10,887	74.33%	11.19%	11.29%	13.78%	13.78%	16.67%	16.67%	16.67%	16.67%	
39210	2008	488,495	0	0	0	0.00%	2.16%	6.48%	7.11%	8.67%	8.67%	10.49%	10.49%	10.49%	10.49%
39210	2009	521,644	0	0	0	0.00%	0.00%	1.06%	4.47%	5.09%	6.22%	6.22%	7.52%	7.52%	7.52%
39210	2010	72,868	0	0	0	0.00%	0.00%	0.00%	0.99%	4.29%	4.90%	5.98%	5.98%	7.23%	7.23%
39210	2011	1,172,583	0	0	0	0.00%	0.00%	0.00%	0.00%	0.48%	2.57%	3.04%	3.71%	3.71%	4.48%
39210	2012	-	0	0	0	NA	0.00%	0.00%	0.00%	0.00%	0.48%	2.57%	3.04%	3.71%	3.71%
39210	2013	886,440	0	0	0	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.34%	1.97%	2.36%	2.88%
39210	2014	446,064	44,234	0	44,234	9.92%	3.32%	3.32%	1.77%	1.72%	1.43%	1.23%	1.53%	2.80%	3.12%
39210	2015	355,871	58,515	0	58,515	16.44%	12.81%	6.09%	6.09%	3.59%	3.50%	2.97%	2.61%	2.87%	3.86%
39210	2016	5,527,237	182,281	0	182,281	3.30%	4.09%	4.50%	3.95%	3.95%	3.40%	3.37%	3.17%	3.01%	3.12%
39210	2017	426,565	71,477	0	71,477	16.76%	4.26%	4.95%	5.28%	4.66%	4.66%	4.04%	4.01%	3.79%	3.60%
39210	2018	732,831	125,757	0	125,757	17.16%	17.01%	5.68%	6.22%	6.44%	5.76%	5.76%	5.05%	5.01%	4.76%
39210	2019	-	0	0	0	NA	17.16%	17.01%	5.68%	6.22%	6.44%	5.76%	5.76%	5.05%	5.01%
39210	2020	-	0	0	0	NA	NA	17.16%	17.01%	5.68%	6.22%	6.44%	5.76%	5.76%	5.05%
5 Year		1,337,326	75,903	0	75,903										
3 Year		244,277	41,919	0	41,919										
39220	1999	-	0	0	0	NA									
39220	2000	-	0	0	0	NA	NA								
39220	2001	-	0	0	0	NA	NA	NA							
39220	2002	-	0	0	0	NA	NA	NA	NA						
39220	2003	-	0	0	0	NA	NA	NA	NA	NA					

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39220	2004	-	0	0	0	NA	NA	NA	NA	NA	NA				
39220	2005	-	0	0	0	NA	NA	NA	NA	NA	NA	NA			
39220	2006	-	0	0	0	NA	NA	NA	NA	NA	NA	NA	NA		
39220	2007	-	0	0	0	NA	NA	NA	NA	NA	NA	NA	NA	NA	
39220	2008	-	0	0	0	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA
39220	2009	-	0	0	0	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA
39220	2010	-	0	0	0	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA
39220	2011	92,280	0	0	0	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
39220	2012	-	0	0	0	NA	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
39220	2013	76,703	0	0	0	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
39220	2014	-	0	0	0	NA	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
39220	2015	31,697	0	0	0	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
39220	2016	147,181	27,188	0	27,188	18.47%	15.20%	15.20%	10.64%	10.64%	7.82%	7.82%	7.82%	7.82%	7.82%
39220	2017	31,127	10,667	0	10,667	34.27%	21.23%	18.03%	18.03%	13.20%	13.20%	9.99%	9.99%	9.99%	9.99%
39220	2018	58,162	40,848	0	40,848	70.23%	57.69%	33.28%	29.35%	29.35%	22.82%	22.82%	18.00%	18.00%	18.00%
39220	2019	-	0	0	0	NA	70.23%	57.69%	33.28%	29.35%	29.35%	22.82%	22.82%	18.00%	18.00%
39220	2020	-	0	0	0	NA	NA	70.23%	57.69%	33.28%	29.35%	29.35%	22.82%	22.82%	18.00%
5 Year		47,294	15,741	0	15,741										
3 Year		19,387	13,616	0	13,616										

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39230	1999	-	0	0	0	NA									
39230	2000	-	0	0	0	NA	NA								
39230	2001	-	0	0	0	NA	NA	NA							
39230	2002	-	0	0	0	NA	NA	NA	NA						
39230	2003	-	0	0	0	NA	NA	NA	NA	NA					
39230	2004	-	0	0	0	NA	NA	NA	NA	NA	NA				
39230	2005	-	0	0	0	NA	NA	NA	NA	NA	NA	NA			
39230	2006	-	0	0	0	NA	NA	NA	NA	NA	NA	NA	NA		
39230	2007	-	0	0	0	NA	NA	NA	NA	NA	NA	NA	NA	NA	
39230	2008	12,098	0	0	0	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
39230	2009	-	0	0	0	NA	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
39230	2010	-	0	0	0	NA	NA	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
39230	2011	-	0	0	0	NA	NA	NA	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
39230	2012	-	0	0	0	NA	NA	NA	NA	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
39230	2013	-	0	0	0	NA	NA	NA	NA	NA	0.00%	0.00%	0.00%	0.00%	0.00%
39230	2014	-	0	0	0	NA	NA	NA	NA	NA	NA	0.00%	0.00%	0.00%	0.00%
39230	2015	-	0	0	0	NA	NA	NA	NA	NA	NA	NA	0.00%	0.00%	0.00%
39230	2016	1,409,025	177,228	0	177,228	12.58%	12.58%	12.58%	12.58%	12.58%	12.58%	12.58%	12.58%	12.47%	12.47%
39230	2017	692,789	128,378	0	128,378	18.53%	14.54%	14.54%	14.54%	14.54%	14.54%	14.54%	14.54%	14.54%	14.46%
39230	2018	586,146	33,450	0	33,450	5.71%	12.65%	12.61%	12.61%	12.61%	12.61%	12.61%	12.61%	12.61%	12.61%
39230	2019	-	0	0	0	NA	5.71%	12.65%	12.61%	12.61%	12.61%	12.61%	12.61%	12.61%	12.61%
39230	2020	-	0	0	0	NA	NA	5.71%	12.65%	12.61%	12.61%	12.61%	12.61%	12.61%	12.61%
5 Year		537,592	67,811	0	67,811										
3 Year		195,382	11,150	0	11,150										

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392 All	1999	-	-	-	0	NA									
392 All	2000	-	-	-	0	NA	NA								
392 All	2001	-	-	-	0	NA	NA	NA							
392 All	2002	-	23,991	-	23,991	NA	NA	NA	NA						
392 All	2003	-	-	-	0	NA	NA	NA	NA	NA					
392 All	2004	-	20,637	-	20,637	NA	NA	NA	NA	NA	NA				
392 All	2005	158,460	18,570	-	18,570	11.72%	24.74%	24.74%	39.88%	39.88%	39.88%	39.88%			
392 All	2006	657,243	64,311	-	64,311	9.78%	10.16%	12.69%	12.69%	15.63%	15.63%	15.63%	15.63%		
392 All	2007	14,647	10,887	-	10,887	74.33%	11.19%	11.29%	13.78%	13.78%	16.67%	16.67%	16.67%	16.67%	
392 All	2008	500,593	-	-	0	0.00%	2.11%	6.41%	7.05%	8.60%	8.60%	10.40%	10.40%	10.40%	10.40%
392 All	2009	521,644	-	-	0	0.00%	0.00%	1.05%	4.44%	5.06%	6.18%	6.18%	7.47%	7.47%	7.47%
392 All	2010	72,868	-	-	0	0.00%	0.00%	0.00%	0.98%	4.26%	4.87%	5.94%	5.94%	7.19%	7.19%
392 All	2011	1,264,863	-	-	0	0.00%	0.00%	0.00%	0.00%	0.46%	2.48%	2.94%	3.59%	3.59%	4.34%
392 All	2012	-	-	-	0	NA	0.00%	0.00%	0.00%	0.00%	0.46%	2.48%	2.94%	3.59%	3.59%
392 All	2013	963,143	-	-	0	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.33%	1.88%	2.26%	2.75%
392 All	2014	446,064	44,234	-	44,234	9.92%	3.14%	3.14%	1.65%	1.61%	1.35%	1.17%	1.46%	2.69%	3.00%
392 All	2015	387,567	58,515	-	58,515	15.10%	12.33%	5.72%	5.72%	3.36%	3.28%	2.81%	2.47%	2.72%	3.69%
392 All	2016	7,083,442	402,789	-	402,789	5.69%	6.17%	6.39%	5.69%	5.69%	4.98%	4.95%	4.71%	4.50%	4.59%
392 All	2017	1,150,480	210,747	-	210,747	18.32%	7.45%	7.80%	7.90%	7.14%	7.14%	6.34%	6.30%	6.02%	5.78%
392 All	2018	1,377,139	200,605	-	200,605	14.57%	16.27%	8.47%	8.73%	8.78%	8.04%	8.04%	7.24%	7.19%	6.91%
392 All	2019	18,833	-	-	0	0.00%	14.37%	16.15%	8.45%	8.71%	8.76%	8.02%	8.02%	7.22%	7.18%
392 All	2020	-	-	-	0	NA	0.00%	14.37%	16.15%	8.45%	8.71%	8.76%	8.02%	8.02%	7.22%
5 Year		1,925,979	162,828	0	162,828										
3 Year		465,324	66,868	0	66,868										
393	1999	-	0	0	0	NA									
393	2000	-	0	0	0	NA	NA								
393	2001	-	0	0	0	NA	NA	NA							
393	2002	-	0	0	0	NA	NA	NA	NA						
393	2003	-	0	0	0	NA	NA	NA	NA	NA					
393	2004	-	0	0	0	NA	NA	NA	NA	NA	NA				
393	2005	-	0	0	0	NA	NA	NA	NA	NA	NA	NA			
393	2006	-	0	0	0	NA	NA	NA	NA	NA	NA	NA	NA		
393	2007	-	0	0	0	NA	NA	NA	NA	NA	NA	NA	NA	NA	
393	2008	-	0	0	0	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA
393	2009	-	0	0	0	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA
393	2010	-	0	0	0	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA
393	2011	-	0	0	0	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA
393	2012	-	0	0	0	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA
393	2013	137,798	0	0	0	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
393	2014	22,742	0	0	0	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
393	2015	129,057	0	0	0	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%

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393	2016	3,749	0	0	0	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
393	2017	-	0	0	0	NA	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
393	2018	-	0	0	0	NA	NA	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
393	2019	3,717	0	0	0	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
393	2020	-	0	0	0	NA	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
394	1999	-	0	0	0	NA									
394	2000	-	0	0	0	NA	NA								
394	2001	-	0	0	0	NA	NA	NA							
394	2002	-	0	0	0	NA	NA	NA	NA						
394	2003	-	0	0	0	NA	NA	NA	NA	NA					
394	2004	-	0	0	0	NA	NA	NA	NA	NA	NA				
394	2005	-	0	0	0	NA	NA	NA	NA	NA	NA	NA			
394	2006	-	0	0	0	NA	NA	NA	NA	NA	NA	NA	NA		
394	2007	-	0	0	0	NA	NA	NA	NA	NA	NA	NA	NA	NA	
394	2008	1,274	0	0	0	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
394	2009	-	0	0	0	NA	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
394	2010	-	0	0	0	NA	NA	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
394	2011	-	0	0	0	NA	NA	NA	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
394	2012	-	0	0	0	NA	NA	NA	NA	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
394	2013	4,110,187	0	0	0	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
394	2014	56,243	34,000	0	34,000	60.45%	0.82%	0.82%	0.82%	0.82%	0.82%	0.82%	0.82%	0.82%	0.82%
394	2015	1,156,973	0	0	0	0.00%	2.80%	0.64%	0.64%	0.64%	0.64%	0.64%	0.64%	0.64%	0.64%
394	2016	188,956	0	0	0	0.00%	0.00%	2.42%	0.62%	0.62%	0.62%	0.62%	0.62%	0.62%	0.62%
394	2017	279,078	0	0	0	0.00%	0.00%	0.00%	2.02%	0.59%	0.59%	0.59%	0.59%	0.59%	0.59%
394	2018	-	0	0	0	NA	0.00%	0.00%	0.00%	2.02%	0.59%	0.59%	0.59%	0.59%	0.59%
394	2019	82,781	0	0	0	0.00%	0.00%	0.00%	0.00%	0.00%	1.93%	0.58%	0.58%	0.58%	0.58%
394	2020	-	0	0	0	NA	0.00%	0.00%	0.00%	0.00%	0.00%	1.93%	0.58%	0.58%	0.58%
5 Year		110,163	0	0	0										
3 Year		27,594	0	0	0										
395	1999	-	0	0	0	NA									
395	2000	-	0	0	0	NA	NA								
395	2001	-	0	0	0	NA	NA	NA							
395	2002	-	0	0	0	NA	NA	NA	NA						
395	2003	-	0	0	0	NA	NA	NA	NA	NA					
395	2004	-	0	0	0	NA	NA	NA	NA	NA	NA				
395	2005	-	0	0	0	NA	NA	NA	NA	NA	NA	NA			
395	2006	-	0	0	0	NA	NA	NA	NA	NA	NA	NA	NA		
395	2007	-	0	0	0	NA	NA	NA	NA	NA	NA	NA	NA	NA	
395	2008	-	0	0	0	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA
395	2009	-	0	0	0	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA
395	2010	-	0	0	0	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA

Elizabethtown Gas Company
Depreciation Study at December 31, 2020
Net Salvage As Adjusted

Account	TransYear	Retirement	Salvage	Removal Cost	Net Salvage	Net Salvage %	2-Yr Net Salvage %	3-Yr Net Salvage %	4-Yr Net Salvage %	5-Yr Net Salvage %	6-Yr Net Salvage %	7-Yr Net Salvage %	8-Yr Net Salvage %	9-Yr Net Salvage %	10-Yr Net Salvage %
395	2011	-	0	0	0	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA
395	2012	-	0	0	0	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA
395	2013	21,114	0	0	0	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
395	2014	-	0	0	0	NA	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
395	2015	-	0	0	0	NA	NA	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
395	2016	-	0	0	0	NA	NA	NA	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
395	2017	-	0	0	0	NA	NA	NA	NA	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
395	2018	-	0	0	0	NA	NA	NA	NA	NA	0.00%	0.00%	0.00%	0.00%	0.00%
395	2019	-	0	0	0	NA	NA	NA	NA	NA	NA	0.00%	0.00%	0.00%	0.00%
395	2020	-	0	0	0	NA	NA	NA	NA	NA	NA	NA	0.00%	0.00%	0.00%
39600	1999	-	0	0	0	NA									
39600	2000	-	0	0	0	NA	NA								
39600	2001	-	0	0	0	NA	NA	NA							
39600	2002	-	0	0	0	NA	NA	NA	NA						
39600	2003	-	0	0	0	NA	NA	NA	NA	NA					
39600	2004	-	0	0	0	NA	NA	NA	NA	NA	NA				
39600	2005	-	0	0	0	NA	NA	NA	NA	NA	NA	NA			
39600	2006	-	0	0	0	NA	NA	NA	NA	NA	NA	NA	NA		
39600	2007	-	0	0	0	NA	NA	NA	NA	NA	NA	NA	NA	NA	
39600	2008	-	0	0	0	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA
39600	2009	-	0	0	0	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA
39600	2010	-	0	0	0	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA
39600	2011	-	0	0	0	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA
39600	2012	-	0	0	0	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA
39600	2013	-	0	0	0	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA
39600	2014	16,600	0	0	0	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
39600	2015	-	0	0	0	NA	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
39600	2016	82,111	0	0	0	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
39600	2017	-	0	0	0	NA	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
39600	2018	-	0	0	0	NA	NA	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
39600	2019	-	0	0	0	NA	NA	NA	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
39600	2020	-	0	0	0	NA	NA	NA	NA	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
5 Year		16,422	0	0	0										
3 Year		0	0	0	0										
39610	1999	-	0	0	0	NA									
39610	2000	-	0	0	0	NA	NA								
39610	2001	-	0	0	0	NA	NA	NA							
39610	2002	-	0	0	0	NA	NA	NA	NA						
39610	2003	-	0	0	0	NA	NA	NA	NA	NA					
39610	2004	-	0	0	0	NA	NA	NA	NA	NA	NA				
39610	2005	-	0	0	0	NA	NA	NA	NA	NA	NA	NA			

Elizabethtown Gas Company
Depreciation Study at December 31, 2020
Net Salvage As Adjusted

Account	TransYear	Retirement	Salvage	Removal Cost	Net Salvage	Net Salvage %	2-Yr Net Salvage %	3-Yr Net Salvage %	4-Yr Net Salvage %	5-Yr Net Salvage %	6-Yr Net Salvage %	7-Yr Net Salvage %	8-Yr Net Salvage %	9-Yr Net Salvage %	10-Yr Net Salvage %
39610	2006	-	0	0	0	NA	NA	NA	NA	NA	NA	NA	NA		
39610	2007	-	0	0	0	NA	NA	NA	NA	NA	NA	NA	NA	NA	
39610	2008	-	0	0	0	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA
39610	2009	-	0	0	0	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA
39610	2010	-	0	0	0	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA
39610	2011	-	0	0	0	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA
39610	2012	-	0	0	0	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA
39610	2013	123,082	0	0	0	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
39610	2014	23,945	0	0	0	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
39610	2015	-	0	0	0	NA	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
39610	2016	130,286	42,575	0	42,575	32.68%	32.68%	27.60%	15.35%	15.35%	15.35%	15.35%	15.35%	15.35%	15.35%
39610	2017	245,200	0	0	0	0.00%	11.34%	11.34%	10.66%	8.15%	8.15%	8.15%	8.15%	8.15%	8.15%
39610	2018	-	0	0	0	NA	0.00%	11.34%	11.34%	10.66%	8.15%	8.15%	8.15%	8.15%	8.15%
39610	2019	-	0	0	0	NA	NA	0.00%	11.34%	11.34%	10.66%	8.15%	8.15%	8.15%	8.15%
39610	2020	-	0	0	0	NA	NA	NA	0.00%	11.34%	11.34%	10.66%	8.15%	8.15%	8.15%
5 Year		75,097	8,515	0	8,515										
3 Year		0	0	0	0										
39620	1999	-	0	0	0	NA									
39620	2000	-	0	0	0	NA	NA								
39620	2001	-	0	0	0	NA	NA	NA							
39620	2002	-	0	0	0	NA	NA	NA	NA						
39620	2003	-	0	0	0	NA	NA	NA	NA	NA					
39620	2004	-	0	0	0	NA	NA	NA	NA	NA	NA				
39620	2005	-	0	0	0	NA	NA	NA	NA	NA	NA	NA			
39620	2006	-	0	0	0	NA	NA	NA	NA	NA	NA	NA	NA		
39620	2007	-	0	0	0	NA	NA	NA	NA	NA	NA	NA	NA	NA	
39620	2008	-	0	0	0	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA
39620	2009	-	0	0	0	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA
39620	2010	-	0	0	0	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA
39620	2011	-	0	0	0	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA
39620	2012	-	0	0	0	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA
39620	2013	-	0	0	0	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA
39620	2014	-	0	0	0	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA
39620	2015	8,133	0	0	0	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
39620	2016	-	0	0	0	NA	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
39620	2017	-	0	0	0	NA	NA	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
39620	2018	-	0	0	0	NA	NA	NA	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
39620	2019	-	0	0	0	NA	NA	NA	NA	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
39620	2020	-	0	0	0	NA	NA	NA	NA	NA	0.00%	0.00%	0.00%	0.00%	0.00%
397	1999	-	0	0	0	NA									
397	2000	-	0	0	0	NA	NA								
397	2001	14,679	0	0	0	0.00%	0.00%	0.00%							
397	2002	-	0	0	0	NA	0.00%	0.00%	0.00%						

Elizabethtown Gas Company
Depreciation Study at December 31, 2020
Net Salvage As Adjusted

Account	TransYear	Retirement	Salvage	Removal Cost	Net Salvage	Net Salvage %	2-Yr Net Salvage %	3-Yr Net Salvage %	4-Yr Net Salvage %	5-Yr Net Salvage %	6-Yr Net Salvage %	7-Yr Net Salvage %	8-Yr Net Salvage %	9-Yr Net Salvage %	10-Yr Net Salvage %
397	2003	-	0	0	0	NA	NA	0.00%	0.00%	0.00%					
397	2004	-	0	0	0	NA	NA	NA	0.00%	0.00%	0.00%				
397	2005	-	0	0	0	NA	NA	NA	NA	0.00%	0.00%	0.00%			
397	2006	-	0	0	0	NA	NA	NA	NA	NA	0.00%	0.00%	0.00%		
397	2007	2,221,989	0	0	0	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	
397	2008	-	0	0	0	NA	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
397	2009	-	0	0	0	NA	NA	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
397	2010	-	0	0	0	NA	NA	NA	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
397	2011	-	0	0	0	NA	NA	NA	NA	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
397	2012	-	0	0	0	NA	NA	NA	NA	NA	0.00%	0.00%	0.00%	0.00%	0.00%
397	2013	1,850,786	0	0	0	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
397	2014	-	0	0	0	NA	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
397	2015	-	0	0	0	NA	NA	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
397	2016	-	0	0	0	NA	NA	NA	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
397	2017	68,683	0	0	0	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
397	2018	-	0	0	0	NA	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
397	2019	-	0	0	0	NA	NA	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
397	2020	-	0	0	0	NA	NA	NA	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
398	1999	-	0	0	0	NA									
398	2000	-	0	0	0	NA	NA								
398	2001	-	0	0	0	NA	NA	NA							
398	2002	-	0	0	0	NA	NA	NA	NA						
398	2003	-	0	0	0	NA	NA	NA	NA	NA					
398	2004	-	0	0	0	NA	NA	NA	NA	NA	NA				
398	2005	-	0	0	0	NA	NA	NA	NA	NA	NA	NA			
398	2006	-	0	0	0	NA	NA	NA	NA	NA	NA	NA	NA		
398	2007	-	0	0	0	NA	NA	NA	NA	NA	NA	NA	NA	NA	
398	2008	-	0	0	0	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA
398	2009	-	0	0	0	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA
398	2010	-	0	0	0	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA
398	2011	-	0	0	0	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA
398	2012	-	0	0	0	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA
398	2013	912,842	0	0	0	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
398	2014	7,539	0	0	0	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
398	2015	217,755	0	0	0	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
398	2016	32,416	0	123,802	(123,802)	-381.91%	-49.49%	-48.04%	-10.58%	-10.58%	-10.58%	-10.58%	-10.58%	-10.58%	-10.58%
398	2017	39,158	0	53,892	(53,892)	-137.62%	-248.26%	-61.42%	-59.86%	-14.69%	-14.69%	-14.69%	-14.69%	-14.69%	-14.69%
398	2018	-	0	15,187	(15,187)	NA	-176.41%	-269.48%	-66.66%	-64.97%	-15.94%	-15.94%	-15.94%	-15.94%	-15.94%
398	2019	-	0	42,149	(42,149)	NA	NA	-284.05%	-328.37%	-81.23%	-79.17%	-19.43%	-19.43%	-19.43%	-19.43%
398	2020	-	0	0	0	NA	NA	NA	-284.05%	-328.37%	-81.23%	-79.17%	-19.43%	-19.43%	-19.43%
5 Year		14,315	0	47,006	(47,006)										
3 Year		0	0	19,112	(19,112)										

Dane Watson Testimony Appearances

Asset Location	Commission	Docket (If Applicable	Company	Year	Description
Alaska	Regulatory Commission of Alaska	TA116-118, TA115-97, TA160-37 and TA110-290	Fairbanks Water and Wastewater	2021	Water and Waste Water Depreciation Study
Alaska	Regulatory Commission of Alaska	U-21-025	Golden Valley Electric Association	2021	Electric Depreciation Study
Colorado	Public Utilities Commission of Colorado	21AL-0317E	Public Service of Colorado	2021	Electric and Common Depreciation Study
Wisconsin	Public Serice Commission of Wisconsin	5-DU-103	WE Energies	2021	Electric and Gas Depreciation Study
Kentucky	Public Service Commission of Kentucky	2021-00214	Atmos Kentucky	2021	Gas Depreciation Study
Missouri	Missouri Public Service Commission	ER-2021-0312	Empire District Electric Company	2021	Electric Depreciation Study
Louisiana	Louisiana Public Service Commission	U-35951	Atmos Louisiana	2021	Gas Depreciation Study
Minnesota	Minnesota Public Utilities Commission	E015-D-21-229	Allete Minnesota Power	2021	Intangible, Transmission, Distribution, and General Depreciation Study
Michigan	Michigan Public Service Commission	U-20849	Consumers Energy	2021	Electric and Common Depreciation Study
Texas	Texas Public Utility Commission	51802	Southwestern Public Service Company	2021	Electric Technical Update
MultiState	FERC	RP21-441-000	Florida Gas Transmission	2021	Gas Depreciation Study
New Mexico	New Mexico Public Regulation Commission	20-00238-UT	Southwestern Public Service Company	2021	Electric Technical Update
MultiState	FERC	ER21-709-000	American Transmission Company	2020	Electric Depreciation Study
Texas	Texas Public Utility Commission	51611	Sharyland Utilities	2020	Electric Depreciation Study
Texas	Texas Public Utility Commission	51536	Brownsville Public Utilities Board	2020	Electric Depreciation Study
New Jersey	New Jersey Board of Public Utilities	WR20110729	Suez Water New Jersey	2020	Water and Waste Water Depreciation Study
Idaho	Idaho Public Service Commission	SUZ-W-20-02	Suez Water Idaho	2020	Water Depreciation Study
Texas	Texas Public Utility Commission	50944	Monarch Utilities	2020	Water and Waste Water Depreciation Study
Michigan	Michigan Public Service Commission	U-20844	Consumers Energy/DTE Electric	2020	Ludington Pumped Storage Depreciation Study

Dane Watson Testimony Appearances

Asset Location	Commission	Docket (If Applicable	Company	Year	Description
Tennessee	Tennessee Public Utility Commission	20-00086	Piedmont Natural Gas	2020	Gas Depreciation Study
Texas	Railroad Commission of Texas	OS-00005136	CoServ Gas	2020	Gas Depreciation Study
Texas	Railroad Commission of Texas	GUD 10988	EPCOR Gas Texas	2020	Gas Depreciation Study
Florida	Florida Public Service Commission	20200166-GU	People Gas System	2020	Gas Depreciation Study
Mississippi	Federal Energy Regulatory Commission	ER20-1660-000	Mississippi Power Company	2020	Electric Depreciation Study
Texas	Public Utility Commission of Texas	50557	Corix Utilities	2020	Water and Waste Water Depreciation Study
Georgia	Georgia Public Service Commission	42959	Liberty Utilities Peach State Natural Gas	2020	Gas Depreciation Study
New Jersey	New Jersey Board of Public Utilities	GR20030243	South Jersey Gas	2020	Gas Depreciation Study
Colorado	Colorado Public Utilities Commission	20AL-0049G	Public Service of Colorado	2020	Gas Depreciation Study
New York	Federal Energy Regulatory Commission	ER20-716-000	LS Power Grid New York, Corp.	2019	Electric Transmission Depreciation Study
Mississippi	Mississippi Public Service Commission	2019-UN-219	Mississippi Power Company	2019	Electric Depreciation Study
Texas	Public Utility Commission of Texas	50288	Kerrville Public Utility District	2019	Electric Depreciation Study
Texas	Railroad Commission of Texas	GUD 10920	CenterPoint Gas	2019	Gas Depreciation Study and Propane Air Study
Texas, New Mexico	Federal Energy Regulatory Commission	ER20-277-000	Southwestern Public Service Company	2019	Electric Production and General Plant Depreciation Study
Alaska	Regulatory Commission of Alaska	U-19-086	Alaska Electric Light and Power	2019	Electric Depreciation Study
Delaware	Delaware Public Service Commission	19-0615	Suez Water Delaware	2019	Water Depreciation Study
Texas	Public Utility Commission of Texas	49831	Southwestern Public Service Company	2019	Electric Depreciation Study
New Mexico	New Mexico Public Regulation Commission	19-00170-UT	Southwestern Public Service Company	2019	Electric Depreciation Study
Georgia	Georgia Public Service Commission	42516	Georgia Power Company	2019	Electric Depreciation Study
Georgia	Georgia Public Service Commission	42315	Atlanta Gas Light	2019	Gas Depreciation Study
Arizona	Arizona Corporation Commission	G-01551A-19-0055	Southwest Gas Corporation	2019	Gas Removal Cost Study
New Hampshire	New Hampshire Public Service Commission	DE 19-064	Liberty Utilities	2019	Electric Distribution and General

Dane Watson Testimony Appearances

Asset Location	Commission	Docket (If Applicable	Company	Year	Description
New Jersey	New Jersey Board of Public Utilities	GR19040486	Elizabethtown Natural Gas	2019	Gas Depreciation Study
Texas	Public Utility Commission of Texas	49421	CenterPoint Houston Electric LLC	2019	Electric Depreciation Study
North Carolina	North Carolina Utilities Commission	Docket No. G-9, Sub 743	Piedmont Natural Gas	2019	Gas Depreciation Study
Alaska	Regulatory Commission of Alaska	U-18-121	Municipal Power and Light City of Anchorage	2018	Electric Depreciation Study
Various	FERC	RP19-352-000	Sea Robin	2018	Gas Depreciation Study
Texas New Mexico	Federal Energy Regulatory Commission	ER19-404-000	Southwestern Public Service Company	2018	Electric Transmission Depreciation Study
California	Federal Energy Regulatory Commission	ER19-221-000	San Diego Gas and Electric	2018	Electric Transmission Depreciation Study
Kentucky	Kentucky Public Service Commission	2018-00281	Atmos Kentucky	2018	Gas Depreciation Study
Alaska	Regulatory Commission of Alaska	U-18-054	Matanuska Electric Coop	2018	Electric Generation Depreciation Study
California	California Public Utilities Commission	A17-10-007	San Diego Gas and Electric	2018	Electric and Gas Depreciation Study
Texas	Public Utility Commission of Texas	48401	Texas New Mexico Power	2018	Electric Depreciation Study
Nevada	Public Utility Commission of Nevada	18-05031	Southwest Gas	2018	Gas Depreciation Study
Texas	Public Utility Commission of Texas	48231	Oncor Electric Delivery	2018	Depreciation Rates
Texas	Public Utility Commission of Texas	48371	Entergy Texas	2018	Electric Depreciation Study
Kansas	Kansas Corporation Commission	18-KCPE-480-RTS	Kansas City Power and Light	2018	Electric Depreciation Study
Arkansas	Arkansas Public Service Commission	18-027-U	Liberty Pine Bluff Water	2018	Water Depreciation Study
Kentucky	Kentucky Public Service Commission	2017-00349	Atmos KY	2018	Gas Depreciation Rates
Tennessee	Tennessee Public Utility Commission	18-00017	Chattanooga Gas	2018	Gas Depreciation Study
Texas	Railroad Commission of Texas	10679	Si Energy	2018	Gas Depreciation Study
Alaska	Regulatory Commission of Alaska	U-17-104	Anchorage Water and Wastewater	2017	Water and Waste Water Depreciation Study
Michigan	Michigan Public Service Commission	U-18488	Michigan Gas Utilities Corporation	2017	Gas Depreciation Study
Texas	Railroad Commission of Texas	10669	CenterPoint South Texas	2017	Gas Depreciation Study

Dane Watson Testimony Appearances

Asset Location	Commission	Docket (If Applicable	Company	Year	Description
Arkansas	Arkansas Public Service Commission	17-061-U	Empire District Electric Company	2017	Depreciation Rates for New Wind Generation
Kansas	Kansas Corporation Commission	18-EPDE-184-PRE	Empire District Electric Company	2017	Depreciation Rates for New Wind Generation
Oklahoma	Oklahoma Corporation Commission	PUD 201700471	Empire District Electric Company	2017	Depreciation Rates for New Wind Generation
Missouri	Missouri Public Service Commission	EO-2018-0092	Empire District Electric Company	2017	Depreciation Rates for New Wind Generation
Michigan	Michigan Public Service Commission	U-18457	Upper Peninsula Power Company	2017	Electric Depreciation Study
Florida	Florida Public Service Commission	20170179-GU	Florida City Gas	2017	Gas Depreciation Study
Michigan	FERC	ER18-56-000	Consumers Energy	2017	Electric Depreciation Study
Missouri	Missouri Public Service Commission	GR-2018-0013	Liberty Utilities	2017	Gas Depreciation Study
Michigan	Michigan Public Service Commission	U-18452	SEMCO	2017	Gas Depreciation Study
Texas	Public Utility Commission of Texas	47527	Southwestern Public Service Company	2017	Electric Production Depreciation Study
MultiState	FERC	ER17-1664	American Transmission Company	2017	Electric Depreciation Study
Alaska	Regulatory Commission of Alaska	U-17-008	Municipal Power and Light City of Anchorage	2017	Generating Unit Depreciation Study
Mississippi	Mississippi Public Service Commission	2017-UN-041	Atmos Energy	2017	Gas Depreciation Study
Texas	Public Utility Commission of Texas	46957	Oncor Electric Delivery	2017	Electric Depreciation Study
Oklahoma	Oklahoma Corporation Commission	PUD 201700078	CenterPoint Oklahoma	2017	Gas Depreciation Study
New York	FERC	ER17-1010-000	New York Power Authority	2017	Electric Depreciation Study
Texas	Railroad Commission of Texas	GUD 10580	Atmos Pipeline Texas	2017	Gas Depreciation Study
Texas	Railroad Commission of Texas	GUD 10567	CenterPoint Texas	2016	Gas Depreciation Study
MultiState	FERC	ER17-191-000	American Transmission Company	2016	Electric Depreciation Study
New Jersey	New Jersey Board of Public Utilities	GR16090826	Elizabethtown Natural Gas	2016	Gas Depreciation Study
North Carolina	North Carolina Utilities Commission	Docket G-9 Sub 77H	Piedmont Natural Gas	2016	Gas Depreciation Study
Michigan	Michigan Public Service Commission	U-18195	Consumers Energy/DTE Electric	2016	Ludington Pumped Storage Depreciation Study

Dane Watson Testimony Appearances

Asset Location	Commission	Docket (If Applicable	Company	Year	Description
Alabama	FERC	ER16-2313-000	SEGCO	2016	Electric Depreciation Study
Alabama	FERC	ER16-2312-000	Alabama Power Company	2016	Electric Depreciation Study
Michigan	Michigan Public Service Commission	U-18127	Consumers Energy	2016	Natural Gas Depreciation Study
Mississippi	Mississippi Public Service Commission	2016 UN 267	Willmut Natural Gas	2016	Natural Gas Depreciation Study
Iowa	Iowa Utilities Board	RPU-2016-0003	Liberty-Iowa	2016	Natural Gas Depreciation Study
Illinois	Illinois Commerce Commission	GRM #16-208	Liberty-Illinois	2016	Natural Gas Depreciation Study
Kentucky	FERC	RP16-097-000	KOT	2016	Natural Gas Depreciation Study
Alaska	Regulatory Commission of Alaska	U-16-067	Alaska Electric Light and Power	2016	Generating Unit Depreciation Study
Florida	Florida Public Service Commission	160170-EI	Gulf Power	2016	Electric Depreciation Study
California	California Public Utilities Commission	A 16-07-002	California American Water	2016	Water and Waste Water Depreciation Study
Arizona	Arizona Corporation Commission	G-01551A-16-0107	Southwest Gas	2016	Gas Depreciation Study
Texas	Public Utility Commission of Texas	45414	Sharyland	2016	Electric Depreciation Study
Colorado	Colorado Public Utilities Commission	16A-0231E	Public Service Company of Colorado	2016	Electric Depreciation Study
Multi-State NE US	FERC	16-453-000	Northeast Transmission Development, LLC	2015	Electric Depreciation Study
Arkansas	Arkansas Public Service Commission	15-098-U	CenterPoint Arkansas	2015	Gas Depreciation Study and Cost of Removal Study
New Mexico	New Mexico Public Regulation Commission	15-00296-UT	Southwestern Public Service Company	2015	Electric Depreciation Study
Atmos Energy Corporation	Tennessee Regulatory Authority	14-00146	Atmos Tennessee	2015	Natural Gas Depreciation Study
New Mexico	New Mexico Public Regulation Commission	15-00261-UT	Public Service Company of New Mexico	2015	Electric Depreciation Study
Hawaii	NA	NA	Hawaii American Water	2015	Water/Wastewater Depreciation Study
Kansas	Kansas Corporation Commission	16-ATMG-079-RTS	Atmos Kansas	2015	Gas Depreciation Study
Texas	Public Utility Commission of Texas	44704	Entergy Texas	2015	Electric Depreciation Study
Alaska	Regulatory Commission of Alaska	U-15-089	Fairbanks Water and Wastewater	2015	Water and Waste Water Depreciation Study

Dane Watson Testimony Appearances

Asset Location	Commission	Docket (If Applicable	Company	Year	Description
Arkansas	Arkansas Public Service Commission	15-031-U	Source Gas Arkansas	2015	Underground Storage Gas Depreciation Study
New Mexico	New Mexico Public Regulation Commission	15-00139-UT	Southwestern Public Service Company	2015	Electric Depreciation Study
Texas	Public Utility Commission of Texas	44746	Wind Energy Transmission Texas	2015	Electric Depreciation Study
Colorado	Colorado Public Utilities Commission	15-AL-0299G	Atmos Colorado	2015	Gas Depreciation Study
Arkansas	Arkansas Public Service Commission	15-011-U	Source Gas Arkansas	2015	Gas Depreciation Study
Texas	Railroad Commission of Texas	GUD 10432	CenterPoint- Texas Coast Division	2015	Gas Depreciation Study
Kansas	Kansas Corporation Commission	15-KCPE-116-RTS	Kansas City Power and Light	2015	Electric Depreciation Study
Alaska	Regulatory Commission of Alaska	U-14-120	Alaska Electric Light and Power	2014-2015	Electric Depreciation Study
Texas	Public Utility Commission of Texas	43950	Cross Texas Transmission	2014	Electric Depreciation Study
New Mexico	New Mexico Public Regulation Commission	14-00332-UT	Public Service of New Mexico	2014	Electric Depreciation Study
Texas	Public Utility Commission of Texas	43695	Xcel Energy	2014	Electric Depreciation Study
Multi State – SE US	FERC	RP15-101	Florida Gas Transmission	2014	Gas Transmission Depreciation Study
California	California Public Utilities Commission	A.14-07-006	Golden State Water	2014	Water and Waste Water Depreciation Study
Michigan	Michigan Public Service Commission	U-17653	Consumers Energy Company	2014	Electric and Common Depreciation Study
Colorado	Public Utilities Commission of Colorado	14AL-0660E	Public Service of Colorado	2014	Electric Depreciation Study
Wisconsin	Wisconsin	05-DU-102	WE Energies	2014	Electric, Gas, Steam and Common Depreciation Studies
Texas	Public Utility Commission of Texas	42469	Lone Star Transmission	2014	Electric Depreciation Study
Nebraska	Nebraska Public Service Commission	NG-0079	Source Gas Nebraska	2014	Gas Depreciation Study
Alaska	Regulatory Commission of Alaska	U-14-055	TDX North Slope Generating	2014	Electric Depreciation Study
Alaska	Regulatory Commission of Alaska	U-14-054	Sand Point Generating LLC	2014	Electric Depreciation Study

Dane Watson Testimony Appearances

Asset Location	Commission	Docket (If Applicable	Company	Year	Description
Alaska	Regulatory Commission of Alaska	U-14-045	Matanuska Electric Coop	2014	Electric Generation Depreciation Study
Texas, New Mexico	Public Utility Commission of Texas	42004	Southwestern Public Service Company	2013-2014	Electric Production, Transmission, Distribution and General Plant Depreciation Study
New Jersey	New Jersey Board of Public Utilities	GR13111137	South Jersey Gas	2013	Gas Depreciation Study
Various	FERC	RP14-247-000	Sea Robin	2013	Gas Depreciation Study
Arkansas	Arkansas Public Service Commission	13-078-U	Arkansas Oklahoma Gas	2013	Gas Depreciation Study
Arkansas	Arkansas Public Service Commission	13-079-U	Source Gas Arkansas	2013	Gas Depreciation Study
California	California Public Utilities Commission	Proceeding No.: A.13-11-003	Southern California Edison	2013	Electric Depreciation Study
North Carolina/South Carolina	FERC	ER13-1313	Progress Energy Carolina	2013	Electric Depreciation Study
Wisconsin	Public Service Commission of Wisconsin	4220-DU-108	Northern States Power Company - Wisconsin	2013	Electric, Gas and Common Transmission, Distribution and General
Texas	Public Utility Commission of Texas	41474	Sharyland	2013	Electric Depreciation Study
Kentucky	Kentucky Public Service Commission	2013-00148	Atmos Energy Corporation	2013	Gas Depreciation Study
Minnesota	Minnesota Public Utilities Commission	13-252	Allete Minnesota Power	2013	Electric Depreciation Study
New Hampshire	New Hampshire Public Service Commission	DE 13-063	Liberty Utilities	2013	Electric Distribution and General
Texas	Railroad Commission of Texas	10235	West Texas Gas	2013	Gas Depreciation Study
Alaska	Regulatory Commission of Alaska	U-12-154	Alaska Telephone Company	2012	Telecommunications Utility
New Mexico	New Mexico Public Regulation Commission	12-00350-UT	Southwestern Public Service Company	2012	Electric Depreciation Study
Colorado	Colorado Public Utilities Commission	12AL-1269ST	Public Service Company of Colorado	2012	Gas and Steam Depreciation Study
Colorado	Colorado Public Utilities Commission	12AL-1268G	Public Service Company of Colorado	2012	Gas and Steam Depreciation Study
Alaska	Regulatory Commission of Alaska	U-12-149	Municipal Power and Light City of Anchorage	2012	Electric Depreciation Study
Texas	Texas Public Utility Commission	40824	Xcel Energy	2012	Electric Depreciation Study

Dane Watson Testimony Appearances

Asset Location	Commission	Docket (If Applicable	Company	Year	Description
South Carolina	Public Service Commission of South Carolina	Docket 2012-384-E	Progress Energy Carolina	2012	Electric Depreciation Study
Alaska	Regulatory Commission of Alaska	U-12-141	Interior Telephone Company	2012	Telecommunications Utility
Michigan	Michigan Public Service Commission	U-17104	Michigan Gas Utilities Corporation	2012	Gas Depreciation Study
North Carolina	North Carolina Utilities Commission	E-2 Sub 1025	Progress Energy Carolina	2012	Electric Depreciation Study
Texas	Texas Public Utility Commission	40606	Wind Energy Transmission Texas	2012	Electric Depreciation Study
Texas	Texas Public Utility Commission	40604	Cross Texas Transmission	2012	Electric Depreciation Study
Minnesota	Minnesota Public Utilities Commission	12-858	Northern States Power Company - Minnesota	2012	Electric, Gas and Common Transmission, Distribution and General
Texas	Railroad Commission of Texas	10170	Atmos Mid-Tex	2012	Gas Depreciation Study
Texas	Railroad Commission of Texas	10174	Atmos West Texas	2012	Gas Depreciation Study
Texas	Railroad Commission of Texas	10182	CenterPoint Beaumont/ East Texas	2012	Gas Depreciation Study
Kansas	Kansas Corporation Commission	12-KCPE-764-RTS	Kansas City Power and Light	2012	Electric Depreciation Study
Nevada	Public Utility Commission of Nevada	12-04005	Southwest Gas	2012	Gas Depreciation Study
Texas	Railroad Commission of Texas	10147, 10170	Atmos Mid-Tex	2012	Gas Depreciation Study
Kansas	Kansas Corporation Commission	12-ATMG-564-RTS	Atmos Kansas	2012	Gas Depreciation Study
Texas	Texas Public Utility Commission	40020	Lone Star Transmission	2012	Electric Depreciation Study
Michigan	Michigan Public Service Commission	U-16938	Consumers Energy Company	2011	Gas Depreciation Study
Colorado	Public Utilities Commission of Colorado	11AL-947E	Public Service of Colorado	2011	Electric Depreciation Study
Texas	Texas Public Utility Commission	39896	Entergy Texas	2011	Electric Depreciation Study
MultiState	FERC	ER12-212	American Transmission Company	2011	Electric Depreciation Study
California	California Public Utilities Commission	A1011015	Southern California Edison	2011	Electric Depreciation Study
Mississippi	Mississippi Public Service Commission	2011-UN-184	Atmos Energy	2011	Gas Depreciation Study
Michigan	Michigan Public Service Commission	U-16536	Consumers Energy Company	2011	Wind Depreciation Rate Study

Dane Watson Testimony Appearances

Asset Location	Commission	Docket (If Applicable	Company	Year	Description
Texas	Public Utility Commission of Texas	38929	Oncor	2011	Electric Depreciation Study
Texas	Railroad Commission of Texas	10038	CenterPoint South TX	2010	Gas Depreciation Study
Alaska	Regulatory Commission of Alaska	U-10-070	Inside Passage Electric Cooperative	2010	Electric Depreciation Study
Texas	Public Utility Commission of Texas	36633	City Public Service of San Antonio	2010	Electric Depreciation Study
Texas	Texas Railroad Commission	10000	Atmos Pipeline Texas	2010	Gas Depreciation Study
Multi State – SE US	FERC	RP10-21-000	Florida Gas Transmission	2010	Gas Depreciation Study
Maine/ New Hampshire	FERC	10-896	Granite State Gas Transmission	2010	Gas Depreciation Study
Texas	Public Utility Commission of Texas	38480	Texas New Mexico Power	2010	Electric Depreciation Study
Texas	Public Utility Commission of Texas	38339	CenterPoint Electric	2010	Electric Depreciation Study
Texas	Texas Railroad Commission	10041	Atmos Amarillo	2010	Gas Depreciation Study
Georgia	Georgia Public Service Commission	31647	Atlanta Gas Light	2010	Gas Depreciation Study
Texas	Public Utility Commission of Texas	38147	Southwestern Public Service	2010	Electric Technical Update
Alaska	Regulatory Commission of Alaska	U-09-015	Alaska Electric Light and Power	2009-2010	Electric Depreciation Study
Alaska	Regulatory Commission of Alaska	U-10-043	Utility Services of Alaska	2009-2010	Water Depreciation Study
Michigan	Michigan Public Service Commission	U-16055	Consumers Energy/DTE Energy	2009-2010	Ludington Pumped Storage Depreciation Study
Michigan	Michigan Public Service Commission	U-16054	Consumers Energy	2009-2010	Electric Depreciation Study
Michigan	Michigan Public Service Commission	U-15963	Michigan Gas Utilities Corporation	2009	Gas Depreciation Study
Michigan	Michigan Public Service Commission	U-15989	Upper Peninsula Power Company	2009	Electric Depreciation Study
Texas	Railroad Commission of Texas	9869	Atmos Energy	2009	Shared Services Depreciation Study
Mississippi	Mississippi Public Service Commission	09-UN-334	CenterPoint Energy Mississippi	2009	Gas Depreciation Study
Texas	Railroad Commission of Texas	9902	CenterPoint Energy Houston	2009	Gas Depreciation Study
Colorado	Colorado Public Utilities Commission	09AL-299E	Public Service Company of Colorado	2009	Electric Depreciation Study
Louisiana	Louisiana Public Service Commission	U-30689	Cleco	2008	Electric Depreciation Study

Dane Watson Testimony Appearances

Asset Location	Commission	Docket (If Applicable	Company	Year	Description
Texas	Public Utility Commission of Texas	35763	Southwestern Public Service Company	2008	Electric Production, Transmission, Distribution and General Plant Depreciation Study
Wisconsin	Wisconsin	05-DU-101	WE Energies	2008	Electric, Gas, Steam and Common Depreciation Studies
North Dakota	North Dakota Public Service Commission	PU-07-776	Northern States Power Company - Minnesota	2008	Net Salvage
New Mexico	New Mexico Public Regulation Commission	07-00319-UT	Southwestern Public Service Company	2008	Testimony – Depreciation
Multiple States	Railroad Commission of Texas	9762	Atmos Energy	2007-2008	Shared Services Depreciation Study
Minnesota	Minnesota Public Utilities Commission	E015/D-08-422	Minnesota Power	2007-2008	Electric Depreciation Study
Texas	Public Utility Commission of Texas	35717	Oncor	2008	Electric Depreciation Study
Texas	Public Utility Commission of Texas	34040	Oncor	2007	Electric Depreciation Study
Michigan	Michigan Public Service Commission	U-15629	Consumers Energy	2006-2009	Gas Depreciation Study
Colorado	Colorado Public Utilities Commission	06-234-EG	Public Service Company of Colorado	2006	Electric Depreciation Study
Arkansas	Arkansas Public Service Commission	06-161-U	CenterPoint Energy – Arkla Gas	2006	Gas Distribution Depreciation Study and Removal Cost Study
Texas, New Mexico	Public Utility Commission of Texas	32766	Southwestern Public Service Company	2005-2006	Electric Production, Transmission, Distribution and General Plant Depreciation Study
Texas	Railroad Commission of Texas	9670/9676	Atmos Energy Corp	2005-2006	Gas Distribution Depreciation Study
Texas	Railroad Commission of Texas	9400	TXU Gas	2003-2004	Gas Distribution Depreciation Study
Texas	Railroad Commission of Texas	9313	TXU Gas	2002	Gas Distribution Depreciation Study
Texas	Railroad Commission of Texas	9225	TXU Gas	2002	Gas Distribution Depreciation Study
Texas	Public Utility Commission of Texas	24060	TXU	2001	Line Losses
Texas	Public Utility Commission of Texas	23640	TXU	2001	Line Losses
Texas	Railroad Commission of Texas	9145-9148	TXU Gas	2000-2001	Gas Distribution Depreciation Study
Texas	Public Utility Commission of Texas	22350	TXU	2000-2001	Electric Depreciation Study, Unbundling
Texas	Railroad Commission of Texas	8976	TXU Pipeline	1999	Pipeline Depreciation Study

Dane Watson Testimony Appearances

Asset Location	Commission	Docket (If Applicable	Company	Year	Description
Texas	Public Utility Commission of Texas	20285	TXU	1999	Fuel Company Depreciation Study
Texas	Public Utility Commission of Texas	18490	TXU	1998	Transition to Competition
Texas	Public Utility Commission of Texas	16650	TXU	1997	Customer Complaint
Texas	Public Utility Commission of Texas	15195	TXU	1996	Mining Company Depreciation Study
Texas	Public Utility Commission of Texas	12160	TXU	1993	Fuel Company Depreciation Study
Texas	Public Utility Commission of Texas	11735	TXU	1993	Electric Depreciation Study

IN THE MATTER OF THE PETITION OF ELIZABETHTOWN GAS COMPANY FOR APPROVAL OF INCREASED BASE TARIFF RATES AND CHARGES FOR GAS SERVICE AND OTHER TARIFF REVISIONS

BPU DOCKET NO. GR21________

DIRECT TESTIMONY

OF

ALAN D. FELSENTHAL

PricewaterhouseCoopers LLP

On Behalf of
Elizabethtown Gas Company

Exhibit P-10

December 28, 2021

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Exhibit P-10

ELIZABETHTOWN GAS COMPANY
DIRECT TESTIMONY OF
ALAN D. FELSENTHAL

I. INTRODUCTION

Q. PLEASE STATE YOUR NAME, ADDRESS, OCCUPATION AND EMPLOYER.

A. My name is Alan D. Felsenthal. My business address is One North Wacker Drive, Chicago, Illinois 60606. I am a Managing Director at the Firm of PricewaterhouseCoopers LLP ("PwC").

Q. PLEASE DESCRIBE YOUR EDUCATIONAL BACKGROUND AND INDUSTRY RELATED EXPERIENCE.

A. I graduated from the University of Illinois in 1971 and began my career at Arthur Andersen LLP ("Arthur Andersen"), where I was an auditor and focused on audits of financial statements of regulated entities. In 2002, I joined PwC and became a Managing Director in its Power and Utilities Group and continued performing audits for regulated entities. I was hired by Huron Consulting Group ("Huron") in 2008 and returned to PwC in November of 2010. At both Arthur Andersen and PwC, I supervised audits of financial statements on which the firms issued audit opinions that were filed with the Securities and Exchange Commission, the Federal Communications Commission, the Federal Energy Regulatory Commission ("FERC") and various state commissions. At Arthur Andersen, PwC, and Huron, I consulted on a significant number of utility rate cases and helped develop testimony for myself and others on a variety of issues, including construction work in progress in rate base, projected test years, lead-lag studies, cost allocation, several accounting issues (*e.g.*, pension accounting, regulatory accounting, income tax accounting, and cost of removal) and compliance with the income tax normalization requirements.

Q. PLEASE DESCRIBE YOUR DUTIES AND RESPONSIBILITIES AT PWC.

A. I am currently a member of PwC's Complex Accounting and Regulatory Support ("CARS") team, which advises clients on complex technical accounting and regulatory / ratemaking matters. Throughout my career, my focus has been on the regulated industry sector, primarily electric, gas, telecommunication and water utilities. I have focused on utility accounting, income tax and regulatory issues, primarily as a result of auditing regulated enterprises. The unique accounting standards applicable to regulated entities embodied in Accounting Standards Codification ("ASC") 980, Regulated Operations (formerly, Statement of Financial Accounting Standards ("SFAS") 71), FAS 90, FAS 92, FAS 101 and various Emerging Issues Task Force issues, all need to be understood so that auditors can determine whether a company's financial statements are fairly presented in accordance with generally accepted accounting principles ("GAAP"). I have witnessed the issuance of these standards and have consulted with utilities as to how they should be applied. At both Arthur Andersen and PwC, I worked with the technical industry, accounting, and auditing leadership to communicate and consult on utility accounting and audit matters. My curriculum vitae is attached as Schedule ADF-1.

Q. HAVE YOU PREVIOUSLY TESTIFIED OR SUBMITTED TESTIMONY BEFORE THE NEW JERSEY BOARD OF PUBLIC UTILITIES ("BOARD" OR "BPU") OR ANY OTHER REGULATORY COMMISSION?

A. Yes. I have submitted testimony to the Board in the previous Elizabethtown Gas Company ("Elizabethtown" or "Company") rate case, Docket No. GR19040486, as well as in the most recent South Jersey Gas Company rate case, Docket GR20030243. I have also provided testimony before the Arizona Corporation Commission, the Florida Public Service Commission, the Illinois Commerce Commission, the Indiana Utility Regulatory Commission, the Missouri Public Service Commission, the Public Utility Commission of Ohio, the Public Utility Commission of Texas, the Public Service Commission of Utah, the Washington Utilities and Transportation Commission, the Public Service Commission of West Virginia and FERC. See Schedule ADF-1 for specific dockets in which I have testified.

Q. HAVE YOU PROVIDED TRAINING ON THE APPLICATION OF GAAP TO REGULATED ENTERPRISES?

A. Yes. At Arthur Andersen, Huron and PwC, I developed and taught utility accounting seminars focusing on the unique aspects of the regulatory process and the resulting accounting consequences of the application of GAAP. I have presented seminars as well as delivered training on an in-house basis. Seminar participants have included utility company and regulatory commission staff accountants, utility rate departments and internal auditors, tax accountants and others. I have also conducted these seminars for FERC and several state commissions and have presented at various Edison Electric Institute and American Gas Association ratemaking and accounting seminars. The income tax training programs I have presented include topics such as the normalization requirements for public utilities in the Internal Revenue Code ("IRC"), protected and unprotected deferred taxes, and the mechanics and application of the Average Rate Assumption Method ("ARAM").

II. PURPOSE OF TESTIMONY

Q. WHAT IS THE PURPOSE OF YOUR TESTIMONY?

A. My testimony addresses certain income tax amounts included in the rate case filing of Elizabethtown, specifically: 1) the amount of the Consolidated Tax Adjustment ("CTA"); 2) the amount of excess accumulated deferred income taxes ("Excess ADIT") reversing in the test period; and 3) the balance of the Excess ADIT regulatory liability that reduces the Company's rate base.[1]

Q. ARE YOU SPONSORING ANY SCHEDULES AS PART OF YOUR DIRECT TESTIMONY?

A. Yes. I am supporting the following schedules that were prepared by me or under my supervision or direction:

- Schedule ADF-1: Curriculum Vitae;
- Schedule ADF-2: Determination of CTA for the test period – Confidential; and

[1] This direct testimony was prepared in connection with Elizabethtown Gas Company's rate case and for the use and benefit of Elizabethtown Gas Company. PwC disclaims any contractual or other responsibility to others based on their access to or use of this direct testimony and the information contained herein.

- Schedule ADF-3: Calculation of Excess ADIT test period reversal and Excess ADIT regulatory liability at end of test period.

Q. WHERE DID YOU OBTAIN THE INFORMATION USED IN THE PREPARATION OF YOUR SCHEDULES ADF-2 AND ADF-3?

A. All amounts included in Schedules ADF-2 and ADF-3 were obtained from the books and records of the Company, from the Company's last rate case (Docket No. GR19040486) or information submitted by the Company in Docket Nos. AX18010001 and GR18030232, the regulatory proceeding in which the BPU considered the impacts on Elizabethtown's rates associated with the passage of the Tax Cuts and Jobs Act of 2017 ("TCJA").

III. <u>INCOME TAX ACCOUNTING AND RATEMAKING FUNDAMENTALS</u>

Q. PLEASE DESCRIBE THE ACCOUNTING FOR INCOME TAXES UNDER GAAP?

A. Accounting for income taxes under GAAP is addressed in the accounting literature in section ASC 740 (formerly SFAS No. 109, <u>Accounting for Income Taxes</u> ("SFAS 109")) of the accounting codification. There are several components to the calculation: currently payable income taxes; deferred income taxes; and investment tax credit. My testimony will only focus on the first two components as the investment tax credit is not an issue in this proceeding. Also, my descriptions will focus on federal currently payable income taxes and federal deferred income taxes, although the same basic explanation would also be applicable for relevant state income taxing regimes.

Q. PLEASE DESCRIBE THE FIRST COMPONENT, CURRENTLY PAYABLE INCOME TAXES.

A. Currently payable income tax expense represents the estimated amount of current year income taxes payable to the U.S. Treasury based on current year taxable income, determined in accordance with the IRC. For purposes of preparing an income tax return each year, the IRC contains guidance for determining if and when an item is "taxable" or "deductible."

Q. ARE THE TAXABLE OR DEDUCTIBLE AMOUNTS UNDER THE IRC FOR DETERMINING IRC TAXABLE INCOME THE SAME AS THOSE USED IN DETERMINING REVENUE OR EXPENSE UNDER GAAP?

A. No, not always. The IRC rules for determining what is taxable or deductible may differ from what is reportable as "revenue," "income" or "expense" under GAAP. For instance, certain expenses recorded on the financial statements under GAAP in one year may be deductible on the tax return in a different accounting period. There are also instances where the amounts shown as deductions on the tax return in one year are not reflected on the financial statements until a later year. As a result, at the end of each reporting period, there will likely be accumulated differences on the book and income tax balance sheets of reported assets and liabilities resulting from different book treatment and tax return treatment of revenues, income and expenses. These differences are referred to as timing or temporary differences.

Q. CAN YOU FURTHER EXPLAIN WHAT IS MEANT BY A TIMING OR TEMPORARY DIFFERENCE AND PROVIDE AN EXAMPLE?

A. Yes. One common temporary difference relates to the concept of depreciation. For book purposes, when a company acquires a fixed asset, GAAP requires that the asset be depreciated over its estimated useful life in a systematic and rational manner. In so doing, the cost of the fixed asset is "allocated" to the periods in which the fixed asset is being used to provide service. Most utilities depreciate their fixed assets for book purposes using the straight-line depreciation method, wherein the same depreciation amount is recorded each year of a fixed asset's estimated useful life.

In contrast to the straight-line depreciation method used for determining depreciation expense under GAAP, an accelerated depreciation method is commonly used for income tax purposes. Under an accelerated depreciation approach, that same fixed asset may be depreciated on the income tax return using an accelerated method (more than a straight-line method) and/or different (generally shorter) estimated useful life. When the annual depreciation charge for book purposes is compared to the annual depreciation for income tax purposes, there will likely be differences. In the early years of an asset's life, tax depreciation using an accelerated method and/or shorter lives will be greater than book depreciation which is computed under a straight-line approach. In the later years, the reverse will be true because given the same capitalized asset cost, the cumulative tax and book depreciation amounts over the entire life of the asset must equal. The sum of the annual book-tax depreciation differences results in accumulated book-tax depreciation differences when comparing the net book value and net tax value of fixed assets.

Q. CAN YOU PROVIDE AN EXAMPLE OF HOW THE DEPRECIATION BOOK TAX DIFFERENCE ARISES AND REVERSES?

A. Yes. Assume a utility acquires property, plant and equipment for $10 million cash. The entry to record the asset is to debit property, plant and equipment and to credit cash. For book purposes, assume that asset has a useful life of ten years. For income tax purposes, assume that same asset qualifies as a five-year tax depreciation asset under the Modified Accelerated Cost Recovery System ("MACRS" – an allowable approach under the IRC). Under MACRS for a five-year asset, the asset is depreciated using double declining balance, switching to straight line at the tax midpoint of its life. Thus, the depreciation deduction is 20 percent the first year, 32 percent in year two, 19.2 percent in year three, 11.52 percent in years four and five and 5.76 percent in year six. The annual depreciation charges for book and tax would be as follows:

Year	Book Depreciation	Tax Depreciation	Difference	Cumulative Book-Tax Difference
1	1,000,000	2,000,000	1,000,000	1,000,000
2	1,000,000	3,200,000	2,200,000	3,200,000
3	1,000,000	1,920,000	920,000	4,120,000
4	1,000,000	1,152,000	152,000	4,272,000
5	1,000,000	1,152,000	152,000	4,424,000
6	1,000,000	576,000	(424,000)	4,000,000
7	1,000,000		(1,000,000)	3,000,000
8	1,000,000		(1,000,000)	2,000,000
9	1,000,000		(1,000,000)	1,000,000
10	1,000,000		(1,000,000)	0
Total	10,000,000	10,000,000	0	

At the end of year 1, the net book basis of property, plant and equipment for book purposes would be $9 million ($10 million gross plant, less $1 million of accumulated book depreciation) while its tax basis would be $8 million ($10 million gross tax basis less $2 million of accumulated tax depreciation). Each year's book depreciation expense would reduce the net book basis of property, plant and equipment and each year's tax depreciation would affect the tax basis of property, plant and equipment. The difference between the book basis and tax basis of property, plant and equipment represents a temporary difference under ASC 740.

However, because total depreciation expense/deductions are limited to the gross capitalized cost of the property, plant and equipment, accelerated income tax depreciation claimed in the early years (reducing income tax payments) will reverse in subsequent periods when book depreciation exceeds tax depreciation (increasing income tax payments) so that when the asset is retired, the depreciation temporary difference will have completely reversed.

Q. WHAT IS THE ACCOUNTING FOR TEMPORARY DIFFERENCES UNDER ASC 740?

A. Under GAAP, because the financial statements reflect accrual, not cash basis accounting, deferred income taxes are recorded on temporary differences. As a result, income tax expense under GAAP includes both a currently payable component (as previously described, based on the tax return) as well as a "deferred" income tax component (based on timing/temporary differences). Such deferred income taxes reflect the liability or asset for income taxes payable or receivable in the future stemming from transactions recorded in the financial statements currently. The balance sheet liability or asset for future taxes is Accumulated Deferred Income Taxes ("ADIT"). In other words, to the extent that accelerated tax depreciation is claimed on the income tax return in an amount that exceeds book depreciation reported on the financial statements (reducing the current year's taxable income and tax obligation), a liability for future taxes results. The future tax liability will be "paid" in later years when book depreciation exceeds income tax deductible tax depreciation.

Under ASC 740, a calculation of required ADIT is performed at the end of each annual reporting period. The required ADIT is measured by multiplying the temporary differences by the currently applicable income tax rates. The difference obtained by comparing the ADIT at the current balance sheet date to the ADIT at the previous balance sheet date results in "deferred income tax expense." For regulated entities, such as Elizabethtown, the process of recording deferred income taxes on temporary differences is referred to as "normalization," "deferred tax accounting," or "comprehensive interperiod income tax allocation."

Q. PLEASE EXPLAIN HOW CURRENT AND DEFERRED INCOME TAXES WOULD BE RECORDED ON THE FINANCIAL STATEMENTS FOR THE DEPRECIATION DIFFERENCE EXAMPLE YOU DISCUSSED PREVIOUSLY.

A. In year 1 of the example, the Company would record depreciation expense on the books in accordance with GAAP of $1 million. In that same year, they would reduce taxable income on the income tax return by tax depreciation of $2 million. Assuming a 21 percent income tax rate, by claiming a $2 million depreciation deduction, **current** taxes payable and **current** tax expense would be reduced by $420,000 (21 percent income tax rate times the $2 million tax depreciation deduction).

However, by claiming an additional $1 million of tax depreciation ($2 million tax depreciation compared to $1 million of book depreciation) the Company will also record a **deferred** income tax liability and **deferred** tax expense of $210,000 (21 percent income tax rate times book/tax difference of $1 million). The deferred tax will become payable when the book depreciation exceeds tax depreciation. In other words, by claiming accelerated depreciation (compared to straight line book depreciation) in years 1-5, the Company has incurred a deferred tax obligation that will become payable in years 6-10.

Thus, a timing or temporary difference that reduces current income tax expense and current taxes payable is offset by an equal increase in deferred tax expense and ADIT. When the timing or temporary difference reverses, current income tax expense and current taxes payable will increase and be offset by a decrease in deferred income tax expense and ADIT.

Q. HOW ARE DEFERRED INCOME TAXES TREATED IN THE RATEMAKING PROCESS?

A. In the ratemaking process, revenue requirements are unaffected by such timing or temporary differences (from the expense side) as the reduction (or increase) in current tax expense is offset by an equal and offsetting increase (or reduction) of deferred tax expense. In this manner, it should be noted that utility customers do not pay deferred income taxes (offsetting current and deferred expense amounts). Instead, the source of such deferred income taxes is the U.S. Treasury. As a result, ADIT balances are often characterized as an "interest free loan" from the U.S. Treasury. This was the objective Congress intended when it enacted accelerated depreciation in the IRC. Congress believed that allowing companies to increase their tax depreciation deductions (and thereby reduce current income tax payments), would lower the financing costs of their investment in capital assets more quickly and thus they would be incented to make such expenditures.

Q. DOES THE IRC PROVIDE GUIDANCE ON HOW BOOK-TAX DIFFERENCES SHOULD BE TREATED IN THE UTILITY RATEMAKING PROCESS?

A. Yes. To ensure that regulated utilities enjoy the benefits intended by Congress, there are separate rules applicable to depreciation differences resulting from using tax methods and tax lives to determine deductible tax depreciation versus using book methods and lives to determine book depreciation on public utility property. These depreciation-related method and life timing/temporary differences are referred to as “protected differences” (protected by the IRC) in that the IRC governs how the associated deferred income taxes are to be treated in determining revenue requirements. The IRC requires deferred income tax expense on such book-tax differences must be permitted as a recoverable expense in the ratemaking process with the related, remaining ADIT on such differences reducing rate base. Because the ADIT balance reduces rate base, the customer benefits from this procedure as the U.S. Treasury is providing funds that, in the absence of accelerated tax deductions and deferred tax accounting, would need to be obtained from other sources, such as debt and equity, which have a cost (interest or return).

To ensure compliance, if such normalization rules are not followed, the Company is prohibited from claiming accelerated depreciation for income tax purposes and, instead, can only use straight-line depreciation in determining the depreciation deduction for income tax purposes. In such a case, there is no depreciation book-tax difference and no interest-free loan. Being unable to claim accelerated depreciation is a significant penalty.

Q. YOU SAID THAT THE IRS NORMALIZATION RULES APPLY TO PROTECTED BOOK-TAX DIFFERENCES AND DEFINE PROTECTED BOOK-TAX DIFFERENCES AS PRIMARILY DUE TO DIFFERENCES BETWEEN THE BOOK AND TAX DEPRECIATION METHODS AND BETWEEN BOOK AND TAX LIVES USED IN THE CALCULATIONS. ARE THE REST OF A COMPANY'S BOOK-TAX TIMING/TEMPORARY DIFFERENCES CONSIDERED UNPROTECTED?

A. Basically, yes. The normalization rules apply to protected book-tax differences, which are primarily differences between book and tax depreciation caused by different depreciation methods (accelerated for tax, straight-line for books) and depreciation lives (different, generally shorter lives for tax purposes). There are several other book-tax differences that are also considered protected, such as the book-tax difference associated with contributions in aid of construction and the appropriate treatment of Net Operating Loss ("NOL") Deferred Tax Assets. All other book-tax temporary/timing differences are considered unprotected and are not subject to the normalization requirements of the IRC. For example, rate case expense is deferred and amortized for book purposes but a current income tax deduction is permitted for such expense in the year accrued.

Q. IS DEFERRED INCOME TAX ACCOUNTING APPROPRIATE FOR RATEMAKING PURPOSES?

A. Yes. Income tax expense in a given year is the result of that year's economic activity. In determining the revenue requirement, it is important for regulatory commissions to consider the recovery of all appropriate costs of providing service (return, operating expense, maintenance expense, depreciation expense, etc.) and, after such pre-tax amounts are determined, including the associated income tax effects of the permitted cost of service.

Q. FROM A RATEMAKING PERSPECTIVE, IS THERE A WAY TO COMPUTE OR CHECK THAT THE APPROPRIATE INCOME TAXES HAVE BEEN CONSIDERED IN DETERMINING THE REVENUE REQUIREMENT?

A. Yes. Federal income taxes requested by the Company and included in the revenue requirement determination should be based on pre-tax revenues, income and expenses included in the cost of service calculation. It is neither appropriate nor equitable to increase or reduce cost of service by tax costs or benefits that are not related to the rendition of utility service to customers.

Said another way, income taxes have no independent existence of their own. They are based on revenues, income and expenses. Once the Board decides on the appropriate revenues and expenses that are necessary for the provision of service, the related income taxes can be determined.

One way to check the ratemaking income tax calculation is to begin with after-tax equity return as a starting point. Under this method, equity return (rate base times the weighted cost of equity), or total return less synchronized interest (rate base times the weighted cost of debt), is adjusted for items for which there is no tax deduction to offset amounts recovered through revenues – such as book amortization of flow-through differences (if any), permanent items, and the reversal of Excess ADIT. The resulting "adjusted equity return" is then grossed-up to a revenue requirement level, multiplied by the statutory income tax rate and then adjusted for flow-through and permanent differences and the reversal of Excess ADIT. This approach is used to determine Federal income tax expense in total, with no segregation between current and deferred Federal income taxes.

IV. CONSOLIDATED TAX ADJUSTMENT ("CTA")

Q. PLEASE EXPLAIN THE CONCEPT OF A CTA.

A. A CTA is calculated as the "benefit realized" attributable to an affiliated group's filing of a consolidated income tax return and results when the consolidated tax liability for the group is less than what the liability would have been had each member of the group calculated income taxes on a stand-alone basis.

Q. DOES THE BOARD HAVE RULES FOR DETERMINING AND APPLYING CTAS IN RATE CASES?

A. Yes. The Board has issued rules that require utilities to calculate and apply CTAs in determining revenue requirements. The methodology for the CTA calculation has fluctuated over the years. Recently, however, the Board adopted regulations – codified at N.J.A.C. 14:1-5.12(a)(ii) that clarified the CTA methodology for rate case filings. The Board stated that a CTA calculation shall be included in a regulatory filing if the company filing the rate case is a member of a group that files a consolidated tax return. Under the recently enacted rule, the CTA is to be calculated using each affiliate's taxable income/loss for each of five consecutive years (including the complete tax year within the utility's test year) using statutory income tax rates or the alternative minimum tax, whichever was applicable. Under the Board's enacted CTA rules, the rate base may be reduced by up to 25 percent of the full CTA.

Q. HAS ELIZABETHTOWN COMPUTED A CTA IN THE MANNER REQUIRED BY THE BOARD'S REGULATIONS?

A. Yes. However, because the Company has only been a member of the South Jersey Industries Consolidated group since 2018, the year in which it was acquired by South Jersey Industries, Inc. ("SJI"), there are only three years (2018-2020) of information from which to determine a CTA for the Company. Schedule ADF-2 (Confidential) is the CTA calculation for Elizabethtown for the period in which Elizabethtown has been a member of the SJI Consolidated group.

Q. PLEASE DESCRIBE THE CTA CALCULATION ON SCHEDULE ADF-2.

A. For the five-year period 2016-2020, the entities included in SJI's consolidated tax return, including Elizabethtown, were identified, along with their taxable income or losses for the year. Elizabethtown has taxable losses for each of the years in which it is included in SJI's consolidated income tax return. And, obviously, Elizabethtown has a cumulative taxable loss for this period. Because Elizabethtown is a loss company, there is no CTA and no CTA adjustment should be made to rate base.

Q. EVEN THOUGH THE BOARD HAS SET FORTH REQUIREMENTS FOR A CTA TO BE APPLIED IN RATE CASES, DO YOU AGREE WITH THE CONCEPT?

A. No. The vast majority (more than 45) of regulatory jurisdictions, including FERC, have rejected the concept of the CTA. Almost all regulatory jurisdictions use a "stand-alone" approach. Under this methodology, federal income taxes are computed based on revenues, income and expenses of the Company included in the utility's revenue requirement as if the Company were a stand-alone taxpayer. This approach appropriately allocates federal income taxes among members of the consolidated group using the benefits/burdens criteria outlined by FERC in Opinion 173.[2]

Q. IF A PARTICULAR UTILITY'S INCOME TAX CALCULATION IS OFFSET BY TAXABLE LOSSES OF OTHER MEMBERS OF A CONSOLIDATED GROUP, DOES THAT CREATE A "HYPOTHETICAL" INCOME TAX FOR THAT UTILITY?

A. No. There is nothing "hypothetical" about the utility's income tax calculation. It is the federal/state income tax determined on an accrual basis (not cash basis) as are the other cost of service transactions that relate to/match/result from the revenues, income, and expenses associated with providing utility service to customers. The benefits and burdens criterion refers to computing the tax consequences of transactions based on the revenue and expense transactions themselves.

With that said, the Company applied the CTA methodology consistent with the Board's regulations in this proceeding and determined that no CTA should be reflected in rate base.

[2] *Columbia Gulf Transmission Co. et al.*, 23 FERC ¶ 61,396 (1983).

V. EXCESS ADIT

Q. WHAT ARE EXCESS ADIT?

A. Excess ADIT arise when the federal income tax rate is reduced and ADIT previously recorded at the prior income tax rate are remeasured using the revised/reduced income tax rate. The TCJA did just that, reducing the federal income tax rate from 35 percent to 21 percent. This reduction in income tax rates reduced current income tax expense and current income taxes payable, but also reduced **originating** deferred tax expense and ADIT beginning in 2017. From a regulated utility revenue requirement perspective, this change also impacts the income tax gross-up calculation I discussed previously. At the previous 35 percent federal income tax rate, revenue of $1.5385 was required to provide $1.00 of after-tax income. A corporate tax rate of 21 percent requires $1.2685 of revenue to generate $1.00 of after-tax income. A separate New Jersey state income tax rate of 9 percent exists. The New Jersey state income tax rate is deductible for federal income tax purposes and therefore the "combined federal and state income tax rate" has changed from 40.85 percent to 28.11 percent. The combined income tax gross-up factor before and after the TCJA has changed from 1.6906 to 1.3910, respectively.

Further, as a result of the lower 21 percent income tax rate becoming effective under the TCJA, all companies, including utilities, were required under ASC 740 to "remeasure," as of December 31, 2017, the amounts of ADIT in their financial statements. Regulated utilities reclassified the reduction in ADIT to a regulatory liability representing the Excess ADIT that will be used to reduce future revenue requirements.

Q. HOW IS EXCESS ADIT DETERMINED?

A. The Excess ADIT calculation measures the ADIT balance existing **immediately prior** to the reduction in the corporate tax rate less the amount that would have been in the ADIT balance had that balance been determined using the revised lower corporate income tax rate. Because reductions in income tax expense will reduce revenue requirements and those reduced revenue requirements will affect income taxes, the Excess ADIT regulatory liability is "grossed-up" for income taxes at the aforementioned gross-up rate, net of an ADIT offset calculated by multiplying the ADIT regulatory liability times the combined statutory income tax rate.

Q. IF THERE IS AN INCREASE IN THE CORPORATE INCOME TAX RATE, WOULD THE REVERSE BE TRUE?

A. Yes. If the federal or state statutory income tax rate increases, following the same logic as discussed above, the ADIT would need to be remeasured. However, instead of an "excess" ADIT, there would likely be a "deficient" ADIT that would need to be addressed.

Q. CAN YOU EXPLAIN HOW THE REDUCTION IN THE FEDERAL CORPORATE INCOME TAX RATE AFFECTED ELIZABETHTOWN'S ADIT, INCLUDING EXCESS ADIT?

A. As mentioned, with the reduced income tax rate, regulated utilities remeasured their ADIT at December 31, 2017 using a 21 percent income tax rate instead of the 35 percent tax rate that had been previously applied to most of the book-tax basis differences. The resulting Excess ADIT was grossed-up and reclassified as a regulatory liability or regulatory asset depending on the nature of the book-tax difference. The Excess ADIT regulatory liability, net of an ADIT offset, established prior to the acquisition of Elizabethtown by SJI carries over to reduce the revenue requirements of Elizabethtown's customers.

Q. DID THE TCJA ADDRESS HOW REGULATED PUBLIC UTILITIES WERE TO PASS BACK EXCESS ADIT?

A. Yes. The TCJA requires that Excess ADIT on protected book-tax differences reduce rates over the book lives of the related property no more rapidly than under ARAM or, if the necessary books and records are not available to compute the reversal under ARAM, an alternative approach, the Reverse South Georgia Method ("RSGM"), can be used. The RSGM is simple: determine the Excess ADIT and spread the amount over the estimated remaining useful lives of the assets giving rise to the Excess ADIT.

Q. HOW IS THE ARAM COMPUTED?

A. The ARAM requires the development of an average rate which is determined by dividing the aggregate normalized protected timing/temporary differences into the ADIT that have been provided on such timing/temporary differences. The average rate so calculated is applied to reversing timing differences to derive the deferred taxes that are credited to income tax expense. Under this approach, protected ADIT are reduced over the remaining lives of the property which gave rise to the ADIT as the timing/temporary differences reverse. Public utilities must take care to properly apply the ARAM to protected ADIT because a normalization violation could occur if the amount of protected excess ADIT is reduced more rapidly or to a greater extent than under the ARAM.

Q. WHAT WOULD HAPPEN IF THE EXCESS ADIT IS REVERSED MORE RAPIDLY THAN ARAM ON PROTECTED EXCESS ADIT?

A. The normalization requirements would be violated resulting in an increase in current income taxes payable for the amount of the more rapid reduction, and more importantly, accelerated depreciation methods could not be used for income tax purposes going forward. Rather, book depreciation would have to be used for income tax purposes, reducing future ADIT, to the detriment of customers.

Q. DOES THE TCJA PRESCRIBE A METHOD FOR REVERSING EXCESS ADIT ON "UNPROTECTED" EXCESS ADIT?

A. No. Prior to the TCJA, the ADIT provided on all book-tax differences typically reversed at the tax rate used to record the deferred tax expense when the book-tax difference originated; however, the TCJA does not contain such a requirement on the Excess ADIT on unprotected book-tax differences. Reversal of the balance of unprotected ADIT is thus up to a decision by the utility and its regulator.

Q. HOW IS THE COMPANY RETURNING EXCESS ADIT TO CUSTOMERS?

A. In the Company's last rate case, the ARAM methodology was used to reverse protected excess ADIT, consisting mostly of depreciation method and life differences. That same methodology is being used in this rate case.

Q. HOW DID ELIZABETHTOWN CALCULATE THE ARAM REVERSAL OF PROTECTED EXCESS ADIT?

A. Prior to SJI's acquisition of the Company, a year-by-year run-out schedule was prepared by Elizabethtown's previous owner reversing the Excess ADIT using the ARAM methodology. The Excess ADIT calculations at December 31, 2017 were the subject of a stipulation submitted to the Board and approved in its June 29, 2018 Order in Docket Nos. AX18010001 and GR18030232. Such amounts were used to determine Excess ADIT test year balances and amortization in the Company's last rate case. That run-out schedule is being used to determine the test year ARAM reversal in this proceeding.

Q. HOW DID YOU DETERMINE THE AMOUNT OF PROTECTED EXCESS ADIT REVERSING IN THE TEST YEAR?

A. As of April 1, 2021, the remaining unamortized excess ADIT balance for protected book-tax differences was $79,677,173. Per the run-out schedules provided by Elizabethtown's previous parent, ARAM amortization for 2021 is $1,114,751 ($92,896 per month). From the same run-out schedules, the ARAM amortization in 2022 is scheduled at $1,162,097 ($96,841 per month). In the test year, ARAM amortization is calculated by taking nine months of 2021 amortization and three months of 2022 ARAM amortization, producing the test year ARAM amortization of $1,126,588. As of March 31, 2022, the unamortized protected excess ADIT balance (reducing rate base) is $78,550,586.

The normalization rules require consistency between rate base components (Property, Plant and Equipment; Accumulated Depreciation; ADIT, including

Excess ADIT). Because Elizabethtown determines these other components using an end of period rate base, the rate base reduction for Excess ADIT at the end of the test period was used.

Q. HOW DID YOU DETERMINE THE AMOUNT OF UNPROTECTED EXCESS ADIT AND THE DEFICIENT ADIT RELATING TO THE COMPANY'S NOL?

A. In the Company's last rate case, a five-year amortization period was used to reduce both the unprotected excess ADIT and the deficient ADIT NOL asset balances. In the test period for this rate case, the following amounts are included as a reduction to test period income tax expense:

Reversing April 1, 2021-March 31, 2022:

Unprotected excess ADIT: ($733,523) ($61,127/month x 12 months)

Deficient NOL ADIT Asset: $ 256,713 ($21,393/month x 12 months)

Q. HAVE YOU INCLUDED A SCHEDULE SHOWING THESE CALCULATIONS?

A. Yes. Schedule ADF-3 shows the balances and monthly reversals for the protected excess ADIT, the unprotected excess ADIT and the deficient NOL ADIT Asset for 2021 and 2022, incorporating the April 1, 2021 to March 31, 2022 test period.

Q. HOW DO THESE AMOUNTS ENTER INTO THE REVENUE REQUIREMENT CALCULATION?

A. The property-related Excess ADIT balance at March 31, 2022 ($78,550,586) and the deficient NOL ADIT Asset balance at that date ($192,534) reduce rate base (rate base reduction of $78,358,051).

The previously discussed test year amortization of these three excess/deficient ADIT components reduces income tax expense by $1,603,398 (ARAM - $1,126,588, Unprotected excess - $733,523, Deficient NOL - $256,713) which will reduce revenue requirements at a grossed-up amount when run through the revenue requirement calculation.

Q. DOES THIS CONCLUDE YOUR DIRECT TESTIMONY?

A. Yes.

CURRICULUM VITAE

ALAN D. FELSENTHAL

EDUCATIONAL BACKGROUND

June, 1971	B.S. in Accounting University of Illinois Champaign, Illinois
May, 1972	Certified Public Accountant

EMPLOYMENT

2010-	Managing Director, Power and Utilities and member of PricewaterhouseCoopers LLP's Complex Accounting and Regulatory Solutions ("CARS") practice.
2008-2010	Managing Director-Utilities Industry Huron Consulting Group
2002-2007	Managing Director—Utilities Industry PricewaterhouseCoopers LLP
1985-2002	Principal in Utilities and Telecommunications Practice, Arthur Andersen LLP, Chicago
1976-1985	Manager in Utilities and Telecommunications Practice, Arthur Andersen LLP, Chicago
1971-1976	Staff and Senior Accountant, Arthur Andersen LLP, Utilities and Telecommunications Division, Chicago

TESTIMONY EXPERIENCE

Testified before the Illinois Commerce Commission on behalf of Town Gas Company of Illinois, 1985. Accounting witness covering cost of service issues.

Testified before the Illinois Commerce Commission on behalf of Town Gas Company of Illinois, 1986. Generic hearing regarding high gas costs.

Testified before the Florida Public Service Commission on behalf of Central Telephone Company of Florida (1991). Testimony addressed projected test year, a computer model we developed to simplify forecast procedures and propriety of including pension asset in rate base.

Submitted an expert report and testified in an appeal by Yellow Cab Company versus the City of Chicago, (2000). Topic dealt with the adequacy of taxicab lease rates. Yellow Cab was appealing the lease rates they were permitted to charge lessees. The model developed by the City of Chicago to set lease rates was based on traditional utility ratemaking principles. Was hired by the City of Chicago to review Yellow Cab's appeal compared to traditional ratemaking principles and submit a report. Yellow Cab appealed the decision and a hearing before a judge resulted.

Testified before the Arizona Corporation Commission on behalf of Tucson Electric Power Company, 2008. Rebuttal testimony addressed application of FAS 71 when a portion of the business was opened to competition and appropriate treatment of the FAS 143 cost of removal regulatory liability.

Testified before the Florida Public Service Commission on behalf of Tampa Electric Company and Peoples Gas, (2008). Direct testimony on income taxes, including the appropriate accumulated deferred income tax calculation when a projected test period is used.

Testified before the Washington Utilities and Transportation Commission on behalf of Avista Corporation, (2008).

Testified before the Illinois Commerce Commission on behalf of The Peoples Gas, Light and Coke Company/North Shore Gas Company (2009). Rebuttal and Surrebuttal testimony on the appropriate treatment of prepaid pension asset in rate base.

Testified before the Indiana Utility Regulatory Commission on behalf of Northern Indiana Public Service Company (2009). Rebuttal testimony on the appropriate treatment of cost of removal vis a vis FAS 143.

Submitted an expert report and a reply expert report to a Seattle-based arbitration panel in a dispute involving Grays Harbor Energy LLC vs. Energy Northwest, 2009. Subject involved the appropriate determination of fixed costs and cost of capital pursuant to a purchase and sale agreement.

Testified before the Public Utility Commission of Texas on behalf of CenterPoint Energy (2010). Direct and Rebuttal testimony on a number of income tax issues including consolidated income tax adjustments and FIN 48.

Testified before the Indiana Utility Regulatory Commission on behalf of Indianapolis Power & Light Company (2015). Rebuttal testimony on including prepaid pension asset in rate base.

Testified before the Public Utility Commission of Ohio on behalf of Dayton Power & Light Company (2015). Direct testimony on the results of a lead-lag study.

Submitted rebuttal testimony to the Indiana Utility Regulatory Commission on behalf of Northern Indiana Public Service Company (2016) on the appropriateness of including the prepaid pension asset in rate base.

Submitted an expert report to the Virginia State Corporation Commission regarding the allocation of Dominion Resources Inc. shared service costs to Virginia Electric Power Company (2016).

Submitted an expert report to the Oregon Public Service Commission regarding the capitalization of administrative and general overhead costs. (2017).

Testified before the Florida Public Service Commission on behalf of Tampa Electric Company and Peoples Gas on the subject of the appropriate treatment of excess Accumulated Deferred Income Taxes resulting from the Tax Cuts and Jobs Act (2018).

Testified before the Indiana Utility Regulatory Commission on behalf of Indianapolis Power & Light Company (2018). Rebuttal testimony supporting a return on the Company's prepaid pension asset.

Testified before the FERC on behalf of GridLiance West (2018). Direct testimony supporting the derivation and reasonableness of the Company's Start-Up Regulatory Asset.

Submitted rebuttal testimony to the Indiana Utility Regulatory Commission on behalf of Northern Indiana Public Service Company (2019) on reasons why including a return on the Company's prepaid pension asset is appropriate.

Submitted direct testimony to the New Jersey Board of Public Utilities on behalf of Elizabethtown Gas Company (2019) discussing consolidated income tax adjustments and Excess Accumulated Deferred Income Taxes being passed on to customers after the acquisition of the Company from Southern Company by South Jersey Industries.

Submitted direct testimony to the Hawaii Public Utilities Commission on behalf of Young Brothers (2019) on a number of income tax topics (Excess Accumulated Deferred Income Taxes, including the NOL Deferred Tax Asset in Rate Base, treatment of the Hawaii Capital Goods Excise Tax Credit) and including the prepaid pension asset in rate base.

Participated on accounting panels before the Maine Public Utilities Commission supporting 1) a market study of Central Maine Power Company's shared service costs and 2) the treatment of Excess Accumulated Deferred Income Taxes (2019).

Submitted rebuttal testimony before the Utah Public Service Commission on pension accounting symmetry in connection with the rate case of Dominion Energy Utah (2019).

Submitted direct testimony to the New Jersey Board of Public Utilities on behalf of South Jersey Gas Company (2020) discussing consolidated income tax adjustments and Excess Accumulated Deferred Income Taxes being passed on to customers using the Average Rate Assumption method for protected book-tax differences to comply with the Tax Cuts and Jobs Act.

Participated on a panel before the Connecticut Public Regulatory Authority supporting GenConn Energy LLC's Accumulated Deferred Income Taxes in their Revenue Requirement proceeding (2020).

Submitted direct and rebuttal testimony and was cross-examined before the Public Service Commission of West Virginia for Dominion Energy West Virginia (Hope Gas) supporting 1) the treatment of excess Accumulated Deferred Income Taxes 2) why it is inappropriate to include Accumulated Deferred Income Tax and Excess Accumulated Deferred Income Tax balances as a rate base offset when the book-tax difference relates to costs not being recovered in revenue requirements 3) the need for consistency between the treatment of pension expense (credit), the prepaid pension asset and the related pension-related ADIT and 4) the inappropriateness of including a parent company loss adjustment. (2020/2021)

Submitted direct and rebuttal testimony and was cross-examined before the Public Service Commission of Missouri supporting Spire Missouri, Inc.'s 1) treatment of pension costs 2) the need to include the NOL ADIT Asset in rate base and 3) the appropriate treatment of excess ADIT (2020/2021).

REGULATORY CONSULTING EXPERIENCE

Synopsis—Throughout the late 1970's, the 1980's, 1990's, 2000's and 2010's assisted Andersen and PwC partners in the preparation of regulatory testimony covering a variety of accounting issues. Much of this testimony involved income tax accounting issues related to flow-through versus normalization or investment tax credit and the appropriate accounting and ratemaking treatment of excess accumulated deferred income taxes when statutory tax rates change. Also developed testimony on CWIP in rate base and working capital (lead-lag technique), appropriateness of allocation of service company costs to regulated entities, recovery of pre-operating cost regulatory assets and capital structure issues. Below are examples of such consuling projects.

In 2015, assisted with the preparation of an Expert Report for EverSource Energy subsidiary Connecticut Light & Power which was submitted to the Connecticut regulator. The issue concerned reopening a rate order to address the treatment of accumulated deferred income taxes which was incorrectly decided in the rate order.

In 2018, assisted with the preparation of a private letter ruling by American Transmission Company as to whether an internal transfer between a regulated and non-regulated partner would trigger the elimination of accumulated deferred income taxes that would need to be reflected on the books and records of the partnership.

In 2018, assisted with the preparation of an Expert Report for Enmax (in Alberta, Canada) supporting the capitalization of overheads. Issue involved explaining the increase in capitalized overheads compared to the prior rate case filing.

In 2018 and 2019, assisted with the preparation of Expert testimony and a private letter ruling discussing the appropriate income tax treatment of a like-kind exchange between Oncor and Sharyland. The issue concerned whether the accumulated deferred income taxes relating to the exchanged assets could carry over or would need to be eliminated.

In 2020, assisted in developing support for Hydro One's overhead capitalization in which PwC issued a report.

In 2021, performed time studies to support overhead capitalization for Liberty Utilities as well as reviewing the Company's cost allocation manual for potential improvements.

In 2021, supported rebuttal testimony for Southwestern Power on the issue of including the deficient NOL ADIT asset in rate base after the NOL itself had been utilized.

In 2021, supported rebuttal testimony for CenterPoint Arkansas supporting the removal of ADIT balances upon the sale of CenterPoint Arkansas asset.

Provided assistance on rate case testimony for the following companies:

- Ameritech Corporation
- Central Illinois Light Company
- Central Illinois Public Service Company
- Central Telephone Company of Florida
- Central Telephone Company of Nevada
- Central Telephone Company of Texas
- Connecticut Light and Power Company
- Dayton Power & Light Company
- Dominion Energy Utah
- Elizabethtown Gas Company
- El Paso Electric Company
- GridLiance Corporation
- Hawaiian Electric Companies
- Indiana Bell Telephone Company
- Indianapolis Power & Light Company
- Integrys Energy Group, Inc.
- Iowa-Illinois Gas and Electric Company
- Iowa Power Company

- New Mexico Gas Company
- Northern Indiana Public Service Company
- Pacific Gas & Electric Company
- Peoples Gas Systems (Tampa)
- PPL Montana (contract dispute)
- The Peoples Gas Light and Coke Company
- Public Service Company of New Mexico
- San Gabriel Valley Water Company
- Southern Bell Telephone Company
- South Jersey Gas Company
- Tampa Electric Company/Peoples Gas Company
- Transco Pipeline
- Young Brothers, Limited

Provided regulatory consulting for the Panama Canal Company. Tariffs charged to transit the Panama Canal were based on a cost of service approach. Assisted the Panama Canal Company in determining test year costs. Tariffs were established based on these costs.

2012-2020. Led several projects to evaluate a rate case filing prior to filing validating the completeness, accuracy, consistency and support of the filing. As a result, adjustments and edits were made to the filing to increase the credibility of the utility's filing. Provided a similar role with respect to date request responses and rebuttal testimony.

FINANCIAL CONSULTING EXPERIENCE

Assisted two Chinese utility companies in registration filings to have their shares traded on the New York Stock Exchange. Huaneng Power International and Shandong Huaneng Power Company were the first two Chinese utilities to list on the NYSE. Process involved working with attorneys, company personnel and the Securities and Exchange Commission to file the equivalent of a Form S-1.

Assisted a number of companies in the preparation, review and filing of Registration Statements with the SEC to raise debt and equity capital.

Consulted with an electric transmission company on whether costs charged to generation companies based on specific costs are in accordance with the costs permitted by the Federal Energy Regulatory Commission.

Consulted with Ameritech Corporation on a number of projects involving cost allocations and compliance with the Federal Communications Commission separations rules.

Consulted with several entities in the preparation of a private letter ruling request to determine whether certain regulatory/ratemaking approaches would violate the Internal Revenue Service ("IRS") normalization rules. Provided the ratemaking aspect of the request when, combined with income tax consulting assistance formed the basis for a complete request, accepted by the IRS.

FINANCIAL AUDIT EXPERIENCE

- Allegheny Energy
- Ameritech Cellular
- Ameritech Corporation
- Ameritech New Media
- Centel Corporation
- Chicago Skyway
- Constellation Energy
- Focal Communications
- Iowa-Illinois Gas and Electric Company
- Louisville Gas and Electric Company
- Nicor, Inc.
- Nisource
- Peoples Energy
- United Airlines
- Utilities, Inc.

LECTURES AND SEMINARS

Speaker at Edison Electric Institute/American Gas Association Introductory, Intermediate and Advanced Accounting Seminar 1996-2019.

Speaker at SNL (Regulatory Research Associates) Utility Foundations Seminar 2013-2017

Speaker at Power Plan Associates annual conference (2012, 2010, 2008, 2006, 2004, 2002) on recent accounting, regulatory and SEC matters affecting utilities.

Developed and conducted Utilities Industry Basic Accounting and Ratemaking Seminar. This two-day seminar is conducted each year for Andersen, Huron and PwC personnel assigned to utility audits or projects. In addition, the seminar is periodically offered on an open-registration basis for utility company personnel as well as offered and conducted for specific utility companies at their training sites.

Developed and conducted Utility Income Taxes-Accounting and Ratemaking Issues. This two-day or two-and-a-half day seminar has been conducted each year for Andersen, PwC and Huron personnel assigned to utility audits or income tax projects. The seminar focus is the accounting, tax return/compliance and financial statement aspects of utility income taxes taking into consideration the consequences of ratemaking/revenue requirements. In addition, the seminar is conducted annually on an open-registration basis for utility company personnel as well as offered and conducted for specific utility companies at their training sites.

Developed and conducted Rate Case Experience Seminar, a week-long seminar taking participants through the process of filing a rate case, including preparing direct testimony based on a mock case study and sitting for cross-examination. At the conclusion of the seminar, an Order is presented. The course is conducted each year on an open-registration basis for utility company personnel as well as offered and conducted for specific utility companies at their training sites.

Specific examples of special training conducts for utility companies/regulators are as follows:

- Alaska Regulatory Commission

- American Electric Power
- American Water Works
- Ameritech Corporation
- Arizona Public Service Company
- Arkansas Public Service Commission
- Centerpoint Energy
- Cleco Corporation
- Consolidated Edison
- Consumers Power Company
- Dominion Resources
- Duke Energy
- Enbridge Pipeline
- Entergy Corporation
- Exelon Corporation
- Federal Energy Regulatory Commission
- Georgia Power Company
- Illinois Commerce Commission
- Louisville Gas and Electric Company
- National Grid
- Natural Gas Pipeline Company of America
- Nicor, Inc.
- Nisource, Inc.
- Northwest Pipeline
- Oklahoma Corporation Commission
- One Gas Corporation
- Pembina Pipeline
- Peoples Energy
- Pepco Holdings, Inc.
- PG&E Corporation
- Portland General Electric Company
- PPL Corporation
- Qwest Corporation
- Sempra Energy
- Southern California Edison Company
- Sprint Corporation
- Tampa Electric Company
- The Southern Company
- Transco Pipeline
- Tucson Electric Power
- Williams Pipeline
- Xcel Energy

PROFESSIONAL ASSOCIATIONS

American Institute of Certified Public Accountants

Illinois CPA Society

Exhibit P-10

PRELIMINARY PUBLIC COPY

** The confidential version of this schedule will be provided after the execution of a Non-Disclosure Agreement.

Schedule ADF-2

REDACTED

		(A)	(B)	(C)	(D)	(E)
	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]						
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]			[redacted]	[redacted]	[redacted]

[redacted]

EXCESS ADIT REVERSAL Schedule ADF-3

	Depreciation-related (ARAM)	Unprotected (5 year) (See Note)	NOL (5 year) (See Note)	Total per Stipulation/Previous Rate Case
Excess ADIT Balance December 31, 2020	**$ 80,679,833**	**$ 1,961,715**	**$ (513,426)**	**$ 82,128,122**
Tax Return true-ups and other miscellaneous adj to tie to final Southe	$ (254,085)	$ (762,074)		$ (1,016,159)
2018 ARAM True-up / Amortization True-up	$ (638,947)	$ 53,481		$ (585,466)
2019 ARAM True-up / Amortization True-up	$ 671,895	$ 106,962		$ 778,857
2020 ARAM True-up / Amortization True-up	$ (502,835)	$ 106,962		$ (395,873)
Excess ADIT Balance at December 31, 2020, as adjusted	**$ 79,955,861**	**$ 1,467,046**	**$ (513,426)**	**$ 80,909,481**
Jan-21	$ (92,896)	$ (61,127)	$ 21,393	$ (132,630)
Feb-21	$ (92,896)	$ (61,127)	$ 21,393	$ (132,630)
Mar-21	$ (92,896)	$ (61,127)	$ 21,393	$ (132,630)
Apr-21	**$ (92,896)**	**$ (61,127)**	**$ 21,393**	**$ (132,630)**
May-21	**$ (92,896)**	**$ (61,127)**	**$ 21,393**	**$ (132,630)**
Jun-21	**$ (92,896)**	**$ (61,127)**	**$ 21,393**	**$ (132,630)**
Jul-21	**$ (92,896)**	**$ (61,127)**	**$ 21,393**	**$ (132,630)**
Aug-21	**$ (92,896)**	**$ (61,127)**	**$ 21,393**	**$ (132,630)**
Sep-21	**$ (92,896)**	**$ (61,127)**	**$ 21,393**	**$ (132,630)**
Oct-21	**$ (92,896)**	**$ (61,127)**	**$ 21,393**	**$ (132,630)**
Nov-21	**$ (92,896)**	**$ (61,127)**	**$ 21,393**	**$ (132,630)**
Dec-21	**$ (92,896)**	**$ (61,127)**	**$ 21,393**	**$ (132,630)**
Estimated excess ADIT reversals 2021	**$ (1,114,751)**	**$ (733,523)**	**$ 256,713**	**$ (1,591,561)**
Excess ADIT Balance December 31, 2021	**$ 78,841,110**	**$ 733,523**	**$ (256,713)**	**$ 79,317,920**
Jan-22	**$ (96,841)**	**$ (61,127)**	**$ 21,393**	**$ (136,576)**
Feb-22	**$ (96,841)**	**$ (61,127)**	**$ 21,393**	**$ (136,576)**
Mar-22	**$ (96,841)**	**$ (61,127)**	**$ 21,393**	**$ (136,576)**
Apr-22	$ (96,841)	$ (61,127)	$ 21,393	$ (136,576)
May-22	$ (96,841)	$ (61,127)	$ 21,393	$ (136,576)
Jun-22	$ (96,841)	$ (61,127)	$ 21,393	$ (136,576)
Jul-22	$ (96,841)	$ (61,127)	$ 21,393	$ (136,576)
Aug-22	$ (96,841)	$ (61,127)	$ 21,393	$ (136,576)
Sep-22	$ (96,841)	$ (61,127)	$ 21,393	$ (136,576)
Oct-22	$ (96,841)	$ (61,127)	$ 21,393	$ (136,576)
Nov-22	$ (96,841)	$ (61,127)	$ 21,393	$ (136,576)
Dec-22	$ (96,841)	$ (61,127)	$ 21,393	$ (136,576)
Estimated excess ADIT reversals 2022	$ (1,162,097)	$ (733,523)	$ 256,713	$ (1,638,907)
Excess ADIT Balance December 31, 2022	$ 77,679,013	$ (0)	$ 0	$ 77,679,013
*********** *********** ******************	******************	** ** ******************	** * ****************** * *	******************
Test Year reversal (April 1, 2021 to March 31, 2022)	$ (1,126,588)	$ (733,523)	$ 256,713	$ (1,603,398)
				$ -
Excess ADIT balance at March 31, 2022	$ 78,550,586		$ (192,534)	$ 78,358,051

Note: The 5 year amortization for the Unprotected Excess ADIT and the NOL ADIT Asset began Januaryt 1m 2018m upon remeasurement of the ADIT balances due to the enactment of the TCJA.

IN THE MATTER OF THE PETITION OF ELIZABETHTOWN GAS COMPANY FOR APPROVAL OF INCREASED BASE TARIFF RATES AND CHARGES FOR GAS SERVICE, CHANGES TO DEPRECIATION RATES AND OTHER TARIFF REVISIONS

BPU DOCKET NO. GR__________

DIRECT TESTIMONY

OF

DANIEL P. YARDLEY

On Behalf Of
Elizabethtown Gas Company

Exhibit P-11

December 28, 2021

TABLE OF CONTENTS

ELIZABETHTOWN GAS COMPANY
DIRECT TESTIMONY OF
DANIEL P. YARDLEY

I. INTRODUCTION

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

A. My name is Daniel P. Yardley. I am Principal, Yardley Associates, and my business address is 2409 Providence Hills Drive, Matthews, North Carolina 28105.

Q. ON WHOSE BEHALF ARE YOU TESTIFYING?

A. I am testifying on behalf of Elizabethtown Gas Company ("Elizabethtown" or the "Company").

Q. PLEASE SUMMARIZE YOUR PROFESSIONAL AND EDUCATIONAL BACKGROUND.

A. I have been employed as a consultant to the natural gas industry for over 30 years. During this period, I have directed or participated in numerous consulting assignments on behalf of local distribution companies ("LDCs"). A number of these assignments involved the development of gas distribution company cost allocation, pricing, service unbundling, revenue decoupling and other tariff analyses. In addition to this work, I have performed interstate pipeline cost of service and rate design analyses, gas supply and capacity planning analyses, and financial evaluation analyses. I received a Bachelor of Science Degree in Electrical Engineering from the Massachusetts Institute of Technology.

Q. HAVE YOU PREVIOUSLY TESTIFIED BEFORE THE NEW JERSEY BOARD OF PUBLIC UTILITIES AND OTHER REGULATORY BODIES?

A. Yes. Over the last 20 years, I have testified before the New Jersey Board of Public Utilities (the "BPU") on various ratemaking and regulatory matters including rate unbundling, cost allocation, service design, rate design, revenue decoupling, cost recovery mechanisms and tariff design. My testimony in various proceedings has been presented on behalf of Elizabethtown, New Jersey Natural Gas Company and South Jersey Gas Company. I have also testified in proceedings before several other state utility regulatory commissions, the Federal Energy Regulatory Commission, and the Canada Energy Regulator on a variety of rate and regulatory topics. A summary of my previous expert testimony is provided as Attachment A to my direct testimony.

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

A. I have been asked by Elizabethtown to evaluate the manner in which it recovers its base distribution revenue requirements from customers and to propose changes that are consistent with the nature of the services it provides as well as important rate design objectives. In this regard, my testimony addresses two topics. First, I will describe the Company's rate design goals, which appropriately reflect important public policy and industry developments. Second, I will support the derivation of specific rates and charges for distribution services that fairly apportion the Company's revenue requirement among customer classes. The new charges are based on appropriate rate design considerations including the results of an allocated cost of service study ("ACOSS") performed in a consistent manner with other elements of the Company's filing.

Q. PLEASE SUMMARIZE YOUR RECOMMENDATIONS.

A. The following four findings and recommendations are supported through my direct testimony:

(1) **Elizabethtown's Conservation Incentive Program ("CIP") provides an appropriate foundation for the Company's base rate structure.** The

CIP aligns the financial interests of Elizabethtown and its customers with respect to energy consumption by adjusting margin recoveries for changes in customer use. This rate mechanism promotes important rate design goals and recognizes the important role of utilities in promoting the most efficient use of energy by customers. As such, Elizabethtown's rate design, which incorporates the CIP, contributes to longer term consumer and environmental benefits.

(2) **The majority of Elizabethtown's fixed distribution costs are recovered through variable charges applied to customer usage.** Recovering a portion of the base revenue increase through fixed charges is necessary to appropriately balance revenue stability with rate moderation considerations.

(3) **The cost of distribution service provided to Elizabethtown's residential customers is subsidized through service provided to commercial and industrial customers.** The results of the ACOSS demonstrate that the Company is currently providing service to residential customers at a below-average rate of return and that remaining classes subsidize the cost of residential service. Further, within the residential class, non-heating customers receive the greatest level of subsidy.

(4) **Elizabethtown's proposed rates recover the proposed revenue requirements in an appropriate manner.** The Company's rate design proposal reflects an equalized percentage increase in rates to all rate classes. The only exception is to limit the increase to the Natural Gas Vehicle

("NGV") rate schedule to one-half the average overall percentage base revenue increase.

Q. DO YOU SPONSOR ANY SCHEDULES AS PART OF YOUR TESTIMONY?

A. Yes. I sponsor the following schedules, which were prepared by me or under my supervision and direction and which I discuss in greater detail later in my testimony:

Schedule DPY-1: Allocated Cost of Service Study;

Schedule DPY-2: Allocation of Proposed Revenue Adjustments to Customer Classes; and

Schedule DPY-3: Summary of Existing and Proposed Rates and Revenues.

II. <u>DEVELOPMENT OF ELIZABETHTOWN'S RATE DESIGN GOALS</u>

Q. WHAT RELATIONSHIP EXISTS BETWEEN A UTILITY'S RATE DESIGN AND ENERGY POLICY OBJECTIVES?

A. From a public policy perspective, rate design is a critically important tool for achieving specific energy policy goals that influence the quality of life for New Jersey's citizens and the State's competitive position. Policy goals affected by rate design include end-use fuel mix, energy efficiency and the resulting environmental and cost impacts of energy consumption. Therefore, the form of a utility's rate structure is an important building block that can contribute to achieving important energy policy goals.

The nexus between rate design and energy policy objectives has been receiving increased attention throughout the U.S., due in large part to the prevalence of throughput-based rate designs. Throughput-based rate designs recover a substantial portion of LDC fixed-cost revenue requirements through volumetric charges applied to the amount of natural gas consumed by customers. The inherent operating incentives under this form of rate structure are for the LDC to add new customers and to promote increased consumption by its existing customers. The incentive to increase consumption by current customers is at odds with other public policy goals that favor energy conservation and reductions in customer energy bills. These policy goals are being pursued through programs run by LDCs such as Elizabethtown that promote increased energy efficiency to their customers. Better-aligning the form of rate design with these goals enables LDCs to fully embrace the energy efficiency imperative while also meeting financial responsibilities to shareholders, regulators and customers alike.

Q. WHAT COMMON APPROACHES HAVE BEEN IMPLEMENTED TO ADDRESS THE THROUGHPUT INCENTIVE ASSOCIATED WITH TRADITIONAL LDC RATE DESIGNS?

A. Regulators in many individual jurisdictions have approved various types of rate design changes that address the shortcomings associated with traditional rate designs that recover the majority of LDC fixed costs through variable charges. The changes include fixed-cost rate design approaches as well as revenue decoupling mechanisms. The BPU recently approved a CIP for Elizabethtown that incorporates changes to the way that the Company recovers its fixed costs from residential and commercial customers.[1]

Q. HOW DOES THE CIP ADDRESS THE THROUGHPUT INCENTIVE ASSOCIATED WITH ELIZABETHTOWN'S UNDERLYING RATE DESIGN?

A. A fundamental tenet of the CIP Tariff is the alignment of Elizabethtown's financial interests with those of its customers with respect to reductions in total energy costs to

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[1] *I/M/O the Implementation of* L. *2018,* C. *17 Regarding the Establishment of Energy Efficiency and Peak Demand Reduction Programs* and *I/M/O the Petition of Elizabethtown Gas Company for Approval of New Energy Efficiency Programs and Associated Cost Recovery Pursuant to the Clean Energy Act and the Establishment of a Conservation Incentive Program*, BPU Docket Nos. QO19010040 and GO20090619, "Order Adopting Stipulation" (Apr. 7, 2021).

customers. In particular, the base revenue impacts of any customer savings from energy efficiency and conservation do not contribute negatively to the Company's financial performance. The CIP Tariff mitigates fixed cost recovery concerns that would otherwise be present when customers reduce consumption. At the same time, the lower consumption results in reduced gas supply commodity costs. The CIP and other similar programs adopted in other jurisdictions are recognized as supporting important local and national policy goals to lower energy use and reduce the associated environmental impacts.

Q. PLEASE DESCRIBE ELIZABETHTOWN'S RATE DESIGN GOALS THAT GUIDED THE RATE DESIGN APPROACH YOU RECOMMEND.

A. The rate design approach I am recommending seeks to achieve the following six goals:

(1) **Fairness** – Fairness is accomplished through pricing services based on the underlying cost. Fairness is important in many respects including; (i) between the Company and its customers, (ii) across rate classes served by Elizabethtown, and (iii) among customers taking service under a common rate schedule.

(2) **Not Discriminatory** – Avoiding undue discrimination requires rates that do not grant an unreasonable preference or subject any customer or group of customers to an unreasonable disadvantage.

(3) **Rate Moderation** – Moderation allows for the implementation of price changes over time to ensure that customers are not exposed to dramatic price changes all at once.

(4) **Revenue Stability** – Revenue stability means that Elizabethtown's base rate revenues are more predictable in view of future uncertainties. As

customer usage patterns have become less certain, improved revenue stability through rate design takes on greater importance as a way of mitigating the increased risks to customers and the Company associated with such unpredictable consumption patterns.

(5) **Energy Efficiency** – Reducing energy consumption through energy efficiency and conservation supports policy objectives that benefit customers and the environment.

(6) **Simplicity** – Simplicity means a rate structure that is easy for customers to understand and straightforward to administer.

III. ELIZABETHTOWN'S DISTRIBUTION RATE DESIGN

Q. PLEASE DESCRIBE THE COMPANY'S EXISTING RATE SCHEDULES.

A. Elizabethtown's existing rate schedules are segregated by sector, nature of service (firm or interruptible), customer size, and by end-use in some cases. Nearly 98 percent of the Company's customers are served under either the Residential Delivery Service ("RDS") or Small General Service ("SGS") rate schedules. These rate schedules provide service to small customers, with average annual use of approximately 885 therms for the RDS rate schedule and 1,375 therms for the SGS rate schedule. General service customers whose annual use exceeds 5,000 therms take service under the General Delivery Service ("GDS") rate schedule. The RDS, SGS and GDS rate schedules provide customers with the opportunity to purchase gas supply from Elizabethtown by paying the applicable Basic Gas Supply Service ("BGSS") rate or from a third-party supplier under the terms of the customer's contract with the supplier.

Large industrial customers, whose peak demands exceed 200 dekatherms per day in most cases, take service under one of the Company's industrial rate schedules. Firm industrial customers taking sales service as well as those purchasing supply from a third-party gas supplier are served under the Large Volume Demand ("LVD") rate schedule. Interruptible industrial customers purchasing supply from Elizabethtown take service under the Interruptible Sales ("IS") rate schedule, while interruptible customers purchasing supply from a third-party supplier take service under the Interruptible Transportation Service ("ITS") rate schedule.

Elizabethtown also provides service under rate schedules applicable to specific end-uses. Customers using natural gas to refuel vehicles are eligible to take service pursuant to the NGV rate schedule. Customers utilizing natural gas to fuel qualifying cogeneration facilities take service under the Electric Generation Firm Service ("EGF") or the Cogeneration Service Interruptible ("CSI") rate schedules. A limited number of customers are served under various other rate schedules targeted to specific end-uses including for Gas Light Service ("GLS") and public utility Contract Service ("CS") customers.

Q. WHAT RATES AND CHARGES ARE INCORPORATED INTO THE RDS AND SGS RATE SCHEDULES?

A. The existing rate design for these rate schedules is similar and includes two types of base rate charges that are intended to recover Elizabethtown's non-gas revenue requirements or cost of service: (i) a monthly fixed customer charge and (ii) distribution charges applicable to monthly volumes. Fixed monthly customer charges are applied per customer per month and distribution charges are applied to each customer's monthly usage. Under this rate structure, all customers pay a minimum monthly amount to Elizabethtown equal to the fixed customer charge, regardless of their monthly usage. The rate design also results in customers paying higher amounts as their consumption increases due to the per-therm distribution charge. The distribution charge is considered a variable charge because all associated revenues are linked to customer usage or throughput.

For RDS service, the monthly fixed charge is $9.38 and the volumetric charge is $0.4110 per therm. The monthly fixed charge for SGS service is $25.33 and the volumetric charge is $0.3570 per therm. These prices, and all others described throughout my testimony, exclude the New Jersey Sales and Use Tax and regulatory assessments.

Q. PLEASE DESCRIBE THE RATES INCORPORATED IN ELIZABETHTOWN'S RATE SCHEDULES GDS, LVD AND EGF.

A. The base rates applicable to the GDS, LVD and EGF rate schedules incorporate a demand charge in addition to a monthly fixed charge and volumetric charges. The demand charge is an important means of recovering fixed, peak-related costs from customers in an equitable manner. The base rates for the GDS rate class are a monthly fixed charge of $35.17 and a monthly demand charge of $0.900 per therm of peak daily contract demand. A distribution charge of $0.2158 applies to all use, except for air conditioning and distributed generation use during the summer months of May through October. GDS customers that qualify for an economic development discount receive a 50 percent discount off the applicable distribution charge. The base rates for the LVD rate class are a monthly fixed charge of $304.81, a monthly demand charge of $1.250 per therm of contract demand and a distribution charge of $0.0400 per therm of monthly use. Lastly, the base rates for the EGF rate class are a monthly fixed charge of $70.34, a monthly demand charge of

$0.600 per therm of contract demand and a distribution charge of $0.0395 per therm of monthly use.

Q. WHAT RATES AND CHARGES ARE INCORPORATED INTO THE NGV RATE SCHEDULE?

A. NGV service is compressed natural gas for use as a motor vehicle fuel delivered to customers at stations that may be owned by a customer or by Elizabethtown. The rates for NGV service incorporate three variable charges applied to NGV service usage. The first is a distribution charge that is comparable to the charges for other commercial customers. The second is a fueling charge that is intended to recover operating costs of the refueling station. Lastly, a facilities charge is applied to recover the costs of a typical refueling station that exceed ten times expected revenues. If the Company owns and operates an NGV refueling station on a customer's property, it may enter into an agreement that sets forth negotiated fueling station and facilities charges that differ from the tariff charges.

Q. DID YOU PERFORM AN ACOSS TO SUPPORT YOUR RATE DESIGN RECOMMENDATIONS?

A. Yes. I believe that an ACOSS provides an important means of assessing the reasonableness of existing prices and to guide the development of price changes. In particular, the ACOSS that I performed for Elizabethtown examines all of the Company's common costs reflected in its base rate petition, and through appropriate cost assignments and allocations, establishes measures of investments, expenses and income by customer class. The ACOSS is an important tool because many of the Company's costs are common and are incurred to serve many classes of customers collectively.

The ACOSS calculates the total investment and operating costs incurred to serve each customer class, thereby establishing class-specific total revenue requirements. The class-specific revenue requirements are compared to class revenues in order to establish class income and rate of return on investment. The class-specific rates of return are used to guide the apportionment of the revenue requirements among all of Elizabethtown's customer classes in conjunction with the development of proposed rates. The ACOSS also determines the classification of costs among demand, customer and volumetric components. The classification of costs within a rate classification is used to guide the development of the form of billing rates for that class. Although the ACOSS is not the only factor relied upon to design rates, it is an invaluable guide to ensuring that the process is fair and reasonable.

Q. PLEASE DESCRIBE THE GENERAL COSTING METHODOLOGY THAT IS INCORPORATED IN THE ELIZABETHTOWN ACOSS.

A. The most significant consideration in the development of an ACOSS is the methodological approach to allocating fixed demand costs. The ACOSS performed for Elizabethtown reflects a system design approach to the allocation of fixed demand costs that closely follows principles of cost causation. A full description of the Elizabethtown ACOSS and detailed results are presented in Schedule DPY-1.

Q. PLEASE SUMMARIZE THE RESULTS OF THE ACOSS.

A. The primary results from the ACOSS are the rate of return by class and the unit customer and demand-related costs. The ACOSS demonstrates that the rates of return for the Residential Heating, and Residential Non-Heating customers are less than the system-average rate of return of 3.71% at present rates. The residential class is by far

Elizabethtown's largest class. The rate of return for all other classes, except NGV, is above the system-average, indicating that these classes are subsidizing the prices for residential customers. Table 1 provides a summary of the rate of return by class.

Table 1

Rate of Return by Class and

	ACOSS Rate of Return	Unitized
Residential Heating	1.1%	0.3
Residential Non-Heating	(5.5%)	(1.5)
SGS	4.8%	1.3
GDS	26.3%	7.1
LVD	22.2%	6.0
NGV	0.4%	0.1
Non-Firm	19.9%	5.4
Overall	3.7%	1.0

With respect to unit costs, the ACOSS indicates that the system-wide average customer cost is $59 per month, and the cost generally varies with the size of the customer. The lowest average customer cost of $55 per month is indicated for the residential non-heating class. A comparison of existing monthly customer charges to customer-related costs is presented in Table 2.

Table 2

Comparison of Existing Customer Charges and Customer-Related Costs

	Existing Customer Charge	Customer-Related Cost	Difference
Residential Heating	$9.38	$56.66	$47.28
Residential Non-Heating	$9.38	$55.17	$45.79
SGS	$25.33	$62.28	$36.95
GDS	$35.17	$106.03	$70.86
LVD	$304.81	$1,592.08	$1,287.27
Non-Firm	$589.50	$3,086.05	$2,496.55

The significant variance between monthly customer-related costs and existing customer charges is taken into consideration when designing the intra-class rate design.

Q. WHAT STEPS DID YOU EMPLOY TO ESTABLISH THE SPECIFIC BASE RATES YOU ARE PROPOSING?

A. First, I determined the class-by-class revenue requirements, which reflect the results of the ACOSS and other rate design principles. Next, I evaluated the existing level of customer charges and proposed increases, where appropriate, to recover a greater proportion of customer-related costs through monthly fixed customer charges. Lastly, I established the appropriate rate structure and rate levels to recover the remaining portion of class revenue requirements.

Q. HOW DID YOU DEVELOP THE CLASS-BY-CLASS REVENUE REQUIREMENTS?

A. I first calculated the level of existing base revenues from each customer class taking into account Infrastructure Investment Program ("IIP") revenues. This calculation is provided in Schedule DPY-2, Column (D). I am proposing to allocate the proposed incremental base revenue increase of $76.6 million reflected on Exhibit P-3, Schedule TK-1 to all rate classes in proportion to existing base revenues. The only exception to this approach is for the NGV rate class, where I propose to limit the increase to one-half of the overall base revenue increase as a means of supporting the continued development of alternate fuel vehicle use in New Jersey. The resulting base revenues by rate class for proposed rates are reflected in Schedule DPY-2, Column (F).

Q. WHAT FACTORS GUIDED YOUR RECOMMENDATION THAT THE PROPOSED REVENUE INCREASE BE APPLIED ON AN EQUAL PERCENTAGE BASIS TO ALL RATE CLASSES?

A. The results of the ACOSS are one consideration in the development of proposed rates. The ACOSS results indicate that the greatest areas of concern are the monthly customer charges and the rate of return for the residential non-heating class. Another important consideration is the current rate structure including the CIP and the level of fixed and variable charges. In addition, the historic level of returns and existing rates for each class are important considerations, as is the need to develop prices that are fair and not unduly discriminatory. Taking into account all of these factors, I believe that applying the revenue increase on an equal percentage basis to all rate classes is reasonable and appropriate in this case as it reflects an emphasis on needed changes to intra-class rate design.

Q. WHY IS THE LEVEL OF THE MONTHLY FIXED CUSTOMER CHARGE IMPORTANT?

A. The level of the monthly fixed customer charge is important for a variety of reasons that relate to the Company's rate design goals I described earlier. First, the monthly fixed customer charge provides customers with an important price signal concerning the impact of connecting to Elizabethtown's distribution system. Second, recovering customer-related costs through monthly fixed customer charges contributes to intra-class fairness. To the extent that a portion of customer-related costs are recovered through volumetric charges, intra-class subsidies are created as larger customers pay a disproportionate share of customer-related costs. Third, the fixed monthly customer charge provides revenue stability as fixed costs that are incurred to serve customers are recovered through a fixed charge.

Q. WHAT MONTHLY FIXED CUSTOMER CHARGE DO YOU PROPOSE FOR THE RESIDENTIAL CLASS?

A. While it is desirable to recover a greater proportion of the class revenue requirement increase through the customer charge, I am limiting the increase to the residential customer charge in order to reduce the impacts to residential non-heating customers. For the residential class, the proposed customer charge is $12.45 per month. A larger increase would be needed to bring the charge closer to the cost-based level indicated by the ACOSS and to address the very low rate of return for residential non-heating customers. The higher residential customer charge reduces the increases needed to volumetric charges in order to recover the class-specific revenue requirements. Even with the increase to the residential customer charge, 78 percent of the target revenue requirements of the class are recovered through the volumetric charge under the proposed residential rates.

Q. HOW DID YOU DERIVE THE VARIABLE DELIVERY CHARGES APPLICABLE TO RESIDENTIAL CUSTOMERS?

A. The remaining revenue requirements allocated to the residential class are recovered through the variable delivery charge. The resulting distribution charge is $0.6025 per therm.

Q. PLEASE EXPLAIN THE PROPOSED CHANGES TO THE BASE RATES FOR THE SGS CLASS.

A. I am proposing to increase the monthly SGS customer charge from $25.33 to $34.50 and the distribution charge from $0.3570 to $0.5248 per therm. The proposed changes to SGS base rates moderately increase the recovery of fixed costs through fixed charges.

Q. PLEASE EXPLAIN THE PROPOSED CHANGES TO THE BASE RATES FOR THE GDS CLASS.

A. I am proposing to increase the monthly GDS customer charge from $35.17 to $58.00 and the monthly demand charge from $0.900 to $1.090 per therm per Demand Charge Quantity ("DCQ"). The remainder of the base revenue change is recovered through an increase to the distribution charge from $0.2158 to $0.3453 per therm. I am proposing to change the distribution charge for air conditioning use from $0.0552 to $0.0607 per therm.

Q. PLEASE EXPLAIN THE PROPOSED CHANGES TO THE BASE RATES FOR THE LVD CLASS.

A. I am proposing to increase the monthly LVD customer charges from $304.81 to $380.00 and the monthly demand charge from $1.250 to $1.750 per therm per DCQ. The remainder of the base revenue change is recovered through an increase to the distribution charge from $0.0400 to $0.0614 per therm.

Q. PLEASE EXPLAIN THE PROPOSED CHANGES TO THE BASE RATES FOR THE EGF CLASS.

A. I am proposing to increase the monthly EGF customer charge from $70.34 to $95.00 and the monthly demand charge from $0.600 to $0.750 per therm per DCQ. I am proposing to maintain the distribution charge of $0.0395 per therm.

Q. PLEASE EXPLAIN THE PROPOSED CHANGES TO THE BASE RATES FOR NON-FIRM IS AND ITS CLASSES.

A. I am proposing to increase the existing monthly customer charge for the IS and ITS classes from $589.50 to $690.00. I am also proposing to increase the monthly demand charge for IS customers from $0.092 to $0.252 per therm per DCQ and for ITS customers from $0.400 to $0.500 per therm per DCQ. I am proposing to maintain the IS distribution charge of $0.0791 per therm. For ITS customers, I am proposing to change the distribution charge from $0.0926 to $0.1305 per therm.

Q. ARE YOU PROPOSING ANY CHANGES TO THE RATES FOR NGV SERVICE?

A. I am proposing to increase the NGV service distribution charge from $0.3133 to $0.4500 per therm, the fueling charge from $0.3600 to $0.4100 per therm and the facilities charge from $0.2987 to $0.3771 per therm.

Q. HAVE YOU PREPARED A SUMMARY OF THE PROPOSED RATE CHANGES?

A. Yes. The existing and proposed rates for each class are compared in Schedule DPY-3. In addition, Schedule DPY-3 provides a proof of revenues demonstrating that the proposed charges yield the requested base revenue increase based on the Company's forecasts of sales and customers.

Q. PLEASE COMMENT ON THE IMPACT OF THE PROPOSED RATE CHANGES ON ELIZABETHTOWN'S RECOVERY OF ITS OVERALL BASE DISTRIBUTION COSTS OF PROVIDING SERVICE TO CUSTOMERS.

A. The majority of Elizabethtown's revenue requirements are associated with ensuring ongoing reliability of service and safety to customers and the communities the Company serves. These costs are all fixed in nature and do not increase or decrease with the level of natural gas consumed by customers. The rate design changes that I propose moderately improve the recovery of reliability and safety expenses by more closely aligning them with the manner in which these costs are incurred. Even so, the majority of Elizabethtown's revenue requirements continue to be recovered through variable charges that are dependent on customer throughput. While the proposed rates do not eliminate existing subsidies, moderate improvement in intra-class revenue responsibility is achieved through the application of the proposed revenue increase among individual rate elements. In my view, the proposed rates in this proceeding result from a fair and reasonable rate design approach balancing the rate design goals described earlier in my testimony.

Q. DOES THIS CONCLUDE YOUR PREPARED DIRECT TESTIMONY?

A. Yes, it does.

ELIZABETHTOWN GAS
ALLOCATED COST OF SERVICE STUDY

I. PURPOSE AND GUIDING PRINCIPLES

Elizabethtown Gas Company ("Elizabethtown") is proposing to change existing rates in connection with a proposed increase in base rate revenue requirements. An allocated cost of service study ("ACOSS") assesses the reasonableness of existing prices, and guides the development of price changes. In particular, the ACOSS examines all of a utility's common costs, and through appropriate cost assignments and allocations, establishes measures of investments, expenses and income by customer class. An ACOSS is necessary to determine the cost responsibility for each customer class because many of the Company's costs are common and are incurred to serve many classes of customers collectively.

The ACOSS calculates the total investment and operating costs incurred to serve each customer class, establishing class-specific total revenue requirements. The class-specific revenue requirements are compared to class revenues in order to establish class income and rate of return on investment. The class-specific rates of return are one element considered in the apportionment of the base rate increase among all of Elizabethtown's customer classes in conjunction with the development of proposed rates. The ACOSS also determines the classification of costs among demand, customer and commodity components. The classification of costs within a rate classification is used to guide the development of the form of billing rates for that class. Although the ACOSS is not the only factor relied upon to design rates, it is an invaluable guide to ensuring that the process is fair and reasonable.

The primary principle that guides the ACOSS process is that of cost causation. Each step in the development of the ACOSS is consistent with the factors that drive or contribute to the incurrence of costs on the Elizabethtown system. For example, the principle of cost causation requires that the costs incurred by the Company for billing be apportioned to classes on the basis of the number of bills issued or customers in each class.

II. Specification of Elizabethtown ACOSS

A. Overview

The ACOSS follows a three-part process, which consists of the functionalization, classification and allocation of Elizabethtown's total cost of service. First, cost functionalization involves the segregation of costs into categories based on the function that each cost is incurred to provide. In the ACOSS, the functions are production, transmission, storage and distribution – the direct functions associated with costs incurred by the Company. Second, cost classification further separates costs according to the primary cost causative forces exhibited on Elizabethtown's system. The cost classifications used in the ACOSS relate to fixed costs required to serve peak requirements (demand-related), fixed costs associated with providing customers with access to and active status on the system (customer-related), and variable costs associated with system throughput (commodity-related). Finally, cost allocation takes each classification of cost for each function and apportions that cost to each of the Company's customer classes. Cost allocation utilizes a variety of factors to apportion the various types of costs among classes in a manner that is consistent with principles of cost responsibility.

B. Customer Classes

The ACOSS includes seven customer groupings, which are: Residential Heating, Residential Non-Heating, Small General Service ("SGS"), General Delivery Service ("GDS"), Firm Industrial, Natural Gas Vehicle ("NGV"), and Non-Firm Industrial.

The Residential Heating and Residential Non-Heating customers are served under the same rate schedule, Residential Delivery Service ("RDS"); however, the two types of customers are studied separately to guide the design of the customer and delivery rates that apply to RDS customers. This approach provides for the evaluation of the cost of serving subsets of customers with disparate characteristics served under a common rate schedule. Residential Non-Heating customers have much lower use than Residential Heating customers and also have a much higher load factor, both of which have important implications for designing rates that are revealed by separating the groups in the ACOSS.

The Firm Industrial customer group includes industrial customers serviced under both the Large Volume Demand ("LVD") and Firm Transportation Service ("FTS") rate schedules. Similarly, the Non-Firm Industrial customer group includes customers served under the Interruptible Sales ("IS") and Interruptible Transportation Service ("ITS") rate schedules.

B. Data Sources

The primary data sources fall in two general categories: data related to the establishment of the total cost of service, and data used as the basis for allocating the total cost of service among customer classes. The total cost of service or revenue requirement data utilized in the ACOSS are taken from schedules supporting Elizabethtown's base rate application in this proceeding. The Company's forecasts of sales, customers and revenues by class supporting the application, as adjusted for pro forma changes, are used as allocation bases for several categories of costs. The remaining allocation data are derived from special studies of facility or operating costs. All of the data utilized in the ACOSS correspond to a common time period of April 2021 through March 2022, as adjusted for known changes through December 2022. This is Elizabethtown's adjusted test year, which is the period for which rates are to be determined.

C. Cost Functionalization

The functionalization of costs refers to the segregation of costs among the primary functions provided by gas utilities to their retail customers. The chart of accounts prescribed by the New Jersey Board of Public Utilities separates the majority of costs into the following four functions:

- *Production:* The production function includes costs associated with the upstream commodity gas supply, interstate pipeline transportation capacity necessary to deliver the supply to Elizabethtown's system, and upstream storage facilities. Additionally, the costs of any production facilities and the administrative costs associated with procuring natural gas and transportation are categorized as production-related.

- *Storage:* The storage function includes costs associated with on-system facilities that are able to receive injected supplies or delivered liquid natural gas for later withdrawals.

- *Transmission:* The transmission function includes costs associated with large diameter, high pressure facilities that deliver gas to smaller distribution facilities. Transmission facilities include transmission mains and compressors.

- *Distribution:* The distribution function includes costs associated with delivering supplies within areas that are close in proximity to gas loads, such as distribution mains. The costs associated with connecting customers to the distribution system are also considered distribution-related, which include costs associated with services, meters and regulators.

The majority of Elizabethtown's non-gas supply costs are associated with the distribution function. Costs that do not directly fall into one of these primary functions, such as administrative and general expenses, are functionalized on the same basis as other related costs.

D. Cost Classification

Classification is the apportionment of costs among demand, customer and commodity categories. Each of Elizabethtown's rate base and expense accounts is classified consistent with the manner in which the associated costs are incurred. Costs that are associated with serving peak requirements on the system are classified as demand-related, e.g., costs associated with transmission accounts. Costs that are associated with providing customers access to and active status on the distribution system are classified as customer-related. Customer-related costs are incurred regardless of the amount of gas a customer consumes in any given period and include the costs of services, meters and regulators, and meter reading and billing expenses. Costs that are associated with the quantity of gas purchased or transported are classified as commodity-related. Examples of commodity-related costs are purchased gas costs. Demand and customer-related costs are considered fixed, while commodity-related costs are variable. Some categories of costs vary with more than one of the classifications described previously.

Lastly, some categories of costs are appropriately classified based on how other related costs are classified. For example, distribution operations supervision and engineering expenses are classified based on the classification of all other distribution operations accounts.

The Company's investment in distribution mains is its largest category of plant investment. The classification of distribution mains reflects the distinct cost causative factors that drive the Company's investments in these facilities. The first factor is the coincident peak demand on the system. Distribution mains are designed to deliver the maximum quantities that are required during a peak period from Elizabethtown's transmission pipelines or interstate pipeline interconnects to the interconnection with each individual customer service. The second factor is the number of customers on the system. Distribution mains are also designed to deliver supplies in reasonable proximity to customers in order to minimize the overall investment in pipe needed to collectively serve all customers.

The breakdown of distribution mains investment costs between the demand and customer-related components is determined through a minimum-size study. The premise underlying this study is that the size of distribution main installed in a given location is most affected by the peak load that will be served by the main, and that the length of distribution main is most affected by the number of customers that are served. The validity of this premise is supported by the system design criteria taken into consideration by the Company's distribution engineering staff.

The minimum size study evaluates the cost of replacing the existing distribution mains of the system under two different sets of assumptions. The first determines the cost of replacing existing distribution mains with the same type, diameter and lengths of pipe as is currently installed. The second determines the replacement cost assuming that the entire system is replaced with two-inch diameter plastic pipe, which is the smallest, least-expensive size and type of pipe presently being installed. The customer component of distribution mains is equal to the ratio of the replacement cost using the smallest size pipe to the replacement cost using the installed sizes of pipe. Based on the results of this study, 65.6% of Elizabethtown's distribution mains investment is classified as customer-related.

E. Cost Allocation

Cost allocation is the apportionment of individual elements of the Company's classified cost of service among rate classes based on each class' responsibility for the cost being incurred. Cost allocation follows cost causation principles and requires the development of numerous allocation factors that reflect the different types of costs included in Elizabethtown's overall revenue requirements. Considerable effort is required to yield the set of allocation factors underlying the ACOSS.

The ACOSS follows system-design criteria in order to allocate costs on the basis of cost causation. The demand allocator used in the ACOSS is the coincident design day demand factor. Under this method, the allocation of demand costs reflects the manner in which the Company designs, plans and constructs its system to satisfy firm demands. Off-peak loads do not increase the Company's demand-related investments, and therefore, are not factored into the demand allocator in a system-design ACOSS.

The other allocation factors used in the ACOSS may be grouped into three categories as follows: (i) class summary statistics reflected in the base rate filing, such as the number of customers and throughput by class; (ii) special studies that examine the costs associated with a specific type of investment or expense; and (iii) internal allocation factors, which are composite factors determined on the basis of how related cost items are allocated. All of the various factors must be developed assuming a consistent time period for the ACOSS to be accurate.

Six special studies were performed related to significant capital investment and operations and maintenance ("O&M") expense accounts. The studies are as follows:

- *Meter Investment Study:* The meter investment study establishes the aggregate investment in meters based on the type and replacement cost of various meters installed to serve each class.
- *Service Investment Study:* Elizabethtown's investment in distribution services is the largest investment on its books after the Company's investment in mains. The service investment study separates the cost of services into two categories using a minimum-size study comparable to the minimum size distribution mains study. While services investment is appropriately classified as customer-related, the minimum size approach allocates a proportion of services investments on the basis of peak consumption, reflecting the increased costs of services for customers with larger peak consumption.
- *Industrial Customer Investment Study:* The industrial customer investment study examines the Company's investments in services and meters to serve the largest customers on the system.
- *Working Capital Study:* The working capital study examines the components of Elizabethtown's proposed working capital allowance. A composite

allocator is derived from the allocation of each component within the ACOSS.

- *Labor Expense Study:* A study of the Company's payroll expense examines components of the Company's payroll costs. The labor study is used as the basis for allocating costs that vary with direct payroll costs, such as pensions and benefits costs.

- *Write-offs Study:* The write-offs study examines historical write-offs for residential and non-residential customers.

Together, these special studies are utilized to allocate a substantial portion of the Company's total revenue requirements to customer classes.

III. Results

Detailed ACOSS results are provided in Schedule DPY-1, Attachment I. The first two pages of the attached results provide an income statement by class at existing and proposed rates, respectively. Pages three, four and five contain summaries of allocated rate base, O&M expense and total revenue requirements by classification and rate class. Lastly, page six provides a detailed analysis of the components of monthly customer-related costs.

The ACOSS demonstrates that the rates of return for the Residential Heating, and Residential Non-Heating customers are less than the system-average rate of return of 3.71% at present rates. The residential class is by far Elizabethtown's largest class. The rate of return for all other classes is above the system-average, indicating that these classes are subsidizing the prices for residential customers.

Monthly customer costs are derived from the costs that are classified as customer-related and the apportionment of these costs to Elizabethtown's various customer classes. The system-wide average monthly customer cost is $59, and the cost generally varies with the size of the customer. The lowest average customer cost of $55 per month is associated with serving the Residential Non-Heating class.

Exhibit P-11

Schedule DPY-1
Attachment 1
Page 1

Elizabethtown Gas
Income and Rate of Return at Present Rates

	Total System	Residential Heating	Residential Non-Heating	General Service SGS	General Service GDS	Firm Industrial	NGV	Non-Firm
REVENUES								
Margin Revenues	$ 223,721,787	$ 137,622,996	$ 7,400,762	$ 14,634,871	$ 50,192,677	$ 8,408,173	$ 50,225	$ 5,412,083
Rider Revenues	-	-	-	-	-	-	-	-
Miscellaneous Revenues	2,422,978	1,769,061	194,539	148,722	222,510	41,777	1,304	30,864
Total	**$ 226,144,765**	**$ 139,392,057**	**$ 7,595,301**	**$ 14,783,593**	**$ 50,415,187**	**$ 8,449,950**	**$ 51,528**	**$ 5,442,946**
OPERATING EXPENSES								
Operations and Maintenance	$ 86,892,019	$64,210,328	$6,758,014	$5,178,496	$8,443,461	$1,551,090	$4,286	$740,685
Depreciation and Amortization	60,832,003	44,417,807	4,943,275	3,835,527	5,697,997	1,069,978	31,881	835,539
Taxes Other Than Income Taxes	5,142,696	3,645,557	355,176	317,438	637,229	116,533	848	69,914
Total	**$ 152,866,718**	**$ 112,273,692**	**$ 12,056,464**	**$ 9,331,461**	**$ 14,778,687**	**$ 2,737,601**	**$ 37,015**	**$ 1,646,139**
OPERATING INCOME BEFORE TAXES	**$ 73,278,047**	**$ 27,118,365**	**$ (4,461,163)**	**$ 5,452,132**	**$ 35,636,500**	**$ 5,712,350**	**$ 14,513**	**$ 3,796,807**
INCOME TAXES								
Federal Income Taxes	$ 17,821,337	$ 13,011,690	$ 1,430,858	$ 1,093,870	$ 1,636,593	$ 307,276	$ 9,588	$ 227,006
State Income Taxes	6,033,796	4,405,387	484,448	370,353	554,104	104,035	3,246	76,858
Deferred Income Taxes	-	-	-	-	-	-	-	-
Total	**$ 23,855,133**	**$ 17,417,077**	**$ 1,915,306**	**$ 1,464,223**	**$ 2,190,696**	**$ 411,311**	**$ 12,834**	**$ 303,864**
RATEMAKING ADJUSTMENTS	**$ 2,225,191**	**$1,624,653**	**$178,658**	**$136,582**	**$204,347**	**$38,367**	**$1,197**	**$28,344**
NET INCOME	**$ 51,648,105**	**$ 11,325,942**	**$ (6,197,811)**	**$ 4,124,491**	**$ 33,650,151**	**$ 5,339,406**	**$ 2,876**	**$ 3,521,287**
	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
ADJUSTED NET INCOME	**$ 51,648,105**	**$ 11,325,942**	**$ (6,197,811)**	**$ 4,124,491**	**$ 33,650,151**	**$ 5,339,406**	**$ 2,876**	**$ 3,521,287**
RATE BASE	**$ 1,392,067,037**	**$1,016,374,065**	**$111,767,727**	**$85,444,762**	**$127,838,155**	**$24,002,063**	**$748,910**	**$17,732,002**
RATE OF RETURN AT PRESENT RATE	**3.71%**	**1.11%**	**-5.55%**	**4.83%**	**26.32%**	**22.25%**	**0.38%**	**19.86%**

Elizabethtown Gas
Income and Rate of Return at Proposed Rates

	Total System	Residential Heating	Residential Non-Heating	General Service SGS	General Service GDS	Firm Industrial	NGV	Non-Firm
REVENUES								
Margin Revenues	$ 300,337,638	$ 184,803,393	$ 9,892,497	$ 19,646,932	$ 67,381,015	$ 11,288,236	$ 58,827	$ 7,266,739
Rider Revenues	-	-	-	-	-	-	-	-
Miscellaneous Revenues	2,423,472	1,769,422	194,578	148,752	222,555	41,786	1,304	30,870
Total	**$ 302,761,110**	**$ 186,572,814**	**$ 10,087,075**	**$ 19,795,684**	**$ 67,603,571**	**$ 11,330,022**	**$ 60,130**	**$ 7,297,609**
OPERATING EXPENSES								
Operations and Maintenance	$ 87,401,378	$64,609,463	$6,779,478	$5,195,002	$8,500,071	$1,560,573	$4,343	$746,790
Depreciation and Amortization	60,832,003	44,417,807	4,943,275	3,835,527	5,697,997	1,069,978	31,881	835,539
Taxes Other Than Income Taxes	5,348,723	3,772,330	361,962	330,916	683,452	124,277	888	74,899
Total	**$ 153,582,104**	**$ 112,799,599**	**$ 12,084,714**	**$ 9,361,445**	**$ 14,881,519**	**$ 2,754,827**	**$ 37,112**	**$ 1,657,228**
OPERATING INCOME BEFORE TAXES	**$ 149,179,005**	**$ 73,773,215**	**$ (1,997,639)**	**$ 10,434,239**	**$ 52,722,051**	**$ 8,575,194**	**$ 23,018**	**$ 5,640,381**
INCOME TAXES								
Federal Income Taxes	$ 33,760,969	$ 24,649,512	$ 2,710,636	$ 2,072,241	$ 3,100,382	$ 582,108	$ 18,163	$ 430,044
State Income Taxes	11,430,500	8,345,621	917,744	701,601	1,049,701	197,085	6,149	145,600
Deferred Income Taxes	-	-	-	-	-	-	-	-
Total	**$ 45,191,469**	**$ 32,995,133**	**$ 3,628,380**	**$ 2,773,842**	**$ 4,150,083**	**$ 779,193**	**$ 24,312**	**$ 575,644**
RATEMAKING ADJUSTMENTS	**$ 2,225,191**	**$1,624,653**	**$178,658**	**$136,582**	**$204,347**	**$38,367**	**$1,197**	**$28,344**
NET INCOME	**$ 106,212,727**	**$ 42,402,735**	**$ (5,447,361)**	**$ 7,796,979**	**$ 48,776,315**	**$ 7,834,368**	**$ (97)**	**$ 5,093,081**
RATE BASE	**$ 1,392,067,037**	**$1,016,374,065**	**$111,767,727**	**$85,444,762**	**$127,838,155**	**$24,002,063**	**$748,910**	**$17,732,002**
RATE OF RETURN AT PROPOSED RAT	**7.63%**	**4.17%**	**-4.87%**	**9.13%**	**38.15%**	**32.64%**	**-0.01%**	**28.72%**

Elizabethtown Gas
Rate Base

	Total System	Residential Heating	Residential Non-Heating	General Service SGS	General Service GDS	Firm Industrial	NGV	Non-Firm
I. PLANT IN SERVICE								
Demand	$ 572,045,312	$ 336,060,594	$ 9,167,712	$37,295,075	$136,532,227	$32,452,501	$1,165,295	$19,371,908
Customer	1,418,914,786	1,107,893,106	148,182,977	85,720,154	54,497,493	7,837,939	8,515	14,774,603
Commodity	-	-	-	-	-	-	-	-
	$ 1,990,960,098	$1,443,953,700	$157,350,689	$123,015,228	$191,029,720	$40,290,439	$1,173,811	$34,146,510
II. ACCUMULATED RESERVE FOR DEPRECIATION								
Demand	$ 164,341,425	$ 98,201,348	$ 2,678,927	$10,898,114	$39,896,522	$8,627,823	$328,283	$3,710,407
Customer	314,693,663	235,314,084	31,509,778	18,769,202	12,596,277	5,749,463	1,999	10,752,859
Commodity	-	-	-	-	-	-	-	-
	$ 479,035,088	$333,515,432	$34,188,705	$29,667,316	$52,492,799	$14,377,287	$330,283	$14,463,267
III. NET PLANT IN SERVICE								
Demand	$ 407,703,887	$ 237,859,245	$ 6,488,785	$26,396,961	$96,635,706	$23,824,677	$837,012	$15,661,500
Customer	1,104,221,123	872,579,023	116,673,199	66,950,951	41,901,216	2,088,475	6,516	4,021,743
Commodity	-	-	-	-	-	-	-	-
	$ 1,511,925,010	$1,110,438,268	$123,161,984	$93,347,912	$138,536,922	$25,913,153	$843,528	$19,683,243
IV. RATE BASE ADDITIONS								
Demand	$ 36,187,889	$ 23,289,541	$ 1,025,538	$2,197,452	$5,813,312	$1,148,632	$5,775	$105,847
Customer	48,545,651	32,022,329	4,006,662	2,457,179	2,276,242	467,851	9,674	548,977
Commodity	-	-	-	-	-	-	-	-
	$ 84,733,540	$55,311,870	$5,032,200	$4,654,631	$8,089,554	$1,616,484	$15,448	$654,824
V. RATE BASE DEDUCTIONS								
Demand	$ (56,879,093)	$ (33,462,900)	$ (962,865)	($3,664,011)	($13,127,540)	($3,200,012)	($107,992)	($2,020,385)
Customer	(147,712,420)	(115,913,173)	(15,463,591)	(8,893,770)	(5,660,780)	(327,561)	(2,074)	(585,680)
Commodity	-	-	-	-	-	-	-	-
	$ (204,591,513)	($149,376,073)	($16,426,456)	($12,557,781)	($18,788,320)	($3,527,573)	($110,067)	($2,606,065)
VI. TOTAL RATE BASE								
Demand	**$ 387,012,683**	**$ 227,685,886**	**$ 6,551,458**	**$24,930,402**	**$89,321,478**	**$21,773,297**	**$734,794**	**$13,746,962**
Customer	**1,005,054,354**	**788,688,179**	**105,216,270**	**60,514,360**	**38,516,678**	**2,228,766**	**14,115**	**3,985,040**
Commodity	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**
	$ 1,392,067,037	**$1,016,374,065**	**$111,767,727**	**$85,444,762**	**$127,838,155**	**$24,002,063**	**$748,910**	**$17,732,002**

Elizabethtown Gas
O&M Expense

	Total	Residential		General Service		Firm		
	System	Heating	Non-Heating	SGS	GDS	Industrial	NGV	Non-Firm
I. PRODUCTION EXPENSE								
Demand	$ 285,199	$ 176,499	$ 4,815	$19,587	$71,707	$12,583	$9	$0
Customer	-	-	-	-	-	-	-	-
Commodity	-	-	-	-	-	-	-	-
	$ 285,199	$176,499	$4,815	$19,587	$71,707	$12,583	$9	$0
II. STORAGE EXPENSE								
Demand	$ 526,176	$ 325,630	$ 8,883	$ 36,137	$ 132,294	$ 23,214	$ 17	$ -
Customer	-	-	-	-	-	-	-	-
Commodity	-	-	-	-	-	-	-	-
	$ 526,176	$325,630	$8,883	$36,137	$132,294	$23,214	$17	$0
III. TRANSMISSION EXPENSE								
Demand	$ 1,525	$ 944	$ 26	$ 105	$ 384	$ 67	$ 0	$ -
Customer	-	-	-	-	-	-	-	-
Commodity	-	-	-	-	-	-	-	-
	$ 1,525	$944	$26	$105	$384	$67	$0	$0
IV. DISTRIBUTION EXPENSE								
Demand	$ 3,088,680	$ 1,911,464	$ 52,145	$212,129	$776,575	$136,269	$99	$0
Customer	6,405,351	5,065,642	679,615	371,621	203,085	29,918	31	55,439
Commodity	-	-	-	-	-	-	-	-
	$ 9,494,032	$6,977,105	$731,760	$583,750	$979,661	$166,186	$130	$55,439
V. CUSTOMER ACCOUNTS EXPENSE								
Demand	$ 943,225	$ 739,113	$ 39,746	$ 30,566	$ 104,830	$ 17,561	$ 105	$ 11,303
Customer	2,904,604	2,288,946	153,487	104,864	281,933	45,679	274	29,421
Commodity	-	-	-	-	-	-	-	-
	$ 3,847,828	$3,028,059	$193,233	$135,430	$386,763	$63,239	$379	$40,724
VI. CUSTOMER SERVICE AND SALES EXPENSE								
Demand	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Customer	1,930,342	1,567,298	213,219	108,105	41,120	312	6	281
Commodity	-	-	-	-	-	-	-	-
	$ 1,930,342	$ 1,567,298	$ 213,219	$ 108,105	$ 41,120	$ 312	$ 6	$ 281
VII. ADMINISTRATIVE AND GENERAL EXPENSE								
Demand	$ 21,614,465	$ 13,330,936	$ 363,903	$1,479,196	$5,413,789	$971,813	$3,572	$49,682
Customer	49,701,812	39,202,992	5,263,639	2,832,691	1,474,354	323,158	229	600,663
Commodity	-	-	-	-	-	-	-	-
	$ 71,316,277	$52,533,928	$5,627,542	$4,311,887	$6,888,142	$1,294,971	$3,802	$650,345
VIII. TOTAL O&M EXPENSE								
Demand	**$ 26,459,270**	**$ 16,484,585**	**$ 469,518**	**$ 1,777,721**	**$ 6,499,578**	**$ 1,161,506**	**$ 3,803**	**$ 60,985**
Customer	**60,942,109**	**48,124,878**	**6,309,960**	**3,417,282**	**2,000,493**	**399,067**	**540**	**685,804**
Commodity	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**
	$ 87,401,378	**$ 64,609,463**	**$ 6,779,478**	**$ 5,195,002**	**$ 8,500,071**	**$ 1,560,573**	**$ 4,343**	**$ 746,790**

Elizabethtown Gas
Total Revenue Requirements

		Total System	Residential Heating	Residential Non-Heating	General Service SGS	General Service GDS	Firm Industrial	NGV	Non-Firm
I. O&M EXPENSE									
	Demand	$ 26,459,270	$ 16,484,585	$ 469,518	$ 1,777,721	$ 6,499,578	$ 1,161,506	$ 3,803	$ 60,985
	Customer	60,942,109	48,124,878	6,309,960	3,417,282	2,000,493	399,067	540	685,804
	Commodity	-	-	-	-	-	-	-	-
		$ 87,401,378	$ 64,609,463	$ 6,779,478	$ 5,195,002	$ 8,500,071	$ 1,560,573	$ 4,343	$ 746,790
II. DEPRECIATION									
	Demand	$ 15,426,867	$ 9,226,723	$ 251,704	$ 1,023,956	$ 3,748,565	$ 806,098	$ 31,574	$ 338,247
	Customer	45,405,136	35,191,084	4,691,570	2,811,571	1,949,432	263,880	307	497,293
	Commodity	-	-	-	-	-	-	-	-
		$ 60,832,003	$ 44,417,807	$ 4,943,275	$ 3,835,527	$ 5,697,997	$ 1,069,978	$ 31,881	$ 835,539
III. TAXES OTHER THAN INCOME									
	Demand	$ 1,576,531	$ 965,294	$ 32,208	$ 106,082	$ 382,848	$ 70,823	$ 690	$ 18,587
	Customer	3,772,192	2,807,036	329,754	224,834	300,603	53,454	199	56,312
	Commodity	-	-	-	-	-	-	-	-
		$ 5,348,723	$3,772,330	$361,962	$330,916	$683,452	$124,277	$888	$74,899
IV. DEFERRED INCOME TAXES									
	Demand	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
	Customer	-	-	-	-	-	-	-	-
	Commodity	-	-	-	-	-	-	-	-
		$ -	$0	$0	$0	$0	$0	$0	$0
V. RATEMAKING ADJUSTMENTS									
	Demand	$ (618,632)	$ (363,951)	$ (10,472)	$ (39,851)	$ (142,779)	$ (34,804)	$ (1,175)	$ (21,974)
	Customer	(1,606,559)	(1,260,702)	(168,186)	(96,731)	(61,568)	(3,563)	(23)	(6,370)
	Commodity	-	-	-	-	-	-	-	-
		$ (2,225,191)	($1,624,653)	($178,658)	($136,582)	($204,347)	($38,367)	($1,197)	($28,344)
VI. RETURN									
	Demand	$ 29,529,068	$ 17,372,433	$ 499,876	$ 1,902,190	$ 6,815,229	$ 1,661,303	$ 56,065	$ 1,048,893
	Customer	76,685,647	60,176,908	8,028,001	4,617,246	2,938,823	170,055	1,077	304,059
	Commodity	-	-	-	-	-	-	-	-
		$ 106,214,715	$77,549,341	$8,527,878	$6,519,435	$9,754,051	$1,831,357	$57,142	$1,352,952
VII. INCOME TAXES									
	Demand	$ 12,563,814	$ 7,391,497	$ 212,684	$ 809,330	$ 2,899,694	$ 706,839	$ 23,854	$ 446,275
	Customer	32,627,655	25,603,636	3,415,696	1,964,512	1,250,389	72,354	458	129,369
	Commodity	-	-	-	-	-	-	-	-
		$ 45,191,469	$32,995,133	$3,628,380	$2,773,842	$4,150,083	$779,193	$24,312	$575,644
VIII. TOTAL REVENUE REQUIREMENTS									
	Demand	**$ 84,936,918**	**$ 51,076,581**	**$ 1,455,518**	**$ 5,579,427**	**$ 20,203,136**	**$ 4,371,764**	**$ 114,811**	**$ 1,891,014**
	Customer	**217,826,179**	**170,642,839**	**22,606,795**	**12,938,713**	**8,378,171**	**955,246**	**2,558**	**1,666,466**
	Commodity	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**
		$ 302,763,097	**$221,719,420**	**$24,062,313**	**$18,518,140**	**$28,581,307**	**$5,327,011**	**$117,369**	**$3,557,480**

Elizabethtown Gas
Monthly Customer Cost Detail

	Total System	Residential Heating	Residential Non-Heating	General Service SGS	General Service GDS	Firm Industrial	NGV	Non-Firm
I. AVERAGE CUSTOMER COSTS								
Customer-Related Revenue Req.	$ 217,746,756	$ 170,642,839	$ 22,606,795	$ 12,938,713	$ 8,378,171	$ 955,246	$ 2,558	$ 1,666,466
Average Customers	309,126	250,988	34,145	17,312	6,585	50	1	45
Average Monthly Customer Cost	**$ 58.70**	**$ 56.66**	**$ 55.17**	**$ 62.28**	**$ 106.03**	**$ 1,592.08**	**$ 213.19**	**$ 3,086.05**
II. MONTHLY CUSTOMER COST DETAIL								
O&M Expense								
Mains and Services Expense	$ 1.52	$ 1.51	$ 1.50	$ 1.53	$ 1.84	$ 0.81	$ 1.79	$ 0.81
Meter & Regulator Expense	0.13	0.09	0.09	0.18	0.64	48.78	0.71	101.36
Meter Reading Expense	0.03	0.03	0.03	0.03	0.03	0.03	0.03	0.03
Customer Records and Collections	0.09	0.09	0.09	0.09	0.09	0.09	0.09	0.09
Uncollectible Accounts	0.66	0.64	0.25	0.38	3.45	76.01	22.70	54.36
All Other O&M	13.99	13.61	13.44	14.23	19.26	539.39	19.69	1,113.35
Total O&M	$ 16.43	$ 15.98	$ 15.40	$ 16.45	$ 25.32	$ 665.11	$ 45.01	$ 1,270.01
Depreciation								
Mains	$ 2.60	$ 2.60	$ 2.60	$ 2.60	$ 2.60	$ 2.60	$ 2.60	$ 2.60
Services	4.06	4.03	3.92	4.11	5.93	-	5.61	-
Meters and Meter Installations	1.80	1.54	1.46	3.05	10.60	-	11.77	-
Regulators	0.11	0.09	0.09	0.18	0.63	-	0.70	-
All Other Depreciation	3.67	3.43	3.39	3.59	4.91	437.20	4.90	918.31
Total Depreciation	$ 12.24	$ 11.68	$ 11.45	$ 13.53	$ 24.67	$ 439.80	$ 25.58	$ 920.91
Taxes Other Than Income Taxes	$ 1.02	$ 0.93	$ 0.80	$ 1.08	$ 3.80	$ 89.09	$ 16.55	$ 104.28
Deferred Income Taxes	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Ratemaking Adjustments	$ (0.43)	$ (0.42)	$ (0.41)	$ (0.47)	$ (0.78)	$ (5.94)	$ (1.88)	$ (11.80)
Rate Base-Related (Return and Income Taxes)								
Mains	$ 12.55	$ 12.55	$ 12.55	$ 12.55	$ 12.55	$ 12.55	$ 12.55	$ 12.55
Services	13.06	12.96	12.62	13.22	19.09	-	18.05	-
Meters and Meter Installations	3.51	2.99	2.83	5.94	20.63	-	22.91	-
Regulators	0.23	0.19	0.18	0.38	1.33	-	1.48	-
All Other Rate Base-Related	0.11	(0.21)	(0.26)	(0.42)	(0.59)	391.46	72.94	790.09
Total Rate Base-Related	$ 29.47	$ 28.48	$ 27.93	$ 31.68	$ 53.01	$ 404.01	$ 127.93	$ 802.64
Total Average Monthly Customer Cost	**$ 58.72**	**$ 56.66**	**$ 55.17**	**$ 62.28**	**$ 106.03**	**$ 1,592.08**	**$ 213.19**	**$ 3,086.05**

Elizabethtown Gas
Allocation of Proposed Revenue Adjustments to Base Rates

Description (A)	Current Base Revenue (B)	IIP Revenue (C)	Current Base, Current Base and IIP Revenue (D) = (B) + (C)	Proposed Revenue Increase (E)	Proposed Base Revenues (F) = (D) + (E)
Rate Schedule Revenues:					
Residential Service	$ 135,848,720	$ 9,175,039	$ 145,023,759	$ 49,672,172	$ 194,695,931
Small General Service	13,751,629	883,242	14,634,871	5,012,598	19,647,469
General Delivery Service	46,913,033	3,279,644	50,192,677	17,191,523	67,384,200
LVD	7,883,730	524,443	8,408,173	2,879,888	11,288,062
Electric Generation Firm	-	-	-	-	-
Natural Gas Vehicle	46,221	4,004	50,225	8,600	58,825
Gas Lights	1,343	99	1,442	494	1,936
CSI	1,472	-	1,472	504	1,976
Interruptible Service	7,943	-	7,943	2,721	10,663
ITS-LVD	5,290,312	-	5,290,312	1,811,988	7,102,300
ITS-IS	112,356	-	112,356	38,483	150,839
Subtotal	$ 209,856,759	$ 13,866,471	$ 223,723,230	$ 76,618,971	$ 300,342,201
Other Revenues:					
Special Contract and Flex Revenues	$ 1,398,067	$28,012	$ 1,426,079	$ 575	$ 1,426,654
Other Miscellaneous Revenues	995,456	-	995,456	-	995,456
Subtotal	$ 2,393,523	$ 28,012	$ 2,421,535	$ 575	$ 2,422,110
Total Revenues	**$ 212,250,282**	**$ 13,894,483**	**$ 226,144,765**	**$ 76,618,396**	**$ 302,764,311**

Elizabethtown Gas
Base Rate Revenues at Present and Proposed Rates

Component (a)	Amount (b)	Units (c)	Present Rates Rate (d)	Present Rates Revenue (e)	Proposed Rates Rate (f)	Proposed Rates Revenue (g)
			RDS		RDS	
Residential Service						
Customer Charge	3,421,596	Bills	$ 9.38	$ 32,094,570	$ 12.45	$ 42,598,870
Distribution Charge	252,443,185	Therms	0.4110	103,754,149	0.6025	152,097,019
IIP Revenue				9,175,039		
Total Base Revenues				**$ 145,023,759**		**$ 194,695,889**
			SGS		SGS	
Small General Service						
Customer Charge	207,744	Bills	$ 25.33	$ 5,262,156	$ 34.50	$ 7,167,168
Distribution Charge	23,780,038	Therms	0.3570	8,489,474	0.5248	12,479,764
IIP Revenue				883,242		
Total Base Revenues				**$ 14,634,871**		**$ 19,646,932**
			GDS		GDS	
General Delivery Service						
Customer Charge	79,020	Bills	$ 35.17	$ 2,779,133	$ 58.00	$ 4,583,160
Demand Charge	22,336,313	Therms	0.900	20,102,682	1.090	24,346,581
Distribution	111,344,277	Therms	0.2158	24,028,095	0.3453	38,447,179
Distribution - A/C Large	32,668	Therms	0.0552	1,803	0.0607	1,983
Distribution - Economic Dev.	12,232	Therms	0.1079	1,320	0.1727	2,112
IIP Revenue				3,279,644		
Total Base Revenues				**$ 50,192,677**		**$ 67,381,015**
			LVD		LVD	
LVD						
Customer Charge	600	Bills	$ 304.81	$ 182,886	$ 380.00	$ 228,000
Demand Charge	4,507,025	Therms	1.250	5,633,781	1.750	7,887,294
Distribution	51,676,578	Therms	0.0400	2,067,063	0.0614	3,172,942
IIP Revenue				524,443		
Total Base Revenues				**$ 8,408,173**		**$ 11,288,236**

Elizabethtown Gas
Base Rate Revenues at Present and Proposed Rates

Component (a)	Amount (b)	Units (c)	Present Rates Rate (d)	Present Rates Revenue (e)	Proposed Rates Rate (f)	Proposed Rates Revenue (g)
			EGF		EGF	
Electric Generation Firm						
Customer Charge	0	Bills	$ 70.34	$ -	$ 95.00	$ -
Demand Charge	0	Therms	0.600	-	0.750	-
Distribution	0	Therms	0.0395	-	0.0395	-
IIP Revenue				-		
Total Base Revenues				**$ -**		**$ -**

Component (a)	Amount (b)	Units (c)	Present Rates Rate (d)	Present Rates Revenue (e)	Proposed Rates Rate (f)	Proposed Rates Revenue (g)
			NGV		NGV	
Natural Gas Vehicle						
Distribution Charge	47,552	Therms	$ 0.3133	$ 14,898	$ 0.4500	$ 21,398
Fueling Charge	47,552	Therms	0.3600	17,119	0.4100	19,496
Facilities Charge	47,552	Therms	0.2987	14,204	0.3771	17,932
IIP Revenue				4,004		
Total Base Revenues				**$ 50,225**		**$ 58,827**

Component (a)	Amount (b)	Units (c)	Present Rates Rate (d)	Present Rates Revenue (e)	Proposed Rates Rate (f)	Proposed Rates Revenue (g)
			Gas Lights		Gas Lights	
Gas Lights						
Service Charge		Mantles	$ 7.36	$ -	$ 10.61	$ -
Distribution	2,664	Therms	0.5041	1,343	0.7266	1,936
IIP Revenue				99		
Total Base Revenues				**$ 1,442**		**$ 1,936**

Elizabethtown Gas
Base Rate Revenues at Present and Proposed Rates

Component (a)	Amount (b)	Units (c)	Present Rates Rate (d)	Present Rates Revenue (e)	Proposed Rates Rate (f)	Proposed Rates Revenue (g)
			CSI		CSI	
CSI						
Customer Charge	12	Bills	$ 122.65	$ 1,472	$ 164.67	$ 1,976
Distribution	0	Therms	0.0300	-	0.0300	-
Total Base Revenues				**$ 1,472**		**$ 1,976**

Component (a)	Amount (b)	Units (c)	Present Rates Rate (d)	Present Rates Revenue (e)	Proposed Rates Rate (f)	Proposed Rates Revenue (g)
			IS		IS	
Interruptible Service						
Customer Charge	12	Bills	$ 589.50	$ 7,074	$ 690.00	$ 8,280
Demand Charge	9,444	Therms	0.092	869	0.252	2,380
Distribution	0	Therms	0.0791	-	0.0791	-
Total Base Revenues				**$ 7,943**		**$ 10,660**

Component (a)	Amount (b)	Units (c)	Present Rates Rate (d)	Present Rates Revenue (e)	Proposed Rates Rate (f)	Proposed Rates Revenue (g)
			ITS-LVD		ITS-LVD	
ITS-LVD						
Customer Charge	420	Bills	$ 589.50	$ 247,590	$ 690.00	$ 289,800
Demand Charge	4,277,425	Therms	0.400	1,710,970	0.500	2,138,713
Distribution	35,980,038	Therms	0.0926	3,331,752	0.1305	4,695,395
Total Base Revenues				**$ 5,290,312**		**$ 7,123,907**

Component (a)	Amount (b)	Units (c)	Present Rates Rate (d)	Present Rates Revenue (e)	Proposed Rates Rate (f)	Proposed Rates Revenue (g)
			ITS-IS		ITS-IS	
ITS-IS						
Customer Charge	120	Bills	$ 589.50	$ 70,740	$ 690.00	$ 82,800
Demand Charge 1/	289,000	Therms	0.400	41,616	0.500	47,396
Distribution	0	Therms	-	-	-	-
Total Base Revenues				**$ 112,356**		**$ 130,196**

Elizabethtown Gas
Base Rate Revenues at Present and Proposed Rates

Component	Amount	Units	Present Rates Rate	Present Rates Revenue	Proposed Rates Rate	Proposed Rates Revenue
(a)	(b)	(c)	(d)	(e)	(f)	(g)
TOTAL SYSTEM BASE DISTRIBUTION REVENUES				***$ 223,723,230***		***$ 300,339,574***
Other Revenues						
Special Contract and Flex Revenues				**$ 1,426,079**		**$ 1,426,654**
Other Miscellaneous Revenues				**995,456**		**995,456**
Total Other Revenues				**$ 2,421,535**		**$ 2,422,110**
TOTAL SYSTEM INCLUDING OTHER REVENUES				***$ 226,144,765***		***$ 302,761,684***

INCREASE	**76,616,919**
TARGET INCREASE	**76,618,971**
Difference	**($2,052)**

1/ ITS-IS demand charge revenues reduced by 80% sharing above $0.08