ELIZABETHTOWN GAS

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February 29, 2024

Electronic Filing

Sherri L. Golden
Board Secretary
NJ Board of Public Utilities
44 South Clinton Avenue, 1st Floor
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 Golden,

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 New Jersey Board of Public Utilities' ("BPU") e-Filing rules.

Schedule E to the Petition (Exhibit P-1) and Schedules JLH-1 and JLH-2 to the Direct Testimony of John L. Houseman (Exhibit P-5) each contain information that is non-public confidential financial information. Accordingly, this filing only contains the preliminary public version of Schedule E to the Petition and Schedules JLH-1 and JLH-2 to Mr. Houseman's testimony. On this same day, a filing is being made pursuant to the Open Public Records Act (N.J.S.A. 47:1A-1 et seq. and N.J.A.C. 14:1-12.1 et seq.) that contains the full confidential version of this filing.

In accordance with the BPU's March 19, 2020 and June 10, 2020 Orders issued in Docket No. EO20030254, hard copies are not being submitted at this time, but can be provided at a later time, if needed.

If you have any questions, please feel free to contact me directly.

Respectfully submitted,

Dominick DiRocco

Dominick DiRocco

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. __________

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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

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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

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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 "Company") proposes to increase its base tariff rates, modify its depreciation rates and implement certain other tariff revisions, including the implementation of an Uncollectible Adjustment Clause to account for fluctuations in uncollectible costs, 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 $276.3 million of plant additions, net of retirements, that are not currently reflected in rates, and projects that an additional $213.4 million of capital investment, net of retirements, will be added to the Utility Plant In Service balance by December 31, 2024. 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 and reliable natural gas service for Elizabethtown's customers.

With these investments, the Company must be given the opportunity to earn a fair return on and 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 base rate case. Such under-earnings could negatively impact Elizabethtown's ability to attract capital at reasonable rates, which will in turn negatively impact customers.

As demonstrated in this filing, Elizabethtown's projected operating revenues for the twelve-month period ending June 30, 2024 (utilizing six months of actual data and six months of estimated data) total $457,198,140. Inclusive of post-test year *pro forma* adjustments, the rates proposed in this filing would yield additional total operating revenues of $75,558,923, representing an increase of approximately 16% above adjusted post-test year revenues of $470,797,010. 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 heating customer using 100 therms per month would be $21.92 or 15.8%. 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" or "BPU") for authority pursuant to N.J.S.A. 48:2-21, 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, establish and/or recover certain regulatory assets, and to implement certain other tariff revisions, including the implementation of an Uncollectible Adjustment Clause ("UAC") to account for fluctuations in uncollectible costs. 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 herein, 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 316,000 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"), which in turn is owned by IIF US Holding 2, LP ("IIF"), a private equity fund.[1]

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; GR21121254, effective September 1, 2022; GR22070466, effective June 7, 2023; ER23060409 and GR23040270, effective October 1, 2023; GR23060335, effective December 1, 2023; and GR23070476, GR23070477 and GR23070478, effective February 15, 2024.

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.

[1] The acquisition of SJI by IIF (the "Merger") was approved in the Board's January 25, 2023 Order in BPU Docket No. GM22040270 *In the Matter of the Merger of South Jersey Industries, Inc. and Boardwalk Merger Sub, Inc.* ("2023 Merger Order"). Upon such acquisition, SJI became a privately-held company.

Kaufmann as Schedule TK-24 and is also incorporated herein by reference. It is requested that the Proposed Tariff be made effective September 1, 2024, in compliance with the 2023 Merger Order.[2]

II. BASE RATES

5. Petitioner's projected operating revenues for the twelve-month test year period ending June 30, 2024 (utilizing six months' actual data and six months' estimated data) total $457,198,140. Inclusive of post-test year *pro forma* adjustments, the rates proposed in this Petition would yield additional operating revenues of $75,558,923, or approximately 16 percent above adjusted post-test year revenues of $470,797,010.

6. The impact of this Petition on the bill of an average residential heat customer using 100 therms per month would be an increase of $21.92 or 15.8 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, 2023 was $405,415,985. Petitioner proposes to establish rates based on a post-test year rate base of $1,862,108,979.

8. The Company proposes to include a Cash Working Capital allowance in rate base of $50,475,720. This is based, in part, on a lead-lag study sponsored in the Direct Testimony of Timothy S. Lyons, attached to the Petition and marked as Exhibit P-8.

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[2] In the 2023 Merger Order, the Board adopted a stipulation in which it was agreed that Elizabethtown would not file another base rate case "for new rates effective prior to two (2) years from the effective date of the Board's Order" in Elizabethtown's previous base rate case ("2021 Base Rate Case"). The effective date of the rates approved in Elizabethtown's 2021 Base Rate Case was September 1, 2022. *See I/M/O The Petition of Elizabethtown Gas Company For Approval Of Increased Base Tariff Rates And Changes For Gas Service, Changes To Depreciation Rates And Other Tariff Revisions*, BPU Docket No. GR21121254 "Decision And Order Adopting Initial Decision And Stipulation" dated August 17, 2022 ("August 17 Order"). Elizabethtown is filing its base rate petition at this time in order to afford the Board, its Staff and other parties the opportunity to resolve this proceeding prior to the proposed rates effective date of September 1, 2024.

9. Petitioner's filing proposes a return on equity of 10.75 percent applied to a capital structure that consists of 57 percent common equity and 43 percent long-term debt, which results in an overall rate of return of 8.31 percent. Petitioner's proposed capital costs and cost of capital are discussed in the Direct Testimony of Ann E. Bulkley, attached to the Petition and marked as Exhibit P-7.

10. Further, the Company has calculated a consolidated tax adjustment ("CTA"), as required by N.J.A.C. 14:1-5.12(a)(11) and determined that no adjustment should be applied in this case. The Company's CTA calculation is attached to the Petition and marked as Exhibit P-1, Schedule E. After the execution of an Agreement of Non-Disclosure, a proposed version of which is included with this filing as Exhibit P-1, Schedule C, a CTA 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 June 30, 2024. Petitioner is proposing to reflect changes in certain capital expenditures through December 31, 2024 and changes in certain revenues and expenses through March 31, 2025. These post-test year changes are being made in a manner consistent with the Board's May 23, 1985 decision in *In Re Elizabethtown Water Company Rate Case*, BPU Docket No. WR8504330.

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 June 30, 2024 will reflect actual results.

13. Petitioner has implemented an Infrastructure Investment Program ("IIP") in accordance with the Board's June 12, 2019 Order in BPU Docket No. GR18101197, which authorized the Company to implement an IIP to invest up to $300 million over a five-year period

beginning July 1, 2019 and ending June 30, 2024. As discussed by Company witness Thomas Kaufmann, the Board authorized the Company to include IIP investment costs from July 1, 2021 through June 30, 2022 and from July 1, 2022 through June 30, 2023 in rates on a provisional basis by Orders dated September 28, 2022 and September 27, 2023 in BPU Docket Nos. GR22040316 and GR23040270, respectively. Petitioner is proposing to roll these IIP Investment costs into the rates to be established in this proceeding on a final basis. The Direct Testimony of the Engineering Panel, attached to the Petition and marked as Exhibit P-4, discusses the prudence of Petitioner's capital expenditures under the IIP.

III. NEED FOR RATE RELIEF

14. Since the conclusion of Elizabethtown's 2021 Base Rate Case, 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 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 2021 Base Rate Case was resolved by the Board's August 17 Order in which the Board authorized Petitioner to increase its base rates by approximately 9.7%. In that proceeding, Petitioner's test year end Utility Plant In Service ("UPIS") balance at March 31, 2022, excluding Year 3 IIP amounts, was $1.867 billion. Since that time, excluding IIP spending, Elizabethtown has made approximately $276.3 million of plant additions, net of retirements, that are not currently reflected in rates, and projects that an additional $213.4 million of capital investment, net of retirements, will be added to the UPIS balance by December 31, 2024, to ensure

that the Company's customers continue to receive safe and reliable natural gas service.[3] 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. For municipal projects, the Company endeavors to control costs by engaging with the municipalities before and during the project to minimize the costs associated with these projects and coordinating with other utility or municipal projects, where possible, in an effort to share costs.

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 2021 Base Rate Case. Without appropriate rate relief in this proceeding, allowing a reasonable return of and return on these investments, Elizabethtown would earn a 5.26 percent return on equity ("ROE") for the test year ended June 30, 2024. This represents a significant under-earning relative to the 9.60 percent ROE authorized by the Board in the Company's 2021 Base 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.

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[3] A proposed IIP ("IIP 2") is currently under consideration by the Board in BPU Docket No. GR23120882. As the proceeding remains pending, the Company has included projects that would otherwise fall within the scope of the IIP 2 in its post-test year capital expenditures as shown on Schedule EP-4 to Exhibit P-4. In the event that the IIP 2 proceeding reaches a resolution during this rate case that provides for a recovery of the costs of IIP 2 projects that are reflected in the proposed rates, the Company will remove investments included in a Board-approved IIP 2 from the post-test year expenditures in this proceeding.

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 the Engineering Panel, attached hereto as Exhibit P-4. These projects are necessary to improve Elizabethtown's transmission and distribution infrastructure and maintain safety and reliability.

19. Despite the Company's efforts to effectively manage costs while continuing to provide customers with safe and reliable service, ongoing infrastructure investments and related capital expenditures, combined with an increase in the cost of capital, the impact of historical inflation 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.

IV. COMPLIANCE WITH JUNE 22 ORDER AND 2023 MERGER ORDER

20. In July 2018, SJI, through an affiliate that is now Elizabethtown, acquired substantially all of the assets of Pivotal Utility Holdings, Inc. d/b/a Elizabethtown Gas. That transaction ("the 2018 Acquisition") was approved by the Board, subject to a number of conditions, by Order dated June 22, 2018 in BPU Docket No. GM17121309 ("June 22 Order").

21. Subsequently, in 2023, IIF acquired SJI in a merger transaction that was approved by the Board's 2023 Merger Order. The 2023 Merger Order imposed a number of conditions on its approval of the 2023 Merger, including the requirement that Elizabethtown continues to comply with all applicable continuing obligations including conditions imposed by the Board in connection with the 2018 Acquisition. Company witnesses Thomas Kaufmann, John Houseman and Ann Bulkley discuss Elizabethtown's compliance with all applicable conditions of the June 22 Order and the 2023 Merger Order.

V. UNCOLLECTIBLE ADJUSTMENT CLAUSE ("UAC")

22. The Company seeks to implement a UAC, as a component of its Rider "D" – Societal Benefits Clause ("SBC") to the Company's tariff, to protect itself and customers from variations in its uncollectible expense on a going-forward basis.

23. As discussed in the Direct Testimony of Thomas Kaufmann, under the UAC, the Company proposes to reconcile its actual uncollectible expense to the base level of uncollectible expense recovered in base rates and through the revenue factor used in deriving revenue requirements associated with Rider "E" – Energy Efficiency Program ("EEP Rider") and Rider "F" – Infrastructure Investment Program ("IIP Rider") to the Company's tariff. Any variance would be recovered from, or credited to, customers over a subsequent period.

24. This symmetrical reconciliation serves the interests of both the Company and customers by safeguarding against the variability and uncertainty of the Company's uncollectible expense.

VI. TARIFF PROPOSALS

25. The Company also proposes certain tariff changes as discussed in the Direct Testimony of Thomas Kaufmann. The changes proposed by Mr. Kaufmann roll the Company's IIP Year 3 and Year 4 revenue requirements currently collected through the IIP Rider into base rates and include the proposed UAC as a component of the SBC. All other changes are housekeeping in nature.

VII. OTHER REQUESTED RELIEF

26. As more fully discussed in the Direct Testimony of Dane A. Watson, attached hereto and marked 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 Exhibit P-9, Schedule DAW-1, Appendix B. The effect of the proposed depreciation rates on Petitioner's proposed revenue requirement is discussed by Company witness John Houseman (Exhibit P-5). Petitioner requests that its revised depreciation rates take effect simultaneously with the effective date of the new rates resulting from this proceeding.

27. As set forth in the Direct Testimony of John Houseman (Exhibit P-5), the Company was authorized in the 2021 Base Rate Case to establish a regulatory asset for Transmission Integrity Management Program ("TIMP") incremental costs if the Company incurred such costs prior to the effective date of rates in its next base rate proceeding. While a regulatory asset has been established, the Company has yet to spend any material incremental costs related to the TIMP. However, the federal pipeline safety regulations are continuing to evolve and will likely result in costs associated with new requirements applicable to the Company and its transmission lines. Therefore, the Company proposes to continue the deferral authority for a TIMP regulatory asset.

28. As discussed in the Direct Testimony of Mr. Houseman, Petitioner has established a regulatory asset to defer any costs which would otherwise be expensed related to the BPU Energy and Water Benchmarking Program in BPU Docket No. QO21071023.[4] The 2022 Benchmarking Order requires utilities to provide web services that allow the owner or operator of any commercial building over 25,000 square feet in the State to benchmark its energy usage for the prior calendar year using the United States Environmental Protection Agency's Portfolio Manager tool. The 2022 Benchmarking Order directed "the regulated utilities to file for cost recovery of the reasonable and prudent costs of implementing the Benchmarking Requirement, which may include

[4] *In the Matter of the Implementation of P.L. 2018, C. 17 – Energy and Water Benchmarking of Commercial Buildings*, BPU Docket No. QO21071023, Order dated September 7, 2022 ("2022 Benchmarking Order").

establishing, operating, and maintaining data aggregation and data access services, for the Board to evaluate in future base rate case proceedings". The Company proposes to amortize costs forecast to be incurred through June 30, 2024, the end of the test year period, over a three-year period.

29. As also discussed in the Direct Testimony of Mr. Houseman, Petitioner has established a regulatory asset to defer certain expenses related to Elizabethtown's most recent BPU management audit in BPU Docket No. GA22030141. The Company proposes to amortize such costs over a three-year period.

30. As explained in the Direct Testimony of Mr. Kaufmann, Elizabethtown is proposing to establish a regulatory asset and 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.

VIII. PROPOSED PROCEDURAL SCHEDULE

31. The Company respectfully requests that the Board establish a procedural schedule and/or transfer this proceeding to the Office of Administrative Law so as to render a final decision before the proposed rates effective date of September 1, 2024.

IX. MISCELLANEOUS

32. 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 Exhibit P-1, 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. The Engineering Panel, which consists of Michael P. Scacifero, Senior Director, Engineering Services, Elizabethtown Gas Company, and Ian Azar, Senior Director, Construction Operations, Elizabethtown Gas Company, whose testimony addresses the Company's actual and forecast capital expenditures (Exhibit P-4);

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

e. Howard S. Gorman, President, HSG Group, whose testimony includes a cost of service study and rate design based on the Company's revenue requirement (Exhibit P-6);

f. Ann E. Bulkley, Principal, The Brattle Group, Inc., whose testimony discusses the cost of capital and capital structure 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); and

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

33. Elizabethtown has included as part of this filing certain confidential information that should be protected from public disclosure. This confidential information includes:

a. The Company's 2023 balance sheet and 2023 income statement, attached as Schedules JLH-1 and JLH-2, respectively, to the Direct Testimony of John Houseman. Following the close of the Merger approved by the Board's 2023 Merger Order, the Company is now a privately held entity and the 2023 financial data included in these schedules constitutes proprietary financial information that is not publicly available.

b. A CTA calculation determined in accordance with *N.J.A.C.* 14:1-5.12(a)(11), attached to this Petition as Exhibit P-1, Schedule E.

34. Preliminary public copies of Exhibit P-1, Schedule C and Schedules JLH-1 and JLH-2 are included with this filing, with confidential information redacted. Concurrent with this filing, in accordance with the Open Public Records Act ("OPRA"), N.J.S.A. 47:1A-1, et seq. and the Board's implementing regulations, N.J.A.C. 14:1-12.1 et seq., Elizabethtown is submitting confidential versions of these schedules to the Board's Records Custodian designated to oversee the public's access to government records along with the materials required under the Board's regulations to substantiate the confidentiality of the information contained therein. After the execution of an Agreement of Non-Disclosure, a proposed version of which is included with this filing as Exhibit P-1, Schedule C, the confidential information will be provided to the parties.

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

Dominick DiRocco
VP, Rates & Regulatory Affairs
SJI Utilities, Inc.
1 South Jersey Place
Atlantic City, NJ 08401
ddirocco@sjindustries.com

Sheree Kelly
Regulatory Affairs Counsel
SJI Utilities, Inc.
520 Green Lane
Union, New Jersey 07083
skelly@sjindustries.com

Cindy Capozzoli
Director, Rates
SJI Utilities, Inc.
1 South Jersey Place
Atlantic City, NJ 08401

ccapozzoli@sjindustries.com

Kenneth T. Maloney
Cullen and Dykman LLP
1101 14th Street, NW
Suite 750
Washington, DC 20005
kmaloney@cullenllp.com

Terrence Regan
Cullen and Dykman LLP
One Battery Park Plaza, 34th Floor
New York, NY 10004
tregan@cullenllp.com

36. Petitioner is serving notice and a copy of this Petition, together with a copy of the exhibits and schedules annexed hereto on the Director, New Jersey Division of Rate Counsel via

electronic mail in lieu of providing hard copies. In accordance with the BPU's March 19, 2020 and June 10, 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, as needed.

37. 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.

38. 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 Exhibit P-1, Schedule B.

39. 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 Exhibit P-1, Schedule A.

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

a. To be afforded 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 December 31, 2024, the end of the six month post-test year period for capital reflected in this filing. These investments are not currently included in rate base and Petitioner currently bears carrying charges and depreciation expense associated with these facilities;

b. To recover revenue and expense adjustments through March 31, 2025, 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.

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

X. CONCLUSION

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 September 1, 2024; 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: Dominick DiRocco
Dominick DiRocco
VP, Rates & Regulatory Affairs
SJI Utilities, Inc.

Dated: February 29, 2024

Exhibit P-1

VERIFICATION

I, Dominick DiRocco, of full age, being duly sworn according to law, upon my oath, depose and say:

1. I am the Vice President, Rates & Regulatory Affairs 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.

Dominick DiRocco

Dominick DiRocco
VP, Rates & Regulatory Affairs

Sworn to and subscribed
before me this 29th day
of February, 2024

Carolyn A. Jacobs

Carolyn A. Jacobs
NOTARY PUBLIC
State of New Jersey
My Commission Expires
October 28, 2028

NOTICE OF PUBLIC HEARINGS

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:

On February 29, 2024, Elizabethtown Gas Company ("Elizabethtown" or "Company") filed a Petition with the New Jersey Board of Public Utilities ("Board") in Docket No. GR24__________, for approval of a request to increase base tariff rates and charges for gas service as well as implement other rate design and tariff revisions, including the implementation of an Uncollectible Adjustment Clause ("UAC") to account for fluctuations in uncollectible costs ("Petition"). The Company is also proposing to modify its existing depreciation rates and requesting authorization to defer certain costs that are not reflected in the Company's base rate request for recovery in future proceedings. The Company is proposing that these changes become effective September 1, 2024, or such other later date as the Board may determine. The new base rates proposed herein would increase annual revenues of approximately $75.6 million or 16%. 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.

Set forth below are the current versus proposed rates on a per therm basis, 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 Heating	$10.50	-	$0.6148	$12.00	-	$0.8190
Small General Service	$36.79	-	$0.4897	$41.05	-	$0.6527
General Delivery Service	$61.84	$1.162	$0.3170	$64.93	1.431	$0.3566
Public Station, per therm	-	-	$1.3918	-	-	$1.6177
Large Volume Demand	$405.18	$1.866	$0.0470	$421.17	2.289	$0.0455
Electric Generation Firm	$101.29	$0.800	$0.0696	$106.63	0.936	$0.0493
Unmetered Gas Light, per mantle	-	-	$10.43	-	-	$13.17
Interruptible Cogeneration Srv.	$154.17	-	$0.0320	$162.07	-	$0.0374
Interruptible Service	$735.71	$0.123	$0.0843	$773.03	0.144	$0.0986
Interruptible Transportation Srv.	$735.71	$0.533	$0.1129	$773.03	0.624	$0.1322

* The sum of the current distribution rate and Rider F (Infrastructure Investment Program or "IIP") rates.
** 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 Heating Monthly Bills (RDS Customers)

Consumption in Therms	Present Bill 03/01/24	Proposed Bill	Proposed Change	Percent Change
10	$23.34	$26.89	$3.55	15.2%
50	$74.72	$86.43	$11.71	15.7%
100	$138.93	$160.85	$21.92	15.8%
250	$331.58	$384.13	$52.55	15.8%

Pursuant to N.J.S.A. 48:2.21, the Board may set these rates at levels it finds just and reasonable and establish the effective date of such rates. Therefore, the Board may establish these rates at levels and/or an effective date other than those proposed by Elizabethtown.

Copies of Elizabethtown's Petition can be reviewed on the Company's website at www.elizabethtowngas.com under "regulatory information". The Petition is also available to review online through the Board's website at https://publicaccess.bpu.state.nj.us where you can search by the above-captioned docket number. In addition, the Petition and Board file may be reviewed at the Board located at 44 South Clinton Avenue, 1st Floor, Trenton, NJ by appointment. To make an appointment, please call (609) 913-6298.

PLEASE TAKE FURTHER NOTICE that virtual public hearings will be conducted on the following date and times so that members of the public may present their views on the Company's Petition:

DATE: HEARING TIMES: 4:30 p.m. and 5:30 p.m. LOCATION: Microsoft Teams Meeting ID: PASSCODE: (Access the Microsoft Teams App or Microsoft Teams on the web. On the left side of the screen, click the "Teams" icon. Select "Join or 'create a team". Press "Join" and enter the Meeting ID and Passcode when prompted.) or Dial In: Conference ID: followed by the # sign

A copy of this Notice is being served upon the clerk, executive or administrator of each municipality and county within the Company's service territory.

Representatives of the Company, Board Staff and the New Jersey Division of Rate Counsel will participate in the virtual public hearings. Members of the public are invited to participate by utilizing the Microsoft Teams link or the Dial-In Number and Conference ID set forth above and may express their views on this Petition. All comments will be made part of the final record of the proceeding and will be considered by the Board. To encourage full participation in this opportunity for public comment, please submit any requests for needed accommodations, such as interpreters or listening assistance, 48 hours prior to the above hearings to the Board Secretary at board.secretary@bpu.nj.gov.

The Board is also accepting written and electronic comments. Comments may be submitted directly to the specific docket listed above using the "Post Comments" button on the Board's Public Document Search tool at https://publicaccess.bpu.state.nj.us. Comments are considered public documents for purposes of the State's Open Public Records Act. Only public documents should be submitted using the "Post Comments" button on the Board's Public Document Search tool. Any confidential information should be submitted in accordance with the procedures set forth in N.J.A.C. 14:1-12.3. In addition to hard copy submission, confidential information may also be filed electronically vis the Board's e-filing system or by email to the Secretary of the Board. Please include "Confidential Information" in the subject line of any email. Instructions for confidential e-filing are found on the Board's webpage at https://www.nj.gove/bpu/agenda/efiling/.

Emailed and/or written comments may be submitted to:
Secretary of the Board
New Jersey Board of Public Utilities
44 South Clinton Avenue, 1st Floor
P.O. Box 350
Trenton, New Jersey 08625-0350
Phone: 609-923-6241
Email: board.secretary@bpu.nj.gov

Elizabethtown Gas Company

Exhibit P-1
Schedule B

[add date]

VIA REGULAR MAIL

TO: **County Administrators, Municipal Clerks and Board of County Commissioner Clerks in the Elizabethtown Gas Company Service Area**

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.____________

Pursuant to law, Elizabethtown Gas Company ("Elizabethtown" or the "Company") is providing you with Notice of Filing for the above referenced matters with the New Jersey Board of Public Utilities. You may obtain the filing from the Company's website by going to the Public Hearings section of https://www.elizabethtowngas.com/regulatory: **[add link]**.

A public hearing related to the above-referenced matters has been scheduled for **[add date]** and Elizabethtown hereby serves upon you the related notice of that hearing. The Notice of Public Hearings can be accessed from the Company's website by going to the Public Hearings section at the same location noted above.

If you would like to receive an electronic copy of our Public Notices in PDF format, kindly provide us with your e-mail address to gakmentins@sjindustries.com.

Respectfully yours,

Dominick DiRocco

Dominick DiRocco

DD/gla

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 2024, 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 unfiled discovery materials are not subject to public access under the Open Public Records Act ("OPRA"), *N.J.S.A.* 47:1A-1 *et seq*.

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 ("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 N.J.A.C. 14:1-12.1 et seq., 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: ________________________________
Sheree L. Kelly
Regulatory Affairs Counsel

MATTHEW J. PLATKIN **ATTORNEY GENERAL OF** **THE STATE OF NEW JERSEY** **Attorney for the Staff of the** **New Jersey Board of Public Utilities**	**BRIAN O. LIPMAN, ESQ.** **DIRECTOR** **NEW JERSEY** **DIVISION OF RATE COUNSEL**
By: ________________________________	By: ________________________________
Deputy Attorney General	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, ¶ 26
***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 (Confidential)
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 (Confidential)
A balance sheet at the most recent date available *N.J.A.C.* 14:1-5.12(a)(3)	Schedule JLH-1 (Confidential)
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 100 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)(10)	Petition, Schedule E (Confidential)

PRELIMINARY PUBLIC COPY

Exhibit P-1
Schedule E

Elizabethtown Gas Company
Consolidated Tax Adjustment Calculation
Calculated in Accordance with N.J.A.C. 14:1-5.12(a)(11)

					(A)	(B)	(C)	(D)	(E)
								(B)/ Total(B)	Total(C) times (D)
2018	2019	2020	2021	2022	Total 2018-2022	Income Companies	Loss Companies	Income Company Percent of Income Companies Total	Allocate Total of Loss Companies to Income Companies based on Taxable Income Share

[redacted]

**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. GR24__________

DIRECT TESTIMONY

OF

CHRISTIE MCMULLEN

President and Chief Operations Officer

**On Behalf Of
Elizabethtown Gas Company**

Exhibit P-2

February 29, 2024

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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 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 am a member of the Board of Directors for the Northeast Gas Association and currently serve as Chairman.

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 Elizabethtown's past two rate cases in BPU Docket No. GR19040486[1] and in BPU Docket No. GR21121254 ("2021 Base Rate Case")[2] as well as in the Company's recent Infrastructure Investment Program 2 ("IIP 2") filing made on December 17, 2023 in BPU Docket No. GR23120882 ("IIP 2 Petition"). I have also previously testified before the Maryland Public Service Commission regarding BGE's strategic infrastructure development and enhancement ("STRIDE") program.

II. PURPOSE OF TESTIMONY

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

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[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).

[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. GR21121254, "Decision and Order Approving Initial Decision and Stipulation" (August 17, 2022).

(ii) describe the corporate structure and mission of Elizabethtown, its direct parent, SJI Utilities, Inc. ("SJIU"), and SJIU's direct parent, South Jersey Industries, Inc. ("SJI") which is owned by IIF US Holding 2, LP ("IIF"), a private equity fund[3];

(iii) explain SJI's philosophy for managing utility operations in a manner that ensures that Elizabethtown provides safe, reliable and clean natural gas service at just and reasonable rates;

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

(v) discuss actions taken by Elizabethtown to promote New Jersey's clean energy future as 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;

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

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

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

I will 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,

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[3] The acquisition of SJI by IIF (the "Merger") was approved in the Board's January 25, 2023 Order in BPU Docket No. GM22040270, In the Matter of the Merger of South Jersey Industries, Inc. and Boardwalk Merger Sub, Inc. ("2023 Merger Order"). Upon such acquisition, SJI became a privately-held company.

reliable, affordable and clean natural gas service to the benefit of its customers, the Board and the State of New Jersey.

III. DISCUSSION

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 2021 Base Rate Case, excluding the Company's Infrastructure Investment Program ("IIP") investments approved by the Board in BPU Docket No. GR18101197, the Company has invested $276.3 million in plant additions, net of retirements, that are not currently reflected in rates. The Company projects that an additional $213.4 million of capital investments, net of retirements, will be added to its plant in service balance by December 31, 2024.[4] These capital investments have been and will be made to maintain and enhance the safety, reliability and resiliency of Elizabethtown's distribution system, support customer needs, and maintain customer service. The Company's continuing investments play a significant role in providing 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.

[4] On December 11, 2023, Elizabethtown proposed a new IIP ("IIP 2"), which is currently under consideration by the Board in BPU Docket No. GR23120882. As the proceeding remains pending, the Company has included projects that would otherwise fall within the scope of the IIP 2 in its post-test year capital expenditures as shown on Schedule EP-4 to Exhibit P-4. In the event that the IIP 2 proceeding reaches a resolution prior to the resolution of this rate case that provides for recovery of the proposed costs of the IIP 2 projects reflected in the proposed rules, the Company will remove investments included in a Board-approved IIP 2 from the post-test year expenditures in this proceeding.

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

A. Elizabethtown is seeking to increase its base delivery rates by approximately $76 million annually or approximately 16 percent above adjusted post-test year revenues. This request is based on a proposed rate of return on invested capital of 8.31percent, with a capital structure that includes a common equity component of 57 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. 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.

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

A. Elizabethtown provides natural gas distribution service to approximately 316,000 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, which in turn is owned by IIF. As set out in the 2023 Merger Order, IIF formed New Jersey Boardwalk Holdings, LLC ("Boardwalk") as a wholly-owned, indirect subsidiary and special purpose entity to directly hold 100% of the common equity of SJI. Boardwalk has no operational functions other than those relating to holding interests in SJI. Company witness Thomas Kaufmann addresses the Company's compliance with the relevant terms of the 2023 Merger Order.

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. By adhering to these core values, the Company has been able to continue to offer award-winning customer service and fulfill its 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 the investments discussed in this filing and 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 the Company. It is a guiding principle behind everything we do. We expect our system to operate safely and reliably for customers and for our employees to get home to their families safely every day. In addition to infrastructure replacement projects, which are vital to ensuring the continued safety and reliability of the gas distribution system, the Company has undertaken other important safety initiatives to support customers, employees, and the communities we serve.

In this regard, the Company continues its efforts to conform to American Petroleum Institute Recommended Practice 1173 Pipeline Safety Management Systems. Conforming to this recommended practice provides the foundation for the safe and effective operation of pipeline facilities. Management of these complex systems and processes requires coordinated actions to address dynamic activities. The elements of a pipeline safety management system address ways to continually operate and improve safety performance. For example, the Company continues to develop and implement Best Practices in Excavation Damage Reduction, including development of various Dashboards, Scorecards and Tracking mechanisms to review and improve locate contractor performance. These efforts resulted in a 24% reduction in excavation damages per 1,000 tickets in 2023 as compared to 2022, achieving the Company's best year on record with an excavation damage rate of 1.80 per 1,000 tickets, in some of the oldest and most difficult to locate infrastructure in the state. Elizabethtown has also implemented a robust Distribution

Integrity Management Program ("DIMP"), which aims to ensure the integrity of the Company's infrastructure. The primary elements of DIMP are to establish thorough knowledge of the system, identify existing and potential threats to it, evaluate and rank those risks, implement measures to address risk, monitor performance of the program, and make continuous improvements.

DIMP has led to and informed several key safety programs for Elizabethtown, including pipeline replacement initiatives, a Leak Management Program, a Damage Prevention Program, and a Public Awareness Program. These programs are designed to mitigate risk to the Company's distribution pipelines. Examples of specific mitigative actions include increased leak survey frequency of cast iron and bare steel facilities, targeted replacement of low-pressure distribution pipelines, and relocation of inside meters to the outside of buildings.

To enhance the effectiveness of the DIMP, the Company has begun developing a new probabilistic risk modeling tool that will be able to predict future risk and evaluate the effectiveness of mitigative actions. This tool will also provide the ability to better prioritize the riskiest segments of pipe for replacement, leading to more efficient risk mitigation.

Elizabethtown has also conducted an emissions study of its entire service territory utilizing Advanced Leak Detection ("ALD") equipment. The Company plans to administer multiple ALD surveys to measure the quantity of emissions from pipelines and then use the data to target and prioritize the largest emissions facilities. The results of the studies will also be utilized in the new probabilistic risk model being developed.

Q. WHAT OTHER EFFORTS HAS THE COMPANY UNDERTAKEN TO PROMOTE SAFETY?

A. The Company recently completed a safety culture survey to understand how employees perceive safety. Results of this survey will drive internal and external process improvements. Additionally, we completed essential job function analysis and hazard assessments to identify hazards and create a risk register that will allow us to identify new or increasing risks and determine the correct mitigation tactics. The Company also improved and enhanced training for both employees and our communities. For example, the Company 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 "dos 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. Training activities 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. The Company also launched a new comprehensive learning management system, "Safety Smart." This computer-based training platform supports our internal in-person training program by providing additional content to ensure knowledge recall, while meeting compliance requirements for completion and records retention. The

Company also established an improved Lone Worker Program to equip employees with the tools and techniques needed to de-escalate conflict situations. To improve occupational and operational incident investigations, the Company has committed to implementing a model that explores incidents classified as Serious Injury or Fatality or Potential Serious Injury or Fatality. The Company also continues to monitor and evaluate employees' driving skills using telematics. Finally, the Company's near miss reporting program was enhanced to improve reporting and evaluation.

Q. CAN YOU PROVIDE EXAMPLES OF HOW ELIZABETHTOWN WORKS TO MAINTAIN 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.

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 nine consecutive years. Elizabethtown has also been recognized by Cogent/Escalent as a Utility Customer Champion (2020-2004) as well as Easiest To Do Business With (2020-2023) and Most Trusted Brand and Environmental Champion (2021 and 2023).

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

A. Elizabethtown has consistently performed well in the metrics established by the Board for Customer Service Standards. During the 2021-2023 period, the Company has read 99.95% of meters in the service territory accurately and on time, with only 3.04 rebills per 1,000 customers. During this time period, the Company has also responded to 99.0% of leak calls within 60 minutes and has met or exceeded the 95% benchmark in all months. The Company has also performed well in meeting customer appointments, with 99.0% of appointments met on average between 2021 and 2023. In addition, in terms of knowledge and courtesy, the Company's field representatives continue to receive high marks. Field Representatives achieved an average satisfaction score of 96.5% for courtesy and 97% for knowledge between January 2021 and December 2022. In 2023, these targets were combined into a single metric, and field representatives continued to maintain averages of over 95%, illustrating a culture of consistent high performance and professionalism. Lastly, overall customer service agent quality scores have remained steady at an average of 94.8% for the past three years.

Q. DID THE 2023 MERGER ORDER REQUIRE ELIZABETHTOWN TO IMPROVE CERTAIN ASPECTS OF THE COMPANY'S CUSTOMER SERVICE?

A. Yes. The 2023 Merger Order required the Company to develop and submit a Call Center Customer Service Improvement Plan ("CCCSIP") on or before March 15, 2023 and submit quarterly reports on its customer service performance thereafter. The CCCSIP required Elizabethtown to develop a plan for improving its results and reporting on its improvement with respect to the percentage of calls answered within 30 seconds and call abandonment rate. In connection with CCCSIP, Elizabethtown was further required to describe in its reports efforts to prevent disconnection for non-payment and processes adopted as a result of sharing best practices with other IIF portfolio companies. Elizabethtown submitted its initial CCCSIP to Board Staff and the New Jersey Division of Rate Counsel on March 15, 2023 and continues to file such quarterly reports as required by the 2023 Merger Order.

Q. HAS ELIZABETHTOWN UNDERTAKEN ANY EFFORTS TO IMPROVE THE ASPECTS OF ITS CUSTOMER SERVICE ADDRESSED IN THE 2023 MERGER ORDER?

A. In the first half of 2023, a leadership reorganization was completed to best support operations, employees and customers at both Elizabethtown and its sister utility, South Jersey Gas Company. To help address call volume and attrition in the call center, the Company contracted with a new supplemental vendor that began taking calls in July 2023 and is now assisting Elizabethtown with an average of 150 calls per day. To keep attrition to a minimum, the leadership team finalized a successful candidate profile to support talent attraction in the fourth quarter of 2023. The Company increased the use of call wrap-up reason codes to understand call volume drivers to better inform resource planning and workforce allocations, introduced new Chat technology within the MyAccount customer portal in the second quarter of 2023 and updated the contact center phone technology and Interactive Voice Response system to RingCentral in October 2023. Due to these efforts, the call center achieved an 81.67% service level between July and December of 2023 which is a significant improvement from the first half of 2023 which had an 71.17% service level.

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

A. Yes. SJI is positioning the entire 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 neutrality by 2040 and (3) dedicate at least 25 percent of annual capital expenditures to sustainability projects. SJI is committed to investing in projects that will 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. Replacement of leak prone pipe through Elizabethtown's IIP and base capital spending will greatly reduce methane emissions on the Company's system. . In its IIP 2 Petition, Elizabethtown proposes to further modernize and enhance the safety and reliability of its gas distribution system by installing approximately 250 miles of new main, and retiring approximately 274 miles of vintage, at-risk facilities, which include low pressure cast iron pipe, vintage plastic pipe and vintage steel pipe and associated services over a 5-year period commencing July 1, 2024. The accelerated replacement of the Company's highest risk pipe is fully consistent with applicable governmental policies as identified in the United States Department of Transportation's Call to Action,[5] the National Association of Regulatory Utility Commissioners' expanded emphasis on pipeline safety and infrastructure replacement, the Pipeline and Hazardous Materials Safety Administration's pending Notice of Proposed Rulemaking on Safety of Gas Distribution Pipelines and Other Pipeline Safety Industries,[6] the U.S. Methane Emissions Reduction Action Plan,[7] the New Jersey Energy Master Plan[8] and Executive Order No. 317 issued by Governor Murphy on February 15, 2023.

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[5] U.S. Department of Transportation, "U.S Transportation Secretary Ray LaHood Announces Pipeline Safety Action Plan (Apr. 4, 2011), https://www.phmsa.dot.gov/sites/phmsa.dot.gov/files/docs/dot4111.pdf?bcs-agent-scanner=05993b13-e614-f24e-a1a0-3d4aa7cb2331.

[6] Federal Register :: Pipeline Safety: Safety of Gas Distribution Pipelines and Other Pipeline Safety Initiatives, 88 FR 61746.

[7] White House Office of Domestic Climate Policy, U.S. Methane Emissions Reduction Action Plan (Nov. 2021), https://www.whitehouse.gov/wp-content/uploads/2021/11/US-Methane-Emissions-Reduction-Action-Plan-1.pdf?bcs-agent-scanner=0e436478-aaac-0441-a8a5-1d518ac007bb.

[8] *See*, 2019 New Jersey Energy Master Plan, at p.5 and p. 41, http://d31hzlhk6di2h5.cloudfront.net/20200127/84/84/03/b2/2293766d081ff4a3cd8e60aa/NJBPU_EMP.pdf.

In 2021, Elizabethtown also received BPU approval to invest approximately $76 million in a variety of energy efficiency programs ("Triennium 1 Programs"), over a 3-year period through June 30, 2024, 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. On November 20, 2023 the Company filed a Petition to extend its Triennium 1 Programs through December 31, 2024 pursuant to the Board's Order dated October 25, 2023 in BPU Docket Nos. QO19010040, QO23030150 and QO17091004. In addition, on December 1, 2023 in BPU Docket No. QO23120869, the Company made a filing seeking Board approval of proposed energy efficiency programs, building decarbonization programs and demand response programs (collectively referred to as "Triennium 2 Programs") for a 2.5-year period commencing January 1, 2025, with a total budget of approximately $277.2 million. These continued investments will help customers to reduce and make better informed decisions about their energy usage, and lower their energy bills.

The current and proposed programs also solidify Elizabethtown's commitment to the State's climate priorities and advance New Jersey's clean energy goals in a manner that will benefit customers, the environment, and the State's green economy

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

A. Natural gas remains in strong demand driven by the superior reliability of the service, the favorable affordability of natural gas compared to alternate energy sources, and our commitment to helping our customers save energy and money through a robust suite of Energy Efficiency programs. In 2022 and 2023, Elizabethtown added 5,105 and 4,701 customers, respectively. The Company projects that it will add approximately 6,430 new customers through March 31, 2025, the end of the post-test year period applicable to determinants.

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

A. Yes. Elizabethtown is investing in replacement vaporization equipment at its Erie Street Liquefied Natural Gas ("LNG") Facility. The Company's LNG facility, which was placed in service over fifty years ago in 1971, is critical to the Company's efforts to provide reliable gas supply during peak periods. As described more fully in the Direct Testimony of the Engineering Panel, the Company is replacing the vaporizers that had reached the end of their useful lives with facilities that doubled the peak day deliverability of the LNG Plant. The replacement of the vaporizers increases system reliability and better protects customers from potential gas supply disruptions.

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 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 its 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 New Jersey Veteran's Network, a Union Township based organization that is dedicated to helping veterans and their families live a better life by creating a system of community veteran liaisons whose role it is to identify veterans and connect them with resources and solutions designed to meet their unique set of needs. In 2023, Elizabethtown Gas along with its parent company SJI donated a total of $67,602 to this organization. Elizabethtown has also continued its partnership with Union County College and its "Fueling the Future" scholarship program, awarding $1,000 scholarships to ten 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, we established a First Responders Grant Program in 2021 that provides financial support to various fire and police departments of many municipalities in the communities we serve. Along the same lines, we also created the Game on Grant Program which supports little league and other recreational sports teams in the communities we serve by awarding twenty teams with a $1,000 donation. Additionally, among those I have mentioned, are the following groups that we have built significant relationships with and are actively involved in assisting with their mission each year: Sussex County College Education Foundation, Trinitas Health Foundation, The ARC of New Jersey, the American Red Cross, the Boys and Girls Club, Josephine's Place, NORWESCAP, Hyacinth, the

Nature Conservancy and the Urban League of Union County. These are just some examples of the donations we make in connection with Elizabethtown's charitable contributions of over $500,000 per year.

Q. DOES ELIZABETHTOWN PROVIDE SUPPORT TO LOW INCOME CUSTOMERS?

A. Yes, supporting low income customers through energy assistance programs is a primary focus of the Company. Communication of these programs is provided via customer welcome letters, newsletters and bill inserts, payment reminder notices and messages, the customer service Interactive Voice Response system, website and social media accounts. Elizabethtown has strong partnerships with providers to promote financial assistance, including the BPU-Outreach Division, the Department of Community Affairs, 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. Due in part to these partnerships, 19,290 customers received $10.3 million in utility assistance in the 2023 calendar year.

Elizabethtown offers energy assistance training to all customer-facing employees on an annual basis. In addition to the communication channels mentioned above, Elizabethtown actively participates in many community-related events throughout the year to educate customers and promote the various energy assistance programs. Through these efforts, Elizabethtown was able to participate in 111 community events during 2023, including speaking engagements, webinars and various networking meetings and events. These important efforts offer a path to utility bill affordability 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. IS THE COMPANY SEEKING TO ESTABLISH A TARIFF MECHANISM TO ENABLE IT TO FULLY RECONCILE ITS UNCOLLECTIBLE EXPENSE IN THIS PROCEEDING?

A. Yes. Elizabethtown has experienced an increase in payment arrears since the end of the COVID-19 pandemic. To address this situation, the Company is undertaking a number of efforts including proposing to establish an Uncollectible Adjustment Clause that will permit the Company to fully reconcile its uncollectible expenses to the level collected through rates. The proposed mechanism will benefit both the Company and its customers be ensuring that Elizabethtown will recover no more and no less than its actual uncollectible expenses. The circumstances surrounding the Company's increase of uncollectible expense and its efforts to address those expenses are more fully discussed by Company witness Thomas Kaufmann.

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 for Elizabethtown, whose testimony presents the Company's proposed revenue requirement, revenue forecast, and sponsors the Company's revised tariff;
- The Engineering Panel, whose testimony discusses capital expenditures made by the Company, which consists of the following individuals who address capital expenditures:

- Michael P. Scacifero, Senior Director, Engineering Services for Elizabethtown, and
- Ian Azar, Senior Director, Construction Operations for Elizabethtown;

- John L. Houseman, Director of Accounting, SJI, whose testimony discusses certain accounting issues and sponsors historic financial data required by the Board's regulations;
- Ann E. Bulkley, Principal, of The Brattle Group, Inc., 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; and
- Howard S. Gorman, President, HSG Group, presents the Company's embedded cost of service study and proposed rate design.

IV. CONCLUSION

Q. DO YOU HAVE ANY CONCLUDING REMARKS?

A. Yes. Elizabethtown continues to manage its operations responsibly and effectively to uphold its commitment to provide superior service to our customers at reasonable rates. Our proposed rate increase in this case 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 2021 Base Rate Case 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

February 29, 2024

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ELIZABETHTOWN GAS COMPANY
DIRECT TESTIMONY OF
THOMAS KAUFMANN

I. INTRODUCTION

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

A. My name is Thomas Kaufmann and I am the Manager of Rates and Tariffs 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. 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. as a Rate Analyst. I 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. South Jersey Industries, Inc. ("SJI") acquired Elizabethtown Gas on July 1, 2018.

II. PURPOSE OF TESTIMONY

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 June 30, 2024, 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 Orders approving (i) SJI's acquisition of the assets of Elizabethtown in 2018,[1] and (ii) IIF US Holding 2, LP's ("IIF") subsequent acquisition of SJI in 2023[2] that are relevant to this rate proceeding. In addition, I will present the Company's revenue determinants forecast and proposed tariff revisions and will provide bill comparisons between present and proposed rates.

[1] SJI's acquisition of Elizabethtown's assets was approved by the Board's Order dated June 22, 2018 in BPU Docket No. GM17121309 ("2018 Acquisition Order").
[2] In February 2023, SJI was acquired by IIF, a private equity fund. That transaction (the "Merger") was approved in the Board's January 25, 2023 Order in BPU Docket No. GM22040270 ("2023 Merger Order").

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. TEST YEAR

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 June 30, 2024. This filing utilizes six months of actual data ending December 31, 2023 and six months of estimated data through June 30, 2024. 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 December 31, 2024 and changes in certain revenues and expenses through March 31, 2025, as described later in my testimony as well as in the Direct Testimony of the Engineering Panel (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 STRUCTURE OF SJI AND ITS RELATIONSHIP TO ELIZABETHTOWN.

A. Elizabethtown is a wholly-owned subsidiary of SJI Utilities, Inc. ("SJIU"), which in turn is a wholly-owned subsidiary of SJI, which in turn is owned by IIF. As set out in the 2023 Merger Order, IIF formed NJ Boardwalk Holdings, LLC ("Boardwalk") as a wholly-owned, indirect subsidiary and special purpose entity to directly hold 100% of the common equity of SJI. Boardwalk has no operational functions other than those relating to holding interests in SJI. SJIU owns 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 in the Board's 2018 Acquisition Order. Shared services costs are assessed to Elizabethtown by SJIU and SJI in accordance with the cost assignment methodologies set forth in the services agreements. IIF assesses no costs to Elizabethtown, either directly or indirectly.

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 December 31, 2023 and six months of estimated data through June 30, 2024. 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. <u>REQUIREMENTS CREATED BY THE 2023 MERGER ORDER AND THE 2018 ACQUISITION ORDER</u>

Q. DID THE 2023 MERGER 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 2023 Merger Order:

i. No recovery in rates will be sought for (i) any acquisition premium associated with the Merger or any previous acquisition/merger, (ii) any costs associated with goodwill arising from the Merger or any previous acquisition, or (iii) any transaction costs incurred in connection with the Merger. For purposes of this commitment, transaction costs are defined as (a) consultant, investment banker, legal and regulatory support fees (internal as well as external), and printing and similar expenses in each case paid to advance or consummate the Merger, and (b) severance, retention or change-in-control payments made to employees of the Joint Petitioners related to the Merger. Any such costs will be considered “transaction costs”.

ii. Elizabethtown will not include any common equity associated with goodwill (including Merger-related goodwill on Boardwalk’s or SJI’s balance sheet or goodwill arising from prior transactions) in its ratemaking capital structures. Goodwill associated with the Merger will not be included in rates, rate base, any common equity balance reflected in the determination of allowance for funds used during construction (AFUDC), cost of capital, operating expenses, or any other ratemaking component in future Elizabethtown proceedings.

iii. Any savings realized by Elizabethtown by virtue of the Merger will be tracked beginning with the merger closing until the first rate case. Savings will be flowed through to utility customers in a future base rate case, net of any costs to achieve such savings.

iv. Elizabethtown’s current rates reflect the cost of first mortgage bonds and senior notes that contain “change-in-control” provisions that allow the bond and note investors to sell (put) their bonds and notes back to the respective issuer at the face amount of the debt in connection with the Transaction. The Parties acknowledge that (a) to the extent Elizabethtown incurs increased interest expense as a result of issuing new debt (referred to as the "Refinanced Debt") solely to replace any first mortgage bonds and senior notes that are redeemed by Elizabethtown as a result of an investor exercising a put in connection with the Transaction (referred to as the "CIC Debt") and (b) such increased interest costs are included in the base rates set in future base rate cases, then Elizabethtown, as applicable, will provide customers with a rate credit (referred to as the "CIC Rate Credit") in future base rate cases for the remaining tenor of the CIC Debt. Any positive amount resulting from subtracting CIC Debt test year interest from Refinanced Debt test year interest will be refunded to customers through an adjustment to customer rates ("CIC Rate Credit Adjustment").

In addition, the 2023 Merger Order required that Elizabethtown would continue to comply with all applicable continuing obligations arising from prior transactions including those imposed in the 2018 Acquisition Order.

Q. DID THE 2018 ACQUISITION 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 2018 Acquisition 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.

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

A. No.

Q. HAS ELIZABETHTOWN INCLUDED ANY COMMON EQUITY ASSOCIATED WITH GOODWILL (INCLUDING MERGER-RELATED GOODWILL ON BOARDWALK'S OR SJI'S BALANCE SHEET OR GOODWILL ARISING FROM PRIOR TRANSACTIONS) IN ITS RATEMAKING CAPITAL STRUCTURES?

A. No. As discussed in the Direct Testimony of Ms. Bulkley, Elizabethtown is not seeking to include any goodwill arising from the Merger in its ratemaking capital structure.

Q. HAVE ANY SAVINGS BEEN REALIZED BY ELIZABETHTOWN BY VIRTUE OF THE MERGER?

A. The Company has not identified any net savings realized by Elizabethtown as a result of the Merger.

Q. IS ELIZABETHTOWN SEEKING TO RECOVER ANY COSTS TO ACHIEVE ANY NET SAVINGS ASSOCIATED WITH PRIOR TRANSACTIONS?

A. No.

Q. HAS ELIZABETHTOWN INCLUDED A CIC RATE CREDIT ADJUSTMENT IN THIS RATE CASE?

A. Yes. Elizabethtown has included the CIC Rate Credit on an after-tax basis as a ratemaking adjustment to Net Operating Income on Schedule TK-3. This amount is grossed-up to a pre-tax basis of $6.4 million, once the revenue factor is applied to the income deficiency on Schedule TK-1, which represents the CIC Rate Credit Adjustment required to be made to customer rates in accordance with the 2023 Merger Order.

Q. WERE THERE ANY TERMS IN THE 2023 MERGER ORDER RELATED TO COVID UNCOLLECTIBLE AMOUNTS AND CUSTOMER BILL CREDITS?

A. Yes. Within 30 days of the completion of the 2023 Merger Order, Elizabethtown was required to write-off 100 percent of the total COVID uncollectible write-off deferrals ("COVID Deferral") outstanding as of such date inclusive of all cost categories, including customer arrearages. The Company wrote off the COVID Deferral in the amount of $8.8 million ("COVID Deferral Writeoff"). Elizabethtown was also required to issue bill credits to all customers ("IIF Merger Credit"). The Company issued two bill credits of approximately $13 million each in April 2023 and January 2024.

Q. HOW DOES THE COVID DEFERRAL WRITEOFF AFFECT THE COMPANY'S FILING IN THIS CASE?

A. As discussed more fully below, in determining the uncollectible adjustment to be applied in determining the revenue requirement in this case, the Company used a five-year average of uncollectible costs that excluded the Covid Deferral Writeoff from the calculation in order to arrive at reasonable, normalized level of expected uncollectible expense. As discussed more fully below, the Company faces a great deal of uncertainty with respect to its future uncollectible expense and is proposing an uncollectible adjustment mechanism to address that uncertainty.

V. 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 $75,558,923, as supported by Company witnesses in this case. The calculation of this amount is as follows and discussed below:

REVENUE REQUIREMENT

Adjusted Rate Base	$1,862,108,979	TK-2
Rate of Return	8.31%	
Required Operating Income	154,741,256	
Adjusted Net Operating Income	101,055,057	TK-3
Income Deficiency	53,686,199	
Revenue Factor	1.407418	TK-6
Operating Revenue Adjustment to Base Rates	$75,558,923	

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 Ms. Ann Bulkley (Exhibit P-7). The required operating income calculated on Schedule TK-1 is the adjusted rate base multiplied by 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 multiplied by the income deficiency.

The Adjusted Net Operating Income includes the Company's proposal to roll the Board approved amounts of IIP operating revenues for IIP Year 3 and IIP Year 4 from the IIP Rider into base rates in this case as shown on Schedule TK-5 and detailed on Schedule TK-8, as discussed further below. It also includes the CIC Rate Credit Adjustment required by the 2023 Merger Order. After adjusting operating revenues for the roll-in of IIP revenues and other net income and after considering the CIC Rate Credit Adjustment, the Company's revenue deficiency is $75,558,923 as shown in Schedule TK-1.

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

A. Since the Company's 2021 Base Rate Case[3], excluding IIP spending, Elizabethtown has invested approximately $276.3 million of plant additions net of retirements that are not currently reflected in rates, and projects that an additional $213.4 million of capital investment net of retirements will be added to the Utility Plant In Service ("UPIS") balance by December 31, 2024, to ensure that our customers continue to receive safe and reliable

[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, Docket No. GR21121254, "Decision and Order Approving Initial Decision and Stipulation" dated August 17, 2022 ("2021 Base Rate Case")("August 2022 Order").

natural gas service.[4] 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 UPIS balances and 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.

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 New Jersey 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. As I discussed previously, the adjustment for uncollectibles is based on the Company's five-year average, excluding increased uncollectible costs associated with the impact of the COVID Deferral Writeoff. Each of the components of the revenue expansion factor must be included for the Company to recover each incremental dollar of income from the required revenue increase.

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[4] On December 11, 2023, Elizabethtown proposed a new IIP ("IIP 2"), which is currently under consideration by the Board in BPU Docket No. GR23120882. As the proceeding remains pending, the Company has included projects that would otherwise fall within the scope of the IIP 2 in its post-test year capital expenditures as shown on Schedule EP-4 to Exhibit P-4. In the event that the IIP 2 proceeding reaches a resolution prior to the resolution of this rate case that provides for recovery of the proposed IIP 2 projects reflected in the proposed rates, the Company will remove investments included in a Board-approved IIP 2 from the post-test year expenditures in this proceeding.

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." This filing complies with the requirements of the IIP Order and provides for a prudence review of the IIP expenditures placed in service since its previous rate case. The prudence of the Company's IIP expenditures is discussed in the Direct Testimony of the Engineering Panel.

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 that 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. GR22040316 and GR23040270. In addition, please see Schedule HSG-2 to the Direct Testimony of Howard Gorman in Exhibit P-6, which reflects the roll-in to base rate revenues.

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

A. The IIP expenditures are for mains and services that are included in the Company's UPIS, as well as the associated depreciation and deferred taxes, that are components of rate base.

The Company's proposed roll-in of IIP Year 3 and IIP Year 4 costs on Schedule TK-8 is similar to the treatment of such costs for IIP Year 1 and IIP Year 2 were in the 2021 Base Rate Case.

Q. WHAT WILL HAPPEN TO THE CURRENTLY APPROVED IIP RIDER 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 IIP Rider rates, which may be zero if this case is resolved before IIP Year 5 rates go into effect.

VI. <u>OPERATING INCOME</u>

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

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	($23,908,526)	$37,507,396	$13,598,870
Cost of Sales-Rider Revenue Offsets	$0	$0	$0
Cost of Sales Purchased Gas (Inc)/Dec	$0	($16,899,125)	($16,899,125)
Operating Margin Revenues	($23,908,526)	$20,608,271	($3,300,255)

Cost of Sales Rider Revenue Offsets are zero as they are no longer included in Cost of Sales but are now being booked as Amortization Expenses on the Company's income statement.

The adjustments to the 12-month test year ending June 30, 2024 shown on Schedule TK-3 are from Schedules TK-4 and TK-5. Schedule TK-4 summarizes the *pro forma* revenue and offsetting expense 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.

Pro Forma Adjustments: Schedule TK-4 adjustments for Tariff Rider revenues, the IIF Merger Credit issued in January 2024 and Rider Revenue Offsets are detailed on Schedule TK-7. These adjustments to revenues and expenses 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 that are 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 expenses associated with these riders from the *pro forma* income statement in this case. The proposal to roll the IIP Rider rates into base rates, based on previously approved in-service capital amounts, was discussed earlier in my testimony. This is accomplished by replacing the removed IIP booked revenue amounts shown on Schedule TK-7 with those approved as shown on Schedules TK-5 and TK-8.

Annualization and Normalization Adjustment: 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 forecast post-test year therms. The annualization component is calculated by applying the monthly normalized forecast use-per-customer during the twelve-month post-test year period to the difference between the monthly forecast customer count and the customer count at the end of the post-test year, March 31, 2025. 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 Gorman 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 forecast 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 later in my testimony.

Q. PLEASE OUTLINE AND EXPLAIN THE *PRO FORMA* O&M EXPENSE 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	$1,334,543
Employee Benefits Expense	TK-10	$344,241
Service Company Expense	TK-11	($996,117)
Rate Case Expenses	TK-12	$429,333
Non-Recoverable and Other Expenses Adjustments	TK-13	($5,474,559)
Inflation Adjustment	TK-14	$1,436,991
		($2,925,568)

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 4 percent effective March 1, 2024, retroactive to January 1, 2024. 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 contains a 4 percent increase similar to Elizabethtown.

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.

Other O&M Expenses: The BPU Energy and Water Benchmarking Order dated September 7, 2022 in BPU Docket No. QO21071023[5] included language that directed "the regulated utilities to file for cost recovery of the reasonable and prudent costs of implementing" the requirements under such order. The Company proposes to amortize costs forecast to be incurred through June 30, 2024, the end of the test year period, over a three year period. Schedule TK-13 also reflects the *pro forma* adjustment made for expenses related to Elizabethtown's most recent management audit performed in accordance with BPU Docket No. GA19091305 and identifies the costs incurred and deferred as of December 31, 2023, which the Company proposes to amortize over three years. These proposed regulatory assets are further discussed in the Direct Testimony of Mr. John L. Houseman (Exhibit P-5).

Schedule TK-13 also reflects certain management fee expense adjustments for expenses that are excluded from the determination of the revenue requirement. In addition, Schedule TK-13 reflects the removal of Charitable and Civic Contributions Expense and other expenses that are considered shareholder expenses. As such they are being removed consistent with Board policy.

Inflation Adjustment: 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

[5] *In the Matter of the Implementation of P.L. 2018, C. 17 – Energy and Water Benchmarking of Commercial Buildings*, BPU Docket No. QO21071023, Order dated September 7, 2022 ("2022 Benchmarking Order").

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 Implicit Price Inflator for the end of the post-test year period compared to that at the mid-point of the test year.

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

A. The annualization and normalization adjustment for O&M expenses, shown on line 6 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 on Schedule TK-2, line 2, are set forth on Schedule JLH-5. Adjustments to depreciation expense are included on Schedule TK-3, line 7. These adjustments are discussed in further detail in Mr. Houseman's testimony. The changes to depreciation rates reflected in the proposed depreciation expense are based on the results of a study prepared by Company witness 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	$102,093
Revenue Taxes	TK-15	($32,830)
		$69,263

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 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.

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 the Company has 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 set forth in *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 December 6, 2023 and effective January 1, 2024 to the projected post-test year customer deposit balance on Schedule TK-16. This amount, when compared to the June 30, 2024 test year interest expense on Schedule TK-3, results in the *pro forma* post-test year adjustment shown on Schedule TK-3.

VII. 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 December 31, 2023. Those amounts include approved actual IIP investments through June 30, 2023. Any IIP Year 5 actual in-service amounts from July 2023 through December 2023 have been removed. This IIP Year 5 adjustment is required to remove IIP amounts from UPIS that have not yet been filed for and approved by the Board. A similar adjustment is not made to January 2024 through June 2024 given those amounts are based on a forecast that does not include IIP investments. Once UPIS is actualized for these months in the Company's 9+3 and 12+0 Updates of this filing, IIP Year 5 amounts included in those numbers will need to be removed as well.

As shown on Schedule EP-4 to the Direct Testimony of the Engineering Panel, the post test year includes amounts for investments that are included in the Company's proposed IIP 2 program that is currently pending before the Board in BPU Docket No. GR GR23120882. In the event that the IIP 2 proceeding reaches a resolution during this rate case that provides for the recovery of the costs of the IIP 2 projects that are reflected in the proposed rates, the Company will remove investments included in a Board-approved IIP 2 from the post-test year expenditures in this proceeding . Forecast plant additions (other than those recovered through the IIP) for the six month period January 2024 through June 2024 were added and estimates for plant retirements for the same time period were deducted to develop the estimated test year ending balance as of June 30, 2024. The Company also included forecast plant additions, reduced for plant retirements, for the six-month post test year period ending December 31, 2024. The forecast plant additions are discussed in further detail by the Engineering Panel (Exhibit P-4).

Accumulated Depreciation & Amortization: The balance for accumulated depreciation and amortization was calculated using the actual balance as of December 31, 2023, adjusted for an Acquisition adjustment discussed more fully by Company witness Houseman. The balance was further adjusted by adding estimated depreciation expense and subtracting estimated plant retirements and cost of removal for the period January 2024 through June 2024 to develop the estimated test year ending balance as of June 30, 2024. 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 July 2024 through December 2024. The *pro forma* post-test year accumulated depreciation adjustment is calculated on Schedule JLH-5 and discussed in further detail by Company witness 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 by the Board's Order dated June 30, 2017 in Docket No. GR16090826 and reaffirmed by the Board's Order dated November 13, 2019 in Docket No. GR19040486 and most recently, in the Board's August 2022 Order. 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 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.

Customer Deposits and Customer Advances: Customer Deposits set forth on Schedule TK-16 and summarized on lines 11-13 reflect the Company's projected 13-month average of 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.

Deferred Income Taxes: The test year deferred income tax balances were estimated starting with the actual balances as of December 30, 2023 and then projecting changes to the components of the deferred income tax balances through June 30, 2024. Schedules JLH-6 and JLH-7, sponsored by Company witness Houseman, reflect the post-test year rate base adjustment to capture the increase in Federal and State deferred taxes for the period through December 31, 2024. The Company has also included the Excess Deferred Income Tax balance reflected on its books through December 31, 2024. Deferred income tax adjustments are discussed in further detail by Company witness Houseman.

Consolidated Tax Adjustment ("CTA"): The Company's proposed statement of rate base reflects a CTA of $0 because Elizabethtown has incurred tax losses in each of the last five years. The confidential CTA calculation is attached to the Company's petition as Exhibit P-1, Schedule E.

VIII. REVENUE FORECAST

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

A. Elizabethtown's forecast determinants reflect annualized and normalized firm demand for a test year ending June 30, 2024 and a post-test year period ending nine months later, on March 31, 2025, 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 March 31, 2025. The forecast 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 March 31, 2025 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 its demand forecast based upon two sets of conditions as specified at given points in time: (i) the number of customers and (ii) the forecast normalized use per customer by class. The Company applies these two points to the difference in the customer counts from those on March 31, 2025, the end of the post-test year, and then uses the post-test year monthly therm usage per customer amounts in computing the annualized therms attributable to that month's change in the customer count from those on March 31, 2025. Schedule TK-20 presents actuals and projections of the number of customers and therms billed for the test year and nine month post-test year period from July 2024 to March 2025. The post-test year reflects normalized and annualized therms on Schedule 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 MARCH 31, 2025?

A. Demand and revenue are calculated as of March 31, 2025 to match the outside date at 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 forecast 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 Schedule TK-19 therms) of total Company sales by class. The methodology employed consists of the following four (4) steps:

1. Weather normalization of class-by-class monthly actual data for the gas use–per-customer for the 35 month period of October 2020 – March 2023 for RDS and GDS non-heat sensitive customers and the 56 month period of January 2019 – March 2023, for all others, 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, 2003 through December 31, 2022) 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 forecast 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 provided a comprehensive explanatory data set consisting of 33 macroeconomic and demographic variables.

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 historical databases noted above in order to capture the most recent effects from customers installing of more efficient gas-consuming appliances, smart thermostats and Heating, Ventilation and Air Conditioning equipment that have affected the use per customer for each class and also the most recent impacts of conservation efforts and programs. For heating customers the contiguous April 2020 thru March 2021 timeframe contained the 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 in March 2020 through the following 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 March 31, 2025 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. UNCOLLECTIBLE ADJUSTMENT CLAUSE

Q. HOW ARE UNCOLLECTIBLE EXPENSES CURRENTLY RECOVERED FROM CUSTOMERS?

A. Uncollectible expenses are currently recovered in base rates and through the Rider "E" – Energy Efficiency Program ("EEP Rider") rates and Rider "F" – Infrastructure Investment Program ("IIP Rider") rates. An average uncollectible rate was included in the revenue factor that was used to gross-up the revenue increase in the Company's 2021 Base Rate Case approved by the Board's August 2022 Order as well as in the EEP and IIP revenue increase requests approved by the Board subsequent to the August 2022 Order.. There is no true-up between the actual uncollectible expense incurred and the recovery through base rates, EEP Rider rates and IIP Rider rates.

Q. PLEASE DESCRIBE THE PROPOSED UNCOLLECTIBLE ADJUSTMENT CLAUSE.

A. The Company is proposing an Uncollectible Adjustment Clause ("UAC") to enable the Company to true-up costs associated with annual uncollectible expenses. It is proposing that the UAC be a component of Rider "D" - Societal Benefits Charge ("SBC") to the Company's tariff.

Q. WHY IS THE COMPANY SEEKING A MECHANISM TO ADDRESS UNCOLLECTIBLE EXPENSES IN THIS PROCEEDING?

A. As stated previously, there is currently no true-up between actual uncollectible expenses incurred and the related recovery through base rates, EEP Rider rates and IIP Rider rates. Balances are heavily affected by changes in gas costs, which have fluctuated and are generally beyond the Company's control. In addition, the UAC will serve the interests of both the Company and customers. It will ensure recovery of an accurate amount of uncollectible expense, with neither the Company nor its customers subject to under or over recovery or charge.

Q. HOW WILL THE UAC PROTECT AND ASSIST CUSTOMERS?

A. The UAC's symmetrical reconciliation serves the interests of both the Company and customers by safeguarding against variability, by addressing fluctuations in bad debt and by addressing the uncertainty of the Company's uncollectible expenses. The Company's proposal will ensure that customers pay no more and no less than the Company's actual uncollectible expense in any given year.

Q. HAS THE COMPANY EXPERIENCED VARIABILITY IN UNCOLLECTIBLE EXPENSES POST-PANDEMIC?

A. Beginning on March 13, 2020, at the outset of the COVID-19 Pandemic, the Company, along with all other New Jersey gas and electric utilities, agreed to voluntarily suspend service shutoffs in recognition of the public health emergency and the associated economic impact on customers. On October 15, 2020, Governor Murphy issued Executive Order No. 190 that, in part, implemented a moratorium on disconnection of utility service for non-payment. The moratorium was extended until June 30, 2021 by Executive Order No. 229, issued on March 3, 2021. On June 14, 2021, Executive Order No. 246 provided that the moratorium on utility shutoffs would be terminated effective July 1, 2021, but established a "grace period" allowing customers until December 31, 2021 to allow customers to avoid shutoff. This grace period was subsequently extended until March 15, 2022 by legislation signed into law on December 22, 2021. As a result of the pandemic and the associated suspension of shutoffs, customers were not terminated by Elizabethtown for non-payment for more than two years. When shut offs were permitted again in early 2022, the Company also received federal assistance which (1) reduced balances without any payment by the customer and (2) protected customers receiving assistance from being shut off. In addition, customer balances were further reduced pursuant to the 2023 Merger Order COVID Deferral Writeoff as discussed earlier in my testimony. This extended period of nonpayment without consequence appears to have shifted behavior for certain customers with respect to bill payment, leading to greater and more volatile uncollectibles than the Company had experienced prior to the COVID-19 Pandemic.

Q. WHAT STEPS HAS THE COMPANY TAKEN TO ADDRESS PAST DUE BALANCES AND REDUCE UNCOLLECTIBLES EXPENSE POST-PANDEMIC?

A. Elizabethtown has sought to mitigate uncollectible issues discussed above through focusing on customer assistance programs and initiatives that facilitate customer payment and arrears management. These efforts include (1) performing targeted outreach to customers who were not enrolled in Universal Service Fund ("USF")/Fresh Start Energy Assistance programs prior to the September 30, 2023 application deadline; (2) providing additional flexibility to customer enrolling in deferred payment arrangements (i.e., increased the length of terms of the arrangement to make it more affordable); and (3) partnering with local agencies, food banks and various community events to deliver Energy Assistance information to customers. The Company also improved its collections processes in 2023, by (1) revamping the Automated Collections Outbound messaging to emphasize the need to make timely payments, which uses a system ensures that both phone calls and emails are routinely sent to customers with past due balances; and (2) introducing Manual Outbound Collection calls performed by the Company's remittance team as a way to complement the work of the field collections team. In addition, Elizabethtown anticipates rolling out a Text to Pay option in the first quarter of 2024 that will enable customer service representatives to text a My Account guest payment link directly to a customer's mobile phone. Finally, in 2024, the Company is adding a QR code to collection door hangers, which will bring customers directly to a My Account guest payment link to facilitate electronic bill payment.

Q. PLEASE EXPLAIN HOW THE UAC WILL OPERATE.

A. The UAC will reconcile actual incurred uncollectible expense to the base level of uncollectible expense collected through base rates as well as through EEP Rider rates and IIP Rider rates, with any variance recovered from (or credited to) customers over a set period. The Company's UAC Year will be the twelve-month period ended June 30 of each year. The annual UAC Recovery Period will be from each November 1 through October 31. The UAC will be a historical reconciliation mechanism, with any deviation from the authorized base level for the prior UAC Year to be collected (or credited) in the subsequent UAC Recovery Period.

Q. PLEASE DESCRIBE THE INITIAL UAC FILING.

A. The initial filing may represent more or less than a full year, depending upon the effective date of base rates in this proceeding. As a component of the SBC, the Company anticipates that the initial UAC rate would be proposed in the SBC filing with the BPU, which will be made on or before July 31, 2025. The filing will reconcile actual uncollectible expense activity against the base level of uncollectible expense collected through rates established in this proceeding as well as through EEP Rider rates and IIP Rider rates for the period beginning on the first of the month closest to the effective date of base rates in this proceeding through June 2025. Once filed with the Board and after its 60-day review, the initial UAC rate would be implemented no later November 1, 2023. The UAC rate will be set at zero until such time as the Board makes the initial UAC rate effective.

Q. PLEASE DESCRIBE SUBSEQUENT UAC FILINGS.

A. On or before July 31 of each year, the Company would make its annual SBC filing, of which the UAC will be a component, with rates effective no later than the subsequent November 1. This filing will include: 1) the difference between the actual uncollectible expense activity for the UAC Year ending June 30 against the base level of uncollectible expense collected through rates established in the Company's most recent base rate case proceeding as well as through EEP Rider rates and IIP Rider rates; and 2) a true up of the actual amount collected from customers versus the amount authorized to be recovered during the UAC Recovery Period ending October 31 of such year.

Q. HAVE ANY OTHER NEW JERSEY UTILITIES IMPLEMENTED OR SOUGHT TO IMPLEMENT A SIMILAR MECHANISM?

A. Public Service Electric & Gas Company is seeking to implement a similar mechanism to recover gas bad debt expenses through the SBC as set forth in its pending rate case petition filed on December 29, 2023.[6] In addition, the recovery of uncollectible expenses through the SBC has been authorized by the Board for the State's electric utilities. There is no reason why Elizabethtown should be treated differently with respect to having a true-up mechanism in place to reconcile actual uncollectible expense activity against the base level of uncollectible expense collected through rates on an annual basis.

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[6] *In the Matter of the Petition of Public Service Electric And Gas Company for Approval of an Increase in Electric and Gas Rates and for Changes in the Tariffs for Electric and Gas Service, B.P.U.N.J. No. 17 Electric and B.P.U.N.J. No. 17 Gas, and for Changes In Depreciation Rates, Pursuant To N.J.S.A. 48:2-18, N.J.S.A. 48:2-21 And N.J.S.A. 48:2-21.1, and for Other Appropriate Relief*, BPU Docket. No. GR23120925.

Q. DOES THE PROPOSED TARIFF INCLUDE ANY NEW RATE SCHEDULES?

A. The Company is proposing that the UAC be a component of the SBC. Proposed changes are reflected in Tariff Schedules TK-24 and TK-25.

X. 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. These proposed changes are as follows:

(i) roll-in the revenues associated with the IIP Rider per actual amounts through June 30, 2023, and reset the IIP Rider rates to remove these amounts;

(ii) increase meter turn-on and reconnection fees from $15 to $45 in an attempt to more closely assign the cost of providing these services to customers on a causal basis as noted on Schedule HSG 2-2;

(iii) certain housekeeping items related to the Clean Energy Program (“CEP”) component of SBC in Rider “D”; and

(iv) including a UAC to enable the Company to recover the costs associated with annual uncollectible expenses as described above.

Q. PLEASE DESCRIBE THE HOUSEKEEPING ITEM RELATED TO THE CEP INCLUDED IN THIS FILING.

A. The Company is making certain housekeeping changes in connection with the Stipulation in the Company’s 2021 Base Rate Case, effective September 1, 2022. The Company is submitting tariff housekeeping changes to correct Sheet Nos. 116 and 117 applicable to the determination of the CEP interest rate. Sections I3(b) and I3(c) of Original Sheet 116 of the Company's current tariff state that interest will be "at the rate applicable to the RAC component of the SBC". Such rate is set annually on a date "on or closest to August 31st of each year." Appendix B of the 2021 Base Rate Case Stipulation required the use of a two year constant maturity Treasury rate for the CEP.

In modifying the CEP annual interest rate from a seven year to a two year constant maturity Treasury rate to align with Appendix B of the 2021 Base Rate Case Stipulation, on Sheet No. 117 the Company inadvertently inserted language from the USF and Lifeline Components section of SBC Rider "D" in the Company's tariff which uses a two year constant maturity Treasury rate that is set monthly rather than annually. In addition to removing any reference to the RAC component of the SBC on Sheet No. 116 and moving the interest language on Sheet No. 117, the revised tariff language reflects a two year constant maturity Treasury rate set annually, as discussed above, which the Company began utilizing effective September 1, 2022 to be consistent with Appendix B of the Stipulation that resolved the Company's previous base rate case in Docket No. GR21121254.

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

A. The Company is proposing to update the BUC for the annualized and normalized customer usages shown on Schedule TK-21. 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 Howard Gorman.

Q. WHAT EFFECTIVE DATE IS THE COMPANY PROPOSING FOR THESE RATES?

A. It is requested that the Proposed Tariff be made effective on September 1, 2024, in compliance with the 2023 Merger Order.

XI. 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 HEATING CUSTOMER USING 100 THERMS.

A. The proposed rates for a residential heating customer using 100 therms would result in a bill increase of $21.92 or 15.8%.

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	$1,862,108,979	TK-2
2	Rate of Return	8.31%	
3	Required Operating Income	154,741,256	
4	Adjusted Net Operating Income	101,055,057	TK-3
5	Income Deficiency	53,686,199	
6	Revenue Factor	1.407418	TK-6
7	Operating Revenue Adjustment to Base Rates	$75,558,923	

ELIZABETHTOWN GAS COMPANY
STATEMENT OF RATE BASE

Line No.		G/L Accounts	6 MONTHS ACTUAL BALANCES AS OF Dec-23	TEST YEAR ADJUSTMENT	12 MONTH RATE BASE 6/30/2024	POST TEST YEAR ADJUSTMENT	ADJUSTED RATE BASE 12/30/2024	REFERENCE TO RATEMAKING ADJUSTMENTS
1	Utility Plant In Service	10100, 10110	$2,351,244,886	$38,198,175	$2,389,443,061	$139,983,782	$2,529,426,843	EP-1
2	Accumulated Depreciation & Amortization	10800, 10810, 10820, 10830, 10850, 29110, Acq Adj.	($481,965,493)	($7,420,289)	($489,385,782)	($9,052,227)	($498,438,009)	JLH-5
3	Net Utility Plant		$1,869,279,393	$30,777,886	$1,900,057,279	$130,931,555	$2,030,988,834	
4	Pension/OPEB	Reg Asset: 16120 Accrued: 27510, 27500	$26,263,347	($1,624,314)	$24,639,033	($1,624,314)	$23,014,719	JLH-9
5	Cash Working Capital		$0	$40,343,966	$40,343,966	$10,131,754	$50,475,720	TK-17
6	Inventory Average Balances	14600, 14610	$0	$10,922,864	$10,922,864	($169,319)	$10,753,545	TK-18
7	Customer Deposits [1]	22000	($4,917,509)	($48,235)	($4,965,744)	($47,310)	($5,013,054)	TK-16
8	Customer Advances [1]	29430	($1,677,027)	$0	($1,677,027)	$0	($1,677,027)	
9	Deferred Income Taxes:							
10	Excess Protected ADIT	28110 Reg Liability	($76,472,651)	$891,207	($75,581,444)	$891,206	($74,690,238)	ADF-3
11	Federal Income Tax	27000	($106,384,825)	($5,205,608)	($111,590,433)	($5,165,834)	($116,756,267)	JLH-6
12	NJ CBT	27000	($50,102,743)	($2,451,621)	($52,554,364)	($2,432,889)	($54,987,253)	JLH-7
13	Consolidated Tax Adjustment		$0	$0	$0	$0	$0	ADF-2
14	Total Rate Base		$1,655,987,985	$73,606,145	$1,729,594,130	$132,514,849	$1,862,108,979	

[1] Represents Thirteen Month Averages of Account Balances

ELIZABETHTOWN GAS COMPANY
OPERATING INCOME STATEMENT

Line No.		6 MONTHS ACTUAL Dec-2023	6 MONTHS PROJECTED DATA	TEST YEAR 12 MOS ENDED 6/30/2024	TEST & POST TEST YR. PRO FORMA ADJUSTMENTS	ANNUALIZATION & NORMALIZATION ADJUSTMENTS	POST TEST YEAR ENDED 3/31/2025	REVENUE DEFICIENCY	POST TEST YEAR 12 MOS ENDED 3/31/2025
1	**Operating Revenues**	$167,982,357	$289,215,783	$457,198,140	($23,908,526)	$37,507,396	$470,797,010	$75,558,923	$546,355,933
2	**Cost of Sales-Rider Revenue Offsets ***	$0	$0	$0	$0	$0	$0	$0	$0
3	**Cost of Sales Purchased Gas**	($40,831,839)	($121,902,388)	($162,734,227)	$0	($16,899,125)	($179,633,352)	$0	($179,633,352)
4	**Operating Margin Revenues**	$127,150,518	$167,313,395	$294,463,913	($23,908,526)	$20,608,271	$291,163,658	$75,558,923	$366,722,581
5	**Operating Expenses:**								
6	**Operation & Maintenance Exps.**	$41,327,306	$52,126,696	$93,454,002	($2,925,568)	$333,778	$90,862,212	$672,399	$91,534,611
7	**Depreciation Expense**	$32,919,138	$35,567,726	$68,486,864	5,300,386	$0	$73,787,250	$0	$73,787,250
8	**Amortization Expense ***	$7,851,262	$15,388,425	$23,239,687	($19,836,742)	$0	$3,402,945	$0	$3,402,945
9	**Taxes Other Than Income Taxes**	$2,532,262	$2,687,357	$5,219,619	$69,263	$103,370	$5,392,252	$208,240	$5,600,492
10	**Federal Income Taxes & NJ CBT**	$4,893,580	$11,027,161	$15,920,741	$1,896,218	$5,670,103	$23,487,062	$20,992,066	$44,479,128
11	**Excess Deferred Tax Amortization**	($603,181)	($891,207)	($1,494,388)	($891,206)	$0	($2,385,594)	$0	($2,385,594)
12	**Total Operating Expenses**	$88,920,367	$115,906,158	$204,826,525	($16,387,649)	$6,107,251	$194,546,127	$21,872,705	$216,418,832
13	**Net Operating Income**	$38,230,151	$51,407,237	$89,637,388	($7,520,877)	$14,501,020	$96,617,531	$53,686,218	$150,303,749
14	**Ratemaking Adjustment - After Tax:**								
15	**Interest on Customer Deposits AT**	$23,777	$90,654	$114,431	$69,922	$0	$184,353	$0	$184,353
16	**CIC Rate Credit Adjustment AT**	$0	$0	$0	($4,621,879)	$0	($4,621,879)	$0	($4,621,879)
17	**Adjusted Net Operating Income**	$38,206,374	$51,316,583	$89,522,957	($2,968,920)	$14,501,020	$101,055,057	$53,686,218	$154,741,275
18	**Total Rate Base**			$1,729,594,130			$1,862,108,979		$1,862,108,979
19	**Return on Rate Base**			5.18%			5.43%		8.31%
20	**Adjusted Net Income**			$51,817,805			$60,461,081		$114,147,299
21	**Return on Equity**			5.26%			5.70%		10.75%

* Rider Offsets were previously in Cost of Sales, now in Depreciation & Amortization.

ELIZABETHTOWN GAS COMPANY
PRO FORMA ADJUSTMENTS TO JUNE 30, 2024 OPERATING INCOME

		Test & Post Test Year Pro Forma Adjustments
1. Rider Operating Revenue Adjustments		
(a) Remove Rider Revenues Adjustments (TK-7)	$	(36,946,874)
(b) IIF Bill Credit January 2024 (TK-7)	$	13,038,348
		(23,908,526)
2. Operation and Maintenance expenses		
(a) Annualization of Payroll (TK-9)	$	1,334,543
(b) Annualization of Benefits (TK-10)	$	344,241
(c) Annualization of Allocated Service Company Salaries & Benefits (TK-11)	$	(996,117)
(d) Amortization of Rate Case expenses (TK-12)	$	429,333
(e) Non-Recoverable and Other Expense Adjustments (TK-13)	$	(5,474,559)
(f) Inflation Adjustment (TK-14)	$	1,436,991
		(2,925,568)
3. Depreciation and Amortization Expense		
(a) Annualize Test Year Depreciation Expense (JLH-5)	$	(960,463)
(b) Annualize Post Test Year Depreciation Expense (JLH-5)	$	4,224,340
(c) Test Year Income Statement Adj. to WP-1 Depreciation TY @ Current Rates	$	2,036,509
		5,300,386
4. Amortization Expense		
(d) Rider Revenue Offsets (TK-7) *	$	(19,836,742)
		(19,836,742)
5. Taxes Other Than Income		
(a) FICA Payroll Tax Adjustment (TK-9)	$	102,093
(b) Adjustment for PUA (TK-15)	$	(32,830)
(c) Extraordinary Item, if any	$	-
		69,263
6. Excess Deferred Tax Amortization		
(a) Excess Deferred Tax Amortization	$	(891,206)
		(891,206)
7. Taxes - Income - Current, Increase / (decrease)		
(a) Interest Synchronization Tax Expense Change (JLH-8)	$	3,727,828
(b) Income Tax effect of adjustments 1 - 5 times tax rate	$	(1,831,610)
		1,896,218

* Previously in Cost of Sales - Rider Revenue Offsets

ELIZABETHTOWN GAS COMPANY
PRO FORMA ADJUSTMENTS TO JUNE 30, 2024 OPERATING INCOME
POST TEST YEAR REVENUE & COST OF GAS ADJUSTMENTS
ANNUALIZATION & NORMALIZATION ADJUSTMENTS

Line No.		Test Year	TK-7 Revenue Adjustments	Annualization & Normalization Adjustments	Net of Adjustments	
1	Income Statement					
2	Operating Revenues	$457,198,140	($23,908,526)	$37,507,396	$470,797,010	
3	Cost of Sales-Rider Revenue Offsets	$0			$0	
4	Cost of Sales Purchased Gas	($162,734,227)		($16,899,125)	($179,633,352)	
5	**Operating Margin Revenues**	$294,463,913	($23,908,526)	$20,608,271	$291,163,658	
		$0	$0	$0	$0	
					Present Proof Revenues	
6	Test Year per Annulaized and Normalized Determinants at Current Rates plus IIP Roll-In:					
7	Total System Base Distribution Revenue including Other Revenues				$278,654,921	HSG-2 Base Rates
8	IIP Revenue Requirement from Rider F to Base Rates				$12,508,737	TK-8 IIP Yrs 3&4
					$291,163,658	HSG-3 Present w/ IIP
9	Net of Operating Margin Revenue Adjustments:					
10	On-System Margin Sharing Credit ("OSMC") Revenue		($173,029)			
11	Energy Efficiency Program ("EEP") Revenue		($8,033,575)			
12	Remediation Adjustment Clause ("RAC") Revenue		($4,338,937)			
13	Clean Energy Program ("CEP") Revenue		($12,489,321)			
14	Infrastructure Investment Program ("IIP") Billed Revenue - Rider to Base Rates		($11,912,012)			
15	IIF Bill Credit January 2024		$13,038,348			
			($23,908,526)			
			-			
16	Annualization and Normalization Adjustments:					
17	IIP Approved Revenue Requirement from Rider F to Base Rates (TK-8)			$12,508,737		
18	Annualization Normalization			$8,099,534		
19	Gas Sales Revenue, Increase / (Decrease)			$16,899,125		
20	Operating Revenues			$37,507,396		
21	Purchase Gas Cost, (Increase) / Decrease			($16,899,125)		
				$20,608,271		

ELIZABETHTOWN GAS COMPANY
DERIVATION OF REVENUE EXPANSION FACTOR

Line No.			
1	Additional Required Revenue Percentage		100.0000%
2	Percentage Adjustment for Uncollectibles		0.8899%
3	BPU Assessments		0.2224%
4	Rate Counsel Assessments		0.0532%
5	Percentage of Income Before State Income Tax		98.8345%
6	State Income Tax Percentage	9.00%	8.8951%
7	Percentage of Income Before Federal Income Tax		89.9394%
8	Federal Income Tax Percentage	21.00%	18.8873%
9	Revenue Expansion Factor - Percent		71.0521%
10	Revenue Expansion Factor - Whole Number		**1.407418**

ELIZABETHTOWN GAS COMPANY
PRO FORMA ADJUSTMENTS TO JUNE 30, 2024 OPERATING INCOME
RIDER and OTHER ADJUSTMENTS

Line No.		TOTAL
1	On-System Margin Sharing Credit (“OSMC”) Revenue	$173,029
2	Energy Efficiency Program (“EEP”) Revenue	$8,033,575
3	Remediation Adjustment Clause (“RAC”) Revenue	$4,338,937
4	Clean Energy Program (“CEP”) Revenue	$12,489,321
5	Infrastructure Investment Program (“IIP”) Billed Revenue - Rider to Base Rates	$11,912,012
6	**Total Rider Revenue Adjustments**	**$36,946,874**
7	IIF Bill Credit January 2024	**($13,038,348)**
8	**Net Revenue Adjustment**	**$23,908,526**

ELIZABETHTOWN GAS COMPANY
INFRASTRUCTURE INVESTMENT PROGRAM (“IIP”)

SUMMARY OF APPROVED AND PROPOSED REVENUE REQUIREMENTS
FROM RIDER "F" TO BASE RATES
YEARS 3 and 4

	Filing Date		12 Months Ending	In-Service Capital *	Revenue Requirement **
Approved	07/15/22	Docket. No. GR22040316, Dated 9-28-22 Effective on: 10-1-22	Jun-22	$58,167,862	$6,300,195
Approved	07/17/23	Docket. No. GR23040270, Dated 9-27-23 Effective on: 10-1-23	Jun-23	$58,402,300	$6,208,542
IIP Revenue Requirement from Rider F to Base Rates				**$116,570,162**	**$12,508,737**

* 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 5 IIP rates go into effect, which remain in Rider F until a future case.

ELIZABETHTOWN GAS COMPANY
PRO FORMA ADJUSTMENTS TO JUNE 30, 2024 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	$38,364,318	$41,142,936	$2,778,618
4	Variable Compensation	$2,064,729	$2,064,729	$0
5	Total Compensation	$40,429,047	$43,207,665	$2,778,618
6	Capitalized Payroll Expenses			
7	Direct Payroll	($15,206,024)	($16,650,099)	($1,444,075)
8	Variable Compensation	($818,373)	($818,373)	$0
9	Capitalized Compensation	($16,024,397)	($17,468,472)	($1,444,075)
10	Net Compensation Expense	$24,404,650	$25,739,193	$1,334,543
11	Retention Bonus Adjustment	$0	$0	$0
12	**Pro Forma Payroll Adjustment (O&M)**	$24,404,650	$25,739,193	**$1,334,543**
13	FICA Tax Rate			7.65%
14	**Pro Forma FICA Payroll Tax Adjustment - Sch. TK-3 Taxes Other than Income**			**$102,093**
15	**Lead Lag Test Year and Post Year:**			
16	Regular Payroll	**$23,158,294**	$24,492,837	**$1,334,543**
17	Variable Compensation	**$1,246,356**	$1,246,356	**$0**
18	Net Compensation Expense	$24,404,650	$25,739,193	$1,334,543

*Additional Post Test Year months include a 4% merit increase effective March 1, 2024.

ELIZABETHTOWN GAS COMPANY
PRO FORMA ADJUSTMENTS TO JUNE 30, 2024 OPERATING INCOME
EMPLOYEE BENEFITS EXPENSE

Line No.		Test Year	Annualized Post Test Year	Adjustment To Test Year
	Employee Benefits Expenses:			
1	Employee Benefits Expense	$7,949,768	$8,491,119	$541,351
2	less: Capitalized Benefits	($2,894,564)	($3,091,674)	($197,110)
3	**Pro Forma Benefits Adjustment**	$5,055,204	$5,399,445	**$344,241**

ELIZABETHTOWN GAS COMPANY
PRO FORMA ADJUSTMENTS TO JUNE 30, 2024 OPERATING INCOME
ALLOCATED SALARIES & BENEFITS EXPENSE TO ETG

Line No.			
	Allocated Service Company Salaries & Benefits Expenses:		
1	Annualized Post Test Year Expenses	$3,698,783	
2	Less: Test Year Expenses	($4,694,900)	
3	**Pro Forma Allocated Expense Adjustment**		**($996,117)**

ELIZABETHTOWN GAS COMPANY
PRO FORMA ADJUSTMENTS TO JUNE 30, 2024 OPERATING INCOME
RATE CASE EXPENSES

Line No.	Category		Expense
1	Legal Expenses		$900,000
2	Consultant Expenses		$215,000
3	Newspaper Notices		$900
4	Court Reporting		$600
5	Postage & Office Supplies		$0
6	Miscellaneous Expenses		$1,500
7	Contingency/Rebuttal Witnesses		$170,000
8	Total Rate Case Expenses		$1,288,000
9	**Pro Forma Adjustment per Amortization Period**	3	**$429,333**

Schedule TK-13
6+6

ELIZABETHTOWN GAS COMPANY
PRO FORMA ADJUSTMENTS TO JUNE 30, 2024 OPERATING INCOME
NON-RECOVERABLE AND OTHER EXPENSE ADJUSTMENTS

Line No.		Proposed In This Case	Adjustment to Test Year
1	**Management Fee Expense, Adjustments per 12 Mos December 2023**		
2	Membership Dues & Subscriptions	($295,112)	
3	Conferences and Seminars	($135,181)	
4	Travel Expense	($129,225)	
5	Entertainment Non-Deductible	($74,347)	
6	Meals and Entertainment	($147,718)	($781,583)
7	**Company Expense, Adjustments**		
8	51350 - Membership Dues & Subscriptions	($205,352)	
9	51410 - Charitable Contributions	($625,359)	
10	51420 - Travel and Entertainment	($139,465)	
11	51390 - Advertising Expense net of Public Notices	($2,245,302)	
12	EE O&M Expenses	($1,795,033)	($5,010,511)
13	**BPU Energy and Water Benchmarking Docket No. QO21071023 ***		
14	Deferred Development & Implementation Costs, not capitalized	$12,500	
15	Deferred Subscription Fees, 4/23 - 3/24	$68,297	
16	Deferred Amount	$80,797	
17	Proposed Recovery Years	3	$26,932
18	9 Mos. Of Year 2 PTY Expenses 7/24 -3/25		$51,223
19	**Transmission Integrity Management Program (TIMP) ***		
20	Deferred Expenses	$0	
21	Proposed Recovery Years	3	$0
22	**BPU Management Audit ***		
23	Deferred BPU Contract Total	$718,140	
24	Proposed Recovery Years	3	$239,380
25	**Total Pro Forma Adjustment - Other O&M Expense**		**($5,474,559)**

* See the Direct Testimony of J. Houseman.

ELIZABETHTOWN GAS COMPANY
PRO FORMA ADJUSTMENTS TO JUNE 30, 2024 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	December 1, 2023	123.7
4	January 1, 2024	123.9
5	Average	123.8
6	GDPIPD Index Value at the End of the Post-Test Year:	
7	March 1, 2025	127.5
8	April 1, 2025	127.7
9	Average	127.6
10	Projected Inflation Rate	3.0695%
11	Calculation of O&M Inflation Adjustment	
12	Post-Test Year Total O&M Expenses	$90,862,212
13	Less: Normalizing Adjustments	
14	Annualization of Payroll (TK-9)	$25,739,193
15	Annualization of Benefits (TK-10)	$5,399,445
16	Annualization of Allocated Service Company Costs (TK-11)	$3,698,783
17	Amortization of Rate Case expenses (TK-12)	$429,333
18	Other Operations and Maintenance Expenses (TK-13)	($5,474,559)
19	Total Normalizing Adjustments	$29,792,195
20	Less: Items Not Subject to Inflation	
21	Pension / OBEP (TK-17.2)	$4,233,062
22	Uncollectibles (TK-17.2)	$10,021,812
23	Total Items Not Subject to Inflation	$14,254,874
24	Residual O&M Expenses	$46,815,143
25	Inflation Rate	3.0695%
26	Pro Forma Adjustment to O&M Expense	**$1,436,991**

ELIZABETHTOWN GAS COMPANY
PRO FORMA ADJUSTMENTS TO JUNE 30, 2024 OPERATING INCOME
REVENUE TAXES - TAXES OTHER THAN INCOME

Line No.		
1	**PUA Adjustments**	
2	Removed IIP Rider Revenues (TK-7) *	($11,912,012)
3	Other	$0
4	Total Revenue Adjustment	($11,912,012)
5	PUA Tax Rate, sum of the BPU and RC Assessment Factors	0.2756%
6	**Pro Forma Adjustment to PUA**	**($32,830)**

* Removed PUA per its replacement with IIP amount on Schedule TK-8 which includes PUA.

Schedule TK-16
6+6

ELIZABETHTOWN GAS COMPANY
PRO FORMA ADJUSTMENTS TO JUNE 30, 2024 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	Dec-22	Actual	309,896	30,453	9.83%	$157	$4,783,297	0.06%	$206	
2	Jan-23	Actual	310,772	30,587	9.84%	$159	$4,869,903	1.40%	$5,610	
3	Feb-23	Actual	311,905	30,624	9.82%	$159	$4,869,086	1.40%	$5,529	
4	Mar-23	Actual	312,360	30,790	9.86%	$161	$4,948,404	1.40%	$5,101	
5	Apr-23	Actual	312,583	30,657	9.81%	$161	$4,926,911	1.40%	$5,664	
6	May-23	Actual	312,594	30,639	9.80%	$162	$4,962,851	1.40%	$5,737	
7	Jun-23	Actual	312,565	30,371	9.72%	$163	$4,949,550	1.40%	$5,815	
TY	Jul-23	Actual	312,637	29,823	9.54%	$165	$4,916,631	1.40%	$5,684	
2	Aug-23	Actual	312,870	29,590	9.46%	$166	$4,920,483	1.40%	$5,801	
3	Sep-23	Actual	313,200	29,314	9.36%	$167	$4,894,513	1.40%	$4,794	
4	Oct-23	Actual	313,910	29,042	9.25%	$169	$4,917,619	1.40%	$5,739	
5	Nov-23	Actual	314,761	28,924	9.19%	$172	$4,963,521	1.40%	$5,963	
6	Dec-23	Actual	315,569	28,713	9.10%	$174	$5,004,847	1.40%	$5,093	$4,917,509
7	Jan-24	Projected	315,013	28,666	9.10%	$174	$4,987,884	5.06%	$21,436	$4,933,246
8	Feb-24	Projected	315,310	28,693	9.10%	$174	$4,992,582	5.06%	$20,072	$4,942,683
9	Mar-24	Projected	315,579	28,718	9.10%	$174	$4,996,932	5.06%	$21,474	$4,952,518
10	Apr-24	Projected	315,793	28,737	9.10%	$174	$5,000,238	5.06%	$20,796	$4,956,505
11	May-24	Projected	315,978	28,754	9.10%	$174	$5,003,196	5.06%	$21,501	$4,962,373
12	Jun-24	Projected	316,200	28,774	9.10%	$174	$5,006,676	5.06%	$20,822	$4,965,744
PTY	Jul-24	Projected	316,444	28,796	9.10%	$174	$5,010,504	5.06%	$21,533	$4,970,433
2	Aug-24	Projected	316,724	28,822	9.10%	$174	$5,015,028	5.06%	$21,552	$4,978,002
3	Sep-24	Projected	317,102	28,856	9.10%	$174	$5,020,944	5.06%	$20,882	$4,985,730
4	Oct-24	Projected	317,836	28,923	9.10%	$174	$5,032,602	5.06%	$21,628	$4,996,352
5	Nov-24	Projected	318,602	28,993	9.10%	$174	$5,044,782	5.06%	$20,981	$5,006,134
6	Dec-24	Projected	319,154	29,043	9.10%	$174	$5,053,482	5.06%	$21,718	$5,013,054
7	Jan-25	Projected	319,491	29,074	9.10%	$174	$5,058,876	5.06%	$21,741	$5,017,210
8	Feb-25	Projected	319,789	29,101	9.10%	$174	$5,063,574	5.06%	$19,655	$5,023,032
9	Mar-25	Projected	320,062	29,126	9.10%	$174	$5,067,924	5.06%	$21,780	$5,028,828
	Post-Test Year Annualization of Interest									
10	Mar-25	Projected	320,062	29,126	9.10%	$174	$5,067,924	5.06%	$256,437	

Rate Base Test Year Adjustment

Line No.			13 mo average
11	Actual Ending	Dec-23	$4,917,509
12	TY ending	Jun-24	$4,965,744
13	Test Year Adjustment		$48,235

Rate Base PTY Pro-Forma Adjustment

Line No.			13 mo average
11	TY ending	Jun-24	$4,965,744
12	To BS PTY Ending	Dec-24	$5,013,054
13	Pro-Forma PTY Adjustment		$47,310

Income Statement Interest Pro-Forma Adjustment

Line No.		Pre Tax	After Tax 71.89%
	Actual	$33,074	$23,777
	Projected	$126,101	$90,654
11	**Test Year Interest**	$159,175	**$114,431**
12	**Post Test Year Annualized Interest**	$256,437	$184,353
13	**Pro-Forma Adjustment**	$97,262	**$69,922**

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 and O&M Expenses									
2	Purchased Gas Costs		$ 162,734,227	445,847	58.65	A	(40.22)	B	18.4300	$ 8,216,960
3	Regular Payroll		23,158,294	63,447	58.65	A	(9.92)	C	48.7300	3,091,772
4	Variable Compensation		1,246,356	3,415	58.65	A	(251.29)	C	(192.6400)	(657,866)
5	Pension/OPEB		4,233,062	11,597	58.65	A	-		58.6500	680,164
6	Retirement Savings Plan		1,539,868	4,219	58.65	A	(23.59)	C	35.0600	147,918
7	Group Insurance		4,042,113	11,074	58.65	A	(42.91)	C	15.7400	174,305
8	Uncollectible Expense		9,349,413	25,615	58.65	A	(274.24)	C	(215.5900)	(5,522,338)
9	Service Company Charges		28,579,136	78,299	58.65	A	(42.88)	C	15.7700	1,234,775
10	Other Third-Party O&M Expenses		21,305,760	58,372	58.65	A	(39.15)	C	19.5000	1,138,254
11	Total Gas Costs and O&M Expenses		$ 256,188,229				.			$ 8,503,944
12	Income Taxes									
13	Excess Deferred Tax Amortization		$ (1,494,388)	(4,094)	58.65		-		58.6500	$ (240,113)
14	Federal Income Taxes	21%	10,823,386	29,653	58.65	A	(37.00)	D	21.6500	641,987
15	State Income Tax	9%	5,097,356	13,965	58.65	A	(37.00)	D	21.6500	302,342
16	Total Income Taxes		$ 14,426,354							$ 704,216
17	Taxes Other Than Income Taxes		$ 5,219,619	14,300	58.65	A	(17.82)	E	40.8300	$ 583,869
18	Depreciation Expense		$ 68,486,864	187,635	58.65	A	-		58.6500	$ 11,004,793
19	Amortization Expense		$ 23,239,687	63,670	58.65	A	-		58.6500	$ 3,734,246
20	Interest Expense									
21	Interest on Long-Term Debt		$ 39,272,444	107,596	58.65	A	-	F	58.6500	$ 6,310,505
22	Interest on Short-Term Debt		-	-	58.65	A	-	F	58.6500	-
23	Interest on Customer Deposits		114,431	314	58.65	A	(250.43)	F	(191.7800)	(60,219)
24	Total Interest Expense		$ 39,386,875							$ 6,250,286
25	Return		$ 50,250,513	137,673	58.65	A	-		58.6500	$ 8,074,521
26	Other Adjustments									
27	Incidental collections									$ 1,985,982
28	Employee deductions									(497,891)
29	Total Other Adjustments		$ -	$ -						$ 1,488,091
30	Total		$ 457,198,141	$ 339,608						**$ 40,343,966**

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 and O&M Expenses										
2	Purchased Gas Costs		$16,899,125	$ 179,633,352	492,146	58.65	A	(40.22)	B	18.4300	$ 9,070,251
3	Regular Payroll		1,334,543	24,492,837	67,104	58.65	A	(9.92)	C	48.7300	3,269,978
4	Variable Compensation		-	1,246,356	3,415	58.65	A	(251.29)	C	(192.6400)	(657,866)
5	Pension/OPEB		0	4,233,062	11,597	58.65	A	-		58.6500	680,164
6	Retirement Savings Plan		0	1,539,868	4,219	58.65	A	(23.59)	C	35.0600	147,918
7	Group Insurance		344,241	4,386,354	12,017	58.65	A	(42.91)	C	15.7400	189,148
8	Uncollectible Expense		672,399	10,021,812	27,457	58.65	A	(274.24)	C	(215.5900)	(5,919,455)
9	Service Company Charges		(996,117)	27,583,019	75,570	58.65	A	(42.88)	C	15.7700	1,191,739
10	Other Third-Party O&M Expenses		(3,274,457)	18,031,303	49,401	58.65	A	(39.15)	C	19.5000	963,320
11	Total Gas Costs and O&M Expenses		(359,266,704)	$ 271,167,963				.			$ 8,935,197
12	Income Taxes										
13	Excess Deferred Tax Amortization			$ (2,385,594)	(6,536)	58.65		-		58.6500	$ (383,336)
14	Federal Income Taxes	21.00%		30,238,213	82,844	58.65	A	(37.00)	D	21.6500	1,793,573
15	State Income Tax	9.00%		14,240,917	39,016	58.65	A	(37.00)	D	21.6500	844,696
16	Total Income Taxes			$ 42,093,536							$ 2,254,933
17	Taxes Other Than Income Taxes			$ 5,600,492	15,344	58.65	A	(17.82)	E	40.8300	$ 626,496
18	Depreciation Expense			$ 73,787,250	202,157	58.65	A	-		58.6500	$ 11,856,508
19	Amortization Expense			$ 3,402,945	9,323	58.65	A	-		58.6500	$ 546,794
20	Interest Expense										
21	Interest on Long-Term Debt			$ 34,164,877	93,602	58.65	A	-	F	58.6500	$ 5,489,757
22	Interest on Short-Term Debt			-	-	58.65	A	-	F	58.6500	-
23	Interest on Customer Deposits			184,353	505	58.65	A	(250.43)	F	(191.7800)	(96,849)
24	Total Interest Expense			$ 34,349,230							$ 5,392,908
25	Return			$ 120,576,379	330,346	58.65	A	-		58.6500	$ 19,374,793
26	Other Adjustments										
27	Incidental collections										$ 1,985,982
28	Employee deductions										(497,891)
29	Total Other Adjustments			$ -	$ -						$ 1,488,091
30	Total			$ 550,977,795	$ 547,847						**$ 50,475,720**

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	$10,486,010	$10,316,691
2	Materials and Supplies *	$436,854	$436,854
3	**Total**	**$10,922,864**	**$10,753,545**

* Based on 13 Mo. through: Dec-23

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ELIZABETHTOWN GAS COMPANY
Revenue Proof Billing Determinants

		Number of Bills Test Year 12 *'s March-2025	Daily Contract Quantity (DCQ) Monthly Therms	Annual Therms =Mo DCQ Thms*12	Therms Post Test Year	Customer Annualization to: March-2025	Total Therms
RDSH	Residential Heating	3,184,476			255,344,703	1,291,355	256,636,058
RDSNH	Residential Non-Heating	369,252			7,955,904	14,661	7,970,565
RDS	Residential Delivery Service	3,553,728			263,300,607	1,306,016	264,606,623
SGS	Small General Service	205,236			25,501,773	(20,902)	25,480,871
GDS	General Delivery Service	80,388	1,880,123.0	22,561,476	123,045,436	1,242,309	124,287,745
GDSAC May-Oct	GDS - CIAC , May-Oct Discounted Rate	48	-	-	19,185	-	19,185
GDSEDS	GDS Economic Development	12	-	-	13,827	-	13,827
NGV	Public Station, per therm	12	-	-	116,571	-	116,571
LVD	Large Volume Demand	660	373,822.7	4,485,872	49,432,246	-	49,432,246
EGF	Electric Generation Firm	-	-	-	0	-	-
GLS	Unmetered Gas Light, per mantle	60	-	-	2,304	-	2,304
CSI	Interruptible Cogeneration Srv.	-	-	-	0	-	-
IS	Interruptible Service	-	-	-	0	-	-
ITS-IS	Interruptible Transportation Srv.	120	24,083.5	289,002	1,991,169	-	1,991,169
ITS-CSI	Interruptible Transportation Srv.	-	-	-	0	-	-
ITS-LVD	Int.Trans.Srv.	408	309,058.1	3,708,697	31,740,712	-	31,740,712
Proof Flex and Special Contracts:							
FTS-MSC		24	-	-	18,345,133	-	18,345,133
CS-4		12	-	-	3,848,170	-	3,848,170
S.B ITS -LVD Flex		12	52,498.5	629,982	266,730	-	266,730
D.NP All ITS-LVD		12	-	-	7,436,366	-	7,436,366
M.ULT. ITS-LVD		12	-	-	16,485,748	-	16,485,748
	Total	3,840,744	2,639,585.8	31,675,029	541,545,977	2,527,423	544,073,400

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

Schedule TK- 20
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Consisting of 2 Pages

	Proof Rate Classes	Jul-23 Actual	Aug-23 Actual	Sep-23 Actual	Oct-23 Actual	Nov-23 Actual	Dec-23 Actual	Jan-24 Projected	Feb-24 Projected	Mar-24 Projected	Apr-24 Projected	May-24 Projected	Jun-24 Projected
RDSH	Residential Heating	254,473	258,721	259,011	259,611	260,295	260,798	260,666	260,946	261,203	261,394	261,574	261,781
RDSNH	Residential Non-Heating	34,488	30,520	30,517	30,533	30,550	30,697	30,586	30,599	30,608	30,619	30,629	30,642
RDS	Residential Delivery Service	288,961	289,241	289,528	290,144	290,845	291,495	291,252	291,545	291,811	292,013	292,203	292,423
SGS	Small General Service	17,286	17,244	17,277	17,343	17,464	17,575	17,181	17,178	17,171	17,161	17,143	17,126
GDS	General Delivery Service	6,279	6,274	6,284	6,312	6,344	6,387	6,464	6,471	6,481	6,503	6,516	6,535
GDSAC	GDS - CIAC	4	4	4	4	4	4	4	4	4	4	4	4
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	53	52	53	53	52	53	55	55	55	55	55	55
EGF	Electric Generation Firm	-	-	-	-	-	-	-	-	-	-	-	-
GLS	Unmetered Gas Light, per mantle	5	5	5	5	5	5	5	5	5	5	5	5
CSI	Interruptible Cogeneration Srv.	-	-	-	-	-	-	-	-	-	-	-	-
IS	Interruptible Service	-	-	-	-	-	-	-	-	-	-	-	-
ITS-IS	Interruptible Transportation Srv.	10	10	10	10	7	7	10	10	10	10	10	10
ITS-CSI	Interruptible Transportation Srv.	-	-	-	-	-	-	-	-	-	-	-	-
ITS-LVD	Int.Trans.Srv.	31	32	31	31	32	35	34	34	34	34	34	34
Proof Flex and Special Contracts:													
FTS-MSC		1	1	1	1	1	1	2	2	2	2	2	2
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	312,637	312,870	313,200	313,910	314,761	315,569	315,013	315,310	315,579	315,793	315,978	316,200
RDSH	Residential Heating	4,558,876	6,069,323	5,396,720	10,620,656	28,634,680	32,346,289	45,488,108	45,653,706	37,304,299	27,393,005	12,241,379	6,021,894
RDSNH	Residential Non-Heating	251,562	332,928	203,655	300,627	550,885	640,167	1,232,687	1,248,057	1,150,017	871,135	481,110	337,238
RDS	Residential Delivery Service	4,810,438	6,402,251	5,600,375	10,921,283	29,185,565	32,986,456	46,720,795	46,901,763	38,454,316	28,264,140	12,722,489	6,359,132
SGS	Small General Service	422,382	662,200	525,261	1,064,214	2,877,102	3,893,312	4,850,222	4,989,254	3,946,286	2,692,381	1,028,053	586,927
GDS	General Delivery Service	3,177,255	3,969,570	3,821,617	6,344,777	13,386,349	15,549,822	19,943,218	19,502,389	16,592,728	12,118,755	5,701,145	3,865,543
GDSAC	GDS CIAC	3,843	10,056	2,205	1,323	4,080	3,268	14,144	13,858	11,715	8,676	4,150	2,896
GDSEDS	Public Station, per therm	361	464	1,154	7,111	11,961	17,123	2,364	2,295	1,973	1,373	609	373
NGV	Public Station, per therm	9,618	8,648	5,953	6,068	5,604	6,504	15,101	10,619	8,982	5,201	4,859	7,497
LVD	Large Volume Demand	2,861,371	3,251,166	3,427,620	4,415,318	3,634,390	4,484,936	5,115,326	4,769,876	4,733,291	3,918,125	3,870,994	3,428,229
EGF	Electric Generation Firm	-	-	-	-	-	-	-	-	-	-	-	-
GLS	Unmetered Gas Light, per mantle	192	192	192	192	192	192	192	192	192	192	192	192
CSI	Interruptible Cogeneration Srv.	-	-	-	-	-	-	-	-	-	-	-	-
IS	Interruptible Service	-	-	-	-	-	-	-	-	-	-	-	-
ITS-IS	Interruptible Transportation Srv.	113,159	128,937	119,341	145,666	192,432	127,516	226,428	205,423	221,006	163,736	150,654	121,762
ITS-CSI	Interruptible Transportation Srv.	-	-	-	-	-	-	-	-	-	-	-	-
ITS-LVD	Int.Trans.Srv.	2,158,292	2,174,038	2,194,874	2,298,501	2,258,577	1,977,892	2,688,232	2,529,000	2,745,924	2,417,192	2,701,263	2,479,622
Proof Flex and Special Contracts:													
FTS-MSC		1,303,922	1,519,197	1,457,213	1,466,400	1,228,070	1,485,176	556,219	1,201,443	1,556,880	1,063,993	1,602,091	1,442,420
CS-4		2,561,770	272,000	462,070	368,380	-	4,050	-	171,150	5,410	-	-	230,840
S.B ITS -LVD Flex		14,324	14,438	6,056	10,196	54,376	17,795	164,822	69,853	6,622	73,233	423	6,882
D.NP All ITS-LVD		499,570	497,089	477,318	499,792	501,710	636,145	794,517	756,985	834,179	771,640	523,050	770,290
M.ULT. ITS-LVD		1,441,147	1,472,458	1,462,240	1,259,773	1,628,403	1,779,204	1,640,220	1,558,000	1,509,428	1,461,038	1,288,677	1,288,692
	Total	19,377,644	20,382,704	19,563,489	28,808,994	54,968,811	62,969,391	82,731,800	82,682,100	70,628,932	52,959,675	29,598,649	20,591,297

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

Schedule TK- 20
6+6
Consisting of 2 Pages

	Proof Rate Classes	Apr-24 Projected	May-24 Projected	Jun-24 Projected	Jul-24 Projected	Aug-24 Projected	Sep-24 Projected	Oct-24 Projected	Nov-24 Projected	Dec-24 Projected	Jan-25 Projected	Feb-25 Projected	Mar-25 Projected
RDSH	Residential Heating	261,394	261,574	261,781	262,007	262,265	262,625	263,316	264,031	264,534	264,830	265,113	265,373
RDSNH	Residential Non-Heating	30,619	30,629	30,642	30,655	30,668	30,679	30,704	30,720	30,736	30,749	30,762	30,771
RDS	Residential Delivery Service	292,013	292,203	292,423	292,662	292,933	293,304	294,020	294,751	295,270	295,579	295,875	296,144
SGS	Small General Service	17,161	17,143	17,126	17,112	17,106	17,101	17,097	17,107	17,115	17,116	17,110	17,103
GDS	General Delivery Service	6,503	6,516	6,535	6,554	6,569	6,581	6,603	6,628	6,653	6,680	6,688	6,699
GDSAC	GDS - CIAC	4	4	4	4	4	4	4	4	4	4	4	4
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	55	55	55	55	55	55	55	55	55	55	55	55
EGF	Electric Generation Firm	-	-	-	-	-	-	-	-	-	-	-	-
GLS	Unmetered Gas Light, per mantle	5	5	5	5	5	5	5	5	5	5	5	5
CSI	Interruptible Cogeneration Srv.	-	-	-	-	-	-	-	-	-	-	-	-
IS	Interruptible Service	-	-	-	-	-	-	-	-	-	-	-	-
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		2	2	2	2	2	2	2	2	2	2	2	2
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	315,793	315,978	316,200	316,444	316,724	317,102	317,836	318,602	319,154	319,491	319,789	320,062

		Apr-24	May-24	Jun-24	Jul-24	Aug-24	Sep-24	Oct-24	Nov-24	Dec-24	Jan-25	Feb-25	Mar-25	Total Post Test Year
RDSH	Residential Heating	27,809,987	12,419,168	6,104,523	6,103,654	6,103,553	6,103,701	6,759,695	19,614,987	34,713,900	46,309,499	46,693,516	37,899,875	256,636,058
RDSNH	Residential Non-Heating	875,460	483,340	338,658	277,110	277,225	276,932	286,745	569,875	933,863	1,240,143	1,255,073	1,156,141	7,970,565
RDS	Residential Delivery Service	28,685,447	12,902,508	6,443,181	6,380,764	6,380,778	6,380,633	7,046,440	20,184,862	35,647,763	47,549,642	47,948,589	39,056,016	264,606,623
SGS	Small General Service	2,683,281	1,025,654	586,139	586,024	585,023	598,505	652,771	1,511,040	3,437,185	4,857,976	4,997,030	3,960,243	25,480,871
GDS	General Delivery Service	12,484,013	5,861,260	3,962,551	3,962,005	3,967,459	3,969,259	4,971,152	10,147,889	17,030,383	20,615,443	20,131,839	17,117,164	124,220,417
GDSAC	GDS CIAC	8,676	4,150	2,896	2,900	2,908	2,914	3,417	7,082	11,635	14,220	13,930	11,785	86,513
GDSEDS	Public Station, per therm	1,373	609	373	373	374	375	567	1,126	1,996	2,374	2,305	1,982	13,827
NGV	Public Station, per therm	5,201	4,859	7,497	9,618	8,648	5,953	6,068	12,260	21,765	15,101	10,619	8,982	116,571
LVD	Large Volume Demand	3,918,125	3,870,994	3,428,229	3,263,252	3,757,399	3,237,331	4,083,399	4,417,575	5,219,484	4,769,876	4,733,291	4,733,291	49,432,246
EGF	Electric Generation Firm	-	-	-	-	-	-	-	-	-	-	-	-	-
GLS	Unmetered Gas Light, per mantle	192	192	192	192	192	192	192	192	192	192	192	192	2,304
CSI	Interruptible Cogeneration Srv.	-	-	-	-	-	-	-	-	-	-	-	-	-
IS	Interruptible Service	-	-	-	-	-	-	-	-	-	-	-	-	-
ITS-IS	Interruptible Transportation Srv.	163,736	150,654	121,762	112,855	119,079	120,796	148,660	179,253	226,939	205,423	221,006	221,006	1,991,169
ITS-CSI	Interruptible Transportation Srv.	-	-	-	-	-	-	-	-	-	-	-	-	-
ITS-LVD	Int.Trans.Srv.	2,417,192	2,701,263	2,479,622	2,305,148	2,845,718	2,744,798	2,532,201	2,713,905	2,980,017	2,529,000	2,745,924	2,745,924	31,740,712
Proof Flex and Special Contracts:		-	-	-	-	-	-	-	-	-	-	-	-	
FTS-MSC		1,063,993	1,602,091	1,442,420	1,303,922	1,543,410	1,480,170	1,549,481	1,548,143	1,332,300	1,589,443	1,944,880	1,944,880	18,345,133
CS-4		-	-	230,840	2,561,770	272,000	226,920	-	6,720	367,950	171,150	5,410	5,410	3,848,170
S.B ITS -LVD Flex		73,233	423	6,882	11,459	4,272	231	27,571	27,570	31,992	69,853	6,622	6,622	266,730
D.NP All ITS-LVD		771,640	523,050	770,290	497,072	422,882	386,182	218,455	604,099	817,353	756,985	834,179	834,179	7,436,366
M.ULT. ITS-LVD		1,461,038	1,288,677	1,288,692	1,334,967	1,307,147	1,193,546	1,340,950	994,321	1,699,554	1,558,000	1,509,428	1,509,428	16,485,748
	Total	53,737,140	29,936,384	20,771,566	22,332,321	21,217,289	20,347,805	22,581,324	42,356,037	68,826,508	84,704,678	85,105,244	72,157,104	544,073,400

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

Schedule TK- 21
6+6

		Apr-24	May-24	Jun-24	Jul-24	Aug-24	Sep-24	Oct-24	Nov-24	Dec-24	Jan-25	Feb-25	Mar-25	
		4	5	6	7	8	9	10	11	12	1	2	3	Sum Of
		Projected	Projected	Projected	Projected	Projected	Projected	Projected	Projected	Projected	Projected	Projected	Projected	Bills & Therms
Customer Counts:														
RDSH	Residential Heating	261,394	261,574	261,781	262,007	262,265	262,625	263,316	264,031	264,534	264,830	265,113	265,373	3,158,843
RDSNH	Residential Non-Heating	30,619	30,629	30,642	30,655	30,668	30,679	30,704	30,720	30,736	30,749	30,762	30,771	368,334
RDS	Residential Delivery Service	292,013	292,203	292,423	292,662	292,933	293,304	294,020	294,751	295,270	295,579	295,875	296,144	3,527,177
SGS	Small General Service	17,161	17,143	17,126	17,112	17,106	17,101	17,097	17,107	17,115	17,116	17,110	17,103	205,397
GDS	General Delivery Service	6,508	6,521	6,540	6,559	6,574	6,586	6,608	6,633	6,658	6,685	6,693	6,704	79,269
	Total	315,682	315,867	316,089	316,333	316,613	316,991	317,725	318,491	319,043	319,380	319,678	319,951	3,811,843
Therms:	**Forecast Pre Annualization**													
RDSH	Residential Heating	27,393,005	12,241,379	6,021,894	6,026,235	6,032,069	6,040,496	6,707,298	19,515,793	34,604,149	46,214,742	46,647,768	37,899,875	255,344,703
RDSNH	Residential Non-Heating	871,135	481,110	337,238	276,065	276,297	276,104	286,121	568,930	932,801	1,239,256	1,254,706	1,156,141	7,955,904
RDS	Residential Delivery Service	28,264,140	12,722,489	6,359,132	6,302,300	6,308,366	6,316,600	6,993,419	20,084,723	35,536,950	47,453,998	47,902,474	39,056,016	263,300,607
SGS	Small General Service	2,692,381	1,028,053	586,927	586,332	585,126	598,435	652,542	1,511,393	3,439,597	4,861,669	4,999,075	3,960,243	25,501,773
GDS	General Delivery Service	12,128,804	5,705,904	3,868,812	3,879,520	3,893,749	3,902,631	4,903,897	10,048,544	16,927,072	20,573,567	20,115,017	17,130,931	123,078,448
	Total	43,085,325	19,456,446	10,814,871	10,768,152	10,787,241	10,817,666	12,549,858	31,644,660	55,903,619	72,889,234	73,016,566	60,147,190	411,880,828
Therms:	**Annualization Adjustments**													
RDSH	Residential Heating	416,982	177,789	82,629	77,419	71,484	63,205	52,397	99,194	109,751	94,757	45,748	0	1,291,355
RDSNH	Residential Non-Heating	4,325	2,230	1,420	1,045	928	828	624	945	1,062	887	367	0	14,661
RDS	Residential Delivery Service	421,307	180,019	84,049	78,464	72,412	64,033	53,021	100,139	110,813	95,644	46,115	0	1,306,016
SGS	Small General Service	(9,100)	(2,399)	(788)	(308)	(103)	70	229	(353)	(2,412)	(3,693)	(2,045)	0	(20,902)
GDS	General Delivery Service	365,258	160,115	97,008	85,758	76,992	69,917	71,239	107,553	116,942	58,470	33,057	0	1,242,309
	Total	777,465	337,735	180,269	163,914	149,301	134,020	124,489	207,339	225,343	150,421	77,127	0	2,527,423
Therms:	**Annualized**													
RDSH	Residential Heating	27,809,987	12,419,168	6,104,523	6,103,654	6,103,553	6,103,701	6,759,695	19,614,987	34,713,900	46,309,499	46,693,516	37,899,875	256,636,058
RDSNH	Residential Non-Heating	875,460	483,340	338,658	277,110	277,225	276,932	286,745	569,875	933,863	1,240,143	1,255,073	1,156,141	7,970,565
RDS	Residential Delivery Service	28,685,447	12,902,508	6,443,181	6,380,764	6,380,778	6,380,633	7,046,440	20,184,862	35,647,763	47,549,642	47,948,589	39,056,016	264,606,623
SGS	Small General Service	2,683,281	1,025,654	586,139	586,024	585,023	598,505	652,771	1,511,040	3,437,185	4,857,976	4,997,030	3,960,243	25,480,871
GDS	General Delivery Service	12,494,062	5,866,019	3,965,820	3,965,278	3,970,741	3,972,548	4,975,136	10,156,097	17,044,014	20,632,037	20,148,074	17,130,931	124,320,757
	Total	43,862,790	19,794,181	10,995,140	10,932,066	10,936,542	10,951,686	12,674,347	31,851,999	56,128,962	73,039,655	73,093,693	60,147,190	414,408,251
CIP-BUC	**Annualized Therms / End of PTY Customer Count:**													Sum of Months
RDSH	Residential Heating	104.8	46.8	23.0	23.0	23.0	23.0	25.5	73.9	130.8	174.5	176.0	142.8	967.1
RDSNH	Residential Non-Heating	28.5	15.7	11.0	9.0	9.0	9.0	9.3	18.5	30.3	40.3	40.8	37.6	259.0
SGS	Small General Service	156.9	60.0	34.3	34.3	34.2	35.0	38.2	88.3	201.0	284.0	292.2	231.6	1,490.0
GDS	General Delivery Service	1,863.7	875.0	591.6	591.5	592.3	592.6	742.1	1,514.9	2,542.4	3,077.6	3,005.4	2,555.3	18,544.4

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
Src: Harbor Front Weather Normals Tab

Test Year		Post Test Year	
Month	**Degree Days Base 65ºF**	**Month**	**Degree Days Base 65ºF**
Jul-23	0	Apr-24	342
Aug-23	0	May-24	43
Sep-23	0	Jun-24	0
Oct-23	201	Jul-24	0
Nov-23	514	Aug-24	0
Dec-23	810	Sep-24	0
Jan-24	1,005	Oct-24	201
Feb-24	842	Nov-24	514
Mar-24	683	Dec-24	810
Apr-24	342	Jan-25	1,005
May-24	43	Feb-25	842
Jun-24	0	Mar-25	683
Total	**4,440**	**Total**	**4,440**

ELIZABETHTOWN GAS COMPANY
2024 Rate Case

Proposed Bill Changes
To March 1, 2024 Rates

Residential Service	Class Avg Thms	From	Rate Change	To	$$$ Change	% Chg.
Customer Charge		$10.50	1.50	$12.00		
Distribution Charge		$0.5797	0.2393	$0.8190		
BGSS-P		$0.5042	-	$0.5042		
CIP		$0.0858	-	$0.0858		
IIP		$0.0351	(0.0351)	$0.0000		
CAC, all other Riders		$0.0795	-	$0.0795		
100 Therm Bill	100	$138.93		$160.85	$21.92	15.8%
Ann 1,000 Therm Bill	1,000	$1,410.30		$1,632.50	$222.20	15.8%
Small General Service						
Customer Charge		$36.79	4.26	$41.05		
Distribution Charge		$0.4522	0.2005	$0.6527		
BGSS-P		$0.5042	-	$0.5042		
CIP		$0.0199	-	$0.0199		
IIP		$0.0375	(0.0375)	$0.0000		
CAC, all other Riders		$0.0795	-	$0.0795		
Average Bill	124	$172.36		$196.83	$24.47	14.2%
Average Annual Bill	1,490	$2,070.50		$2,364.49	$293.99	14.2%
General Delivery Service						
Customer Charge		$61.84	3.09	$64.93		
Demand Charge	280	$1.162	0.269	$1.431		
Distribution Charge		$0.2895	0.0671	$0.3566		
BGSS-M, using P as a proxy		$0.5042	-	$0.5042		
CIP		($0.0078)	-	($0.0078)		
IIP		$0.0275	(0.0275)	$0.0000		
CAC, all other Riders		$0.0795	-	$0.0795		
Average Bill	1,545	$1,766.73		$1,906.32	$139.59	7.9%
Average Annual Bill	18,544	$20,476.20		$22,117.61	$1,641.41	8.0%

ELIZABETHTOWN GAS COMPANY

TARIFF FOR GAS SERVICE
B.P.U. NO. 19

2024 Rate Case

ELIZABETHTOWN GAS COMPANY

TARIFF FOR GAS SERVICE

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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 (26^{th}) 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. A charge of $45.00 shall be made when the Company turns on or restores 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.

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. <u>NEGOTIATED RATES, TERMS AND CONDITIONS</u>

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	$12.00	$12.00
Distribution Charge per Therm	$0.8190	$0.8190
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	$41.05	$41.05
Distribution Charge per Therm	$0.6527	$0.6527
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	$64.93	$64.93
Demand Charge per DCQ	$1.431	$1.431
Distribution Charge per Therm	$0.3566	$0.3566
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 $0.0798 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.

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 – 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 - $0.6313 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	$0.6313 per therm
Fueling Station Charge	$0.4842 per therm
Facilities Charge	$0.4017 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	$395.00	$421.17
Demand Charge per DCQ	$2.147	$2.289
Distribution Charge per Therm	$0.0427	$0.0455
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	$100.00	$106.63
Demand Charge per DCQ	$0.878	$0.936
Distribution Charge per Therm	$0.0462	$0.0493
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 $13.17 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	$152.00	$162.07
Quantity Charge	*	*

*The Quantity Charge shall be the monthly Basic Gas Supply Service Charge (“BGSS-M”) plus $0.0351 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	$773.03
Demand Charge per DCQ	$0.144
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 $0.0986 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 sulfur 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 $0.05 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.

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 – 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 $0.05 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 $0.0708 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	$725.00	$773.03
Demand Charge per DCQ	$0.585	$0.624
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 $0.1322 per therm or $0.1240 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 $0.03 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 $0.02 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
March 1, 2023	$0.5011	$0.2692
April 1, 2023	$0.4512	$0.2692
May 1, 2023	$0.4649	$0.2692
June 1, 2023	$0.4719	$0.2692
July 1, 2023	$0.5177	$0.2692
August 1, 2023	$0.5056	$0.2692
September 1, 2023	$0.5125	$0.2692
October 1, 2023	$0.5352	$0.2692
November 1, 2023	$0.5785	$0.2692
December 1, 2023	$0.5289	$0.3255
January 1, 2024	$0.5194	$0.3255
February 1, 2024	$0.5054	$0.3846
March 1, 2024	*	$0.5042

**To be determined*

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”)

Suspended October 1, 2021

For the duration of the Conservation Incentive Program, Rider “G”:

Section I below shall only be utilized to calculate the value of the weather-related changes in customer usage in the Conservation Incentive Program. The deadband degree days shall not be included in this calculation. For all other purposes, Sections I through III below shall be suspended as of October 1, 2021.

Applicable to all customers in service classifications RDS, SGS and GDS.

October 1 through May 31 of any year	$0.0000 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	201	201
November	514	514
December	810	810
January	1,005	1,005
February.	842	872
March	683	683
April	342	342
May	43	43
Total	4,440	4,470

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 for purposes of calculating the weather-related portion of the CIP are as follows:

Month	Base Number of Customers	Therms per Degree Day
October	313,804	51,924
November	314,658	62,695
December	315,462	69,188
January	314,902	68,423
February	315,199	65,801
March	315,468	63,989
April	315,682	52,634
May	315,867	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 $0.6319 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.

($0.0045) 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.	Clean Energy Program ("CEP")	$0.0270
II.	Remediation Adjustment Charge ("RAC")	$0.0225
III.	Universal Service Fund and Lifeline:	
	1. Universal Service Fund ("USF")	$0.0115
	2. Lifeline	$0.0062
IV.	Uncollectible Adjustment Clause ("UAC")[1]	$0.0000
	TOTAL	$0.0672

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.

[1] As a component of the SBC, the initial UAC rate would be proposed in an annual filing with the BPU on or about July 31, 2025. The UAC rate will be set at zero prior to this date.

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 CEP 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, 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. Per Board Order dated August 17, 2022 in Docket No. GR21121254, the interest rate on CEP 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 August[3]1st of each year (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.

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.

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. Uncollectible Adjustment Clause Component ("UAC")

A provision that authorizes the utility to adjust its rates to compensate for an increase or decrease in uncollectible expense, established by Board Order dated XXXXXX in Docket No. XXXXXX.

1. The rates currently approved in this tariff include a projected uncollectible expense of $XXXX or XXXX%. The actual amount of uncollectible expense will be tracked and compared to the authorized amount of uncollectible expense.

   The UAC Year will be from July 1 through June 30. As part of an annual filing with the BPU due on or about July 31 of each year, the Company will file the UAC calculation and support for annual adjustments to be made effective under this tariff. The BPU will have 60 days to review the filing. Any under- or over-collection will be recovered from or credited to customers via a surcharge or credit, respectively, from October 1 through September 30 following the filing date.

V. 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.

RIDER "D"

SOCIETAL BENEFITS CHARGE ("SBC")
(continued)

V. LCAPP Exemption Procedures (continued)

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:

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. 23070478, per a four-year amortization	$0.0006 per therm
Docket No. 23070478, per a ten-year amortization	$0.0162 per therm
TOTAL	$0.0168 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.

Cost recovery under the IIP is contingent on an earnings test. If the product of the earnings test calculation exceeds the Company's most recently approved ROE by fifty (50) basis points or more, cost recovery under the IIP shall not be allowed. Any disallowance resulting from the earnings test will not be charged to customers in a subsequent IIP filing period, but the Company may seek such recovery in a subsequent base rate case.

RIDER "F"

INFRASTRUCTURE INVESTMENT PROGRAM ("IIP")

(continued)

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 jurisdictional common equity balance for such annual period. The average jurisdictional common equity balance will be derived by multiplying the average of the Company's beginning and ending net rate base for the annual period by the Board-approved equity ratio in the Company's most recent rate case. The Company's regulated jurisdictional net income shall be calculated by subtracting from total net income the Company's share of margins from: (1) Interruptible Sales; (2) Interruptible Transportation; (3) Off-System Sales and Capacity Release; and (4) the Energy Efficiency Program.

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
$0.0156 per therm	$0.0858 per therm	$0.0199 per therm	($0.0078) 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	9.0	23.0	34.3	591.5
August	9.0	23.0	34.2	592.3
September	9.0	23.0	35.0	592.6
October	9.3	25.5	38.2	742.1
November	18.5	73.9	88.3	1,514.9
December	30.3	130.8	201.0	2,542.4
January	40.3	174.5	284.0	3,077.6
February	40.8	176.0	292.2	3,005.4
March	37.6	142.8	231.6	2,555.3
April	28.5	104.8	156.9	1,863.7
May	15.7	46.8	60.0	875.0
June	11.0	23.0	34.3	591.6
Total Annual	259.0	967.1	1,490.0	18,544.4

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) Cost recovery under the CIP is contingent on an earnings test. If the product of the earnings test calculation exceeds the Company's most recently approved ROE by fifty (50) basis points or more, cost recovery under the CIP shall not be allowed.

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 jurisdictional common equity balance for such annual period. The average jurisdictional common equity balance will be derived by multiplying the average of the Company's beginning and ending net rate base for the annual period by the Board approved equity ratio in the Company's most recent rate case. The Company's regulated jurisdictional net income shall be calculated by subtracting from total net income the CIP booked margin revenue accruals and the Company's share of margins from: (1) Interruptible Sales; (2) Interruptible Transportation; (3) Off-System Sales and Capacity Release; and (4) the Energy Efficiency 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-HTG	RDS Heating	SGS	GDS
Service Charge (monthly)	$12.00	$12.00	$41.05	$64.93
Distribution	$0.8190	$0.8190	$0.6527	$0.3566
Demand	na	na	na	$1.4310
Riders				
A - BGSS	$0.5042	$0.5042	$0.5042	BGSS-M
B- WNC	$0.0000	$0.0000	$0.0000	$0.0000
C - OSMC	($0.0045)	($0.0045)	($0.0045)	($0.0045)
D - SBC	$0.0672	$0.0672	$0.0672	$0.0672
E- EEP	$0.0168	$0.0168	$0.0168	$0.0168
F - IIP	$0.0000	$0.0000	$0.0000	$0.0000
G - CIP	$0.0156	$0.0858	$0.0199	($0.0078)

-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 suspended for the duration of the CIP.

-“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)	$421.17	$106.63	$773.03 (ceiling)	$773.03 (ceiling)
Distribution	$0.0455	$0.0493	$0.9405	$0.1322
Demand	$2.2890	$0.9360	$0.1440	$0.6240
Riders				
A - BGSS	BGSS-M	BGSS-M	BGSS-M	per TPS only
B- WNC	na	na	na	na
C - OSMC	($0.0045)	($0.0045)	na	na
D - SBC	$0.0672	$0.0672	$0.0672	$0.0672
E- EEP	$0.0168	$0.0168	$0.0168	$0.0168
F - IIP	$0.0000	$0.0000	na	na
G - CIP	na	na	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. ~~18~~19

2024 Rate Case

ELIZABETHTOWN GAS COMPANY

TARIFF FOR GAS SERVICE

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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 (26^{th}) 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. A charge of $45.00 shall be made when the Company turns on or ~~and/or to~~ restores 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	$~~10.50~~12.00	$~~10.50~~12.00
Distribution Charge per Therm	$~~0.5797~~0.8190	$~~0.5797~~0.8190
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~~41.05	$~~36.79~~41.05
Distribution Charge per Therm	$~~0.4522~~0.6527	$~~0.4522~~0.6527
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~~64.93	$~~61.84~~64.93
Demand Charge per DCQ	$~~1.162~~1.431	$~~1.162~~1.431
Distribution Charge per Therm	$~~0.2895~~0.3566	$~~0.2895~~0.3566
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~~0.0798 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 - $~~0.4013~~0.6313 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	$~~0.4013~~0.6313 per therm
Fueling Station Charge	$~~0.4611~~0.4842 per therm
Facilities Charge	$~~0.3826~~0.4017 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~~395.00	$~~405.18~~421.17
Demand Charge per DCQ	$~~1.750~~2.147	$~~1.866~~2.289
Distribution Charge per Therm	$~~0.0348~~0.0427	$~~0.0371~~0.0455
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~~100.00	$~~101.29~~106.63
Demand Charge per DCQ	$~~0.750~~0.878	$~~0.800~~0.936
Distribution Charge per Therm	$~~0.0395~~0.0462	$~~0.0421~~0.0493
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 $~~9.94~~13.17 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	$~~144.59~~152.00	$~~154.17~~162.07
Quantity Charge	*	*

*The Quantity Charge shall be the monthly Basic Gas Supply Service Charge ("BGSS-M") plus $~~0.0300~~0.0351 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	$~~735.71~~773.03
Demand Charge per DCQ	$~~0.123~~0.144
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~~0.0986 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~~sulfur 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~~$0.05 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~~$0.05 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~~ 0708 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~~725.00	$~~735.71~~773.03
Demand Charge per DCQ	$~~0.5000~~0.585	$~~0.533~~0.624
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 $~~0.1129~~0.1322 per therm or $~~0.1059~~0.1240 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~~$0.03 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~~$0.02 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
March 1, 2023	$0.5011	$0.2692
April 1, 2023	$0.4512	$0.2692
May 1, 2023	$0.4649	$0.2692
June 1, 2023	$0.4719	$0.2692
July 1, 2023	$0.5177	$0.2692
August 1, 2023	$0.5056	$0.2692
September 1, 2023	$0.5125	$0.2692
October 1, 2023	$0.5352	$0.2692
November 1, 2023	$0.5785	$0.2692
December 1, 2023	$0.5289	$0.3255
January 1, 2024	$0.5194	$0.3255
February 1, 2024	$0.5054	$0.3846
March 1, 2024	*	$0.5042

**To be determined*

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”)

Suspended October 1, 2021

For the duration of the Conservation Incentive Program, Rider “G”:

Section I below shall only be utilized to calculate the value of the weather-related changes in customer usage in the Conservation Incentive Program. The deadband degree days shall not be included in this calculation. For all other purposes, Sections I through III below shall be suspended as of October 1, 2021.

Applicable to all customers in service classifications RDS, SGS and GDS.

October 1 through May 31 of any year	$0.0000 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 gas 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	201 ~~212~~	201 ~~212~~
November	514 ~~516~~	514 ~~516~~
December	810 ~~818~~	810 ~~818~~
January	1,005 ~~992~~	1,005 ~~992~~
February.	842 ~~834~~	872 ~~860~~
March	683 ~~693~~	683 ~~693~~
April	342 ~~340~~	342 ~~340~~
May	43 ~~52~~	43 ~~52~~
Total	4,440 ~~4,457~~	4,470 ~~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 for purposes of calculating the weather-related portion of the CIP are as follows:

Month	Base Number of Customers	Therms per Degree Day
October	313,804 ~~293,159~~	51,924 ~~51,818~~
November	314,658 ~~293,834~~	62,695 ~~62,593~~
December	315,462 ~~294,633~~	69,188 ~~69,064~~
January	314,902 ~~295,059~~	68,423 ~~68,081~~
February	315,199 ~~295,322~~	65,801 ~~67,808~~
March	315,468 ~~295,477~~	63,989 ~~63,693~~
April	315,682 ~~295,126~~	52,634 ~~52,489~~
May	315,867 ~~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 $~~0.4914~~0.6319 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.

($0.0045) 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.	Clean Energy Program ("CEP")	$0.0270
II.	Remediation Adjustment Charge ("RAC")	$0.0225
III.	Universal Service Fund and Lifeline:	
	1. Universal Service Fund ("USF")	$0.0115
	2. Lifeline	$0.0062
IV.	Uncollectible Adjustment Clause ("UAC")[1]	$0.0000
	TOTAL	$0.0672

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.

[1] As a component of the SBC, the initial UAC rate would be proposed in an annual filing with the BPU on or about July 31, 2025. The UAC rate will be set at zero prior to this date.

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~~ CEP 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. Per Board Order dated August 17, 2022 in Docket No. GR21121254, the interest rate on ~~USF~~CEP 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 August [3]1st of each year (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.

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. ~~Per Board Order dated August 17, 2022 in Docket No. GR21121254, 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.~~

Date of Issue: ~~August 22, 2022~~XXX1

Effective: Service Rendered on and after ~~September 1, 2022~~XXX2

Issued by: Christie McMullen, President
520 Green Lane
Union, New Jersey 07083

Filed Pursuant to Order of the Board of Public Utilities
Dated ~~August 17, 2022~~XXX3 in Docket No. ~~GR21121254~~XXX4

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. Uncollectible Adjustment Clause Component ("UAC")

A provision that authorizes the utility to adjust its rates to compensate for an increase or decrease in uncollectible expense, established by Board Order dated XXXXXX in Docket No. XXXXXX.

1. The rates currently approved in this tariff include a projected uncollectible expense of $XXXX or XXXX%. The actual amount of uncollectible expense will be tracked and compared to the authorized amount of uncollectible expense.

   The UAC Year will be from July 1 through June 30. As part of ~~its~~an annual filing with the BPU due on or about July 31 of each year, the Company will file the UAC calculation and support for annual adjustments to be made effective under this tariff. The BPU will have 60 days to review the filing. Any under- or over-collection will be recovered from or credited to customers via a surcharge or credit, respectively, from October 1 through September 30 following the filing date.

~~IV.~~V. 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.

RIDER "D"

SOCIETAL BENEFITS CHARGE ("SBC")
(continued)

V. LCAPP Exemption Procedures (continued)

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:

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. 23070478, per a four-year amortization	$0.0006 per therm
Docket No. 23070478, per a ten-year amortization	$0.0162 per therm
TOTAL	$0.0168 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	$~~0.0351~~0.0000
SGS	Small General Service	$~~0.0375~~0.0000
GDS	General Delivery Service	$~~0.0275~~0.0000
GDS	Seasonal SP#1 May-Oct	$~~0.0031~~0.0000
NGV	Natural Gas Vehicles	$~~0.0644~~0.0000
LVD	Large Volume Demand	$~~0.0099~~0.0000
EGF	Electric Generation	$~~0.0275~~0.0000
GLS	Gas Lights	$~~0.0333~~0.0000
Firm Special Contracts		$~~0.0016~~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.

Cost recovery under the IIP is contingent on an earnings test. If the product of the earnings test calculation exceeds the Company's most recently approved ROE by fifty (50) basis points or more, cost recovery under the IIP shall not be allowed. Any disallowance resulting from the earnings test will not be charged to customers in a subsequent IIP filing period, but the Company may seek such recovery in a subsequent base rate case.

RIDER "F"

INFRASTRUCTURE INVESTMENT PROGRAM ("IIP")

(continued)

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 jurisdictional common equity balance for such annual period. The average jurisdictional common equity balance will be derived by multiplying the average of the Company's beginning and ending net rate base for the annual period by the Board-approved equity ratio in the Company's most recent rate case. The Company's regulated jurisdictional net income shall be calculated by subtracting from total net income the Company's share of margins from: (1) Interruptible Sales; (2) Interruptible Transportation; (3) Off-System Sales and Capacity Release; and (4) the Energy Efficiency Program.

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
$0.0156 per therm	$0.0858 per therm	$0.0199 per therm	($0.0078) 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~~9.0	~~19.8~~23.0	~~23.8~~34.3	~~511.0~~591.5
August	~~8.4~~9.0	~~18.6~~23.0	~~23.9~~34.2	~~512.3~~592.3
September	~~9.3~~9.0	~~22.0~~23.0	~~23.9~~35.0	~~512.7~~592.6
October	~~14.0~~9.3	~~45.2~~25.5	~~60.5~~38.2	~~980.5~~742.1
November	~~25.1~~18.5	~~109.9~~73.9	~~122.9~~88.3	~~1,767.1~~1,514.9
December	~~32.8~~30.3	~~161.7~~130.8	~~230.0~~201.0	~~2,524.8~~2,542.4
January	~~41.0~~40.3	~~193.3~~174.5	~~304.4~~284.0	~~3,109.8~~3,077.6
February	~~35.6~~40.8	~~158.1~~176.0	~~270.5~~292.2	~~2,804.6~~3,005.4
March	~~21.6~~37.6	~~127.7~~142.8	~~176.7~~231.6	~~2,048.1~~2,555.3
April	~~13.5~~28.5	~~63.6~~104.8	~~84.9~~156.9	~~1,075.1~~1,863.7
May	~~11.8~~15.7	~~31.8~~46.8	~~28.5~~60.0	~~508.6~~875.0
June	~~10.7~~11.0	~~22.4~~23.0	~~23.6~~34.3	~~561.1~~591.6
Total Annual	~~233.0~~259.0	~~974.1~~967.1	~~1,373.6~~1,490.0	~~16,915.7~~18,544.4

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) Cost recovery under the CIP is contingent on an earnings test. If the product of the earnings test calculation exceeds the Company’s most recently approved ROE by fifty (50) basis points or more, cost recovery under the CIP shall not be allowed.

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 jurisdictional common equity balance for such annual period. The average jurisdictional common equity balance will be derived by multiplying the average of the Company’s beginning and ending net rate base for the annual period by the Board approved equity ratio in the Company’s most recent rate case. The Company’s regulated jurisdictional net income shall be calculated by subtracting from total net income the CIP booked margin revenue accruals and the Company’s share of margins from: (1) Interruptible Sales; (2) Interruptible Transportation; (3) Off-System Sales and Capacity Release; and (4) the Energy Efficiency 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-HTG	RDS Heating	SGS	GDS
Service Charge (monthly)	~~$10.50~~ $12.00	~~$10.50~~ $12.00	~~$36.79~~ $41.05	~~$61.84~~ $64.93
Distribution	~~$0.5797~~ $0.8190	~~$0.5797~~ $0.8190	~~$0.4522~~ $0.6527	~~$0.2895~~ $0.3566
Demand	na	na	na	~~$1.1620~~ $1.4310~~0~~
Riders				
A - BGSS	$0.5042	$0.5042	$0.5042	BGSS-M
B- WNC	$0.0000	$0.0000	$0.0000	$0.0000
C - OSMC	($0.0045)	($0.0045)	($0.0045)	($0.0045)
D - SBC	$0.0672	$0.0672	$0.0672	$0.0672
E- EEP	$0.0168	$0.0168	$0.0168	$0.0168
F - IIP	~~$0.0351~~ $0.0000	~~$0.0351~~ $0.0000	~~$0.0375~~ $0.0000	~~$0.0275~~ $0.0000
G - CIP	$0.0156	$0.0858	$0.0199	($0.0078)

-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 suspended for the duration of the CIP.

-"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~~ $421.17	~~$101.29~~ $106.63	~~$735.71~~ $773.03 (ceiling)	~~$735.71~~ $773.03 (ceiling)
Distribution	~~$0.0371~~ $0.0455	~~$0.0421~~ $0.0493	$0.9405	~~$0.1129~~ $0.1322
Demand	~~$1.8660~~ $2.28900	~~$0.8000~~ $0.93600	~~$0.1230~~ $0.1440	~~$0.5330~~ $0.6240
Riders				
A - BGSS	BGSS-M	BGSS-M	BGSS-M	per TPS only
B- WNC	na	na	na	na
C - OSMC	($0.0045)	($0.0045)	na	na
D - SBC	$0.0672	$0.0672	$0.0672	$0.0672
E- EEP	$0.0168	$0.0168	$0.0168	$0.0168
F - IIP	~~$0.0099~~ $0.0000	~~$0.0275~~ $0.0000	na	na
G - CIP	na	na	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.

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. GR24__________

DIRECT TESTIMONY

OF

THE ENGINEERING PANEL

MICHAEL P. SCACIFERO
IAN AZAR

On Behalf Of
Elizabethtown Gas Company

Exhibit P-4

February 29, 2024

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ELIZABETHTOWN GAS COMPANY
DIRECT TESTIMONY OF
THE ENGINEERING PANEL

I. INTRODUCTION

Q. PLEASE INTRODUCE THE MEMBERS OF THE PANEL.

A. The members of the Engineering Panel are Michael P. Scacifero and Ian Azar.

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

A. [Mr. Scacifero] My name is Michael P. Scacifero and I am the Senior Director of Engineering Services for Elizabethtown Gas Company ("Elizabethtown" or "Company"). My business address is 520 Green Lane, Union, New Jersey 07083.

[Mr. Azar] My name is Ian Azar and I am the Senior Director of Construction Operations for Elizabethtown. My business address is 520 Green Lane, Union, New Jersey 07083.

Q. MR. SCACIFERO, PLEASE DESCRIBE YOUR PROFESSIONAL RESPONSIBILITIES.

A. As Senior 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, United States Department of Transportation ("DOT") projects, and large new business projects, as well as field operations associated with System Integrity and Measurement & Regulation. 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. PLEASE SUMMARIZE YOUR PROFESSIONAL AND EDUCATIONAL BACKGROUND.

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 32 years in Engineering and Operations. Two of those years were spent as a Project Engineer, five years as a Division Engineer, and twenty-five years as Manager of Engineering, Manager of Operations, Director of Engineering and, currently, Senior 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 American Gas Association and New Jersey Utilities Association, as well as the National Society of Professional Engineers.

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

A. Yes, I have submitted testimony on behalf of Elizabethtown in several proceedings, including the Company's 2016 Base Rate Case[1], 2019 Base Rate Case[2] and 2021 Base Rate Case[3], several proceedings involving Elizabethtown's accelerated infrastructure filings, including the Company's ENDURE and AIR Programs in BPU Docket Nos.

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[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").

[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*, Docket No. GR21121254, "Decision and Order Approving Initial Decision and Stipulation" (August 17, 2022) ("2021 Base Rate Case").

GO13090826, GR15060656 and GO12090693 and its Infrastructure Investment Program ("IIP") proceedings in BPU Docket Nos. GR18101197, GR20050327, GR21040747, GR22040316 and GR23040270.

Q. MR. AZAR, PLEASE DESCRIBE YOUR PROFESSIONAL RESPONSIBILITIES.

A. As Senior Director of Construction Operations for Elizabethtown, I oversee the construction of pipeline assets in a safe and quality manner for all of Elizabethtown's distribution system improvements, renewals, pressure improvements, New Jersey DOT projects, and new business-related projects capital construction projects. I am also involved with the development of Elizabethtown's capital budget, and I am familiar with its components.

Q. PLEASE SUMMARIZE YOUR PROFESSIONAL AND EDUCATIONAL BACKGROUND.

A. I am a graduate of Rutgers University with a B.S. degree in civil engineering and a M.S. in construction management. I am also a Licensed Professional Engineer in the State of New Jersey. I have been employed by Elizabethtown for 9 years in Construction Operations. I have overseen the Construction Operations department as Manger, Director, and currently as Senior Director. Prior to joining Elizabethtown, I was a Project Manager for 7 years at Mott MacDonald specializing in engineering design and construction management for a portfolio of clients and projects that included heavy civil, highway, infrastructure, and municipal projects. Prior to that, I was employed for almost 2 years by Livingston Township as a Staff Engineer specializing in municipal engineering. I am a member of the American Gas Association and New Jersey Utilities Association, as well as the National Society of Professional Engineers.

II. PURPOSE OF TESTIMONY

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

A. In connection with Elizabethtown's 2024 base rate filing, our testimony in this case will address the recovery of capital expenditures incurred since the Company's 2021 Base Rate Case. Specifically, we will provide a summary of Elizabethtown's capital expenditures for the twelve-month test year period ending June 30, 2024 and the six-month post-test year period from July 1, 2024 through December 31, 2024, as well as a description of the categories of expenditures that comprise the capital expenditures forecast. We will also discuss the Company's progress under its current IIP. Finally, we will discuss certain elements of the large 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. We are sponsoring the following schedules supporting the Company's capital expenditures utilized in rate base, which were prepared by us or under our supervision or direction:

- Schedule EP-1 – Utility Plant in Service ("UPIS");
- Schedule EP-2 – Test Year Plant Additions;
- Schedule EP-2.1 – Test Year Large Capital Projects;
- Schedule EP-3 – Post-Test Year Plant Additions; and
- Schedule EP-4 – Post-Test Year Large 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 June 30, 2024.

III. OVERVIEW OF THE COMPANY'S DISTRIBUTION SYSTEM

Q. PLEASE PROVIDE A BRIEF OVERVIEW OF ELIZABETHTOWN'S DISTRIBUTION SYSTEM.

A. Elizabethtown provides natural gas service to approximately 316,000 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 3,317 miles of various pressure gas distribution and transmission main, and related services. As of December 31, 2023, approximately 5 percent of the Company's system included cast iron, ductile iron or bare and unprotected steel and 20 percent is comprised of vintage steel (pre-1971) 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 2021 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 2021 Base Rate Case, Elizabethtown has invested approximately $276.3 million of plant additions net of retirements, excluding IIP, that are not currently reflected in rates, and projects that an additional $213.4 million of capital investment net of retirements, excluding IIP, will be added to the UPIS balance by December 31, 2024, to ensure that customers continue to receive safe and reliable natural gas service. As reflected on Schedule EP-1, the Company's actual UPIS as of December 31, 2023 totaled approximately $2.4 billion. The majority of plant additions since the 2021 Base Rate Case were related to the replacement of the aging infrastructure and the hardening of the Company's distribution system.

Q. PLEASE SUMMARIZE THE CAPITAL EXPENDITURES DURING THE TEST YEAR.

A. Schedule EP-2, attached hereto, provides a summary of the test year capital expenditures excluding large projects based on six months of actual data and six months of projected data. The projected six months of capital expenditures from January 1, 2024 through June 30, 2024, as well as projected plant retirements for the same period, were utilized to calculate the projected UPIS balance for the test year ending June 30, 2024. As shown on Schedule EP-1, the total projected plant additions, large projects and plant retirements for the remaining months of the test year period are approximately $57.7 million, $35.6 million and $19.8 million, respectively. The large capital projects that are projected to be placed in-service during the test year are summarized in Schedule EP-2.1. These large capital projects are the Whittier Street project, the Colonial and Washington Avenue project, the Tracking and Traceability project, the Erie Street Liquified Natural Gas ("LNG") vaporizer, and the Metuchen Edison project, all discussed further in our testimony below. In addition, Year 5 IIP Program amounts of approximately $34.7 million for the period July through December 2023 have been removed. This results in a total projected UPIS balance of approximately $2.4 billion as of June 30, 2024, 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 June 2024 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, the Panel is sponsoring post-test year adjustments based upon a projection of capital expenditures to be made by the Company during the six-month period July 1, 2024 through December 31, 2024. These expenditures consist of approximately $73.8 million of post-test year plant additions, summarized in Schedule EP-3, and approximately $86.0 million of large capital projects that are projected to be placed in-service during the post-test year period, summarized in Schedule EP-4. These large capital projects are all discussed further in our testimony below. As reflected on Schedule EP-1, by the end of the post-test year, net of plant retirements of $19.8 million, the Company projects a UPIS balance of approximately $2.5 billion.

Q. WHAT ARE THE CAPITAL EXPENDITURE CATEGORIES REFLECTED ON SCHEDULES EP-2 AND EP-3?

A. The expenditure categories reflected on Schedules EP-2 and EP-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 Base Spending, Distribution Integrity Management Program (“DIMP”), DIMP Large Diameter (“DIMP-LD”) and Transmission Integrity Management Program (“TIMP”).

Q. PLEASE EXPLAIN THE TYPES OF COSTS ASSOCIATED WITH THE CAPITAL EXPENDITURE CATEGORIES REFLECTED ON SCHEDULES EP-2 AND EP-3.

A. We will address the IIP Base Spending, DIMP, DIMP-LD and TIMP categories later in our 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 7,760 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 training center renovations, HVAC replacements, roof replacement, IT space renovations, parking lot resurfacing and underground tank replacement at the Green Lane Service Center; HVAC upgrades, exterior drainage improvements, bathroom/locker room renovations, IT space renovations and underground tank replacements at the New Village Service Center; and the construction of a meter testing facility at Erie Street property and other various improvements at the Company's satellite facilities.

Fleet includes costs associated with the Company's operations vehicles, such as pick-up trucks, responder vans, dump trucks, crew trucks, backhoes, and automobiles. In total, the Fleet expenditures include the purchase and upfitting of 53 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.

<u>Measurement Operations</u> include costs related to measurement operations, including asset replacement of meter and regulation functions station controls and station heater replacements.

<u>LNG</u> includes peaking costs related to LNG Plant operations, specifically instrument air compressor, tool purchases, and a tank top fire suppression upgrade.

<u>Information Technology (IT)</u> includes costs associated with various system implementations or upgrades related to the Company's Information Technology applications. Specifically, this category includes, but is not limited to, IT costs related to the renewal of an Oracle license, the replacement of end of life systems for dispatch scheduling and mobile field work management, improvements to the leak survey process, BPU-mandated changes to the leak grade logic, replacement of the enterprise phone systems including dispatch and call center operations, and the consolidation of the PowerPlan application into one server..

<u>Mandatory</u> includes costs associated with projects that are required to be undertaken by the Company for compliance related improvements consistent with 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 Meters</u> include costs arising from the periodic testing of the Company's meter inventory, primarily for the purchase of new meters.

Pressure Improvements (PRIM) include costs related to projects that improve the system pressures within the distribution mains and services to reliably serve customers.

Corrosion Work includes costs to improve the cathodic protection of the Company's steel distribution or transmission systems.

Relocation 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.

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 EXPLAIN THE IIP BASELINE SPENDING REQUIREMENT.

A. Pursuant to the IIP Order[4], 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 ("EFVs") on new service lines. 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

[4]*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").

Elizabethtown's base rates. The IIP Base Spending Category reflected on Schedules EP-2 and EP-3 pertains to the latter 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 or exceeded this minimum level of IIP Baseline Spend.

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 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 or exceeded the minimum level of Total Capital Baseline Spend.

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. WERE THE COMPANY'S IIP INVESTMENTS PRUDENT CAPITAL INVESTMENTS?

A. Yes. Since the inception of the IIP, through December 31, 2023, Elizabethtown has installed 223.5 miles of mains, 27,273 services and 27,176 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 17 reports covering program activity through December 2023 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 was 3,315, which is the average number of year-end open leaks the Company has experienced during the last five calendar years. After Year 1, the cap has been 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 December 31, 2023, the Company's actual open leak inventory is 577.

Q. PLEASE DESCRIBE THE COSTS REFLECTED IN THE INTEGRITY MANAGEMENT CATEGORIES (I.E., DIMP, DIMP-LD, AND TIMP) OF SCHEDULES EP-2 AND EP-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 and DIMP-LD categories, excluding those listed on Schedule EP-4, total approximately $28.5 million and $18.9 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 $7,000 in the test year and $228,000 in the Post-Test year.

Q. PLEASE DESCRIBE THE LARGE PROJECTS INCLUDED ON SCHEDULE EP-2.1.

A. There are five large projects detailed on Schedule EP-2.1:

1. Whittier Street to West Elizabeth Avenue, Rahway – 16 inch Elevated Pressure ("EP") Cast Iron Replacement (DIMP-LD) – Replaced and retired 7,004 feet of 16 inch elevated pressure cast iron main and 107 associated services as part of the Company's commitment to retire its aging infrastructure under the DIMP guidelines. This project enabled Company to continue safe and reliable distribution of gas to its customers in the Union Division.
2. Colonial and Washington Avenue, Union – 16 inch EP Cast Iron Replacement (DIMP-LD) – Replaced and retired 6,256 feet of 16 inch elevated pressure cast iron main and 81 associated services as part of the Company's commitment to retire its aging infrastructure under the DIMP guidelines. This project enabled the Company to continue safe and reliable distribution of gas to its customers in the Union Division.

3. Tracking and Traceability (IT) – Tracking and Traceability is a system that utilizes GPS, barcodes, and barcode readers/mobile devices to help more easily identify and accurately locate above and below ground assets. Information about the field personnel that installed or inspected the asset is also captured, including Operator Qualifications. Tracking and Traceability allows for easier accessibility of information on a given asset, helping to ensure safety as well as service reliability.

4. Erie Street LNG Vaporizer – The Erie Street LNG facility has been in service since 1971. This facility is filled by LNG liquid tanker trucks or by on-site liquefaction equipment or both. This facility is a critical part of Elizabethtown's peak day and near peak day gas system resources, as Erie Street LNG is presently able to deliver 25,000 Dth per day of peaking gas supply into the gas system during times of high gas demand. Elizabethtown finds this present pumping and vaporization capacity inadequate and plans to increase it to 50,000 Dth per day. The 25,000 Dth per day capacity was installed in the early 1970s when the Company's gas system firm load was a fraction of what it is today. The cost of doubling the pumping and vaporization capacity will increase the project cost by approximately 6%.

Cost Component	30 MMSCFD	50 MMSCFD	Cost Delta (Component)	Cost Delta (% of Project Cost)
LNG Vaporizers	$ 2,999,568	$ 3,749,460	$ 749,892	3.0%
LNG Pumps	$ 462,070	$ 577,588	$ 115,518	0.5%
Valves		$ 120,000	$ 120,000	0.5%
Piping		$ 180,000	$ 180,000	0.7%
Electrical		$ 30,000	$ 30,000	0.1%
Foundations/Impoundment		$ 235,000	$ 235,000	0.9%
Totals	$ 23,528,591	$ 24,959,000	$ 1,430,410	5.7%

The project includes replacement and upgrade of the vaporization system (pumps, vaporizers, buildings, and all appurtenances). This is needed to replace the aging equipment and increase the reliability and injection capability of the plant. The state-of-the-art equipment improves the reliability of the facility when vaporization is needed and the additional capacity increases the reliability of delivering natural gas to our customers during potential service interruptions, such as a force majeure event, curtailment, pipeline rupture, or cyber attack. The LNG pumps were originally installed in 1971 and had exceeded their expected useful life. Additionally, the facility experienced a number of malfunctions and costly repairs in the years leading up to the upgrade. The early 1990s vaporizers were also near the end of their expected useful life and the original design left them susceptible to dangerous leaks. The upgrade creates a greater daily source of on-system supply for peak day support and to meet the demand of Elizabethtown and more specifically, the Union Division. The new equipment includes two 100% capacity water bath vaporizers, three 50% capacity pumps, a vaporizer Power Distribution Center / Motor Control building, spray shield and deluge water spray nozzles and all associated foundations, racks, cables and measurement and regulation equipment.

5. Metuchen – Edison High Pressure ("HP") to EP Reinforcement (PRIM) – A 2.2 mile, 12 inch diameter, high pressure gas main installed on Central and Plainfield Avenues from Forest Avenue, Metuchen to Oak Tree Road, Edison and an HP to EP district regulator station on Marion Avenue in Edison. New distribution main is needed to boost system pressures in the Company's elevated pressure system

from a critical 7 pounds per square inch gauge ("psig") to 15 psig in order to support the existing customer demand during peak winter conditions.

Q. PLEASE DESCRIBE THE LARGE PROJECTS INCLUDED ON SCHEDULE EP-4.

A. There are eleven large projects detailed on Schedule EP-4:

1. Springfield Avenue and Kenilworth Boulevard – 16 inch EP Cast Iron Replacement (DIMP-LD) – This project has been designed and is scheduled to start construction in Spring 2024. The project will replace and retire approximately 15,570 feet of elevated pressure cast iron main and associated services as part of the Company's commitment to retire its aging infrastructure under the DIMP guidelines. This project will enable the Company to continue safe and reliable distribution of gas to its customers in the Union Division.
2. Bridge replacements (DOT) — This project is to replace 3 pipeline crossings on Warren County and Mercer County bridges that are being reconstructed by the respective counties. New pipelines will consist of steel and operate at 50 psig pressure.
3. Erie Street Upgrades (Gas Ops) - This project is to update the warehouse and welding shop at Erie Street. The warehouse is approximately 110 years old and the welding shop is approximate 100 years old. The Company plans to install a replacement roof, windows and shelving at the warehouse. The Company will install replacement windows, a ventilation system and lighting at the welding shop.
4. SJI Long Term Financial Planning (IT) – This effort is to implement a technical solution platform to automate the long-term financial planning and budget

modeling process and expand modeling capabilities. South Jersey Industries, Inc. ("SJI") selected Utility International as the solution partner for this project because it has extensive utility experience that will help to implement this solution in partnership with SJI's IT and Financial Planning and Analysis ("FP&A") department. Developing the budget for future years is an arduous process for both Operation and FP&A teams. The Long-Term Financial Planning functionality enables SJI to have an agile, holistic financial modeling and analytical tool to help implement and explain SJI's business strategies. The intent is to help address the process deficiency of manually consolidating, reconciling, and analyzing the budget for future years, which is currently a difficult process for the various Business Units and Finance teams. Without a robust financial modeling tool, the processes would remain manual, outside of the systems. Moreover, related manual processes would remain labor intensive, and the long-term financial model would not be robust enough to satisfy business needs in the long term.

5. SJI Server Blade Refresh (IT) – Cisco recently announced the end of sale for the current blades used by SJI, which means that SJI can no longer maintain their system environment using the current model. Cisco also announced the end of life for the blades used by SJI, which is a warning to start an upgrade. Cisco's last date for routine failure analysis is October 2024. This means that this is last possible date a routine failure analysis may be performed to determine the cause of a failure or defect. Upgrading to the new blades will provide both years of services from more enhanced hardware and the latest technology advancements though faster and newer technology.

6. SJI TSA SD - Cyber Implementation Plan (IT) – This project involves the establishment and implementation of a TSA-approved Cybersecurity Implementation Plan that describes the specific cybersecurity measures employed and the schedule for achieving the outcomes required by TSA Security Directive 02C. The Cybersecurity Implementation Plan must provide the information required by the TSA and describe in detail the Owner/Operator's defense-in-depth plan, including physical and logical security controls, for meeting each of the requirements of the TSA's directive.

7. Tamarack Road – Byram (Large Strategic/New Business) - This project is a distribution system expansion in Byram Township, Morris County to convert a targeted 82 residential customers to natural gas. The project will consist of installing 21,548 feet of a combined 2 inch, 4 inch, 6 inch and 8 inch diameter main piping and associated services. A district regulator station will also be installed. The system will operate at 50 psig.

8. Forest Lake – Byram (Large Strategic/New Business) – This project is a distribution system expansion in Byram Township, Morris County to convert a targeted 421 residential customers and 1 commercial customer to natural gas. The project will consist of installing 33,470 feet of 2 inch, 14,500 feet of 4 inch, and 530 feet of 6 inch diameters mains and associated services. The system will operate at 50 psig and will be fed from an existing elevated pressure system also in Byram.

9. Pennington Gate Station Upgrades (PRIM) – This project consists of installing new high pressure regulators, upsizing the existing elevated pressure outlet piping and installing new high pressure outlet piping to set up for reinforcement of the

Company's existing distribution system due to significant pressure losses resulting from added growth in the Hopewell/Pennington area.

10. Washington Boro 10 psig EP Upgrade (PRIM) – This project is a pressure upgrade to reinforce the existing distribution system during peak winter operations. The existing 10 psig vintage steel mains will be replaced with plastic mains and existing services will be replaced with newer materials. The new system pressure will be increased to 50 psig to increase reliability to the Company's customer base in the area.

11. Erie Street Renovation (Facilities) - This project involves construction of new building will house the Measurement & Regulation ("M&R") Team and include room for Meter Storage. The M&R Team is currently housed at the Company's Green Lane facility. Moving to Erie Street will free up space at Green Lane for the expansion of the Elizabethtown Training Center and the shape up and locker room areas for the Company's Street, Utility and Responder Crews. Additionally, by moving the M&R Team to a larger, single use structure at the Erie Street site, the Company will be able to perform duties that are currently contracted to third parties.

Q. PLEASE PROVIDE A BRIEF OVERVIEW OF THE COMPANY'S PROPOSED IIP 2.

A. On December 11, 2023, the Company filed a petition with the Board seeking authorization to implement an IIP 2 in accordance with the BPU's Infrastructure Investment and Recovery Regulations as set forth in N.J.A.C. 14:3-2A. Elizabethtown proposed a five-year, $625 million IIP 2 to commence on July 1, 2024. Elizabethtown proposed to replace approximately 250 miles of leak prone facilities through the IIP 2, including 20 miles of low pressure cast iron facilities, 115 miles of pre-code coated steel facilities, and 115 miles of pre-1984 plastic piping, as well as to install approximately 35,000 EFVs on new service lines.

Q. **ARE THERE ANY COSTS RELATED TO PROPOSED IIP 2 PROJECTS INCLUDED IN THIS RATE FILING?**

A. Yes. The Company's proposed IIP 2 is currently under consideration by the Board in BPU Docket No. GR23120882. As the proceeding remains pending, the Company has included projects that would otherwise fall within the scope of the IIP 2 in its post-test year capital expenditures as shown on Schedule EP-4. In the event that the IIP 2 is approved during this rate case, the Company will remove investments included in a Board-approved IIP 2 from the post-test year expenditures in this proceeding.

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). On April 8, 2022, PHMSA issued an additional pipeline safety regulation "Pipeline Safety: Requirement of Valve Installation and Minimum Rupture Detection Standards." On August 4, 2022, PHMSA issued the final part of the new pipeline safety regulation "Pipeline Safety: Safety of Gas Transmission Pipeline: Repair Criteria, Integrity

Management Improvements, Cathodic Protection, Management of Change, and Other Related Amendments." The PHMSA Transmission Mega Rule creates additional regulatory requirements. The enactment of these regulations is expected to increase gas distribution operating costs. As discussed by Company witness Mr. Houseman, the Company established a TIMP regulatory asset, as approved in the 2021 Base Rate Case, to track and defer for later recovery the Company's incremental transmission integrity management costs. Through December 31, 2023, no incremental costs have been deferred. However, the Company proposes to continue the deferral authority in this filing.

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 so that the project can be competitively 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, the Company continuously monitors the performance of its contractors, and uses that information to evaluate the bids received from contractors who have worked for Elizabethtown previously. This helps ensure that the work performed by contractors delivers pipeline assets constructed in both a safe, quality and compliant manner, as well as the most cost-effective way possible. Finally, the Company closely tracks capital expenditures after a project commences to monitor the financial performance of each capital project. Specifically, each project is examined 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, the Company undertakes a review to determine the causes, identify potential cost mitigation solutions and/or modify the scope of the project as appropriate.

V. SUMMARY

Q. CAN YOU BRIEFLY SUMMARIZE YOUR TESTIMONY?

A. The issues discussed in our 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, the Company requests 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 12/31/2023**	**$2,350,766,442**	
2	UPIS Year 5 IIP Removal 7/1/2023 - 12/31/2023	($34,746,073)	
3	Projected Test Year Plant Additions	$57,654,517	EP-2
4	Projected Test Year Large Projects	$35,609,575	EP-2.1
5	Projected Test Year Plant Retirements	($19,841,400)	
6	**Projected Test Year Ending UPIS at 6/30/2024**	**$2,389,443,061**	
7	Projected Post Test Year Plant Additions	$73,814,023	EP-3
8	Projected Post Test Year Large Projects	$86,011,159	EP-4 & EP-2.1 PTY, if any
9	Projected Post Test Year Plant Retirements	($19,841,400)	
10	**Projected Post Test Year Ending UPIS at 12/30/2024**	**$2,529,426,843**	

ELIZABETHTOWN GAS COMPANY
TEST YEAR PLANT ADDITIONS
12 MONTHS ENDING 6/30/2024
Includes OH and AFUDC - Excluding Large Projects

WP-2 #'s		Jul-23 Actual	Aug-23 Actual	Sep-23 Actual	Oct-23 Actual	Nov-23 Actual	Dec-23 Actual	Jan-24 Projected	Feb-24 Projected	Mar-24 Projected	Apr-24 Projected	May-24 Projected	Jun-24 Projected	Test Year
1	New Business	5,103,905	5,706,339	4,460,324	5,093,834	6,591,800	4,591,745	3,840,099	3,580,800	4,072,912	4,628,113	4,432,063	4,018,414	56,120,348
2	Facilities	436,003	463,621	298,786	505,009	341,811	287,403	72,734	223,106	223,923	224,740	374,318	726,799	4,178,253
3	Fleet	937,819	9,478	71,057	164,394	256,373	390,371	50,138	1,094,590	300,817	-	441,190	300,795	4,017,022
4	Measurement Operations	7,597	213,159	1,117,077	271,336	200,313	864,811	61,001	579,910	131,189	181,325	935,857	346,750	4,910,325
5	LNG	20,801	45,880	11,527	2,273	4,383	36,263	4,331	4,331	15,774	15,833	42,809	82,019	286,224
6	Information Technology (IT)	271,203	394,654	399,794	396,431	590,126	1,414,059	500,717	505,999	581,287	1,481,751	1,276,724	995,257	8,808,002
7	Mandatory	502,552	402,310	685,368	46,800	635,391	647,333	589,576	589,558	589,557	589,557	589,546	589,514	6,457,062
8	Distribution Integrity Management (DIMP)	2,355,100	2,440,619	1,659,699	2,357,240	1,978,239	1,441,037	2,389,151	2,388,536	2,388,339	2,866,055	2,865,032	3,017,378	28,146,425
9	Distribution Integrity Management (DIMP-LD)	-	292,323	12,496	-	16,597	253	-	-	-	-	-	-	321,669
10	Transmission Integrity Mgt Prog (TIMP)	858	865	874	2,844	896	903	-	-	-	-	-	-	7,240
11	DOT	20,969	32,214	13,171	163,519	84,449	34,395	-	-	-	190,716	1,029	191,709	732,171
12	Periodic Testing (PT) Meter	-	-	-	-	-	-	-	-	-	-	-	-	-
13	Pressure Improvement (PRIM)	41,961	57,078	75,610	1,400,799	396,228	(92,012)	3,572	3,532	3,529	3,529	3,504	3,434	1,900,764
14	Corrosion Work	1,977	37,525	24,624	7,328	9	10,309	-	-	43,592	43,592	43,591	43,589	256,136
15	Relocation	9,334	505	(3)	-	-	(2,973)	-	-	-	-	-	-	6,863
16	Security	21	13,529	7,600	330	-	31,181	7,629	7,629	7,629	7,629	7,628	116,600	207,405
17	Tools and Equipment	-	-	-	-	-	-	-	-	-	-	-	-	-
18	IIP Base Spending	502,992	908,034	552,408	939,905	401,430	184,754	-	-	-	372,038	705,538	43,065	4,610,164
	TOTAL ETG PLANT ADDITIONS	**10,213,092**	**11,018,133**	**9,390,412**	**11,352,042**	**11,498,045**	**9,839,832**	**7,518,948**	**8,977,991**	**8,358,548**	**10,604,878**	**11,718,829**	**10,475,323**	**120,966,073**

Note * Excludes IIP Year 5 amounts remaining under IIP, to be filed for under Rider F in 2024.

ELIZABETHTOWN GAS COMPANY
TEST YEAR LARGE CAPITAL PROJECTS
Not Included on Schedules EP-2, EP-3 or EP-4

FERC	Project Name	Type	Projected In Service Date	Test Year (Includes Pre Test Year) Actual	Projected	Jun-24 Total	Post Test Year If Any Projected	Total At Dec-24
37600	Whittier Street to W. Elizabeth Avenue-Mains	DIMP-LD	Aug-23	$ 5,075,193	$ -	$ 5,075,193	$ -	$ 5,075,193
38210	Whittier Street to W. Elizabeth Avenue-Meter Installation	DIMP-LD	Aug-23	$ 30,546	$ -	$ 30,546	$ -	$ 30,546
38000	Whittier Street to W. Elizabeth Avenue-Services	DIMP-LD	Aug-23	$ 436,063	$ -	$ 436,063	$ -	$ 436,063
37600	Colonial -Mains	DIMP-LD	Sep-23	$ 5,483,559	$ -	$ 5,483,559	$ -	$ 5,483,559
38210	Colonial-Meter Installation	DIMP-LD	Sep-23	$ 61,507	$ -	$ 61,507	$ -	$ 61,507
38000	Colonial-Services	DIMP-LD	Sep-23	$ 759,382	$ -	$ 759,382	$ -	$ 759,382
39100	Tracking & Traceability ETG	IT	Apr-24	$ -	$ 3,934,257	$ 3,934,257	$ -	$ 3,934,257
36320	Vaporizing Project	LNG	Apr-24	$ -	$ 27,782,553	$ 27,782,553	$ -	$ 27,782,553
37600	Vaporizing Project-Mains	LNG	Apr-24	$ -	$ 2,800,133	$ 2,800,133	$ -	$ 2,800,133
38300	Edison Reliability-HS Regulator	PRIM	Dec-23	$ 11,135	$ -	$ 11,135	$ -	$ 11,135
37600	Edison Reliability-Mains	PRIM	Dec-23	$ 6,817,821	$ 1,092,632	$ 7,910,453	$ -	$ 7,910,453
	Totals			**$ 18,675,206**	**$ 35,609,575**	**$ 54,284,781**	**$ -**	**$ 54,284,781**

ELIZABETHTOWN GAS COMPANY
POST-TEST YEAR PLANT ADDITIONS
6 MONTHS ENDING 12/30/2024
Includes OH and AFUDC - Excluding Large Projects

WP-2 #'s		Jul-24 Projected	Aug-24 Projected	Sep-24 Projected	Oct-24 Projected	Nov-24 Projected	Dec-24 Projected	Post-Test Year
1	New Business	3,660,204	3,782,687	4,643,056	8,478,663	7,290,918	6,007,354	33,862,882
2	Facilities	579,846	75,299	147,875	147,875	72,681	72,675	1,096,251
3	Fleet	150,397	601,566	1,084,686	661,677	541,993	431,361	3,471,680
4	Measurement Operations	903,220	856,563	400,180	239,774	616,700	221,366	3,237,803
5	LNG	59,910	5,154	5,133	4,332	4,332	4,407	83,268
6	Information Technology (IT)	430,524	459,785	489,175	373,275	330,509	230,306	2,313,574
7	Mandatory	589,514	589,491	589,449	589,450	589,420	599,409	3,546,733
8	Distribution Integrity Management (DIMP)	3,188,807	3,188,681	3,188,459	3,333,298	3,188,302	2,757,575	18,845,122
9	Distribution Integrity Management (DIMP-LD)	25,066	25,196	25,318	381	374	362	76,697
10	Transmission Integrity Mgt Prog (TIMP)	54,486	54,768	55,032	61,846	1,115	1,080	228,327
11	DOT	2,016	192,680	193,580	194,546	195,409	199,409	977,640
12	Periodic Testing (PT) Meter	-	-	-	-	-	-	-
13	Pressure Improvement (PRIM)	112,406	166,835	166,733	3,292	112,183	3,127	564,576
14	Corrosion Work	152,561	152,555	152,545	133,803	43,582	44,321	679,367
15	Relocation	-	-	-	-	-	-	-
16	Security	7,628	7,628	89,348	7,627	7,627	7,756	127,614
17	Tools and Equipment	-	-	-	-	-	-	-
18	IIP Base Spending°	778,378	776,141	854,665	860,180	744,349	688,776	4,702,489
	TOTAL ETG PLANT ADDITIONS	**10,694,963**	**10,935,029**	**12,085,234**	**15,090,019**	**13,739,494**	**11,269,284**	**73,814,023**

Note ° IIP 2 amounts and notes are included on EP-4.

ELIZABETHTOWN GAS COMPANY
POST TEST YEAR LARGE CAPITAL PROJECTS
Not Included on Schedules EP-2, EP-2.1 or EP-3

FERC	Project Name	TYPE	Projected In Service Date	Test Year (Includes Pre Test Year) Spending Actual	Projected	Total	6 Months Post Test Year Projected	Total At Dec-24
37600	Springfield Ave and Kenilworth-Mains	DIMP-LD	Dec-24	$ 398,378	$ 4,187,675	$ 4,586,053	$ 10,318,399	$ 14,904,452
38000	Springfield Ave and Kenilworth-Services	DIMP-LD	Dec-24	$ -	$ -	$ -	$ 1,765,938	$ 1,765,938
37600	DOT-Bridge Replacements	DOT	Dec-24	$ -	$ -	$ -	$ 987,424	$ 987,424
39000	Erie Street Upgrades-Gas Ops	Gas Ops	Dec-24	$ -	$ 200,530	$ 200,530	$ 467,966	$ 668,496
39100	SJI Long Term Financial Planning	IT	Nov-24	$ -	$ 520,335	$ 520,335	$ 654,448	$ 1,174,783
39100	SJI Server Blade Refresh - Shared	IT	Nov-24	$ -	$ 317,511	$ 317,511	$ 435,469	$ 752,980
39100	SJI-TSA SD Major Projects	IT	Dec-24	$ 455,676	$ 356,505	$ 812,181	$ 346,899	$ 1,159,080
37600	Tamarack Rd Area - Byram	Large Strategic	Jul-24	$ -	$ 1,041,637	$ 1,041,637	$ 1,047,142	$ 2,088,779
37600	Forest Lake - Byram	Large Strategic	Dec-24	$ -	$ -	$ -	$ 5,190,312	$ 5,190,312
37900	Pennington Gate Station Upgrades -ETG	PRIM	Oct-24	$ 784,794	$ -	$ 784,794	$ 1,423,702	$ 2,208,496
37600	S443 WASHINGTON 10 PSIG SYSTEM	PRIM	Dec-24	$ 252,745	$ 8,148	$ 260,893	$ 3,210,956	$ 3,471,849
39000	Erie Street M&R Project	Facility	Dec-24	$ -	$ 500,000	$ 500,000	$ 2,700,000	$ 3,200,000
37600	IIP 2 Post Test Year Mains	IIP	Jul - Dec 24	$ -	$ -	$ -	$ 29,063,143	$ 29,063,143
38000	IIP 2 Post Test Year Services	IIP	Jul - Dec 24	$ -	$ -	$ -	$ 19,375,427	$ 19,375,427
	Totals			**$ 1,891,593**	**$ 7,132,341**	**$ 9,023,934**	**$ 76,987,225**	**$ 86,011,159**

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Notes:
1) PTY IIP 2 is based on projected CWIP spending with a 60% Mains 40% Services split and lagged a month as a proxy for In-Service amounts in the PTY.
2) The IP 2 amounts in this filing's Post Test Year that will be removed if the Company's IIP 2 filing made on December 11, 2023 is approved prior to the Board's approval of this case.
If not, then the IIP 2 amounts in this case identified in Settlement from July 2024 through December 2025 will be excluded from IIP 2 when approved.

**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. GR24__________

DIRECT TESTIMONY

OF

JOHN L. HOUSEMAN

**On Behalf Of
Elizabethtown Gas Company**

Exhibit P-5

February 29, 2024

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Exhibit P-5

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 financial statements, 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 2024 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, Energy and Water Benchmarking costs and costs related to the BPU management audit. 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, including certain confidential schedules given Elizabethtown is now a privately held company[1]:

- Schedule JLH-1 – Elizabethtown's Balance Sheets at December 31, 2021, 2022 and 2023 – Confidential;
- Schedule JLH-2 –Elizabethtown's Statements of Income for the twelve months ended December 31, 2021, 2022 and 2023 – Confidential;
- Schedule JLH-3 – Elizabethtown's Statement of Gas Operating Revenues for the twelve months ended December 31, 2023;
- Schedule JLH-4 – Elizabethtown's Payments and Accruals to Affiliates for the twelve months ended December 31, 2023;
- 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

[1] Following the close of the merger in which IIF US Holding2 LP ("IIF") acquired SJI, as approved by the Board's Order dated January 25, 2023 in BPU Docket No. GM22040270 ("2023 Merger Order"), the Company is now a privately held entity and the Company's financial data as of the close of the merger constitutes proprietary financial information that is not publicly available. As such, this filing includes preliminary public versions of Schedules JLH-1 and JLH-2. The confidential versions of these schedules are being submitted to the Board's Records Custodian concurrent with this filing, subject to a claim for confidential treatment pursuant to the Open Public Records Act ("OPRA"), N.J.S.A. 47:1A-1 et seq., and the Board's implementing regulations, N.J.A.C. 14:1-12.1 et seq. The Company will provide these schedules to the parties following the execution of a Non-Disclosure Agreement in this proceeding.

- 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 – Confidential provides comparative balance sheets for Elizabethtown at December 31, 2021, 2022 and 2023. Schedule JLH-2 – Confidential provides comparative statements of income for Elizabethtown for the twelve months ended December 31, 2021, 2022 and 2023. Schedule JLH-3 provides Elizabethtown's statement of gas operating revenues for the twelve months ended December 31, 2023. Finally, Schedule JLH-4 provides Elizabethtown's payments and accruals to affiliates for the twelve months ended December 31, 2023. Please note that the data for 2023 have not yet been audited. It is expected that the Company will have audited 2023 results available when it files the 9&3 Update of this filing in May 2024.

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 7 on Schedule TK-3 (Operating Income Statement) and on line 2 on Schedule TK-2 (Statement of Rate Base), to the Direct Testimony of Thomas Kaufmann (Exhibit P-3).

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 ($960,463) (Schedule JLH-5, line 4) is based upon projected depreciable plant as of the test year ending June 30, 2024. 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 $139,983,782 from July 2024 through December 2024, as discussed in the Direct Testimonies of the Engineering Panel and Mr. Kaufmann. The resulting increase in depreciation expense related to post-test year plant is $4,224,340 (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 $9,052,227 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 December 31, 2023 reflects a credit of $94 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. The DFIT and DCBT amounts included in rate base for the adjusted test year ending June 30, 2024 are ($111,590,433) and ($52,554,364), respectively. DFIT and DCBT included in rate base for the adjusted post-test year ending December 31, 2024 are ($116,756,267) and ($54,987,253), 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. 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 2.18

percent, as set forth in the Direct Testimony of Ann Bulkley. In compliance with the 2023 Merger Order, the annualized interest expense is further reduced by the positive amount that results when subtracting test year interest expense on the first mortgage bonds and senior notes that were redeemed by Elizabethtown as a result of a debt holder exercising a put in connection with the Merger ("CIC Debt") from the test year interest expense on the new debt issued solely to replace the CIC Debt ("Refinanced Debt")("CIC Rate Credit Adjustment").

Th interest synchronization 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. As noted previously, the projected tax expense is adjusted for the CIC Rate Credit Adjustment in compliance with the 2023 Merger Order. The resulting $3,727,828 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 Utility Holdings, Inc.'s d/b/a Elizabethtown Gas ("Pivotal") base rate proceeding in BPU Docket No. GR16090826, Pivotal 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 Company. 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 Elizabethtown's previous base rate proceeding in BPU Docket No. GR19040486 and reaffirmed in the Company's last base rate proceeding in BPU Docket No. GR21121254. 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. GR21121254, Elizabethtown 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. While a regulatory asset has been established, the Company has yet to incur 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 the Engineering Panel testimony.

Q. PLEASE DESCRIBE THE COMPANY'S PROPOSED RECOVERY FOR ENERGY AND WATER BENCHMARKING COSTS.

A. As authorized in the Board's 2022 Benchmarking Order,[2] the Company is requesting the recovery of its reasonable and prudent costs of implementing the Energy Benchmarking Requirements which consist of the operating and maintenance costs of data aggregation, data access services, and cloud platform subscription fees necessary for the Company to be able provide web services that allow the owner or operator of each commercial building over 25,000 square feet in the State to benchmark their energy usage As of June 30, 2024, the balance of such costs is expected to be $80,797, which the Company is requesting to recover over a three-year period.

Q. PLEASE DESCRIBE THE COMPANY'S PROPOSED RECOVERY OF BPU MANAGEMENT AUDIT COSTS.

A. The Company is requesting recovery of $718,140 of deferred management audit costs over a three-year period related to cost of the consultant conducting the BPU management audit in accordance with BPU Docket No. GA19091305.

[2] *In the Matter of the Implementation of P.L. 2018, C. 17 – Energy and Water Benchmarking of Commercial Buildings*, BPU Docket No. QO21071023, Order dated September 7, 2022 ("2022 Benchmarking Order").

VIII. CONCLUSION

Q. DOES THIS CONCLUDE YOUR DIRECT TESTIMONY?

A. Yes, it does.

PRELIMINARY PUBLIC COPY

Schedule JLH-1

Elizabethtown Gas Company
Balance Sheet
As of December 31, 2021

		2021
Assets And Other Debits		
Utility Plant		
101	Utility Plant in Service	$ 1,989,951,291
105	10130:Gas Plant Held for Future Use	1,851,000
107	Construction Work in Progress	77,643,237
108	Accumulated Provision for Depreciation	(318,790,639)
	Net Utility Plant	1,750,654,888
Other Property And Investments		
121	Non-utility Property	
122	Accumulated Provision for Depreciation	
124	Other Investments	-
176	Long Term Portion of Derivative Assets - Hedges	
	Total Other Property and Investments	-
Current And Accrued Assets		
131	Cash	20,984
136	Temporary Cash Investments	-
142	Customer Accounts Receivable	98,703,679
143	Other Accounts Receivable	918,941
144	Accumulated Provisions for Uncollectible Accounts	(16,596,774)
146	Accounts Receivable from Associated Companies	1,150,191
154	Plant Materials & Operating Supplies	446,605
156	Other Materials and Supplies	-
163	Stores Expense Undistributed	-
164.1	Gas Stored Underground - Current	17,362,300
164.2	Liquefied natural gas stored	1,140,765
164.3	Liquefied Natural Gas Held for Processing	-
165	Prepayments	19,814,616
174	Miscellaneous Current and Accrued Assets	-
175	Derivative instrument assets - Current	12,711,702
176	(Less) Long Term Portion of Derivative Assets - Hedges	
	Total Current and Accrued Assets	135,673,011
Deferred Debits		
175	Derivative instrument assets	2,949,669
181	Unamortized Debt Expense	7,459,626
182.3	Other Regulatory Assets	187,047,332
183.2	Preliminary Survey & Investigation Costs	146,101
184	Clearing Accounts	-
186	Miscellaneous Deferred Debits	701,916,688
189	Unamortized Loss on Reacquired Debt	2,623,182
190	Accumulated Deferred Income Taxes	-
191	Unrecovered Purchased Gas Costs	-
	Total Deferred Debits	902,142,597
Total Assets And Other Debits		$ 2,788,470,496

PRELIMINARY PUBLIC COPY

Schedule JLH-1

Elizabethtown Gas Company
Balance Sheet
As of December 31, 2021

		2021
Liabilities And Other Credits		
Proprietary Capital		
208-211	Other Paid-In Capital	$ 1,183,797,343
216	Retained Earnings	127,292,778
219	Accumulated Other Comprehensive Income	-
	Total Proprietary Capital	1,311,090,121
Long-Term Debt		
224	Other Long-Term Debt	925,000,000
	Total Long-Term Debt	925,000,000
Other Noncurrent Liabilities		
227	Obligations Under Capital Leases	-
228.2	Accumulated Provision for Injuries & Damages	668,654
228.3	Accumulated Provision for Pensions & Benefits	(3,853,019)
228.4	Accumulated Miscellaneous Operating Provisions	-
230	Asset Retirement Obligations	125,404,955
245	Long Term Portion of Derivative Assets - Hedges	-
	Total Other Noncurrent Liabilities	122,220,590
Current And Accrued Liabilities		
231	Notes Payable	83,000,000
232	Accounts Payable	25,493,196
234	Accounts Payable to Associated Companies	24,337,708
235	Customer Deposits	14,999,266
236	Taxes Accrued	471,719
237	Interest Accrued	2,008,427
241	Tax Collections Payable	753,212
242	Miscellaneous Current & Accrued Liabilities	24,156,674
243	Obligations Under Capital Leases	-
244	Derivative Instrument Liabilities - Current	195,641
245	(Less) Long Term Portion of Derivative Assets - Hedges	-
	Total Current and Accrued Liabilities	175,415,843
Deferred Credits		
244	Derivative Instrument Liabilities	471,406
252	Customer Advances for Construction	1,787,296
253	Other Deferred Credits	73,984,265
254	Other Regulatory Liabilities	173,004,865
255	Accumulated Deferred Investment Tax Credits	-
282	Accumulated Deferred Other Property	-
283	Accumulated Deferred Other	5,496,109
	Total Deferred Credits	254,743,942
Total Liabilities And Other Credits		$ 2,788,470,496

PRELIMINARY PUBLIC COPY

Schedule JLH-1

Elizabethtown Gas Company
Balance Sheet
As of December 31, 2022

		2022
Assets And Other Debits		
Utility Plant		
101	Utility Plant in Service	$ 2,246,331,856
105	Gas Plant Held for Future Use	-
107	Construction Work in Progress	40,122,297
108	Accumulated Provision for Depreciation	(346,228,245)
	Net Utility Plant	1,940,225,908
Other Property And Investments		
121	Non-utility Property	-
122	Accumulated Provision for Depreciation	-
124	Other Investments	-
176	Long Term Portion of Derivative Assets - Hedges	-
	Total Other Property and Investments	-
Current And Accrued Assets		
131	Cash	1,077,772
136	Temporary Cash Investments	-
142	Customer Accounts Receivable	131,671,469
143	Other Accounts Receivable	1,657,722
144	Accumulated Provisions for Uncollectible Accounts	(12,182,223)
146	Accounts Receivable from Associated Companies	877,034
154	Plant Materials & Operating Supplies	431,273
156	Other Materials and Supplies	-
163	Stores Expense Undistributed	-
164.1	Gas Stored Underground - Current	39,172,727
164.2	Liquefied natural gas stored	775,341
164.3	Liquefied Natural Gas Held for Processing	-
165	Prepayments	16,904,391
174	Miscellaneous Current and Accrued Assets	-
175	Derivative instrument assets - Current	10,270,807
176	(Less) Long Term Portion of Derivative Assets - Hedges	
	Total Current and Accrued Assets	190,656,313
Deferred Debits		
175	Derivative instrument assets	810,076
181	Unamortized Debt Expense	7,034,897
182.3	Other Regulatory Assets	190,745,206
183.2	Preliminary Survey & Investigation Costs	620,692
184	Clearing Accounts	-
186	Miscellaneous Deferred Debits	710,475,668
189	Unamortized Loss on Reacquired Debt	2,163,368
190	Accumulated Deferred Income Taxes	-
191	Unrecovered Purchased Gas Costs	-
	Total Deferred Debits	911,849,907
Total Assets And Other Debits		$ 3,042,732,129

PRELIMINARY PUBLIC COPY

Schedule JLH-1

Elizabethtown Gas Company
Balance Sheet
As of December 31, 2022

		2022
Liabilities And Other Credits		
Proprietary Capital		
208-211	Other Paid-In Capital	$ 1,283,797,343
216	Retained Earnings	170,592,563
219	Accumulated Other Comprehensive Income	-
	Total Proprietary Capital	1,454,389,906
Long-Term Debt		
224	Other Long-Term Debt	925,000,000
	Total Long-Term Debt	925,000,000
Other Noncurrent Liabilities		
227	Obligations Under Capital Leases	-
228.2	Accumulated Provision for Injuries & Damages	628,266
228.3	Accumulated Provision for Pensions & Benefits	-
228.4	Accumulated Miscellaneous Operating Provisions	-
230	Asset Retirement Obligations	125,995,629
245	Long Term Portion of Derivative Assets - Hedges	-
	Total Other Noncurrent Liabilities	126,623,895
Current And Accrued Liabilities		
231	Notes Payable	161,300,000
232	Accounts Payable	17,107,503
234	Accounts Payable to Associated Companies	27,720,798
235	Customer Deposits	16,074,750
236	Taxes Accrued	524,791
237	Interest Accrued	2,219,459
241	Tax Collections Payable	31,226
242	Miscellaneous Current & Accrued Liabilities	25,525,032
243	Obligations Under Capital Leases	-
244	Derivative Instrument Liabilities - Current	1,595,616
245	(Less) Long Term Portion of Derivative Assets - Hedges	-
	Total Current and Accrued Liabilities	252,099,174
Deferred Credits		
244	Derivative Instrument Liabilities	3,355,135
252	Customer Advances for Construction	1,690,737
253	Other Deferred Credits	78,901,392
254	Other Regulatory Liabilities	178,556,809
255	Accumulated Deferred Investment Tax Credits	-
282	Accumulated Deferred Other Property	-
283	Accumulated Deferred Other	22,115,080
	Total Deferred Credits	284,619,153
Total Liabilities And Other Credits		$ 3,042,732,129

PRELIMINARY PUBLIC COPY

Schedule JLH-1

Elizabethtown Gas Company
Balance Sheet
As of December 31, 2023

2023

[redacted]

PRELIMINARY PUBLIC COPY

Schedule JLH-1

Elizabethtown Gas Company
Balance Sheet
As of December 31, 2023

	2023

[redacted]

PRELIMINARY PUBLIC COPY

Schedule JLH-2

Elizabethtown Gas Company
Statements of Income for the Twelve Months
Ending December 31, 2022

		2021
Utility Operating Income		
400	Operating Revenues	$ 360,024,163
Operating Expenses		
401	Operation Expenses	218,659,828
402	Maintenance Expenses	4,505,676
403	Depreciation	45,120,480
404-405	Amort. & depl. Of Utility Plant	-
408.1	Taxes Other Than Income Taxes	3,844,666
409.1	Income Taxes - Federal	-
409.1	Income Taxes - Other (State)	-
410.1	Provision for Deferred Income Taxes	11,971,894
411.4	Investment Tax Credit Adjustments - Net	-
	Total Operating Expenses	284,102,544
Net Operating Income (Loss)		75,921,620
Other Income (Deductions)		
415-421.1	Other Income	1,760,467
426.1-426.5	Miscellaneous Income Deductions	(664,226)
409.2-410.2	Income Taxes	(3)
	Net Other Income (Deductions)	1,096,238
Interest Charges		
427	Interest on Long - Term Debt	33,644,966
428/ 428.1	Amort of Debt Disc and Exp & Loss on Reacquired Debt	906,471
430	Interest on Debt to Assoc. Companies	-
431	Other Interest Expense	768,858
432	Allowance for Borrowed Funds	(1,164,908)
	Net Interest Charges	34,155,387
Income Before Extraordinary Items		$ 42,862,470
Extraordinary Items		
409.3 Income taxes, extraordinary items. Net income		3,080,859
434.0 Extraordinary income.		(10,960,013)
	Total Extraordinary Items	(7,879,154)
Net Income (Loss)		$ 50,741,624

PRELIMINARY PUBLIC COPY

Schedule JLH-2

Elizabethtown Gas Company
Statements of Income for the Twelve Months
Ending December 31, 2022

			2022
Utility Operating Income			
400	Operating Revenues	$	441,297,493
Operating Expenses			
401	Operation Expenses		280,572,024
402	Maintenance Expenses		4,032,351
403	Depreciation		52,120,926
404-405	Amort. & depl. Of Utility Plant		-
408.1	Taxes Other Than Income Taxes		4,194,531
409.1	Income Taxes - Federal		-
409.1	Income Taxes - Other (State)		-
410.1	Provision for Deferred Income Taxes		23,357,521
411.4	Investment Tax Credit Adjustments - Net		-
	Total Operating Expenses		364,277,353
Net Operating Income (Loss)			77,020,140
Other Income (Deductions)			
415-421.1	Other Income		685,304
426.1-426.5	Miscellaneous Income Deductions		(7,108,449)
409.2-410.2	Income Taxes		9,688,912
	Net Other Income (Deductions)		3,265,767
Interest Charges			
427	Interest on Long - Term Debt		34,789,337
428/ 428.1	Amort of Debt Disc and Exp & Loss on Reacquired Debt		1,156,821
430	Interest on Debt to Assoc. Companies		-
431	Other Interest Expense		2,685,436
432	Allowance for Borrowed Funds		(1,645,472)
	Net Interest Charges		36,986,122
Income Before Extraordinary Items		$	43,299,784
Extraordinary Items			
409.3 Income taxes, extraordinary items. Net income			-
434.0 Extraordinary income.			-
	Total Extraordinary Items		-
Net Income (Loss)		$	43,299,784

PRELIMINARY PUBLIC COPY

Schedule JLH-2

Elizabethtown Gas Company
Statements of Income for the Twelve Months
Ending December 31, 2023

	2023
[redacted]	

Elizabethtown Gas Company
Statement of Gas Operating Revenues
For the Twelve Months Ending December 31, 2023

			Year To Date 2023
Gas Operating Revenues			
Sales of Gas			
480	Residential	$	262,107,240
481	Commercial and Industrial	$	89,026,737
482	Other sales public authorities	$	-
483	Sales for resale	$	-
484	Interdepartmental sales.	$	(552,651)
	Total Sales of Gas		350,581,326
Other Gas Revenues			
487	Forfeited Discounts	$	1,092,525
488	Miscellaneous Service Revenues	$	718,499
489.2	Revenues from Transportation of Gas - Transmission	$	-
489.3	Revenues from Transportation of Gas - Distribution	$	52,943,130
492	Incidental Gasoline & Oil Sale	$	-
493	Rent from Gas Property	$	-
495	Other Gas Revenues	$	80,506
496	(Less) Provision for Rate Refund	$	-
	Total Other Gas Revenues		54,834,659
Total Gas Operating Revenues		$	405,415,985

Schedule JLH-4

Elizabethtown Gas Company
Payments and Accruals to Affiliates
For the Twelve Months Ended December 31, 2023

Line No.	Description of the Good or Service	Name of Associated/Affiliated Company	Amount Charged or Credited
	(a)	(b)	(c)
1	Goods or Services Provided by Affiliated Company		
2			
3	Management Service Charge (Operating)	SJI Utilities, Inc.	6,173,952
4	Management Service Charge (Capital)	SJI Utilities, Inc.	289,431
5	Direct Payroll Charge (Operating)	SJI Utilities, Inc.	539,404
6	Direct Payroll Charge (Capital)	SJI Utilities, Inc.	2,994,487
7	Management Service Charge (Operating)	South Jersey Industries, Inc.	17,553,096
8	Management Service Charge (Capital)	South Jersey Industries, Inc.	4,369,490
9	Direct Payroll Charge (Operating)	South Jersey Industries, Inc.	3,537,897
10	Direct Payroll Charge (Capital)	South Jersey Industries, Inc.	9,487,461
11	Gas Purchases	South Jersey Resources Group, LLC	122,329,468
12	Fixed margin sharing Gas Purchases	South Jersey Resources Group, LLC	(3,650,000)
13	Variable margin sharing Gas Purchases	South Jersey Resources Group, LLC	(3,360,857)
14			
15			
16			
17	**TOTAL**		**160,263,830**

ELIZABETHTOWN GAS COMPANY
PRO FORMA ADJUSTMENTS TO JUNE 30, 2024 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 6/30/2024	$2,389,443,061	$69,562,910	
3	Test Year Depreciation Expense at Current Rates		$70,523,373	
4	Test Year Difference of Annual Depreciation Expense Current to Proposed Rates		($960,463)	
5	Post Test Year UPIS Change and Depreciation Expense for UPIS Additions	$139,983,782	$4,224,340	
6	**Total Pro Forma Adjustment to Depreciation Expense (Income Statement)**	**$2,529,426,843**	**$3,263,877**	
7				
8	**Accumulated Depreciation & Amortization Balance at Current Rates**			
9	Accumulated Depreciation & Amortization Balance at 12/31/2023		($387,965,477)	
10	Acquisition Adjustment Balance as of 12/31/2023		($94,000,016)	(1)
11	Adjusted Balance at 12/31/2023		($481,965,493)	
12				
13	**Accumulated Depreciation Test Year Adjustments per 6 Months of Projections**			
14	UPIS Depreciation Expense per Remaing Projected Months at Current Rates		($35,261,687)	
15	Acquisition Adjustment Amortization, Balance Reduction		$7,999,998	(2)
16	Retirements		$19,841,400	
17	Cost of Removal		$0	
18	**Test Year Balance as of 6/30/2024**		**($489,385,782)**	
19				
20	**Accumulated Depreciation Changes plus 6 Months of Post Test Year Adjustments:**			
21	Incremental UPIS Additions Depreciation Expense at Proposed Rates		($2,112,170)	
22	UPIS Post Test Year Depreciation Expense Proposed Rates		($34,781,455)	
23	Acquisition Adjustment Amortization, Balance Reduction		$7,999,998	(3)
24	Retirements		$19,841,400	
25	Cost of Removal		$0	
26	**Post Test Year Balance as of 12/30/2024**		**($498,438,009)**	

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:	Months	Monthly Amort.	Adj. & Balances
	11/15/2019	120	**$1,333,333**	($160,000,000)
	12/31/2023	49.5	$1,333,333	$65,999,984
(1)	Acquisition Adjustment Balance as of 12/31/2023			($94,000,016)
	Balance Reductions Test Year and Post Test Year ending:			
(2)	6/30/2024	6.0	$1,333,333	$7,999,998
(3)	12/30/2024	6.0	$1,333,333	$7,999,998
	Acquisition Adjustment Balance as of 12/30/2024			($78,000,020)

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 6/30/2024**			(111,590,433)
2	**Adjustments to DFIT Through 12/30/2024:**			
3	Test Year Book Depreciation at Proposed Rates	34,781,455		
4	Post Test Year Book Depreciation at Proposed Rates	2,112,170		
5	Sum of Test and Post Test Year Book Depreciation	36,893,625		
6	Tax Depreciation-Federal	(63,925,724)		
7	Federal Tax Depreciation Over Book		(27,032,099)	
8	Deferred FIT (@ effective FIT rate)	21%		(5,676,741)
9	Federal benefit of Deferred CBT state taxes @FIT Rate	2,432,889	21%	510,907
10	**Adjusted DFIT Rate Base Balance 12/30/2024:**			**(116,756,267)**

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	DCBT IN RATE BASE
1	DCBT Rate Base Balance 6/30/2024			(52,554,364)
2	**Adjustments to DCBT Through 12/30/2024:**			
3	Test Year Book Depreciation at Proposed Rates	34,781,455		
4	Post Test Year Book Depreciation at Proposed Rates	2,112,170		
5	Sum of Test and Post Test Year Book Depreciation	36,893,625		
6	Tax Depreciation-Federal	(63,925,724)		
7	Federal Tax Depreciation Over Book		(27,032,099)	
8	Pro Forma Adjustment - Deferred NJ CBT @	9.00%		(2,432,889)
9	**Adjusted DCBT Rate Base Balance 12/30/2024:**			**(54,987,253)**

ELIZABETHTOWN GAS COMPANY
PRO FORMA ADJUSTMENTS TO JUNE 30, 2024 OPERATING INCOME

INCOME TAXES - INTEREST SYNCHRONIZATION

Line No.			
1	Annualized Rate Base Interest Expense:		
2	Adjusted Rate Base	$1,862,108,979	
3	Total Weighted Cost of Long Term Debt	2.18%	$40,593,976
4	CIC Rate Credit Adjustment *		($6,429,099)
5	Adjusted Annualized Rate Base Interest Expense		$34,164,877
6	Less: Test Year Interest Expense		$47,426,451
7	Interest Expense Higher / (Lower) (L3-L4)		($13,261,574)
8	Income Tax Rate		28.11%
9	**Income Tax Expense (Increase) due to Lower Interest Expense**		**($3,727,828)**

* per clause 35(ii) of the Board's Order in BPU Docket No. GM22040270

ELIZABETHTOWN GAS COMPANY
PRO FORMA ADJUSTMENTS TO RATE BASE
PENSION AND OPEB REGULATORY ASSETS

Line No.		
1	Pension and OPEB as of 12/31/2023	**$26,263,347**
2	Adjusted for amortization expense and net periodic benefit costs	($1,624,314)
3	Projected / Actual Pension and OPEB as of 6/30/2024	**$24,639,033**
4	Adjusted for amortization expense and net periodic benefit costs	($1,624,314)
5	Projected Pension and OPEB as of 12/30/2024	**$23,014,719**

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

HOWARD S. GORMAN

On Behalf Of
Elizabethtown Gas Company

Exhibit P-6

February 29, 2024

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ELIZABETHTOWN GAS COMPANY
DIRECT TESTIMONY OF
HOWARD GORMAN

I. INTRODUCTION AND QUALIFICATIONS

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

A. My name is Howard S. Gorman. I am the President of HSG Group, Inc. ("HSG"), a consulting firm specializing in utility rate and regulatory matters. My business address is 45 Hillpark Avenue, Great Neck, New York 11021.

Q. PLEASE DESCRIBE YOUR EDUCATIONAL AND PROFESSIONAL BACKGROUND.

A. In 1976, I received a Bachelor of Science in Accounting from New York University. In 1981, I received a Master of Business Administration from Harvard Business School.

I held positions as a Staff Accountant at Touche Ross & Co. (1976-1979), Director, Treasury at Coleco Industries, Inc. (1982-1987) and Corporate Controller and Treasurer at Trigen Energy Corporation (1987-1995). In 1997, I joined R. J. Rudden Associates, Inc., a consulting firm specializing in utility rate and regulatory matters, as a Principal Consultant; R. J. Rudden joined Black & Veatch Corporation in 2005. In 2010, I started HSG. I have over 35 years of experience in the energy industry, including 25 years in rate and regulatory matters. My areas of expertise include embedded class cost of service studies, marginal cost studies, revenue allocation, rate design and revenue requirements for both electric and gas utilities.

Q. HAVE YOU PREVIOUSLY TESTIFIED BEFORE A REGULATORY COMMISSION?

A. Yes. I have testified before the Massachusetts Department of Public Utilities, New Jersey Board of Public Utilities ("Board"), New Hampshire Public Utilities Commission, New

York State Public Service Commission, Ontario Energy Board, Pennsylvania Public Utility Commission and Rhode Island Public Utilities Commission. Schedule HSG-5 presents my resume and relevant experience.

II. PURPOSE OF TESTIMONY

Q. ON WHOSE BEHALF ARE YOU TESTIFYING TODAY?

A. I am testifying on behalf of Elizabethtown Gas Company ("Elizabethtown" or "Company").

Q. WHAT IS THE PURPOSE OF YOUR TESTIMONY?

A. The purpose of my testimony is to present the following topics:

- Embedded Cost of Service Study ("ECOSS") for Elizabethtown for the Post Test Year 12 months ending March 31, 2025 ("PTY");
- Elizabethtown's proposed revenue allocation of the revenue requirement; and
- Elizabethtown's proposed rate design for each service classification.
- ECOSS using the Peak and Average method for the PTY ("P&A ECOSS").

Q. ARE YOU SPONSORING ANY SCHEDULES?

A. Yes, I am sponsoring the following schedules that were prepared or compiled by me or under my direction and supervision:

- Schedule HSG-1 presents the ECOSS.
- Schedule HSG-2 presents the proposed allocation of the revenue requirement among the rate classes for the normalized and annualized determinants.
- Schedule HSG-3 presents the proposed rate design for each rate class.
- Schedule HSG-4 presents the P&A ECOSS.
- Schedule HSG-5 presents my resume and relevant experience.

III. EMBEDDED COST OF SERVICE STUDY

A. PURPOSE OF ECOSS AND OVERVIEW OF METHODOLOGY

Q. WHAT IS AN ECOSS AND WHAT IS ITS PURPOSE?

A. The purpose of an ECOSS is to apportion a utility's total revenue requirement, including plant and other investments, operating expenses, depreciation and taxes among the rate classes served by the utility. An ECOSS computes, for each class, the return on rate base at present rates for the year being examined, and the total and incremental revenue that must be collected from each class to produce the system average rate of return on rate base. This information provides guidance in revenue allocation and in the development of rates.

Q. PLEASE SUMMARIZE THE METHODOLOGY EMPLOYED FOR THE ECOSS.

A. The ECOSS is prepared by analyzing each element of the utility's revenue requirement and assigning or allocating it among the rate classes. The ECOSS was performed using a proprietary Excel(R)-based model developed by HSG. This model uses the traditional three-step process as follows:

- Functionalization – Each of the Company's costs and expenses, as well as rate base components, are assigned or allocated among each of the utility's gas functions.
- Classification – Each functionalized cost element is separated into demand, commodity, and customer cost categories.
- Class allocation – Each functionally classified cost element is assigned or allocated among one or more of the Company's rate classes.

Q. PLEASE DESCRIBE THE FUNCTIONALIZATION STEP OF THE ECOSS.

A. In the functionalization step, cost elements are separated among the utility's basic service functions by determining what physical purpose each cost element serves.

Q. WHAT ARE THE FUNCTIONS INCLUDED IN THE ECOSS PREPARED FOR ELIZABETHTOWN?

A. The functions included in Elizabethtown's ECOSS are:

- Distribution – All Elizabethtown costs and rate base in the revenue requirement are part of the Distribution function. This follows the approach used in the Company's last rate case in BPU Docket No. GR21121254 ("2021 Rate Case").

Q. PLEASE DESCRIBE THE CLASSIFICATION STEP OF THE ECOSS.

A. The Company's gas distribution system is designed to meet three primary objectives:

1. Connect customers to the Company's distribution system;
2. Meet the aggregate peak design day capacity requirements of all customers entitled to service on the peak day; and
3. Deliver natural gas commodity to customers, whether they are sales or transportation customers.

Based on these objectives, each functionalized cost element is classified as being customer-related, demand-related, or commodity-related, depending on which of the foregoing objectives it serves.

Cost elements classified as customer-related are incurred to attach a customer to the distribution system, meter gas usage, and maintain the customer's account. Customer-related cost elements are primarily a function of the number of customers served and are incurred by the Company regardless of whether an individual customer uses any gas. Such costs may include capital costs associated with the customer component of distribution mains, as well as costs for services, meters and metering, billing, customer service, and accounting and collection activities.

Demand- or capacity-related cost elements are associated with plant that is designed, installed, and operated to meet peak hourly or daily customer gas flow requirements. Demand-related components include transmission and distribution mains, localized distribution facilities, and dedicated facilities that are designed to satisfy individual customer maximum demands. Demand-related cost elements are allocated among the classes based on their contributions to the peak demand for which the system is designed.

Cost elements classified as commodity-related generally vary with the volume of gas sold or delivered (*i.e.*, throughput) to customers, either annually or seasonally. Costs related to obtaining gas supply are classified as commodity-related.

Q. HOW ARE THE COMPANY'S MAINS CLASSIFIED BETWEEN DEMAND-RELATED AND CUSTOMER-RELATED?

A. Distribution mains are installed to connect customers to the distribution system (customer-related) as well as to provide capacity to meet customer requirements on the design day (demand-related). Therefore, the cost of mains is classified as partly customer-related and partly demand-related. A minimum-system study was performed to determine the split between customer-related and demand-related.

Q. PLEASE DESCRIBE THE MINIMUM-SYSTEM STUDY THAT YOU PERFORMED.

A. The minimum-system study that was performed is presented on Schedule HSG-3- 6.

Minimum-system studies are a widely accepted method to classify mains between customer- and demand-related costs. The customer-related component is the portion of cost representing the least-cost system the utility would install simply to connect customers, without regard to the need to meet demand.

The analysis begins by obtaining from Company records setting forth the recent cost per foot of installing mains, detailed by material (plastic, steel, and cast iron), length, and diameter. The installed cost per foot is computed for each material/diameter type.

The minimum system ratio is computed as the ratio of (X) the cost of replacing the entire mains distribution system with the minimum component, which is two-inch plastic, to (Y) the cost of replacing the entire mains distribution system with plastic of the same diameter as installed.

The minimum-system ratio using the most recent costs was computed to be 62.67%. To promote stability and to broaden the period of data used in the study, the Company took the average of this study and the prior study (62.46%). The result, a minimum-system component of 62.57%, was the customer component used in the ECOSS.

The customer component of 62.57% represents the cost to connect customers regardless of their contribution to design-day demand and is allocated among the customer classes based on the number of customers. The remaining 37.43% is the demand component and is allocated among the customer classes based on their contribution to design-day demand.

Q. PLEASE EXPLAIN THE ALLOCATION STEP OF THE ECOSS.

A. In the allocation phase of the ECOSS, the cost elements that have been functionalized and classified are allocated among the service classes. Two types of allocation factors, or allocators, are used: (1) external allocators and (2) internal allocators. External allocators are based on special studies derived from data in the Company's accounting and other records. For example, the number of customers by service class is an external allocator.

Other examples of external allocators are annual deliveries, design day requirements and historic bad debt experience. Internal allocators are based on a combination of external allocators, directly assigned costs and other internal allocators. For example, property insurance expense is allocated based on plant investment allocated to each service class; therefore, it is necessary to compute plant investment by class before property insurance costs can be allocated.

Q. WHICH SERVICE CLASSES WERE IDENTIFIED FOR PURPOSES OF THE ALLOCATION PHASE?

A. In the allocation phase of the ECOSS, the functionalized, classified cost elements were allocated among the service classifications shown in the table below.

Service Class
Residential Heat
Residential Non-Heat
Small General Service (SGS)
General Distribution Service (GDS)
Large Volume Delivery Firm (LVD)
Natural Gas Vehicles (NGV)
Non-Firm, comprising Interruptible Cogeneration (CSI), Commercial and Industrial (IS), Interruptible Transportation (ITS) and Interruptible Transportation-Large Volume Demand (ITS-LVD)

Q. DID YOU PREPARE A SCHEDULE THAT SHOWS THE ALLOCATORS USED FOR EACH COST ELEMENT?

A. Yes. Schedule HSG-1-7A presents the allocator used for each cost element for each step of the ECOSS – functionalization, classification, and class allocation.

Q. DID YOU PREPARE A SCHEDULE THAT PRESENTS THE EXTERNAL ALLOCATORS?

A. Yes, Schedule HSG-3 presents the following information regarding the external allocator:

- Schedule HSG-3-1 - Summary of the external allocator values, and each class' share of the total.
- Schedule HSG-3-2 - Deliveries by class by month for the PTY, provided by the Company.
- Schedule HSG-3-3 - Present rates and Present rate revenue for the PTY.
- Schedule HSG-3-4 - Customers by class by month for the PTY, provided by the Company.
- Schedule HSG-3-5 - Design Day (Peak Sendout) requirements for the PTY for each rate class, prepared by the Company.
- Schedule HSG-3-6 - Mains minimum system study, discussed above.
- Schedule HSG-3-7 - Services allocator, based on current cost for a typical installation for customers in each rate class.
- Schedule HSG-3-8 - Meters allocator, based on current costs for each type of meter currently installed for the typical customers in each rate class.
- Schedule HSG-3-9 - Write-offs allocator, using the ratio of Net Write-Offs to Revenue for Residential and Non-Residential classes, applied to Test Year revenue; and Customer Deposits by rate class provided by the Company.

Q. ARE THE ALLOCATORS ASSIGNED TO EACH ELEMENT IN THE ECOSS THE SAME AS IN THE 2021 RATE CASE?

A. With the minor exceptions discussed below, the allocators assigned to each element in the ECOSS are the same as in the 2021 Rate Case.

- In the 2021 Rate Case, Customer Deposits were allocated in proportion to Rate Base. In this ECOSS, Customer Deposits are directly assigned (Schedule HSG-1-

7A, line 60).

- In the 2021 Rate Case, Accumulated Deferred Income Tax ("ADIT") was allocated in proportion to Rate Base. In this ECOSS, ADIT was allocated on proportion to Plant, because ADIT arises mainly due to timing differences between accounting and tax depreciation (Schedule HSG-1-7A, line 62).
- In the 2021 Rate Case, Load Dispatching expense, Account 571, was allocated in proportion to Design Day deliveries. In this ECOSS, this item was allocated in proportion to Annual Deliveries, because load dispatch is needed throughout the year (Schedule HSG-1-7A, line 86).

B. ECOSS RESULTS

Q. PLEASE EXPLAIN SCHEDULE HSG 1.

A. Schedule HSG-1 presents the ECOSS, with the following schedules:

- Schedule HSG-1-1 is a summary of the ECOSS results, discussed below.
- Schedule HSG-1-2 summarizes the results of the class allocation step of the ECOSS and shows how each element of the total distribution revenue requirement is allocated among the services classes.
- Schedule HSG-1-3 presents for each class, the unitized Demand-related (line 3) and the unitized Customer-related revenue requirement (line 7), as well as the costs typically considered for inclusion on the Customer charge (line 36).
- Schedule HSG-1-4 presents the functionalization step of the ECOSS. The cost elements include plant, depreciation reserve, and other components of rate base, operation and maintenance ("O&M") expenses, depreciation expense, other taxes, income taxes, revenue, and return. The total distribution revenue requirements are

presented using the Federal Energy Regulatory Commission ("FERC") Uniform System of Accounts.

- Schedule HSG-1-5 presents the classification step of the ECOSS for Distribution, with each cost element classified between demand and customer. The cost elements are the same as for the functionalization step.
- Schedules HSG-1-6A and HSG-1-6B present the class allocation step of the ECOSS. The cost elements are the same as for the functionalization and the classification steps.
  - Schedule HSG-1-6A – Distribution Demand-Related
  - Schedule HSG-1-6B –Distribution Customer-Related
- Schedule HSG-1-7A presents the allocator used for each cost element for each step of the ECOSS – functionalization, classification, and class allocation.
- Schedules HSG-1-7B, HSG-1-7C and HSG-1-7D present, respectively, the values for each functionalization factor, classification factor, and class allocation factor.

Q. PLEASE DISCUSS THE ECOSS RESULTS ON SCHEDULE HSG-1-1.

A. Schedule HSG-1-1 presents by service class the revenue at present rates (line 3), rate of return on rate base at present rates (line 10), the revenue needed for the class to achieve the overall rate of return that the Company is requesting in this proceeding (line 12), and the increase or decrease to revenue at current rates, both in dollars (line 26) and percent (line 27), needed for the class to achieve that rate of return. This information provides guidance for allocation of the Company's proposed revenue increase and rate design.

Q. PLEASE DISCUSS THE INFORMATION ON SCHEDULE HSG-1- HSG-1-2, HSG-1-4, HSG-1-5, HSG-1-6A AND HSG-1-6B.

A. Schedule HSG-1- 2 presents by service class the results of the allocation of each cost element among the rate classes. Schedules-HSG 1-4, HSG-1-5, HSG-1-6A and HSG-1-6B show the information for, respectively, Functionalization, Classification, Distribution Demand and Distribution Customer.

The cost elements are Rate Base (lines 1-67), Operating expenses (lines 69-135), Depreciation expense (lines 137-150) and Taxes and Other (lines 152-167). Total Expenses are on line 169. Revenue is on lines 171-181. Net income is on line 183 and Return on rate base is on line 186. The computation of the revenue requirement needed for each class to produce the system average return is on lines 188-202.

Q. PLEASE DISCUSS THE P&A ECOSS, PRESENTED IN SCHEDULE HSG-4.

A. Schedule HSG-4 presents a version of the ECOSS in which Mains are 100% Demand-classified, and the Peak_Sendout allocator used in the ECOSS presented on Schedule HSG-2 is replaced by a Peak_Average allocator. The Peak_Average allocator blends the Gas Deliveries allocator, assigning it a weight equal to the System Load Factor, and the Peak Sendout allocator, assigning it a weight equal to 1 minus the system loss factor. The Peak_Average is computed in Schedule HSG-3-1, line 9. The Gas Deliveries allocator is on line 27 and Peak Sendout is on line 30. The System Load Factor, 41.1% is computed in Schedule HSG-3-5, line 21.

Q. DO YOU SUPPORT THE USE OF THE P&A ECOSS FOR ANY PURPOSE IN THIS PROCEEDING?

A. No, I do not. The P&A ECOSS is presented pursuant to a requirement of the Board's order in the prior rate case. It does not properly reflect the Company's costs because it ignores the customer component of Mains and is therefore not the most appropriate allocator for Mains.

IV. REVENUE ALLOCATION AND RATE DESIGN

A. SCHEDULES

Q. PLEASE SUMMARIZE THE SCHEDULES RELATING TO THE COMPANY'S PROPOSED REVENUE ALLOCATION AND RATE DESIGN.

A. Schedule HSG-2 presents and supports the Company's proposed revenue allocation, and rate design with the following schedules:

- Schedule HSG-2-1 presents the Company's proposed revenue allocation targets by service class.
- Schedule HSG-2-2 presents the proposed rates that produce, for each class, the revenue allocation targets developed on Schedule HSG-2-1.

B. REVENUE ALLOCATION

Q. PLEASE SUMMARIZE THE METHODOLOGY USED TO DEVELOP THE COMPANY'S PROPOSED REVENUE ALLOCATION.

A. The proposed revenue allocation is intended to produce revenue from each service class that will move the service class rate of return closer to the overall rate of return that the Company is requesting, a concept known as "unity," while mitigating extreme impacts on customer groups, a concept known as "gradualism."

Q. WHAT IS ELIZABETHTOWN'S REVENUE REQUIREMENT THAT IS ALLOCATED IN THE ECOSS?

A. Elizabethtown is requesting an increase in distribution revenue for the PTY of approximately $75.6 million, as provided by Company witness Thomas Kaufmann and presented in Exhibit P-3, Schedule TK-1. At present rates, Total revenue for the PTY would be $291.2 million (Schedule HSG-2-1 line 6). This is made up of Total Delivery revenue of $288.2 million, inclusive of IIP Revenue shown for the applicable rate classes as shown on Schedule HSG-2-2, and $3.0 million of Other revenue. The return on rate base at present rates is 5.43% (Schedule HSG-2-1 line 12). The proposed Total Revenue Requirement of $366.7 million is an increase of $75.6 million and produces a return on rate base of 8.31% as shown on line 20. The increase in the Total Revenue is equal to the Target Increase for Distribution of approximately $74.5 million (line 37) plus and increase of $1.1 million related to the Company's proposed increased in turn-on fees shown (Schedule HSG-2-2, line 69).

Q. PLEASE DISCUSS THE COMPANY'S PROPOSED REVENUE ALLOCATION.

A. The development of the proposed revenue allocation is presented on Schedule HSG-2-1. Lines 1-13 present the results of the ECOSS, including Return on rate base at present rates and Relative return at present rates (lines 12-13). The proposed increases are guided by the class returns relative to the system average (line 13).

A tolerance band was established where classes with returns at present rates near the average (0.75X-1.25X average, SGS class) were given an increase of 25.50%, approximately the average increase. Classes with returns somewhat below this band (0.50X-0.75X, Residential Heat) were given an increase of 29.65%, larger than average. Classes with negative returns (Residential Non-Heat) were given an even larger increase of 36.5%. Classes with returns above the average (1.25X-2.50X, NGV) were given an increase of 19.5%, smaller than average. Classes with returns well above the average (over

2.50X, GDS, Large Volume Demand, Non-firm) were given an increase of 16.5%, smaller than average. The table presenting this is on lines 22-28 of Schedule HSG-2-1.

Based on the assigned percentage increases, revenue increase percentages and revenue targets were developed for each class (lines 30-39).

Q. WHAT ARE THE PROPOSED DISTRIBUTION REVENUE TARGETS FOR EACH RATE CLASS?

A. The target revenues are shown on Schedule HSG-2-1, line 42.

Q. DID YOU COMPUTE RATES OF RETURN AT THE PROPOSED CLASS REVENUE TARGETS?

A. Yes. The rates of return are computed on Schedule HSG-2-1, lines 42-50.

Q. DOES THE PROPOSED REVENUE ALLOCATION MOVE THE CLASSES CLOSER TO THE SYSTEM AVERAGE RATE OF RETURN?

A. Yes. Line 53 shows that with the revenue allocation proposed by the Company, the relative return for each class moves closer to 1.00X than under present rates.

C. RATE DESIGN

Q. WHAT CONSIDERATIONS WERE USED IN DEVELOPING THE COMPANY'S PROPOSED RATES?

A. The following objectives were considered in developing the proposed rates:

- To collect the revenue target established for each service class in the revenue allocation process, shown on Schedule HSG-2-1, line 42.
- To avoid severely disproportionate impacts on customer subgroups within a class.
- To provide signals to customers to reflect the effects of their usage on the overall system, including supporting conservation.

Q. DID YOU PREPARE A SCHEDULE SHOWING THE COMPUTATION OF THE RATES NEEDED TO PRODUCE THE TARGET REVENUE FOR EACH CLASS?

A. Yes, the computations are on Schedule HSG-2-2.

Q. DO THE RATES PRESENTED IN YOUR EXHIBITS AND DISCUSSED IN YOUR TESTIMONY EXCLUDE NEW JERSEY SALES AND USE TAX?

A. Yes, the rates exclude the New Jersey Sales and Use Tax.

Q. HOW WERE THE RATES DEVELOPED FOR RESIDENTIAL HEAT AND RESIDENTIAL NON-HEAT?

A. Although these classes are presented separately in the ECOSS to reflect their different usage profiles, the rates are the same. The total revenue target is $243.2 million, an increase of 29.95% over present rate revenue. The proposed customer charge was increased from $9.85 to $11.25 per customer-month, an increase of 14.2%. To produce the balance of the target revenue, the volumetric charge was increased from $0.5437 to $0.7681 per therm, an increase of 33.57% when considering the current IIP revenue. This information is on Schedule HSG 2-2, lines 1-5.

Q. HOW WERE THE PROPOSED RATES DEVELOPED FOR SMALL GENERAL SERVICE, SGS?

A. The revenue target is $23.52 million, an increase of 25.5% over present rate revenue. The proposed customer charge was increased from $34.50 to $38.50 per customer-month, an increase of 11.6%. To produce the balance of the target revenue, the volumetric charge was increased from $0.4241 to $0.6121 per therm, an increase of 33.95% when considering the current IIP revenue.

Q. HOW WERE THE PROPOSED RATES DEVELOPED FOR GENERAL DELIVERY SERVICE, GDS?

A. The revenue target is $76.7 million, an increase of 16.5% over present rate revenue. The proposed customer charge was increased from $58.00 to $60.90 per customer-month, an increase of 5.0%. To produce the balance of the target revenue, each of the other rate components was increased by approximately 23.15%, to produce an increase in volumetric revenue of 17.4% when considering the current IIP revenue.

Q. HOW WERE THE PROPOSED RATES DEVELOPED FOR LARGE VOLUME DELIVERY, LVD?

A. The revenue target is $12.0 million, an increase of approximately 16.5% over present rate revenue. The proposed customer charge was increased from $380.00 to $395.00 per customer-month, an increase of 3.9%. To produce the balance of the target revenue, each of the other rate components was increased by approximately 22.69%, to produce an increase in volumetric revenue of 16.8% when considering the current IIP revenue.

Q. HOW WERE THE PROPOSED RATES DEVELOPED FOR NATURAL GAS VEHICLE, NGV?

A. The revenue target is $177,000, an increase of approximately 19.5% over present rate revenue. The Fueling charge and Facilities charge were each increased by 5.0%. The volumetric charge was increased from $0.4013 to $0.6313 per them, or 57.3%, to produce the balance of the target revenue.

Q. HOW WERE THE PROPOSED RATES DEVELOPED FOR THE NON-FIRM (INTERRUPTIBLE) CLASSES IS, ITS-IS AND ITS-LVD?

A. The revenue target is $7.0 million, an increase of 16.5% over present rate revenue. The proposed customer charge was increased from $690.00 to $725.00 per customer-month, an increase of 5.1%. Each of the other rate components was increased by approximately 17.1% to produce the balance of the target revenue.

Q. HOW WERE THE PROPOSED RATES DEVELOPED FOR CSI AND ELECTRIC GENERATION FIRM SERVICE (“EGF”)?

A. There are no customers taking service under either of these rate classes and no current rate revenue. The proposed customer charges were each increased by approximately 5.1%, with CSI increasing from $144.59 to $152.00 per customer-month and EGF from $95.00 to $100.00 per customer-month. Each of the other rate components for each of these classes was increased by approximately 17.0%.

Q. DOES THIS CONCLUDE YOUR TESTIMONY?

A. Yes, it does.

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Elizabethtown Gas Company
Embedded Cost of Service Study (ECOSS)
Post Test Year 2025-03-31 (Using 2024 6+6)
Summary of Results

Line	Account	Balance	Residential Heat	Residential Non-Heat	Small General SGS	General GDS	Large Volume LVD	NGV	Non-Firm
1	Base Delivery	288,211.191	178,827	8,340	18,724	65,876	10,302	148	5,993
2	Other Revenue	2,952	1,940	139	168	514	184	1	7
3	**Total Revenue**	291,164	180,767	8,480	18,893	66,390	10,486	149	6,000
4									
5	Expenses	190,109	139,980	13,352	11,681	20,082	3,620	66	1,328
6	Net income	101,055	40,787	(4,872)	7,212	46,308	6,867	83	4,672
7									
8	Rate Base	1,862,109	1,373,945	138,472	115,891	174,304	41,753	1,117	16,627
9	BPU GR211211254	*3.71%*	*1.11%*	*(5.55%)*	*4.83%*	*26.32%*	*22.25%*	*0.38%*	*19.86%*
10	Return on Rate Base	5.4269%	2.97%	(3.52%)	6.22%	26.57%	16.45%	7.39%	28.10%
11	*Rekative*	*1.00 X*	*0.55 X*	*(0.65) X*	*1.15 X*	*4.90 X*	*3.03 X*	*1.36 X*	*5.18 X*
12	Revenue Requirement	366,723	275,708	29,330	22,410	30,096	6,756	169	2,252
13	BPU GR211211254 Relative	*1.000*	*0.30 X*	*(1.49) X*	*1.30 X*	*7.09 X*	*6.00 X*	*0.10 X*	*5.35 X*
14	Operating expenses	81,784	63,569	6,705	4,766	5,483	1,088	4	169
15	Uncollectibles expense	9,750	7,231	1,576	483	316	114	5	25
16	Depreciation expense	73,787	56,305	6,073	4,626	5,445	1,039	39	260
17	General tax / Other	9,188	6,779	683	572	860	206	6	82
18	GRT	0	0	0	0	0	0	0	0
19		174,510	133,885	15,037	10,448	12,104	2,446	54	536
20	Pre-tax income	192,213	141,823	14,294	11,963	17,992	4,310	115	1,716
21	Income taxes	37,472	27,648	2,787	2,332	3,508	840	22	335
22	Net income	154,741	114,175	11,507	9,631	14,485	3,470	93	1,382
23									
24	Return on Rate Base	8.31%	8.31%	8.31%	8.31%	8.31%	8.31%	8.31%	8.31%
25									
26	Revenue increase (decrease)	75,559	94,941	20,851	3,518	(36,294)	(3,730)	21	(3,748)
27	Revenue increase (decrease) %	25.95%	52.52%	245.90%	18.62%	(54.67%)	(35.57%)	13.83%	(62.46%)

Elizabethtown Gas Company
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Class Allocations - Total

Line	Account	No.	Balance	Residential Heat	Residential Non-Heat	Small General SGS	General GDS	Large Volume LVD	NGV	Non-Firm
1	**I. GAS PLANT IN SERVICE**									
2	**A. INTANGIBLE PLANT**									
3	Franchise & Consents	302	651	539	63	35	14	0	0	0
4	Software & Other Intangibles	303I	0	0	0	0	0	0	0	0
5	**Intangible Plant**		651	539	63	35	14	0	0	0
6										
7	**B. Storage / LNG**									
8	Land & Land Rights	360	68	42	1	4	16	4	0	0
9	Structures and Improvements	361	6,512	4,025	98	406	1,569	414	1	0
10	Gas Holders- LNG/ Storage	362	3,400	2,101	51	212	819	216	0	0
11	363G- Vapor / Compress/ Regulatir		85,911	53,098	1,289	5,359	20,695	5,462	8	0
12	NGV Station	363	2,298	0	0	0	0	0	2,298	0
13	**Storage Plant**	304-338	98,189	59,267	1,438	5,982	23,099	6,096	2,307	0
14										
15	**C. TRANSMISSION PLANT**									
16	Land	365	631	390	9	39	152	40	0	0
17	Structures and Improvements	366	0	0	0	0	0	0	0	0
18	Mains	367	15,849	9,796	238	989	3,818	1,008	2	0
19	Measuring and Reg. Sta. Equip.	369	8,600	5,315	129	537	2,072	547	1	0
20	**Transmission Plant**	360-368	25,080	15,501	376	1,565	6,041	1,594	2	0
21										
22	**D. DISTRIBUTION PLANT**									
23	Land and Land Rights	374	4,438	3,274	330	279	417	98	5	36
24	Structures and Improvements	375	10,587	7,810	786	666	995	233	11	86
25	Mains	376	1,238,550	928,515	81,808	70,665	127,797	29,610	47	107
26	Mains Direct	376TC	14,248	0	0	0	0	3,476	0	10,772
27	Meas. & Reg. Stat. Equip. - Genera	378	44,669	27,608	670	2,787	10,760	2,840	4	0
28	Services	380	635,224	493,753	67,291	46,140	28,041	0	0	0
29	Services Direct	380D	6,381	0	0	0	0	2,096	0	4,285
30	Meters / Install	381/382	198,942	157,878	17,714	13,397	8,322	858	1	773
31	Ind M&R	385	16,742	0	0	2,847	10,993	2,901	0	0
32	House Reg/ Install	384	12,207	9,688	1,087	822	511	53	0	47
33	OPEN		0	0	0	0	0	0	0	0
34	OPEN		3,768	0	0	0	0	1,018	0	2,750
35	**Distribution Plant**	374-388	2,185,756	1,628,525	169,686	137,602	187,836	43,182	67	18,858
36										
37	**E. GENERAL PLANT**									
38	General Pt- Labor	389	219,750	170,937	18,096	12,843	14,617	2,834	4	419
39	General Pt- Plant	398	0	0	0	0	0	0	0	0
40	**General Plant**	389-399	219,750	170,937	18,096	12,843	14,617	2,834	4	419
41										
42	**TOTAL UTILITY PLANT**		2,529,427	1,874,770	189,659	158,027	231,607	53,707	2,381	19,277

Elizabethtown Gas Company
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Class Allocations - Total

Line	Account	No.	Balance	Residential Heat	Residential Non-Heat	Small General SGS	General GDS	Large Volume LVD	NGV	Non-Firm
43										
44	**II. DEPRECIATION RESERVE**									
45	Mains-Services Direct	108	0	0	0	0	0	0	0	0
46	NGV Station	111	958	0	0	0	0	0	958	0
47	Storage Plant	108	10,325	6,382	155	644	2,487	656	1	0
48	Transmission Plant	109	1,433	885	21	89	345	91	0	0
49	Distribution- Mains	108M	206,859	155,078	13,663	11,802	21,344	4,945	8	18
50	Distribution- Services	108S	77,823	60,491	8,244	5,653	3,435	0	0	0
51	Distribution- Meters	108Mt	63,394	50,309	5,645	4,269	2,652	273	0	246
52	Distribution- Other	108O	46,871	34,575	3,481	2,946	4,404	1,033	48	383
53	General Pt- Labor	109	90,775	70,611	7,475	5,305	6,038	1,171	2	173
54	General Pt- Plant	398	0	0	0	0	0	0	0	0
55	**Depreciation Reserve**	108	498,438	378,331	38,685	30,709	40,706	8,170	1,018	820
56										
57	**III. OTHER RATE BASE ITEMS**									
58	Materials and Supplies, Prepay	105	0	0	0	0	0	0	0	0
59	Storage Gas	107M	10,754	6,260	174	634	2,876	807	2	0
60	Cust Dep / Adv	Cust	(6,690)	(3,904)	(368)	(877)	(1,365)	(175)	(1)	0
61	Other Regulatory Assets	182P	23,015	17,902	1,895	1,345	1,531	297	0	44
62	Accum Deferred Income Taxes	190	(246,434)	(181,786)	(18,304)	(15,491)	(23,157)	(5,429)	(254)	(2,013)
63	CWC	CWC	50,476	39,035	4,100	2,962	3,518	717	5	139
64	OPEN	CWC-Su	0	0	0	0	0	0	0	0
65	**Other Rate Base**		(168,880)	(122,494)	(12,502)	(11,427)	(16,597)	(3,784)	(247)	(1,830)
66										
67	**TOTAL RATE BASE**		1,862,109	1,373,945	138,472	115,891	174,304	41,753	1,117	16,627
68										
69	**I. OPERATING AND MAINTENANCE EXPENSES**									
70	**A. PRODUCTION EXPENSE**									
71	Purchased Gas									
72	Natural Gas City Gate Purchases	804	0	0	0	0	0	0	0	0
73	**Subtotal-Production expenses**	710-813	0	0	0	0	0	0	0	0
74										
75	**B. STORAGE, LNG EXPENSES**									
76	Storage Operations	841	700	433	10	44	169	44	0	0
77	**Subtotal- Storage expenses**	840-850	700	433	10	44	169	44	0	0
78										

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Class Allocations - Total

Line	Account	No.	Balance	Residential Heat	Residential Non-Heat	Small General SGS	General GDS	Large Volume LVD	NGV	Non-Firm
79	**C. TRANSMISSION EXPENSES**									
80	Mains Operating	850-856	0	0	0	0	0	0	0	0
81	Maintenance Other Equip.	865	174	108	3	11	42	11	0	0
82	**Subtotal-Transmission**	850-867	174	108	3	11	42	11	0	0
83										
84	**D. DISTRIBUTION O&M EXPENSE**									
85	Operation Supv & Engineering	870	0	0	0	0	0	0	0	0
86	Distribution Load Dispatching	871	288	159	5	16	77	31	0	0
87	Mains and Services Expenses	874	4,186	3,143	329	258	344	78	0	34
88	Meas & Reg Exp- General	875	29	18	0	2	7	2	0	0
89	Meas & Reg Exp- Industrial	876	0	0	0	0	0	0	0	0
90	Meter-Regulator- Citygate	878	917	567	14	57	221	58	0	0
91	Cust Installations Field	879	835	692	81	45	17	0	0	0
92	Other Expenses	880	3	3	0	0	0	0	0	0
93	Rents	881	16	12	1	1	1	0	0	0
94	Maint Compressor Station Equip	879	0	0	0	0	0	0	0	0
95	Maint Supv & Engineering	885	0	0	0	0	0	0	0	0
96	Maint of Mains	887	1,457	1,092	96	83	150	35	0	0
97	Maint. of Meas. & Reg. General	889	104	64	2	6	25	7	0	0
98	Maint. of Meas. & Reg.- Indust	890	0	0	0	0	0	0	0	0
99	Maint. of Services	892	615	478	65	45	27	0	0	0
100	Maint. of Meters & House Regulatc	893	142	113	13	10	6	1	0	1
101	Maint. Other Equip.	894	61	45	5	4	6	1	0	0
102	**Dist. Oper. & Maint. Exp.**	870-899	8,653	6,386	611	527	883	212	0	35
103	**Total O&M Expenses**		9,527	6,926	624	581	1,093	268	0	35
104										
105	**II. CUSTOMER ACCOUNTS AND SERVICE**									
106	Supervision	901	0	0	0	0	0	0	0	0
107	Meter Reading Expenses	902	509	421	49	27	11	0	0	0
108	Customer Records & Collection Ex	903	850	704	82	46	18	0	0	0
109	Uncollectible Accounts	904	9,078	6,698	675	565	850	204	5	81
110	Miscellaneous Customer Accounts I	905	0	0	0	0	0	0	0	0
111	**Customer Accts. Exp.**	901-905	10,437	7,824	806	638	878	204	5	81
112										
113	**III. CUSTOMER ACCOUNTS AND INFORMATION**									
114	Customer Assistance Expenses	908	3,652	3,025	353	197	76	1	0	1
115	Low Income Discount	908LI	0	0	0	0	0	0	0	0
116	Cust Assist Other	909-912	4,802	3,978	464	259	100	1	0	1
117	Advertising	913	692	573	67	37	14	0	0	0
118	**Customer Service Exp.**	908-919	9,146	7,577	883	493	190	2	0	1
119	**Customer Accts. & Serv. Exp.**	901-919	19,582	15,400	1,690	1,131	1,068	205	5	83

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Class Allocations - Total

Line	Account	No.	Balance	Residential Heat	Residential Non-Heat	Small General SGS	General GDS	Large Volume LVD	NGV	Non-Firm
120										
121	**E. ADMINISTRATIVE AND GENERAL**									
122	Administrative & General Salaries	920	17,114	13,312	1,409	1,000	1,138	221	0	33
123	Office Supplies & Expenses	921	7,904	6,148	651	462	526	102	0	15
124	Outside Services Employed	923	27,397	21,311	2,256	1,601	1,822	353	1	52
125	Property Insurance	924	1,987	1,466	148	125	187	44	2	16
126	Injuries & Damages	925	235	183	19	14	16	3	0	0
127	Employee Pensions and Benefits	926	5,796	4,509	477	339	386	75	0	11
128	Franchise Reqirements	927	0	0	0	0	0	0	0	0
129	Regulatory Commission Expenses	928	360	266	27	22	34	8	0	3
130	Misc General Exp	930	840	654	69	49	56	11	0	2
131	A&G- Rents	931	118	92	10	7	8	2	0	0
132	Maint General Plant	932	0	0	0	0	0	0	0	0
133	**Admin & Genl. Exp.**	920-932	61,753	47,941	5,066	3,619	4,172	818	3	133
134										
135	**Total Operating Expenses**		90,862	70,267	7,380	5,331	6,333	1,291	9	250
136										
137	**II. DEPRECIATION EXPENSE**									
138	Land and ROW	403	448	330	33	28	42	10	0	4
139	Storage Plant	403	1,841	1,138	28	115	444	117	0	0
140	Transmission Plant	404	523	323	8	33	126	33	0	0
141	Mains	403M	21,144	15,705	1,393	1,192	2,125	548	1	180
142	Services	403S	19,828	15,412	2,100	1,440	875	0	0	0
143	Meters	403Mt	7,248	5,752	645	488	303	31	0	28
144	Distr Other	403O	687	507	51	43	65	15	1	6
145	General Pt- Labor	404	22,032	17,138	1,814	1,288	1,465	284	0	42
146	General Pt- Plant	404	0	0	0	0	0	0	0	0
147	Mains/Services Direct	404	0	0	0	0	0	0	0	0
148	NGV Station	404	37	0	0	0	0	0	37	0
149	Amort Regulatory Debits	403	0	0	0	0	0	0	0	0
150	**Depreciation Expense**		73,787	56,305	6,073	4,626	5,445	1,039	39	260
151										
152	**III. TAXES and OTHER**		73,750	56,305	6,073	4,626	5,445	1,039	3	260
153	**A. GENERAL TAXES**									
154	Taxes- Labor based	408L	3,269	2,543	269	191	217	42	0	6
155	Taxes- Plant based	408P	1,076	794	80	68	101	24	1	9
156	Other Taxes	408O	1,047	773	78	65	98	23	1	9
157	Tax Amortization	408	3,587	2,647	267	223	336	80	2	32
158	**General Taxes**		8,980	6,756	694	547	752	170	4	56
159										
160	**B. GROSS RECEIPTS TAX**									
161	Gross Receipts tax		0	0	0	0	0	0	0	0
162	**Gross Receipts Tax**		0	0	0	0	0	0	0	0

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Class Allocations - Total

Line	Account	No.	Balance	Residential Heat	Residential Non-Heat	Small General SGS	General GDS	Large Volume LVD	NGV	Non-Firm
163										
164	**B. FEDERAL / STATE INCOME TAXES**									
165	Federal Income Tax Expense		16,480	6,651	(795)	1,176	7,552	1,120	13	762
166	**Income Taxes**	409-411	16,480	6,651	(795)	1,176	7,552	1,120	13	762
167	**Total Taxes**	408-411	25,459	13,407	(101)	1,723	8,304	1,290	17	818
168										
169	**TOTAL EXPENSES**		190,109	139,980	13,352	11,681	20,082	3,620	66	1,328
170										
171	**IV. OPERATING REVENUES at Present Rates**									
172	Base Delivery	480	288,211	178,827	8,340	18,724	65,876	10,302	148	5,993
173	Commodity	480C	0	0	0	0	0	0	0	0
174	Rent from Gas Property	488	0	0	0	0	0	0	0	0
175	Late payment	493	769	567	57	48	72	17	0	7
176	Other Revenues	495	1,442	798	25	79	386	154	0	0
177	Marketer	495	34	19	1	2	9	4	0	0
178	Turn On	495	564	467	54	30	12	0	0	0
179	Capacity Release	415/416	144	89	2	9	35	9	0	0
180	Adjust to Case Model		0	0	0	0	0	0	0	0
181	**TOTAL REVENUE**		291,164	180,767	8,480	18,893	66,390	10,486	149	6,000
182										
183	**V. Net Income at Present Rates**		101,055	40,787	(4,872)	7,212	46,308	6,867	83	4,672
184										
185	**RATE BASE**		1,862,109	1,373,945	138,472	115,891	174,304	41,753	1,117	16,627
186	Return on Rate Base		5.43%	2.97%	(3.52%)	6.22%	26.57%	16.45%	7.39%	28.10%
187										
188	**REVENUE REQUIREMENTS**									
189	Target Rate of Return		8.3100%	8.3100%	8.3100%	8.3100%	8.3100%	8.3100%	8.3100%	8.3100%
190	Rate Base		1,862,109	1,373,945	138,472	115,891	174,304	41,753	1,117	16,627
191										
192	Operating expenses, Depreciation		155,571	119,874	12,778	9,393	10,928	2,127	43	429
193	Uncollectible accounts		9,750	7,231	1,576	483	316	114	5	25
194	General taxes / Other		9,188	6,779	683	572	860	206	6	82
195	Subtotal- Operating Costs to recove		174,510	133,885	15,037	10,448	12,104	2,446	54	536
196										
197	Target Return on rate base		154,741	114,175	11,507	9,631	14,485	3,470	93	1,382
198	Income Taxes		37,472	27,648	2,787	2,332	3,508	840	22	335
199										
200	Subtotal- Rev Req before GRT		366,723	275,708	29,330	22,410	30,096	6,756	169	2,252
201	GRT needed		0	0	0	0	0	0	0	0
202	**TOTAL REVENUE REQUIREMENT**		366,723	275,708	29,330	22,410	30,096	6,756	169	2,252
203										

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Elizabethtown Gas Company
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Unit Costs

Line	Account Description		Total	Residential Heat and Residential Non-Heat	Small General SGS	General GDS	Large Volume LVD	NGV	Non-Firm
1	Demand-related Revenue Req		91,768	56,463	5,746	21,542	6,262	134	1,622
2	Gas Deliveries, dth		497,688,949	264,606,623	25,480,871	124,320,757	49,432,246	116,571	33,731,881
3	**Demand-related, Per dth**		**$0.18**	**$0.21**	**$0.23**	**$0.17**	**$0.13**	**$1.15**	**$0.05**
4									
5	Customer-related Revenue Req		274,955	248,575	16,664	8,555	495	36	630
6	Number of Bills		3,813,043	3,527,177	205,397	79,269	660	12	528
7	**Customer-related, Per bill**		**$72.11**	**$70.47**	**$81.13**	**$107.92**	**$749.31**	**$2,962.90**	**$1,194.03**
8									
9	**Total revenue requirement**		**366,723**	**305,038**	**22,410**	**30,096**	**6,756**	**169**	**2,252**
10									
11	**Customer-related costs, per customer-month:**								
12	Return component								
13	Mains, net		$17.47	$17.47	$17.47	$17.47	$17.47	$17.47	$17.47
14	Services, net	CC	$15.26	$14.41	$20.35	$32.04	$327.85	$0.00	$837.65
15	Meters and Regulators, net	CC	$4.00	$3.82	$5.00	$8.05	$99.64	$3.66	$112.25
16	ADIT		($4.73)	($4.10)	($5.51)	($7.41)	($52.77)	($2.82)	($109.47)
17	Other Rate Base		$3.64	$3.15	$3.60	$3.05	($8.78)	$15.43	$16.55
18	Return Component		$35.65	$34.75	$40.91	$53.20	$383.42	$33.74	$874.46
19									
20	Expense component								
21	Mains O&M		$1.06	$1.04	$1.18	$1.47	$7.71	$0.69	$18.62
22	Services O&M	CC	$0.00	$0.00	$0.00	$0.00	$0.01	$0.01	$0.01
23	Meters and Regul O&M	CC	$0.04	$0.04	$0.05	$0.07	$0.93	$0.03	$1.05
24	Other O&M		$0.39	$0.39	$0.45	$0.58	$0.40	$0.29	$0.52
25	Customer Accounting	CC	$2.75	$2.75	$2.75	$2.75	$2.75	$2.75	$2.75
26	Uncollectible Accounts		$1.91	$1.95	$1.60	$0.87	$6.34	$70.87	$10.68
27	Admin & General		$13.05	$12.90	$14.01	$16.46	$49.17	$28.26	$82.85
28	Mains Depr Exp		$3.75	$3.47	$0.20	$0.08	$0.00	$0.00	$0.00
29	Services Depr Exp	CC	$5.20	$4.96	$7.01	$11.04	$0.00	$0.00	$0.00
30	Meters and Regul Depr Exp	CC	$1.90	$1.81	$2.38	$3.82	$47.35	$1.74	$53.34
31	Other Depr Exp		$4.61	$4.83	$8.51	$9.45	$17.99	$2,481.27	$33.65
32	General Taxes		$1.80	$1.58	$2.08	$8.11	$233.25	$343.24	$116.10
33	Expense component		$36.46	$35.72	$40.23	$54.72	$365.89	$2,929.16	$319.58
34	Total revenue requirement		$72.11	$70.47	$81.13	$107.92	$749.31	$2,962.90	$1,194.03
35									
36	**Customer charge costs**	**CC**	**$29.16**	**$27.79**	**$37.54**	**$57.79**	**$478.53**	**$8.20**	**$1,007.05**

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Line	Account	No.	Balance	Allocator	Supply-Storage	Distribution	Billing	Procurement	Labor $	Labor %
1	**I. GAS PLANT IN SERVICE**									
2	**A. INTANGIBLE PLANT**									
3	Franchise & Consents	302	651	Dist	-	651	-	-	-	
4	Software & Other Intangibles	303I	-	Dist	-	-	-	-	-	
5	**Intangible Plant**		651		-	651	-	-	-	
6										
7	**B. Storage / LNG**								-	
8	Land & Land Rights	360	68	Dist	-	68	-	-	-	
9	Structures and Improvements	361	6,512	Dist	-	6,512	-	-	-	
10	Gas Holders- LNG/ Storage	362	3,400	Dist	-	3,400	-	-	-	
11	363G- Vapor / Compress/ Regulating		85,911	Dist	-	85,911	-	-	-	
12	NGV Station	363	2,298	Dist	-	2,298	-	-	-	
13	Storage Plant	304-338	98,189		-	98,189	-	-	-	
14										
15	**C. TRANSMISSION PLANT**								-	
16	Land	365	631	Dist	-	631	-	-	-	
17	Structures and Improvements	366	-	Dist	-	-	-	-	-	
18	Mains	367	15,849	Dist	-	15,849	-	-	-	
19	Measuring and Reg. Sta. Equip.	369	8,600	Dist	-	8,600	-	-	-	
20	**Transmission Plant**	360-368	25,080		-	25,080	-	-	-	
21										
22	**D. DISTRIBUTION PLANT**									
23	Land and Land Rights	374	4,438	Dist	-	4,438	-	-	-	
24	Structures and Improvements	375	10,587	Dist	-	10,587	-	-	-	
25	Mains	376	1,238,550	Dist	-	1,238,550	-	-	-	
26	Mains Direct	376TC	14,248	Dist	-	14,248	-	-	-	
27	Meas. & Reg. Stat. Equip. - General	378	44,669	Dist	-	44,669	-	-	-	
28	Services	380	635,224	Dist	-	635,224	-	-	-	
29	Services Direct	380D	6,381	Dist	-	6,381	-	-	-	
30	Meters / Install	381/382	198,942	Dist	-	198,942	-	-	-	
31	Ind M&R	385	16,742	Dist	-	16,742	-	-	-	
32	House Reg/ Install	384	12,207	Dist	-	12,207	-	-	-	
33	OPEN		-	Dist	-	-	-	-	-	
34	OPEN		3,768	Dist	-	3,768	-	-	-	
35	Distribution Plant	374-388	2,185,756		-	2,185,756	-	-	-	
36										
37	**E. GENERAL PLANT**									
38	General Pt- Labor	389	219,750	Dist	-	219,750	-	-	-	
39	General Pt- Plant	398	-	Dist	-	-	-	-	-	
40	**General Plant**	389-399	219,750		-	219,750	-	-	-	
41										
42	**TOTAL UTILITY PLANT**		2,529,427		-	2,529,427	-	-	-	

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Line	Account	No.	Balance	Allocator	Supply-Storage	Distribution	Billing	Procurement		Labor $	Labor %
43											
44	**II. DEPRECIATION RESERVE**										
45	Mains-Services Direct	108	-	Dist	-	-	-	-	-		
46	NGV Station	111	958	Dist	-	958	-	-	-		
47	Storage Plant	108	10,325	Dist	-	10,325	-	-	-		
48	Transmission Plant	109	1,433	Dist	-	1,433	-	-	-		
49	Distribution- Mains	108M	206,859	Dist	-	206,859	-	-	-		
50	Distribution- Services	108S	77,823	Dist	-	77,823	-	-	-		
51	Distribution- Meters	108Mt	63,394	Dist	-	63,394	-	-	-		
52	Distribution- Other	108O	46,871	Dist	-	46,871	-	-	-		
53	General Pt- Labor	108.7	90,775	Dist	-	90,775	-	-	-		
54	General Pt- Plant	398	-	Dist	-	-	-	-	-		
55	Depreciation Reserve	108	498,438		-	498,438	-	-	-		
56											
57	**III. OTHER RATE BASE ITEMS**										
58	Materials and Supplies, Prepay	105	-	Dist	-	-	-	-	-		
59	Storage Gas	107M	10,754	Dist	-	10,754	-	-	-		
60	Cust Dep / Adv	Cust	(6,690)	Dist	-	(6,690)	-	-	-		
61	Other Regulatory Assets	182P	23,015	Dist	-	23,015	-	-	-		
62	Accum Deferred Income Taxes	190	(246,434)	Dist	-	(246,434)	-	-	-		
63	CWC	CWC	50,476	Dist	-	50,476	-	-	-		
64	OPEN	CWC-Su	-	Dist	-	-	-	-	-		
65	**Other Rate Base**		(168,880)		-	(168,880)	-	-	-		
66											
67	**TOTAL RATE BASE**		1,862,109		-	1,862,109	-	-	-		
68											
69	**I. OPERATING AND MAINTENANCE EXPENSES**										
70	**A. PRODUCTION EXPENSE**										
71	Purchased Gas										
72	Natural Gas City Gate Purchases	804	-	Dist	-	-	-	-	-	0	0.00%
73	**Subtotal-Production expenses**	710-813	-		-	-	-	-		-	
74											
75	**B. STORAGE, LNG EXPENSES**										
76	Storage Operations	841	700	Dist	-	700	-	-	-	306	43.66%
77	**Subtotal- Storage expenses**	840-850	700		-	700	-	-		306	
78											

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Line	Account	No.	Balance	Allocator	Supply-Storage	Distribution	Billing	Procurement		Labor $	Labor %
79	**C. TRANSMISSION EXPENSES**										
80	Mains Operating	850-856	-	Dist	-	-	-	-	-	0	0.00%
81	Maintenance Other Equip.	865	174	Dist	-	174	-	-	-	0	0.00%
82	**Subtotal-Transmission**	850-867	174		-	174	-	-		0	
83											
84	**D. DISTRIBUTION O&M EXPENSE**										
85	Operation Supv & Engineering	870	0	Dist	-	0	-	-	-	0	0.00%
86	Distribution Load Dispatching	871	288	Dist	-	288	-	-	-	0	0.01%
87	Mains and Services Expenses	874	4,186	Dist	-	4,186	-	-	-	1,035	24.72%
88	Meas & Reg Exp- General	875	29	Dist	-	29	-	-	-	29	97.34%
89	Meas & Reg Exp- Industrial	876	0	Dist	-	0	-	-	-	0	0.00%
90	Meter-Regulator- Citygate	878	917	Dist	-	917	-	-	-	52	5.65%
91	Cust Installations Field	879	835	Dist	-	835	-	-	-	813	97.34%
92	Other Expenses	880	3	Dist	-	3	-	-	-	0	7.57%
93	Rents	881	16	Dist	-	16	-	-	-	0	0.00%
94	Maint Compressor Station Equip	879	-	Dist	-	-	-	-	-	0	0.00%
95	Maint Supv & Engineering	885	-	Dist	-	-	-	-	-	0	0.00%
96	Maint of Mains	887	1,457	Dist	-	1,457	-	-	-	347	23.85%
97	Maint. of Meas. & Reg. General	889	104	Dist	-	104	-	-	-	93	89.63%
98	Maint. of Meas. & Reg.- Indust	890	-	Dist	-	-	-	-	-	0	0.00%
99	Maint. of Services	892	615	Dist	-	615	-	-	-	398	64.72%
100	Maint. of Meters & House Regulators	893	142	Dist	-	142	-	-	-	0	0.09%
101	Maint. Other Equip.	894	61	Dist	-	61	-	-	-	0	0.00%
102	Dist. Oper. & Maint. Exp.	870-899	8,653		-	8,653	-	-	-	2,767	
103	**Total O&M Expenses**		9,527		-	9,527	-	-	-	3,073	
104											
105	**II. CUSTOMER ACCOUNTS AND SERVICE**										
106	Supervision	901	-	Dist	-	-	-	-	-	0	0.00%
107	Meter Reading Expenses	902	509	Dist	-	509	-	-	-	260	51.16%
108	Customer Records & Collection Expen	903	850	Dist	-	850	-	-	-	727	85.48%
109	Uncollectible Accounts	904	9,078	Dist	-	9,078	-	-	-	0	0.00%
110	Miscellaneous Customer Accounts Exp	905	-	Dist	-	-	-	-	-	0	0.00%
111	**Customer Accts. Exp.**	901-905	10,437		-	10,437	-	-	-	987	
112											
113	**III. CUSTOMER ACCOUNTS AND INFORMATION**										
114	Customer Assistance Expenses	908	3,652	Dist	-	3,652	-	-	-	467	12.80%
115	Low Income Discount	908LI	-	Dist	-	-	-	-	-	0	0.00%
116	Cust Assist Other	909-912	4,802	Dist	-	4,802	-	-	-	0	0.00%
117	Advertising	913	692	Dist	-	692	-	-	-	0	0.00%
118	**Customer Service Exp.**	908-919	9,146		-	9,146	-	-	-	467	
119	**Customer Accts. & Serv. Exp.**	901-919	19,582		-	19,582	-	-	-	1,454	

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Line	Account	No.	Balance	Allocator	Supply-Storage	Distribution	Billing	Procurement		Labor $	Labor %
120											
121	**E. ADMINISTRATIVE AND GENERAL**										
122	Administrative & General Salaries	920	17,114	Dist	-	17,114	-	-	-	16,388	95.76%
123	Office Supplies & Expenses	921	7,904	Dist	-	7,904	-	-	-	1,830	23.15%
124	Outside Services Employed	923	27,397	Dist	-	27,397	-	-	-	21,277	77.66%
125	Property Insurance	924	1,987	Dist	-	1,987	-	-	-	0	0.00%
126	Injuries & Damages	925	235	Dist	-	235	-	-	-	0	0.00%
127	Employee Pensions and Benefits	926	5,796	Dist	-	5,796	-	-	-	0	0.00%
128	Franchise Reqirements	927	-	Dist	-	-	-	-	-	0	0.00%
129	Regulatory Commission Expenses	928	360	Dist	-	360	-	-	-	0	0.00%
130	Misc General Exp	930.2	840	Dist	-	840	-	-	-	0	0.00%
131	A&G- Rents	931	118	Dist	-	118	-	-	-	0	0.00%
132	Maint General Plant	932	-	Dist	-	-	-	-	-	0	0.00%
133	**Admin & Genl. Exp.**	920-932	61,753		-	61,753	-	-	-	39,496	
134											
135	**Total Operating Expenses**		90,862		-	90,862	-	-	-	44,023	
136											
137	**II. DEPRECIATION EXPENSE**										
138	Land and ROW	403	448	Dist	-	448	-	-	-		
139	Storage Plant	403	1,841	Dist	-	1,841	-	-	-		
140	Transmission Plant	404	523	Dist	-	523	-	-	-		
141	Mains	403M	21,144	Dist	-	21,144	-	-	-		
142	Services	403S	19,828	Dist	-	19,828	-	-	-		
143	Meters	403Mt	7,248	Dist	-	7,248	-	-	-		
144	Distr Other	403O	687	Dist	-	687	-	-	-		
145	General Pt- Labor	404	22,032	Dist	-	22,032	-	-	-		
146	General Pt- Plant	404	-	Dist	-	-	-	-	-		
147	Mains/Services Direct	404	-	Dist	-	-	-	-	-		
148	NGV Station	404	37	Dist	-	37	-	-	-		
149	Amort Regulatory Debits	403	-	Dist	-	-	-	-	-		
150	**Depreciation Expense**		73,787		-	73,787	-	-	-		
151											
152	**III. TAXES and OTHER**										
153	**A. GENERAL TAXES**										
154	Taxes- Labor based	408L	3,269	Dist	-	3,269	-	-	-		
155	Taxes- Plant based	408P	1,076	Dist	-	1,076	-	-	-		
156	Other Taxes	408O	1,047	Dist	-	1,047	-	-	-		
157	Tax Amortization	408	3,587	Dist	-	3,587	-	-	-		
158	**General Taxes**		8,980		-	8,980	-	-	-		
159											
160	**B. GROSS RECEIPTS TAX**										
161	Gross Receipts tax		-	Dist	-	-	-	-	-		
162	**Gross Receipts Tax**		-		-	-	-	-	-		

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Functionalization

Line	Account	No.	Balance	Allocator	Supply-Storage	Distribution	Billing	Procurement	Labor $	Labor %
163										
164	**B. FEDERAL / STATE INCOME TAXES**									
165	Federal Income Tax Expense		16,480	Pretax	-	16,480	-	-	-	
166	**Income Taxes**	409-411	16,480		-	16,480	-	-	-	
167	**Total Taxes**	408-411	25,459		-	25,459	-	-	-	
168										
169	**TOTAL EXPENSES**		190,109		-	190,109	-	-	-	
170										
171	**IV. OPERATING REVENUES at Present Rates**									
172	Base Delivery	480	288,211	RevReq_PF	-	288,211	-	-	-	
173	Commodity	480C	-	Dist	-	-	-	-	-	
174	Rent from Gas Property	488	-	Dist	-	-	-	-	-	
175	Late payment	493	769	Dist	-	769	-	-	-	
176	Other Revenues	495	1,442	Dist	-	1,442	-	-	-	
177	Marketer	495	34	Dist	-	34	-	-	-	
178	Turn On	495	564	Dist	-	564	-	-	-	
179	Capacity Release	415/416	144	Dist	-	144	-	-	-	
180	Adjust to Case Model		-	RevReq_PF	-	-	-	-	-	
181	**TOTAL REVENUE**		291,164		-	291,164	-	-	-	
182										
183	**V. Net Income at Present Rates**		101,055		-	101,055	-	-	# -	
184										
185	**RATE BASE**		1,862,109		-	1,862,109	-	-	-	
186	Return on Rate Base		5.43%		-	5.43%	-	-		
187										
188	**REVENUE REQUIREMENTS**									
189	Target Rate of Return		8.31%		8.31%	8.31%	8.31%	8.3100%		
190	Rate Base		1,862,109		0	1,862,109	0	0	-	
191									-	
192	Operating expenses, Depreciation		155,571		0	155,571	0	0	-	
193	Uncollectible accounts		9,750	Uncollect_RR	-	9,750	-	-	-	
194	General taxes / Other		9,188	RateBase	-	9,188	-	-	-	
195	Subtotal- Operating Costs to recover		174,510		0	174,510	0	0	-	
196										
197	Target Return on rate base		154,741		0	154,741	0	0	-	
198	Income Taxes		37,472	24.22%	0	37,472	0	0	-	
199										
200	Subtotal- Rev Req before GRT		366,723	211,981	0	366,723	0	0	-	
201	GRT needed		0	0.00%	0	0	0	0	-	
202	**TOTAL REVENUE REQUIREMENT**		366,723		0	366,723	0	0	-	
203										

Classify
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Classification

Line	Account	No.		Distribution		Demand	Commodity	Customer	
1	**I. GAS PLANT IN SERVICE**								
2	**A. INTANGIBLE PLANT**								
3	Franchise & Consents	302		651	Customer	-	-	651	-
4	Software & Other Intangibles	303I		-	None	-	-	-	-
5	**Intangible Plant**		-	651		-	-	651	-
6									
7	**B. Storage / LNG**								
8	Land & Land Rights	360		68	Demand	68	-	-	-
9	Structures and Improvements	361		6,512	Demand	6,512	-	-	-
10	Gas Holders- LNG/ Storage	362		3,400	Demand	3,400	-	-	-
11	363G- Vapor / Compress/ Regulating			85,911	Demand	85,911	-	-	-
12	NGV Station	363		2,298	Demand	2,298	-	-	-
13	**Storage Plant**	304-338		98,189		98,189	-	-	-
14									
15	**C. TRANSMISSION PLANT**								
16	Land	365		631	Demand	631	-	-	-
17	Structures and Improvements	366		-	Demand	-	-	-	-
18	Mains	367		15,849	Demand	15,849	-	-	-
19	Measuring and Reg. Sta. Equip.	369		8,600	Demand	8,600	-	-	-
20	**Transmission Plant**	360-368		25,080		25,080	-	-	-
22	**D. DISTRIBUTION PLANT**								
23	Land and Land Rights	374		4,438	Dist Pt	1,289	-	3,149	-
24	Structures and Improvements	375		10,587	Dist Pt	3,075	-	7,512	-
25	Mains	376		1,238,550	MinSys-Mains	463,649	-	774,901	-
26	Mains Direct	376TC		14,248	Demand	14,248	-	-	-
27	Meas. & Reg. Stat. Equip. - General	378		44,669	Demand	44,669	-	-	-
28	Services	380		635,224	Customer	-	-	635,224	-
29	Services Direct	380D		6,381	Customer	-	-	6,381	-
30	Meters / Install	381/382		198,942	Customer	-	-	198,942	-
31	Ind M&R	385		16,742	Demand	16,742	-	-	-
32	House Reg/ Install	384		12,207	Customer	-	-	12,207	-
33	OPEN			-	Demand	-	-	-	-
34	OPEN			3,768	Demand	3,768	-	-	-
35	**Distribution Plant**	374-388		2,185,756		547,440	-	1,638,317	-
36									
37	**E. GENERAL PLANT**								
38	General Pt- Labor	389		219,750	Dist Lab	42,246	-	177,505	-
39	General Pt- Plant	398		-	Dist_Pt	-	-	-	-
40	**General Plant**	389-399		219,750		42,246	-	177,505	-
41									
42	**TOTAL UTILITY PLANT**			2,529,427		712,954	-	1,816,472	-

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Line	Account	No.	Distribution		Demand	Commodity	Customer	
43								
44	**II. DEPRECIATION RESERVE**							
45	Mains-Services Direct	108	-	Mains Serv Di	-	-	-	-
46	NGV Station	111	958	Demand	958	-	-	-
47	Storage Plant	108	10,325	Demand	10,325	-	-	-
48	Transmission Plant	109	1,433	Demand	1,433	-	-	-
49	Distribution- Mains	108M	206,859	MinSys-Mains	77,437	-	129,422	-
50	Distribution- Services	108S	77,823	Customer	-	-	77,823	-
51	Distribution- Meters	108Mt	63,394	Customer	-	-	63,394	-
52	Distribution- Other	108O	46,871	Dist_Pt	13,615	-	33,256	-
53	General Pt- Labor	109	90,775	Dist_Lab	17,451	-	73,324	-
54	General Pt- Plant	398	-	Dist_Pt	-	-	-	-
55	**Depreciation Reserve**	108	498,438		121,219	-	377,219	-
56								
57	**III. OTHER RATE BASE ITEMS**							
58	Materials and Supplies, Prepay	105	-	Dist_OM	-	-	-	-
59	Storage Gas	107M	10,754	Demand	10,754	-	-	-
60	Cust Dep / Adv	Cust	(6,690)	Customer	-	-	(6,690)	-
61	Other Regulatory Assets	182P	23,015	Dist_Lab	4,424	-	18,590	-
62	Accum Deferred Income Taxes	190	(246,434)	Dist_Pt	(71,582)	-	(174,851)	-
63	CWC	CWC	50,476	Dist_OM	10,057	-	40,418	-
64	OPEN	CWC-Su	-	None	-	-	-	-
65	**Other Rate Base**		(168,880)		(46,347)	-	(122,533)	-
66								
67	**TOTAL RATE BASE**		1,862,109		545,388	-	1,316,721	-
68								
69	**I. OPERATING AND MAINTENANCE EXPENSES**							
70	**A. PRODUCTION EXPENSE**							
71								
72	Natural Gas City Gate Purchases	804	-	None	-	-	-	-
73	**Subtotal-Production expenses**	710-813	-		-	-	-	-
74								
75	**B. STORAGE, LNG EXPENSES**							
76	Storage Operations	841	700	Demand	700	-	-	-
77	**Subtotal- Storage expenses**	840-850	700		700	-	-	-
78								

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Line	Account	No.	Distribution		Demand	Commodity	Customer	
79	**C. TRANSMISSION EXPENSES**							
80	Mains Operating	850-856	-	Demand	-	-	-	-
81	Maintenance Other Equip.	865	174	Demand	174	-	-	-
82	**Subtotal-Transmission**	850-867	174		174	-	-	-
83								
84	**D. DISTRIBUTION O&M EXPENSE**							
85	Operation Supv & Engineering	870	0	Dist Lab	0	-	0	-
86	Distribution Load Dispatching	871	288	Demand	288	-	-	-
87	Mains and Services Expenses	874	4,186	Mains Serv	1,056	-	3,130	-
88	Meas & Reg Exp- General	875	29	Demand	29	-	-	-
89	Meas & Reg Exp- Industrial	876	0	Demand	0	-	-	-
90	Meter-Regulator- Citygate	878	917	Demand	917	-	-	-
91	Cust Installations Field	879	835	Customer	-	-	835	-
92	Other Expenses	880	3	Dist OM	1	-	3	-
93	Rents	881	16	Dist_OM	3	-	13	-
94	Maint Compressor Station Equip	879	-	Demand	-	-	-	-
95	Maint Supv & Engineering	885	-	Dist Lab	-	-	-	-
96	Maint of Mains	887	1,457	MinSys-Mains	545	-	911	-
97	Maint. of Meas. & Reg. General	889	104	Demand	104	-	-	-
98	Maint. of Meas. & Reg.- Indust	890	-	Demand	-	-	-	-
99	Maint. of Services	892	615	Customer	-	-	615	-
100	Maint. of Meters & House Regulators	893	142	Customer	-	-	142	-
101	Maint. Other Equip.	894	61	Dist_Pt	18	-	43	-
102	**Dist. Oper. & Maint. Exp.**	870-899	8,653		2,961	-	5,692	-
103	**Total O&M Expenses**		9,527		3,836	-	5,692	-
104								
105	**II. CUSTOMER ACCOUNTS AND SERVICE**							
106	Supervision	901	-	Customer	-	-	-	-
107	Meter Reading Expenses	902	509	Customer	-	-	509	-
108	Customer Records & Collection Expen	903	850	Customer	-	-	850	-
109	Uncollectible Accounts	904	9,078	D-RevReq_PF	2,272	-	6,806	-
110	Miscellaneous Customer Accounts Exp	905	-	Customer	-	-	-	-
111	**Customer Accts. Exp.**	901-905	10,437		2,272	-	8,165	-
112								
113	**III. CUSTOMER ACCOUNTS ANI**							
114	Customer Assistance Expenses	908	3,652	Customer	-	-	3,652	-
115	Low Income Discount	908LI	-	Customer	-	-	-	-
116	Cust Assist Other	909-912	4,802	Customer	-	-	4,802	-
117	Advertising	913	692	Customer	-	-	692	-
118	**Customer Service Exp.**	908-919	9,146		-	-	9,146	-
119	**Customer Accts. & Serv. Exp.**	901-919	19,582		2,272	-	17,311	-

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Line	Account	No.	Distribution		Demand	Commodity	Customer	
120								
121	**E. ADMINISTRATIVE AND GENERAL**							
122	Administrative & General Salaries	920	17,114	Dist_Lab	3,290	-	13,824	-
123	Office Supplies & Expenses	921	7,904	Dist_Lab	1,520	-	6,385	-
124	Outside Services Employed	923	27,397	Dist_Lab	5,267	-	22,130	-
125	Property Insurance	924	1,987	Dist_Pt	577	-	1,410	-
126	Injuries & Damages	925	235	Dist_Lab	45	-	190	-
127	Employee Pensions and Benefits	926	5,796	Dist_Lab	1,114	-	4,682	-
128	Franchise Reqirements	927	-	Customer	-	-	-	-
129	Regulatory Commission Expenses	928	360	Customer	-	-	360	-
130	Misc General Exp	930	840	Dist_Lab	162	-	679	-
131	A&G- Rents	931	118	Dist_Lab	23	-	96	-
132	Maint General Plant	932	-	Dist_Lab	-	-	-	-
133	**Admin & Genl. Exp.**	920-932	61,753		11,997	-	49,755	-
134								
135	**Total Operating Expenses**		90,862		18,105	-	72,758	-
136								
137	**II. DEPRECIATION EXPENSE**							
138	Land and ROW	403	448	Dist_Pt	130	-	318	-
139	Storage Plant	403	1,841	Demand	1,841	-	-	-
140	Transmission Plant	404	523	Demand	523	-	-	-
141	Mains	403M	21,144	MinSys-Mains	7,915	-	13,229	-
142	Services	403S	19,828	Customer	-	-	19,828	-
143	Meters	403Mt	7,248	Customer	-	-	7,248	-
144	Distr Other	403O	687	Dist_Pt	200	-	488	-
145	General Pt- Labor	404	22,032	Dist_Lab	4,236	-	17,796	-
146	General Pt- Plant	404	-	Dist_Lab	-	-	-	-
147	Mains/Services Direct	404	-	Dist_Lab	-	-	-	-
148	NGV Station	404	37	Dist_Lab	7	-	30	-
149	Amort Regulatory Debits	403	-	Demand	-	-	-	-
150	**Depreciation Expense**		73,787		14,852	-	58,936	-
151								
152	**III. TAXES and OTHER**							
153	**A. GENERAL TAXES**							
154	Taxes- Labor based	408L	3,269	Dist_Lab	628	-	2,640	-
155	Taxes- Plant based	408P	1,076	Dist_Pt	313	-	764	-
156	Other Taxes	408O	1,047	Dist_Pt	304	-	743	-
157	BPU	408	3,587	Dist_Pt	1,042	-	2,545	-
158	**General Taxes**		8,980		2,287	-	6,692	-
159								
160	**B. GROSS RECEIPTS TAX**							
161	Gross Receipts tax		-	D-RevReq_PF	-	-	-	-
162	**Gross Receipts Tax**		-		-	-	-	-

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Line	Account	No.	Distribution		Demand	Commodity	Customer	
163								
164	**B. FEDERAL / STATE INCOME TAXES**							
165	Federal Income Tax Expense		16,480	Dist Pretax	5,218	-	11,262	-
166	**Income Taxes**	409-411	16,480		5,218	-	11,262	-
167	**Total Taxes**	408-411	25,459		7,505	-	17,954	-
168								
169	**TOTAL EXPENSES**		190,109		40,461	-	149,647	-
170								
171	**IV. OPERATING REVENUES at Present Rates**							
172	Base Delivery	480	288,211	D-RevReq PF	72,121	-	216,090	-
173	Commodity	480C	-	None	-	-	-	-
174	Rent from Gas Property	488	-	None	-	-	-	-
175	Late payment	493	769	D-RevReq PF	192	-	576	-
176	Other Revenues	495	1,442	Customer	-	-	1,442	-
177	Marketer	495	34	Customer	-	-	34	-
178	Turn On	495	564	Customer	-	-	564	-
179	Capacity Release	415/416	144	Demand	144	-	-	-
180	Adjust to Case Model		-	D-RevReq PF	-	-	-	-
181	**TOTAL REVENUE**	- -	291,164	-	72,458	-	218,706	
182								
183	**V. Net Income at Present Rates**	- -	101,055	-	31,996	-	69,059	-
184								
185	**RATE BASE**		1,862,109		545,388	-	1,316,721	-
186	Return on Rate Base		5.43%		5.87%	-	5.24%	
187								
188	**REVENUE REQUIREMENTS**							
189	Target Rate of Return		8.3100%		8.3100%	8.3100%	8.3100%	
190	Rate Base		1,862,109		545,388	0	1,316,721	-
191								
192	Operating expenses, Depreciation		155,571		30,685	0	124,887	-
193	Uncollectible accounts		9,750	Dist_Unc_RR	2,464	-	7,286	-
194	General taxes / Other		9,188	Dist Unc RR	2,322	-	6,866	-
195	Subtotal- Operating Costs to recover		174,510		35,471	0	139,039	-
196								
197	Target Return on rate base		154,741		45,322	0	109,419	-
198	Income Taxes	24.22%	37,472		10,975	0	26,497	-
199								
200	Subtotal- Rev Req before GRT		366,723		91,768	0	274,955	-
201	GRT needed	0.00%	0		0	0	0	-
202	**TOTAL REVENUE REQUIREMENT**		366,723		91,768	0	274,955	-
203								

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Class Allocation - Distribution Demand

Line	Account	No.	Balance	Allocator	Residential Heat	Residential Non-Heat	Small General SGS	General GDS	Large Volume LVD	NGV	Non-Firm
1	**I. GAS PLANT IN SERVICE**										
2	**A. INTANGIBLE PLANT**										
3	Franchise & Consents	302	-	None	-	-	-	-	-	-	-
4	Software & Other Intangibles	303I	-	None	-	-	-	-	-	-	-
5	**Intangible Plant**		-		-	-	-	-	-	-	-
6											
7	**B. Storage / LNG**										
8	Land & Land Rights	360	68	Peak_Sendout	42	1	4	16	4	0	-
9	Structures and Improvements	361	6,512	Peak_Sendout	4,025	98	406	1,569	414	1	-
10	Gas Holders- LNG/ Storage	362	3,400	Peak_Sendout	2,101	51	212	819	216	0	-
11	363G- Vapor / Compress/ Regulating		85,911	Peak_Sendout	53,098	1,289	5,359	20,695	5,462	8	-
12	NGV Station	363	2,298	NGV Direct	-	-	-	-	-	2,298	-
13	**Storage Plant**	304-338	98,189		59,267	1,438	5,982	23,099	6,096	2,307	-
14											
15	**C. TRANSMISSION PLANT**										
16	Land	365	631	Peak_Sendout	390	9	39	152	40	0	-
17	Structures and Improvements	366	-	Peak_Sendout	-	-	-	-	-	-	-
18	Mains	367	15,849	Peak_Sendout	9,796	238	989	3,818	1,008	2	-
19	Measuring and Reg. Sta. Equip.	369	8,600	Peak_Sendout	5,315	129	537	2,072	547	1	-
20	**Transmission Plant**	360-368	25,080		15,501	376	1,565	6,041	1,594	2	-
21											
22	**D. DISTRIBUTION PLANT**										
23	Land and Land Rights	374	1,289	DistD-Pt	753	18	81	315	92	5	26
24	Structures and Improvements	375	3,075	DistD-Pt	1,795	44	194	750	219	11	62
25	Mains	376	463,649	Peak_Sendout	286,563	6,954	28,924	111,688	29,476	45	-
26	Mains Direct	376TC	14,248	Mains Direct	-	-	-	-	3,476	-	10,772
27	Meas. & Reg. Stat. Equip. - General	378	44,669	Peak_Sendout	27,608	670	2,787	10,760	2,840	4	-
28	Services	380	-	Service_Invest	-	-	-	-	-	-	-
29	Services Direct	380D	-	None	-	-	-	-	-	-	-
30	Meters / Install	381/382	-	None	-	-	-	-	-	-	-
31	Ind M&R	385	16,742	Ind M&R	-	-	2,847	10,993	2,901	-	-
32	House Reg/ Install	384	-	None	-	-	-	-	-	-	-
33	OPEN		-	None	-	-	-	-	-	-	-
34	OPEN		3,768	Mains_Ser_Dir	-	-	-	-	1,018	-	2,750
35	**Distribution Plant**	374-388	547,440		316,719	7,686	34,833	134,506	40,021	64	13,611
36											
37	**E. GENERAL PLANT**										
38	General Pt- Labor	389	42,246	DistD-Lab	25,877	628	2,612	10,085	2,754	4	286
39	General Pt- Plant	398	-	DistD-Pt	-	-	-	-	-	-	-
40	**General Plant**	389-399	42,246		25,877	628	2,612	10,085	2,754	4	286
41											
42	**TOTAL UTILITY PLANT**		712,954		417,364	10,128	44,991	173,732	50,465	2,378	13,897
43											

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Class Allocation - Distribution Demand

Line	Account	No.	Balance	Allocator	Residential Heat	Residential Non-Heat	Small General SGS	General GDS	Large Volume LVD	NGV	Non-Firm
44	**II. DEPRECIATION RESERVE**										
45	Mains-Services Direct	108	-	Mains_Ser_Dir	-	-	-	-	-	-	-
46	NGV Station	111	958	NGV Direct	-	-	-	-	-	958	-
47	Storage Plant	108	10,325	Peak_Sendout	6,382	155	644	2,487	656	1	-
48	Transmission Plant	109	1,433	Peak_Sendout	885	21	89	345	91	0	-
49	Distribution- Mains	108M	77,437	Peak_Sendout	47,861	1,161	4,831	18,654	4,923	7	-
50	Distribution- Services	108S	-	Service_Invest	-	-	-	-	-	-	-
51	Distribution- Meters	108Mt	-	None	-	-	-	-	-	-	-
52	Distribution- Other	108O	13,615	DistD-Pt	7,947	193	860	3,322	968	48	276
53	General Pt- Labor	109	17,451	DistD-Lab	10,689	259	1,079	4,166	1,138	2	118
54	General Pt- Plant	398	-	DistD-Pt	-	-	-	-	-	-	-
55	**Depreciation Reserve**	108	121,219		73,764	1,790	7,503	28,974	7,777	1,017	394
56											
57	**III. OTHER RATE BASE ITEMS**										
58	Materials and Supplies, Prepay	105	-	DistD-OM	-	-	-	-	-	-	-
59	Storage Gas	107M	10,754	Firm_Winter	6,260	174	634	2,876	807	2	-
60	Cust Dep / Adv	Cust	-	None	-	-	-	-	-	-	-
61	Other Regulatory Assets	182P	4,424	DistD-Lab	2,710	66	274	1,056	288	0	30
62	Accum Deferred Income Taxes	190	(71,582)	DistD-Pt	(41,782)	(1,014)	(4,523)	(17,465)	(5,092)	(253)	(1,453)
63	CWC	CWC	10,057	DistD-OM	6,300	225	622	2,224	610	3	74
64	OPEN	CWC-Su	-	None	-	-	-	-	-	-	-
65	**Other Rate Base**		(46,347)		(26,512)	(549)	(2,994)	(11,309)	(3,387)	(248)	(1,349)
66											
67	**TOTAL RATE BASE**		545,388		317,087	7,789	34,494	133,450	39,302	1,113	12,154
68											
69	**I. OPERATING AND MAINTENANCE EXPENSES**										
70	**A. PRODUCTION EXPENSE**										
71	Purchased Gas										
72	Natural Gas City Gate Purchases	804	-	None	-	-	-	-	-	-	-
73	**Subtotal-Production expenses**	710-813	-		-	-	-	-	-	-	-
74											
75	**B. STORAGE, LNG EXPENSES**										
76	Storage Operations	841	700	Peak_Sendout	433	10	44	169	44	0	-
77	**Subtotal- Storage expenses**	840-850	700		433	10	44	169	44	0	-
78											

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Class Allocation - Distribution Demand

Line	Account	No.	Balance	Allocator	Residential Heat	Residential Non-Heat	Small General SGS	General GDS	Large Volume LVD	NGV	Non-Firm
79	**C. TRANSMISSION EXPENSES**										
80	Mains Operating	850-856	-	Peak_Sendout	-	-	-	-	-	-	-
81	Maintenance Other Equip.	865	174	Peak_Sendout	108	3	11	42	11	0	-
82	**Subtotal-Transmission**	850-867	174		108	3	11	42	11	0	-
83											
84	**D. DISTRIBUTION O&M EXPENSE**										
85	Operation Supv & Engineering	870	0	DistD-Lab	0	0	0	0	0	0	0
86	Distribution Load Dispatching	871	288	Gas_Del_Firm	159	5	16	77	31	0	-
87	Mains and Services Expenses	874	1,056	DistD-MainsSvc	633	15	64	247	73	0	24
88	Meas & Reg Exp- General	875	29	Peak_Sendout	18	0	2	7	2	0	-
89	Meas & Reg Exp- Industrial	876	0	Ind M&R	-	-	0	0	0	-	-
90	Meter-Regulator- Citygate	878	917	Peak_Sendout	567	14	57	221	58	0	-
91	Cust Installations Field	879	-	None	-	-	-	-	-	-	-
92	Other Expenses	880	1	DistD-OM	0	0	0	0	0	0	0
93	Rents	881	3	DistD-OM	2	0	0	1	0	0	0
94	Maint Compressor Station Equip	879	-	None	-	-	-	-	-	-	-
95	Maint Supv & Engineering	885	-	None	-	-	-	-	-	-	-
96	Maint of Mains	887	545	Peak_Sendout	337	8	34	131	35	0	-
97	Maint. of Meas. & Reg. General	889	104	Peak_Sendout	64	2	6	25	7	0	-
98	Maint. of Meas. & Reg.- Indust	890	-	None	-	-	-	-	-	-	-
99	Maint. of Services	892	-	None	-	-	-	-	-	-	-
100	Maint. of Meters & House Regulators	893	-	None	-	-	-	-	-	-	-
101	Maint. Other Equip.	894	18	DistD-Pt	10	0	1	4	1	0	0
102	**Dist. Oper. & Maint. Exp.**	870-899	2,961		1,791	45	181	714	206	0	24
103	**Total O&M Expenses**		3,836		2,332	58	235	924	262	0	24
104											
105	**II. CUSTOMER ACCOUNTS AND SERVICE**										
106	Supervision	901	-	None	-	-	-	-	-	-	-
107	Meter Reading Expenses	902	-	None	-	-	-	-	-	-	-
108	Customer Records & Collection Expense	903	-	None	-	-	-	-	-	-	-
109	Uncollectible Accounts	904	2,272	WriteOff_Del	1,676	169	141	213	51	1	20
110	Miscellaneous Customer Accounts Exp.	905	-	None	-	-	-	-	-	-	-
111	**Customer Accts. Exp.**	901-905	2,272		1,676	169	141	213	51	1	20
112											
113	**III. CUSTOMER ACCOUNTS AND IN**										
114	Customer Assistance Expenses	908	-	None	-	-	-	-	-	-	-
115	Low Income Discount	908LI	-	None	-	-	-	-	-	-	-
116	Cust Assist Other	909-912	-	None	-	-	-	-	-	-	-
117	Advertising	913	-	None	-	-	-	-	-	-	-
118	**Customer Service Exp.**	908-919	-		-	-	-	-	-	-	-
119	**Customer Accts. & Serv. Exp.**	901-919	2,272		1,676	169	141	213	51	1	20

DistDem
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Elizabethtown Gas Company
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Class Allocation - Distribution Demand

Line	Account	No.	Balance	Allocator	Residential Heat	Residential Non-Heat	Small General SGS	General GDS	Large Volume LVD	NGV	Non-Firm
120											
121	**E. ADMINISTRATIVE AND GENERAL**										
122	Administrative & General Salaries	920	3,290	DistD-Lab	2,015	49	203	785	214	0	22
123	Office Supplies & Expenses	921	1,520	DistD-Lab	931	23	94	363	99	0	10
124	Outside Services Employed	923	5,267	DistD-Lab	3,226	78	326	1,257	343	1	36
125	Property Insurance	924	577	DistD-Pt	337	8	36	141	41	2	12
126	Injuries & Damages	925	45	DistD-Lab	28	1	3	11	3	0	0
127	Employee Pensions and Benefits	926	1,114	DistD-Lab	683	17	69	266	73	0	8
128	Franchise Reqirements	927	-	None	-	-	-	-	-	-	-
129	Regulatory Commission Expenses	928	-	None	-	-	-	-	-	-	-
130	Misc General Exp	930	162	DistD-Lab	99	2	10	39	11	0	1
131	A&G- Rents	931	23	DistD-Lab	14	0	1	5	1	0	0
132	Maint General Plant	932	-	DistD-Lab	-	-	-	-	-	-	-
133	**Admin & Genl. Exp.**	920-932	11,997		7,332	178	743	2,867	786	3	89
134											
135	**Total Operating Expenses**		18,105		11,340	405	1,119	4,004	1,098	5	133
136											
137	**II. DEPRECIATION EXPENSE**										
138	Land and ROW	403	130	DistD-Pt	76	2	8	32	9	0	3
139	Storage Plant	403	1,841	Peak_Sendout	1,138	28	115	444	117	0	-
140	Transmission Plant	404	523	Peak_Sendout	323	8	33	126	33	0	-
141	Mains	403M	7,915	DistD-Mains	4,746	115	479	1,850	546	1	178
142	Services	403S	-	Service_Invest	-	-	-	-	-	-	-
143	Meters	403Mt	-	None	-	-	-	-	-	-	-
144	Distr Other	403O	200	DistD-Pt	117	3	13	49	14	1	4
145	General Pt- Labor	404	4,236	DistD-Lab	2,594	63	262	1,011	276	0	29
146	General Pt- Plant	404	-	DistD-Pt	-	-	-	-	-	-	-
147	Mains/Services Direct	404	-	Mains_Ser_Dir	-	-	-	-	-	-	-
148	NGV Station	404	7	NGV Direct	-	-	-	-	-	7	-
149	Amort Regulatory Debits	403	-	NGV Direct	-	-	-	-	-	-	-
150	**Depreciation Expense**		14,852		8,994	218	909	3,511	996	10	214
151											
152	**III. TAXES and OTHER**										
153	**A. GENERAL TAXES**										
154	Taxes- Labor based	408L	628	DistD-Lab	385	9	39	150	41	0	4
155	Taxes- Plant based	408P	313	DistD-Pt	182	4	20	76	22	1	6
156	Other Taxes	408O	304	RateBase	224	23	19	28	7	0	3
157	Tax Amortization	408	1,042	RateBase	769	77	65	98	23	1	9
158	**General Taxes**		2,287		1,561	114	142	352	93	2	23
159											
160	**B. GROSS RECEIPTS TAX**										
161	Gross Receipts tax		-	None	-	-	-	-	-	-	-
162	**Gross Receipts Tax**		-		-	-	-	-	-	-	-

DistDem
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Elizabethtown Gas Company
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Class Allocation - Distribution Demand

Line	Account	No.	Balance	Allocator	Residential Heat	Residential Non-Heat	Small General SGS	General GDS	Large Volume LVD	NGV	Non-Firm
163											
164	**B. FEDERAL / STATE INCOME TAXES**										
165	Federal Income Tax Expense		5,218	DistD-Pretax	3,237	192	356	1,216	57	3	159
166	**Income Taxes**	409-411	5,218		3,237	192	356	1,216	57	3	159
167	**Total Taxes**	408-411	7,505		4,797	306	498	1,568	150	5	181
168											
169	**TOTAL EXPENSES**		40,461		25,132	928	2,526	9,083	2,244	19	528
170											
171	**IV. OPERATING REVENUES at Present Rates**										
172	Base Delivery	480	72,121	Total_Del_Rev	44,749	2,087	4,686	16,485	2,578	37	1,500
173	Commodity	480C	-	None	-	-	-	-	-	-	-
174	Rent from Gas Property	488	-	DistD-Pt	-	-	-	-	-	-	-
175	Late payment	493	192	WriteOff_Del	142	14	12	18	4	0	2
176	Other Revenues	495	-	None	-	-	-	-	-	-	-
177	Marketer	495	-	None	-	-	-	-	-	-	-
178	Turn On	495	-	None	-	-	-	-	-	-	-
179	Capacity Release	415/416	144	Peak_Sendout	89	2	9	35	9	0	-
180	Adjust to Case Model		-	Total_Del_Rev	-	-	-	-	-	-	-
181	**TOTAL REVENUE**		72,458		44,980	2,104	4,706	16,537	2,592	37	1,501
182											
183	**V. Net Income at Present Rates**		31,996		19,848	1,175	2,180	7,454	347	18	973
184											
185	**RATE BASE**		545,388		317,087	7,789	34,494	133,450	39,302	1,113	12,154
186	Return on Rate Base		5.87%		6.26%	15.09%	6.32%	5.59%	0.88%	1.59%	8.01%
187											
188	**REVENUE REQUIREMENTS**										
189	Target Rate of Return		8.3100%		8.3100%	8.3100%	8.3100%	8.3100%	8.3100%	8.3100%	8.3100%
190	Rate Base		545,388		317,087	7,789	34,494	133,450	39,302	1,113	12,154
191											
192	Operating expenses, Depreciation		30,685		18,658	454	1,887	7,302	2,043	13	327
193	Uncollectible accounts		2,464	DistD-Unc_RR	1,821	109	154	247	110	4	20
194	General taxes / Other		2,322	RateBase	1,713	173	145	217	52	1	21
195	Subtotal- Operating Costs to recover		35,471		22,192	736	2,185	7,767	2,205	19	367
196											
197	Target Return on rate base		45,322		26,350	647	2,866	11,090	3,266	93	1,010
198	Income Taxes		10,975	24.22%	6,381	157	694	2,685	791	22	245
199											
200	Subtotal- Rev Req before GRT		91,768		54,923	1,540	5,746	21,542	6,262	134	1,622
201	GRT needed		0	-	0	0	0	0	0	0	0
202	**TOTAL REVENUE REQUIREMENT**		91,768		54,923	1,540	5,746	21,542	6,262	134	1,622
203											

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Class Allocation - Distribution Customer

Line	Account	No.	Balance	Allocator	Residential Heat	Residential Non-Heat	Small General SGS	General GDS	Large Volume LVD	NGV	Non-Firm
1	**I. GAS PLANT IN SERVICE**										
2	**A. INTANGIBLE PLANT**										
3	Franchise & Consents	302	651	Cust_Avg	539	63	35	14	0	0	0
4	Software & Other Intangibles	303I	-	None	-	-	-	-	-	-	-
5	**Intangible Plant**		651		539	63	35	14	0	0	0
6											
7	**B. Storage / LNG**										
8	Land & Land Rights	360	-	None	-	-	-	-	-	-	-
9	Structures and Improvements	361	-	None	-	-	-	-	-	-	-
10	Gas Holders- LNG/ Storage	362	-	None	-	-	-	-	-	-	-
11	363G- Vapor / Compress/ Regulating		-	None	-	-	-	-	-	-	-
12	NGV Station	363	-	DistC-Lab	-	-	-	-	-	-	-
13	**Storage Plant**	304-338	-		-	-	-	-	-	-	-
14											
15	**C. TRANSMISSION PLANT**										
16	Land	365	-	None	-	-	-	-	-	-	-
17	Structures and Improvements	366	-	None	-	-	-	-	-	-	-
18	Mains	367	-	None	-	-	-	-	-	-	-
19	Measuring and Reg. Sta. Equip.	369	-	None	-	-	-	-	-	-	-
20	**Transmission Plant**	360-368	-		-	-	-	-	-	-	-
21											
22	**D. DISTRIBUTION PLANT**										
23	Land and Land Rights	374	3,149	DistC-Pt	2,522	311	198	103	6	0	10
24	Structures and Improvements	375	7,512	DistC-Pt	6,015	743	471	245	14	0	24
25	Mains	376	774,901	Cust_Avg	641,952	74,854	41,742	16,109	134	2	107
26	Mains Direct	376TC	-	None	-	-	-	-	-	-	-
27	Meas. & Reg. Stat. Equip. - General	378	-	None	-	-	-	-	-	-	-
28	Services	380	635,224	Service_Invest	493,753	67,291	46,140	28,041	-	-	-
29	Services Direct	380D	6,381	Services Direct	-	-	-	-	2,096	-	4,285
30	Meters / Install	381/382	198,942	Meter_Invest	157,878	17,714	13,397	8,322	858	1	773
31	Ind M&R	385	-	Ind M&R	-	-	-	-	-	-	-
32	House Reg/ Install	384	12,207	Meter_Invest	9,688	1,087	822	511	53	0	47
33	OPEN		-	None	-	-	-	-	-	-	-
34	OPEN		-	None	-	-	-	-	-	-	-
35	**Distribution Plant**	374-388	1,638,317		1,311,806	162,001	102,769	53,330	3,161	3	5,247
36											
37	**E. GENERAL PLANT**										
38	General Pt- Labor	389	177,505	DistC-Lab	145,060	17,468	10,231	4,531	80	0	133
39	General Pt- Plant	398	-	DistC-Pt	-	-	-	-	-	-	-
40	**General Plant**	389-399	177,505		145,060	17,468	10,231	4,531	80	0	133
41											
42	**TOTAL UTILITY PLANT**		1,816,472		1,457,406	179,531	113,036	57,874	3,242	4	5,380
43											

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Line	Account	No.	Balance	Allocator	Residential Heat	Residential Non-Heat	Small General SGS	General GDS	Large Volume LVD	NGV	Non-Firm
44	**II. DEPRECIATION RESERVE**										
45	Mains-Services Direct	108	-	Mains_Ser_Dir	-	-	-	-	-	-	-
46	NGV Station	111	-	NGV Direct	-	-	-	-	-	-	-
47	Storage Plant	108	-	None	-	-	-	-	-	-	-
48	Transmission Plant	109	-	None	-	-	-	-	-	-	-
49	Distribution- Mains	108M	129,422	Cust_Avg	107,217	12,502	6,972	2,691	22	0	18
50	Distribution- Services	108S	77,823	Service_Invest	60,491	8,244	5,653	3,435	-	-	-
51	Distribution- Meters	108Mt	63,394	Meter_Invest	50,309	5,645	4,269	2,652	273	0	246
52	Distribution- Other	108O	33,256	DistC-Pt	26,628	3,288	2,086	1,083	64	0	107
53	General Pt- Labor	109	73,324	DistC-Lab	59,922	7,216	4,226	1,872	33	0	55
54	General Pt- Plant	398	-	DistC-Pt	-	-	-	-	-	-	-
55	**Depreciation Reserve**	108	377,219		304,567	36,895	23,206	11,732	393	1	426
56											
57	**III. OTHER RATE BASE ITEMS**										
58	Materials and Supplies, Prepay	105	-	DistC-OM	-	-	-	-	-	-	-
59	Storage Gas	107M	-	DistC-OM	-	-	-	-	-	-	-
60	Cust Dep / Adv	Cust	(6,690)	CustDep	(3,904)	(368)	(877)	(1,365)	(175)	(1)	-
61	Other Regulatory Assets	182P	18,590	DistC-Lab	15,192	1,829	1,072	475	8	0	14
62	Accum Deferred Income Taxes	190	(174,851)	DistC-Pt	(140,004)	(17,290)	(10,968)	(5,692)	(337)	(0)	(560)
63	CWC	CWC	40,418	DistC-OM	32,735	3,875	2,340	1,294	107	2	65
64	OPEN	CWC-Su	-	None	-	-	-	-	-	-	-
65	**Other Rate Base**		(122,533)		(95,981)	(11,953)	(8,433)	(5,288)	(397)	1	(481)
66											
67	**TOTAL RATE BASE**		1,316,721		1,056,858	130,684	81,396	40,854	2,452	4	4,473
68											
69	**I. OPERATING AND MAINTENANCE EXPENSES**										
70	**A. PRODUCTION EXPENSE**										
71	Purchased Gas										
72	Natural Gas City Gate Purchases	804	-	None	-	-	-	-	-	-	-
73	**Subtotal-Production expenses**	710-813	-		-	-	-	-	-	-	-
74											
75	**B. STORAGE, LNG EXPENSES**										
76	Storage Operations	841	-	None	-	-	-	-	-	-	-
77	**Subtotal- Storage expenses**	840-850	-		-	-	-	-	-	-	-
78											

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Line	Account	No.	Balance	Allocator	Residential Heat	Residential Non-Heat	Small General SGS	General GDS	Large Volume LVD	NGV	Non-Firm
79	**C. TRANSMISSION EXPENSES**										
80	Mains Operating	850-856	-	None	-	-	-	-	-	-	-
81	Maintenance Other Equip.	865	-	None	-	-	-	-	-	-	-
82	**Subtotal-Transmission**	850-867	-		-	-	-	-	-	-	-
83											
84	**D. DISTRIBUTION O&M EXPENSE**										
85	Operation Supv & Engineering	870	0	DistC-Lab	0	0	0	0	0	0	0
86	Distribution Load Dispatching	871	-	Gas_Deliveries	-	-	-	-	-	-	-
87	Mains and Services Expenses	874	3,130	DistC-MainsSvc	2,509	314	194	98	5	0	10
88	Meas & Reg Exp- General	875	-	None	-	-	-	-	-	-	-
89	Meas & Reg Exp- Industrial	876	-	None	-	-	-	-	-	-	-
90	Meter-Regulator- Citygate	878	-	Meter_Invest	-	-	-	-	-	-	-
91	Cust Installations Field	879	835	Cust_Avg	692	81	45	17	0	0	0
92	Other Expenses	880	3	DistC-OM	2	0	0	0	0	0	0
93	Rents	881	13	DistC-OM	10	1	1	0	0	0	0
94	Maint Compressor Station Equip	879	-	None	-	-	-	-	-	-	-
95	Maint Supv & Engineering	885	-	DistC-Lab	-	-	-	-	-	-	-
96	Maint of Mains	887	911	Cust_Avg	755	88	49	19	0	0	0
97	Maint. of Meas. & Reg. General	889	-	None	-	-	-	-	-	-	-
98	Maint. of Meas. & Reg.- Indust	890	-	None	-	-	-	-	-	-	-
99	Maint. of Services	892	615	Service_Invest	478	65	45	27	-	-	-
100	Maint. of Meters & House Regulators	893	142	Meter_Invest	113	13	10	6	1	0	1
101	Maint. Other Equip.	894	43	DistC-Pt	34	4	3	1	0	0	0
102	**Dist. Oper. & Maint. Exp.**	870-899	5,692		4,594	566	346	169	6	0	11
103	**Total O&M Expenses**		5,692		4,594	566	346	169	6	0	11
104											
105	**II. CUSTOMER ACCOUNTS AND SERVICE**										
106	Supervision	901	-	None	-	-	-	-	-	-	-
107	Meter Reading Expenses	902	509	Cust_Avg	421	49	27	11	0	0	0
108	Customer Records & Collection Expense	903	850	Cust_Avg	704	82	46	18	0	0	0
109	Uncollectible Accounts	904	6,806	WriteOff_Del	5,022	506	424	637	153	4	61
110	Miscellaneous Customer Accounts Exp.	905	-	Cust_Avg	-	-	-	-	-	-	-
111	**Customer Accts. Exp.**	901-905	8,165		6,147	637	497	665	153	4	61
112											
113	**III. CUSTOMER ACCOUNTS AND IN**										
114	Customer Assistance Expenses	908	3,652	Cust_Avg	3,025	353	197	76	1	0	1
115	Low Income Discount	908LI	-	Total_Del_Rev	-	-	-	-	-	-	-
116	Cust Assist Other	909-912	4,802	Cust_Avg	3,978	464	259	100	1	0	1
117	Advertising	913	692	Cust_Avg	573	67	37	14	0	0	0
118	**Customer Service Exp.**	908-919	9,146		7,577	883	493	190	2	0	1
119	**Customer Accts. & Serv. Exp.**	901-919	17,311		13,724	1,521	989	855	154	4	62

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Class Allocation - Distribution Customer

Line	Account	No.	Balance	Allocator	Residential Heat	Residential Non-Heat	Small General SGS	General GDS	Large Volume LVD	NGV	Non-Firm
120											
121	**E. ADMINISTRATIVE AND GENERAL**										
122	Administrative & General Salaries	920	13,824	DistC-Lab	11,297	1,360	797	353	6	0	10
123	Office Supplies & Expenses	921	6,385	DistC-Lab	5,218	628	368	163	3	0	5
124	Outside Services Employed	923	22,130	DistC-Lab	18,085	2,178	1,276	565	10	0	17
125	Property Insurance	924	1,410	DistC-Pt	1,129	139	88	46	3	0	5
126	Injuries & Damages	925	190	DistC-Lab	155	19	11	5	0	0	0
127	Employee Pensions and Benefits	926	4,682	DistC-Lab	3,826	461	270	120	2	0	4
128	Franchise Reqirements	927	-	RateBase	-	-	-	-	-	-	-
129	Regulatory Commission Expenses	928	360	RateBase	266	27	22	34	8	0	3
130	Misc General Exp	930	679	DistC-Lab	555	67	39	17	0	0	1
131	A&G- Rents	931	96	DistC-Lab	78	9	6	2	0	0	0
132	Maint General Plant	932	-	DistC-Lab	-	-	-	-	-	-	-
133	**Admin & Genl. Exp.**	920-932	49,755		40,609	4,888	2,877	1,305	32	0	44
134											
135	**Total Operating Expenses**		72,758		58,927	6,975	4,212	2,329	193	4	117
136											
137	**II. DEPRECIATION EXPENSE**										
138	Land and ROW	403	318	DistC-Pt	254	31	20	10	1	0	1
139	Storage Plant	403	-	None	-	-	-	-	-	-	-
140	Transmission Plant	404	-	None	-	-	-	-	-	-	-
141	Mains	403M	13,229	DistC-Mains	10,959	1,278	713	275	2	0	2
142	Services	403S	19,828	Service_Invest	15,412	2,100	1,440	875	-	-	-
143	Meters	403Mt	7,248	Meter_Invest	5,752	645	488	303	31	0	28
144	Distr Other	403O	488	DistC-Pt	390	48	31	16	1	0	2
145	General Pt- Labor	404	17,796	DistC-Lab	14,544	1,751	1,026	454	8	0	13
146	General Pt- Plant	404	-	DistC-Pt	-	-	-	-	-	-	-
147	Mains/Services Direct	404	-	Mains_Ser_Dir	-	-	-	-	-	-	-
148	NGV Station	404	30	NGV Direct	-	-	-	-	-	30	-
149	Amort Regulatory Debits	403	-	DistC-Lab	-	-	-	-	-	-	-
150	**Depreciation Expense**		58,936		47,311	5,855	3,717	1,934	43	30	46
151											
152	**III. TAXES and OTHER**										
153	**A. GENERAL TAXES**										
154	Taxes- Labor based	408L	2,640	DistC-Lab	2,158	260	152	67	1	0	2
155	Taxes- Plant based	408P	764	DistC-Pt	611	76	48	25	1	0	2
156	Other Taxes	408O	743	RateBase	548	55	46	70	17	0	7
157	Tax Amortization	408	2,545	RateBase	1,878	189	158	238	57	2	23
158	**General Taxes**		6,692		5,195	580	405	400	76	2	34
159											
160	**B. GROSS RECEIPTS TAX**										
161	Gross Receipts tax		-	None	-	-	-	-	-	-	-
162	**Gross Receipts Tax**		-		-	-	-	-	-	-	-

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Line	Account	No.	Balance	Allocator	Residential Heat	Residential Non-Heat	Small General SGS	General GDS	Large Volume LVD	NGV	Non-Firm
163											
164	**B. FEDERAL / STATE INCOME TAXES**										
165	Federal Income Tax Expense		11,262	DistC-Pretax	3,415	(986)	821	6,336	1,063	11	603
166	**Income Taxes**	409-411	11,262		3,415	(986)	821	6,336	1,063	11	603
167	**Total Taxes**	408-411	17,954		8,610	(406)	1,225	6,736	1,140	13	637
168											
169	**TOTAL EXPENSES**		149,647		114,848	12,424	9,155	10,999	1,375	47	800
170											
171	**IV. OPERATING REVENUES at Present Rates**										
172	Base Delivery	480	216,090	Total_Del_Rev	134,078	6,253	14,039	49,392	7,724	111	4,493
173	Commodity	480C	-	None	-	-	-	-	-	-	-
174	Rent from Gas Property	488	-	Peak_Sendout	-	-	-	-	-	-	-
175	Late payment	493	576	WriteOff_Del	425	43	36	54	13	0	5
176	Other Revenues	495	1,442	Gas_Del_Firm	798	25	79	386	154	0	-
177	Marketer	495	34	Gas_Del_Firm	19	1	2	9	4	0	-
178	Turn On	495	564	Cust_Avg	467	54	30	12	0	0	0
179	Capacity Release	415/416	-	None	-	-	-	-	-	-	-
180	Adjust to Case Model		-	Total_Del_Rev	-	-	-	-	-	-	-
181	**TOTAL REVENUE**		218,706		135,786	6,376	14,186	49,853	7,895	112	4,498
182											
183	**V. Net Income at Present Rates**		69,059		20,938	(6,048)	5,031	38,854	6,519	65	3,699
184											
185	**RATE BASE**		1,316,721		1,056,858	130,684	81,396	40,854	2,452	4	4,473
186	Return on Rate Base		5.24%		1.98%	(4.63%)	6.18%	95.10%	265.92%	1653.47%	82.69%
187											
188	**REVENUE REQUIREMENTS**										
189	Target Rate of Return		8.3100%		8.3100%	8.3100%	8.3100%	8.3100%	8.3100%	8.3100%	8.3100%
190	Rate Base		1,316,721		1,056,858	130,684	81,396	40,854	2,452	4	4,473
191											
192	Operating expenses, Depreciation		124,887		101,216	12,324	7,506	3,626	83	30	102
193	Uncollectible accounts		7,286	DistC-Unc_RR	5,410	1,467	329	69	4	1	6
194	General taxes / Other		6,866	RateBase	5,066	511	427	643	154	4	61
195	Subtotal- Operating Costs to recover		139,039		111,692	14,301	8,262	4,338	241	35	169
196											
197	Target Return on rate base		109,419		87,825	10,860	6,764	3,395	204	0	372
198	Income Taxes		26,497	24.22%	21,267	2,630	1,638	822	49	0	90
199											
200	Subtotal- Rev Req before GRT		274,955		220,785	27,791	16,664	8,555	495	36	630
201	GRT needed		0	-	0	0	0	0	0	0	0
202	**TOTAL REVENUE REQUIREMENT**		274,955		220,785	27,791	16,664	8,555	495	36	630
203											

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Line	Account	No.	Balance	Functional	Distribution	Class Allocation SuppDem	DistDem	DistCus	BillCus
1	**I. GAS PLANT IN SERVICE**								
2	**A. INTANGIBLE PLANT**								
3	Franchise & Consents	302	651	Dist	Customer	-	-	Cust_Avg	-
4	Software & Other Intangibles	303I	0	-	-	-	-	-	-
5	**Intangible Plant**		651						
6									
7	**B. Storage / LNG**								
8	Land & Land Rights	360	68	Dist	Demand	-	Peak_Sendout	-	-
9	Structures and Improvements	361	6,512	Dist	Demand	-	Peak_Sendout	-	-
10	Gas Holders- LNG/ Storage	362	3,400	Dist	Demand	-	Peak_Sendout	-	-
11	363G- Vapor / Compress/ Regulating		85,911	Dist	Demand	-	Peak_Sendout	-	-
12	NGV Station	363	2,298	Dist	Demand	-	NGV Direct	-	-
13	**Storage Plant**	304-338	98,189						
14									
15	**C. TRANSMISSION PLANT**								
16	Land	365	631	Dist	Demand	-	Peak_Sendout	-	-
17	Structures and Improvements	366	0	-	-	-	-	-	-
18	Mains	367	15,849	Dist	Demand	-	Peak_Sendout	-	-
19	Measuring and Reg. Sta. Equip.	369	8,600	Dist	Demand	-	Peak_Sendout	-	-
20	**Transmission Plant**	360-368	25,080						
21									
22	**D. DISTRIBUTION PLANT**								
23	Land and Land Rights	374	4,438	Dist	Dist_Pt	-	DistD-Pt	DistC-Pt	-
24	Structures and Improvements	375	10,587	Dist	Dist_Pt	-	DistD-Pt	DistC-Pt	-
25	Mains	376	1,238,550	Dist	MinSys-Mains	-	Peak_Sendout	Cust_Avg	-
26	Mains Direct	376TC	14,248	Dist	Demand	-	Mains Direct	-	-
27	Meas. & Reg. Stat. Equip. - General	378	44,669	Dist	Demand	-	Peak_Sendout	-	-
28	Services	380	635,224	Dist	Customer	-	-	Service_Inves	-
29	Services Direct	380D	6,381	Dist	Customer	-	-	Services Direc	-
30	Meters / Install	381/382	198,942	Dist	Customer	-	-	Meter_Invest	-
31	Ind M&R	385	16,742	Dist	Demand	-	Ind M&R	-	-
32	House Reg/ Install	384	12,207	Dist	Customer	-	-	Meter_Invest	-
33	OPEN		0	-	-	-	-	-	-
34	OPEN		3,768	Dist	Demand	-	Mains_Ser_Di	-	-
35	**Distribution Plant**	374-388	2,185,756						
36									
37	**E. GENERAL PLANT**								
38	General Pt- Labor	389	219,750	Dist	Dist_Lab	-	DistD-Lab	DistC-Lab	-
39	General Pt- Plant	398	0	-	-	-	-	-	-
40	**General Plant**	389-399	219,750						
41									
42	**TOTAL UTILITY PLANT**		2,529,427						
43			*2,529,427*						

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						Class Allocation			
Line	**Account**	No.	**Balance**	**Functional**	**Distribution**	**SuppDem**	**DistDem**	**DistCus**	**BillCus**
44	**II. DEPRECIATION RESERVE**								
45	Mains-Services Direct	108	0	-	-	-	-	-	-
46	NGV Station	111	958	Dist	Demand	-	NGV Direct	-	-
47	Storage Plant	108	10,325	Dist	Demand	-	Peak_Sendout	-	-
48	Transmission Plant	109	1,433	Dist	Demand	-	Peak_Sendout	-	-
49	Distribution- Mains	108M	206,859	Dist	MinSys-Mains	-	Peak_Sendout	Cust_Avg	-
50	Distribution- Services	108S	77,823	Dist	Customer	-	-	Service_Inves	-
51	Distribution- Meters	108Mt	63,394	Dist	Customer	-	-	Meter_Invest	-
52	Distribution- Other	108O	46,871	Dist	Dist_Pt	-	DistD-Pt	DistC-Pt	-
53	General Pt- Labor	109	90,775	Dist	Dist_Lab	-	DistD-Lab	DistC-Lab	-
54	General Pt- Plant	398	0	-	-	-	-	-	-
55	**Depreciation Reserve**	108	498,438						
56			*498,438*						
57	**III. OTHER RATE BASE ITEMS**								
58	Materials and Supplies, Prepay	105	0	-	-	-	-	-	-
59	Storage Gas	107M	10,754	Dist	Demand	-	Firm_Winter	-	-
60	Cust Dep / Adv	Cust	(6,690)	Dist	Customer	-	-	CustDep	-
61	Other Regulatory Assets	182P	23,015	Dist	Dist_Lab	-	DistD-Lab	DistC-Lab	-
62	Accum Deferred Income Taxes	190	(246,434)	Dist	Dist_Pt	-	DistD-Pt	DistC-Pt	-
63	CWC	CWC	50,476	Dist	Dist_OM	-	DistD-OM	DistC-OM	-
64	OPEN	CWC-Su	0	-	-	-	-	-	-
65	**Other Rate Base**		(168,880)						
66									
67	**TOTAL RATE BASE**		1,862,109						
68			*1,862,109*						
69	**I. OPERATING AND MAINTENANCE EXPENSES**								
70	**A. PRODUCTION EXPENSE**								
71									
72	Natural Gas City Gate Purchases	804	0	-	-	-	-	-	-
73	Subtotal-Production expenses	710-813	-						
74									
75	**B. STORAGE, LNG EXPENSES**								
76	Storage Operations	841	700	Dist	Demand	-	Peak_Sendout	-	-
77	Subtotal- Storage expenses	840-850	700						
78									

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Line	Account	No.	Balance	Functional	Distribution	SuppDem	DistDem	DistCus	BillCus
						Class Allocation			
79	**C. TRANSMISSION EXPENSES**								
80	Mains Operating	850-856	0	-	-	-	-	-	-
81	Maintenance Other Equip.	865	174	Dist	Demand	-	Peak_Sendout	-	-
82	**Subtotal-Transmission**	850-867	174						
83									
84	**D. DISTRIBUTION O&M EXPENSE**								
85	Operation Supv & Engineering	870	0	-	-	-	-	-	-
86	Distribution Load Dispatching	871	288	Dist	Demand	-	Gas_Del_Firm	-	-
87	Mains and Services Expenses	874	4,186	Dist	Mains_Serv	-	DistD-MainsSv	DistC-MainsSv	-
88	Meas & Reg Exp- General	875	29	Dist	Demand	-	Peak_Sendout	-	-
89	Meas & Reg Exp- Industrial	876	0	-	-	-	-	-	-
90	Meter-Regulator- Citygate	878	917	Dist	Demand	-	Peak_Sendout	-	-
91	Cust Installations Field	879	835	Dist	Customer	-	-	Cust_Avg	-
92	Other Expenses	880	3	Dist	Dist_OM	-	-	DistC-OM	-
93	Rents	881	16	Dist	Dist_OM	-	DistD-OM	DistC-OM	-
94	Maint Compressor Station Equip	879	0	-	-	-	-	-	-
95	Maint Supv & Engineering	885	0	-	-	-	-	-	-
96	Maint of Mains	887	1,457	Dist	MinSys-Mains	-	Peak_Sendout	Cust_Avg	-
97	Maint. of Meas. & Reg. General	889	104	Dist	Demand	-	Peak_Sendout	-	-
98	Maint. of Meas. & Reg.- Indust	890	0	-	-	-	-	-	-
99	Maint. of Services	892	615	Dist	Customer	-	-	Service_Invest	-
100	Maint. of Meters & House Regulators	893	142	Dist	Customer	-	-	Meter_Invest	-
101	Maint. Other Equip.	894	61	Dist	Dist_Pt	-	DistD-Pt	DistC-Pt	-
102	**Dist. Oper. & Maint. Exp.**	870-899	8,653						
103	Total O&M Expenses		9,527						
104									
105	**II. CUSTOMER ACCOUNTS AND SERVICE**								
106	Supervision	901	0	-	-	-	-	-	-
107	Meter Reading Expenses	902	509	Dist	Customer	-	-	Cust_Avg	-
108	Customer Records & Collection Expense	903	850	Dist	Customer	-	-	Cust_Avg	-
109	Uncollectible Accounts	904	9,078	Dist	D-RevReq_PF	-	WriteOff_Del	WriteOff_Del	-
110	Miscellaneous Customer Accounts Exp.	905	0	-	-	-	-	-	-
111	**Customer Accts. Exp.**	901-905	10,437						
112									
113	**III. CUSTOMER ACCOUNTS AND IN**								
114	Customer Assistance Expenses	908	3,652	Dist	Customer	-	-	Cust_Avg	-
115	Low Income Discount	908LI	0	-	-	-	-	-	-
116	Cust Assist Other	909-912	4,802	Dist	Customer	-	-	Cust_Avg	-
117	Advertising	913	692	Dist	Customer	-	-	Cust_Avg	-
118	**Customer Service Exp.**	908-919	9,146						
119	**Customer Accts. & Serv. Exp.**	901-919	19,582						
120									

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Elizabethtown Gas Company
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						Class Allocation			
Line	**Account**	No.	**Balance**	**Functional**	**Distribution**	**SuppDem**	**DistDem**	**DistCus**	**BillCus**
121	**E. ADMINISTRATIVE AND GENERAL**								
122	Administrative & General Salaries	920	17,114	Dist	Dist_Lab	-	DistD-Lab	DistC-Lab	-
123	Office Supplies & Expenses	921	7,904	Dist	Dist_Lab	-	DistD-Lab	DistC-Lab	-
124	Outside Services Employed	923	27,397	Dist	Dist_Lab	-	DistD-Lab	DistC-Lab	-
125	Property Insurance	924	1,987	Dist	Dist_Pt	-	DistD-Pt	DistC-Pt	-
126	Injuries & Damages	925	235	Dist	Dist_Lab	-	DistD-Lab	DistC-Lab	-
127	Employee Pensions and Benefits	926	5,796	Dist	Dist_Lab	-	DistD-Lab	DistC-Lab	-
128	Franchise Reqirements	927	0	-	-	-	-	-	-
129	Regulatory Commission Expenses	928	360	Dist	Customer	-	-	RateBase	-
130	Misc General Exp	930	840	Dist	Dist_Lab	-	DistD-Lab	DistC-Lab	-
131	A&G- Rents	931	118	Dist	Dist_Lab	-	DistD-Lab	DistC-Lab	-
132	Maint General Plant	932	0	-	-	-	-	-	-
133	**Admin & Genl. Exp.**	920-932	61,753						
134									
135	**Total Operating Expenses**		90,862						
136			*90,862*						
137	**II. DEPRECIATION EXPENSE**								
138	Land and ROW	403	448	Dist	Dist_Pt	-	DistD-Pt	DistC-Pt	-
139	Storage Plant	403	1,841	Dist	Demand	-	Peak_Sendout	-	-
140	Transmission Plant	404	523	Dist	Demand	-	Peak_Sendout	-	-
141	Mains	403M	21,144	Dist	MinSys-Mains	-	DistD-Mains	DistC-Mains	-
142	Services	403S	19,828	Dist	Customer	-	-	Service_Inves	-
143	Meters	403Mt	7,248	Dist	Customer	-	-	Meter_Invest	-
144	Distr Other	403O	687	Dist	Dist_Pt	-	DistD-Pt	DistC-Pt	-
145	General Pt- Labor	404	22,032	Dist	Dist_Lab	-	DistD-Lab	DistC-Lab	-
146	General Pt- Plant	404	0	-	-	-	-	-	-
147	Mains/Services Direct	404	0	-	-	-	-	-	-
148	NGV Station	404	37	Dist	Dist_Lab	-	NGV Direct	NGV Direct	-
149	Amort Regulatory Debits	403	0	-	-	-	-	-	-
150	**Depreciation Expense**		73,787						
151									
152	**III. TAXES and OTHER**								
153	**A. GENERAL TAXES**								
154	Taxes- Labor based	408L	3,269	Dist	Dist_Lab	-	DistD-Lab	DistC-Lab	-
155	Taxes- Plant based	408P	1,076	Dist	Dist_Pt	-	DistD-Pt	DistC-Pt	-
156	Other Taxes	408O	1,047	Dist	Dist_Pt	-	RateBase	RateBase	-
157	Tax Amortization	408	3,587	RateBase	Dist_Pt	-	RateBase	RateBase	-
158	**General Taxes**		8,980						
159									
160	**B. GROSS RECEIPTS TAX**								
161	Gross Receipts tax		0	-	-	-	-	-	-
162	**Gross Receipts Tax**		0						

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Line	Account	No.	Balance	Functional	Distribution	SuppDem	DistDem	DistCus	BillCus
						Class Allocation			
163									
164	**B. FEDERAL / STATE INCOME TAXES**								
165	Federal Income Tax Expense		16,480	Pretax	Dist_Pretax	-	DistD-Pretax	DistC-Pretax	-
166	**Income Taxes**	409-411	16,480						
167	**Total Taxes**	408-411	25,459						
168									
169	**TOTAL EXPENSES**		190,109						
170			*190,109*						
171	**IV. OPERATING REVENUES at Present Rates**								
172	Base Delivery	480	288,211	RevReq_PF	D-RevReq_PF	-	Total_Del_Re	Total_Del_Re	-
173	Commodity	480C	0	-	-	-	-	-	-
174	Rent from Gas Property	488	0	-	-	-	-	-	-
175	Late payment	493	769	Dist	D-RevReq_PF	-	WriteOff_Del	WriteOff_Del	-
176	Other Revenues	495	1,442	Dist	Customer	-	-	Gas_Del_Firm	-
177	Marketer	495	34	Dist	Customer	-	-	Gas_Del_Firm	-
178	Turn On	495	564	Dist	Customer	-	-	Cust_Avg	-
179	Capacity Release	415/416	144	Dist	Demand	-	Peak_Sendout	-	-
180	Adjust to Case Model		0	-	-	-	-	-	-
181	**TOTAL REVENUE**		291,164		0 #	0	0		
182			*291,164*						
183	**V. Net Income at Present Rates**		101,055		- -	-	-		
184			*101,055*						

FuncFctr
Functionalization Factors
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Functionalization Factors

	Allocator Name	Total	Supply-Storage	Distribution	Billing
1	None	0			
2		0.00%	0.00%	0.00%	0.00%
3					
4	Supp	1	1		
5		100.00%	100.00%	0.00%	0.00%
6					
7	Dist	1		1	
8		100.00%	0.00%	100.00%	0.00%
9					
10	Bill	1			1
11		100.00%	0.00%	0.00%	100.00%
12					
13	Dist-Pt	2,185,756	-	2,185,756	-
14		100.00%	0.00%	100.00%	0.00%
15					
16	Plant	2,309,026	-	2,309,026	-
17		100.00%	0.00%	100.00%	0.00%
18					
19	O&MxGas	90,862		90,862	-
20		100.00%	0.00%	100.00%	0.00%
21					
22	Labor	44,022	-	44,022	-
23		100.00%	0.00%	100.00%	0.00%
24					
25	Pretax	117,535	-	117,535	-
26		100.00%	-	100.00%	-
27					
28	RateBase	1,862,109	0	1,862,109	0
29		100.00%	0.00%	100.00%	0.00%
30					
31	RevReq	366,723	0	366,723	0
32		100.00%	0.00%	100.00%	0.00%
33					
34	RevReq_PF	1,862,109		1,862,109	0
35		100.00%	0.00%	100.00%	0.00%
36					
37	Uncollect_RR	11,342	0	11,342	0
38		100.00%	0.00%	100.00%	0.00%
39					

ClassFctr
Classification Factors
Schedule HSG-1-7C
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Elizabethtown Gas Company
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Classification Factors

Allocator Name	Total	Demand	Commodity	Customer
None	0			
	0.00%	0.00%	0.00%	0.00%
Demand	1	1		
	100.00%	100.00%	0.00%	0.00%
Commodity	1		1	
	100.00%	0.00%	100.00%	0.00%
Customer	1			1
	100.00%	0.00%	0.00%	100.00%
Services	635,224	-	-	635,224
	100.00%	0.00%	0.00%	100.00%
MinSys-Mains	100.00%	37.43%	0.00%	62.57%
	100.00%	37.43%	0.00%	62.57%
Mains_Serv_Dir	20,629	14,248	-	6,381
	100.00%	69.07%	0.00%	30.93%
Mains_Serv	1,894,403	477,896	-	1,416,506
	100.00%	25.23%	0.00%	74.77%
Mains_Dist	1,252,797	477,896	-	774,901
	100.00%	38.15%	0.00%	61.85%
Dist_Pt	2,309,026	670,709	-	1,638,317
	100.00%	29.05%	0.00%	70.95%
Dist_Int	651	-	-	651
	100.00%	0.00%	0.00%	100.00%
Dist_Oth	47,743	24,874	-	22,869
	100.00%	52.10%	0.00%	47.90%

ClassFctr
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Embedded Cost of Service Study (ECOSS)
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Classification Factors

	Allocator Name	Total	Demand	Commodity	Customer
37	Dist_OM	90,862	18,105	-	72,758
38		100.00%	19.93%	0.00%	80.07%
39					
40	Dist_Lab	44,022	8,463	-	35,559
41		100.00%	19.22%	0.00%	80.78%
42					
43	Dist_Pretax	117,535	37,214	-	80,321
44		100.00%	31.66%	0.00%	68.34%
45					
46	Dist_Unc_RR	11,342	2,867	-	8,475
47		100.00%	25.27%	0.00%	74.73%
48					
49	D-RevReq_PF	366,723	91,768	-	274,955
50		100.00%	25.02%	0.00%	74.98%
51					
52	Dist_Rev	288,211	72,121	-	216,090
53		100.00%	25.02%	0.00%	74.98%
54					

AllocFctr
Class Allocation Factors
Schedule HSG-1-7D
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Class Allocation Factors

	Allocator Name	In Use	Total	Residential Heat	Residential Non-Heat	Small General SGS	General GDS	Large Volume LVD	NGV	Non-Firm
1	None		-							
2		FALSE	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
3			0							
4	Cust_Avg		317,754	263,237	30,695	17,116	6,606	55	1	44
5		TRUE	100.00%	82.84%	9.66%	5.39%	2.08%	0.02%	0.00%	0.01%
6										
7	Cust_Res		293,931	263,237	30,695	-	-	-	-	-
8		TRUE	100.00%	89.56%	10.44%	0.00%	0.00%	0.00%	0.00%	0.00%
9										
10	Mains_Ser_Dir		20,628,591	-	-	-	-	5,571,767	-	15,056,824
11		TRUE	100.00%	0.00%	0.00%	0.00%	0.00%	27.01%	0.00%	72.99%
12										
13	Cust_Mains		163,559	118,457	30,695	7,702	6,606	55	1	44
14		TRUE	100.00%	72.42%	18.77%	4.71%	4.04%	0.03%	0.00%	0.03%
15										
16	Gas_Deliveries		497,688,949	256,636,058	7,970,565	25,480,871	124,320,757	49,432,246	116,571	33,731,881
17		TRUE	100.00%	51.57%	1.60%	5.12%	24.98%	9.93%	0.02%	6.78%
18										
19	Gas_Del_Firm		463,957,068	256,636,058	7,970,565	25,480,871	124,320,757	49,432,246	116,571	-
20		TRUE	100.00%	55.31%	1.72%	5.49%	26.80%	10.65%	0.03%	0.00%
21										
22	Thru_Winter		332,972,140	185,231,777	5,155,095	18,763,474	85,111,153	23,873,517	68,727	14,768,397
23		TRUE	100.00%	55.63%	1.55%	5.64%	25.56%	7.17%	0.02%	4.44%
24										
25	Firm_Winter		318,203,743	185,231,777	5,155,095	18,763,474	85,111,153	23,873,517	68,727	
26		TRUE	100.00%	58.21%	1.62%	5.90%	26.75%	7.50%	0.02%	0.00%
27										
28	Peak_Sendout		510,527	315,537	7,657	31,848	122,980	32,456	49	-
29		TRUE	100.00%	61.81%	1.50%	6.24%	24.09%	6.36%	0.01%	0.00%
30										
31	Peak_XRes		49						49	-
32		TRUE	100.00%	0.00%	0.00%	0.00%	0.00%	0.00%	100.00%	0.00%
33										
34	Winter Firm		318,203,743	185,231,777	5,155,095	18,763,474	85,111,153	23,873,517	68,727	-
35		TRUE	100.00%	58.21%	1.62%	5.90%	26.75%	7.50%	0.02%	0.00%
36										

Elizabethtown Gas Company
Embedded Cost of Service Study (ECOSS)
Post Test Year 2025-03-31 (Using 2024 6+6)
Class Allocation Factors

Allocator Name	In Use	Total	Residential Heat	Residential Non-Heat	Small General SGS	General GDS	Large Volume LVD	NGV	Non-Firm
Peak_Avg		100.00%	57.60%	1.54%	5.78%	24.46%	7.83%	0.02%	2.79%
	TRUE	100.00%	57.60%	1.54%	5.78%	24.46%	7.83%	0.02%	2.79%
NGV Direct		0	0	0	0	0	0	0	0
	TRUE	100.00%	0.00%	0.00%	0.00%	0.00%	0.00%	100.00%	0.00%
Total_Del_Rev		288,211	178,827	8,340	18,724	65,876	10,302	148	5,993
	TRUE	100.00%	62.05%	2.89%	6.50%	22.86%	3.57%	0.05%	2.08%
Rev-BaseDel		275,722,379	170,900,114	7,970,728	17,887,079	63,005,159	9,821,318	145,131	5,992,850
	TRUE	100.00%	61.98%	2.89%	6.49%	22.85%	3.56%	0.05%	2.17%
IIP-Rev		12,488,812	7,926,720	369,700	837,245	2,871,170	481,104	2,873	-
	TRUE	100.00%	63.47%	2.96%	6.70%	22.99%	3.85%	0.02%	0.00%
CustDep		4,993,172	2,914,035	274,585	654,310	1,018,812	130,717	714	-
	TRUE	100.00%	58.36%	5.50%	13.10%	20.40%	2.62%	0.01%	0.00%
Meter_Invest		342,364,293	271,695,797	30,484,346	23,055,491	14,321,046	1,476,200	986	1,330,428
	TRUE	100.00%	79.36%	8.90%	6.73%	4.18%	0.43%	0.00%	0.39%
Ind M&R		187,284			31,848	122,980	32,456		
	TRUE	100.00%	0.00%	0.00%	17.01%	65.66%	17.33%	0.00%	0.00%
Service_Invest		1,131,062,881	879,161,980	119,817,282	82,154,994	49,928,626	-	-	-
	TRUE	100.00%	77.73%	10.59%	7.26%	4.41%	0.00%	0.00%	0.00%
Services Direct		6,380,901	-	-	-	-	2,096,217	-	4,284,684
	TRUE	100.00%	0.00%	0.00%	0.00%	0.00%	32.85%	0.00%	67.15%
Mains Direct		14,247,690	-	-	-	-	3,475,550	-	10,772,140
	TRUE	100.00%	0.00%	0.00%	0.00%	0.00%	24.39%	0.00%	75.61%
DistD-Lab		8,463	5,184	126	523	2,020	552	1	57
	TRUE	100.00%	61.25%	1.49%	6.18%	23.87%	6.52%	0.01%	0.68%

Elizabethtown Gas Company
Embedded Cost of Service Study (ECOSS)
Post Test Year 2025-03-31 (Using 2024 6+6)
Class Allocation Factors

Allocator Name	In Use	Total	Residential Heat	Residential Non-Heat	Small General SGS	General GDS	Large Volume LVD	NGV	Non-Firm
DistD-Pt		670,709	391,487	9,500	42,379	163,647	47,711	2,374	13,611
	TRUE	100.00%	58.37%	1.42%	6.32%	24.40%	7.11%	0.35%	2.03%
DistD-Mains		477,896	286,563	6,954	28,924	111,688	32,951	45	10,772
	TRUE	100.00%	59.96%	1.46%	6.05%	23.37%	6.90%	0.01%	2.25%
DistD-MainsSvc		477,896	286,563	6,954	28,924	111,688	32,951	45	10,772
	TRUE	100.00%	59.96%	1.46%	6.05%	23.37%	6.90%	0.01%	2.25%
DistD-OM		18,105	11,340	405	1,119	4,004	1,098	5	133
	TRUE	100.00%	62.64%	2.23%	6.18%	22.12%	6.07%	0.03%	0.74%
DistD-Unc_RR		2,758	2,038	122	172	276	123	5	22
	TRUE	100.00%	73.89%	4.44%	6.23%	10.02%	4.45%	0.18%	0.79%
			5184	126	523	2020	552	1	57
DistD-Pretax		37,214	23,085	1,367	2,536	8,670	404	21	1,132
	TRUE	100.00%	62.03%	3.67%	6.81%	23.30%	1.09%	0.06%	3.04%
DistC-Lab		35,559	29,060	3,499	2,050	908	16	0	27
	TRUE	100.00%	81.72%	9.84%	5.76%	2.55%	0.05%	0.00%	0.08%
DistC-Pt		1,638,317	1,311,806	162,001	102,769	53,330	3,161	3	5,247
	TRUE	100.00%	80.07%	9.89%	6.27%	3.26%	0.19%	0.00%	0.32%
DistC-Mains		774,901	641,952	74,854	41,742	16,109	134	2	107
	TRUE	100.00%	82.84%	9.66%	5.39%	2.08%	0.02%	0.00%	0.01%
DistC-MainsSvc		1,416,506	1,135,704	142,146	87,881	44,150	2,230	2	4,392
	TRUE	100.00%	80.18%	10.03%	6.20%	3.12%	0.16%	0.00%	0.31%
DistC-OM		72,758	58,927	6,975	4,212	2,329	193	4	117
	TRUE	100.00%	80.99%	9.59%	5.79%	3.20%	0.27%	0.01%	0.16%
DistC-Unc_RR		10,911	8,102	2,196	493	103	6	1	8
	TRUE	100.00%	74.26%	20.13%	4.52%	0.95%	0.06%	0.01%	0.08%

AllocFctr
Class Allocation Factors
Schedule HSG-1-7D
Fac

Elizabethtown Gas Company
Embedded Cost of Service Study (ECOSS)
Post Test Year 2025-03-31 (Using 2024 6+6)
Class Allocation Factors

Allocator Name	In Use	Total	Residential Heat	Residential Non-Heat	Small General SGS	General GDS	Large Volume LVD	NGV	Non-Firm
DistC-Pretax		80,321	24,353	(7,034)	5,852	45,190	7,582	75	4,302
	TRUE	100.00%	30.32%	-8.76%	7.29%	56.26%	9.44%	0.09%	5.36%
OM_xGas		-	-	-	-	-	-	-	-
	FALSE	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
WriteOff_Del		1,047	773	78	65	98	23	1	9
	TRUE	100.00%	73.78%	7.44%	6.22%	9.36%	2.24%	0.06%	0.89%
RateBase		1,862,109	1,373,945	138,472	115,891	174,304	41,753	1,117	16,627
	TRUE	100.00%	73.78%	7.44%	6.22%	9.36%	2.24%	0.06%	0.89%
Total_Labor		44,022	34,244	3,625	2,573	2,928	568	1	84
	TRUE	100.00%	77.79%	8.23%	5.84%	6.65%	1.29%	0.00%	0.19%
Total_RR		366,723	275,708	29,330	22,410	30,096	6,756	169	2,252
	TRUE	100.00%	75.18%	8.00%	6.11%	8.21%	1.84%	0.05%	0.61%

RevAlloc

Elizabethtown Gas Company
Revenue Allocation for Post Test Year Ending 2025-03-31
ACOS Results for Post Test Year 2025-03-31 (Using 2024 6+6)

Line		Total	Residential Heat	Residential Non-Heat	Small General SGS	General GDS	Large Volume LVD	NGV	Non-Firm
1	**Delivery revenue present rates**	288,211	178,827	8,340	18,724	65,876	10,302	148	5,993
2	Other revenue	2,952	1,940	139	168	514	184	1	7
3		0							
4	**Delivery revenue, pro forma**	291,164	180,767	8,480	18,893	66,390	10,486	149	6,000
5	Commodity and Other revenue	0							
6	Total revenue, pro forma	291,164	180,767	8,480	18,893	66,390	10,486	149	6,000
7	Expenses	173,629	133,329	14,147	10,505	12,530	2,500	53	566
8	Inc Tax Exp	16,480	6,651	(795)	1,176	7,552	1,120	13	762
9	Net operating income, pro forma	101,055	40,787	(4,872)	7,212	46,308	6,867	83	4,672
10	Rate Base	1,862,109	1,373,945	138,472	115,891	174,304	41,753	1,117	16,627
11									
12	Return at Present Rates	5.43%	2.97%	(3.52%)	6.22%	26.57%	16.4%	7.39%	28.10%
13	Relative Return at Present Rates	1.00X	0.55X	(0.65)X	1.15X	4.90X	3.03X	1.36X	5.18X
14									
15	**Step 1- ECOS with Revenue Requirement at Full Cost of Service**								
16	Total Revenue Requirement	366,723	275,708	29,330	22,410	30,096	6,756	169	2,252
17	Expenses	(174,510)	(133,885)	(15,037)	(10,448)	(12,104)	(2,446)	(54)	(536)
18	Income Tax Exp	(37,472)	(27,648)	(2,787)	(2,332)	(3,508)	(840)	(22)	(335)
19	Net Income	154,741	114,175	11,507	9,631	14,485	3,470	93	1,382
20	Rate of Return	8.31%	8.31%	8.31%	8.31%	8.31%	8.31%	8.31%	8.31%
21									
22	**Step 2- Tolerance Band for Return at Present Rates**			Bottom	Top	Increase	Caption	Revenue	
23	1.500%	35.000%		(5.00)	-	36.50%	V Low	8,340	
24	1.500%	32.000%		-	0.50	33.50%	Low	-	
25	1.548%	28.103%		0.50	0.75	29.6513%	Under	178,827	
26	1.500%	24.000%		0.75	1.25	25.50%	Within	18,724	
27	1.500%	18.000%		1.25	2.50	19.50%	High	148	
28	1.500%	15.000%		2.50	10.00	16.50%	V High	82,172	288,211
29									
30	**Step 3- Position : Tolerance Band**		Under	V Low	Within	V High	V High	High	V High

RevAlloc

Elizabethtown Gas Company
Revenue Allocation for Post Test Year Ending 2025-03-31
ACOS Results for Post Test Year 2025-03-31 (Using 2024 6+6)

Line		Total	Residential Heat	Residential Non-Heat	Small General SGS	General GDS	Large Volume LVD	NGV	Non-Firm
31	**Step 3- Position : Tolerance Band**		Under	V Low	Within	V High	V High	High	V High
32									
33	**Step 4- Increase for Target Revenue**								
34	Target Increase (line 1 X line 36)	74,431	53,024	3,044	4,775	10,870	1,700	29	989
35	Distribution Revenue Change	**74,431**	**53,024**	**3,044**	**4,775**	**10,870**	**1,700**	**29**	**989**
36	**Target % Increase**		**29.65%**	**36.50%**	**25.50%**	**16.50%**	**16.50%**	**19.50%**	**16.50%**
37	**Target Increase for Dist**	**74,431**	0.25825						
38									
39	Distrib Incr Line 37 / Line 4	25.56%	29.33%	35.90%	25.27%	16.37%	16.21%	19.39%	16.48%
40	Total Incr Line 37 / Line 6	25.56%	29.33%	35.90%	25.27%	16.37%	16.21%	19.39%	16.48%
41									
42	**Proposed Delivery Revenue**	**362,642**	**231,851**	**11,385**	**23,499**	**76,746**	**12,002**	**177**	**6,982**
43	Other Revenue	4,081	2,681	192	233	710	254	1	10
44									
45	Expenses	(174,510)	(133,885)	(15,037)	(10,448)	(12,104)	(2,446)	(54)	(536)
46		192,213	100,648	(3,460)	13,284	65,352	9,810	124	6,455
47	Income tax expense	(37,472)	(19,621)	675	(2,590)	(12,740)	(1,912)	(24)	(1,258)
48	**Net income**	154,741	81,026	(2,785)	10,694	52,612	7,897	100	5,197
49	*Check*	*154,741*							
50	**Rate of return on rate base**	**8.31%**	**5.90%**	**(2.01%)**	**9.23%**	**30.18%**	**18.91%**	**8.93%**	**31.26%**
51	Relative Return at Proposed Rates	1.00	0.71	(0.24)	1.11	3.63	2.28	1.07	3.76
52	Relative Return at Present Rates	1.00	0.55	(0.65)	1.15	4.90	3.03	1.36	5.18
53	Progress Towards Unity		36%	25%	25%	32%	37%	79%	34%

Elizabethtown Gas Company
Rate Design for Post Test Year Ending 2025-03-31

Line	Component	Amount	Units	Present Rates: Rate	Present Rates: Revenue	Proposed Rates: Rate	Proposed Rates: Revenue	Target	Difference
	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)
1	Residential Service			RDS		RDS			
2	Customer Charge	3,553,728	Bills	$ 9.85	$ 35,004,221	$ 11.25	$ 39,979,440		
3	Distribution Charge	264,606,623	Therms	0.5437	143,866,621	0.7681	203,244,347		
4	IIP Revenue				8,296,420				
5	**Total**				**$ 187,167,262**		**$ 243,223,787**	$ 243,235,911	(12,124)
6	Small General Service			SGS		SGS			
7	Customer Charge	205,236	Bills	$ 34.50	$ 7,080,642	$ 38.50	$ 7,901,586		
8	Distribution Charge	25,480,871	Therms	0.4241	$ 10,806,437	0.6121	15,596,841		
9	IIP Revenue				$ 837,245				
10	**Total**				**$ 18,724,324**		**$ 23,498,427**	$ 23,499,027	(600)
11	General Delivery Service			GDS		GDS			
12	Customer Charge	80,448	Bills	$ 58.00	$ 4,665,984	$ 60.90	$ 4,899,283		
13	Demand Charge	22,561,476	Therms	1.090	24,592,009	1.342	30,277,501		
14	Distribution Charge	124,287,745	Therms	$0.2715	33,744,123	0.3344	41,561,822		
15	Distribution - A/C Large	19,185	Therms	$0.0607	1,165	0.0748	1,435		
16	Distribution - Econ Dev.	13,827	Therms	$0.1358	1,878	0.1672	2,312		
17	IIP Revenue				2,871,170				
18	**Total**				**$ 65,876,329**		**$ 76,742,353**	$ 76,745,923	(3,570)
19	LVD			LVD		LVD			
20	Customer Charge	660	Bills	$380.00	$ 250,800	$ 395.00	$ 260,700		
21	Demand Charge	4,485,872	Therms	1.750	7,850,276	2.147	9,631,167		
22	Distribution Charge	49,432,246	Therms	$0.0348	1,720,242	0.0427	2,110,757		
23	IIP Revenue				481,104				
24	**Total**				**$ 10,302,422**		**$ 12,002,624**	$ 12,002,322	302

Elizabethtown Gas Company
Rate Design for Post Test Year Ending 2025-03-31

Line	Component (a)	Amount (b)	Units (c)	Present Rates: Rate (d)	Present Rates: Revenue (e)	Proposed Rates: Rate (f)	Proposed Rates: Revenue (g)	Target (h)	Difference (i)
25	Natural Gas Vehicle			NGV		NGV			
26	Distribution Charge	116,571	Therms	$ 0.4013	$ 46,780	0.6313	$ 73,591		
27	Fueling Charge	116,571	Therms	0.4611	53,751	0.4842	56,444		
28	Facilities Charge	116,571	Therms	0.3826	44,600	0.4017	46,827		
29	IIP Revenue				2,873				
30	**Total**				**$ 148,004**		**$ 176,862**	$ 176,865	(3)
31	CSI			CSI		CSI			
32	Customer Charge	0	Bills	$ 144.59	$ -	$ 152.00	$ -		
33	Distribution Charge	0	Therms	0.0300	-	0.0351	-		
34	**Total**				**$ -**		**$ -**	$ -	-
35	Interruptible Service			IS		IS			
36	Customer Charge	0	Bills	$ 690.00	$ -	$ 725.00	-		
37	Demand Charge	0	Therms	0.115	-	0.135	-		
38	Distribution Charge	0	Therms	0.0791	-	0.0925	-		
39	**Total**				**$ -**		**$ -**	$ -	-
40	ITS-LVD			ITS-LVD		ITS-LVD			
41	Customer Charge	420	Bills	$ 690.00	$ 289,800	$ 725.00	304,500		
42	Demand Charge	4,338,679	Therms	0.500	2,169,340	0.585	2,538,127		
43	Distribution Charge	31,740,712	Therms	0.1059	3,361,341	0.1240	3,935,848		
44	**Total**				**$ 5,820,481**		**$ 6,778,475**	$ 6,780,860	(2,385)
45	*Distribution excludes Flex therms under Special Contracts*								
46	ITS-IS			ITS-IS		ITS-IS			
47	Customer Charge	120	Bills	$ 690.00	$ 82,800	$ 725.00	87,000		
48	Demand Charge 1/	289,002	Therms	0.500	47,396	0.585	52,309		
49	Distribution Charge 2/	1,991,169	Therms	0.1059	42,173	0.1240	49,381		
50	**Total**				**$ 172,369**		**$ 188,690**	$ 200,810	(12,120)
51	1/ ITS-IS demand charge revenues reduced by 80% sharing above $0.08								
52	2/ ITS-IS distribution charge revenues reduced by 80% sharing.								

Elizabethtown Gas Company
Rate Design for Post Test Year Ending 2025-03-31

Line	Component (a)	Amount (b)	Units (c)	Present Rates Rate (d)	Present Rates Revenue (e)	Proposed Rates Rate (f)	Proposed Rates Revenue (g)	Target (h)	Difference (i)
53	**Total Base Rate Revenue**				**$ 288,211,191**		**$ 362,611,218**	$ 362,641,718	(30,500)
54	*excludes Gas Light Service (GLS) and Elec Gen Firm (EGF)*								
55	**Other Revenues**								
56	GLS Customer Charge		Mantles	$ 9.32	$ -	$ 12.35	$ -		
57	GLS Distribution	2,304	Therms	$0.6381	1,470	0.8459	1,949		
58	GLS IIP Revenue				83				
59	Total Gas Lights				**$ 1,553**		**$ 1,949**	$ 1,949	-
60	EGF Customer Charge	0	Bills	$95.00	$ -	$ 100.00	$ -		
61	EGF Demand	0	Therms	$0.750	-	0.878	-		
62	EGF Distribution	0	Therms	$0.0395	-	0.0462	-		
63	EGF IIP Revenue								
64	Total EGF				**$ -**		**$ -**		-
65	Special Contract w/IIP and Flex Revenues				1,440,814		1,440,814		
66	Late Payment Charges				660,000		660,000		
67	Bad Check Charges				60,000		60,000		
68	Collection Charges				48,500		48,500		
69	Turn On Charges			$15 to $45	564,000	1,128,000	1,692,000		
70	Marketer Billing Fees				33,600		33,600		
71	Capacity Release				144,000		144,000		
72	Total Other Revenues				2,952,467	1,128,000	4,080,863	1,949	-
73	**TOTAL DISTRIBUTION REVENUE**				**$ 291,163,658**		**$ 366,692,081**	362,643,667	(30,500)
74	Increase Computed						75,528,423		
75	Difference Due to Rounding Rates						30,500		
76							**75,558,923**		
77						TARGET INCREASE	75,558,923		
78						Difference	($0)		

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Schedule HSG-3-Index
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Elizabethtown Gas Company
Embedded Cost of Service Study (ECOSS)
Post Test Year 2025-03-31 (Using 2024 6+6)

Schedule HSG 3, Development of Allocators

Line	Tab	Schedule HSG 3	Exhibit
1	Index	Schedule HSG-3-Index	Index to Schedule HSG 3
2	Allocators	Schedule HSG-3-1	Summary of External Allocator Values
3	Deliveries	Schedule HSG-3-2	Gas Deliveries (dekatherms)
4	Revenue	Schedule HSG-3-3	Post Test Year (3/31/2025) Revenue at Present Rates
5	Customers	Schedule HSG-3-4	Number of Customers
6	Demand	Schedule HSG-3-5	Design Day Requirements
7	Mains	Schedule HSG-3-6	Mains- Minimum System Study
8	Services	Schedule HSG-3-7	Services Investment
9	Meters	Schedule HSG-3-8	Meters Investment
10	WriteOff	Schedule HSG-3-9	Write-Offs

Allocators
Schedule HSG-3-1
AllocSum

Elizabethtown Gas Company
Embedded Cost of Service Study (ECOSS)
Summary of External Allocator Values
Post Test Year 2025-03-31 (Using 2024 6+6)

	Allocator Name	TOTAL	Residential Heat	Residential Non-Heat	Small General SGS	General GDS	Large Volume LVD	NGV	Non-Firm
	ALLOCATOR VALUES								
1	Cust_Avg	317,754	263,237	30,695	17,116	6,606	55	1	44
2	Cust_Res	293,931	263,237	30,695					
3	Cust_XRes	23,822			17,116	6,606	55	1	44
4	Gas_Deliveries	497,688,949	256,636,058	7,970,565	25,480,871	124,320,757	49,432,246	116,571	33,731,881
5	Gas_Del_Firm	463,957,068	256,636,058	7,970,565	25,480,871	124,320,757	49,432,246	116,571	
6	Thru_Winter	332,972,140	185,231,777	5,155,095	18,763,474	85,111,153	23,873,517	68,727	14,768,397
7	Peak_Sendout	510,527	315,537	7,657	31,848	122,980	32,456	49	
8	Winter Firm	318,203,743	185,231,777	5,155,095	18,763,474	85,111,153	23,873,517	68,727	
9	Peak_Avg	100.0%	57.6%	1.5%	5.8%	24.5%	7.8%	0.0%	2.8%
10	WriteOff_Del	3,237,571	2,576,605	120,172	100,214	352,574	55,139	792	32,074
11	Mains	510,527	315,537	7,657	31,848	122,980	32,456	49	
12	Mains Direct	14,247,690					3,475,550		10,772,140
13	NGV Direct	1						1	
14	Total_Del_Rev	288,211,191	178,826,834	8,340,428	18,724,324	65,876,329	10,302,422	148,004	5,992,850
15	Rev-BaseDel	275,722,379	170,900,114	7,970,728	17,887,079	63,005,159	9,821,318	145,131	5,992,850
16	IIP-Rev	12,488,812	7,926,720	369,700	837,245	2,871,170	481,104	2,873	0
17	CustDep	4,993,172	2,914,035	274,585	654,310	1,018,812	130,717	714	0
18	Meter_Invest	342,364,293	271,695,797	30,484,346	23,055,491	14,321,046	1,476,200	986	1,330,428
19	OPEN	0							
20	Service_Invest	1,131,062,881	879,161,980	119,817,282	82,154,994	49,928,626	0	0	0
21	Services Direct	6,380,901					2,096,217		4,284,684
22									

Allocators
Schedule HSG-3-1
AllocSum

Elizabethtown Gas Company
Embedded Cost of Service Study (ECOSS)
Summary of External Allocator Values
Post Test Year 2025-03-31 (Using 2024 6+6)

	Allocator Name	TOTAL	Residential Heat	Residential Non-Heat	Small General SGS	General GDS	Large Volume LVD	NGV	Non-Firm
23	**ALLOCATOR PERCENTAGES**		Residential Heat	Residential Non-Heat	Small General SGS	General GDS	Large Volume LVD	NGV	Non-Firm
24	Cust_Avg	100.0%	82.8%	9.7%	5.4%	2.1%	0.0%	0.0%	0.0%
25	Cust_Res	100.0%	89.6%	10.4%	0.0%	0.0%	0.0%	0.0%	0.0%
26	Cust_XRes	100.0%	0.0%	0.0%	71.9%	27.7%	0.2%	0.0%	0.2%
27	Gas_Deliveries	100.0%	51.6%	1.6%	5.1%	25.0%	9.9%	0.0%	6.8%
28	Gas_Del_Firm	100.0%	55.3%	1.7%	5.5%	26.8%	10.7%	0.0%	0.0%
29	Thru_Winter	100.0%	55.6%	1.5%	5.6%	25.6%	7.2%	0.0%	4.4%
30	Peak_Sendout	100.0%	61.8%	1.5%	6.2%	24.1%	6.4%	0.0%	0.0%
31	Winter Firm	100.0%	58.2%	1.6%	5.9%	26.7%	7.5%	0.0%	0.0%
32	Peak_Avg	100.0%	57.6%	1.5%	5.8%	24.5%	7.8%	0.0%	2.8%
33	WriteOff_Del	100.0%	79.6%	3.7%	3.1%	10.9%	1.7%	0.0%	1.0%
34	Mains	100.0%	61.8%	1.5%	6.2%	24.1%	6.4%	0.0%	0.0%
35	Mains Direct	100.0%	0.0%	0.0%	0.0%	0.0%	24.4%	0.0%	75.6%
36	NGV Direct	100.0%	0.0%	0.0%	0.0%	0.0%	0.0%	100.0%	0.0%
37	Total_Del_Rev	100.0%	62.0%	2.9%	6.5%	22.9%	3.6%	0.1%	2.1%
38	Rev-BaseDel	100.0%	62.0%	2.9%	6.5%	22.9%	3.6%	0.1%	2.2%
39	IIP-Rev	100.0%	63.5%	3.0%	6.7%	23.0%	3.9%	0.0%	0.0%
40	CustDep	100.0%	58.4%	5.5%	13.1%	20.4%	2.6%	0.0%	0.0%
41	Meter_Invest	100.0%	79.4%	8.9%	6.7%	4.2%	0.4%	0.0%	0.4%
42	OPEN	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
43	Service_Invest	100.0%	77.7%	10.6%	7.3%	4.4%	0.0%	0.0%	0.0%
44	Services Direct	100.0%	0.0%	0.0%	0.0%	0.0%	32.9%	0.0%	67.1%
45									
46			1	2	3	4	5	6	7

Deliveries
Schedule HSG-3-2
Deliv

Elizabethtown Gas Company
Embedded Cost of Service Study (ECOSS)
Gas Deliveries (dekatherms)
Post Test Year 2025-03-31 (Using 2024 6+6)

	Class	Apr-24	May-24	Jun-24	Jul-24	Aug-24	Sep-24	Oct-24
1	Residential Heat	27,809,987	12,419,168	6,104,523	6,103,654	6,103,553	6,103,701	6,759,695
2	Residential Non-Heat	875,460	483,340	338,658	277,110	277,225	276,932	286,745
3	Small General SGS	2,683,281	1,025,654	586,139	586,024	585,023	598,505	652,771
4	General GDS	12,494,062	5,866,019	3,965,820	3,965,278	3,970,741	3,972,548	4,975,136
5	Large Volume LVD	3,918,125	3,870,994	3,428,229	3,263,252	3,757,399	3,237,331	4,083,399
6	NGV	5,201	4,859	7,497	9,618	8,648	5,953	6,068
7	Non-Firm	2,580,928	2,851,917	2,601,384	2,418,003	2,964,797	2,865,594	2,680,861
8	Gas Mantles	192	192	192	192	192	192	192
9	**TOTAL**	**50,367,236**	**26,522,143**	**17,032,442**	**16,623,131**	**17,667,578**	**17,060,756**	**19,444,867**

Deliveries
Schedule HSG-3-2
Deliv

Elizabethtown Gas Company
Embedded Cost of Service Study (ECOSS)
Gas Deliveries (dekatherms)
Post Test Year 2025-03-31 (Using 2024 6+6)

	Class	Winter Nov-24	Winter Dec-24	Winter Jan-25	Winter Feb-25	Winter Mar-25	TOTAL	Winter
1	Residential Heat	19,614,987	34,713,900	46,309,499	46,693,516	37,899,875	**256,636,058**	185,231,777
2	Residential Non-Heat	569,875	933,863	1,240,143	1,255,073	1,156,141	**7,970,565**	5,155,095
3	Small General SGS	1,511,040	3,437,185	4,857,976	4,997,030	3,960,243	**25,480,871**	18,763,474
4	General GDS	10,156,097	17,044,014	20,632,037	20,148,074	17,130,931	**124,320,757**	85,111,153
5	Large Volume LVD	4,417,575	5,219,484	4,769,876	4,733,291	4,733,291	**49,432,246**	23,873,517
6	NGV	12,260	21,765	15,101	10,619	8,982	**116,571**	68,727
7	Non-Firm	2,893,158	3,206,956	2,734,423	2,966,930	2,966,930	**33,731,881**	14,768,397
8	Gas Mantles	192	192	192	192	192	**2,304**	960
9	**TOTAL**	**39,175,184**	**64,577,359**	**80,559,247**	**80,804,725**	**67,856,585**	**497,691,253**	**332,973,100**

Revenue
Schedule HSG-3-3
Rev

Elizabethtown Gas Company
Embedded Cost of Service Study (ECOSS)
Post Test Year (3/31/2025) Revenue at Present Rates

	Class	Bills (final month X 12)	Therms	Therms- A/C Large	Therms- Econ Dev	Demand	Total Base	IIP	Other	Total Delivery
1	Residential Heat	3,184,476	256,636,058							
2	Residential Non-Heat	369,252	7,970,565							
3	Small General SGS	205,236	25,480,871							
4	General GDS	80,448	124,320,757	19,185	13,827	22,561,476				
5	Large Volume LVD	660	49,432,246			4,485,872				
6	NGV	12	116,571							
7	Gas Mantles	60	2,304							
8	Non-Firm CSI									
9	Non-Firm IS									
10	Non-Firm ITS-IS	120	1,991,169			289,002				
11	Non-Firm ITS-LVD	420	31,740,712			4,338,679				
12	Flex and Contracts	60	46,382,147			629,982				
13	**TOTAL**	**3,840,744**	**544,073,400**	**19,185**	**13,827**	**32,305,011**				
14	*Check*	*3,840,744*	*544,073,400*			*32,305,011*				
15	**Present Rates**									
16	Residential	$ 9.85	$ 0.5437							
17	Small General SGS	$ 34.50	$ 0.4241							
18	General GDS	$ 58.00	$ 0.2715	$ 0.0607	$ 0.1358	$ 1.0900				
19	Large Volume LVD	$ 380.00	$ 0.0348			$ 1.7500				
20	NGV		$ 0.4013	$ 0.4611	$ 0.3826					
21	Gas Mantles		$ 0.6381							
22	Non-Firm CSI	$ 144.59	$ 0.0300							
23	Non-Firm IS	$ 690.00				$ 0.1150				
24	Non-Firm ITS-IS	$ 690.00	$ 0.1059			$ 0.5000				
25	Non-Firm ITS-LVD	$ 690.00	$ 0.1059			$ 0.5000				
26										

Elizabethtown Gas Company
Embedded Cost of Service Study (ECOSS)
Post Test Year (3/31/2025) Revenue at Present Rates

	Class	Bills (final month X 12)	Therms	Therms- A/C Large	Therms- Econ Dev	Demand	Total Base	IIP	Other	Total Delivery
27	**Present Rates Revenue**						**Total Base**	**IIP**	**Other**	**Total Delivery**
28	Residential Heat	31,367,089	139,533,025				170,900,114	7,926,720		178,826,834
29	Residential Non-Heat	3,637,132	4,333,596				7,970,728	369,700		8,340,428
30	Small General SGS	7,080,642	10,806,437				17,887,079	837,245		18,724,324
31	General GDS	4,665,984	33,744,123	1,165	1,878	24,592,009	63,005,159	2,871,170		65,876,329
32	Large Volume LVD	250,800	1,720,242			7,850,276	9,821,318	481,104		10,302,422
33	NGV	0	46,780	53,751	44,600		145,131	2,873		148,004
34	Non-Firm (line 44)	372,600	3,403,514			2,216,736	5,992,850	0		5,992,850
35	Distribution Rates Rever	47,374,247	193,587,717	54,916	46,478	34,659,021	275,722,379	12,488,812	0	288,211,191
36	Gas Lights	0	1,470				1,470	83		1,553
37	Other Revenue							19,841	2,931,073	2,950,914
38		47,374,247	193,589,187	54,916	46,478	34,659,021	275,723,849	12,508,736	2,931,073	291,163,658
39										
40	Non-Firm CSI	0	0	0	0	0	0			0
41	Non-Firm IS	0	0	0	0	0	0			0
42	Non-Firm ITS-IS	82,800	42,173	0	0	47,396	172,369			172,369
43	Non-Firm ITS-LVD	289,800	3,361,341	0	0	2,169,340	5,820,481			5,820,481
44	Total Non-Firm	372,600	3,403,514	0	0	2,216,736	5,992,850			5,992,850
45										
46	**Other Revenue**									
47	Special Contracts								1,409,770	
48	ITS-Flex								11,203	
49	Late Pay+Bad Ck+Colleion								768,500	
50	Turn On								564,000	
51	Marketer Billing								33,600	
52	Capacity Release								144,000	
53									2,931,073	

1/ ITS-IS demand chargevenues reduced by 80% sharing above $0.08
2/ ITS-IS distribution clge revenues reduced by 80% sharing.

Customers
Schedule HSG-3-4
Cust

Elizabethtown Gas Company
Embedded Cost of Service Study (ECOSS)
Number of Customers
Post Test Year 2025-03-31 (Using 2024 6+6)

	Classes	Apr-24	May-24	Jun-24	Jul-24	Aug-24	Sep-24	Oct-24	Nov-24	Dec-24	Jan-25	Feb-25	Mar-25	TOTAL	Average
1	Residential Heat	261,394	261,574	261,781	262,007	262,265	262,625	263,316	264,031	264,534	264,830	265,113	265,373	**3,158,843**	263,237
2	Residential Non-Heat	30,619	30,629	30,642	30,655	30,668	30,679	30,704	30,720	30,736	30,749	30,762	30,771	**368,334**	30,695
3	Small General SGS	17,161	17,143	17,126	17,112	17,106	17,101	17,097	17,107	17,115	17,116	17,110	17,103	**205,397**	17,116
4	General GDS	6,508	6,521	6,540	6,559	6,574	6,586	6,608	6,633	6,658	6,685	6,693	6,704	**79,269**	6,606
5	Large Volume LVD	55	55	55	55	55	55	55	55	55	55	55	55	**660**	55
6	NGV	1	1	1	1	1	1	1	1	1	1	1	1	**12**	1
7	Non-Firm	44	44	44	44	44	44	44	44	44	44	44	44	**528**	44
8	Gas Mantles	5	5	5	5	5	5	5	5	5	5	5	5	**60**	
9	**TOTAL**	**315,787**	**315,972**	**316,194**	**316,438**	**316,718**	**317,096**	**317,830**	**318,596**	**319,148**	**319,485**	**319,783**	**320,056**	**3,813,103**	**317,754**
10															

Demand
Schedule HSG-3-5
DDReq

Elizabethtown Gas Company
Embedded Cost of Service Study (ECOSS)
Design Day Requirements
Post Test Year 2025-03-31 (Using 2024 6+6)

Line	Class	Post Test Year DD	Design Day FIRM	Direct Assignment	Design Day Served by System	Design Day %
1	RDS	317,542	315,537		315,537	61.81%
2	RDS-NH	7,657	7,657		7,657	1.50%
3	SGS	33,460	31,848		31,848	6.24%
4	GDS	141,116	122,980		122,980	24.09%
5	LVD	44,627	44,627	(12,171)	32,456	6.36%
6	NGV	49	49		49	0.01%
7		544,451	522,698		**510,527**	100.00%
8						
9	ITS-LVD	37,451	0			
10	IS	18,424	0			
11	GLS	1	0			
12		55,876	0			
13	Total	**600,327**	**522,698**			
14						
15	**System Load Factor**	**Annual**			**Daily**	
16	Average Daily	497,691,253			1,363,538	
17	Less: Non-Firm	33,731,881			92,416	
18	Average Daily , Firm	463,959,372			1,271,122	
19						
20	Design Day (Peak)				522,698	
21	System Load Factor				**41.1%**	
22						

Demand
Schedule HSG-3-5
DDReq

Elizabethtown Gas Company
Embedded Cost of Service Study (ECOSS)
Design Day Requirements
Post Test Year 2025-03-31 (Using 2024 6+6)

23	**Description**	**Post Test Year DD**	**Design Day FIRM**	**Service**	**Class**
24	Residential Heat	311,701	311,701	Sales	RDS
25	Residential No Heat	7,657	7,657	Sales	RDS-NH
26	Small General Service	28,605	28,605	Sales	SGS
27	General Delivery Service	70,776	70,776	Sales	GDS
28	Natural Gas Vehicles	49	49	Sales	NGV
29	Gas Light Service	1		Sales	GLS
30	Large Volume Demand	10,156	10,156	Sales	LVD
31	ITS-LVD Special Contract	5,000		Sales	ITS-LVD
32					
33	Large Commercial Transport	366	366	Balancing	GDS
34	Industrial Firm Transport	1,642	1,642	Balancing	LVD
35	Interruptible Transport (LVD)	1,545		Balancing	ITS-LVD
36	Interruptible Transport (IS)	877		Balancing	IS
37					
38	Residential	2,005		Transport > DDQ	RDS
39	Small Commercial	1,612		Transport > DDQ	SGS
40	Large Commercial	18,136		Transport > DDQ	GDS
41		**460,128**	**430,952**		
42					
43	LVD-T[5]	26,970	26,970	Transport-Firm	LVD
44	LVD-T[5] Special Contracts	5,859	5,859	Transport-Firm	LVD
45	RDS-T	3,836	3,836	Transport-Firm	RDS
46	SGS-T	3,243	3,243	Transport-Firm	SGS
47	GDS-T	51,838	51,838	Transport-Firm	GDS
48					
49	Transport Interruptible				
50	Large Volume Demand	30,906		Transport-Interr	ITS-LVD
51	Interruptible Service	17,547		Transport-Interr	IS
52	***Total Transport***	**140,199**	**91,746**		
53					
54	***Total Company***	**600,327**	**522,698**		
55	*Check*	*600,327*	*522,698*		

Mains
Schedule I
Mains

Elizabethtown Gas Company
Embedded Cost of Service Study (ECOSS)
Mains- Minimum System Study
Post Test Year 2025-03-31 (Using 2024 6+6)

Line	NOMINAL DIAMETER	MATERIAL	FEET	Replacement Cost Per Foot	Replacement Cost
1	0.50	Plastic	105	$ 140	$ 14,700
2	0.63	Plastic	7	$ 140	$ 980
3	0.75	Plastic	754	$ 140	$ 105,560
4	1.00	Plastic	301	$ 140	$ 42,140
5	1.25	Plastic	11,586	$ 140	$ 1,622,040
6	2.00	Plastic	6,676,991	$ 140	$ 934,778,733
7	3.00	Plastic	256	$ 150	$ 38,400
8	4.00	Plastic	2,475,537	$ 150	$ 371,330,561
9	6.00	Plastic	1,101,600	$ 170	$ 187,272,000
10	8.00	Plastic	847,314	$ 235	$ 199,118,790
11	10.00	Plastic	8	$ 460	$ 3,680
12	12.00	Plastic	104,047	$ 460	$ 47,861,620
13	20.00	Plastic	3,743	$ 2,350	$ 8,796,050
14	0.75	Steel	430	$ 160	$ 68,800
15	1.00	Steel	515	$ 160	$ 82,400
16	1.25	Steel	2,375	$ 160	$ 380,000
17	1.50	Steel	580	$ 160	$ 92,800
18	2.00	Steel	1,894,321	$ 160	$ 303,091,360
19	2.50	Steel	490	$ 185	$ 90,650
20	3.00	Steel	8,713	$ 185	$ 1,611,905
21	3.25	Steel	316	$ 185	$ 58,460
22	3.50	Steel	3,284	$ 185	$ 607,540
23	4.00	Steel	875,503	$ 185	$ 161,968,042
24	6.00	Steel	661,531	$ 265	$ 175,305,715
25	8.00	Steel	1,022,004	$ 450	$ 459,901,800
26	10.00	Steel	14,462	$ 850	$ 12,292,700
27	12.00	Steel	591,000	$ 850	$ 502,350,000
28	14.00	Steel	1	$ 1,325	$ 1,325
29	16.00	Steel	140,694	$ 1,325	$ 186,419,550
30	20.00	Steel	5,953	$ 2,350	$ 13,989,550
31	24.00	Steel	534	$ 3,050	$ 1,628,700
32	30.00	Steel	0	$ 3,400	$ -
33	1.00	Cast Iron	1	$ 140	$ 140
34	1.25	Cast Iron	5	$ 140	$ 700
35	2.00	Cast Iron	1,393	$ 140	$ 195,020
36	3.00	Cast Iron	606	$ 150	$ 90,900

Mains
Schedule I
Mains

Elizabethtown Gas Company
Embedded Cost of Service Study (ECOSS)
Mains- Minimum System Study
Post Test Year 2025-03-31 (Using 2024 6+6)

Line	NOMINAL DIAMETER	MATERIAL	FEET	Replacement Cost Per Foot		Replacement Cost	
37	4.00	Cast Iron	548,009	$	150	$	82,201,316
38	6.00	Cast Iron	222,649	$	170	$	37,850,267
39	8.00	Cast Iron	50,163	$	235	$	11,788,305
40	10.00	Cast Iron	49,213	$	460	$	22,637,980
41	12.00	Cast Iron	2,990	$	460	$	1,375,400
42	16.00	Cast Iron	70,507	$	1,325	$	93,421,775
43	20.00	Cast Iron	24,399	$	2,350	$	57,337,650
44	30.00	Cast Iron	4,852	$	3,400	$	16,496,800
45	0.88	Copper	48	$	140	$	6,720
46	1.13	Copper	75	$	140	$	10,500
47	1.50	Copper	245	$	140	$	34,300
48	1.63	Copper	1,616	$	140	$	226,240
49	2.13	Copper	135	$	140	$	18,900
50	2.00	Ductile Iron	7	$	140	$	980
51	4.00	Ductile Iron	38,920	$	150	$	5,838,000
52	6.00	Ductile Iron	10,644	$	170	$	1,809,480
53	8.00	Ductile Iron	1,751	$	235	$	411,485
54	10.00	Ductile Iron	1	$	460	$	460
55	12.00	Ductile Iron	1	$	460	$	460
56	6.00	Lined Cast Iron	425	$	265	$	112,625
57	8.00	Lined Cast Iron	873	$	450	$	392,850
58	12.00	Lined Cast Iron	730	$	850	$	620,500
59	**TOTAL**		**17,475,212**				**3,903,806,304**
60	Replace with 2" Plastic			**$**	**140**		**2,446,529,730**
61							
62	Minimum Size Ratio						**62.67%**
63	ETG Prior						**62.46%**
64	**Average**						**62.57%**
65							
66							

Services
Schedule HSG-3-7
Services

Elizabethtown Gas Company
Embedded Cost of Service Study (ECOSS)
Services Investment
Post Test Year 2025-03-31 (Using 2024 6+6)

Line	Diameter	Material	Installed Feet	$/FT Fully Installed	Current Value ($)	# Installed
	1" or less	Steel	588,900	$ 104.27	$ 61,404,603	11,325
	1" or less	Plastic	10,257,208	$ 90.67	$ 930,021,049	197,254
	1" or less (PLS)	Copper	1,018,524	$ 90.67	$ 92,349,571	19,587
			11,864,632		$ 1,083,775,223	228,166
	1" or less		Per Service	$ 4,749.94		
	> 1" <= 2"	Steel	227,344	$ 154.77	$ 35,186,031	4,372
	> 1" <= 2"	Plastic	38,688	$ 134.58	$ 5,206,631	744
			266,032		$ 40,392,662	5,116
	> 1" <= 2"		Per Service	$ 7,895.36		
	> 2" <= 4"	Steel	21,008	$ 166.25	$ 3,492,580	404
	> 2" <= 4"	Plastic	10,920	$ 145.00	$ 1,583,400	210
	> 2" <= 4" (PLS)	Copper	13,156	$ 145.00	$ 1,907,620	253
	Directly assinged				$ (88,604)	(11)
			45,084		$ 6,894,996	856
	> 2" <= 4"		Per Service	$ 8,054.90		
	> 4" <= 8"	Steel	2,860	$ 357.50	$ 1,022,450	55
	> 4" <= 8"	Plastic	1,612	$ 200.50	$ 323,206	31
	Directly assinged				$ (1,345,656)	(86)
			4,472		$ -	-
	> 4" <= 8"		Per Service	$ 15,647.16		
	Total		**12,180,220**	**$ 92.86**	**$ 1,131,062,881**	**234,138**
	Total Installed Cost					

Industrial Services	Count	Cost
Firm Industrial	50	2,096,217
Non-Firm	47	4,284,684
	97	**6,380,901**

Meters
Schedule HSG-3-8
Meters

Elizabethtown Gas Company
Embedded Cost of Service Study (ECOSS)
Meters Investment
Post Test Year 2025-03-31 (Using 2024 6+6)

Line	Classes	Average Cost	Customers (December)	Meter Cost-Total	Total	AC 250	AC 630	AC800	AL425	3M175	15C175	11M175
1	Residential Heat	$1,024	265,373	271,695,797	237,839	226,091	10,253	596	780	25	60	0
2	Residential Non-Heat	$991	30,771	30,484,346	31,478	31,222	171	8	10	0	1	0
3	Small General SGS	$1,348	17,103	23,055,491	14,745	9,638	2,478	1,270	557	338	264	13
4	General GDS	$2,136	6,704	14,321,046	4,590	1,396	656	964	91	647	310	126
5	Large Volume LVD	$26,840	55	1,476,200	66	0	0	0	0	0	0	0
6	NGV	$986	1	986	1	0	0	0	0	0	0	0
7	Non-Firm	$30,237	44	1,330,428	50	0	0	0	0	0	0	0
8												
9			**320,051**	**342,364,293**	288,769	268,347	13,558	2,838	1,438	1,010	635	139
10												
11	Meter Cost					$222	$986	$1,518	$429	$1,805	$1,693	$2,987
12	Labor / OH					$764	$764	$764	$764	$1,528	$1,528	$1,528
13	Total Cost					$986	$1,750	$2,282	$1,193	$3,333	$3,221	$4,515
14												
15												
16	Industrial M&R											
17	Large Volume LVD	21,645	62	1,341,988								
18	Non-Firm	26,814	53	1,421,160								
19			**115**	**2,763,148**								
20												

Meters
Schedule HSG-3-8
Meters

Elizabethtown Gas Company
Embedded Cost of Service Study (ECOSS)
Meters Investment
Post Test Year 2025-03-31 (Using 2024 6+6)

Line	Classes	7M175	8C175	5M175	16M175	16M	T-18	Other
1	Residential Heat	0	11	0	0	0	0	23
2	Residential Non-Heat	0	0	0	0	0	0	66
3	Small General SGS	20	83	5	0	0	0	79
4	General GDS	205	30	62	3	0	0	100
5	Large Volume LVD	0	0	0	0	66	0	0
6	NGV	0	0	0	0	0	0	1
7	Non-Firm	0	0	0	0	0	50	0
8								
9		225	124	67	3	66	50	269
10								
11	Meter Cost	$2,453	$1,645	$2,047	$4,004	$26,840	$30,237	$222
12	Labor / OH	$1,528	$1,528	$1,528	$1,528			$764
13	Total Cost	$3,981	$3,173	$3,575	$5,532	$26,840	$30,237	$986
14								
15								
16	Industrial M&R							
17	Large Volume LVD							
18	Non-Firm							
19								
20								

WriteOff
Schedule HSG-3
WriteOff

Elizabethtown Gas Company
Embedded Cost of Service Study (ECOSS)
Write-Offs
Post Test Year 2025-03-31 (Using 2024 6+6)

	Classes		**Annual Revenue-Delivery**	**W/O % Revenue**	**W/O-Delivery**	**Customer Deposits**
1	Residential Heat	Res	178,826,834	1.44%	2,576,605	2,914,035
2	Residential Non-Heat	ResNH	8,340,428	1.44%	120,172	274,585
3	Small General SGS	SGS	18,724,324	0.54%	100,214	654,310
4	General GDS	GDS	65,876,329	0.54%	352,574	1,018,812
5	Large Volume LVD	LVD	10,302,422	0.54%	55,139	130,717
6	NGV	NGV	148,004	0.54%	792	714
7	Non-Firm		5,992,850	0.54%	32,074	0
8	**Totals**		288,211,191		3,237,571	4,993,172
9	*Check*		*288,211,191*			
10						

11	Customer Types	Revenue Jan-Aug 2020	Revenue Jan-Dec 2020	Revenue Jan-Aug 2021	Revenue Sep 2020-Aug 2021	Write-Offs	Recoveries	Net Write-Offs	Net as % Revenue	Average
12	Residential	149,980,289	229,187,625	149,458,303	228,665,638	2,827,834	769,070	2,058,764	0.900%	1.437%
13	Commercial/Industrial	75,094,582	118,594,406	85,479,164	128,978,988	615,715	167,452	448,262	0.348%	0.534%
14	Total	225,074,871	347,782,030	234,937,466	357,644,626	3,443,548	936,522	2,507,026	0.701%	1.113%
15					357,644,626		936,522			
16										

17	Customer Types	Revenue Jan-Jun 2022	Revenue Jan-Dec 2022	Revenue Jan-Jun 2023	Revenue Jul 2022-Jun 2023	Write-Offs	Recoveries	Net Write-Offs	Net as % Revenue
18	Residential	153,290,476	282,004,081	103,109,817	231,823,422	5,936,005	1,359,868	4,576,137	1.974%
19	Commercial/Industrial	85,355,703	158,245,847	57,068,310	129,958,454	1,216,206	278,618	937,588	0.721%
20	Total	238,646,180	440,249,928	160,178,128	361,781,876	7,152,212	1,638,487	5,513,725	1.524%
21					361,781,876		1,638,487		
22									

23	Customer Types			Net as % Revenue
24	Residential	460,489,059	6,634,901	1.441%
25	Commercial/Industrial	258,937,442	1,385,850	0.535%
26	Total	719,426,502	8,020,751	1.115%
27		719,426,502	8,020,751	
28				

Index

Elizabethtown Gas Company
Peak and Average Embedded Cost of Service Study (ECOSS)
Post Test Year 2025-03-31 (Using 2024 6+6)
Index to Class Cost of Service Study

Schedule	Description
Schedule HSG-4-Index	Index to Class Cost of Service Study
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Schedule HSG-4-2	Class Allocations - Total
Schedule HSG-4-3	Unit Costs
Schedule HSG-4-4	Functionalization
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Schedule HSG-4-7D	Class Allocation Factors

Sum
Summary of Results
Schedule HSG-4-1
Tot

Elizabethtown Gas Company
Peak and Average Embedded Cost of Service Study (ECOSS)
Post Test Year 2025-03-31 (Using 2024 6+6)
Summary of Results

Line	Account	Balance	Residential Heat	Residential Non-Heat	Small General SGS	General GDS	Large Volume LVD	NGV	Non-Firm
1	Base Delivery	288,211.191	178,827	8,340	18,724	65,876	10,302	148	5,993
2	Other Revenue	2,952	1,864	120	168	569	208	1	23
3	**Total Revenue**	291,164	180,691	8,460	18,892	66,445	10,510	149	6,016
4									
5	Expenses	190,109	131,403	11,011	11,657	26,676	6,323	72	2,966
6	Net income	101,055	49,288	(2,551)	7,235	39,769	4,187	77	3,050
7									
8	Rate Base	1,862,109	1,206,052	91,505	115,855	306,181	94,531	1,233	46,753
9	Schedule HSG-1-1	*5.4269%*	*2.97%*	*(3.52%)*	*6.22%*	*26.57%*	*16.45%*	*7.39%*	*28.10%*
10	Return on Rate Base	5.4269%	4.09%	(2.79%)	6.24%	12.99%	4.43%	6.22%	6.52%
11	*Rekative*	*1.00 X*	*0.75 X*	*(0.51) X*	*1.15 X*	*2.39 X*	*0.82 X*	*1.15 X*	*1.20 X*
12	Revenue Requirement	366,723	248,367	21,249	22,442	51,516	15,607	189	7,353
13	Schedule HSG 1-1 Relative	*1.000*	*0.55 X*	*(0.65) X*	*1.15 X*	*4.90 X*	*3.03 X*	*1.36 X*	*5.18 X*
14	Operating expenses	81,784	59,929	5,750	4,742	8,189	2,240	7	929
15	Uncollectibles expense	9,750	6,529	881	545	971	583	6	235
16	Depreciation expense	73,787	51,466	4,721	4,625	9,241	2,560	43	1,132
17	General tax / Other	9,188	5,951	451	572	1,511	466	6	231
18	GRT	0	0	0	0	0	0	0	0
19		174,510	123,875	11,804	10,483	19,911	5,849	62	2,527
20	Pre-tax income	192,213	124,493	9,445	11,959	31,605	9,758	127	4,826
21	Income taxes	37,472	24,270	1,841	2,331	6,161	1,902	25	941
22	Net income	154,741	100,223	7,604	9,628	25,444	7,855	102	3,885
23									
24	Return on Rate Base	8.31%	8.31%	8.31%	8.31%	8.31%	8.31%	8.31%	8.31%
25									
26	Revenue increase (decrease)	75,559	67,676	12,789	3,550	(14,929)	5,097	40	1,337
27	Revenue increase (decrease) %	25.95%	37.45%	151.16%	18.79%	(22.47%)	48.49%	26.99%	22.22%

Elizabethtown Gas Company
Peak and Average Embedded Cost of Service Study (ECOSS)
Post Test Year 2025-03-31 (Using 2024 6+6)
Class Allocations - Total

Line	Account	No.	Balance	Residential Heat	Residential Non-Heat	Small General SGS	General GDS	Large Volume LVD	NGV	Non-Firm
1	**I. GAS PLANT IN SERVICE**									
2	**A. INTANGIBLE PLANT**									
3	Franchise & Consents	302	651	539	63	35	14	0	0	0
4	Software & Other Intangibles	303I	0	0	0	0	0	0	0	0
5	**Intangible Plant**		651	539	63	35	14	0	0	0
6										
7	**B. Storage / LNG**									
8	Land & Land Rights	360	68	39	1	4	17	5	0	2
9	Structures and Improvements	361	6,512	3,751	100	376	1,593	510	1	181
10	Gas Holders- LNG/ Storage	362	3,400	1,958	52	196	831	266	1	95
11	363G- Vapor / Compress/ Regulatir		85,911	49,481	1,324	4,964	21,010	6,725	13	2,394
12	NGV Station	363	2,298	0	0	0	0	0	2,298	0
13	**Storage Plant**	304-338	98,189	55,229	1,478	5,541	23,450	7,506	2,313	2,673
14										
15	**C. TRANSMISSION PLANT**									
16	Land	365	631	363	10	36	154	49	0	18
17	Structures and Improvements	366	0	0	0	0	0	0	0	0
18	Mains	367	15,849	9,128	244	916	3,876	1,241	2	442
19	Measuring and Reg. Sta. Equip.	369	8,600	4,953	133	497	2,103	673	1	240
20	**Transmission Plant**	360-368	25,080	14,445	387	1,449	6,133	1,963	4	699
21										
22	**D. DISTRIBUTION PLANT**									
23	Land and Land Rights	374	4,438	2,844	208	279	757	233	5	112
24	Structures and Improvements	375	10,587	6,785	497	666	1,806	555	12	267
25	Mains	376	1,238,550	713,344	19,094	71,568	302,889	96,947	189	34,519
26	Mains Direct	376TC	14,248	0	0	0	0	3,476	0	10,772
27	Meas. & Reg. Stat. Equip. - Genera	378	44,669	25,727	689	2,581	10,924	3,496	7	1,245
28	Services	380	635,224	493,753	67,291	46,140	28,041	0	0	0
29	Services Direct	380D	6,381	0	0	0	0	2,096	0	4,285
30	Meters / Install	381/382	198,942	157,878	17,714	13,397	8,322	858	1	773
31	Ind M&R	385	16,742	0	0	2,847	10,993	2,901	0	0
32	House Reg/ Install	384	12,207	9,688	1,087	822	511	53	0	47
33	OPEN		0	0	0	0	0	0	0	0
34	OPEN		3,768	0	0	0	0	1,018	0	2,750
35	**Distribution Plant**	374-388	2,185,756	1,410,018	106,581	138,300	364,242	111,632	213	54,770
36										
37	**E. GENERAL PLANT**									
38	General Pt- Labor	389	219,750	161,323	15,589	12,772	21,729	5,878	11	2,448
39	General Pt- Plant	398	0	0	0	0	0	0	0	0
40	**General Plant**	389-399	219,750	161,323	15,589	12,772	21,729	5,878	11	2,448
41										
42	**TOTAL UTILITY PLANT**		2,529,427	1,641,553	124,097	158,098	415,568	126,980	2,541	60,590

Elizabethtown Gas Company
Peak and Average Embedded Cost of Service Study (ECOSS)
Post Test Year 2025-03-31 (Using 2024 6+6)
Class Allocations - Total

Line	Account	No.	Balance	Residential Heat	Residential Non-Heat	Small General SGS	General GDS	Large Volume LVD	NGV	Non-Firm
43										
44	**II. DEPRECIATION RESERVE**									
45	Mains-Services Direct	108	0	0	0	0	0	0	0	0
46	NGV Station	111	958	0	0	0	0	0	958	0
47	Storage Plant	108	10,325	5,947	159	597	2,525	808	2	288
48	Transmission Plant	109	1,433	825	22	83	350	112	0	40
49	Distribution- Mains	108M	206,859	119,141	3,189	11,953	50,588	16,192	32	5,765
50	Distribution- Services	108S	77,823	60,491	8,244	5,653	3,435	0	0	0
51	Distribution- Meters	108Mt	63,394	50,309	5,645	4,269	2,652	273	0	246
52	Distribution- Other	108O	46,871	30,036	2,201	2,949	7,994	2,458	51	1,180
53	General Pt- Labor	109	90,775	66,640	6,439	5,276	8,976	2,428	5	1,011
54	General Pt- Plant	398	0	0	0	0	0	0	0	0
55	**Depreciation Reserve**	108	498,438	333,388	25,900	30,779	76,520	22,272	1,048	8,531
56										
57	**III. OTHER RATE BASE ITEMS**									
58	Materials and Supplies, Prepay	105	0	0	0	0	0	0	0	0
59	Storage Gas	107M	10,754	6,260	174	634	2,876	807	2	0
60	Cust Dep / Adv	Cust	(6,690)	(3,904)	(368)	(877)	(1,365)	(175)	(1)	0
61	Other Regulatory Assets	182P	23,015	16,896	1,633	1,338	2,276	616	1	256
62	Accum Deferred Income Taxes	190	(246,434)	(157,922)	(11,574)	(15,506)	(42,032)	(12,925)	(270)	(6,205)
63	CWC	CWC	50,476	36,558	3,442	2,948	5,378	1,500	7	642
64	OPEN	CWC-Su	0	0	0	0	0	0	0	0
65	**Other Rate Base**		(168,880)	(102,113)	(6,693)	(11,463)	(32,867)	(10,177)	(260)	(5,306)
66										
67	**TOTAL RATE BASE**		1,862,109	1,206,052	91,505	115,855	306,181	94,531	1,233	46,753
68										
69	**I. OPERATING AND MAINTENANCE EXPENSES**									
70	**A. PRODUCTION EXPENSE**									
71	Purchased Gas									
72	Natural Gas City Gate Purchases	804	0	0	0	0	0	0	0	0
73	**Subtotal-Production expenses**	710-813	0	0	0	0	0	0	0	0
74										
75	**B. STORAGE, LNG EXPENSES**									
76	Storage Operations	841	700	403	11	40	171	55	0	20
77	**Subtotal- Storage expenses**	840-850	700	403	11	40	171	55	0	20
78										

Elizabethtown Gas Company
Peak and Average Embedded Cost of Service Study (ECOSS)
Post Test Year 2025-03-31 (Using 2024 6+6)
Class Allocations - Total

Line	Account	No.	Balance	Residential Heat	Residential Non-Heat	Small General SGS	General GDS	Large Volume LVD	NGV	Non-Firm
79	**C. TRANSMISSION EXPENSES**									
80	Mains Operating	850-856	0	0	0	0	0	0	0	0
81	Maintenance Other Equip.	865	174	100	3	10	43	14	0	5
82	**Subtotal-Transmission**	850-867	174	100	3	10	43	14	0	5
83										
84	**D. DISTRIBUTION O&M EXPENSE**									
85	Operation Supv & Engineering	870	0	0	0	0	0	0	0	0
86	Distribution Load Dispatching	871	288	159	5	16	77	31	0	0
87	Mains and Services Expenses	874	4,186	2,667	191	260	731	227	0	110
88	Meas & Reg Exp- General	875	29	17	0	2	7	2	0	1
89	Meas & Reg Exp- Industrial	876	0	0	0	0	0	0	0	0
90	Meter-Regulator- Citygate	878	917	528	14	53	224	72	0	26
91	Cust Installations Field	879	835	692	81	45	17	0	0	0
92	Other Expenses	880	3	2	0	0	0	0	0	0
93	Rents	881	16	12	1	1	2	0	0	0
94	Maint Compressor Station Equip	879	0	0	0	0	0	0	0	0
95	Maint Supv & Engineering	885	0	0	0	0	0	0	0	0
96	Maint of Mains	887	1,457	839	22	84	356	114	0	41
97	Maint. of Meas. & Reg. General	889	104	60	2	6	25	8	0	3
98	Maint. of Meas. & Reg.- Indust	890	0	0	0	0	0	0	0	0
99	Maint. of Services	892	615	478	65	45	27	0	0	0
100	Maint. of Meters & House Regulatc	893	142	113	13	10	6	1	0	1
101	Maint. Other Equip.	894	61	39	3	4	10	3	0	2
102	**Dist. Oper. & Maint. Exp.**	870-899	8,653	5,606	397	525	1,485	458	1	182
103	**Total O&M Expenses**		9,527	6,109	411	575	1,698	526	1	206
104										
105	**II. CUSTOMER ACCOUNTS AND SERVICE**									
106	Supervision	901	0	0	0	0	0	0	0	0
107	Meter Reading Expenses	902	509	421	49	27	11	0	0	0
108	Customer Records & Collection Ex	903	850	704	82	46	18	0	0	0
109	Uncollectible Accounts	904	9,078	5,880	446	565	1,493	461	6	228
110	Miscellaneous Customer Accounts I	905	0	0	0	0	0	0	0	0
111	**Customer Accts. Exp.**	901-905	10,437	7,005	577	638	1,521	461	6	228
112										
113	**III. CUSTOMER ACCOUNTS AND INFORMATION**									
114	Customer Assistance Expenses	908	3,652	3,025	353	197	76	1	0	1
115	Low Income Discount	908LI	0	0	0	0	0	0	0	0
116	Cust Assist Other	909-912	4,802	3,978	464	259	100	1	0	1
117	Advertising	913	692	573	67	37	14	0	0	0
118	**Customer Service Exp.**	908-919	9,146	7,577	883	493	190	2	0	1
119	**Customer Accts. & Serv. Exp.**	901-919	19,582	14,582	1,461	1,131	1,711	463	6	229

Elizabethtown Gas Company
Peak and Average Embedded Cost of Service Study (ECOSS)
Post Test Year 2025-03-31 (Using 2024 6+6)
Class Allocations - Total

Line	Account	No.	Balance	Residential Heat	Residential Non-Heat	Small General SGS	General GDS	Large Volume LVD	NGV	Non-Firm
120										
121	**E. ADMINISTRATIVE AND GENERAL**									
122	Administrative & General Salaries	920	17,114	12,564	1,214	995	1,692	458	1	191
123	Office Supplies & Expenses	921	7,904	5,803	561	459	782	211	0	88
124	Outside Services Employed	923	27,397	20,113	1,944	1,592	2,709	733	1	305
125	Property Insurance	924	1,987	1,274	93	125	339	104	2	50
126	Injuries & Damages	925	235	172	17	14	23	6	0	3
127	Employee Pensions and Benefits	926	5,796	4,255	411	337	573	155	0	65
128	Franchise Reqirements	927	0	0	0	0	0	0	0	0
129	Regulatory Commission Expenses	928	360	233	18	22	59	18	0	9
130	Misc General Exp	930	840	617	60	49	83	22	0	9
131	A&G- Rents	931	118	87	8	7	12	3	0	1
132	Maint General Plant	932	0	0	0	0	0	0	0	0
133	**Admin & Genl. Exp.**	920-932	61,753	45,117	4,325	3,600	6,272	1,712	6	721
134										
135	**Total Operating Expenses**		90,862	65,808	6,196	5,306	9,681	2,701	13	1,157
136										
137	**II. DEPRECIATION EXPENSE**									
138	Land and ROW	403	448	287	21	28	76	23	0	11
139	Storage Plant	403	1,841	1,060	28	106	450	144	0	51
140	Transmission Plant	404	523	301	8	30	128	41	0	15
141	Mains	403M	21,144	12,039	322	1,208	5,112	1,695	3	764
142	Services	403S	19,828	15,412	2,100	1,440	875	0	0	0
143	Meters	403Mt	7,248	5,752	645	488	303	31	0	28
144	Distr Other	403O	687	440	32	43	117	36	1	17
145	General Pt- Labor	404	22,032	16,174	1,563	1,281	2,178	589	1	245
146	General Pt- Plant	404	0	0	0	0	0	0	0	0
147	Mains/Services Direct	404	0	0	0	0	0	0	0	0
148	NGV Station	404	37	0	0	0	0	0	37	0
149	Amort Regulatory Debits	403	0	0	0	0	0	0	0	0
150	**Depreciation Expense**		73,787	51,466	4,721	4,625	9,241	2,560	43	1,132
151										
152	**III. TAXES and OTHER**		73,750	51,466	4,721	4,625	9,241	2,560	6	1,132
153	**A. GENERAL TAXES**									
154	Taxes- Labor based	408L	3,269	2,400	232	190	323	87	0	36
155	Taxes- Plant based	408P	1,076	690	51	68	184	56	1	27
156	Other Taxes	408O	1,047	678	51	65	172	53	1	26
157	Tax Amortization	408	3,587	2,323	176	223	590	182	2	90
158	**General Taxes**		8,980	6,091	510	546	1,269	379	4	180
159										
160	**B. GROSS RECEIPTS TAX**									
161	Gross Receipts tax		0	0	0	0	0	0	0	0
162	**Gross Receipts Tax**		0	0	0	0	0	0	0	0

Elizabethtown Gas Company
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Class Allocations - Total

Line	Account	No.	Balance	Residential Heat	Residential Non-Heat	Small General SGS	General GDS	Large Volume LVD	NGV	Non-Firm
163										
164	**B. FEDERAL / STATE INCOME TAXES**									
165	Federal Income Tax Expense		16,480	8,038	(416)	1,180	6,485	683	12	497
166	**Income Taxes**	409-411	16,480	8,038	(416)	1,180	6,485	683	12	497
167	**Total Taxes**	408-411	25,459	14,129	94	1,726	7,754	1,062	17	677
168										
169	**TOTAL EXPENSES**		190,109	131,403	11,011	11,657	26,676	6,323	72	2,966
170										
171	**IV. OPERATING REVENUES at Present Rates**									
172	Base Delivery	480	288,211	178,827	8,340	18,724	65,876	10,302	148	5,993
173	Commodity	480C	0	0	0	0	0	0	0	0
174	Rent from Gas Property	488	0	0	0	0	0	0	0	0
175	Late payment	493	769	498	38	48	126	39	1	19
176	Other Revenues	495	1,442	798	25	79	386	154	0	0
177	Marketer	495	34	19	1	2	9	4	0	0
178	Turn On	495	564	467	54	30	12	0	0	0
179	Capacity Release	415/416	144	83	2	8	35	11	0	4
180	Adjust to Case Model		0	0	0	0	0	0	0	0
181	**TOTAL REVENUE**		291,164	180,691	8,460	18,892	66,445	10,510	149	6,016
182										
183	**V. Net Income at Present Rates**		101,055	49,288	(2,551)	7,235	39,769	4,187	77	3,050
184										
185	**RATE BASE**		1,862,109	1,206,052	91,505	115,855	306,181	94,531	1,233	46,753
186	Return on Rate Base		5.43%	4.09%	(2.79%)	6.24%	12.99%	4.43%	6.22%	6.52%
187										
188	**REVENUE REQUIREMENTS**									
189	Target Rate of Return		8.3100%	8.3100%	8.3100%	8.3100%	8.3100%	8.3100%	8.3100%	8.3100%
190	Rate Base		1,862,109	1,206,052	91,505	115,855	306,181	94,531	1,233	46,753
191										
192	Operating expenses, Depreciation		155,571	111,395	10,471	9,366	17,429	4,800	49	2,061
193	Uncollectible accounts		9,750	6,529	881	545	971	583	6	235
194	General taxes / Other		9,188	5,951	451	572	1,511	466	6	231
195	Subtotal- Operating Costs to recove		174,510	123,875	11,804	10,483	19,911	5,849	62	2,527
196										
197	Target Return on rate base		154,741	100,223	7,604	9,628	25,444	7,855	102	3,885
198	Income Taxes		37,472	24,270	1,841	2,331	6,161	1,902	25	941
199										
200	Subtotal- Rev Req before GRT		366,723	248,367	21,249	22,442	51,516	15,607	189	7,353
201	GRT needed		0	0	0	0	0	0	0	0
202	**TOTAL REVENUE REQUIREMENT**		366,723	248,367	21,249	22,442	51,516	15,607	189	7,353
203										

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Elizabethtown Gas Company
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Unit Costs

Line	Account Description		Total	Residential Heat and Residential Non-Heat	Small General SGS	General GDS	Large Volume LVD	NGV	Non-Firm
1	Demand-related Revenue Req		185,061	107,843	10,747	44,623	15,028	160	6,659
2	Gas Deliveries, dth		497,688,949	264,606,623	25,480,871	124,320,757	49,432,246	116,571	33,731,881
3	**Demand-related, Per dth**		**$0.37**	**$0.41**	**$0.42**	**$0.36**	**$0.30**	**$1.37**	**$0.20**
4									
5	Customer-related Revenue Req		181,662	161,774	11,695	6,893	578	29	694
6	Number of Bills		3,813,043	3,527,177	205,397	79,269	660	12	528
7	**Customer-related, Per bill**		**$47.64**	**$45.86**	**$56.94**	**$86.96**	**$876.11**	**$2,411.65**	**$1,313.92**
8									
9	**Total revenue requirement**		**366,723**	**269,616**	**22,442**	**51,516**	**15,607**	**189**	**7,353**
10									
11	**Customer-related costs, per customer-month:**								
12	Return component								
13	Mains, net		$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
14	Services, net	CC	$15.26	$14.41	$20.35	$32.04	$327.85	$0.00	$837.65
15	Meters and Regulators, net	CC	$4.00	$3.82	$5.00	$8.05	$99.64	$3.66	$112.25
16	ADIT		($2.48)	($2.08)	($3.26)	($5.16)	($50.52)	($0.56)	($107.22)
17	Other Rate Base		$3.14	$2.88	$3.09	$2.67	($1.78)	$9.78	$22.38
18	Return Component		$19.92	$19.03	$25.18	$37.60	$375.19	$12.87	$865.06
19									
20	Expense component								
21	Mains O&M		$0.37	$0.35	$0.50	$0.78	$7.02	$0.00	$17.93
22	Services O&M	CC	$0.00	$0.00	$0.00	$0.00	$0.02	$0.01	$0.01
23	Meters and Regul O&M	CC	$0.04	$0.04	$0.05	$0.07	$0.93	$0.03	$1.05
24	Other O&M		$0.39	$0.38	$0.45	$0.58	$0.41	$0.27	$0.53
25	Customer Accounting	CC	$2.75	$2.75	$2.75	$2.75	$2.75	$2.75	$2.75
26	Uncollectible Accounts		$1.25	$1.23	$1.32	$1.42	$20.69	$74.70	$38.63
27	Admin & General		$10.67	$10.51	$11.62	$14.40	$62.27	$27.74	$91.51
28	Mains Depr Exp		$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
29	Services Depr Exp	CC	$5.20	$4.96	$7.01	$11.04	$0.00	$0.00	$0.00
30	Meters and Regul Depr Exp	CC	$1.90	$1.81	$2.38	$3.82	$47.35	$1.74	$53.34
31	Other Depr Exp		$3.97	$3.91	$4.32	$5.14	$13.60	$2,043.46	$29.26
32	General Taxes		$1.18	$0.89	$1.36	$9.33	$345.89	$248.07	$213.84
33	Expense component		$27.72	$26.84	$31.76	$49.35	$500.92	$2,398.78	$448.85
34	Total revenue requirement		$47.64	$45.86	$56.94	$86.96	$876.11	$2,411.65	$1,313.92
35									
36	**Customer charge costs**	**CC**	**$29.16**	**$27.79**	**$37.54**	**$57.79**	**$478.53**	**$8.20**	**$1,007.05**

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Line	Account	No.	Balance	Allocator	Supply-Storage	Distribution	Billing	Procurement	Labor $	Labor %
1	**I. GAS PLANT IN SERVICE**									
2	**A. INTANGIBLE PLANT**									
3	Franchise & Consents	302	651	Dist	-	651	-	-	-	
4	Software & Other Intangibles	303I	-	Dist	-	-	-	-	-	
5	**Intangible Plant**		651		-	651	-	-	-	
6										
7	**B. Storage / LNG**								-	
8	Land & Land Rights	360	68	Dist	-	68	-	-	-	
9	Structures and Improvements	361	6,512	Dist	-	6,512	-	-	-	
10	Gas Holders- LNG/ Storage	362	3,400	Dist	-	3,400	-	-	-	
11	363G- Vapor / Compress/ Regulating		85,911	Dist	-	85,911	-	-	-	
12	NGV Station	363	2,298	Dist	-	2,298	-	-	-	
13	Storage Plant	304-338	98,189		-	98,189	-	-	-	
14										
15	**C. TRANSMISSION PLANT**								-	
16	Land	365	631	Dist	-	631	-	-	-	
17	Structures and Improvements	366	-	Dist	-	-	-	-	-	
18	Mains	367	15,849	Dist	-	15,849	-	-	-	
19	Measuring and Reg. Sta. Equip.	369	8,600	Dist	-	8,600	-	-	-	
20	**Transmission Plant**	360-368	25,080		-	25,080	-	-	-	
21										
22	**D. DISTRIBUTION PLANT**									
23	Land and Land Rights	374	4,438	Dist	-	4,438	-	-	-	
24	Structures and Improvements	375	10,587	Dist	-	10,587	-	-	-	
25	Mains	376	1,238,550	Dist	-	1,238,550	-	-	-	
26	Mains Direct	376TC	14,248	Dist	-	14,248	-	-	-	
27	Meas. & Reg. Stat. Equip. - General	378	44,669	Dist	-	44,669	-	-	-	
28	Services	380	635,224	Dist	-	635,224	-	-	-	
29	Services Direct	380D	6,381	Dist	-	6,381	-	-	-	
30	Meters / Install	381/382	198,942	Dist	-	198,942	-	-	-	
31	Ind M&R	385	16,742	Dist	-	16,742	-	-	-	
32	House Reg/ Install	384	12,207	Dist	-	12,207	-	-	-	
33	OPEN		-	Dist	-	-	-	-	-	
34	OPEN		3,768	Dist	-	3,768	-	-	-	
35	Distribution Plant	374-388	2,185,756		-	2,185,756	-	-	-	
36										
37	**E. GENERAL PLANT**									
38	General Pt- Labor	389	219,750	Dist	-	219,750	-	-	-	
39	General Pt- Plant	398	-	Dist	-	-	-	-	-	
40	**General Plant**	389-399	219,750		-	219,750	-	-	-	
41										
42	**TOTAL UTILITY PLANT**		2,529,427		-	2,529,427	-	-	-	

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Functionalization

Line	Account	No.	Balance	Allocator	Supply-Storage	Distribution	Billing	Procurement		Labor $	Labor %
43											
44	**II. DEPRECIATION RESERVE**										
45	Mains-Services Direct	108	-	Dist	-	-	-	-	-		
46	NGV Station	111	958	Dist	-	958	-	-	-		
47	Storage Plant	108	10,325	Dist	-	10,325	-	-	-		
48	Transmission Plant	109	1,433	Dist	-	1,433	-	-	-		
49	Distribution- Mains	108M	206,859	Dist	-	206,859	-	-	-		
50	Distribution- Services	108S	77,823	Dist	-	77,823	-	-	-		
51	Distribution- Meters	108Mt	63,394	Dist	-	63,394	-	-	-		
52	Distribution- Other	108O	46,871	Dist	-	46,871	-	-	-		
53	General Pt- Labor	108.7	90,775	Dist	-	90,775	-	-	-		
54	General Pt- Plant	398	-	Dist	-	-	-	-	-		
55	Depreciation Reserve	108	498,438		-	498,438	-	-	-		
56											
57	**III. OTHER RATE BASE ITEMS**										
58	Materials and Supplies, Prepay	105	-	Dist	-	-	-	-	-		
59	Storage Gas	107M	10,754	Dist	-	10,754	-	-	-		
60	Cust Dep / Adv	Cust	(6,690)	Dist	-	(6,690)	-	-	-		
61	Other Regulatory Assets	182P	23,015	Dist	-	23,015	-	-	-		
62	Accum Deferred Income Taxes	190	(246,434)	Dist	-	(246,434)	-	-	-		
63	CWC	CWC	50,476	Dist	-	50,476	-	-	-		
64	OPEN	CWC-Su	-	Dist	-	-	-	-	-		
65	**Other Rate Base**		(168,880)		-	(168,880)	-	-	-		
66											
67	**TOTAL RATE BASE**		1,862,109		-	1,862,109	-	-	-		
68											
69	**I. OPERATING AND MAINTENANCE EXPENSES**										
70	**A. PRODUCTION EXPENSE**										
71	Purchased Gas										
72	Natural Gas City Gate Purchases	804	-	Dist	-	-	-	-	-	0	0.00%
73	**Subtotal-Production expenses**	710-813	-		-	-	-	-		-	
74											
75	**B. STORAGE, LNG EXPENSES**										
76	Storage Operations	841	700	Dist	-	700	-	-	-	306	43.66%
77	**Subtotal- Storage expenses**	840-850	700		-	700	-	-		306	
78											

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Functionalization

Line	Account	No.	Balance	Allocator	Supply-Storage	Distribution	Billing	Procurement		Labor $	Labor %
79	**C. TRANSMISSION EXPENSES**										
80	Mains Operating	850-856	-	Dist	-	-	-	-	-	0	0.00%
81	Maintenance Other Equip.	865	174	Dist	-	174	-	-	-	0	0.00%
82	**Subtotal-Transmission**	850-867	174		-	174	-	-		0	
83											
84	**D. DISTRIBUTION O&M EXPENSE**										
85	Operation Supv & Engineering	870	0	Dist	-	0	-	-	-	0	0.00%
86	Distribution Load Dispatching	871	288	Dist	-	288	-	-	-	0	0.01%
87	Mains and Services Expenses	874	4,186	Dist	-	4,186	-	-	-	1,035	24.72%
88	Meas & Reg Exp- General	875	29	Dist	-	29	-	-	-	29	97.34%
89	Meas & Reg Exp- Industrial	876	0	Dist	-	0	-	-	-	0	0.00%
90	Meter-Regulator- Citygate	878	917	Dist	-	917	-	-	-	52	5.65%
91	Cust Installations Field	879	835	Dist	-	835	-	-	-	813	97.34%
92	Other Expenses	880	3	Dist	-	3	-	-	-	0	7.57%
93	Rents	881	16	Dist	-	16	-	-	-	0	0.00%
94	Maint Compressor Station Equip	879	-	Dist	-	-	-	-	-	0	0.00%
95	Maint Supv & Engineering	885	-	Dist	-	-	-	-	-	0	0.00%
96	Maint of Mains	887	1,457	Dist	-	1,457	-	-	-	347	23.85%
97	Maint. of Meas. & Reg. General	889	104	Dist	-	104	-	-	-	93	89.63%
98	Maint. of Meas. & Reg.- Indust	890	-	Dist	-	-	-	-	-	0	0.00%
99	Maint. of Services	892	615	Dist	-	615	-	-	-	398	64.72%
100	Maint. of Meters & House Regulators	893	142	Dist	-	142	-	-	-	0	0.09%
101	Maint. Other Equip.	894	61	Dist	-	61	-	-	-	0	0.00%
102	Dist. Oper. & Maint. Exp.	870-899	8,653		-	8,653	-	-	-	2,767	
103	**Total O&M Expenses**		9,527		-	9,527	-	-	-	3,073	
104											
105	**II. CUSTOMER ACCOUNTS AND SERVICE**										
106	Supervision	901	-	Dist	-	-	-	-	-	0	0.00%
107	Meter Reading Expenses	902	509	Dist	-	509	-	-	-	260	51.16%
108	Customer Records & Collection Expen	903	850	Dist	-	850	-	-	-	727	85.48%
109	Uncollectible Accounts	904	9,078	Dist	-	9,078	-	-	-	0	0.00%
110	Miscellaneous Customer Accounts Exp	905	-	Dist	-	-	-	-	-	0	0.00%
111	**Customer Accts. Exp.**	901-905	10,437		-	10,437	-	-	-	987	
112											
113	**III. CUSTOMER ACCOUNTS AND INFORMATION**										
114	Customer Assistance Expenses	908	3,652	Dist	-	3,652	-	-	-	467	12.80%
115	Low Income Discount	908LI	-	Dist	-	-	-	-	-	0	0.00%
116	Cust Assist Other	909-912	4,802	Dist	-	4,802	-	-	-	0	0.00%
117	Advertising	913	692	Dist	-	692	-	-	-	0	0.00%
118	**Customer Service Exp.**	908-919	9,146		-	9,146	-	-	-	467	
119	**Customer Accts. & Serv. Exp.**	901-919	19,582		-	19,582	-	-	-	1,454	

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Line	Account	No.	Balance	Allocator	Supply-Storage	Distribution	Billing	Procurement		Labor $	Labor %
120											
121	**E. ADMINISTRATIVE AND GENERAL**										
122	Administrative & General Salaries	920	17,114	Dist	-	17,114	-	-	-	16,388	95.76%
123	Office Supplies & Expenses	921	7,904	Dist	-	7,904	-	-	-	1,830	23.15%
124	Outside Services Employed	923	27,397	Dist	-	27,397	-	-	-	21,277	77.66%
125	Property Insurance	924	1,987	Dist	-	1,987	-	-	-	0	0.00%
126	Injuries & Damages	925	235	Dist	-	235	-	-	-	0	0.00%
127	Employee Pensions and Benefits	926	5,796	Dist	-	5,796	-	-	-	0	0.00%
128	Franchise Reqirements	927	-	Dist	-	-	-	-	-	0	0.00%
129	Regulatory Commission Expenses	928	360	Dist	-	360	-	-	-	0	0.00%
130	Misc General Exp	930.2	840	Dist	-	840	-	-	-	0	0.00%
131	A&G- Rents	931	118	Dist	-	118	-	-	-	0	0.00%
132	Maint General Plant	932	-	Dist	-	-	-	-	-	0	0.00%
133	**Admin & Genl. Exp.**	920-932	61,753		-	61,753	-	-	-	39,496	
134											
135	**Total Operating Expenses**		90,862		-	90,862	-	-	-	44,023	
136											
137	**II. DEPRECIATION EXPENSE**										
138	Land and ROW	403	448	Dist	-	448	-	-	-		
139	Storage Plant	403	1,841	Dist	-	1,841	-	-	-		
140	Transmission Plant	404	523	Dist	-	523	-	-	-		
141	Mains	403M	21,144	Dist	-	21,144	-	-	-		
142	Services	403S	19,828	Dist	-	19,828	-	-	-		
143	Meters	403Mt	7,248	Dist	-	7,248	-	-	-		
144	Distr Other	403O	687	Dist	-	687	-	-	-		
145	General Pt- Labor	404	22,032	Dist	-	22,032	-	-	-		
146	General Pt- Plant	404	-	Dist	-	-	-	-	-		
147	Mains/Services Direct	404	-	Dist	-	-	-	-	-		
148	NGV Station	404	37	Dist	-	37	-	-	-		
149	Amort Regulatory Debits	403	-	Dist	-	-	-	-	-		
150	**Depreciation Expense**		73,787		-	73,787	-	-	-		
151											
152	**III. TAXES and OTHER**										
153	**A. GENERAL TAXES**										
154	Taxes- Labor based	408L	3,269	Dist	-	3,269	-	-	-		
155	Taxes- Plant based	408P	1,076	Dist	-	1,076	-	-	-		
156	Other Taxes	408O	1,047	Dist	-	1,047	-	-	-		
157	Tax Amortization	408	3,587	Dist	-	3,587	-	-	-		
158	**General Taxes**		8,980		-	8,980	-	-	-		
159											
160	**B. GROSS RECEIPTS TAX**										
161	Gross Receipts tax		-	Dist	-	-	-	-	-		
162	**Gross Receipts Tax**		-		-	-	-	-	-		

Functions
Functionalization
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Functionalization

Line	Account	No.	Balance	Allocator	Supply-Storage	Distribution	Billing	Procurement	Labor $	Labor %
163										
164	**B. FEDERAL / STATE INCOME TAXES**									
165	Federal Income Tax Expense		16,480	Pretax	-	16,480	-	-	-	
166	**Income Taxes**	409-411	16,480		-	16,480	-	-	-	
167	**Total Taxes**	408-411	25,459		-	25,459	-	-	-	
168										
169	**TOTAL EXPENSES**		190,109		-	190,109	-	-	-	
170										
171	**IV. OPERATING REVENUES at Present Rates**									
172	Base Delivery	480	288,211	RevReq_PF	-	288,211	-	-	-	
173	Commodity	480C	-	Dist	-	-	-	-	-	
174	Rent from Gas Property	488	-	Dist	-	-	-	-	-	
175	Late payment	493	769	Dist	-	769	-	-	-	
176	Other Revenues	495	1,442	Dist	-	1,442	-	-	-	
177	Marketer	495	34	Dist	-	34	-	-	-	
178	Turn On	495	564	Dist	-	564	-	-	-	
179	Capacity Release	415/416	144	Dist	-	144	-	-	-	
180	Adjust to Case Model		-	RevReq_PF	-	-	-	-	-	
181	**TOTAL REVENUE**		291,164		-	291,164	-	-	-	
182										
183	**V. Net Income at Present Rates**		101,055		-	101,055	-	- #	-	
184										
185	**RATE BASE**		1,862,109		-	1,862,109	-	-	-	
186	Return on Rate Base		5.43%		-	5.43%	-	-		
187										
188	**REVENUE REQUIREMENTS**									
189	Target Rate of Return		8.31%		8.31%	8.31%	8.31%	8.3100%		
190	Rate Base		1,862,109		0	1,862,109	0	0	-	
191									-	
192	Operating expenses, Depreciation		155,571		0	155,571	0	0	-	
193	Uncollectible accounts		9,750	Uncollect_RR	-	9,750	-	-	-	
194	General taxes / Other		9,188	RateBase	-	9,188	-	-	-	
195	Subtotal- Operating Costs to recover		174,510		0	174,510	0	0	-	
196										
197	Target Return on rate base		154,741		0	154,741	0	0	-	
198	Income Taxes		37,472	24.22%	0	37,472	0	0	-	
199										
200	Subtotal- Rev Req before GRT		366,723	211,981	0	366,723	0	0	-	
201	GRT needed		0	0.00%	0	0	0	0	-	
202	**TOTAL REVENUE REQUIREMENT**		366,723		0	366,723	0	0	-	
203										

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Classification

Line	Account	No.	Distribution		Demand	Commodity	Customer	
1	**I. GAS PLANT IN SERVICE**							
2	**A. INTANGIBLE PLANT**							
3	Franchise & Consents	302	651	Customer	-	-	651	-
4	Software & Other Intangibles	303I	-	None	-	-	-	-
5	**Intangible Plant**	-	651		-	-	651	-
6								
7	**B. Storage / LNG**							
8	Land & Land Rights	360	68	Demand	68	-	-	-
9	Structures and Improvements	361	6,512	Demand	6,512	-	-	-
10	Gas Holders- LNG/ Storage	362	3,400	Demand	3,400	-	-	-
11	363G- Vapor / Compress/ Regulating		85,911	Demand	85,911	-	-	-
12	NGV Station	363	2,298	Demand	2,298	-	-	-
13	**Storage Plant**	304-338	98,189		98,189	-	-	-
14								
15	**C. TRANSMISSION PLANT**							
16	Land	365	631	Demand	631	-	-	-
17	Structures and Improvements	366	-	Demand	-	-	-	-
18	Mains	367	15,849	Demand	15,849	-	-	-
19	Measuring and Reg. Sta. Equip.	369	8,600	Demand	8,600	-	-	-
20	**Transmission Plant**	360-368	25,080		25,080	-	-	-
22	**D. DISTRIBUTION PLANT**							
23	Land and Land Rights	374	4,438	Dist Pt	2,789	-	1,650	-
24	Structures and Improvements	375	10,587	Dist Pt	6,652	-	3,936	-
25	Mains	376	1,238,550	Demand	1,238,550	-	-	-
26	Mains Direct	376TC	14,248	Demand	14,248	-	-	-
27	Meas. & Reg. Stat. Equip. - General	378	44,669	Demand	44,669	-	-	-
28	Services	380	635,224	Customer	-	-	635,224	-
29	Services Direct	380D	6,381	Customer	-	-	6,381	-
30	Meters / Install	381/382	198,942	Customer	-	-	198,942	-
31	Ind M&R	385	16,742	Demand	16,742	-	-	-
32	House Reg/ Install	384	12,207	Customer	-	-	12,207	-
33	OPEN		-	Demand	-	-	-	-
34	OPEN		3,768	Demand	3,768	-	-	-
35	**Distribution Plant**	374-388	2,185,756		1,327,416	-	858,340	-
36								
37	**E. GENERAL PLANT**							
38	General Pt- Labor	389	219,750	Dist Lab	73,343	-	146,407	-
39	General Pt- Plant	398	-	Dist_Pt	-	-	-	-
40	**General Plant**	389-399	219,750		73,343	-	146,407	-
41								
42	**TOTAL UTILITY PLANT**		2,529,427		1,524,028	-	1,005,398	-

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Line	Account	No.	Distribution		Demand	Commodity	Customer	
43								
44	**II. DEPRECIATION RESERVE**							
45	Mains-Services Direct	108	-	Mains_Serv_Di	-	-	-	-
46	NGV Station	111	958	Demand	958	-	-	-
47	Storage Plant	108	10,325	Demand	10,325	-	-	-
48	Transmission Plant	109	1,433	Demand	1,433	-	-	-
49	Distribution- Mains	108M	206,859	Demand	206,859	-	-	-
50	Distribution- Services	108S	77,823	Customer	-	-	77,823	-
51	Distribution- Meters	108Mt	63,394	Customer	-	-	63,394	-
52	Distribution- Other	108O	46,871	Dist_Pt	29,448	-	17,423	-
53	General Pt- Labor	109	90,775	Dist_Lab	30,297	-	60,478	-
54	General Pt- Plant	398	-	Dist_Pt	-	-	-	-
55	**Depreciation Reserve**	108	498,438		279,320	-	219,118	-
56								
57	**III. OTHER RATE BASE ITEMS**							
58	Materials and Supplies, Prepay	105	-	Dist_OM	-	-	-	-
59	Storage Gas	107M	10,754	Demand	10,754	-	-	-
60	Cust Dep / Adv	Cust	(6,690)	Customer	-	-	(6,690)	-
61	Other Regulatory Assets	182P	23,015	Dist_Lab	7,681	-	15,333	-
62	Accum Deferred Income Taxes	190	(246,434)	Dist_Pt	(154,826)	-	(91,607)	-
63	CWC	CWC	50,476	Dist_OM	17,854	-	32,622	-
64	OPEN	CWC-Su	-	None	-	-	-	-
65	**Other Rate Base**		(168,880)		(118,538)	-	(50,342)	-
66								
67	**TOTAL RATE BASE**		1,862,109		1,126,171	-	735,938	-
68								
69	**I. OPERATING AND MAINTENANCE EXPENSES**							
70	**A. PRODUCTION EXPENSE**							
71								
72	Natural Gas City Gate Purchases	804	-	None	-	-	-	-
73	**Subtotal-Production expenses**	710-813	-		-	-	-	-
74								
75	**B. STORAGE, LNG EXPENSES**							
76	Storage Operations	841	700	Demand	700	-	-	-
77	**Subtotal- Storage expenses**	840-850	700		700	-	-	-
78								

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Line	Account	No.	Distribution		Demand	Commodity	Customer	
79	**C. TRANSMISSION EXPENSES**							
80	Mains Operating	850-856	-	Demand	-	-	-	-
81	Maintenance Other Equip.	865	174	Demand	174	-	-	-
82	**Subtotal-Transmission**	850-867	174		174	-	-	-
83								
84	**D. DISTRIBUTION O&M EXPENSE**							
85	Operation Supv & Engineering	870	0	Dist Lab	0	-	0	-
86	Distribution Load Dispatching	871	288	Demand	288	-	-	-
87	Mains and Services Expenses	874	4,186	Mains Serv	2,768	-	1,418	-
88	Meas & Reg Exp- General	875	29	Demand	29	-	-	-
89	Meas & Reg Exp- Industrial	876	0	Demand	0	-	-	-
90	Meter-Regulator- Citygate	878	917	Demand	917	-	-	-
91	Cust Installations Field	879	835	Customer	-	-	835	-
92	Other Expenses	880	3	Dist OM	1	-	2	-
93	Rents	881	16	Dist_OM	6	-	10	-
94	Maint Compressor Station Equip	879	-	Demand	-	-	-	-
95	Maint Supv & Engineering	885	-	Dist Lab	-	-	-	-
96	Maint of Mains	887	1,457	Demand	1,457	-	-	-
97	Maint. of Meas. & Reg. General	889	104	Demand	104	-	-	-
98	Maint. of Meas. & Reg.- Indust	890	-	Demand	-	-	-	-
99	Maint. of Services	892	615	Customer	-	-	615	-
100	Maint. of Meters & House Regulators	893	142	Customer	-	-	142	-
101	Maint. Other Equip.	894	61	Dist_Pt	38	-	23	-
102	**Dist. Oper. & Maint. Exp.**	870-899	8,653		5,608	-	3,045	-
103	**Total O&M Expenses**		9,527		6,483	-	3,045	-
104								
105	**II. CUSTOMER ACCOUNTS AND SERVICE**							
106	Supervision	901	-	Customer	-	-	-	-
107	Meter Reading Expenses	902	509	Customer	-	-	509	-
108	Customer Records & Collection Expen	903	850	Customer	-	-	850	-
109	Uncollectible Accounts	904	9,078	D-RevReq_PF	4,581	-	4,497	-
110	Miscellaneous Customer Accounts Exp	905	-	Customer	-	-	-	-
111	**Customer Accts. Exp.**	901-905	10,437		4,581	-	5,855	-
112								
113	**III. CUSTOMER ACCOUNTS ANL**							
114	Customer Assistance Expenses	908	3,652	Customer	-	-	3,652	-
115	Low Income Discount	908LI	-	Customer	-	-	-	-
116	Cust Assist Other	909-912	4,802	Customer	-	-	4,802	-
117	Advertising	913	692	Customer	-	-	692	-
118	**Customer Service Exp.**	908-919	9,146		-	-	9,146	-
119	**Customer Accts. & Serv. Exp.**	901-919	19,582		4,581	-	15,001	-

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Line	Account	No.	Distribution		Demand	Commodity	Customer	
120								
121	**E. ADMINISTRATIVE AND GENERAL**							
122	Administrative & General Salaries	920	17,114	Dist_Lab	5,712	-	11,402	-
123	Office Supplies & Expenses	921	7,904	Dist_Lab	2,638	-	5,266	-
124	Outside Services Employed	923	27,397	Dist_Lab	9,144	-	18,253	-
125	Property Insurance	924	1,987	Dist_Pt	1,249	-	739	-
126	Injuries & Damages	925	235	Dist_Lab	78	-	156	-
127	Employee Pensions and Benefits	926	5,796	Dist_Lab	1,934	-	3,862	-
128	Franchise Reqirements	927	-	Customer	-	-	-	-
129	Regulatory Commission Expenses	928	360	Customer	-	-	360	-
130	Misc General Exp	930	840	Dist_Lab	281	-	560	-
131	A&G- Rents	931	118	Dist_Lab	40	-	79	-
132	Maint General Plant	932	-	Dist_Lab	-	-	-	-
133	**Admin & Genl. Exp.**	920-932	61,753		21,075	-	40,677	-
134								
135	**Total Operating Expenses**		90,862		32,139	-	58,723	-
136								
137	**II. DEPRECIATION EXPENSE**							
138	Land and ROW	403	448	Dist_Pt	281	-	166	-
139	Storage Plant	403	1,841	Demand	1,841	-	-	-
140	Transmission Plant	404	523	Demand	523	-	-	-
141	Mains	403M	21,144	Demand	21,144	-	-	-
142	Services	403S	19,828	Customer	-	-	19,828	-
143	Meters	403Mt	7,248	Customer	-	-	7,248	-
144	Distr Other	403O	687	Dist_Pt	432	-	255	-
145	General Pt- Labor	404	22,032	Dist_Lab	7,353	-	14,679	-
146	General Pt- Plant	404	-	Dist_Lab	-	-	-	-
147	Mains/Services Direct	404	-	Dist_Lab	-	-	-	-
148	NGV Station	404	37	Dist_Lab	12	-	24	-
149	Amort Regulatory Debits	403	-	Demand	-	-	-	-
150	**Depreciation Expense**		73,787		31,587	-	42,200	-
151								
152	**III. TAXES and OTHER**							
153	**A. GENERAL TAXES**							
154	Taxes- Labor based	408L	3,269	Dist_Lab	1,091	-	2,178	-
155	Taxes- Plant based	408P	1,076	Dist_Pt	676	-	400	-
156	Other Taxes	408O	1,047	Dist_Pt	658	-	389	-
157	BPU	408	3,587	Dist_Pt	2,254	-	1,334	-
158	**General Taxes**		8,980		4,679	-	4,301	-
159								
160	**B. GROSS RECEIPTS TAX**							
161	Gross Receipts tax		-	D-RevReq_PF	-	-	-	-
162	**Gross Receipts Tax**		-		-	-	-	-

Classify
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Classification

Line	Account	No.		Distribution		Demand	Commodity	Customer	
163									
164	**B. FEDERAL / STATE INCOME TAXES**								
165	Federal Income Tax Expense			16,480	Dist Pretax	10,876	-	5,604	-
166	**Income Taxes**	409-411		16,480		10,876	-	5,604	-
167	**Total Taxes**	408-411		25,459		15,555	-	9,904	-
168									
169	**TOTAL EXPENSES**			190,109		79,280	-	110,828	-
170									
171	**IV. OPERATING REVENUES at Present Rates**								
172	Base Delivery	480		288,211	D-RevReq PF	145,441	-	142,770	-
173	Commodity	480C		-	None	-	-	-	-
174	Rent from Gas Property	488		-	None	-	-	-	-
175	Late payment	493		769	D-RevReq PF	388	-	381	-
176	Other Revenues	495		1,442	Customer	-	-	1,442	-
177	Marketer	495		34	Customer	-	-	34	-
178	Turn On	495		564	Customer	-	-	564	-
179	Capacity Release	415/416		144	Demand	144	-	-	-
180	Adjust to Case Model			-	D-RevReq PF	-	-	-	-
181	**TOTAL REVENUE**		- -	291,164	-	145,973	-	145,191	
182									
183	**V. Net Income at Present Rates**		- -	101,055	-	66,692	-	34,363	-
184									
185	**RATE BASE**			1,862,109		1,126,171	-	735,938	-
186	Return on Rate Base			5.43%		5.92%	-	4.67%	
187									
188	**REVENUE REQUIREMENTS**								
189	Target Rate of Return			8.3100%		8.3100%	8.3100%	8.3100%	
190	Rate Base			1,862,109		1,126,171	0	735,938	-
191									
192	Operating expenses, Depreciation			155,571		59,145	0	96,427	-
193	Uncollectible accounts			9,750	Dist_Unc_RR	4,978	-	4,772	-
194	General taxes / Other			9,188	Dist_Unc_RR	4,691	-	4,497	-
195	Subtotal- Operating Costs to recover			174,510		68,814	0	105,696	-
196									
197	Target Return on rate base			154,741		93,585	0	61,156	-
198	Income Taxes	24.22%		37,472		22,662	0	14,809	-
199									
200	Subtotal- Rev Req before GRT			366,723		185,061	0	181,662	-
201	GRT needed	0.00%		0		0	0	0	-
202	**TOTAL REVENUE REQUIREMENT**			366,723		185,061	0	181,662	-
203									

DistDem
Class Allocation - Distribution Demand
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Class Allocation - Distribution Demand

Line	Account	No.	Balance	Allocator	Residential Heat	Residential Non-Heat	Small General SGS	General GDS	Large Volume LVD	NGV	Non-Firm
1	**I. GAS PLANT IN SERVICE**										
2	**A. INTANGIBLE PLANT**										
3	Franchise & Consents	302	-	None	-	-	-	-	-	-	-
4	Software & Other Intangibles	303I	-	None	-	-	-	-	-	-	-
5	**Intangible Plant**		-		-	-	-	-	-	-	-
6											
7	**B. Storage / LNG**										
8	Land & Land Rights	360	68	Peak_Avg	39	1	4	17	5	0	2
9	Structures and Improvements	361	6,512	Peak_Avg	3,751	100	376	1,593	510	1	181
10	Gas Holders- LNG/ Storage	362	3,400	Peak_Avg	1,958	52	196	831	266	1	95
11	363G- Vapor / Compress/ Regulating		85,911	Peak_Avg	49,481	1,324	4,964	21,010	6,725	13	2,394
12	NGV Station	363	2,298	NGV Direct	-	-	-	-	-	2,298	-
13	**Storage Plant**	304-338	98,189		55,229	1,478	5,541	23,450	7,506	2,313	2,673
14											
15	**C. TRANSMISSION PLANT**										
16	Land	365	631	Peak_Avg	363	10	36	154	49	0	18
17	Structures and Improvements	366	-	Peak_Avg	-	-	-	-	-	-	-
18	Mains	367	15,849	Peak_Avg	9,128	244	916	3,876	1,241	2	442
19	Measuring and Reg. Sta. Equip.	369	8,600	Peak_Avg	4,953	133	497	2,103	673	1	240
20	**Transmission Plant**	360-368	25,080		14,445	387	1,449	6,133	1,963	4	699
21											
22	**D. DISTRIBUTION PLANT**										
23	Land and Land Rights	374	2,789	DistD-Pt	1,565	42	162	686	227	5	102
24	Structures and Improvements	375	6,652	DistD-Pt	3,733	100	388	1,636	541	12	243
25	Mains	376	1,238,550	Peak_Avg	713,344	19,094	71,568	302,889	96,947	189	34,519
26	Mains Direct	376TC	14,248	Mains Direct	-	-	-	-	3,476	-	10,772
27	Meas. & Reg. Stat. Equip. - General	378	44,669	Peak_Avg	25,727	689	2,581	10,924	3,496	7	1,245
28	Services	380	-	Service_Invest	-	-	-	-	-	-	-
29	Services Direct	380D	-	None	-	-	-	-	-	-	-
30	Meters / Install	381/382	-	None	-	-	-	-	-	-	-
31	Ind M&R	385	16,742	Ind M&R	-	-	2,847	10,993	2,901	-	-
32	House Reg/ Install	384	-	None	-	-	-	-	-	-	-
33	OPEN		-	None	-	-	-	-	-	-	-
34	OPEN		3,768	Mains_Ser_Dir	-	-	-	-	1,018	-	2,750
35	**Distribution Plant**	374-388	1,327,416		744,368	19,924	77,546	327,127	108,606	213	49,631
36											
37	**E. GENERAL PLANT**										
38	General Pt- Labor	389	73,343	DistD-Lab	42,024	1,125	4,216	17,844	5,804	11	2,319
39	General Pt- Plant	398	-	DistD-Pt	-	-	-	-	-	-	-
40	**General Plant**	389-399	73,343		42,024	1,125	4,216	17,844	5,804	11	2,319
41											
42	**TOTAL UTILITY PLANT**		1,524,028		856,066	22,914	88,752	374,555	123,878	2,540	55,322
43											

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Class Allocation - Distribution Demand

Line	Account	No.	Balance	Allocator	Residential Heat	Residential Non-Heat	Small General SGS	General GDS	Large Volume LVD	NGV	Non-Firm
44	**II. DEPRECIATION RESERVE**										
45	Mains-Services Direct	108	-	Mains_Ser_Dir	-	-	-	-	-	-	-
46	NGV Station	111	958	NGV Direct	-	-	-	-	-	958	-
47	Storage Plant	108	10,325	Peak_Avg	5,947	159	597	2,525	808	2	288
48	Transmission Plant	109	1,433	Peak_Avg	825	22	83	350	112	0	40
49	Distribution- Mains	108M	206,859	Peak_Avg	119,141	3,189	11,953	50,588	16,192	32	5,765
50	Distribution- Services	108S	-	Service_Invest	-	-	-	-	-	-	-
51	Distribution- Meters	108Mt	-	None	-	-	-	-	-	-	-
52	Distribution- Other	108O	29,448	DistD-Pt	16,524	442	1,716	7,241	2,397	51	1,076
53	General Pt- Labor	109	30,297	DistD-Lab	17,360	465	1,742	7,371	2,397	5	958
54	General Pt- Plant	398	-	DistD-Pt	-	-	-	-	-	-	-
55	**Depreciation Reserve**	108	279,320		159,796	4,277	16,090	68,075	21,906	1,048	8,127
56											
57	**III. OTHER RATE BASE ITEMS**										
58	Materials and Supplies, Prepay	105	-	DistD-OM	-	-	-	-	-	-	-
59	Storage Gas	107M	10,754	Firm_Winter	6,260	174	634	2,876	807	2	-
60	Cust Dep / Adv	Cust	-	None	-	-	-	-	-	-	-
61	Other Regulatory Assets	182P	7,681	DistD-Lab	4,401	118	442	1,869	608	1	243
62	Accum Deferred Income Taxes	190	(154,826)	DistD-Pt	(86,880)	(2,325)	(9,022)	(38,070)	(12,602)	(270)	(5,657)
63	CWC	CWC	17,854	DistD-OM	10,408	360	1,039	4,149	1,347	5	546
64	OPEN	CWC-Su	-	None	-	-	-	-	-	-	-
65	**Other Rate Base**		(118,538)		(65,810)	(1,674)	(6,908)	(29,177)	(9,841)	(261)	(4,868)
66											
67	**TOTAL RATE BASE**		1,126,171		630,460	16,963	65,754	277,303	92,132	1,231	42,328
68											
69	**I. OPERATING AND MAINTENANCE EXPENSES**										
70	**A. PRODUCTION EXPENSE**										
71	Purchased Gas										
72	Natural Gas City Gate Purchases	804	-	None	-	-	-	-	-	-	-
73	**Subtotal-Production expenses**	710-813	-		-	-	-	-	-	-	-
74											
75	**B. STORAGE, LNG EXPENSES**										
76	Storage Operations	841	700	Peak_Avg	403	11	40	171	55	0	20
77	**Subtotal- Storage expenses**	840-850	700		403	11	40	171	55	0	20
78											

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Line	Account	No.	Balance	Allocator	Residential Heat	Residential Non-Heat	Small General SGS	General GDS	Large Volume LVD	NGV	Non-Firm
79	**C. TRANSMISSION EXPENSES**										
80	Mains Operating	850-856	-	Peak_Avg	-	-	-	-	-	-	-
81	Maintenance Other Equip.	865	174	Peak_Avg	100	3	10	43	14	0	5
82	**Subtotal-Transmission**	850-867	174		100	3	10	43	14	0	5
83											
84	**D. DISTRIBUTION O&M EXPENSE**										
85	Operation Supv & Engineering	870	0	DistD-Lab	0	0	0	0	0	0	0
86	Distribution Load Dispatching	871	288	Gas_Del_Firm	159	5	16	77	31	0	-
87	Mains and Services Expenses	874	2,768	DistD-MainsSvc	1,576	42	158	669	222	0	100
88	Meas & Reg Exp- General	875	29	Peak_Avg	17	0	2	7	2	0	1
89	Meas & Reg Exp- Industrial	876	0	Ind M&R	-	-	0	0	0	-	-
90	Meter-Regulator- Citygate	878	917	Peak_Avg	528	14	53	224	72	0	26
91	Cust Installations Field	879	-	None	-	-	-	-	-	-	-
92	Other Expenses	880	1	DistD-OM	1	0	0	0	0	0	0
93	Rents	881	6	DistD-OM	3	0	0	1	0	0	0
94	Maint Compressor Station Equip	879	-	None	-	-	-	-	-	-	-
95	Maint Supv & Engineering	885	-	None	-	-	-	-	-	-	-
96	Maint of Mains	887	1,457	Peak_Avg	839	22	84	356	114	0	41
97	Maint. of Meas. & Reg. General	889	104	Peak_Avg	60	2	6	25	8	0	3
98	Maint. of Meas. & Reg.- Indust	890	-	None	-	-	-	-	-	-	-
99	Maint. of Services	892	-	None	-	-	-	-	-	-	-
100	Maint. of Meters & House Regulators	893	-	None	-	-	-	-	-	-	-
101	Maint. Other Equip.	894	38	DistD-Pt	21	1	2	9	3	0	1
102	**Dist. Oper. & Maint. Exp.**	870-899	5,608		3,205	86	321	1,371	452	1	172
103	**Total O&M Expenses**		6,483		3,708	100	372	1,584	521	1	196
104											
105	**II. CUSTOMER ACCOUNTS AND SERVICE**										
106	Supervision	901	-	None	-	-	-	-	-	-	-
107	Meter Reading Expenses	902	-	None	-	-	-	-	-	-	-
108	Customer Records & Collection Expense	903	-	None	-	-	-	-	-	-	-
109	Uncollectible Accounts	904	4,581	WriteOff_Del	2,967	225	285	753	233	3	115
110	Miscellaneous Customer Accounts Exp.	905	-	None	-	-	-	-	-	-	-
111	**Customer Accts. Exp.**	901-905	4,581		2,967	225	285	753	233	3	115
112											
113	**III. CUSTOMER ACCOUNTS AND IN**										
114	Customer Assistance Expenses	908	-	None	-	-	-	-	-	-	-
115	Low Income Discount	908LI	-	None	-	-	-	-	-	-	-
116	Cust Assist Other	909-912	-	None	-	-	-	-	-	-	-
117	Advertising	913	-	None	-	-	-	-	-	-	-
118	**Customer Service Exp.**	908-919	-		-	-	-	-	-	-	-
119	**Customer Accts. & Serv. Exp.**	901-919	4,581		2,967	225	285	753	233	3	115

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Line	Account	No.	Balance	Allocator	Residential Heat	Residential Non-Heat	Small General SGS	General GDS	Large Volume LVD	NGV	Non-Firm
120											
121	**E. ADMINISTRATIVE AND GENERAL**										
122	Administrative & General Salaries	920	5,712	DistD-Lab	3,273	88	328	1,390	452	1	181
123	Office Supplies & Expenses	921	2,638	DistD-Lab	1,512	40	152	642	209	0	83
124	Outside Services Employed	923	9,144	DistD-Lab	5,239	140	526	2,225	724	1	289
125	Property Insurance	924	1,249	DistD-Pt	701	19	73	307	102	2	46
126	Injuries & Damages	925	78	DistD-Lab	45	1	5	19	6	0	2
127	Employee Pensions and Benefits	926	1,934	DistD-Lab	1,108	30	111	471	153	0	61
128	Franchise Reqirements	927	-	None	-	-	-	-	-	-	-
129	Regulatory Commission Expenses	928	-	None	-	-	-	-	-	-	-
130	Misc General Exp	930	281	DistD-Lab	161	4	16	68	22	0	9
131	A&G- Rents	931	40	DistD-Lab	23	1	2	10	3	0	1
132	Maint General Plant	932	-	DistD-Lab	-	-	-	-	-	-	-
133	**Admin & Genl. Exp.**	920-932	21,075		12,061	323	1,213	5,131	1,670	5	673
134											
135	**Total Operating Expenses**		32,139		18,736	648	1,870	7,468	2,424	9	984
136											
137	**II. DEPRECIATION EXPENSE**										
138	Land and ROW	403	281	DistD-Pt	158	4	16	69	23	0	10
139	Storage Plant	403	1,841	Peak_Avg	1,060	28	106	450	144	0	51
140	Transmission Plant	404	523	Peak_Avg	301	8	30	128	41	0	15
141	Mains	403M	21,144	DistD-Mains	12,039	322	1,208	5,112	1,695	3	764
142	Services	403S	-	Service_Invest	-	-	-	-	-	-	-
143	Meters	403Mt	-	None	-	-	-	-	-	-	-
144	Distr Other	403O	432	DistD-Pt	242	6	25	106	35	1	16
145	General Pt- Labor	404	7,353	DistD-Lab	4,213	113	423	1,789	582	1	233
146	General Pt- Plant	404	-	DistD-Pt	-	-	-	-	-	-	-
147	Mains/Services Direct	404	-	Mains_Ser_Dir	-	-	-	-	-	-	-
148	NGV Station	404	12	NGV Direct	-	-	-	-	-	12	-
149	Amort Regulatory Debits	403	-	NGV Direct	-	-	-	-	-	-	-
150	**Depreciation Expense**		31,587		18,014	482	1,809	7,654	2,520	18	1,089
151											
152	**III. TAXES and OTHER**										
153	**A. GENERAL TAXES**										
154	Taxes- Labor based	408L	1,091	DistD-Lab	625	17	63	265	86	0	35
155	Taxes- Plant based	408P	676	DistD-Pt	379	10	39	166	55	1	25
156	Other Taxes	408O	658	RateBase	426	32	41	108	33	0	17
157	Tax Amortization	408	2,254	RateBase	1,460	111	140	371	114	1	57
158	**General Taxes**		4,679		2,890	170	283	910	289	3	132
159											
160	**B. GROSS RECEIPTS TAX**										
161	Gross Receipts tax		-	None	-	-	-	-	-	-	-
162	**Gross Receipts Tax**		-		-	-	-	-	-	-	-

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Line	Account	No.	Balance	Allocator	Residential Heat	Residential Non-Heat	Small General SGS	General GDS	Large Volume LVD	NGV	Non-Firm
163											
164	**B. FEDERAL / STATE INCOME TAXES**										
165	Federal Income Tax Expense		10,876	DistD-Pretax	7,142	411	774	2,427	(0)	6	117
166	**Income Taxes**	409-411	10,876		7,142	411	774	2,427	(0)	6	117
167	**Total Taxes**	408-411	15,555		10,032	581	1,057	3,337	289	9	249
168											
169	**TOTAL EXPENSES**		79,280		46,783	1,711	4,735	18,460	5,233	37	2,322
170											
171	**IV. OPERATING REVENUES at Present Rates**										
172	Base Delivery	480	145,441	Total_Del_Rev	90,242	4,209	9,449	33,243	5,199	75	3,024
173	Commodity	480C	-	None	-	-	-	-	-	-	-
174	Rent from Gas Property	488	-	DistD-Pt	-	-	-	-	-	-	-
175	Late payment	493	388	WriteOff_Del	251	19	24	64	20	0	10
176	Other Revenues	495	-	None	-	-	-	-	-	-	-
177	Marketer	495	-	None	-	-	-	-	-	-	-
178	Turn On	495	-	None	-	-	-	-	-	-	-
179	Capacity Release	415/416	144	Peak_Avg	83	2	8	35	11	0	4
180	Adjust to Case Model		-	Total_Del_Rev	-	-	-	-	-	-	-
181	**TOTAL REVENUE**		145,973		90,576	4,230	9,481	33,342	5,230	75	3,038
182											
183	**V. Net Income at Present Rates**		66,692		43,793	2,519	4,746	14,882	(3)	38	716
184											
185	**RATE BASE**		1,126,171		630,460	16,963	65,754	277,303	92,132	1,231	42,328
186	Return on Rate Base		5.92%		6.95%	14.85%	7.22%	5.37%	(0.00%)	3.09%	1.69%
187											
188	**REVENUE REQUIREMENTS**										
189	Target Rate of Return		8.3100%		8.3100%	8.3100%	8.3100%	8.3100%	8.3100%	8.3100%	8.3100%
190	Rate Base		1,126,171		630,460	16,963	65,754	277,303	92,132	1,231	42,328
191											
192	Operating expenses, Depreciation		59,145		33,784	905	3,393	14,370	4,711	24	1,957
193	Uncollectible accounts		4,978	DistD-Unc_RR	2,920	136	275	858	569	6	215
194	General taxes / Other		4,691	RateBase	3,038	231	292	771	238	3	118
195	Subtotal- Operating Costs to recover		68,814		39,742	1,272	3,960	15,999	5,518	33	2,290
196											
197	Target Return on rate base		93,585		52,391	1,410	5,464	23,044	7,656	102	3,517
198	Income Taxes		22,662	24.22%	12,687	341	1,323	5,580	1,854	25	852
199											
200	Subtotal- Rev Req before GRT		185,061		104,820	3,023	10,747	44,623	15,028	160	6,659
201	GRT needed		0	-	0	0	0	0	0	0	0
202	**TOTAL REVENUE REQUIREMENT**		185,061		104,820	3,023	10,747	44,623	15,028	160	6,659
203											

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Line	Account	No.	Balance	Allocator	Residential Heat	Residential Non-Heat	Small General SGS	General GDS	Large Volume LVD	NGV	Non-Firm
1	**I. GAS PLANT IN SERVICE**										
2	**A. INTANGIBLE PLANT**										
3	Franchise & Consents	302	651	Cust_Avg	539	63	35	14	0	0	0
4	Software & Other Intangibles	303I	-	None	-	-	-	-	-	-	-
5	**Intangible Plant**		651		539	63	35	14	0	0	0
6											
7	**B. Storage / LNG**										
8	Land & Land Rights	360	-	None	-	-	-	-	-	-	-
9	Structures and Improvements	361	-	None	-	-	-	-	-	-	-
10	Gas Holders- LNG/ Storage	362	-	None	-	-	-	-	-	-	-
11	363G- Vapor / Compress/ Regulating		-	None	-	-	-	-	-	-	-
12	NGV Station	363	-	DistC-Lab	-	-	-	-	-	-	-
13	**Storage Plant**	304-338	-		-	-	-	-	-	-	-
14											
15	**C. TRANSMISSION PLANT**										
16	Land	365	-	None	-	-	-	-	-	-	-
17	Structures and Improvements	366	-	None	-	-	-	-	-	-	-
18	Mains	367	-	None	-	-	-	-	-	-	-
19	Measuring and Reg. Sta. Equip.	369	-	None	-	-	-	-	-	-	-
20	**Transmission Plant**	360-368	-		-	-	-	-	-	-	-
21											
22	**D. DISTRIBUTION PLANT**										
23	Land and Land Rights	374	1,650	DistC-Pt	1,280	167	117	71	6	0	10
24	Structures and Improvements	375	3,936	DistC-Pt	3,052	397	279	170	14	0	24
25	Mains	376	-	Cust_Avg	-	-	-	-	-	-	-
26	Mains Direct	376TC	-	None	-	-	-	-	-	-	-
27	Meas. & Reg. Stat. Equip. - General	378	-	None	-	-	-	-	-	-	-
28	Services	380	635,224	Service_Invest	493,753	67,291	46,140	28,041	-	-	-
29	Services Direct	380D	6,381	Services Direct	-	-	-	-	2,096	-	4,285
30	Meters / Install	381/382	198,942	Meter_Invest	157,878	17,714	13,397	8,322	858	1	773
31	Ind M&R	385	-	Ind M&R	-	-	-	-	-	-	-
32	House Reg/ Install	384	12,207	Meter_Invest	9,688	1,087	822	511	53	0	47
33	OPEN		-	None	-	-	-	-	-	-	-
34	OPEN		-	None	-	-	-	-	-	-	-
35	**Distribution Plant**	374-388	858,340		665,650	86,656	60,754	37,115	3,026	1	5,139
36											
37	**E. GENERAL PLANT**										
38	General Pt- Labor	389	146,407	DistC-Lab	119,298	14,464	8,556	3,885	75	0	129
39	General Pt- Plant	398	-	DistC-Pt	-	-	-	-	-	-	-
40	**General Plant**	389-399	146,407		119,298	14,464	8,556	3,885	75	0	129
41											
42	**TOTAL UTILITY PLANT**		1,005,398		785,487	101,183	69,345	41,013	3,101	1	5,268
43											

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Line	Account	No.	Balance	Allocator	Residential Heat	Residential Non-Heat	Small General SGS	General GDS	Large Volume LVD	NGV	Non-Firm
44	**II. DEPRECIATION RESERVE**										
45	Mains-Services Direct	108	-	Mains_Ser_Dir	-	-	-	-	-	-	-
46	NGV Station	111	-	NGV Direct	-	-	-	-	-	-	-
47	Storage Plant	108	-	None	-	-	-	-	-	-	-
48	Transmission Plant	109	-	None	-	-	-	-	-	-	-
49	Distribution- Mains	108M	-	Cust_Avg	-	-	-	-	-	-	-
50	Distribution- Services	108S	77,823	Service_Invest	60,491	8,244	5,653	3,435	-	-	-
51	Distribution- Meters	108Mt	63,394	Meter_Invest	50,309	5,645	4,269	2,652	273	0	246
52	Distribution- Other	108O	17,423	DistC-Pt	13,512	1,759	1,233	753	61	0	104
53	General Pt- Labor	109	60,478	DistC-Lab	49,280	5,975	3,534	1,605	31	0	53
54	General Pt- Plant	398	-	DistC-Pt	-	-	-	-	-	-	-
55	**Depreciation Reserve**	108	219,118		173,591	21,622	14,689	8,445	366	0	404
56											
57	**III. OTHER RATE BASE ITEMS**										
58	Materials and Supplies, Prepay	105	-	DistC-OM	-	-	-	-	-	-	-
59	Storage Gas	107M	-	DistC-OM	-	-	-	-	-	-	-
60	Cust Dep / Adv	Cust	(6,690)	CustDep	(3,904)	(368)	(877)	(1,365)	(175)	(1)	-
61	Other Regulatory Assets	182P	15,333	DistC-Lab	12,494	1,515	896	407	8	0	14
62	Accum Deferred Income Taxes	190	(91,607)	DistC-Pt	(71,042)	(9,249)	(6,484)	(3,961)	(323)	(0)	(548)
63	CWC	CWC	32,622	DistC-OM	26,149	3,082	1,909	1,229	154	2	96
64	OPEN	CWC-Su	-	None	-	-	-	-	-	-	-
65	**Other Rate Base**		(50,342)		(36,303)	(5,019)	(4,555)	(3,690)	(337)	1	(439)
66											
67	**TOTAL RATE BASE**		735,938		575,593	74,541	50,101	28,878	2,399	1	4,425
68											
69	**I. OPERATING AND MAINTENANCE EXPENSES**										
70	**A. PRODUCTION EXPENSE**										
71	Purchased Gas										
72	Natural Gas City Gate Purchases	804	-	None	-	-	-	-	-	-	-
73	**Subtotal-Production expenses**	710-813	-		-	-	-	-	-	-	-
74											
75	**B. STORAGE, LNG EXPENSES**										
76	Storage Operations	841	-	None	-	-	-	-	-	-	-
77	**Subtotal- Storage expenses**	840-850	-		-	-	-	-	-	-	-
78											

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Line	Account	No.	Balance	Allocator	Residential Heat	Residential Non-Heat	Small General SGS	General GDS	Large Volume LVD	NGV	Non-Firm
79	**C. TRANSMISSION EXPENSES**										
80	Mains Operating	850-856	-	None	-	-	-	-	-	-	-
81	Maintenance Other Equip.	865	-	None	-	-	-	-	-	-	-
82	**Subtotal-Transmission**	850-867	-		-	-	-	-	-	-	-
83											
84	**D. DISTRIBUTION O&M EXPENSE**										
85	Operation Supv & Engineering	870	0	DistC-Lab	0	0	0	0	0	0	0
86	Distribution Load Dispatching	871	-	Gas_Deliveries	-	-	-	-	-	-	-
87	Mains and Services Expenses	874	1,418	DistC-MainsSvc	1,091	149	102	62	5	-	9
88	Meas & Reg Exp- General	875	-	None	-	-	-	-	-	-	-
89	Meas & Reg Exp- Industrial	876	-	None	-	-	-	-	-	-	-
90	Meter-Regulator- Citygate	878	-	Meter_Invest	-	-	-	-	-	-	-
91	Cust Installations Field	879	835	Cust_Avg	692	81	45	17	0	0	0
92	Other Expenses	880	2	DistC-OM	2	0	0	0	0	0	0
93	Rents	881	10	DistC-OM	8	1	1	0	0	0	0
94	Maint Compressor Station Equip	879	-	None	-	-	-	-	-	-	-
95	Maint Supv & Engineering	885	-	DistC-Lab	-	-	-	-	-	-	-
96	Maint of Mains	887	-	Cust_Avg	-	-	-	-	-	-	-
97	Maint. of Meas. & Reg. General	889	-	None	-	-	-	-	-	-	-
98	Maint. of Meas. & Reg.- Indust	890	-	None	-	-	-	-	-	-	-
99	Maint. of Services	892	615	Service_Invest	478	65	45	27	-	-	-
100	Maint. of Meters & House Regulators	893	142	Meter_Invest	113	13	10	6	1	0	1
101	Maint. Other Equip.	894	23	DistC-Pt	18	2	2	1	0	0	0
102	**Dist. Oper. & Maint. Exp.**	870-899	3,045		2,401	311	203	114	6	0	10
103	**Total O&M Expenses**		3,045		2,401	311	203	114	6	0	10
104											
105	**II. CUSTOMER ACCOUNTS AND SERVICE**										
106	Supervision	901	-	None	-	-	-	-	-	-	-
107	Meter Reading Expenses	902	509	Cust_Avg	421	49	27	11	0	0	0
108	Customer Records & Collection Expense	903	850	Cust_Avg	704	82	46	18	0	0	0
109	Uncollectible Accounts	904	4,497	WriteOff_Del	2,913	221	280	739	228	3	113
110	Miscellaneous Customer Accounts Exp.	905	-	Cust_Avg	-	-	-	-	-	-	-
111	**Customer Accts. Exp.**	901-905	5,855		4,038	352	353	768	229	3	113
112											
113	**III. CUSTOMER ACCOUNTS AND IN**										
114	Customer Assistance Expenses	908	3,652	Cust_Avg	3,025	353	197	76	1	0	1
115	Low Income Discount	908LI	-	Total_Del_Rev	-	-	-	-	-	-	-
116	Cust Assist Other	909-912	4,802	Cust_Avg	3,978	464	259	100	1	0	1
117	Advertising	913	692	Cust_Avg	573	67	37	14	0	0	0
118	**Customer Service Exp.**	908-919	9,146		7,577	883	493	190	2	0	1
119	**Customer Accts. & Serv. Exp.**	901-919	15,001		11,615	1,236	846	958	230	3	114

DistCus
Class Allocation - Distribution Customer
Schedule HSG-4-6B
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Elizabethtown Gas Company
Peak and Average Embedded Cost of Service Study (ECOSS)
Post Test Year 2025-03-31 (Using 2024 6+6)
Class Allocation - Distribution Customer

Line	Account	No.	Balance	Allocator	Residential Heat	Residential Non-Heat	Small General SGS	General GDS	Large Volume LVD	NGV	Non-Firm
120											
121	**E. ADMINISTRATIVE AND GENERAL**										
122	Administrative & General Salaries	920	11,402	DistC-Lab	9,291	1,126	666	303	6	0	10
123	Office Supplies & Expenses	921	5,266	DistC-Lab	4,291	520	308	140	3	0	5
124	Outside Services Employed	923	18,253	DistC-Lab	14,873	1,803	1,067	484	9	0	16
125	Property Insurance	924	739	DistC-Pt	573	75	52	32	3	0	4
126	Injuries & Damages	925	156	DistC-Lab	127	15	9	4	0	0	0
127	Employee Pensions and Benefits	926	3,862	DistC-Lab	3,147	381	226	102	2	0	3
128	Franchise Reqirements	927	-	RateBase	-	-	-	-	-	-	-
129	Regulatory Commission Expenses	928	360	RateBase	233	18	22	59	18	0	9
130	Misc General Exp	930	560	DistC-Lab	456	55	33	15	0	0	0
131	A&G- Rents	931	79	DistC-Lab	64	8	5	2	0	0	0
132	Maint General Plant	932	-	DistC-Lab	-	-	-	-	-	-	-
133	**Admin & Genl. Exp.**	920-932	40,677		33,056	4,002	2,388	1,141	41	0	48
134											
135	**Total Operating Expenses**		58,723		47,072	5,549	3,437	2,213	277	3	173
136											
137	**II. DEPRECIATION EXPENSE**										
138	Land and ROW	403	166	DistC-Pt	129	17	12	7	1	0	1
139	Storage Plant	403	-	None	-	-	-	-	-	-	-
140	Transmission Plant	404	-	None	-	-	-	-	-	-	-
141	Mains	403M	-	DistC-Mains	-	-	-	-	-	-	-
142	Services	403S	19,828	Service_Invest	15,412	2,100	1,440	875	-	-	-
143	Meters	403Mt	7,248	Meter_Invest	5,752	645	488	303	31	0	28
144	Distr Other	403O	255	DistC-Pt	198	26	18	11	1	0	2
145	General Pt- Labor	404	14,679	DistC-Lab	11,961	1,450	858	389	7	0	13
146	General Pt- Plant	404	-	DistC-Pt	-	-	-	-	-	-	-
147	Mains/Services Direct	404	-	Mains_Ser_Dir	-	-	-	-	-	-	-
148	NGV Station	404	24	NGV Direct	-	-	-	-	-	24	-
149	Amort Regulatory Debits	403	-	DistC-Lab	-	-	-	-	-	-	-
150	**Depreciation Expense**		42,200		33,451	4,238	2,816	1,586	40	25	44
151											
152	**III. TAXES and OTHER**										
153	**A. GENERAL TAXES**										
154	Taxes- Labor based	408L	2,178	DistC-Lab	1,775	215	127	58	1	0	2
155	Taxes- Plant based	408P	400	DistC-Pt	310	40	28	17	1	0	2
156	Other Taxes	408O	389	RateBase	252	19	24	64	20	0	10
157	Tax Amortization	408	1,334	RateBase	864	66	83	219	68	1	33
158	**General Taxes**		4,301		3,201	340	263	358	90	1	48
159											
160	**B. GROSS RECEIPTS TAX**										
161	Gross Receipts tax		-	None	-	-	-	-	-	-	-
162	**Gross Receipts Tax**		-		-	-	-	-	-	-	-

DistCus
Class Allocation - Distribution Customer
Schedule HSG-4-6B
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Elizabethtown Gas Company
Peak and Average Embedded Cost of Service Study (ECOSS)
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Class Allocation - Distribution Customer

Line	Account	No.	Balance	Allocator	Residential Heat	Residential Non-Heat	Small General SGS	General GDS	Large Volume LVD	NGV	Non-Firm
163											
164	**B. FEDERAL / STATE INCOME TAXES**										
165	Federal Income Tax Expense		5,604	DistC-Pretax	896	(827)	406	4,058	683	6	381
166	**Income Taxes**	409-411	5,604		896	(827)	406	4,058	683	6	381
167	**Total Taxes**	408-411	9,904		4,097	(487)	669	4,417	773	7	428
168											
169	**TOTAL EXPENSES**		110,828		84,620	9,300	6,921	8,216	1,090	35	645
170											
171	**IV. OPERATING REVENUES at Present Rates**										
172	Base Delivery	480	142,770	Total_Del_Rev	88,585	4,132	9,275	32,633	5,103	73	2,969
173	Commodity	480C	-	None	-	-	-	-	-	-	-
174	Rent from Gas Property	488	-	Peak_Sendout	-	-	-	-	-	-	-
175	Late payment	493	381	WriteOff_Del	247	19	24	63	19	0	10
176	Other Revenues	495	1,442	Gas_Del_Firm	798	25	79	386	154	0	-
177	Marketer	495	34	Gas_Del_Firm	19	1	2	9	4	0	-
178	Turn On	495	564	Cust_Avg	467	54	30	12	0	0	0
179	Capacity Release	415/416	-	None	-	-	-	-	-	-	-
180	Adjust to Case Model		-	Total_Del_Rev	-	-	-	-	-	-	-
181	**TOTAL REVENUE**		145,191		90,115	4,230	9,411	33,103	5,280	74	2,978
182											
183	**V. Net Income at Present Rates**		34,363		5,495	(5,070)	2,489	24,887	4,190	39	2,334
184											
185	**RATE BASE**		735,938		575,593	74,541	50,101	28,878	2,399	1	4,425
186	Return on Rate Base		4.67%		0.95%	(6.80%)	4.97%	86.18%	174.66%	2579.61%	52.74%
187											
188	**REVENUE REQUIREMENTS**										
189	Target Rate of Return		8.3100%		8.3100%	8.3100%	8.3100%	8.3100%	8.3100%	8.3100%	8.3100%
190	Rate Base		735,938		575,593	74,541	50,101	28,878	2,399	1	4,425
191											
192	Operating expenses, Depreciation		96,427		77,611	9,566	5,973	3,060	89	25	104
193	Uncollectible accounts		4,772	DistC-Unc_RR	3,610	745	270	113	14	1	20
194	General taxes / Other		4,497	RateBase	2,913	221	280	739	228	3	113
195	Subtotal- Operating Costs to recover		105,696		84,133	10,532	6,523	3,912	331	29	237
196											
197	Target Return on rate base		61,156		47,832	6,194	4,163	2,400	199	0	368
198	Income Taxes		14,809	24.22%	11,583	1,500	1,008	581	48	0	89
199											
200	Subtotal- Rev Req before GRT		181,662		143,547	18,226	11,695	6,893	578	29	694
201	GRT needed		0	-	0	0	0	0	0	0	0
202	**TOTAL REVENUE REQUIREMENT**		181,662		143,547	18,226	11,695	6,893	578	29	694
203											

Assigned
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Elizabethtown Gas Company
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Line	Account	No.	Balance	Functional	Distribution	Class Allocation SuppDem	DistDem	DistCus	BillCus
1	**I. GAS PLANT IN SERVICE**								
2	**A. INTANGIBLE PLANT**								
3	Franchise & Consents	302	651	Dist	Customer	-	-	Cust_Avg	-
4	Software & Other Intangibles	303I	0	-	-	-	-	-	-
5	**Intangible Plant**		651						
6									
7	**B. Storage / LNG**								
8	Land & Land Rights	360	68	Dist	Demand	-	Peak_Avg	-	-
9	Structures and Improvements	361	6,512	Dist	Demand	-	Peak_Avg	-	-
10	Gas Holders- LNG/ Storage	362	3,400	Dist	Demand	-	Peak_Avg	-	-
11	363G- Vapor / Compress/ Regulating		85,911	Dist	Demand	-	Peak_Avg	-	-
12	NGV Station	363	2,298	Dist	Demand	-	NGV Direct	-	-
13	**Storage Plant**	304-338	98,189						
14									
15	**C. TRANSMISSION PLANT**								
16	Land	365	631	Dist	Demand	-	Peak_Avg	-	-
17	Structures and Improvements	366	0	-	-	-	-	-	-
18	Mains	367	15,849	Dist	Demand	-	Peak_Avg	-	-
19	Measuring and Reg. Sta. Equip.	369	8,600	Dist	Demand	-	Peak_Avg	-	-
20	**Transmission Plant**	360-368	25,080						
21									
22	**D. DISTRIBUTION PLANT**								
23	Land and Land Rights	374	4,438	Dist	Dist_Pt	-	DistD-Pt	DistC-Pt	-
24	Structures and Improvements	375	10,587	Dist	Dist_Pt	-	DistD-Pt	DistC-Pt	-
25	Mains	376	1,238,550	Dist	Demand	-	Peak_Avg	-	-
26	Mains Direct	376TC	14,248	Dist	Demand	-	Mains Direct	-	-
27	Meas. & Reg. Stat. Equip. - General	378	44,669	Dist	Demand	-	Peak_Avg	-	-
28	Services	380	635,224	Dist	Customer	-	-	Service_Inves	-
29	Services Direct	380D	6,381	Dist	Customer	-	-	Services Direc	-
30	Meters / Install	381/382	198,942	Dist	Customer	-	-	Meter_Invest	-
31	Ind M&R	385	16,742	Dist	Demand	-	Ind M&R	-	-
32	House Reg/ Install	384	12,207	Dist	Customer	-	-	Meter_Invest	-
33	OPEN		0	-	-	-	-	-	-
34	OPEN		3,768	Dist	Demand	-	Mains_Ser_Di	-	-
35	**Distribution Plant**	374-388	2,185,756						
36									
37	**E. GENERAL PLANT**								
38	General Pt- Labor	389	219,750	Dist	Dist_Lab	-	DistD-Lab	DistC-Lab	-
39	General Pt- Plant	398	0	-	-	-	-	-	-
40	**General Plant**	389-399	219,750						
41									
42	**TOTAL UTILITY PLANT**		2,529,427						
43			*2,529,427*						

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Elizabethtown Gas Company
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Line	Account	No.	Balance	Functional	Distribution	Class Allocation SuppDem	DistDem	DistCus	BillCus
44	**II. DEPRECIATION RESERVE**								
45	Mains-Services Direct	108	0	-	-	-	-	-	-
46	NGV Station	111	958	Dist	Demand	-	NGV Direct	-	-
47	Storage Plant	108	10,325	Dist	Demand	-	Peak_Avg	-	-
48	Transmission Plant	109	1,433	Dist	Demand	-	Peak_Avg	-	-
49	Distribution- Mains	108M	206,859	Dist	Demand	-	Peak_Avg	-	-
50	Distribution- Services	108S	77,823	Dist	Customer	-	-	Service_Inves	-
51	Distribution- Meters	108Mt	63,394	Dist	Customer	-	-	Meter_Invest	-
52	Distribution- Other	108O	46,871	Dist	Dist_Pt	-	DistD-Pt	DistC-Pt	-
53	General Pt- Labor	109	90,775	Dist	Dist_Lab	-	DistD-Lab	DistC-Lab	-
54	General Pt- Plant	398	0	-	-	-	-	-	-
55	**Depreciation Reserve**	108	498,438						
56			*498,438*						
57	**III. OTHER RATE BASE ITEMS**								
58	Materials and Supplies, Prepay	105	0	-	-	-	-	-	-
59	Storage Gas	107M	10,754	Dist	Demand	-	Firm_Winter	-	-
60	Cust Dep / Adv	Cust	(6,690)	Dist	Customer	-	-	CustDep	-
61	Other Regulatory Assets	182P	23,015	Dist	Dist_Lab	-	DistD-Lab	DistC-Lab	-
62	Accum Deferred Income Taxes	190	(246,434)	Dist	Dist_Pt	-	DistD-Pt	DistC-Pt	-
63	CWC	CWC	50,476	Dist	Dist_OM	-	DistD-OM	DistC-OM	-
64	OPEN	CWC-Su	0	-	-	-	-	-	-
65	**Other Rate Base**		(168,880)						
66									
67	**TOTAL RATE BASE**		1,862,109						
68			*1,862,109*						
69	**I. OPERATING AND MAINTENANCE EXPENSES**								
70	**A. PRODUCTION EXPENSE**								
71									
72	Natural Gas City Gate Purchases	804	0	-	-	-	-	-	-
73	Subtotal-Production expenses	710-813	-						
74									
75	**B. STORAGE, LNG EXPENSES**								
76	Storage Operations	841	700	Dist	Demand	-	Peak_Avg	-	-
77	Subtotal- Storage expenses	840-850	700						
78									

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Schedule HSG-4-7A
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Line	Account	No.	Balance	Functional	Distribution	Class Allocation			
						SuppDem	DistDem	DistCus	BillCus
79	**C. TRANSMISSION EXPENSES**								
80	Mains Operating	850-856	0	-	-	-	-	-	-
81	Maintenance Other Equip.	865	174	Dist	Demand	-	Peak_Avg	-	-
82	**Subtotal-Transmission**	850-867	174						
83									
84	**D. DISTRIBUTION O&M EXPENSE**								
85	Operation Supv & Engineering	870	0	-	-	-	-	-	-
86	Distribution Load Dispatching	871	288	Dist	Demand	-	Gas_Del_Firr	-	-
87	Mains and Services Expenses	874	4,186	Dist	Mains_Serv	-	)istD-MainsSv	)istC-MainsSv	-
88	Meas & Reg Exp- General	875	29	Dist	Demand	-	Peak_Avg	-	-
89	Meas & Reg Exp- Industrial	876	0	-	-	-	-	-	-
90	Meter-Regulator- Citygate	878	917	Dist	Demand	-	Peak_Avg	-	-
91	Cust Installations Field	879	835	Dist	Customer	-	-	Cust_Avg	-
92	Other Expenses	880	3	Dist	Dist_OM	-	DistD-OM	DistC-OM	-
93	Rents	881	16	Dist	Dist_OM	-	DistD-OM	DistC-OM	-
94	Maint Compressor Station Equip	879	0	-	-	-	-	-	-
95	Maint Supv & Engineering	885	0	-	-	-	-	-	-
96	Maint of Mains	887	1,457	Dist	Demand	-	Peak_Avg	-	-
97	Maint. of Meas. & Reg. General	889	104	Dist	Demand	-	Peak_Avg	-	-
98	Maint. of Meas. & Reg.- Indust	890	0	-	-	-	-	-	-
99	Maint. of Services	892	615	Dist	Customer	-	-	Service_Inves	-
100	Maint. of Meters & House Regulators	893	142	Dist	Customer	-	-	Meter_Invest	-
101	Maint. Other Equip.	894	61	Dist	Dist_Pt	-	DistD-Pt	DistC-Pt	-
102	**Dist. Oper. & Maint. Exp.**	870-899	8,653						
103	Total O&M Expenses		9,527						
104									
105	**II. CUSTOMER ACCOUNTS AND SERVICE**								
106	Supervision	901	0	-	-	-	-	-	-
107	Meter Reading Expenses	902	509	Dist	Customer	-	-	Cust_Avg	-
108	Customer Records & Collection Expense	903	850	Dist	Customer	-	-	Cust_Avg	-
109	Uncollectible Accounts	904	9,078	Dist	D-RevReq_PF	-	WriteOff_Del	WriteOff_Del	-
110	Miscellaneous Customer Accounts Exp.	905	0	-	-	-	-	-	-
111	**Customer Accts. Exp.**	901-905	10,437						
112									
113	**III. CUSTOMER ACCOUNTS AND IN**								
114	Customer Assistance Expenses	908	3,652	Dist	Customer	-	-	Cust_Avg	-
115	Low Income Discount	908LI	0	-	-	-	-	-	-
116	Cust Assist Other	909-912	4,802	Dist	Customer	-	-	Cust_Avg	-
117	Advertising	913	692	Dist	Customer	-	-	Cust_Avg	-
118	**Customer Service Exp.**	908-919	9,146						
119	**Customer Accts. & Serv. Exp.**	901-919	19,582						
120									

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Elizabethtown Gas Company
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Allocator Assignments

Line	Account	No.	Balance	Functional	Distribution	Class Allocation SuppDem	DistDem	DistCus	BillCus
121	**E. ADMINISTRATIVE AND GENERAL**								
122	Administrative & General Salaries	920	17,114	Dist	Dist_Lab	-	DistD-Lab	DistC-Lab	-
123	Office Supplies & Expenses	921	7,904	Dist	Dist_Lab	-	DistD-Lab	DistC-Lab	-
124	Outside Services Employed	923	27,397	Dist	Dist_Lab	-	DistD-Lab	DistC-Lab	-
125	Property Insurance	924	1,987	Dist	Dist_Pt	-	DistD-Pt	DistC-Pt	-
126	Injuries & Damages	925	235	Dist	Dist_Lab	-	DistD-Lab	DistC-Lab	-
127	Employee Pensions and Benefits	926	5,796	Dist	Dist_Lab	-	DistD-Lab	DistC-Lab	-
128	Franchise Reqirements	927	0	-	-	-	-	-	-
129	Regulatory Commission Expenses	928	360	Dist	Customer	-	-	RateBase	-
130	Misc General Exp	930	840	Dist	Dist_Lab	-	DistD-Lab	DistC-Lab	-
131	A&G- Rents	931	118	Dist	Dist_Lab	-	DistD-Lab	DistC-Lab	-
132	Maint General Plant	932	0	-	-	-	-	-	-
133	**Admin & Genl. Exp.**	920-932	61,753						
134									
135	**Total Operating Expenses**		90,862						
136			*90,862*						
137	**II. DEPRECIATION EXPENSE**								
138	Land and ROW	403	448	Dist	Dist_Pt	-	DistD-Pt	DistC-Pt	-
139	Storage Plant	403	1,841	Dist	Demand	-	Peak_Avg	-	-
140	Transmission Plant	404	523	Dist	Demand	-	Peak_Avg	-	-
141	Mains	403M	21,144	Dist	Demand	-	DistD-Mains	-	-
142	Services	403S	19,828	Dist	Customer	-	-	Service_Inves	-
143	Meters	403Mt	7,248	Dist	Customer	-	-	Meter_Invest	-
144	Distr Other	403O	687	Dist	Dist_Pt	-	DistD-Pt	DistC-Pt	-
145	General Pt- Labor	404	22,032	Dist	Dist_Lab	-	DistD-Lab	DistC-Lab	-
146	General Pt- Plant	404	0	-	-	-	-	-	-
147	Mains/Services Direct	404	0	-	-	-	-	-	-
148	NGV Station	404	37	Dist	Dist_Lab	-	NGV Direct	NGV Direct	-
149	Amort Regulatory Debits	403	0	-	-	-	-	-	-
150	**Depreciation Expense**		73,787						
151									
152	**III. TAXES and OTHER**								
153	**A. GENERAL TAXES**								
154	Taxes- Labor based	408L	3,269	Dist	Dist_Lab	-	DistD-Lab	DistC-Lab	-
155	Taxes- Plant based	408P	1,076	Dist	Dist_Pt	-	DistD-Pt	DistC-Pt	-
156	Other Taxes	408O	1,047	Dist	Dist_Pt	-	RateBase	RateBase	-
157	Tax Amortization	408	3,587	RateBase	Dist_Pt	-	RateBase	RateBase	-
158	**General Taxes**		8,980						
159									
160	**B. GROSS RECEIPTS TAX**								
161	Gross Receipts tax		0	-	-	-	-	-	-
162	**Gross Receipts Tax**		0						

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Elizabethtown Gas Company
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Allocator Assignments

						Class Allocation			
Line	**Account**	No.	**Balance**	**Functional**	**Distribution**	**SuppDem**	**DistDem**	**DistCus**	**BillCus**
163									
164	**B. FEDERAL / STATE INCOME TAXES**								
165	Federal Income Tax Expense		16,480	Pretax	Dist_Pretax	-	DistD-Pretax	DistC-Pretax	-
166	**Income Taxes**	409-411	16,480						
167	**Total Taxes**	408-411	25,459						
168									
169	**TOTAL EXPENSES**		190,109						
170			*190,109*						
171	**IV. OPERATING REVENUES at Present Rates**								
172	Base Delivery	480	288,211	RevReq_PF	D-RevReq_PF	-	Total_Del_Re	Total_Del_Re	-
173	Commodity	480C	0	-	-	-	-	-	-
174	Rent from Gas Property	488	0	-	-	-	-	-	-
175	Late payment	493	769	Dist	D-RevReq_PF	-	WriteOff_Del	WriteOff_Del	-
176	Other Revenues	495	1,442	Dist	Customer	-	-	Gas_Del_Firm	-
177	Marketer	495	34	Dist	Customer	-	-	Gas_Del_Firm	-
178	Turn On	495	564	Dist	Customer	-	-	Cust_Avg	-
179	Capacity Release	415/416	144	Dist	Demand	-	Peak_Avg	-	-
180	Adjust to Case Model		0	-	-	-	-	-	-
181	**TOTAL REVENUE**		291,164		0 #	0	0		
182			*291,164*						
183	**V. Net Income at Present Rates**		101,055		- -	-	-		
184			*101,055*						

FuncFctr
Functionalization Factors
Schedule HSG-4-7B
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Elizabethtown Gas Company
k and Average Embedded Cost of Service Study (ECOSS)
Post Test Year 2025-03-31 (Using 2024 6+6)
Functionalization Factors

	Allocator Name	Total	Supply-Storage	Distribution	Billing
1	None	0			
2		0.00%	0.00%	0.00%	0.00%
3					
4	Supp	1	1		
5		100.00%	100.00%	0.00%	0.00%
6					
7	Dist	1		1	
8		100.00%	0.00%	100.00%	0.00%
9					
10	Bill	1			1
11		100.00%	0.00%	0.00%	100.00%
12					
13	Dist-Pt	2,185,756	-	2,185,756	-
14		100.00%	0.00%	100.00%	0.00%
15					
16	Plant	2,309,026	-	2,309,026	-
17		100.00%	0.00%	100.00%	0.00%
18					
19	O&MxGas	90,862		90,862	-
20		100.00%	0.00%	100.00%	0.00%
21					
22	Labor	44,022	-	44,022	-
23		100.00%	0.00%	100.00%	0.00%
24					
25	Pretax	117,535	-	117,535	-
26		100.00%	-	100.00%	-
27					
28	RateBase	1,862,109	0	1,862,109	0
29		100.00%	0.00%	100.00%	0.00%
30					
31	RevReq	366,723	0	366,723	0
32		100.00%	0.00%	100.00%	0.00%
33					
34	RevReq_PF	1,862,109		1,862,109	0
35		100.00%	0.00%	100.00%	0.00%
36					
37	Uncollect_RR	11,342	0	11,342	0
38		100.00%	0.00%	100.00%	0.00%
39					

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Elizabethtown Gas Company
Peak and Average Embedded Cost of Service Study (ECOSS)
Post Test Year 2025-03-31 (Using 2024 6+6)
Classification Factors

	Allocator Name	Total	Demand	Commodity	Customer
1	None	0			
2		0.00%	0.00%	0.00%	0.00%
3					
4	Demand	1	1		
5		100.00%	100.00%	0.00%	0.00%
6					
7	Commodity	1		1	
8		100.00%	0.00%	100.00%	0.00%
9					
10	Customer	1			1
11		100.00%	0.00%	0.00%	100.00%
12					
13	Services	635,224	-	-	635,224
14		100.00%	0.00%	0.00%	100.00%
15					
16	MinSys-Mains	100.00%	37.43%	0.00%	62.57%
17		100.00%	37.43%	0.00%	62.57%
18					
19	Mains_Serv_Dir	20,629	14,248	-	6,381
20		100.00%	69.07%	0.00%	30.93%
21					
22	Mains_Serv	1,894,403	1,252,797	-	641,605
23		100.00%	66.13%	0.00%	33.87%
24					
25	Mains_Dist	1,252,797	1,252,797	-	-
26		100.00%	100.00%	0.00%	0.00%
27					
28	Dist_Pt	2,309,026	1,450,685	-	858,340
29		100.00%	62.83%	0.00%	37.17%
30					
31	Dist_Int	651	-	-	651
32		100.00%	0.00%	0.00%	100.00%
33					
34	Dist_Oth	47,743	29,950	-	17,793
35		100.00%	62.73%	0.00%	37.27%
36					

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Elizabethtown Gas Company
Peak and Average Embedded Cost of Service Study (ECOSS)
Post Test Year 2025-03-31 (Using 2024 6+6)
Classification Factors

	Allocator Name	Total	Demand	Commodity	Customer
37	Dist_OM	90,862	32,139	-	58,723
38		100.00%	35.37%	0.00%	64.63%
39					
40	Dist_Lab	44,022	14,693	-	29,329
41		100.00%	33.38%	0.00%	66.62%
42					
43	Dist_Pretax	117,535	77,568	-	39,966
44		100.00%	66.00%	0.00%	34.00%
45					
46	Dist_Unc_RR	11,343	5,791	-	5,552
47		100.00%	51.06%	0.00%	48.94%
48					
49	D-RevReq_PF	366,723	185,061	-	181,662
50		100.00%	50.46%	0.00%	49.54%
51					
52	Dist_Rev	288,211	145,441	-	142,770
53		100.00%	50.46%	0.00%	49.54%
54					

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Elizabethtown Gas Company
Peak and Average Embedded Cost of Service Study (ECOSS)
Post Test Year 2025-03-31 (Using 2024 6+6)
Class Allocation Factors

	Allocator Name	In Use	Total	Residential Heat	Residential Non-Heat	Small General SGS	General GDS	Large Volume LVD	NGV	Non-Firm
1	None		-							
2		FALSE	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
3			0							
4	Cust_Avg		317,754	263,237	30,695	17,116	6,606	55	1	44
5		TRUE	100.00%	82.84%	9.66%	5.39%	2.08%	0.02%	0.00%	0.01%
6										
7	Cust_Res		293,931	263,237	30,695	-	-	-	-	-
8		TRUE	100.00%	89.56%	10.44%	0.00%	0.00%	0.00%	0.00%	0.00%
9										
10	Mains_Ser_Dir		20,628,591	-	-	-	-	5,571,767	-	15,056,824
11		TRUE	100.00%	0.00%	0.00%	0.00%	0.00%	27.01%	0.00%	72.99%
12										
13	Cust_Mains		163,559	118,457	30,695	7,702	6,606	55	1	44
14		TRUE	100.00%	72.42%	18.77%	4.71%	4.04%	0.03%	0.00%	0.03%
15										
16	Gas_Deliveries		497,688,949	256,636,058	7,970,565	25,480,871	124,320,757	49,432,246	116,571	33,731,881
17		TRUE	100.00%	51.57%	1.60%	5.12%	24.98%	9.93%	0.02%	6.78%
18										
19	Gas_Del_Firm		463,957,068	256,636,058	7,970,565	25,480,871	124,320,757	49,432,246	116,571	-
20		TRUE	100.00%	55.31%	1.72%	5.49%	26.80%	10.65%	0.03%	0.00%
21										
22	Thru_Winter		332,972,140	185,231,777	5,155,095	18,763,474	85,111,153	23,873,517	68,727	14,768,397
23		TRUE	100.00%	55.63%	1.55%	5.64%	25.56%	7.17%	0.02%	4.44%
24										
25	Firm_Winter		318,203,743	185,231,777	5,155,095	18,763,474	85,111,153	23,873,517	68,727	
26		TRUE	100.00%	58.21%	1.62%	5.90%	26.75%	7.50%	0.02%	0.00%
27										
28	Peak_Sendout		510,527	315,537	7,657	31,848	122,980	32,456	49	-
29		TRUE	100.00%	61.81%	1.50%	6.24%	24.09%	6.36%	0.01%	0.00%
30										
31	Peak_XRes		49						49	-
32		TRUE	100.00%	0.00%	0.00%	0.00%	0.00%	0.00%	100.00%	0.00%
33										
34	Winter Firm		318,203,743	185,231,777	5,155,095	18,763,474	85,111,153	23,873,517	68,727	-
35		TRUE	100.00%	58.21%	1.62%	5.90%	26.75%	7.50%	0.02%	0.00%
36										

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Elizabethtown Gas Company
Peak and Average Embedded Cost of Service Study (ECOSS)
Post Test Year 2025-03-31 (Using 2024 6+6)
Class Allocation Factors

Allocator Name	In Use	Total	Residential Heat	Residential Non-Heat	Small General SGS	General GDS	Large Volume LVD	NGV	Non-Firm
Peak_Avg		100.00%	57.60%	1.54%	5.78%	24.46%	7.83%	0.02%	2.79%
	TRUE	100.00%	57.60%	1.54%	5.78%	24.46%	7.83%	0.02%	2.79%
NGV Direct		0	0	0	0	0	0	0	0
	TRUE	100.00%	0.00%	0.00%	0.00%	0.00%	0.00%	100.00%	0.00%
Total_Del_Rev		288,211	178,827	8,340	18,724	65,876	10,302	148	5,993
	TRUE	100.00%	62.05%	2.89%	6.50%	22.86%	3.57%	0.05%	2.08%
Rev-BaseDel		275,722,379	170,900,114	7,970,728	17,887,079	63,005,159	9,821,318	145,131	5,992,850
	TRUE	100.00%	61.98%	2.89%	6.49%	22.85%	3.56%	0.05%	2.17%
IIP-Rev		12,488,812	7,926,720	369,700	837,245	2,871,170	481,104	2,873	-
	TRUE	100.00%	63.47%	2.96%	6.70%	22.99%	3.85%	0.02%	0.00%
CustDep		4,993,172	2,914,035	274,585	654,310	1,018,812	130,717	714	-
	TRUE	100.00%	58.36%	5.50%	13.10%	20.40%	2.62%	0.01%	0.00%
Meter_Invest		342,364,293	271,695,797	30,484,346	23,055,491	14,321,046	1,476,200	986	1,330,428
	TRUE	100.00%	79.36%	8.90%	6.73%	4.18%	0.43%	0.00%	0.39%
Ind M&R		187,284			31,848	122,980	32,456		
	TRUE	100.00%	0.00%	0.00%	17.01%	65.66%	17.33%	0.00%	0.00%
Service_Invest		1,131,062,881	879,161,980	119,817,282	82,154,994	49,928,626	-	-	-
	TRUE	100.00%	77.73%	10.59%	7.26%	4.41%	0.00%	0.00%	0.00%
Services Direct		6,380,901	-	-	-	-	2,096,217	-	4,284,684
	TRUE	100.00%	0.00%	0.00%	0.00%	0.00%	32.85%	0.00%	67.15%
Mains Direct		14,247,690	-	-	-	-	3,475,550	-	10,772,140
	TRUE	100.00%	0.00%	0.00%	0.00%	0.00%	24.39%	0.00%	75.61%
DistD-Lab		14,693	8,419	225	845	3,575	1,163	2	465
	TRUE	100.00%	57.30%	1.53%	5.75%	24.33%	7.91%	0.02%	3.16%

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Peak and Average Embedded Cost of Service Study (ECOSS)
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Class Allocation Factors

Allocator Name	In Use	Total	Residential Heat	Residential Non-Heat	Small General SGS	General GDS	Large Volume LVD	NGV	Non-Firm
DistD-Pt		1,450,685	814,042	21,789	84,536	356,711	118,075	2,529	53,003
	TRUE	100.00%	56.11%	1.50%	5.83%	24.59%	8.14%	0.17%	3.65%
DistD-Mains		1,252,797	713,344	19,094	71,568	302,889	100,422	189	45,291
	TRUE	100.00%	56.94%	1.52%	5.71%	24.18%	8.02%	0.02%	3.62%
DistD-MainsSvc		1,252,797	713,344	19,094	71,568	302,889	100,422	189	45,291
	TRUE	100.00%	56.94%	1.52%	5.71%	24.18%	8.02%	0.02%	3.62%
DistD-OM		32,139	18,736	648	1,870	7,468	2,424	9	984
	TRUE	100.00%	58.30%	2.02%	5.82%	23.24%	7.54%	0.03%	3.06%
DistD-Unc_RR		5,835	3,423	160	322	1,006	667	6	252
	TRUE	100.00%	58.65%	2.74%	5.52%	17.24%	11.43%	0.11%	4.31%
			8419	225	845	3575	1163	2	465
DistD-Pretax		77,568	50,935	2,930	5,520	17,309	(3)	44	833
	TRUE	100.00%	65.66%	3.78%	7.12%	22.31%	0.00%	0.06%	1.07%
DistC-Lab		29,329	23,899	2,898	1,714	778	15	0	26
	TRUE	100.00%	81.48%	9.88%	5.84%	2.65%	0.05%	0.00%	0.09%
DistC-Pt		858,340	665,650	86,656	60,754	37,115	3,026	1	5,139
	TRUE	100.00%	77.55%	10.10%	7.08%	4.32%	0.35%	0.00%	0.60%
DistC-Mains		-	-	-	-	-	-	-	-
	FALSE	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
DistC-MainsSvc		641,605	493,753	67,291	46,140	28,041	2,096	-	4,285
	TRUE	100.00%	76.96%	10.49%	7.19%	4.37%	0.33%	0.00%	0.67%
DistC-OM		58,723	47,072	5,549	3,437	2,213	277	3	173
	TRUE	100.00%	80.16%	9.45%	5.85%	3.77%	0.47%	0.01%	0.29%
DistC-Unc_RR		6,069	4,590	947	344	143	17	1	26
	TRUE	100.00%	75.64%	15.60%	5.66%	2.36%	0.29%	0.02%	0.43%

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Elizabethtown Gas Company
Peak and Average Embedded Cost of Service Study (ECOSS)
Post Test Year 2025-03-31 (Using 2024 6+6)
Class Allocation Factors

Allocator Name	In Use	Total	Residential Heat	Residential Non-Heat	Small General SGS	General GDS	Large Volume LVD	NGV	Non-Firm
DistC-Pretax		39,966	6,391	(5,897)	2,895	28,945	4,873	45	2,714
	TRUE	100.00%	15.99%	-14.76%	7.24%	72.42%	12.19%	0.11%	6.79%
OM_xGas		-	-	-	-	-	-	-	-
	FALSE	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
WriteOff_Del		1,047	678	51	65	172	53	1	26
	TRUE	100.00%	64.77%	4.91%	6.22%	16.44%	5.08%	0.07%	2.51%
RateBase		1,862,109	1,206,053	91,505	115,855	306,181	94,531	1,233	46,753
	TRUE	100.00%	64.77%	4.91%	6.22%	16.44%	5.08%	0.07%	2.51%
Total_Labor		44,022	32,318	3,123	2,559	4,353	1,178	2	490
	TRUE	100.00%	73.41%	7.09%	5.81%	9.89%	2.67%	0.01%	1.11%
Total_RR		366,723	248,367	21,249	22,442	51,516	15,607	189	7,353
	TRUE	100.00%	67.73%	5.79%	6.12%	14.05%	4.26%	0.05%	2.00%

RESUME AND RELEVANT EXPERIENCE OF HOWARD S. GORMAN

Mr. Gorman has more than 35 years of experience in the energy industry, including 25 years in rate and regulatory proceedings. His areas of expertise include embedded class cost of service studies, marginal cost studies, revenue allocation, rate design and revenue requirements, for both electric and gas utilities. He has testified as an expert witness before the Massachusetts Department of Public Utilities, New Jersey Board of Public Utilities, New Hampshire Public Utilities Commission, New York State Public Service Commission, Ontario Energy Board, Pennsylvania Public Utility Commission and Rhode Island Public Utilities Commission. Mr. Gorman also has experience in financial modeling, financial analysis and forecasting and treasury and financial management.

PROFESSIONAL EMPLOYMENT

2010 - Present	HSG Group, Inc. *President*
1997 - 2010	Black & Veatch Corporation (R.J. Rudden Associates, Inc. before 2005) *Principal Consultant*
1995 - 1997	*Independent Consultant*
1987 – 1995	Trigen Energy Corporation 1987-1993 *Corporate Controller*; Trigen was formed in 1987 1993-1995 *Treasurer*; Trigen had IPO with NYSE listing in 1994
1982 - 1987	Coleco Industries, Inc. *Director, Treasury*
1976 - 1979	Touche Ross & Co. *Staff Accountant*

PROFESSIONAL EXPERIENCE

Utility Accounting and Costing

Mr. Gorman has performed numerous class cost of service studies, and has developed and supported revenue requirements, revenue allocation, rate designs and marginal cost studies, in rate cases before regulatory commissions in several jurisdictions, for electric and gas utilities. These assignments included developing test year data and rate year forecasts, establishing cost causality, selecting and developing allocators and analyzing customer impacts and policy considerations.

Energy Project Financing and Analysis

Mr. Gorman has negotiated and completed transactions including construction and term loans, tax-exempt bonds, taxable bonds, subordinated debt and asset-backed (receivables and inventory) revolving credit facilities. He has worked successfully with lenders and borrowers to source and structure transactions, and was instrumental in negotiating loan documents and in designing power sale and supply procurement contracts to be financed. Mr. Gorman has performed financial analyses of energy-related assets, including electric and gas distribution companies, power plants and transmission operators. These analyses included development of cash flows and financial statements based on both regulatory and accounting presentations, and included review of assumptions, analysis of data, modeling and forecasting, sensitivity testing and stress testing.

Accounting and Financial Management

As controller of Trigen Energy Corporation, Mr. Gorman built the finance and accounting function; developed reports, procedures and management tools; and managed subsidiary controllers across North America, including an IPO with NYSE listing. He managed the corporate insurance portfolios and the benefit plans for Trigen Energy Corporation and for Coleco Industries, and has managed interest rate and currency forward contracts for the purpose of managing risk.

Publications And Presentations

"What Wall Street Needs From FERC," published in R. J. Rudden Financial, LLC's *Energy Capital Markets Report*, September 2002

"A Balanced Look at Balance Sheets," published in R.J. Rudden Financial, LLC's *Energy Capital Markets Report,* June 2002

"From Wires To Riches: Shareholder Value Creation In The T&D Business," April 2002 (co-authored).

"Assessment of Retail Choice Programs," presented at the American Gas Association Rate and Strategic Issues Committee Conference, March 2002

"Value Creation With Transmission Assets," quoted in *Electrical World's Special Edition Quarter 1, 2002*, March 2002

"The Remarkable Story of Enron," published in Scudder's *Annual End of Year Issue*, December 2001

Education

New York University, B.S., Accounting, 1976

Harvard Business School, MBA, 1981

Jurisdiction	Docket	Utility	Subject Matter
Massachusetts 2023	DPU 23-150	Massachusetts / Nantucket Electric	Electric class cost of service; revenue allocation; rate design
Massachusetts 2023	DPU 23-115	Massachusetts / Nantucket Electric	Energy Storage System Rates
New York 2023	23-G-0227	Valley Energy, Inc.	Gas revenue requirements, rate design
New York 2023	23-G-0225 /02260	Brooklyn Union Gas / KeySpan Gas East	Gas class cost of service; revenue allocation; rate design; marginal cost
Pennsylvania 2022	R-2022-3032369	Citizens' Electric of Lewisburg, PA	Electric revenue requirements, class cost of service, revenue allocation, rate design
Pennsylvania 2022	R-2022-3032300	Valley Energy, Inc.	Gas revenue requirements, rate design
Pennsylvania 2021	R-2021-3024060	Vicinity Energy Philadelphia	Steam system revenue requirements; sales forecast (formerly Veolia)
Pennsylvania 2021	R-2021-3024750	Duquesne Light	Electric class cost of service; revenue allocation; rate design
New York 2020	20-G-0381	Niagara Mohawk (Gas)	Gas class cost of service; revenue allocation; rate design; marginal cost
New York 2020	20-E-0380	Niagara Mohawk (Electric)	Electric class cost of service; revenue allocation; rate design; marginal cost
Pennsylvania 2019	R-2019-3008212	Citizens' Electric of Lewisburg, PA	Electric revenue requirements, class cost of service, revenue allocation, rate design
Pennsylvania 2019	R-2019-3008208	Wellsboro Electric Company	Electric revenue requirements, class cost of service, revenue allocation, rate design
Pennsylvania 2019	R-2019-3008209	Valley Energy, Inc.	Gas revenue requirements, rate design
New York 2019	19-G-0309 /0310	Brooklyn Union Gas / KeySpan Gas East	Gas class cost of service; revenue allocation; rate design; marginal cost
Massachusetts 2018	DPU 18-150	Massachusetts / Nantucket Electric	Electric class cost of service; revenue allocation; rate design; marginal cost Monthly Minimum Reliability
Pennsylvania 2018	R-2018-30000124	Duquesne Light	Electric class cost of service; revenue allocation; rate design
Rhode Island 2017	RIPUC 4770	Narragansett Electric	Electric class cost of service; revenue allocation; rate design
Pennsylvania 2017	R-2017-2593142	Veolia Energy Philadelphia	Steam system revenue requirements; sales forecast
New York 2017	17-G-0239	Niagara Mohawk (Gas)	Gas class cost of service; revenue allocation; rate design; marginal cost

Jurisdiction	Docket	Utility	Subject Matter
New York 2017	17-E-0238	Niagara Mohawk (Electric)	Electric class cost of service; revenue allocation; rate design; marginal cost
Pennsylvania 2016	R-2016-2531550	Citizens' Electric of Lewisburg, PA	Electric revenue requirements, class cost of service, revenue allocation, rate design
Pennsylvania 2016	R-2016-2531551	Wellsboro Electric Company	Electric revenue requirements, class cost of service, revenue allocation, rate design
New Hampshire 2016	DE 16-383	Granite State Electric	Electric revenue requirement
New York 2016	16-G-0058 /0059	Brooklyn Union Gas / KeySpan Gas East	Gas class cost of service; revenue allocation; rate design; marginal cost
Massachusetts 2015	DPU 15-155	Massachusetts / Nantucket Electric	Marginal cost
New York 2015	15-E-0184	Jamestown Board of Public Utilities	Electric revenue requirements
New Hampshire 2015	DE14-180	Energy North Natural Gas	Gas revenue requirements
New York 2014	14-E-0035	Village of Freeport	Electric revenue requirements; sales forecast; rate design
Pennsylvania 2014	R-2013-2386293	Veolia Energy Philadelphia	Steam system revenue requirements and sales forecast
Pennsylvania 2014	R-2013-2372129	Duquesne Light	Electric class cost of service; revenue allocation; rate design
New Hampshire 2013	DE13-063	Granite State Electric	Electric class cost of service (marginal cost); revenue allocation; rate design
Ontario 2013, 2012, 2010, 2009, 2008, 2006, 2005	EB-2005-0378 et al	Hydro One Networks Inc.	Electric Transmission and Distribution cost allocation; OH capitalization rates
Ontario 2006-2013	EB-2007-0905 et al	Ontario Power Generation	Electric cost allocation methodology (2013, 2010, 2006)
New York 2012	12-E-0201	Niagara Mohawk (Electric)	Electric class cost of service; revenue allocation
Rhode Island 2012	RIPUC 4323	Narragansett Electric	Electric class cost of service
New York 2011	11-E-0590	Village of Rockville Centre	Electric revenue requirements; rate design; sales forecast
New York 2011	11-G-0142	Chautauqua Utilities, Inc.	Gas revenue requirements, rate design
Pennsylvania 2010	R-2010-2179522	Duquesne Light	Electric class cost of service; revenue allocation; rate design

Jurisdiction	Docket	Utility	Subject Matter
Pennsylvania 2010	R-2010-2172662	Wellsboro Electric	Electric revenue requirements, class cost of service, revenue allocation, rate design
Pennsylvania 2010	R-2010-2172665	Citizens' Electric of Lewisburg, PA	Electric revenue requirements, class cost of service, revenue allocation, rate design
Pennsylvania 2010	R-2010-2174470	Valley Energy, Inc.	Gas revenue requirements, rate design
Pennsylvania 2010	R-2010-2161592	PECO Energy (Gas)	Gas class cost of service; revenue allocation; rate design
Pennsylvania 2010	R-2010-2161575	PECO Energy (Electric)	Electric class cost of service; revenue allocation; rate design
New York 2010	10-E-0050	Niagara Mohawk (Electric)	Electric class cost of service
New York 2009	09-E-0862	Jamestown Board of Public Utilities	Electric revenue requirements
Pennsylvania 2009, 2006, 2002, 2001	R-2139884 Et al	Philadelphia Gas Works	Gas class cost of service; revenue allocation; rate design; unbundling; fixed costs recovery
Rhode Island 2009	RIPUC 4065	Narragansett Electric	Electric class cost of service; revenue allocation; rate design
Massachusetts 2009	DPU 09-39	Massachusetts / Nantucket Electric	Electric revenue requirements; class cost of service; revenue allocation; rate design
Pennsylvania 2008	R-2008-2028394	PECO Energy (Gas)	Gas class cost of service; revenue allocation; rate design
Pennsylvania 2007	R-00072350	Wellsboro Electric	Electric revenue requirements; rate design
Pennsylvania 2007	R-00072348	Citizens' Electric of Lewisburg, PA	Electric revenue requirements; rate design
Pennsylvania 2007	R-00072349	Valley Energy, Inc.	Gas revenue requirements; rate design
New York 2006	06-E-0911	Village of Freeport	Electric revenue requirements; rate design
Pennsylvania 2006	R-00061346	Duquesne Light	Electric class cost of service; revenue allocation; rate design
New York 2003	03-E-1568	Village of Rockville Centre	Electric revenue requirements; rate design; sales forecast

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. GR24____

DIRECT TESTIMONY

OF

ANN E. BULKLEY

The Brattle Group

On Behalf of
Elizabethtown Gas Company

Exhibit P-7

February 29, 2024

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ELIZABETHTOWN GAS COMPANY
DIRECT TESTIMONY OF
ANN E. BULKLEY

I. INTRODUCTION

Q. PLEASE STATE YOUR NAME AND BUSINESS ADDRESS.

A. My name is Ann E. Bulkley. I am a Principal at The Brattle Group ("Brattle"). My business address is One Beacon Street, Suite 2600, Boston, Massachusetts 02108.

Q. ON WHOSE BEHALF ARE YOU SUBMITTING THIS TESTIMONY?

A. I am submitting this direct testimony before the New Jersey Board of Public Utilities ("Board" or "BPU") on behalf of Elizabethtown Gas Company ("Elizabethtown", the "Company" or "ETG"), a wholly-owned subsidiary of South Jersey Industries, Inc. ("SJI"). In February 2023, SJI was acquired by IIF US Holding 2, LP ("IIF"), a private equity fund.[1]

Q. PLEASE DESCRIBE YOUR EDUCATION AND EXPERIENCE.

A. I hold a Bachelor's degree in Economics and Finance from Simmons College and a Master's degree in Economics from Boston University, with more than 25 years of experience consulting to the energy industry. I have advised numerous energy and utility clients on a wide range of financial and economic issues with primary concentrations in valuation and utility rate matters. Many of these assignments have included the determination of the cost of capital for valuation and ratemaking purposes. My resume and a listing of the testimony that I have filed in other proceedings are included as Schedule AEB-1.

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[1] The acquisition of SJI by IIF (the "Merger") was approved in the Board's January 25, 2023 Order in BPU Docket No. GM22040270 ("2023 Merger Order"). Upon such acquisition, SJI became a privately-held company.

Q. WHAT IS THE PURPOSE OF YOUR TESTIMONY?

A. The purpose of my direct testimony is to present evidence and provide an opinion regarding the Company's return on equity ("ROE") and capital structure to be used for ratemaking purposes.

Q. ARE YOU SPONSORING ANY SCHEDULES IN SUPPORT OF YOUR DIRECT TESTIMONY?

A. Yes. My analysis and recommendations are supported by the data presented in Exhibit P-7, Schedules AEB-2 through AEB-15, which were prepared by me or under my direction.

Q. PLEASE PROVIDE A BRIEF OVERVIEW OF THE ANALYSES THAT LED TO YOUR RECOMMENDATION REGARDING THE COMPANY'S ROE.

A. In developing my opinion, I have estimated the cost of equity by applying traditional estimation methodologies to a proxy group of comparable utilities, which include the constant growth form of the Discounted Cash Flow ("DCF") model, the Capital Asset Pricing Model ("CAPM"), the Empirical Capital Asset Pricing Model ("ECAPM"), and a Bond Yield Risk Premium ("BYRP" or "Risk Premium") analysis. I also consider the Company's relative business and regulatory risk as compared with the proxy group; and the Company's proposed capital structure as compared with the capital structures of the operating utilities of the proxy group companies. While I do not make specific adjustments to the cost of equity for these factors in developing my opinion regarding the reasonableness of the Company's ROE, I do consider them in the aggregate.

Q. HOW IS THE REMAINDER OF YOUR TESTIMONY ORGANIZED?

A. The remainder of my testimony is organized as follows:

- Section II provides a summary of my analyses and conclusions.

- Section III reviews the regulatory guidelines pertinent to the development of the cost of capital.
- Section IV discusses current and projected capital market conditions and the effect of those conditions the cost of equity.
- Section V explains my selection of the proxy group.
- Section VI describes my cost of equity estimates and the analytical basis for my opinion of the appropriate ROE for Elizabethtown.
- Section VII provides a discussion of specific regulatory, business, and financial risks that have a direct bearing on the ROE to be authorized for the Company in this case.
- Section VIII provides an assessment of the reasonableness of the Company's proposed capital structure relative to the proxy group.
- Section IX presents my conclusions and recommendations.

II. <u>SUMMARY OF ANALYSES AND CONCLUSIONS</u>

Q. PLEASE SUMMARIZE THE KEY FACTORS CONSIDERED IN YOUR ANALYSES AND UPON WHICH YOU BASE YOUR ROE RECOMMENDATION.

A. My analyses and conclusions consider the following:

- The United States Supreme Court's *Hope* and *Bluefield* decisions,[2] which established the standards for determining a fair and reasonable authorized ROE for public utilities, including consistency of the allowed return with the returns of other businesses having similar risk, adequacy of the return to provide access to capital and support credit quality, and the requirement that the result lead to just and reasonable rates.
- The effect of current and projected capital market conditions on cost of equity estimation models and on investors' return requirements.
- The results of several analytical approaches that provide estimates of the Company's cost of equity. Because the Company's authorized ROE should be a forward-looking estimate over the period during which the rates will be in effect, these analyses rely on forward-looking inputs and assumptions (*e.g.*, projected analyst growth rates in the DCF model, forecasted risk-free rate and market risk premium in the CAPM analysis.)
- Although the companies in my proxy group are generally comparable to Elizabethtown, each company is unique, and no two companies have the exact same business and financial risk profiles. Accordingly, I consider the Company's regulatory, business, and financial risks relative to the proxy group of comparable companies in assessing

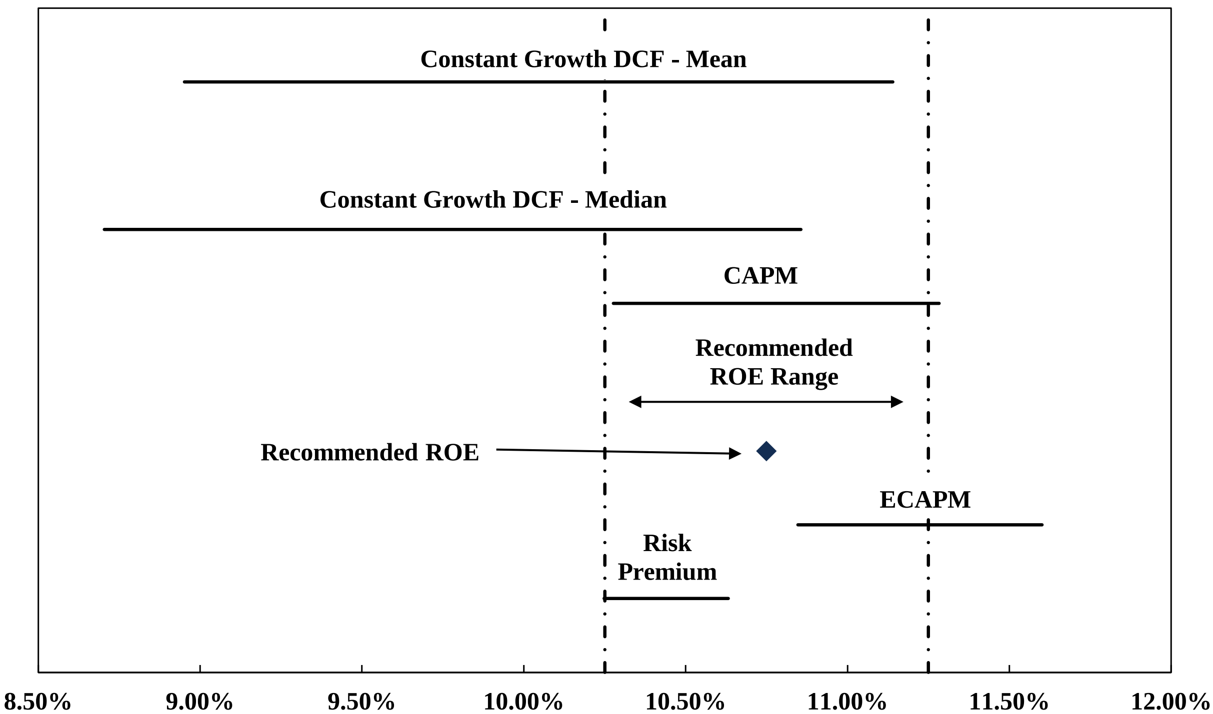
[2] *Federal Power Commission v. Hope Natural Gas Co.*, 320 U.S. 591 (1944) ("*Hope*"); *Bluefield Waterworks & Improvement Co., v. Public Service Commission of West Virginia*, 262 U.S. 679 (1923) ("*Bluefield*").

where within the range of analytical results the Company's ROE should reasonably fall to appropriately account for any residual differences in risk.

Q. WHAT ARE THE RESULTS OF THE MODELS THAT YOU HAVE USED TO ESTIMATE THE COST OF EQUITY FOR ELIZABETHTOWN GAS COMPANY?

A. Figure 1 summarizes the range of results produced by my cost of equity analyses.

Figure 1: Summary of Cost of Equity Model Results



As shown in Figure 1 (and Exhibit P-7, Schedule AEB-2), the range of results produced by the cost of equity estimation models is wide. While it is common to consider multiple models to estimate the cost of equity, it is particularly important when the range of results varies considerably across methodologies.

Q. ARE PROSPECTIVE CAPITAL MARKET CONDITIONS EXPECTED TO AFFECT THE RESULTS OF THE COST OF EQUITY FOR THE COMPANY DURING THE PERIOD IN WHICH THE RATES ESTABLISHED IN THIS PROCEEDING WILL BE IN EFFECT?

A. Yes. Capital market conditions are expected to affect the results of the cost of equity estimation models. Specifically:

- Long-term interest rates have increased substantially in the past year and are expected to remain relatively high at least over the next year as compared to the period prior to the Federal Reserve initiating its restrictive monetary policy.
- Since (i) utility dividend yields are less attractive than the risk-free rates of government bonds; (ii) interest rates are expected to remain near current levels over the next year, and (iii) utility stock prices are inversely related to changes in interest rates; utility share prices may remain depressed.
- Rating agencies have responded to the risks of the utility sector, citing factors including elevated capital expenditures, interest rates, and inflation that create pressures for customer affordability and prompt rate recovery, and have noted the importance of regulatory support in their current outlooks.
- Similarly, equity analysts have noted the increased risk for the utility sector as a result of elevated interest rates and expect the sector to underperform in 2024.
- Consequently, it is important to consider that if utility share prices decline, the results of the DCF model, which relies on current utility share prices, would understate the cost of equity during the period that the Company's rates will be in effect.

It is appropriate to consider all of these factors when estimating a reasonable range of the investor-required cost of equity and the recommended ROE for the Company.

Q. WHAT IS YOUR RECOMMENDATION REGARDING THE COMPANY'S ROE IN THIS PROCEEDING?

A. Based on the analytical results of the cost of equity models, and current and prospective capital market conditions, I conclude that an ROE in the range of 10.25 percent to 11.25 percent is reasonable. Within that range, I recommend an ROE of 10.75 percent, which considers the Company's regulatory, business, and financial risks relative to the proxy group, and the increase in the cost of equity since the Company's last rate proceeding.

Q. WHAT IS YOUR RECOMMENDATION REGARDING THE COMPANY'S CAPITAL STRUCTURE TO BE USED FOR RATEMAKING PURPOSES?

A. As discussed in more detail herein, the Company's actual equity ratio after the removal of goodwill is nearly 70 percent as a result of actions taken in 2023 to improve its credit metrics and prevent a credit rating downgrade. However, the Company is proposing a ratemaking capital structure that consists of 57.00 percent equity and 43.00 percent long-term debt, which is consistent with the average equity and long-term debt ratios for the utility operating subsidiaries of the proxy group companies. Further, the Company's proposed equity ratio is reasonable considering that the Company's business and regulatory risk is higher than the proxy group, yet my recommended ROE is at the middle of the range, as well as the fact that credit rating agencies have identified in their outlook for the utility sector significant risks associated with relatively high interest rates and inflation, record levels of capital spending, and the need to fund capital spending in a credit supportive manner.

III. REGULATORY GUIDELINES

Q. PLEASE DESCRIBE THE PRINCIPLES THAT GUIDE THE ESTABLISHMENT OF THE COST OF CAPITAL FOR A REGULATED UTILITY.

A. The United States Supreme Court's precedent-setting *Hope* and *Bluefield* cases established the standards for determining the fairness or reasonableness of a utility's allowed ROE. Among the standards established by the Court in those cases are: (1) consistency with other businesses having similar or comparable risks; (2) adequacy of the return to support credit quality and access to capital; and (3) the principle that the result reached, as opposed to the methodology employed, is the controlling factor in arriving at just and reasonable rates.[3]

Q. HAS THE BOARD PROVIDED SIMILAR GUIDANCE IN ESTABLISHING THE APPROPRIATE ROE?

Yes. The New Jersey Revised Statutes define a "Base rate case" as a means of "determining the level of revenues necessary to afford the public utility an opportunity to earn a fair and reasonable rate of return on prudently incurred capital investment in the public utility's rate base."[4] In its decision in Docket No. ER12111052 for Jersey Central Power and Light Company ("JCP&L"), the Board noted the following:

> Nevertheless, it is incumbent upon this Board to define a fair rate of return for JCP&L commensurate with risks faced by similar companies, sufficient to attract capital and maintain the financial integrity of the enterprise. As the New Jersey Supreme Court has recognized, a privately owned public utility is a complex mechanism that exists to serve a public need but to do so it must have investor appeal. It must be allowed a reasonable return on its investment so that it may have borrowing power at normal business rates to finance its day-to-day operations. See, Daaleman v. Elizabethtown Gas Co., 77 N.J. 267, 272 (1978).[5]

This guidance is in accordance with the *Hope* and *Bluefield* decisions and the principles that I employed to estimate the ROE for the Company, including the principle that an allowed rate of return must be sufficient to enable regulated companies such as Elizabethtown to attract capital on reasonable terms.

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[3] *Hope*, 320 U.S. 591 (1944); *Bluefield*, 262 U.S. 679 (1923).

[4] NJ Rev Stat § 48:2-21.25.

[5] New Jersey Board of Public Utilities, Docket No. ER12111052, OAL Docket No. PUC16310-12, Order Adopting Initial Decision with Modifications and Clarifications, March 18, 2015, at 71.

Q. WHY IS IT IMPORTANT FOR A UTILITY TO BE ALLOWED THE OPPORTUNITY TO EARN AN ROE THAT IS ADEQUATE TO ATTRACT CAPITAL AT REASONABLE TERMS?

A. An ROE that is adequate to attract capital at reasonable terms enables the Company to continue to provide safe, reliable natural gas service while maintaining its financial integrity. That return should be commensurate with returns expected elsewhere in the market for investments of equivalent risk. If it is not, debt and equity investors will seek alternative investment opportunities for which the expected return reflects the perceived risks, thereby inhibiting the Company's ability to attract capital at reasonable cost.

Q. IS A UTILITY'S ABILITY TO ATTRACT CAPITAL ALSO AFFECTED BY THE ROEs AUTHORIZED FOR OTHER UTILITIES?

A. Yes. Utilities compete directly for capital with other investments of similar risk, which include other electric, natural gas, and water utilities. Therefore, the ROE authorized for a utility sends an important signal to investors regarding whether there is regulatory support for financial integrity, dividends, growth, and fair compensation for business and financial risk. The cost of capital represents an opportunity cost to investors. If higher returns are available elsewhere for other investments of comparable risk over the same time-period, investors have an incentive to direct their capital to those alternative investments. Thus, an authorized ROE significantly below authorized ROEs for other electric, natural gas, and water utilities can inhibit the utility's ability to attract capital for investment.

Q. WHAT IS THE STANDARD FOR SETTING THE ROE IN ANY JURISDICTION?

A. The stand-alone ratemaking principle is the foundation of jurisdictional ratemaking. This principle requires that the rates that are charged in any operating jurisdiction be for the costs incurred in that jurisdiction. The stand-alone ratemaking principle ensures that customers in each jurisdiction only pay for the costs of the service provided in that jurisdiction, which is not influenced by the business operations in other operating companies. In order to maintain this principle, the cost of equity analysis is performed for an individual operating company as a stand-alone entity. As such, I have evaluated the investor-required return for the Company's natural gas operations in New Jersey.

Q. ARE THE REGULATORY FRAMEWORK AND THE AUTHORIZED ROE AND EQUITY RATIO IMPORTANT TO THE FINANCIAL COMMUNITY?

A. Yes. The regulatory framework is one of the most important factors in debt and equity investors' assessments of risk. Specifically, the authorized ROE and equity ratio for regulated utilities is very important for determining the degree of regulatory support for supporting a utility's creditworthiness and financial stability in the jurisdiction. To the extent that authorized returns in a jurisdiction are lower than the returns that have been authorized more broadly, such actions are considered by both debt and equity investors in the overall risk assessment of the regulatory jurisdiction in which the company operates.

Q. WHAT ARE YOUR CONCLUSIONS REGARDING REGULATORY GUIDELINES?

A. The ratemaking process is premised on the principle that, in order for investors and companies to commit the capital needed to provide safe and reliable utility services, a utility must have a reasonable opportunity to recover the return of, and the market-required return on, its invested capital. Accordingly, the Commission's order in this proceeding should establish rates that provide the Company with a reasonable opportunity to earn an ROE that is: (1) adequate to attract capital at reasonable terms; (2) sufficient to ensure its financial integrity; and (3) commensurate with returns on investments in enterprises with similar risk. It is important for the ROE authorized in this proceeding to take into consideration current and projected capital market conditions, as well as investors' expectations and requirements for both risks and returns. Because utility operations are capital-intensive, regulatory decisions should enable the utility to attract capital at reasonable terms under a variety of economic and financial market conditions. Providing the opportunity to earn a market-based cost of capital supports the financial integrity of the Company, which is in the interest of both customers and shareholders.

IV. CAPITAL MARKET CONDITIONS

Q. WHY IS IT IMPORTANT TO ANALYZE CAPITAL MARKET CONDITIONS?

A. The models used to estimate the cost of equity rely on market data and thus the results of those models can be affected by prevailing market conditions at the time the analysis is performed. While the ROE established in a rate proceeding is intended to be forward-looking, the analyst uses current and projected market data, including stock prices, dividends, growth rates, and interest rates, in the cost of equity estimation models to estimate the investor-required return for the subject company.

Analysts and regulatory commissions recognize that current market conditions affect the results of the cost of equity estimation models. As a result, it is important to consider the effect of the market conditions on these models when determining an appropriate range for the ROE, and the reasonableness of an ROE to be used for ratemaking purposes for a future period. If investors do not expect current market conditions to be sustained in the future, it is possible that the cost of equity estimation models will not provide an accurate estimate of investors' required return during that rate period.

Therefore, it is very important to consider projected market data to estimate the return for that forward-looking period.

Q. WHAT FACTORS AFFECT THE COST OF EQUITY FOR REGULATED UTILITIES IN THE CURRENT AND PROSPECTIVE CAPITAL MARKETS?

A. The cost of equity for regulated utility companies is affected by several factors in the current and prospective capital markets, including: (1) changes in monetary policy; (2) relatively high inflation; and (3) increased interest rates that are expected to remain relatively high over the next few years. These factors affect the assumptions used in the cost of equity estimation models.

A. Inflationary Expectations in Current and Projected Capital Market Conditions

Q. WHAT HAS THE LEVEL OF INFLATION BEEN OVER THE PAST FEW YEARS?

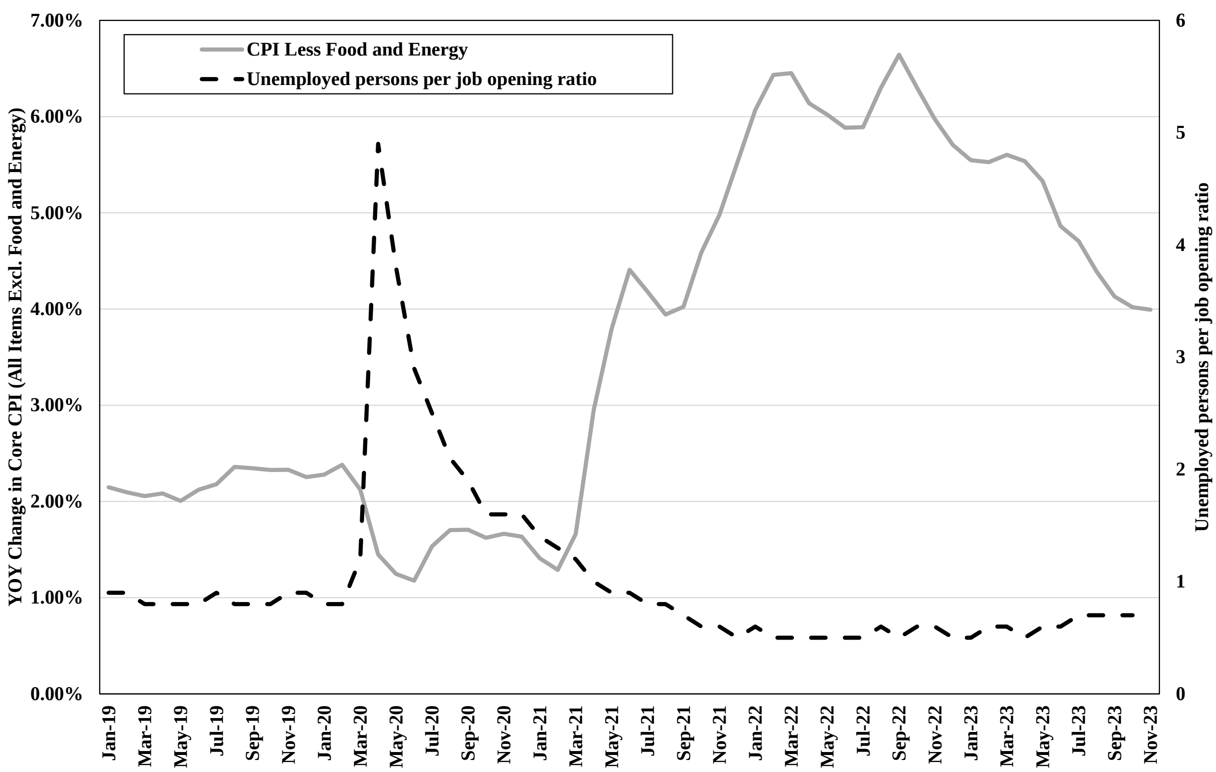
A. As shown in Figure 2, core inflation increased steadily beginning in early 2021, rising from 1.41 percent in January 2021 to a high of 6.64 percent in September 2022, which was the largest 12-month increase since 1982.[6] Since that time, while core inflation has declined in response to the Federal Reserve's monetary policy, it continues to remain above the Federal Reserve's target level of 2.0 percent.

In addition, as shown in Figure 2, I also considered the ratio of unemployed persons per job opening, which is currently 0.7 and has been consistently below 1.0 since 2021, despite the Federal Reserve's accelerated policy normalization. This metric indicates

[6] Figure 2 presents the year-over-year ("YOY") change in core inflation, as measured by the Consumer Price Index ("CPI") excluding food and energy prices as published by the Bureau of Labor Statistics. I considered core inflation because it is the preferred inflation indicator of the Federal Reserve for determining the direction of monetary policy. Core inflation is preferred by the Federal Reserve because it removes the effect of food and energy prices, which can be highly volatile.

sustained strength in the labor market. Given the Federal Reserve's dual mandate of maximum employment and price stability, the continued increased levels of core inflation coupled with the strength in the labor market has resulted in the Federal Reserve's sustained focus on the priority of reducing inflation.

Figure 2: Core Inflation and Unemployed Persons-to-Job Openings, January 2019 to November 2023[7]



Q. WHAT ARE THE EXPECTATIONS FOR INFLATION OVER THE NEAR-TERM?

A. The Federal Reserve has indicated that it expects inflation will remain elevated above its target level until 2026 and that the extent to which it maintains the restrictive monetary policy will depend on market indicators going forward. For example, Federal Reserve

[7] Bureau of Labor Statistics.

Chair Powell at the FOMC meeting on December 13, 2023 observed that while inflation is off of its recent highs, it remains too high and noted that further policy firming is possible based on the data:

> Today, we decided to leave our policy interest rate unchanged and to continue to reduce our securities holdings. Given how far we have come, along with the uncertainties and risks that we face, the Committee is proceeding carefully. We will make decisions about the extent of any additional policy firming and how long policy will remain restrictive based on the totality of the incoming data, the evolving outlook, and the balance of risks.[8]

Chair Powell reiterated that the Federal Open Market Committee ("FOMC") was committed to bringing inflation down to the 2 percent target level, and that while the easing of inflation has been good news, it is currently projected to take until 2026 to reach the Federal Reserve's target of 2.0 percent:

> Inflation has eased over the past year but remains above our longer-run goal of 2 percent. Based on the Consumer Price Index and other data, we estimate that total PCE [*Personal Consumption Expenditures]* prices rose 2.6 percent over the 12 months ending in November; and that, excluding the volatile food and energy categories, core PCE prices rose 3.1 percent. The lower inflation readings over the past several months are welcome, but we will need to see further evidence to build confidence that inflation is moving down sustainably toward our goal. Longer-term inflation expectations appear to remain well anchored, as reflected in a broad range of surveys of households, businesses, and forecasters, as well as measures from financial markets. As is evident from the SEP [*Summary of Economic Projections*], we anticipate that the process of getting inflation all the way to 2 percent will take some time. The median projection in the SEP is 2.8 percent this year, falls to 2.4 percent next year, and reaches 2 percent in 2026.[9]

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8 Federal Reserve, Transcript of Chair Powell's Press Conference, December 13, 2023, at 1.

9 *Id*., at 2-3; clarification added.

Chair Powell noted that the FOMC members project a gradual decline in the federal funds rates over time, although remain cautious and leave open the possibility of further monetary policy tightening as required:

> While we believe that our policy rate is likely at or near its peak for this tightening cycle, the economy has surprised forecasters in many ways since the pandemic, and ongoing progress toward our 2 percent inflation objective is not assured. We are prepared to tighten policy further if appropriate. We are committed to achieving a stance of monetary policy that is sufficiently restrictive to bring inflation sustainably down to 2 percent over time, and to keeping policy restrictive until we are confident that inflation is on a path to that objective.
>
> In our SEP, FOMC participants wrote down their individual assessments of an appropriate path for the federal funds rate based on what each participant judges to be the most likely scenario going forward. While participants do not view it as likely to be appropriate to raise interest rates further, neither do they want to take the possibility off the table. If the economy evolves as projected, the median participant projects that the appropriate level of the federal funds rate will be 4.6 percent at the end of 2024, 3.6 percent at the end of 2025, and 2.9 percent at the end of 2026, still above the median longer-term rate. These projections are not a Committee decision or plan; if the economy does not evolve as projected, the path for policy will adjust as appropriate to foster our maximum employment and price stability goals.[10]

B. The Use of Monetary Policy to Address Inflation

Q. WHAT POLICY ACTIONS HAS THE FEDERAL RESERVE ENACTED TO RESPOND TO INCREASED INFLATION?

A. The dramatic increase in inflation has prompted the Federal Reserve to pursue an aggressive normalization of monetary policy, removing the accommodative policy programs used to mitigate the economic effects of COVID-19. Since the March 2022 meeting, the Federal Reserve increased the target federal funds rate through a series of

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[10] *Id.*, at 3-4.

increases from a range of 0.00 – 0.25 percent to a range of 5.25 percent to 5.50 percent.[11] Further, as noted above, while the Federal Reserve acknowledges that inflation has declined from its peak, it still is well above the Federal Reserve's target of 2 percent. Therefore, the Federal Reserve anticipates the continued need to maintain the federal funds rate at a restrictive level in order to achieve its goal of 2 percent inflation over the long-run.

C. The Effect of Inflation and Monetary Policy on Interest Rates and the Investor-Required Return

Q. HAVE THE YIELDS ON LONG-TERM GOVERNMENT BONDS INCREASED IN RESPONSE TO INFLATION AND THE FEDERAL RESERVE'S NORMALIZATION OF MONETARY POLICY?

A. Yes. As the Federal Reserve has substantially increased the federal funds rate and decreased its holdings of Treasury bonds and mortgage-backed securities in response to increased levels of inflation that have persisted for longer than originally projected, longer term interest rates have also increased. As shown in Figure 3, since the Federal Reserve's December 2021 meeting, the yield on 10-year Treasury bonds has approximately tripled, increasing from 1.47 percent on December 15, 2021, to 4.37 percent at the end of December 2023.

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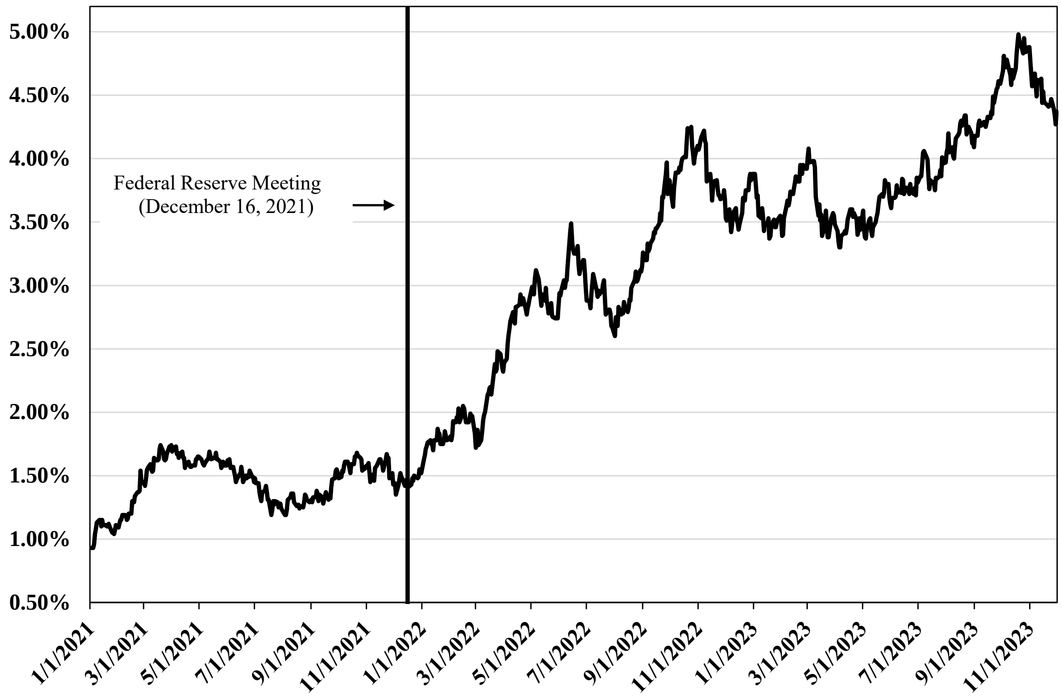
[11] https://www.federalreserve.gov/monetarypolicy/openmarket.htm.

Figure 3: 10-Year Treasury Bond Yield—Janaury 2021 through November 2023[12]



Q. HOW HAVE INTEREST RATES AND INFLATION CHANGED SINCE THE COMPANY'S LAST RATE CASE?

A. As shown in Figure 4, when the Board approved the settlement agreement authorizing an ROE of 9.60 percent in the Company's last rate proceeding, long-term interest rates (as measured by the 30-year Treasury bond yield) were 3.08 percent and core inflation was 6.30 percent. However, since that time, long-term interest rates have increased by nearly 170 basis points as the Federal Reserve has increased the federal funds rate to combat inflation, which, as shown, remains above the Federal Reserve's target.

[12] S&P Capital IQ Pro.

Figure 4: Change in Capital Market Conditions Since the Company's Last Rate Case[13]

Docket	Date	Federal Funds Rate	30-Day Avg of 30-Year Treasury Bond Yield	Core Inflation Rate	Auth'd ROE
PUC-00872-22	8/17/2022	2.33%	3.08%	6.30%	9.60%
Current	11/30/2023	5.33%	4.76%	4.02%	

Q. WHAT HAVE EQUITY ANALYSTS SAID ABOUT LONG-TERM GOVERNMENT BOND YIELDS?

A. Leading equity analysts have noted that they expect the yields on long-term government bonds to remain elevated. For example, in the most recent Big Money poll released by *Barron's* in October 2023, which surveys money managers regarding the outlook for the next twelve months, two-thirds of the money managers surveyed expect the yield on the 10-year Treasury bond to be at least 4.50 percent in October 2024.[14] Similarly, the consensus estimate of the average yields on the 10-year and 30-year Treasury bonds reported by *Blue Chip Financial Forecasts* are 4.22 percent and 4.48 percent, respectively, through the first quarter of 2025.[15] Therefore, investors expect interest rates to remain elevated for at least the next 15 months. As a result, it is reasonable to expect that if government bond yields remain elevated, the cost of equity will remain materially higher than at the time of the Company's last rate proceeding.

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[13] St. Louis Federal Reserve Bank; Bureau of Labor Statistics.

[14] Nicholas Jasinski,"Big Money Pros Are Split on the Outlook for Stocks. But They Are Fans of Bonds," *Barron's*. October 27, 2023.

[15] *Blue Chip Financial Forecasts*, Vol. 42, No. 12, December 1, 2023, p. 2.

D. Expected Performance of Utility Stocks and the Investor-Required Return on Utility Investments

Q. ARE UTILITY SHARE PRICES CORRELATED TO CHANGES IN THE YIELDS ON LONG-TERM GOVERNMENT BONDS?

A. Yes. Interest rates and utility share prices are inversely correlated, which means that increases in interest rates result in declines in the share prices of utilities and vice versa. For example, Goldman Sachs and Deutsche Bank examined the sensitivity of share prices of different industries to changes in interest rates over the past five years. Both Goldman Sachs and Deutsche Bank found that utilities had one of the strongest negative relationships with bond yields (*i.e.*, increases in bond yields resulted in the decline of utility shares).

Q. HOW DO EQUITY ANALYSTS EXPECT THE UTILITIES SECTOR TO PERFORM IN 2024?

A. Equity analysts project that utilities will underperform the broader market given high inflation and the recent increases in interest rates. For example, Fidelity Investments classifies the utility sector as underweight,[16] and Bank of America recently noted that they are "not so constructive on [u]tilities" given that the dividend yields for utilities are below both the yields available on long- and short-term treasury bonds.[17] Moreover, as referenced above, the professional investors surveyed by *Barron's* in its most recent Big Money poll selected the utility sector as one of the four equity sectors that they liked the

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16 Fidelity Investments, "Fourth Quarter 2023 Investment Research Update," October 19, 2023.

17 Julien Dumoulin-Smith, *et. al*. "US Electric Utilities & IPPs: As the leaves fall, preparing for Autumn utility outlook. Macro still has potholes," BofA Securities, September 6, 2023.

least over the next twelve months, indicating they are projecting that utilities will underperform the broader market in 2024.[18]

Q. WHY DO EQUITY ANALYSTS EXPECT THE UTILITY SECTOR TO UNDERPERFORM OVER THE NEAR-TERM?

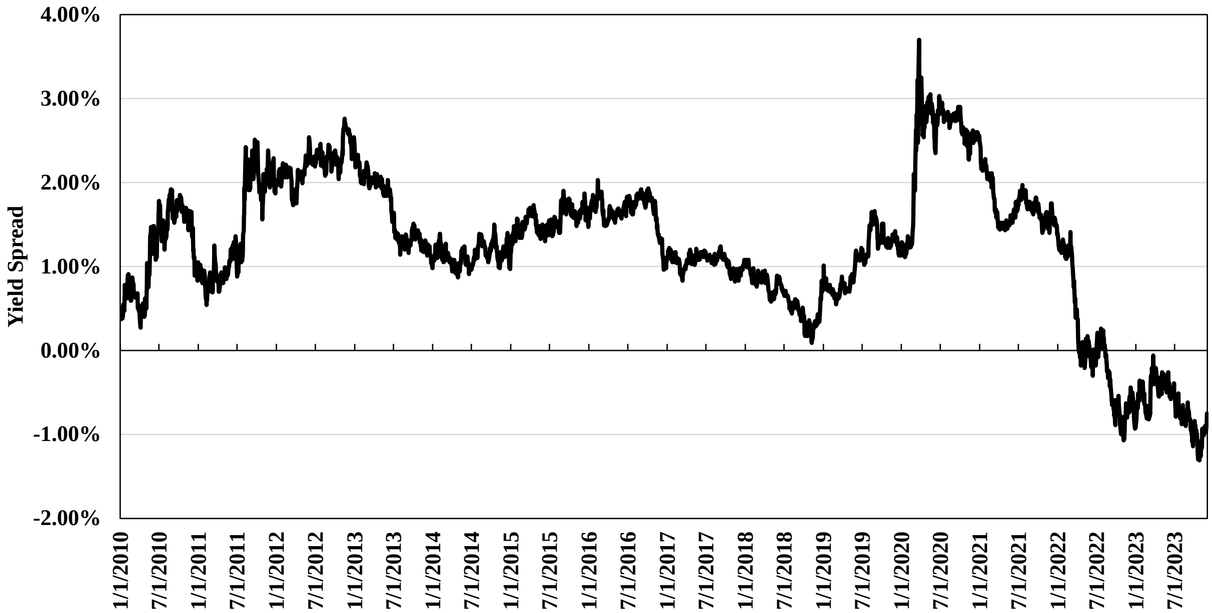
A. Equity analysts expect the utility sector to continue to underperform given that utility dividend yields remain lower than the yields on long-term government bonds. To illustrate this point, I examined the difference between the dividend yields of utility stocks and the yields on long-term government bonds from January 2010 through November 2023 ("yield spread"). I selected the dividend yield on the S&P Utilities Index as the measure of the dividend yields for the utility sector and the yield on the 10-year Treasury bond as the estimate of the yield on long-term government bonds.

As shown in Figure 5, the recent significant increase in long-term government bonds yields has resulted in the yield on long-term government bonds exceeding the dividend yields of utilities. The yield spread as of November 30, 2023 was negative 0.87 percent, meaning that the yield on the 10-year Treasury bond exceeds the dividend yield for the S&P Utilities Index. However, the long-term average yield spread from 2010 to 2023 is 1.23 percent. Therefore, the current yield spread is well below the long-term average. Because of the fact that the yield spread is currently well below the long-term average, and the expectation that interest rates will remain relatively high through at least the next year, it is reasonable to conclude that the utility sector is likely to underperform over the near-term. This is because investors that purchased utility stocks as an alternative

[18] Nicholas Jasinski,"Big Money Pros Are Split on the Outlook for Stocks. But They Are Fans of Bonds." *Barron's*. October 27, 2023.

to the lower yields on long-term government bonds would otherwise be inclined to rotate into government bonds given the yields on long-term government bonds remain elevated and higher than utility dividend yields, thus resulting in a decrease in the share prices of utilities.

Figure 5: Spread between the S&P Utilities Index Dividend Yield and the 10-year Treasury Bond Yield, January 2010 – November 2023[19]



Q. DO YOU HAVE ANY FURTHER CONTEXT AS TO HOW UNLIKELY IT IS TO HAVE A NEGATIVE YIELD SPREAD OF THIS MAGNITUDE?

A. Yes. For further context as to how unlikely it is to have a yield spread of negative 0.87 percent, I calculated the z-score for the current yield spread, which measures the number of standard deviations from the mean. The current yield spread has a z-score of -2.44, indicating that the current yield spread is over 2 standard deviations from the mean of 1.23

[19] S&P Capital IQ Pro and Bloomberg Professional.

percent.[20] In other words, 95 percent of the daily yield spread observations from 2010 through November 2023 fall between -0.49 percent and 2.96 percent, with the current yield spread falling outside of that range. Thus, the current yield spread is an outlier, which is why equity analysts do not expect this current level to hold.

The underperformance of utility stocks in 2023 and negative yield spread both demonstrate that the cost of equity for utility stocks has increased as compared with the market conditions at the time of the Company's last rate proceeding.

E. Conclusion

Q. WHAT ARE YOUR CONCLUSIONS REGARDING THE EFFECT OF CURRENT MARKET CONDITIONS ON THE COST OF EQUITY FOR THE COMPANY?

A. Due to their effect on the estimated cost of equity, it is important that current and projected market conditions be considered in setting the forward-looking ROE in this proceeding. The combination of persistently high inflation and the Federal Reserve's changes in monetary policy that have increased interest rates demonstrate that the cost of equity has increased since the Company's last rate proceeding since (i) there is a strong historical inverse correlation between interest rates (*i.e.*, yields on long-term government bonds) and the share prices of utility stocks (*i.e.*, as interest rates increase, utility share prices decline, and thus utility dividend yields increase); and (ii) the yields on long-term government bonds currently exceed the dividend yields of utilities, when historically long-term government bond yields have been lower than the dividend yields of utilities. Because the cost of equity has increased since the Company's last rate proceeding, cost of equity

[20] The z-score is calculated as: (yield spread at November 30, 2023 minus average yield spread 2010 through October 2023)/standard deviation of yield spread from 2010 through November 2023. This equals: (-0.0087 minus .0123)/0.0086.

estimates based in whole or in part on historical or current market conditions, as opposed to projected market conditions, may understate the cost of equity during the future period that the Company's rates will be in effect. Therefore, these current and expected market conditions support consideration of forward-looking cost of equity estimation models such as the CAPM and ECAPM, which better reflect expected market conditions.

V. <u>PROXY GROUP SELECTION</u>

Q. PLEASE PROVIDE A BRIEF PROFILE OF ELIZABETHTOWN.

A. Elizabethtown is a wholly-owned subsidiary of SJI, which as noted previously, was acquired and taken private in February 2023 by IIF. SJI provides natural gas distribution service across the state of New Jersey through its subsidiaries of Elizabethtown and South Jersey Gas. In total, SJI serves approximately 700,000 natural gas customers,[21] with Elizabethtown serving approximately 314,000 residential, commercial, and industrial customers across seven counties in New Jersey.[22] SJI has withdrawn its rating from Standard & Poor's ("S&P")[23] and maintains an investment-grade long-term rating of BBB (Outlook: Stable) from Fitch.[24]

Q. WHY HAVE YOU USED A GROUP OF PROXY COMPANIES TO ESTIMATE THE COST OF EQUITY FOR THE COMPANY?

A. In this proceeding, the cost of equity is being estimated for a gas utility company that is not itself publicly traded. Because the cost of equity is a market-based concept and

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[21] https://www.sjindustries.com/about-sji/company-overview.

[22] *See*, 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, December 11, 2023, at 1.

[23] S&P Global Ratings, "South Jersey Industries Inc. And Subsidiaries Ratings Withdrawn At Issuer Request," July 6, 2023.

[24] Fitch Ratings.

Elizabethtown's operations do not make up the entirety of a publicly-traded entity, it is necessary to establish a group of companies that are both publicly traded and comparable to the Company in certain fundamental business and financial respects to serve as its "proxy" in the cost of equity estimation process.

The overall purpose of developing a set of screening criteria is to select a proxy group of companies that align with the financial and operational characteristics of Elizabethtown and that investors would view as comparable to the Company. I developed the screens and thresholds for each screen based on judgment with the intention of balancing the need to maintain a proxy group that is of sufficient size with the need to establish a proxy group of companies that are comparable in business and financial risk to Elizabethtown.

Even if Elizabethtown's regulated natural gas distribution business made up the entirety of a publicly-traded entity, it is possible that transitory events could bias its market value over a given time period. A significant benefit of using a proxy group is that it mitigates the effects of anomalous events that may be associated with any one company. The proxy companies used in my analyses all possess a set of operating and financial risk characteristics that are substantially comparable to Elizabethtown, and, therefore, provide a reasonable basis to estimate the appropriate cost of equity for the Company.

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

A. I began with the group of U.S. utilities that *Value Line Investment Survey* ("*Value Line*") classifies as "Natural Gas Distribution Companies" and "Water Utilities." That combined group includes 16 domestic U.S. utilities, and I applied the following screening criteria to select companies that:

- pay consistent quarterly cash dividends, since companies that do not pay dividends cannot be analyzed using the constant growth DCF model;
- have investment grade long-term issuer ratings from both S&P and Moody's Investors Service ("Moody's");
- are covered by more than one utility industry analyst;
- have positive long-term earnings growth forecasts from at least two equity analysts;
- derive more than 70.00 percent of their total operating income from regulated operations; and,
- were not parties to a merger or transformative transaction during the analytical periods relied on.

Q. DID YOU CONSIDER ANY ADDITIONAL COMPANIES FOR INCLUSION IN YOUR PROXY GROUP?

A. Yes. I also considered the group of 36 companies that *Value Line* classifies as "Electric Utilities". In determining which electric utilities would qualify for inclusion in my proxy group, I started by relying on the criteria used to screen the water and natural gas utilities. I then applied two additional screening criteria to only include electric utilities that would be considered risk comparable to Elizabethtown:

- have owned generation comprising less than 10 percent of the Company's MWh sales to ultimate customers to ensure that the electric utilities included did not own a substantial amount of generation and therefore had operations that were primarily transmission and distribution; and,
- own water operations.

Q. WHAT IS THE COMPOSITION OF YOUR PROXY GROUP?

A. The screening criteria just discussed results in a proxy group consisting of the companies shown in Figure 6 (and also in Exhibit P-7, Schedule AEB-3).

Figure 6: Proxy Group Composition

Company	Ticker
Atmos Energy Corporation	ATO
NiSource Inc.	NI
Northwest Natural Gas Company	NWN
ONE Gas, Inc.	OGS
Spire, Inc.	SR
Eversource Energy	ES
American States Water Company	AWR
California Water Service Group	CWT
Middlesex Water Company	MSEX
SJW Group	SJW
Essential Utilities, Inc.	WTRG

Q. ARE WATER AND ELECTRIC DISTRIBUTION UTILITIES REASONABLY COMPARABLE TO NATURAL GAS DISTRIBUTION UTILITIES TO BE INCLUDED IN A PROXY GROUP USED TO ESTIMATE THE COST OF EQUITY IN THIS PROCEEDING?

A. Yes, it is reasonable to rely on a combined proxy group in this circumstance given the small number of natural gas distribution utilities. Specifically, *Value Line* currently classifies only 10 companies as natural gas utilities, which is a relatively small universe even before the screening criteria are applied, and after the screening criteria are applied, there are only 5 companies that remain. Furthermore, as noted, my screening criteria requires that a company derive more than 70 percent of its operating income from regulated operations, which means that the water and electric utilities included in my proxy group generate a large portion of their operating income from regulated operations similar to Elizabethtown and the other natural gas distribution utilities in the proxy group. As a result, it is appropriate to include water and electric distribution utilities companies in my proxy group.

VI. COST OF EQUITY ESTIMATION

Q. PLEASE BRIEFLY DISCUSS THE ROE IN THE CONTEXT OF THE REGULATED RATE OF RETURN.

A. The rate of return for a regulated utility is the weighted average cost of capital, in which the costs of the individual sources of capital are weighted by their respective proportion (*i.e.*, book values) in the utility's capital structure. The ROE is the cost rate applied to the equity capital in calculating the rate of return. While the costs of debt and preferred stock can be directly observed, the cost of equity is market-based and, therefore, must be estimated based on observable market data.

Q. HOW IS THE REQUIRED COST OF EQUITY DETERMINED?

A. The required cost of equity is estimated by using analytical techniques that rely on market-based data to quantify investor expectations regarding equity returns, adjusted for certain incremental costs and risks. Informed judgment is then applied to determine where the company's cost of equity falls within the range of results produced by multiple analytical techniques. The key consideration in determining the cost of equity is to ensure that the methodologies employed reasonably reflect investors' views of the financial markets in general, as well as the subject company (in the context of the proxy group), in particular.

Q. WHAT METHODS HAVE YOU USED TO ESTIMATE THE COMPANY'S COST OF EQUITY IN THIS PROCEEDING?

A. I consider the results of the constant growth DCF model, the CAPM, the ECAPM, and a BYRP approach. A reasonable cost of equity estimate appropriately considers alternative methodologies and the reasonableness of their individual and collective results.

Q. WHY IS IT IMPORTANT TO USE MORE THAN ONE ANALYTICAL APPROACH TO ESTIMATE THE COST OF EQUITY?

A. Because the cost of equity is not directly observable, it must be estimated based on both quantitative and qualitative information. When faced with the task of estimating the cost of equity, analysts and investors are inclined to gather and evaluate as much relevant data as reasonably can be analyzed. Several models have been developed to estimate the cost of equity, and I use multiple approaches to estimate the cost of equity. As a practical matter, however, all of the models available for estimating the cost of equity are subject to limiting assumptions or other methodological constraints. Consequently, many well-regarded finance texts recommend using multiple approaches when estimating the cost of equity. For example, Copeland, Koller, and Murrin[25] suggest using the CAPM and Arbitrage Pricing Theory model, while Brigham and Gapenski[26] recommend the CAPM, DCF, and BYRP approaches. In addition, the Board has previously recognized that rate of return experts typically use a variety of financial models to estimate the returns required by investors.[27]

Further, the recent changes in market conditions discussed previously highlight the benefit of using multiple models since each model relies on different assumptions, certain of which better reflect current and projected market conditions at different times. For example, the CAPM, ECAPM, and BYRP analyses rely directly on interest rates as an

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[25] Tom Copeland, Tim Koller and Jack Murrin, *Valuation: Measuring and Managing the Value of Companies*, New York, McKinsey & Company, Inc., 3rd Ed., 2000, at 214.

[26] Eugene Brigham and Louis Gapenski, *Financial Management: Theory and Practice*, Orlando, Dryden Press, 1994, at 341.

[27] New Jersey Board of Public Utilities, Docket No. ER12111052, OAL Docket No. PUC16310-12, Order Adopting Initial Decision with Modifications and Clarifications, March 18, 2015, at 71.

assumption in the models and therefore may more directly reflect the market conditions expected when the Company's rates are in effect. Accordingly, it is important to use multiple analytical approaches to ensure that the cost of equity results reflect market conditions that are expected during the period that the Company's rates will be in effect.

A. Constant Growth DCF Model

Q. PLEASE DESCRIBE THE DCF APPROACH.

A. The DCF approach is based on the theory that a stock's current price represents the present value of all expected future cash flows. In its most general form, the DCF model is expressed as follows:

$$P_0 = \frac{D_1}{(1+k)} + \frac{D_2}{(1+k)^2} + \cdots + \frac{D_\infty}{(1+k)^\infty} \qquad [1]$$

Where P_0 represents the current stock price, $D_1 \ldots D_\infty$ are all expected future dividends, and k is the discount rate, or required cost of equity. Equation [1] is a standard present value calculation that can be simplified and rearranged into the following form:

$$k = \frac{D_0(1+g)}{P_0} + g \qquad [2]$$

Equation [2] is often referred to as the constant growth DCF model in which the first term is the expected dividend yield and the second term is the expected long-term growth rate.

Q. WHAT ASSUMPTIONS ARE REQUIRED FOR THE CONSTANT GROWTH DCF MODEL?

A. The constant growth DCF model requires the following assumptions: (1) a constant growth rate for earnings and dividends; (2) a stable dividend payout ratio; (3) a constant price-to-earnings ratio; and (4) a discount rate greater than the expected growth rate. To the extent that any of these assumptions are violated, considered judgment and/or specific adjustments should be applied to the results.

Q. WHAT MARKET DATA DO YOU USE TO CALCULATE THE DIVIDEND YIELD IN YOUR CONSTANT GROWTH DCF MODEL?

A. The dividend yield in my constant growth DCF model is based on the proxy group companies' current annual dividend and average closing stock prices over the 30-, 90-, and 180-trading days ended November 30, 2023.

Q. WHY DO YOU USE 30-, 90-, AND 180-DAY AVERAGING PERIODS?

A. In my constant growth DCF model, I use an average of recent trading days to calculate the term P_0 in the DCF model to ensure that the cost of equity is not skewed by anomalous events that may affect stock prices on any given trading day. The averaging period should also be reasonably representative of expected capital market conditions over the long term.

Q. DO YOU MAKE ANY ADJUSTMENTS TO THE DIVIDEND YIELD TO ACCOUNT FOR PERIODIC GROWTH IN DIVIDENDS?

A. Yes. Since utility companies tend to increase their quarterly dividends at different times throughout the year, it is reasonable to assume that dividend increases will be evenly distributed over calendar quarters. Given that assumption, it is reasonable to apply one-half of the expected annual dividend growth rate for purposes of calculating the expected dividend yield component of the DCF model. This adjustment ensures that the expected first year dividend yield is, on average, representative of the coming twelve-month period, and does not overstate the aggregated dividends to be paid during that time.

Q. WHY IS IT IMPORTANT TO SELECT APPROPRIATE MEASURES OF LONG-TERM GROWTH IN APPLYING THE DCF MODEL?

A. In its constant growth form, the DCF model (*i.e.*, Equation [2]) assumes a single long-term growth rate in perpetuity. In order to reduce the long-term growth rate to a single measure, one must assume that the dividend payout ratio remains constant and that earnings per share ("EPS"), dividends per share, and book value per share all grow at the same constant rate. However, over the long run, dividend growth can only be sustained by earnings growth, meaning earnings are the fundamental driver of a company's ability to pay dividends. therefore, projected EPS growth is the appropriate measure of a company's long-term growth. In contrast, changes in a company's dividend payments are based on management decisions related to cash management and other factors. For example, a company may decide to retain earnings rather than pay out a portion of those earnings to shareholders through dividends. Therefore, dividend growth rates are less likely than earnings growth rates to accurately reflect investor perceptions of a company's growth prospects. Accordingly, I have incorporated a number of sources of long-term EPS growth rates into the constant growth DCF model.

Q. WHICH SOURCES OF LONG-TERM EARNINGS GROWTH RATES DO YOU USE?

A. My constant growth DCF model incorporates three sources of long-term projected EPS growth rates: (1) *Zacks Investment Research* ("*Zacks*"); (2) Yahoo! Finance; and (3) *Value Line*.

Q. HOW DO YOU CALCULATE THE RANGE OF RESULTS FOR THE CONSTANT GROWTH DCF MODELS?

A. I calculate the low-end result for the constant growth DCF model using the minimum growth rate of the three sources (*i.e.*, the lowest of the *Zacks*, Yahoo! Finance, and *Value Line* projected EPS growth rates) for each of the proxy group companies. I apply a similar approach to calculate a high-end result, using the maximum growth rate of the three sources for each proxy group company. Lastly, I also calculate results using the average EPS growth rate from all three sources for each proxy group company.

Q. WHAT ARE THE RESULTS OF YOUR CONSTANT GROWTH DCF ANALYSES?

A. Figure 7 (see also Exhibit P-7, Schedule AEB-4) summarizes the results of my DCF analyses. While I also summarize the DCF results using the minimum growth rates, given the recent negative market response to decisions in Illinois for Ameren IL and ComEd,[28] it is evident that the market would not consider these DCF results reflective of the investor-required return, and thus I do not give these DCF results any material weight at this time.

Figure 7: Summary of DCF Results

	Minimum Growth Rate	Average Growth Rate	Maximum Growth Rate
Mean Results:			
30-Day Avg. Stock Price	9.12%	10.16%	11.31%
90-Day Avg. Stock Price	8.97%	10.01%	11.16%
180-Day Avg. Stock Price	8.77%	9.81%	10.96%
Average	8.95%	9.99%	11.14%
Median Results:			
30-Day Avg. Stock Price	8.90%	9.92%	11.10%
90-Day Avg. Stock Price	8.69%	9.61%	10.84%
180-Day Avg. Stock Price	8.52%	9.28%	10.64%
Average	8.70%	9.60%	10.86%

[28] Allison Good, "Ameren, Exelon shares fall after Illinois regulators reject grid plans," *Platts*, December 15, 2023.

Q. HAVE REGULATORY COMMISSIONS ACKNOWLEDGED THAT THE DCF MODEL MIGHT UNDERSTATE THE COST OF EQUITY GIVEN THE CURRENT CAPITAL MARKET CONDITIONS OF RELATIVELY HIGH INFLATION AND ELEVATED INTEREST RATES?

A. Yes. For example, in its May 2022 decision establishing the cost of equity for Aqua Pennsylvania, Inc., the Pennsylvania Public Utility Commission ("PPUC") concluded that the current capital market conditions of high inflation and increased interest rates have resulted in the DCF model understating the utility cost of equity, and that weight should be placed on risk premium models, such as the CAPM, in the determination of the ROE:

> To help control rising inflation, the Federal Open Market Committee has signaled that it is ending its policies designed to maintain low interest rates. Aqua Exc. at 9. Because the DCF model does not directly account for interest rates, consequently, it is slow to respond to interest rate changes. However, I&E's [*the PPUC's Bureau of Investigation and Enforcement*] CAPM model uses forecasted yields on ten-year Treasury bonds, and accordingly, its methodology captures forward looking changes in interest rates.
>
> Therefore, our methodology for determining Aqua's ROE shall utilize both I&E's DCF and CAPM methodologies. As noted above, the Commission recognizes the importance of informed judgment and information provided by other ROE models. In the 2012 PPL Order, the Commission considered PPL's CAPM and RP methods, tempered by informed judgment, instead of DCF-only results. We conclude that methodologies other than the DCF can be used as a check upon the reasonableness of the DCF derived ROE calculation. Historically, we have relied primarily upon the DCF methodology in arriving at ROE determinations and have utilized the results of the CAPM as a check upon the reasonableness of the DCF derived equity return. As such, where evidence based on other methods suggests that the DCF-only results may understate the utility's ROE, we will consider those other methods, to some degree, in determining the appropriate range of reasonableness for our equity return determination. In light of the above, we

> shall determine an appropriate ROE for Aqua using informed judgement based on I&E's DCF and CAPM methodologies.[29]

Similarly, the Massachusetts Department of Public Utilities in a recent rate case for NSTAR Electric Company concluded that given the recent increase in interest rates there was "greater certainty" that the results of the DCF model were understating the cost of equity for the utility.[30]

B. CAPM Analysis

Q. PLEASE BRIEFLY DESCRIBE THE CAPM.

A. The CAPM is a risk premium approach that estimates the cost of equity for a given security as a function of a risk-free return plus a risk premium to compensate investors for the non-diversifiable or "systematic" risk of that security.[31] This second component is the product of the market risk premium and the beta coefficient, which measures the relative riskiness of the security being evaluated.

The CAPM is defined by four components:

$$K_e = r_f + \beta(r_m - r_f) \qquad [3]$$

Where:

K_e = the required market ROE;

β = the beta coefficient of an individual security;

r_f = the risk-free rate of return; and

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[29] Pennsylvania Public Utility Commission, Docket Nos. R-2021-3027385 and R-2021-3027386, Opinion and Order, May 12, 2022, at 154-155; clarification added.

[30] Massachusetts Department of Public Utilities, D.P.U. 22-22, November 30, 2022,at 385-386.

[31] Systematic risk is the risk inherent in the entire market or market segment, which cannot be diversified away using a portfolio of assets. Unsystematic risk is the risk of a specific company that can, theoretically, be mitigated through portfolio diversification.

r_m = the required return on the market as a whole.

In this specification, the term ($r_m - r_f$) represents the market risk premium. According to the theory underlying the CAPM, because unsystematic risk can be diversified away, investors should only be concerned with systematic or non-diversifiable risk. Systematic risk is measured by beta, which is a measure of the volatility of a security as compared to the market as a whole. Beta is defined as:

$$\beta = \frac{Covariance(r_e, r_m)}{Variance(r_m)} \qquad [4]$$

Variance (r_m) represents the variance of the market return, which is a measure of the uncertainty of the general market. *Covariance* (r_e, r_m) represents the covariance between the return on a specific security and the general market, which reflects the extent to which the return on that security will respond to a given change in the general market return. Thus, beta represents the risk of the security relative to the general market.

Q. WHAT RISK-FREE RATE DO YOU USE IN YOUR CAPM ANALYSIS?

A. I rely on three sources for my estimate of the risk-free rate: (1) the current 30-day average yield on 30-year U.S. Treasury bonds, which is 4.77 percent;[32] (2) the average projected 30-year Treasury bond yield for the first quarter of 2024 through the first quarter of 2025, which is 4.48 percent;[33] and (3) the average projected 30-year Treasury bond yield for 2025 through 2029, which is 4.10 percent.[34]

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32 Bloomberg Professional, as of November 30, 2023.

33 *Blue Chip Financial Forecasts*, Vol. 42, No. 12, December 1, 2023, at 2.

34 *Id.*, at 14.

Q. WHAT BETA COEFFICIENTS DO YOU USE IN YOUR CAPM ANALYSIS?

A. As shown in Exhibit P-7, Schedule AEB-5, I use the beta coefficients for the proxy group companies as reported by *Bloomberg Professional* ("*Bloomberg")* and *Value Line*. The beta coefficients reported by *Bloomberg* are calculated using ten years of weekly returns relative to the S&P 500 Index. The beta coefficients reported by *Value Line* are calculated based on five years of weekly returns relative to the New York Stock Exchange Composite Index. Additionally, as shown in Exhibit P-7, Schedules AEB-5 and AEB-6, I also consider an additional CAPM analysis that relies on the long-term average beta coefficient reported by *Value Line* for the companies in my proxy group from 2013 through 2022.

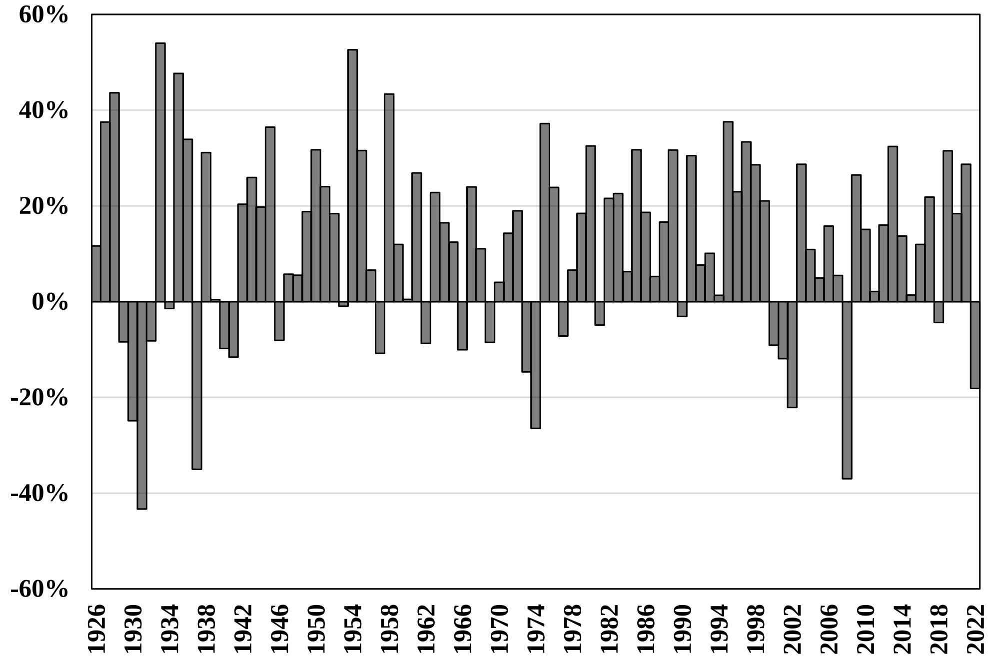
Q. HOW DO YOU ESTIMATE THE MARKET RISK PREMIUM IN THE CAPM?

A. I estimate the market risk premium as the difference between the implied expected equity market return and the risk-free rate. As shown in Exhibit P-7, Schedule AEB-7, the expected return on the S&P 500 Index is calculated using the constant growth DCF model discussed previously as applied to the companies in the S&P 500 Index. Based on an estimated market capitalization-weighted dividend yield of 1.69 percent and a weighted long-term growth rate of 10.78 percent, the estimated required market return for the S&P 500 Index as of November 30, 2023 is 12.56 percent.

Q. HOW DOES THE CURRENT EXPECTED MARKET RETURN YOU HAVE CALCULATED COMPARE TO OBSERVED HISTORICAL MARKET RETURNS?

A. As shown in Figure 8, given the range of annual equity returns that have been observed over the past century, a current expected return of 12.56 percent is not unreasonable. In 50 out of the past 97 years (or roughly 52 percent of observations), the realized equity return was at least 12.56 percent or greater**.**

Figure 8: Realized U.S. equity market returns (1926-2022)[35]



Q. DO YOU ALSO CONSIDER ANOTHER FORM OF THE CAPM IN YOUR ANALYSIS?

A. Yes. I have also considered the results of an ECAPM in estimating the cost of equity for the Company.[36] The ECAPM calculates the product of the adjusted beta coefficient and the market risk premium and applies a weight of 75.00 percent to that result. The model then applies a 25.00 percent weight to the market risk premium without any effect from the beta coefficient. The results of the two calculations are summed, along with the risk-free rate, to produce the ECAPM result, as noted in Equation [5] below:

[35] Depicts total annual returns on large company stocks, as reported in the 2023 *Kroll* SBBI Yearbook.

[36] *See, e.g.*, Roger A. Morin, *New Regulatory Finance*, Public Utilities Reports, Inc., 2006, at 189.

$$k_e = r_f + 0.75\beta(r_m - r_f) + 0.25(r_m - r_f) \qquad [5]$$

Where:

k_e = the required market ROE
β = the adjusted beta coefficient of an individual security
r_f = the risk-free rate of return
r_m = the required return on the market as a whole

The ECAPM addresses the tendency of the "traditional" CAPM to underestimate the cost of equity for companies with low beta coefficients such as regulated utilities. In that regard, the ECAPM is not redundant to the use of adjusted betas in the traditional CAPM, but rather it recognizes the results of academic research indicating that the risk-return relationship is different (in essence, flatter) than estimated by the CAPM, and that the CAPM underestimates the "alpha," or the constant return term.[37]

Consistent with my CAPM, my application of the ECAPM uses the forward-looking market risk premium estimates, the three yields on the 30-year Treasury bonds noted earlier as the risk-free rate, and the current *Bloomberg*, current *Value Line*, and long-term *Value Line* beta coefficients.

Q. WHAT ARE THE RESULTS OF YOUR CAPM ANALYSES?

A. The results of my CAPM and ECAPM analyses are shown in Figure 9, as well as Exhibit P-7, Schedule AEB-5).

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[37] *Id*. at 191.

Figure 9: CAPM and ECAPM Results

	30-Year Treasury Bond Yield		
	Current 30-Day Avg	Near-Term Projected	Longer-Term Projected
CAPM:			
Current *Value Line* Beta	11.28%	11.23%	11.17%
Current Bloomberg Beta	10.72%	10.65%	10.56%
Long-term Avg. *Value Line* Beta	10.46%	10.38%	10.28%
ECAPM:			
Current *Value Line* Beta	11.60%	11.56%	11.52%
Current Bloomberg Beta	11.18%	11.13%	11.06%
Long-term Avg. *Value Line* Beta	10.98%	10.92%	10.85%

C. BYRP Analysis

Q. PLEASE DESCRIBE THE BYRP ANALYSIS.

A. In general terms, this approach is based on the fundamental principle that equity investors bear the residual risk associated with equity ownership and therefore require a premium over the return they would have earned as bondholders. In other words, because returns to equity holders have greater risk than returns to bondholders, equity holders require a higher return for that incremental risk. Thus, risk premium approaches estimate the cost of equity as the sum of the equity risk premium and the yield on a particular class of bonds. In my analysis, I use actual authorized returns for natural gas utilities as the historical measure of the cost of equity to determine the risk premium.

Q. WHAT IS THE FUNDAMENTAL RELATIONSHIP BETWEEN THE EQUITY RISK PREMIUM AND INTEREST RATES?

A. It is important to recognize both academic literature and market evidence indicating that the equity risk premium (as used in this approach) is inversely related to the level of interest rates (*i.e.*, as interest rates increase, the equity risk premium decreases, and vice versa).

Consequently, it is important to develop an analysis that: (1) reflects the inverse relationship between interest rates and the equity risk premium; and (2) relies on recent and expected market conditions. The analysis provided in Exhibit P-7, Schedule AEB-8 establishes that relationship using a regression of the risk premium as a function of Treasury bond yields. When the authorized ROEs serve as the measure of required equity returns and the yield on the long-term Treasury bond is defined as the relevant measure of interest rates, the risk premium is the difference between those two points.[38]

Q. IS THE BYRP ANALYSIS RELEVANT TO INVESTORS?

A. Yes. Investors are aware of authorized ROEs in other jurisdictions and they consider those awards as a benchmark for a reasonable level of equity returns for utilities of comparable risk operating in other jurisdictions. As discussed previously, utilities have experienced credit rating downgrades and been subject to a negative market reaction related to the financial effects of a rate case decision that included a below average authorized ROE. Because my BYRP analysis is based on authorized ROEs for utility companies relative to corresponding Treasury yields, it provides relevant information to assess the return expectations of investors in the current interest rate environment.

Q. WHAT DOES YOUR BYRP ANALYSIS REVEAL?

A. As shown in Figure 10, from 1980 through November 2023, there has been a strong negative relationship between risk premia and interest rates. To estimate that relationship, I conducted a regression analysis using the following equation:

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[38] *See e.g.*, S. Keith Berry,"Interest Rate Risk and Utility Risk Premia during 1982-93," *Managerial and Decision Economics*, Vol. 19, No. 2, March, 1998 (the author used a similar methodology, including using authorized ROEs as the relevant data source, and came to similar conclusions regarding the inverse relationship between risk premia and interest rates). *See also* Robert S.Harris, "Using Analysts' Growth Forecasts to Estimate Shareholder Required Rates of Return," *Financial Management*, Spring 1986, at 66.

$$RP = a + b(T) \; [6]$$

Where:

RP = Risk Premium (difference between authorized ROEs and the yield on 30-year Treasury bonds)

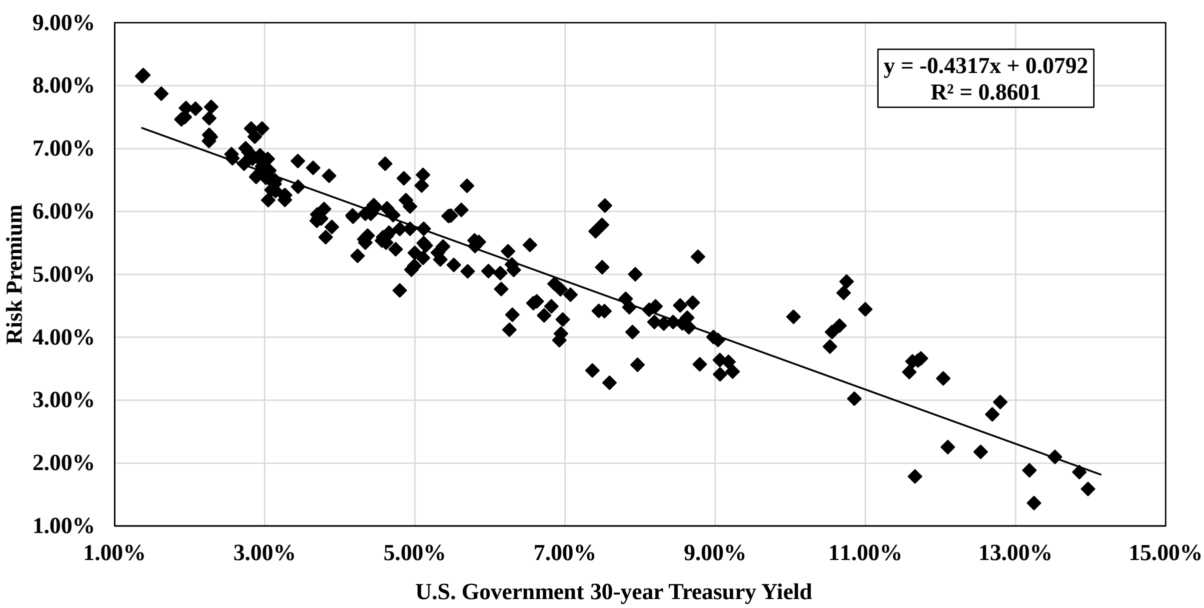
a = intercept term

b = slope term

T = 30-year Treasury bond yield

Data regarding authorized ROEs were derived from all natural gas utility rate cases over this time period as reported by Regulatory Research Associates ("RRA").[39] This equation's coefficients were statistically significant at the 99.00 percent level.

Figure 10: Risk Premium Regression Analysis



Q. WHAT ARE THE RESULTS OF YOUR BYRP ANALYSIS?

A. Figure 11 presents the results of my BYRP analysis, which are also presented in more detail in Exhibit P-7, Schedule AEB-8.

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[39] This analysis was screened to eliminate limited issue rider cases, pipeline transmission cases, and cases that were silent with respect to the authorized ROE.

Figure 11: Summary of BYRP Results

	30-Year Treasury Bond Yield		
	Current 30-Day Avg	Near-Term Projected	Longer-Term Projected
Bond Yield Risk Premium	10.63%	10.46%	10.25%

VII. BUSINESS AND REGULATORY RISKS

Q. DO THE RESULTS OF THE COST OF EQUITY ANALYSES ALONE PROVIDE AN APPROPRIATE ESTIMATE OF THE COST OF EQUITY FOR THE COMPANY?

A. No. The model results provide only a range of the appropriate estimate of the Company's cost of equity. Several additional factors must be considered when determining the reasonableness of where the Company's cost of equity falls within the range of analytical results. These risk factors, discussed below, should be considered with respect to their overall effect on the Company's risk profile relative to the proxy group.

A. Small Size Risk

Q. IS THERE A RISK TO A FIRM ASSOCIATED WITH SMALL SIZE?

A. Yes. Both the financial and academic communities have long accepted the proposition that the cost of equity for small firms is subject to a "size effect." While empirical evidence of the size effect often is based on studies of industries other than regulated utilities, utility analysts also have noted the risk associated with small market capitalizations. Specifically, an analyst for Ibbotson Associates noted:

> For small utilities, investors face additional obstacles, such as a smaller customer base, limited financial resources, and a lack of diversification

> across customers, energy sources, and geography. These obstacles imply a higher investor return.[40]

Q. HOW DOES THE SMALLER SIZE OF A UTILITY AFFECT ITS BUSINESS RISK?

A. In general, smaller companies are less able to withstand adverse events that affect their revenues and expenses. The impact of weather variability, the loss of large customers to bypass opportunities, or the destruction of demand as a result of general macroeconomic conditions or fuel price volatility will have a proportionately greater impact on the earnings and cash flow volatility of smaller utilities. Similarly, capital expenditures for non-revenue producing investments, such as system maintenance and replacements, will put proportionately greater pressure on customer costs, potentially leading to customer attrition or demand reduction. Taken together, these risks affect the return required by investors for smaller companies.

Q. HOW DO ELIZABETHTOWN'S NATURAL GAS OPERATIONS COMPARE IN SIZE TO THE PROXY GROUP COMPANIES?

A. Elizabethtown's natural gas operations in New Jersey are substantially smaller than the median of the proxy group companies in terms of market capitalization. While Elizabethtown is not publicly traded on a stand-alone basis, as shown on Exhibit P-7, Schedule AEB-9, I have estimated the implied market capitalization for the Company (*i.e.*, the market capitalization if the Company were a stand-alone publicly-traded entity) relative to the actual market capitalization for the proxy group companies.

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[40] Michael Annin, "Equity and the Small-Stock Effect." Public Utilities Fortnightly, October 15, 1995.

Specifically, to estimate the size of the Company's implied market capitalization relative to the proxy group, I first calculate the equity component of the Company's capital structure by multiplying the Company's test year rate base of $1.730 billion by the Company's proposed common equity ratio in this proceeding of 57.00 percent. I then apply the median market-to-book ratio for the proxy group of 1.60 to the Company's implied common equity balance to estimate an implied market capitalization, which is approximately $1.576 billion, or just approximately 51 percent of the median market capitalization for the proxy group.

Q. HOW DID YOU ESTIMATE THE SIZE PREMIUM FOR ELIZABETHTOWN GAS COMPANY?

A. Given this relative size information, it is possible to estimate the impact of size on the cost of equity for the Company using *Kroll* Cost of Capital Navigator data that estimates the stock risk premia based on the size of a company's market capitalization.[41] As shown on Exhibit P-7, Schedule AEB-9, the median market capitalization of the proxy group is approximately $3.08 billion, which corresponds to the fifth decile of *Kroll's* market capitalization data.[42] Based on *Kroll's* analysis, that decile corresponds to a size premium of 0.93 percent (*i.e.*, 93 basis points). In comparison, the Company's implied market capitalization falls within the sixth decile, which corresponds to a size premium of 1.16 percent (*i.e.*, 116 basis points). The difference between the size premium for the Company and the size premium for the proxy group is 23 basis points (*i.e.*, 1.16 percent minus 0.93 percent).

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[41] *Kroll* Cost of Capital Navigator – Size Premium; annual data as of December 31, 2022.

[42] *Id*.

Q. WERE UTILITY COMPANIES INCLUDED IN THE SIZE PREMIUM STUDY CONDUCTED BY *KROLL*?

A. Yes. As shown in Exhibit 7.2 of the *Kroll* (formerly *Duff & Phelps*) 2019 Valuation Handbook, OGE Energy Corp. had the largest market capitalization of the companies contained in the fourth decile, which indicates that *Kroll* has included utility companies in its size risk premium study.[43]

Q. IS THE SIZE PREMIUM APPLICABLE TO COMPANIES IN REGULATED INDUSTRIES SUCH AS UTILITIES?

A. Yes. For example, Zepp (2003) provided the results of two studies that showed evidence of the required risk premium for small water utilities. The first study, which was conducted by the Staff of the California Public Utilities Commission, computed proxies for beta risk using accounting data from 1981 through 1991 for 58 water utilities and concluded that smaller water utilities had greater risk and required higher returns on equity than larger water utilities.[44] The second study examined the differences in required returns over the period of 1987 through 1997 for two large and two small water utilities in California. As Zepp (2003) showed, the required return for the two small water utilities calculated using the DCF model was on average 99 basis points higher than the two larger water utilities.[45]

Additionally, Chrétien and Coggins (2011) studied the CAPM and its ability to estimate the risk premium for the utility industry, and in particular subgroups of utilities.[46]

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[43] *Kroll*. Valuation Handbook: Guide to Cost of Capital. 2019, Exhibit 7.2.

[44] Thomas M. Zepp, "Utility Stocks and the Size Effect—Revisited," *The Quarterly Review of Economics and Finance*. Vol. 43, No. 3, 2003, at 578–582.

[45] *Id*.

[46] Stéphane Chrétien and Frank Coggins, "Cost Of Equity For Energy Utilities: Beyond The CAPM," *Energy Studies Review*, Vol. 18, No. 2, 2011.

The article considered the CAPM, the Fama-French three-factor model, and a model similar to the ECAPM, which as previously discussed, I have also considered in estimating the cost of equity for the Company. In the study, the Fama-French three-factor model explicitly included an adjustment to the CAPM for risk associated with size. As Chrétien and Coggins (2011) show, the beta coefficient on the size variable for the U.S. natural gas utility group was positive and statistically significant indicating that small size risk was relevant for regulated natural gas utilities.[47]

Q. HAVE REGULATORS IN OTHER JURISDICTIONS MADE A SPECIFIC RISK ADJUSTMENT TO THE COST OF EQUITY RESULTS BASED ON A COMPANY'S SMALL SIZE?

A. Yes. For example, in Order No. 15, the Regulatory Commission of Alaska ("RCA") concluded that Alaska Electric Light and Power Company ("AEL&P") was riskier than the proxy group companies due to small size as well as other business risks. The RCA did "not believe that adopting the upper end of the range of ROE analyses in this case, without an explicit adjustment, would adequately compensate AEL&P for its greater risk."[48] Thus, the RCA awarded AEL&P an ROE of 12.875 percent, which was 108 basis points above the highest cost of equity estimate from any model presented in the case.[49] Similarly, the RCA has also noted that small size, as well as other business risks such as structural regulatory lag, weather risk, alternative rate mechanisms, gas supply risk, geographic

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[47] *Id.*

[48] Regulatory Commission of Alaska, Docket No. U-10-29, Order No. 15, September 2, 2011, at 37.

[49] *Id.*, at 32 and 37.

isolation and economic conditions, increased the risk of ENSTAR Natural Gas Company.[50] Ultimately, the RCA concluded that:

> Although we agree that the risk factors identified by ENSTAR increase its risk, we do not attempt to quantify the amount of that increase. Rather, we take the factors into consideration when evaluating the remainder of the record and the recommendations presented by the parties. After applying our reasoned judgment to the record, we find that 11.875% represents a fair ROE for ENSTAR.[51]

Additionally, the Minnesota Public Utilities Commission ("Minnesota PUC") authorized an ROE for Otter Tail Power Company ("Otter Tail") above the mean DCF results as a result of multiple factors, including Otter Tail's small size. The Minnesota PUC stated:

> The record in this case establishes a compelling basis for selecting an ROE above the mean average within the DCF range, given Otter Tail's unique characteristics and circumstances relative to other utilities in the proxy group. These factors include the company's relatively smaller size, geographically diffuse customer base, and the scope of the Company's planned infrastructure investments.[52]

Finally, in Opinion Nos. 569 and 569-A, the Federal Energy Regulatory Commission ("FERC") adopted a size premium adjustment in its CAPM estimates for electric utilities. In those decisions, the FERC noted that "the size adjustment was necessary to correct for the CAPM's inability to fully account for the impact of firm size when determining the cost of equity."[53]

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50 Regulatory Commission of Alaska, Docket No. U-16-066, Order No. 19, September 22, 2017, at 50-52.

51 *Id*.

52 Minnesota Public Utilities Commission, Docket No. E017/GR-15-1033, Order, August 16, 2016, at 55.

53 *Ass'n. of Businesses Advocating Tariff Equity, et. al., v. Midcontinent Indep. Sys. Operator, Inc., et. al.*, 171 FERC ¶ 61,154 (2020), at ¶ 75. The U.S. Court of Appeals recently vacated FERC Order No. 569 decisions that related to its risk premium model and remanded the case to FERC to reopen the proceedings. However, in its decision, the Court did not reject FERC's inclusion of the size premium to estimate the CAPM. (*See*, United States Court of Appeals Case No. 16-1325, Decision No. 16-1325, August 9, 2022 at 20).

Q. HOW HAVE YOU CONSIDERED THE SMALLER SIZE OF ELIZABETHTOWN'S NATURAL GAS DISTRIBUTION OPERATIONS IN ASSESSING THE REASONABLENESS OF THE COMPANY'S PROPOSED ROE?

A. While I have estimated the effect of the Company's small size of its natural gas operations in New Jersey on the cost of equity, I am not proposing that a specific adjustment for this risk factor be made. Rather, I have considered the small size of the Company's utility operations in evaluating where within the range of analytical results that the Company's ROE should fall. All else equal, the additional risk associated with the Company's small size supports an ROE that is above the average of the range of results produced by the cost of equity estimation models.

B. Capital Expenditures

Q. WHAT ARE THE COMPANY'S PROJECTED CAPITAL EXPENDITURE REQUIREMENTS OVER THE NEXT FEW YEARS?

A. The Company currently projects capital expenditures for 2024 through 2028 of approximately $1.456 billion, which represents approximately 75 percent of the Company's approximate $1.940 billion in net utility plant as of December 31, 2022.[54]

Q. HOW DO THE COMPANY'S CAPITAL EXPENDITURE REQUIREMENTS COMPARE TO THOSE OF THE PROXY GROUP COMPANIES?

A. As shown on Exhibit P-7, Schedule AEB-10, I have calculated the ratio of expected capital expenditures to net utility plant for the Elizabethtown and each of the companies in the proxy group by dividing each company's projected capital expenditures for the period from

[54] Data provided by the Company.

2024 through 2028 by its total net utility plant as of December 31, 2022. As shown therein, the Company's ratio of capital expenditures as a percentage of net utility plant is well above the median for the proxy group companies, indicating a risk level that is relatively higher than the proxy group companies.

Q. HOW IS THE COMPANY'S RISK PROFILE AFFECTED BY ITS CAPITAL EXPENDITURE REQUIREMENTS?

A. As with any utility faced with substantial capital expenditure requirements, the Company's risk profile may be adversely affected in two significant and related ways: (1) the heightened level of investment increases the risk of under-recovery or delayed recovery of the invested capital; and (2) an inadequate return would put downward pressure on key credit metrics.

Q. DO CREDIT RATING AGENCIES RECOGNIZE THE RISKS ASSOCIATED WITH ELEVATED LEVELS OF CAPITAL EXPENDITURES?

A. Yes. From a credit perspective, the additional pressure on cash flows associated with high levels of capital expenditures exerts corresponding pressure on credit metrics and, therefore, credit ratings. To that point, S&P explains the importance of regulatory support for large capital projects:

> When applicable, a jurisdiction's willingness to support large capital projects with cash during construction is an important aspect of our analysis. This is especially true when the project represents a major addition to rate base and entails long lead times and technological risks that make it susceptible to construction delays. Broad support for all capital spending is the most credit-sustaining. Support for only specific types of capital spending, such as specific environmental projects or system integrity plans, is less so, but still favorable for creditors. Allowance of a cash return on construction work-in-progress or similar ratemaking methods historically were extraordinary measures for use in unusual circumstances, but when construction costs are rising, cash flow support could be crucial to maintain credit quality through the spending program. Even more favorable are those

> jurisdictions that present an opportunity for a higher return on capital projects as an incentive to investors.[55]

Therefore, to the extent that the Company's rates do not permit the opportunity to recover its capital investments on a regular and timely basis, it will face increased recovery risk and thus increased pressure on its credit metrics.

Q. DOES ELIZABETHTOWN HAVE A REGULATORY MECHANISM TO RECOVER THE COSTS ASSOCIATED WITH ITS CAPITAL EXPENDITURES BETWEEN RATE CASES?

A. Yes, in part. Elizabethtown has an Infrastructure Investment Program ("IIP") that was approved by the Board in June 2019, which authorized the recovery of costs associated with investments of approximately $300 million between 2019-2024 to replace cast-iron and bare steel vintage mains and related services.[56] The Company makes annual filings for updated rates to recover the investments made under its IIP. The existing IIP is scheduled to terminate on June 30, 2024, and the Company has recently filed an Infrastructure Investment Program 2 that would commence July 1, 2024 pending approval by the Board.[57] The Company does not have a capital cost recovery mechanism for other capital expenditures.

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55 S&P Global Ratings, "Assessing U.S. Investor-Owned Utility Regulatory Environments," August 10, 2016, at 7.

56 South Jersey Industries website; https://www.sjindustries.com/about-sji/clean-energy/infrastructure-enhancements#:~:text=Elizabethtown%20Gas'%20approved%20program%20authorizes,vintage%20mains%20and%20related%20services.

57 New Jersey Board of Public Utilities, 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, December 11, 2023, at 1.

C. Regulatory Risk

Q. HOW DOES THE REGULATORY ENVIRONMENT AFFECT INVESTORS' RISK ASSESSMENTS?

A. The ratemaking process is premised on the principle that, for investors and companies to commit the capital needed to provide safe and reliable utility services, the subject utility must have the opportunity to recover invested capital and the market-required return on such capital. Regulatory commissions recognize that because utility operations are capital intensive, regulatory decisions should enable the utility to attract capital at reasonable terms, which balances the long-term interests of investors and customers. In that respect, the regulatory framework in which a utility operates is one of the most important factors considered in both debt and equity investors' risk assessments.

From the perspective of debt investors, the authorized return should enable the utility to generate the cash flow needed to meet its near-term financial obligations, make the capital investments needed to maintain and expand its systems, and maintain the necessary levels of liquidity to fund unexpected events. This financial liquidity must be derived not only from internally generated funds, but also by efficient access to capital markets. Moreover, because fixed income investors have many investment alternatives, even within a given market sector, a utility's financial profile must be adequate on a relative basis to ensure its ability to attract capital under a variety of economic and financial market conditions.

Equity investors require that the authorized return be adequate to provide a risk-comparable return on the equity portion of the utility's capital investments. Because equity investors are the residual claimants on the utility's cash flows (*i.e.*, the equity return is subordinate to interest payments), they are particularly concerned with the strength of regulatory support and its effect on future cash flows.

Q. DO CREDIT RATING AGENCIES CONSIDER REGULATORY RISK IN ESTABLISHING A COMPANY'S CREDIT RATING?

A. Yes. Both S&P and Moody's consider the overall regulatory framework in establishing credit ratings. Moody's establishes credit ratings based on four key factors: (1) regulatory framework; (2) the ability to recover costs and earn returns; (3) diversification; and (4) financial strength, liquidity and key financial metrics. Of these criteria, regulatory framework and the ability to recover costs and earn returns are each given a broad rating factor of 25.00 percent. Therefore, Moody's assigns regulatory risk a 50.00 percent weighting in the overall assessment of business and financial risk for regulated utilities.[58]

S&P also identifies the regulatory framework as an important factor in credit ratings for regulated utilities, stating: "One significant aspect of regulatory risk that influences credit quality is the regulatory environment in the jurisdictions in which a utility operates."[59] S&P identifies four specific factors that it uses to assess the credit implications of the regulatory jurisdictions of investor-owned regulated utilities: (1) regulatory stability; (2) tariff-setting procedures and design; (3) financial stability; and (4) regulatory independence and insulation.[60]

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58 Moody's Investors Service, Rating Methodology: Regulated Electric and Gas Utilities, June 23, 2017, at 4.

59 Standard & Poor's Global Ratings, Ratings Direct, U.S. and Canadian Regulatory Jurisdictions Support Utilities' Credit Quality – But Some More So Than Others, June 25, 2018, at 2.

60 *Id.*, at 1.

Q. HOW DOES THE REGULATORY ENVIRONMENT IN WHICH A UTILITY OPERATES AFFECT ITS ACCESS TO AND COST OF CAPITAL?

A. The regulatory environment can significantly affect both the access to and cost of capital in several ways. First, the proportion and cost of debt capital available to utility companies are influenced by the rating agencies' assessment of the regulatory environment. As noted by Moody's, "[f]or rate regulated utilities, which typically operate as a monopoly, the regulatory environment and how the utility adapts to that environment are the most important credit considerations."[61] Moody's further highlighted the relevance of a stable and predictable regulatory environment to a utility's credit quality, noting: "[b]roadly speaking, the Regulatory Framework is the foundation for how all the decisions that affect utilities are made (including the setting of rates), as well as the predictability and consistency of decision-making provided by that foundation."[62]

Q. HAVE YOU CONDUCTED AN ANALYSIS OF THE REGULATORY FRAMEWORK IN NEW JERSEY RELATIVE TO THE JURISDICTIONS IN WHICH THE COMPANIES IN YOUR PROXY GROUP OPERATE?

A. Yes. I have evaluated the regulatory framework in New Jersey on three factors that are important in terms of providing a regulated utility a reasonable opportunity to earn its authorized ROE: (1) test year convention (*i.e.*, forecast vs. historical); (2) use of rate design or other mechanisms that mitigate volumetric risk and stabilize revenue; and (3) prevalence of capital cost recovery between rate cases.

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[61] Moody's Investors Service, Rating Methodology: Regulated Electric and Gas Utilities, June 23, 2017, at 6.

[62] *Id*.

Test Year Convention: Elizabethtown relies on a partially forecast test year in New Jersey with the period ending on June 30, 2024. Similarly, as shown in Exhibit P-7, Schedule AEB-11, approximately 52 percent of the operating utility subsidiaries of the proxy group companies provide service in jurisdictions that use a partially or fully forecast test year.

Revenue Stabilization/Volumetric Risk: Elizabethtown currently has some protection against volumetric risk through its Conservation Incentive Program ("CIP"), which superseded its former weather normalization clause, and is designed to recover lost revenues due to the Company's energy efficiency program. Similarly, as shown in Exhibit P-7, Schedule AEB-11, approximately 91 percent of the utility operating subsidiaries of the proxy group companies also have some form of protection against volumetric risk either through revenue decoupling, formula-based rates, or straight fixed-variable rate design.

Capital Cost Recovery: As noted, Elizabethtown has the IIP capital tracking mechanism available through June 30, 2024 to recover eligible capital expenditures between rate cases, and has filed for approval of a subsequent mechanism. Similarly, as shown in Exhibit P-7, Schedule AEB-11, approximately 59 percent of the operating utility subsidiaries of the proxy group companies have some form of cost recovery for capital investments placed into service between rate cases.

Q. IS THERE EVIDENCE THAT ELIZABETHTOWN HAS BEEN UNABLE TO EARN ITS AUTHORIZED ROE?

A. Yes. As shown in Figure 12, Elizabethtown has significantly under-earned its authorized ROE in each of the past five years since SJI acquired the Company. Specifically, on average over this period, the Company has under-earned its authorized ROE by over 400 basis points per year, which has occurred despite the fact that Elizabethtown has had a partially forecast test year, partial protection against volumetric risk through its weather normalization clause and more recently CIP, and certain capital cost recovery through its IIP.

Figure 12: Comparison of Elizabethtown's Earned vs. Authorized ROE[63]

	Earned ROE	Authorized ROE	Difference (bp)
2019	4.78%	9.60%	-482
2020	6.34%	9.60%	-326
2021	6.32%	9.60%	-328
2022	4.94%	9.60%	-466
2023	4.45%	9.60%	-515
Average	**5.36%**	**9.60%**	**-424**

Q. HAVE YOU DEVELOPED ANY ADDITIONAL ANALYSES TO EVALUATE THE REGULATORY ENVIRONMENT IN NEW JERSEY AS COMPARED TO THE JURISDICTIONS IN WHICH THE COMPANIES IN YOUR PROXY GROUP OPERATE?

A. Yes. I have conducted two additional analyses to compare the regulatory framework of Connecticut to the jurisdictions in which the companies in the proxy group operate. Specifically, I considered two different rankings: (1) the RRA ranking of regulatory jurisdictions; and (2) S&P's ranking of the credit supportiveness of regulatory jurisdictions.

Q. HOW DOES RRA EVALUATE THE REGULATORY ENVIRONMENT IN EACH JURISDICTION?

A. RRA evaluates the regulatory environment from an investor perspective, considering the relative regulatory risk associated with ownership of securities issued by the companies

63 The Company's earned ROE for 2023 is through November 30 with a projection for December. In addition, the Company's earned ROE is based on 70 percent of goodwill deducted from the Company's equity balance consistent with the capital structure that existed at the time of the Company's acquisition.

that are regulated in each jurisdiction. RRA considers several factors that affect the regulatory process including gubernatorial, legislative and court activity, rate case decisions and other regulatory decisions, and information obtained through contact with commissioners, staff, company and government outreach.

Q. HOW DO YOU USE THE RRA RATINGS TO COMPARE THE REGULATORY JURISDICTIONS OF THE PROXY GROUP COMPANIES WITH THE COMPANY'S REGULATORY JURISDICTION?

A. RRA assigns a ranking for each regulatory jurisdiction between "Above Average/1" to "Below Average/3," with nine total rankings between these categories. I applied a numeric ranking system to the RRA rankings with "Above Average/1" assigned the highest ranking ("1") and "Below Average/3" assigned the lowest ranking ("9"). As shown on Exhibit P-7, Schedule AEB-12, the New Jersey jurisdictional ranking is "Below Average/1" (*i.e.*, a "7"), which is two levels below the proxy group average ranking, which is classified as "Average/2" (*i.e.*, a "5").

Q. HOW DO YOU CONDUCT YOUR ANALYSIS OF THE S&P CREDIT SUPPORTIVENESS?

A. For credit supportiveness, S&P classifies each regulatory jurisdiction into five categories that range from "Most Credit Supportive" down to "Credit Supportive." My analysis of the credit supportiveness of the regulatory jurisdictions in which the proxy companies operate as compared to the Company's regulatory jurisdiction is similar to the analysis of the RRA overall regulatory ranking discussed above. Specifically, I have assigned a numerical ranking to each category, from Most Credit Supportive (*i.e.*, a "1") to Credit Supportive (*i.e.*, a "5"). As shown on Exhibit P-7, Schedule AEB-13, similar to the RRA regulatory rankings just discussed, the New Jersey jurisdictional classification of "More Credit Supportive" (*i.e.*, a "4") is below the proxy group average ranking, which is classified as between "Highly Credit Supportive" and "Very Credit Supportive" (*i.e.*, a "2.68").

Q. IS IT IMPORTANT THAT THE BOARD CONSIDER HOW THE ROE TO BE AUTHORIZED FOR THE COMPANY IN THIS PROCEEDING COMPARES TO OTHER COMPARABLE UTILITIES?

A. Yes. Elizabethtown must compete for discretionary capital within the SJI corporate structure, which must in turn compete for capital with other utilities and businesses. Investors consider the business and financial risks for a company like Elizabethtown relative to other comparable investments. Therefore, the Board should consider how the authorized ROE for the Company in this proceeding compares to the ROEs authorized for other natural gas utilities, as well as consider the specific business and regulatory risks of the Company relative to the proxy group, so that the Company's future access to capital is not negatively impacted. To the extent that the returns in a jurisdiction are lower than the returns that have been authorized more broadly, credit rating agencies will consider this in the overall risk assessment of the regulatory jurisdiction in which the company operates. As noted, there are various examples of utilities that have experienced a credit rating downgrade and/or a negative market response related to the financial effects of a rate decision.

D. Decarbonization Risk

Q. IS NEW JERSEY EXPLORING CHANGE IN ITS REGULATORY POLICY THAT INCREASES THE BUSINESS RISK OF THE COMPANY GOING FORWARD?

A. Yes. On February 15, 2023, the New Jersey governor issued an executive order directing the Board to open a proceeding concerning the development of natural gas utility plans that reduce emissions from the natural gas sector to levels that are consistent with achieving the state's 50 percent reduction in greenhouse gas ("GHG") emissions below 2006 levels by 2030. The executive order also directed the Board to develop recommendations within 18 months of the executive order for how the natural gas industry can best meet these goals, considering cost and support for well-paying jobs, including union jobs, necessary to deliver on these goals.[64] As part of this proceeding, the Board directed the Staff to conduct a stakeholder process that will consider, at a minimum:

- Competitive market mechanisms to drive the lowest cost methods for reducing GHG emissions from the natural gas sector, including but not limited to, the adoption of clean heat standards from which the natural gas utilities would develop clean heat plans for meeting GHG emissions reductions.
- The need to ensure the reliable operation and long-term financial viability of natural gas public utilities, and the business model needed to keep the gas system intact while accounting for a shrinking customer base, including ensuring that gas distribution company growth assumptions and peak usage calculations take into account the state's decarbonization policies and minimize investment in new infrastructure so as to reduce the risk of future stranded asset costs.
- Alternative programs and investments that could provide natural gas utilities with new revenue streams and promote good-paying jobs.
- Eliminating subsidies that encourage unnecessary investment in natural gas infrastructure that is likely to be stranded in the future.
- The long-term impacts on those customers that fail or are unable to transition from natural gas, particularly low-income customers, and ways to reduce barriers to that transition.

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[64] New Jersey Board of Public Utilities, Order Initiating a Proceeding, Docket No. GO23020099, March 6, 2023, as revised March 23, 2023.

- Electric grid readiness to handle electrification of building heating and cooling, as well as transportation, and recommendations for shifting investment funding from natural gas to electric system infrastructure upgrades.[65]

Since the opening of the docket, the Staff has held multiple technical conferences and more than 100 sets of comments have submitted by interested parties.

Q. DOES THE PROCEEDING IN DOCKET NO. GO23020099 INCREASE THE COMPANY'S BUSINESS RISK GOING FORWARD?

A. Yes. While the Board stressed the need to ensure the long-term viability of natural gas public utilities, regardless of the ultimate outcome and recommendation from the proceeding, a few factors are clear regarding the Company's future natural gas operations: (1) there is currently significant uncertainty associated with the future of the Company's natural gas system and how or to what extent the Clean Heat standards will affect the Company's operations going forward; (2) the Company's natural gas operations are expected to be smaller with a "shrinking customer base" and transitioning customers off of natural gas; and (3) investment in future natural gas infrastructure is being minimized and a recognition of likely future underutilization/stranded costs. Therefore, the proceeding and subsequent initiatives that come from the proceeding clearly increase the risk of the Company's natural gas operations.

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[65] *Id*.

Q. HOW DO THE RISKS FACED BY THE COMPANY GOING FORWARD ASSOCIATED WITH THE STATE'S MOVEMENT TOWARDS A CLEAN ENERGY FUTURE COMPARE TO OTHER STATES AND JURISDICTIONS IN WHICH THE UTILITY OPERATING SUBSIDIARIES OF THE PROXY GROUP OPERATE?

A. Comparatively, New Jersey has implemented more aggressive decarbonization programs that create greater business risk to natural gas utility service than the proxy group companies face with respect to decarbonization. In fact, the utility operating subsidiaries of the proxy group companies operate in 16 distinct states, and 11 of the 16 states do not have statutory GHG reduction requirements as have been adopted by New Jersey.[66] Likewise, 11 of the 16 states have expressly prohibited natural gas bans and 3 have proposed legislation to prohibit natural gas bans.[67]

E. Conclusion

Q. WHAT ARE YOUR CONCLUSIONS REGARDING THE BUSINESS AND REGULATORY RISKS OF THE COMPANY?

A. Based on my analysis, the Company's small size, relatively high projected capital expenditures, and New Jersey's GHG reduction requirements indicate that the Company's business risks are higher than the proxy group. In particular, although the ultimate future effect on the Company's natural gas utility operations is not yet known as a result of

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[66] National Conference of State Legislatures, Greenhouse Gas Emissions Reduction Targets and Market-based Policies (https://www.ncsl.org/research/energy/greenhouse-gas-emissions-reduction-targets-and-market-based-policies.aspx; updated as of September 5, 2023); Center of Climate and Energy Solutions, U.S. State Greenhouse Gas Emissions Targets (https://www.c2es.org/document/greenhouse-gas-emissions-targets/; updated as of September 2023).

[67] Tom DiChristopher, "Gas Ban Monitor: 1st Mass. Bans advance amid broader New England push," S&P Global Market Intelligence, November 8, 2023.

implementing and achieving the GHG reduction requirements, the Company's natural gas distribution business is nonetheless exposed to significant uncertainty regarding the energy transition in New Jersey, including the timing of and financial ramifications to the Company of such a transition. Therefore, based on this information, it is reasonable that investors would consider Elizabethtown to have greater business risk going forward regarding the effect of GHG reduction requirements to its natural gas utility operations as compared to the proxy group.

Likewise, while the Company's regulatory mechanisms and the ability to timely recover its prudently incurred costs are generally consistent with the operating utilities of the proxy group, both the RRA and S&P rankings for New Jersey indicate a greater regulatory risk than the average for the proxy group. Furthermore, despite the regulatory mechanisms in place, the Company has failed to earn its authorized ROE in each of the past five years by a significant margin.

As a result of all of these factors, I conclude that the Company has greater than average business and regulatory risk when compared to the proxy group.

VIII. CAPITAL STRUCTURE

Q. IS THE CAPITAL STRUCTURE OF THE COMPANY AN IMPORTANT CONSIDERATION IN THE DETERMINATION OF THE APPROPRIATE ROE?

A. Yes. The equity ratio is the primary indicator of financial risk for a regulated utility. All else equal, a higher debt ratio increases the risk to investors. For debt holders, higher debt ratios result in a greater portion of the available cash flow being required to meet debt service, thereby increasing the risk associated with the payments on debt. The result of increased risk is a higher interest rate. The incremental risk of a higher debt ratio is more significant for common equity shareholders, whose claim on the cash flow of the Company is secondary to debt holders. Therefore, the greater the debt service requirement, the less cash flow is available for common equity holders.

Q. WHAT CAPITAL STRUCTURE ARE YOU RECOMMENDING FOR ELIZABETHTOWN IN THIS PROCEEDING?

A. The BPU's order authorizing the acquisition of Elizabethtown's assets by SJI and the acquisition of SJI by IIF prohibit Elizabethtown from recovering goodwill in rates. Accordingly, Elizabethtown's projected capital structure ratios as of June 30, 2024 were adjusted to remove goodwill. For the adjustment, 30.65 percent of goodwill was assigned to debt and 69.35 percent of goodwill was assigned to equity. It is my understanding that this methodology has been used to remove goodwill from Elizabethtown's ratemaking capital structure in the Company's prior rate case. While the Company's projected capital structure as of June 30, 2024 is 68.6 percent common equity and 31.4 percent long-term debt, the Company is requesting a capital structure for ratemaking purposes consisting of 57.0 percent equity and 43.0 percent long-term debt, exclusive of goodwill.

Q. WHY IS THE COMPANY REQUESTING A CAPITAL STRUCTURE THAT IS DIFFERENT FROM ITS ACTUAL IN THIS CIRCUMSTANCE?

A. The Company acknowledges that its actual equity ratio is higher than other comparable utilities; however, this is a result of the fact that the Company's credit metrics have been weak historically and the Company took actions in 2023 to improve its metrics before receiving a credit rating downgrade. Specifically, in February 2023, S&P downgraded the Company's stand-alone credit profile from "a-" to "bbb+" and highlighted that the Company's funds from operations-to-debt ("FFO/debt") ratio was at the lower end of the range for its financial risk level. As a result, the Company subsequently infused additional equity into the Company in order to prevent a further rating action that would have downgraded the Company's credit issuer rating. It is my understanding from discussions with the Company that while the downgrade of the Company's stand-alone credit profile did not affect the Company's access to or cost of debt, a subsequent downgrade would have done so. As a result, in order to strengthen its credit metrics and maintain its current credit rating, the Company decided to finance all of its 2023 funding needs with equity. In addition, in order to stay above S&P's required FFO/debt threshold of 13 percent, the Company also needed to replace approximately $140 million in long-term debt with equity. In total, this resulted in a total equity infusion into the Company of $385 million in 2023.

Q. DID YOU CONDUCT AN ANALYSIS TO ASSESS THE REASONABLENESS OF THE COMPANY'S CAPITAL STRUCTURE?

A. Yes. I compared the Company's proposed capital structure relative to the actual capital structures of the utility operating subsidiaries of the companies in the proxy group. The cost of equity is estimated based on the return that is derived from companies in the proxy group that are deemed to be comparable in risk to the Company; however, those companies must be publicly-traded in order to apply the cost of equity models. The operating utility subsidiaries of the proxy group companies are most risk-comparable to the Company, and thus it is reasonable to look to the average capital structure of the operating utilities of the proxy group to benchmark the equity ratios for the Company. Specifically, I have calculated the average proportion of common equity, long-term debt, preferred equity and short-term debt for the most recent three years for each of the utility operating subsidiaries of the proxy group companies. As shown in Exhibit P-7, Schedule AEB-14, the equity ratios for the utility operating subsidiaries of the proxy group range from 49.41 percent to 59.88 percent, with an average of 55.88 percent. The Company's proposed equity ratio of 57.0 percent is well within the range of the equity ratios of the proxy group, consistent with the average actual equity ratio of the proxy group companies, and substantially lower than the Company's actual equity ratio.

Q. ARE THERE OTHER FACTORS TO BE CONSIDERED IN SETTING THE COMPANY'S CAPITAL STRUCTURE?

A. Yes, there are other factors that should be considered in setting the Company's capital structure, namely the challenges that the credit rating agencies have highlighted as placing pressure on the credit metrics for utilities.

For example, while Moody's recently revised its outlook for the utility sector from "negative" to "stable", Moody's continues to note that high interest rates and increased capital spending will place pressure on credit metrics. Thus, Moody's highlights constructive regulatory outcomes that promote timely cost recovery as a key factor in supporting utility credit quality.[68]

Likewise, while S&P also recently revised its outlook for the industry from negative to stable, S&P continues to see significant risks over the near-term for the industry as a result of inflation and increased levels of capital spending. Specifically, S&P noted:

> Despite the improvement in economic data, we expect inflation, rising interest rates, higher capital spending, and the strategic decision by many companies to operate with only minimal financial cushion from their downgrade thresholds to continue to pressure the industry's credit quality. Throughout 2022 and so far in 2023, the Federal Reserve has consistently raised interest rates to reduce the pace of inflation. While these actions

[68] Moody's Investors Service, Outlook, "Outlook turns stable on low prices and credit-supportive regulation," September 7, 2023 [CONFIDENTIAL].

> appear to have had a positive effect on slowing inflation, there's still been a modest weakening in the industry's financial measures because of inflation and rising interest rates. An environment of continuously rising costs tends to weaken the industry's financial measures because of the timing difference between when the higher costs are incurred and when they are ultimately recovered from ratepayers.[69]

S&P has also recently concluded:

> The confluence of higher operating costs due to rising inflation, higher interest rates, storm restoration costs, increasing capital spending, and the recovery of previously deferred higher commodity costs, has resulted in growing rate case filings and increased rate rider recovery requests from state regulators. We expect to closely monitor the industry's ability to not just recover these rising costs but to do so in such a manner that minimizes the regulatory lag. However, given the impact of these higher costs to the customer bill, the industry's ability to effectively manage regulatory risk could become increasingly challenging, possibly pressuring its credit quality.[70]

Fitch Ratings ("Fitch") has stated that it is maintaining a "deteriorating outlook" on the U.S. utility sector in 2024 based on elevated capital spending and continuing higher interest rates that place pressure on credit metrics. Fitch notes that bill affordability will remain a major issue for the industry that could affect future regulatory outcomes, and that while it expects authorized ROEs to start trending up with the increase in interest rates, albeit with a lag, given the uncertain macroeconomic environment and bill pressure on customers, the lag could be longer than in previous cycles.[71]

The credit ratings agencies' continued concerns over the negative effects of inflation, higher interest rates, and increased capital expenditures underscore the

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[69] S&P Global Ratings, "The Outlook for North American Regulated Utilities Turns Stable," May 18, 2023, at 8 [CONFIDENTIAL].

[70] S&P Global Ratings, "Regulatory Friction Is Constraining Cost Recovery For North American Investor-Owned Utilities," November 6, 2023, at 8.

[71] FitchRatings, "North American Utilities, Power & Gas Outlook," S&P Market Intelligence, November 13, 2023.

importance of maintaining adequate cash flow metrics for Elizabethtown Gas Company in the context of this proceeding.

Q. WILL THE CAPITAL STRUCTURE AND ROE AUTHORIZED IN THIS PROCEEDING AFFECT THE COMPANY'S ACCESS TO CAPITAL AT REASONABLE RATES?

A. Yes. The level of earnings authorized by the Board directly affects the Company's ability to fund its operations with internally-generated funds. Both bond investors and rating agencies expect a significant portion of ongoing capital investments to be financed with internally-generated funds. In addition, it is important to recognize that because a utility's investment horizon is very long, investors require the assurance of a sufficiently high return to satisfy the long term financing requirements of the assets placed into service. Those assurances, which often are measured by the relationship between internally-generated cash flows and debt (or interest expense), depend quite heavily on the capital structure. As a consequence, both the ROE and capital structure are very important to debt and equity investors, particularly given the capital market conditions discussed previously.

IX. <u>COST OF LONG-TERM DEBT</u>

Q. WHAT IS THE COMPANY'S PROPOSED COST OF LONG-TERM DEBT?

A. As shown on Exhibit P-7, Schedule AEB-15, page 2, the Company is proposing a cost of long-term debt of 5.08 percent, which reflects (1) the cost of the Company's long-term debt issued in June 2023 (referred to as "Refinanced Debt") solely to replace first mortgage bonds and senior notes that were redeemed by ETG as a result of a debt holder exercising a put in connection with the Merger (referred to as "CIC Debt"); (2) the cost of any debt issuances that existed prior to SJI's acquisition by IIF in February 2023 and were not tendered as a result of such acquisition; and, (3) a projected new long-term debt issuance in June 2024. As shown on Exhibit P-7, Schedule AEB-15, Page 1, of the $830.4 million in CIC Debt, $140.4 million was refinanced with an equity infusion made by the Company in 2023 that was required regardless of the acquisition because of the Company's need to improve its credit metrics before receiving a credit rating downgrade. As shown on Exhibit P-7, Schedule AEB-15, page 2, the proposed weighted average cost of long-term debt reflects $690 million of CIC Debt.

Q. IS THE COMPANY'S PROPOSED COST OF LONG-TERM DEBT CONSISTENT WITH THE BOARD'S DECISION APPROVING IIF'S ACQUISITION OF SJI?

A. Yes. As the Board stated in paragraph 35 of the 2023 Merger Order:

> ETG's current rates reflect the cost of first mortgage bonds and senior notes that contain "change-in-control" provisions that allow the bond and note investors to sell (put) their bonds and notes back to the respective issuer at the face amount of the debt in connection with the [Merger]. The Parties acknowledge that (a) to the extent ETG incurs increased interest expense as a result of the Refinanced Debt and (b) such increased interest costs are included in the base rates set in future base rate cases, then ETG will provide customers with a rate credit (referred to as the "CIC Rate Credit") in future base rate cases for the remaining tenor of the CIC Debt.[72]

As noted and as shown on Exhibit P-7, Schedule AEB-15, page 2, the Company's proposed cost of long-term debt reflects the weighted average cost of the Refinanced Debt. The required CIC Rate Credit Adjustment to customer rates to account for the difference in Refinanced Debt Interest Expense for the test year and the CIC Debt Interest Expense for the test year, after taking into account the goodwill adjustment, is reflected on an after-tax basis on Schedule TK-3 to the Direct Testimony of Thomas Kaufmann.

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[72] 2023 Merger Order, at 8-9.

Q. HAVE YOU EVALUATED THE REASONABLENESS OF THE COMPANY'S PROPOSED COST OF LONG-TERM DEBT?

A. Yes. I benchmarked the cost of the Company's Refinanced Debt against the 30-day average of the Moody's Baa-rated utility bond yields as of the time of these issuances, and benchmarked the cost of the Company's projected debt issuance against a projection of the Moody's Baa-rated utility bond yield.[73] Specifically, for the Company's projected debt issuance, I developed the projected Moody's Baa-rated utility bond yield by calculating the current spread between the 30-day average yield on the 30-year Treasury bond to the 30-day average yields on the Moody's Baa-rated utility bonds. I applied the spread to the projected yield on the 30-year Treasury bond as of the projected debt issuance. For the debt issuances that existed prior to SJI's acquisition by IIF and were not tendered as a result of such acquisition, I have not benchmarked these debt issuances because they were issued prior the Company's last base rate proceeding and were reflected previously in the Company's cost of long-term debt used for ratemaking purposes as approved by the Board.

As shown on Exhibit P-7, Schedule AEB-15, page 2, the coupon rates for the Company's Refinanced Debt are lower than the Moody's Baa-rated utility bond yield as of the time of these issuances. Likewise, the Company's projected coupon rate for its upcoming issuance is consistent with the projected Baa-rated utility bond yield for June 2024. Based on this analysis, I conclude that the Company's cost of long-term debt for its existing issuances and projected issuance is reasonable.

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[73] I have used the Moody's Baa-rated utility bonds given that the Company has a BBB rating from Fitch, which is equivalent to a Baa2 rating from Moody's.

X. CONCLUSIONS AND RECOMMENDATION

Q. WHAT IS YOUR CONCLUSION REGARDING A FAIR RATE OF RETURN FOR THE COMPANY?

A. First, based on the various quantitative analyses summarized in Figure 13, a reasonable range of ROE results for Elizabethtown is from 10.25 percent to 11.25 percent. Considering the qualitative analyses presented in my direct testimony, and the Company's specific risk factors, within that range, I recommend an ROE of 10.75 percent.

Figure 13: Summary of Analytical Results

Constant Growth DCF

	Minimum Growth Rate	Average Growth Rate	Maximum Growth Rate
Mean Results:			
30-Day Avg. Stock Price	9.12%	10.16%	11.31%
90-Day Avg. Stock Price	8.97%	10.01%	11.16%
180-Day Avg. Stock Price	8.77%	9.81%	10.96%
Average	8.95%	9.99%	11.14%
Median Results:			
30-Day Avg. Stock Price	8.90%	9.92%	11.10%
90-Day Avg. Stock Price	8.69%	9.61%	10.84%
180-Day Avg. Stock Price	8.52%	9.28%	10.64%
Average	8.70%	9.60%	10.86%

CAPM / ECAPM / Bond Yield Risk Premium

	30-Year Treasury Bond Yield		
	Current 30-Day Avg	Near-Term Projected	Longer-Term Projected
CAPM:			
Current *Value Line* Beta	11.28%	11.23%	11.17%
Current Bloomberg Beta	10.72%	10.65%	10.56%
Long-term Avg. *Value Line* Beta	10.46%	10.38%	10.28%
ECAPM:			
Current *Value Line* Beta	11.60%	11.56%	11.52%
Current Bloomberg Beta	11.18%	11.13%	11.06%
Long-term Avg. *Value Line* Beta	10.98%	10.92%	10.85%
Bond Yield Risk Premium	10.63%	10.46%	10.25%

In addition, the Company's proposed capital structure for ratemaking purposes consisting of 57.0 percent common equity and 43.0 percent long-term debt is reasonable given that it is consistent with the actual capital structures of the operating utilities of the proxy group companies, and while the Company has greater business and regulatory risk relative to the proxy group, my recommended ROE is the average of the range. Further, the impact of current and projected market conditions on the cash flows of utilities as raised by the credit rating agencies, also supports the reasonableness of the Company's proposed ratemaking capital structure.

Lastly, as discussed, the Company's proposed cost of debt of 5.08 percent is reasonable, as it is consistent with the 2023 Merger Order, after considering the CIC Rate Credit Adjustment, and reasonably reflects the cost of the Company's projected upcoming long-term debt issuance in June 2024.

Therefore, as shown in Figure 14, an overall rate of return of 8.31 percent for the Company for ratemaking purposes in this proceeding is reasonable.

Figure 14: Summary of Overall Rate of Return

	Capital Structure	Cost Rate	Total
Long-Term Debt	43.00%	5.08%	2.19%
Equity	57.00%	10.75%	6.13%
Wgtd. Avg. Cost of Capital			8.31%

Q. DOES THIS CONCLUDE YOUR DIRECT TESTIMONY?

A. Yes, it does.

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Ann E. Bulkley

PRINCIPAL

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With more than 25 years of experience in the energy industry, Ms. Bulkley specializes in regulatory economics for the electric and natural gas and water utility sectors, including valuation of regulated and unregulated utility assets, cost of capital, and capital structure issues.

Ms. Bulkley has extensive state and federal regulatory experience, and she has provided expert testimony on the cost of capital in nearly 100 regulatory proceedings before 32 state regulatory commissions and the Federal Energy Regulatory Commission (FERC).

In addition to her regulatory experience, Ms. Bulkley has provided valuation and appraisal services for a variety of purposes, including the sale or acquisition of utility assets, regulated ratemaking, ad valorem tax disputes, and other litigation purposes. In addition, she has experience in the areas of contract and business unit valuation, strategic alliances, market restructuring, and regulatory and litigation support.

Ms. Bulkley is a Certified General Appraiser licensed in the Commonwealth of Massachusetts and the State of New Hampshire.

Prior to joining Brattle, Ms. Bulkley was a Senior Vice President at an economic consultancy and held senior positions at several other consulting firms.

AREAS OF EXPERTISE

- Regulatory Economics, Finance & Rates
- Regulatory Investigations & Enforcement
- Tax Controversy & Transfer Pricing
- Electricity Litigation & Regulatory Disputes
- M&A Litigation

EDUCATION

- **Boston University**
  MA in Economics
- **Simmons College**
  BA in Economics and Finance

PROFESSIONAL EXPERIENCE

- **The Brattle Group (2022–Present)**
  Principal
- **Concentric Energy Advisors, Inc. (2002–2021)**
  Senior Vice President
  Vice President
  Assistant Vice President
  Project Manager
- **Navigant Consulting, Inc. (1997–2002)**
  Project Manager
- **Reed Consulting Group (1995-1997)**
  Consultant- Project Manager
- **Cahners Publishing Company (1995)**
  Economist

SELECTED CONSULTING EXPERIENCE & EXPERT TESTIMONY

REGULATORY ANALYSIS AND RATEMAKING

Have provided a range of advisory services relating to regulatory policy analysis and many aspects of utility ratemaking, with specific services including:

- Cost of capital and return on equity testimony, cost of service and rate design analysis and testimony, development of ratemaking strategies
- Development of merchant function exit strategies

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- Analysis and program development to address residual energy supply and/or provider of last resort obligations
- Stranded costs assessment and recovery
  Performance-based ratemaking analysis and design
- Many aspects of traditional utility ratemaking (e.g., rate design, rate base valuation)

COST OF CAPITAL

Have provided expert testimony on the cost of capital and capital structure in nearly 100 regulatory proceedings before state and federal regulatory commissions in the United States.

RATEMAKING

Have assisted several clients with analysis to support investor-owned and municipal utility clients in the preparation of rate cases. Sample engagements include:

- Assisted several investor-owned and municipal clients on cost allocation and rate design issues including the development of expert testimony supporting recommended rate alternatives.
- Worked with Canadian regulatory staff to establish filing requirements for a rate review of a newly regulated electric utility. Along with analyzing and evaluating rate application, attended hearings and conducted investigation of rate application for regulatory staff and prepared, supported, and defended recommendations for revenue requirements and rates for the company. Additionally, developed rates for gas utility for transportation program and ancillary services.

VALUATION

Have provided valuation services to utility clients, unregulated generators, and private equity clients for a variety of purposes, including ratemaking, fair value, ad valorem tax, litigation and damages, and acquisition. Appraisal practices are consistent with the national standards established by the Uniform Standards of Professional Appraisal Practice.

Representative projects/clients have included:

- Prepared appraisals of electric utility transmission and distribution assets for ad valorem tax purposes.
- Prepared appraisals of hydroelectric generating facilities for ad valorem tax purposes.
- Conducted appraisals of fossil fuel generating facilities for ad valorem tax purposes.
- Conducted appraisals of generating assets for the purposes of unwinding sale-leaseback agreements.
- For a confidential utility client, prepared valuation of fossil and nuclear generation assets for financing purposes for regulated utility client.

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- Conducted a strategic review of the acquisition of nuclear generation assets. Review included the evaluation of the operating costs of the facilities and the long-term liabilities associated with the assets including the decommissioning of the assets.
- Prepared a valuation of a portfolio of generation assets for a large energy utility to be used for strategic planning purposes. Valuation approach included an income approach, a real options analysis, and a risk analysis.
- Assisted clients in the restructuring of NUG contracts through the valuation of the underlying assets. Performed analysis to determine the option value of a plant in a competitively priced electricity market following the settlement of the NUG contract.
- Prepared market valuations of several purchase power contracts for large electric utilities in the sale of purchase power contracts. Assignment included an assessment of the regional power market, analysis of the underlying purchase power contracts, and a traditional discounted cash flow valuation approach, as well as a risk analysis. Analyzed bids from potential acquirers using income and risk analysis approached. Prepared an assessment of the credit issues and value at risk for the selling utility.
- Prepared appraisal of a portfolio of generating facilities for a large electric utility to be used for financing purposes.
- Conducted a valuation of regulated utility assets for the fair value rate base estimate used in electric rate proceedings in Indiana.
- Prepared an appraisal of a fleet of fossil generating assets for a large electric utility to establish the value of assets transferred from utility property.
- Conducted due diligence on an electric transmission and distribution system as part of a buy-side due diligence team.
- Provided analytical support and prepared testimony regarding the valuation of electric distribution system assets in five communities in a condemnation proceeding.
- Prepared feasibility reports analyzing the expected net benefits resulting from municipal ownership of investor-owned utility operations.
- Prepared independent analyses of proposal for the proposed government condemnation of the investor-owned utilities in Maine and the formation of a public power district.
- Valued purchase power agreements in the transfer of assets to a deregulated electric market.

STRATEGIC AND FINANCIAL ADVISORY SERVICES

Have assisted several clients across North America with analytically-based strategic planning, due diligence, and financial advisory services.

Representative projects include:

- Preparation of feasibility studies for bond issuances for municipal and district steam clients.
- Assisted in the development of a generation strategy for an electric utility. Analyzed various NERC regions to identify potential market entry points. Evaluated potential competitors and alliance partners. Assisted in the development of gas and electric price forecasts. Developed a framework for the implementation of a risk management program.
- Assisted clients in identifying potential joint venture opportunities and alliance partners. Contacted interviewed and evaluated potential alliance candidates based on company-established criteria for several LDCs and marketing companies. Worked with several LDCs and unregulated marketing companies to establish alliances to enter into the retail energy market. Prepared testimony in support of several merger cases and participated in the regulatory process to obtain approval for these mergers.
- Assisted clients in several buy-side due diligence efforts, providing regulatory insight and developing valuation recommendations for acquisitions of both electric and gas properties.

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BULKLEY TESTIMONY LISTING

SPONSOR	DATE	CASE/APPLICANT	DOCKET /CASE NO.	SUBJECT
Arizona Corporation Commission				
UNS Electric	11/22	UNS Electric	Docket No. E-04204A-15-0251	Return on Equity
Tucson Electric Power Company	6/22	Tucson Electric Power Company	Docket No. G-01933A-22-0107	Return on Equity
Southwest Gas Corporation	12/21	Southwest Gas Corporation	Docket No. G-01551A-21-0368	Return on Equity
Arizona Public Service Company	10/19	Arizona Public Service Company	Docket No. E-01345A-19-0236	Return on Equity
Tucson Electric Power Company	04/19	Tucson Electric Power Company	Docket No. E-01933A-19-0028	Return on Equity
Tucson Electric Power Company	11/15	Tucson Electric Power Company	Docket No. E-01933A-15-0322	Return on Equity
UNS Electric	05/15	UNS Electric	Docket No. E-04204A-15-0142	Return on Equity
UNS Electric	12/12	UNS Electric	Docket No. E-04204A-12-0504	Return on Equity
Arkansas Public Service Commission				
Oklahoma Gas and Electric Co	10/21	Oklahoma Gas and Electric Co	Docket No. D-18-046-FR	Return on Equity
Arkansas Oklahoma Gas Corporation	10/13	Arkansas Oklahoma Gas Corporation	Docket No. 13-078-U	Return on Equity
California Public Utilities Commission				
PacifiCorp, d/b/a Pacific Power	5/22	PacifiCorp, d/b/a Pacific Power	Docket No. A-22-05-006	Return on Equity
San Jose Water Company	05/21	San Jose Water Company	A2105004	Return on Equity

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SPONSOR	DATE	CASE/APPLICANT	DOCKET /CASE NO.	SUBJECT
Colorado Public Utilities Commission				
Public Service Company of Colorado	01/24	Public Service Company of Colorado	Docket No. 24AL-___G	Return on Equity
Public Service Company of Colorado	11/22	Public Service Company of Colorado	Docket No. 22AL-0530E	Return on Equity
Public Service Company of Colorado	01/22	Public Service Company of Colorado	Docket No. 22AL-0046G	Return on Equity
Public Service Company of Colorado	07/21	Public Service Company of Colorado	21AL-0317E	Return on Equity
Public Service Company of Colorado	02/20	Public Service Company of Colorado	20AL-0049G	Return on Equity
Public Service Company of Colorado	05/19	Public Service Company of Colorado	19AL-0268E	Return on Equity
Public Service Company of Colorado	01/19	Public Service Company of Colorado	19AL-0063ST	Return on Equity
Atmos Energy Corporation	05/15	Atmos Energy Corporation	Docket No. 15AL-0299G	Return on Equity
Atmos Energy Corporation	04/14	Atmos Energy Corporation	Docket No. 14AL-0300G	Return on Equity
Atmos Energy Corporation	05/13	Atmos Energy Corporation	Docket No. 13AL-0496G	Return on Equity
Connecticut Public Utilities Regulatory Authority				
The Southern Connecticut Gas Company	11/23	The Southern Connecticut Gas Company	Docket No. 23-11-02	Return on Equity
Connecticut Natural Gas Corporation	11/23	Connecticut Natural Gas Corporation	Docket No. 23-11-02	Return on Equity
Connecticut Water Company	10/23	Connecticut Water Company	Docket No. 23-08-32	Return on Equity
United Illuminating	09/22	United Illuminating	Docket No. 22-08-08	Return on Equity

SPONSOR	DATE	CASE/APPLICANT	DOCKET /CASE NO.	SUBJECT
United Illuminating	05/21	United Illuminating	Docket No. 17-12-03RE11	Return on Equity
Connecticut Water Company	01/21	Connecticut Water Company	Docket No. 20-12-30	Return on Equity
Connecticut Natural Gas Corporation	06/18	Connecticut Natural Gas Corporation	Docket No. 18-05-16	Return on Equity
Yankee Gas Services Co. d/b/a Eversource Energy	06/18	Yankee Gas Services Co. d/b/a Eversource Energy	Docket No. 18-05-10	Return on Equity
The Southern Connecticut Gas Company	06/17	The Southern Connecticut Gas Company	Docket No. 17-05-42	Return on Equity
The United Illuminating Company	07/16	The United Illuminating Company	Docket No. 16-06-04	Return on Equity
Federal Energy Regulatory Commission				
Sea Robin Pipeline	12/22	Sea Robin Pipeline	Docket No. RP22-___	Return on Equity
Northern Natural Gas Company	07/22	Northern Natural Gas Company	Docket No. RP22-___	Return on Equity
Transwestern Pipeline Company, LLC	07/22	Transwestern Pipeline Company, LLC	Docket No. RP22-___	Return on Equity
Florida Gas Transmission	02/21	Florida Gas Transmission	Docket No. RP21-441	Return on Equity
TransCanyon	01/21	TransCanyon	Docket No. ER21-1065	Return on Equity
Duke Energy	12/20	Duke Energy	Docket No. EL21-9-000	Return on Equity
Wisconsin Electric Power Company	08/20	Wisconsin Electric Power Company	Docket No. EL20-57-000	Return on Equity
Panhandle Eastern Pipe Line Company, LP	10/19	Panhandle Eastern Pipe Line Company, LP	Docket Nos. RP19-78-000 RP19-78-001	Return on Equity

SPONSOR	DATE	CASE/APPLICANT	DOCKET /CASE NO.	SUBJECT
Panhandle Eastern Pipe Line Company, LP	08/19	Panhandle Eastern Pipe Line Company, LP	Docket Nos. RP19-1523	Return on Equity
Sea Robin Pipeline Company LLC	11/18	Sea Robin Pipeline Company LLC	Docket# RP19-352-000	Return on Equity
Tallgrass Interstate Gas Transmission	10/15	Tallgrass Interstate Gas Transmission	RP16-137	Return on Equity
Idaho Public Utilities Commission				
Intermountain Gas Co	12/22	Intermountain Gas Co	C-INT-G-22-07	Return on Equity
PacifiCorp d/b/a Rocky Mountain Power	05/21	PacifiCorp d/b/a Rocky Mountain Power	Case No. PAC-E-21-07	Return on Equity
Illinois Commerce Commission				
Peoples Gas Light & Coke Company	01/23	Peoples Gas Light & Coke Company	D-23-0069	Return on Equity
North Shore Gas Company	01/23	North Shore Gas Company	D-23-0068	Return on Equity
Illinois American Water	02/22	Illinois American Water	Docket No. 22-0210	Return on Equity
North Shore Gas Company	02/21	North Shore Gas Company	No. 20-0810	Return on Equity
Indiana Utility Regulatory Commission				
Southern Indiana Gas and Electric Company d/b/a CenterPoint Energy Indiana South	12/23	Southern Indiana Gas and Electric Company d/b/a CenterPoint Energy Indiana South	IURC Cause No. 45990	Return on Equity
Indiana Michigan Power Co.	08/23	Indiana Michigan Power Co.	IURC Cause No. 45933	Return on Equity

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SPONSOR	DATE	CASE/APPLICANT	DOCKET /CASE NO.	SUBJECT
Indiana American Water Company	03/23	Indiana and Michigan American Water Company	IURC Cause No. 45870	Return on Equity
Indiana Michigan Power Co.	07/21	Indiana Michigan Power Co.	IURC Cause No. 45576	Return on Equity
Indiana Gas Company Inc.	12/20	Indiana Gas Company Inc.	IURC Cause No. 45468	Return on Equity
Southern Indiana Gas and Electric Company	10/20	Southern Indiana Gas and Electric Company	IURC Cause No. 45447	Return on Equity
Indiana and Michigan American Water Company	09/18	Indiana and Michigan American Water Company	IURC Cause No. 45142	Return on Equity
Indianapolis Power and Light Company	12/17	Indianapolis Power and Light Company	Cause No. 45029	Fair Value
Northern Indiana Public Service Company	09/17	Northern Indiana Public Service Company	Cause No. 44988	Fair Value
Indianapolis Power and Light Company	12/16	Indianapolis Power and Light Company	Cause No.44893	Fair Value
Northern Indiana Public Service Company	10/15	Northern Indiana Public Service Company	Cause No. 44688	Fair Value
Indianapolis Power and Light Company	09/15	Indianapolis Power and Light Company	Cause No. 44576 Cause No. 44602	Fair Value
Kokomo Gas and Fuel Company	09/10	Kokomo Gas and Fuel Company	Cause No. 43942	Fair Value
Northern Indiana Fuel and Light Company, Inc.	09/10	Northern Indiana Fuel and Light Company, Inc.	Cause No. 43943	Fair Value
Iowa Department of Commerce Utilities Board				

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SPONSOR	DATE	CASE/APPLICANT	DOCKET /CASE NO.	SUBJECT
MidAmerican Energy Company	06/23	MidAmerican Energy Company	Docket No. RPU-2023-___	Return on Equity
MidAmerican Energy Company	01/22	MidAmerican Energy Company	Docket No. RPU-2022-0001	Return on Equity
Iowa-American Water Company	08/20	Iowa-American Water Company	Docket No. RPU-2020-0001	Return on Equity
Kansas Corporation Commission				
Evergy Kansas	04/23	Evergy Kansas	**Docket No. 23-______-______-RTS**	Return on Equity
Atmos Energy Corporation	08/15	Atmos Energy Corporation	Docket No. 16-ATMG-079-RTS	Return on Equity
Kentucky Public Service Commission				
Kentucky American Water Company	06/23	Kentucky American Water Company	Docket No. 2023-_____	Return on Equity
Kentucky American Water Company	11/18	Kentucky American Water Company	Docket No. 2018-00358	Return on Equity
Maine Public Utilities Commission				
Central Maine Power	08/22	Central Maine Power	Docket No. 2022-00152	Return on Equity
Central Maine Power	10/18	Central Maine Power	Docket No. 2018-194	Return on Equity
Maryland Public Service Commission				
Maryland American Water Company	06/18	Maryland American Water Company	Case No. 9487	Return on Equity
Massachusetts Appellate Tax Board				
Hopkinton LNG Corporation	03/20	Hopkinton LNG Corporation	Docket No.	Valuation of LNG Facility

SPONSOR	DATE	CASE/APPLICANT	DOCKET /CASE NO.	SUBJECT
FirstLight Hydro Generating Company	06/17	FirstLight Hydro Generating Company	Docket No. F-325471 Docket No. F-325472 Docket No. F-325473 Docket No. F-325474	Valuation of Electric Generation Assets
Massachusetts Department of Public Utilities				
Massachusetts Electric Company Nantucket Electric Company d/b/a National Grid	11/23	Massachusetts Electric Company Nantucket Electric Company d/b/a National Grid	DPU 23-150	Return on Equity
National Grid USA	11/20	Boston Gas Company	DPU 20-120	Return on Equity
Berkshire Gas Company	05/18	Berkshire Gas Company	DPU 18-40	Return on Equity
Unitil Corporation	01/04	Fitchburg Gas and Electric	DTE 03-52	Integrated Resource Plan; Gas Demand Forecast
Michigan Public Service Commission				
Indiana Michigan Power Co.	09/23	Indiana Michigan Power Co.	Case No. U-21461	Return on Equity
Michigan Gas Utilities Corporation	03/23	Michigan Gas Utilities Corporation	Case No. U-21366	Return on Equity
Michigan Gas Utilities Corporation	03/21	Michigan Gas Utilities Corporation	Case No. U-20718	Return on Equity
Wisconsin Electric Power Company	12/11	Wisconsin Electric Power Company	Case No. U-16830	Return on Equity
Michigan Tax Tribunal				
New Covert Generating Co., LLC.	03/18	The Township of New Covert Michigan	MTT Docket No. 000248TT and 16-001888-TT	Valuation of Electric Generation Assets

SPONSOR	DATE	CASE/APPLICANT	DOCKET /CASE NO.	SUBJECT
Covert Township	07/14	New Covert Generating Co., LLC.	Docket No. 399578	Valuation of Electric Generation Assets
Minnesota Public Utilities Commission				
ALLETE, Inc. d/b/a Minnesota Power	11/23	Allete, Inc. d/b/a Minnesota Power	D-E-015/GR-23-155	Return on Equity
CenterPoint Energy Resources	11/23	CenterPoint Energy Resources	D-G-008/GR-23-173	Return on Equity
Minnesota Energy Resources Corporation	11/22	Minnesota Energy Resources Corporation	Docket No. G011/GR-22-504	Return on Equity
CenterPoint Energy Resources	11/21	CenterPoint Energy Resources	D-G-008/GR-21-435	Return on Equity
ALLETE, Inc. d/b/a Minnesota Power	11/21	Allete, Inc. d/b/a Minnesota Power	D-E-015/GR-21-630	Return on Equity
Otter Tail Power Company	11/20	Otter Tail Power Company	E017/GR-20-719	Return on Equity
ALLETE, Inc. d/b/a Minnesota Power	11/19	Allete, Inc. d/b/a Minnesota Power	E015/GR-19-442	Return on Equity
CenterPoint Energy Resources Corporation d/b/a CenterPoint Energy Minnesota Gas	10/19	CenterPoint Energy Resources Corporation d/b/a CenterPoint Energy Minnesota Gas	G-008/GR-19-524	Return on Equity
Great Plains Natural Gas Co.	09/19	Great Plains Natural Gas Co.	Docket No. G004/GR-19-511	Return on Equity
Minnesota Energy Resources Corporation	10/17	Minnesota Energy Resources Corporation	Docket No. G011/GR-17-563	Return on Equity
Missouri Public Service Commission				

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SPONSOR	DATE	CASE/APPLICANT	DOCKET /CASE NO.	SUBJECT
Ameren Missouri	08/22	Ameren Missouri	File No. ER-2022-0337	Return on Equity
Missouri American Water Company	07/22	Missouri American Water Company	Case No. WR-2022-0303 Case No. SR-2022-0304	Return on Equity
Evergy Missouri West	1/22	Evergy Missouri West	File No. ER-2022-0130	Return on Equity
Evergy Missouri Metro	1/22	Evergy Missouri Metro	File No. ER-2022-0129	Return on Equity
Ameren Missouri	03/21	Ameren Missouri	Docket No. ER-2021-0240 Docket No. GR-2021-0241	Return on Equity
Missouri American Water Company	06/20	Missouri American Water Company	Case No. WR-2020-0344 Case No. SR-2020-0345	Return on Equity
Missouri American Water Company	06/17	Missouri American Water Company	Case No. WR-17-0285 Case No. SR-17-0286	Return on Equity
Montana Public Service Commission				
Montana-Dakota Utilities Co.	11/22	Montana-Dakota Utilities Co.	D2022.11.099	Return on Equity
Montana-Dakota Utilities Co.	06/20	Montana-Dakota Utilities Co.	D2020.06.076	Return on Equity
Montana-Dakota Utilities Co.	09/18	Montana-Dakota Utilities Co.	D2018.9.60	Return on Equity
New Hampshire - Board of Tax and Land Appeals				

SPONSOR	DATE	CASE/APPLICANT	DOCKET /CASE NO.	SUBJECT
Liberty Utilities (EnergyNorth Natural Gas)	07/23	Liberty Utilities (EnergyNorth Natural Gas)	Docket No. DG 23-067	Return on Equity
Liberty Utilities (Granite State Electric)	05/23	Liberty Utilities (Granite State Electric)	Docket No. DE 23-039	Return on Equity
Public Service Company of New Hampshire d/b/a Eversource Energy	11/19 12/19	Public Service Company of New Hampshire d/b/a Eversource Energy	Master Docket No. 28873-14-15-16-17PT	Valuation of Utility Property and Generating Assets
New Hampshire Public Utilities Commission				
Public Service Company of New Hampshire	05/19	Public Service Company of New Hampshire	DE-19-057	Return on Equity
New Hampshire-Merrimack County Superior Court				
Northern New England Telephone Operations, LLC d/b/a FairPoint Communications, NNE	04/18	Northern New England Telephone Operations, LLC d/b/a FairPoint Communications, NNE	220-2012-CV-1100	Valuation of Utility Property
New Hampshire-Rockingham Superior Court				
Eversource Energy	05/18	Public Service Commission of New Hampshire	218-2016-CV-00899 218-2017-CV-00917	Valuation of Utility Property
New Jersey Board of Public Utilities				
Public Service Electric and Gas Company	11/23	Public Service Electric and Gas Company	ER23120924 GR23120925	Return on Equity
New Jersey American Water Company, Inc.	01/22	New Jersey American Water Company, Inc.	WR22010019	Return on Equity
Public Service Electric and Gas Company	10/20	Public Service Electric and Gas Company	EO18101115	Return on Equity
New Jersey American Water Company, Inc.	12/19	New Jersey American Water Company, Inc.	WR19121516	Return on Equity

SPONSOR	DATE	CASE/APPLICANT	DOCKET /CASE NO.	SUBJECT
Public Service Electric and Gas Company	04/19	Public Service Electric and Gas Company	EO18060629 GO18060630	Return on Equity
Public Service Electric and Gas Company	02/18	Public Service Electric and Gas Company	GR17070776	Return on Equity
Public Service Electric and Gas Company	01/18	Public Service Electric and Gas Company	ER18010029 GR18010030	Return on Equity
New Mexico Public Regulation Commission				
Southwestern Public Service Company	07/19	Southwestern Public Service Company	19-00170-UT	Return on Equity
Southwestern Public Service Company	10/17	Southwestern Public Service Company	Case No. 17-00255-UT	Return on Equity
Southwestern Public Service Company	12/16	Southwestern Public Service Company	Case No. 16-00269-UT	Return on Equity
Southwestern Public Service Company	10/15	Southwestern Public Service Company	Case No. 15-00296-UT	Return on Equity
Southwestern Public Service Company	06/15	Southwestern Public Service Company	Case No. 15-00139-UT	Return on Equity
New York State Department of Public Service				
Liberty Utilities (New York Water)	5/23	Liberty Utilities (New York Water)	Case 23-W-0235	Return on Equity
New York State Electric and Gas Company Rochester Gas and Electric	05/22	New York State Electric and Gas Company Rochester Gas and Electric	22-E-0317 22-G-0318 22-E-0319 22-G-0320	Return on Equity
Corning Natural Gas Corporation	07/21	Corning Natural Gas Corporation	Case No. 21-G-0394	Return on Equity
Central Hudson Gas and Electric Corporation	08/20	Central Hudson Gas and Electric Corporation	Electric 20-E-0428 Gas 20-G-0429	Return on Equity

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SPONSOR	DATE	CASE/APPLICANT	DOCKET /CASE NO.	SUBJECT
Niagara Mohawk Power Corporation	07/20	National Grid USA	Case No. 20-E-0380 20-G-0381	Return on Equity
Corning Natural Gas Corporation	02/20	Corning Natural Gas Corporation	Case No. 20-G-0101	Return on Equity
New York State Electric and Gas Company Rochester Gas and Electric	05/19	New York State Electric and Gas Company Rochester Gas and Electric	19-E-0378 19-G-0379 19-E-0380 19-G-0381	Return on Equity
Brooklyn Union Gas Company d/b/a National Grid NY KeySpan Gas East Corporation d/b/a National Grid	04/19	Brooklyn Union Gas Company d/b/a National Grid NY KeySpan Gas East Corporation d/b/a National Grid	19-G-0309 19-G-0310	Return on Equity
Central Hudson Gas and Electric Corporation	07/17	Central Hudson Gas and Electric Corporation	Electric 17-E-0459 Gas 17-G-0460	Return on Equity
Niagara Mohawk Power Corporation	04/17	National Grid USA	Case No. 17-E-0238 17-G-0239	Return on Equity
Corning Natural Gas Corporation	06/16	Corning Natural Gas Corporation	Case No. 16-G-0369	Return on Equity
National Fuel Gas Company	04/16	National Fuel Gas Company	Case No. 16-G-0257	Return on Equity
KeySpan Energy Delivery	01/16	KeySpan Energy Delivery	Case No. 15-G-0058 Case No. 15-G-0059	Return on Equity
New York State Electric and Gas Company Rochester Gas and Electric	05/15	New York State Electric and Gas Company Rochester Gas and Electric	Case No. 15-E-0283 Case No. 15-G-0284 Case No. 15-E-0285 Case No. 15-G-0286	Return on Equity
North Dakota Public Service Commission				

SPONSOR	DATE	CASE/APPLICANT	DOCKET /CASE NO.	SUBJECT
Otter Tail Power Company	11/23	Otter Tail Power Company	Case No. PU-23-___	Return on Equity
Montana-Dakota Utilities Co.	11/23	Montana-Dakota Utilities Co.	Case No. PU-23-___	Return on Equity
Montana-Dakota Utilities Co.	05/22	Montana-Dakota Utilities Co.	C-PU-22-194	Return on Equity
Montana-Dakota Utilities Co.	08/20	Montana-Dakota Utilities Co.	C-PU-20-379	Return on Equity
Northern States Power Company	12/12	Northern States Power Company	C-PU-12-813	Return on Equity
Northern States Power Company	12/10	Northern States Power Company	C-PU-10-657	Return on Equity
Oklahoma Corporation Commission				
Oklahoma Gas & Electric	12/23	Oklahoma Gas & Electric	Cause No. PUD2023-000087	Return on Equity
Oklahoma Gas & Electric	12/21	Oklahoma Gas & Electric	Cause No. PUD 202100164	Return on Equity
Arkansas Oklahoma Gas Corporation	01/13	Arkansas Oklahoma Gas Corporation	Cause No. PUD 201200236	Return on Equity
Oregon Public Service Commission				
PacifiCorp d/b/a Pacific Power & Light	03/22	PacifiCorp d/b/a Pacific Power & Light	Docket No. UE-399	Return on Equity
PacifiCorp d/b/a Pacific Power & Light	02/20	PacifiCorp d/b/a Pacific Power & Light	Docket No. UE-374	Return on Equity
Pennsylvania Public Utility Commission				
American Water Works Company Inc.	11/23	Pennsylvania-American Water Company	Docket No. R-2023-3043189 (water) Docket No. R-2023-3043190 (wastewater)	Return on Equity

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SPONSOR	DATE	CASE/APPLICANT	DOCKET /CASE NO.	SUBJECT
American Water Works Company Inc.	04/22	Pennsylvania-American Water Company	Docket No. R-2020-3031672 (water) Docket No. R-2020-3031673 (wastewater)	Return on Equity
American Water Works Company Inc.	04/20	Pennsylvania-American Water Company	Docket No. R-2020-3019369 (water) Docket No. R-2020-3019371 (wastewater)	Return on Equity
American Water Works Company Inc.	04/17	Pennsylvania-American Water Company	Docket No. R-2017-2595853	Return on Equity
South Dakota Public Utilities Commission				
MidAmerican Energy Company	05/22	MidAmerican Energy Company	D-NG22-005	Return on Equity
Northern States Power Company	06/14	Northern States Power Company	Docket No. EL14-058	Return on Equity
Texas Public Utility Commission				
Entergy Texas, Inc.	07/22	Entergy Texas, Inc.	D-53719	Return on Equity
Southwestern Public Service Commission	08/19	Southwestern Public Service Commission	Docket No. D-49831	Return on Equity
Southwestern Public Service Company	01/14	Southwestern Public Service Company	Docket No. 42004	Return on Equity
Texas Railroad Commission				
CenterPoint Energy Entex and CenterPoint Energy Texas Gas	10/23	CenterPoint Energy Entex and CenterPoint Energy Texas Gas	2023 Texas Division Rate Case Case No. OS-23-00015513	Return on Equity
Utah Public Service Commission				

SPONSOR	DATE	CASE/APPLICANT	DOCKET /CASE NO.	SUBJECT
PacifiCorp d/b/a Rocky Mountain Power	05/20	PacifiCorp d/b/a Rocky Mountain Power	Docket No. 20-035-04	Return on Equity
Virginia State Corporation Commission				
Virginia American Water Company, Inc.	11/23	Virginia American Water Company, Inc.	Docket No. PUR-2023-00194	Return on Equity
Virginia American Water Company, Inc.	11/21	Virginia American Water Company, Inc.	Docket No. PUR-2021-00255	Return on Equity
Virginia American Water Company, Inc.	11/18	Virginia American Water Company, Inc.	Docket No. PUR-2018-00175	Return on Equity
Washington Utilities Transportation Commission				
PacifiCorp d/b/a Pacific Power & Light	03/23	PacifiCorp d/b/a Pacific Power & Light	Docket No. UE-230172	Return on Equity
Cascade Natural Gas Corporation	06/20	Cascade Natural Gas Corporation	Docket No. UG-200568	Return on Equity
PacifiCorp d/b/a Pacific Power & Light	12/19	PacifiCorp d/b/a Pacific Power & Light	Docket No. UE-191024	Return on Equity
Cascade Natural Gas Corporation	04/19	Cascade Natural Gas Corporation	Docket No. UG-190210	Return on Equity
West Virginia Public Service Commission				
West Virginia American Water Company	05/23	West Virginia American Water Company	Case No. 23-0383-W-42T	Return on Equity
West Virginia American Water Company	04/21	West Virginia American Water Company	Case No. 21-02369-W-42T	Return on Equity
West Virginia American Water Company	04/18	West Virginia American Water Company	Case No. 18-0573-W-42T Case No. 18-0576-S-42T	Return on Equity
Wisconsin Public Service Commission				
Wisconsin Power and Light	05/23	Wisconsin Power and Light	Docket No. 6680-UR-124	Return on Equity

SPONSOR	DATE	CASE/APPLICANT	DOCKET /CASE NO.	SUBJECT
Wisconsin Electric Power Company and Wisconsin Gas LLC	04/22	Wisconsin Electric Power Company and Wisconsin Gas LLC	Docket No. 05-UR-110	Return on Equity
Wisconsin Public Service Corp.	04/22	Wisconsin Public Service Corp.	6690-UR-127	Return on Equity
Alliant Energy		Alliant Energy		Return on Equity
Wisconsin Electric Power Company and Wisconsin Gas LLC	03/19	Wisconsin Electric Power Company and Wisconsin Gas LLC	Docket No. 05-UR-109	Return on Equity
Wisconsin Public Service Corp.	03/19	Wisconsin Public Service Corp.	6690-UR-126	Return on Equity
Wyoming Public Service Commission				
PacifiCorp d/b/a Rocky Mountain Power	02/23	PacifiCorp d/b/a Rocky Mountain Power	Docket No. 20000-633-ER-23	Return on Equity
PacifiCorp d/b/a Rocky Mountain Power	03/20	PacifiCorp d/b/a Rocky Mountain Power	Docket No. 20000-578-ER-20	Return on Equity
Montana-Dakota Utilities Co.	05/19	Montana-Dakota Utilities Co.	30013-351-GR-19	Return on Equity

CERTIFICATIONS/ACCREDITATIONS

Certified General Appraiser, licensed in the Commonwealth of Massachusetts

COST OF EQUITY ANALYSES
SUMMARY OF RESULTS

Constant Growth DCF

	Minimum Growth Rate	Average Growth Rate	Maximum Growth Rate
Mean Results:			
30-Day Avg. Stock Price	9.12%	10.16%	11.31%
90-Day Avg. Stock Price	8.97%	10.01%	11.16%
180-Day Avg. Stock Price	8.77%	9.81%	10.96%
Average	8.95%	9.99%	11.14%
Median Results:			
30-Day Avg. Stock Price	8.90%	9.92%	11.10%
90-Day Avg. Stock Price	8.69%	9.61%	10.84%
180-Day Avg. Stock Price	8.52%	9.28%	10.64%
Average	8.70%	9.60%	10.86%

CAPM / ECAPM / Bond Yield Risk Premium

	30-Year Treasury Bond Yield		
	Current 30-Day Avg	Near-Term Projected	Longer-Term Projected
CAPM:			
Current *Value Line* Beta	11.28%	11.23%	11.17%
Current Bloomberg Beta	10.72%	10.65%	10.56%
Long-term Avg. *Value Line* Beta	10.46%	10.38%	10.28%
ECAPM:			
Current *Value Line* Beta	11.60%	11.56%	11.52%
Current Bloomberg Beta	11.18%	11.13%	11.06%
Long-term Avg. *Value Line* Beta	10.98%	10.92%	10.85%
Bond Yield Risk Premium	10.63%	10.46%	10.25%

PROXY GROUP SCREENING DATA AND RESULTS

		[1]	[2]	[3]	[4]	[5]	[6]	[7]	[8]
Company	Ticker	Dividends	S&P Credit Rating Between BBB- and AAA	Covered by More Than 1 Analyst	Positive Growth Rates from at least two sources (Value Line, Yahoo! First Call, and Zacks)	% Regulated Operating Income > 70%	Announced Merger	Electric Companies with < 10% Generation	Electric Companies with Water Operations
Atmos Energy Corporation	ATO	Yes	A-	Yes	Yes	100%	No	n/a	n/a
NiSource Inc.	NI	Yes	BBB+	Yes	Yes	100%	No	n/a	n/a
Northwest Natural Gas Company	NWN	Yes	A+	Yes	Yes	100%	No	n/a	n/a
ONE Gas, Inc.	OGS	Yes	A-	Yes	Yes	100%	No	n/a	n/a
Spire, Inc.	SR	Yes	A-	Yes	Yes	87%	No	0.06%	Yes
Eversource Energy	ES	Yes	A-	Yes	Yes	92%	No	n/a	n/a
American States Water Company	AWR	Yes	A	Yes	Yes	83%	No	n/a	n/a
California Water Service Group	CWT	Yes	A+	Yes	Yes	98%	No	n/a	n/a
Middlesex Water Company	MSEX	Yes	A	Yes	Yes	91%	No	n/a	n/a
SJW Group	SJW	Yes	A-	Yes	Yes	99%	No	n/a	n/a
Essential Utilities, Inc.	WTRG	Yes	A	Yes	Yes	99%	No	n/a	n/a

Notes:
[1] Source: Bloomberg Professional
[2] Source: Bloomberg Professional
[3] Source: Yahoo! Finance, and Zacks
[4] Source: Yahoo! Finance, Value Line Investment Survey, and Zacks
[5] Source: Form 10-K's for 2022, 2021, and 2020
[6] Source: SNL Financial News Releases
[7] Source: S&P Capital IQ Pro
[8] Source: S&P Capital IQ Pro

30-DAY CONSTANT GROWTH DCF

		[1]	[2]	[3]	[4]	[5]	[6]	[7]	[8]	[9]	[10]	[11]
Company		Annualized Dividend	Stock Price	Dividend Yield	Expected Dividend Yield	Value Line Projected EPS Growth Rate	Yahoo! Finance Projected EPS Growth Rate	Zacks Projected EPS Growth Rate	Average Projected EPS Growth Rate	Cost of Equity: Minimum Growth Rate	Cost of Equity: Mean Growth Rate	Cost of Equity: Maximum Growth Rate
Atmos Energy Corporation	ATO	$3.22	$110.15	2.92%	3.03%	7.00%	7.50%	7.30%	7.27%	10.03%	10.30%	10.53%
NiSource Inc.	NI	$1.00	$25.47	3.93%	4.09%	9.50%	8.30%	7.20%	8.33%	11.27%	12.42%	13.61%
Northwest Natural Gas Company	NWN	$1.95	$37.13	5.25%	5.36%	6.50%	2.80%	3.70%	4.33%	8.12%	9.70%	11.92%
ONE Gas, Inc.	OGS	$2.60	$60.91	4.27%	4.39%	6.50%	5.00%	5.00%	5.50%	9.38%	9.89%	10.91%
Spire, Inc.	SR	$2.88	$58.30	4.94%	5.11%	8.00%	n/a	5.60%	6.80%	10.68%	11.91%	13.14%
Eversource Energy	ES	$2.70	$55.95	4.83%	4.95%	6.00%	4.00%	5.00%	5.00%	8.92%	9.95%	10.97%
American States Water Company	AWR	$1.72	$79.00	2.18%	2.24%	6.50%	4.40%	6.30%	5.73%	6.63%	7.97%	8.75%
California Water Service Group	CWT	$1.04	$49.63	2.10%	2.19%	6.50%	10.80%	n/a	8.65%	8.66%	10.84%	13.01%
Middlesex Water Company	MSEX	$1.30	$64.21	2.02%	2.06%	5.00%	2.70%	n/a	3.85%	4.75%	5.91%	7.08%
SJW Group	SJW	$1.52	$62.51	2.43%	2.51%	6.50%	6.10%	n/a	6.30%	8.61%	8.81%	9.01%
Essential Utilities, Inc.	WTRG	$1.23	$34.25	3.59%	3.70%	7.50%	5.20%	5.60%	6.10%	8.88%	9.80%	11.22%
Mean										8.72%	9.77%	10.92%
Median										8.88%	9.89%	10.97%
Excluding Middlesex Water Company												
Mean										9.12%	10.16%	11.31%
Median										8.90%	9.92%	11.10%

Notes:
[1] Bloomberg Professional as of November 30, 2023
[2] Bloomberg Professional 30-day average as of November 30, 2023
[3] Equals [1]/[2]
[4] Equals [3] x (1 + 0.5 x [8])
[5] Value Line
[6] Yahoo! Finance
[7] Zacks
[8] Equals average of [5], [6], [7]
[9] Equals [3] x (1 + 0.5 x (min([5], [6], [7])) + (min([5], [6], [7])
[10] Equals [4] + [8]
[11] Equals [3] x (1 + 0.5 x (max([5], [6], [7])) + (max([5], [6], [7])

90-DAY CONSTANT GROWTH DCF

		[1]	[2]	[3]	[4]	[5]	[6]	[7]	[8]	[9]	[10]	[11]
Company		Annualized Dividend	Stock Price	Dividend Yield	Expected Dividend Yield	Value Line Projected EPS Growth Rate	Yahoo! Finance Projected EPS Growth Rate	Zacks Projected EPS Growth Rate	Average Projected EPS Growth Rate	Cost of Equity: Minimum Growth Rate	Cost of Equity: Mean Growth Rate	Cost of Equity: Maximum Growth Rate
Atmos Energy Corporation	ATO	$3.22	$112.18	2.87%	2.97%	7.00%	7.50%	7.30%	7.27%	9.97%	10.24%	10.48%
NiSource Inc.	NI	$1.00	$25.91	3.86%	4.02%	9.50%	8.30%	7.20%	8.33%	11.20%	12.35%	13.54%
Northwest Natural Gas Company	NWN	$1.95	$38.73	5.04%	5.14%	6.50%	2.80%	3.70%	4.33%	7.91%	9.48%	11.70%
ONE Gas, Inc.	OGS	$2.60	$68.57	3.79%	3.90%	6.50%	5.00%	5.00%	5.50%	8.89%	9.40%	10.42%
Spire, Inc.	SR	$2.88	$58.60	4.91%	5.08%	8.00%	n/a	5.60%	6.80%	10.65%	11.88%	13.11%
Eversource Energy	ES	$2.70	$60.26	4.48%	4.59%	6.00%	4.00%	5.00%	5.00%	8.57%	9.59%	10.61%
American States Water Company	AWR	$1.72	$81.51	2.11%	2.17%	6.50%	4.40%	6.30%	5.73%	6.56%	7.90%	8.68%
California Water Service Group	CWT	$1.04	$49.60	2.10%	2.19%	6.50%	10.80%	n/a	8.65%	8.66%	10.84%	13.01%
Middlesex Water Company	MSEX	$1.30	$70.15	1.85%	1.89%	5.00%	2.70%	n/a	3.85%	4.58%	5.74%	6.90%
SJW Group	SJW	$1.52	$63.65	2.39%	2.46%	6.50%	6.10%	n/a	6.30%	8.56%	8.76%	8.97%
Essential Utilities, Inc.	WTRG	$1.23	$35.83	3.43%	3.53%	7.50%	5.20%	5.60%	6.10%	8.72%	9.63%	11.06%
Mean										8.57%	9.62%	10.77%
Median										8.66%	9.59%	10.61%
Excluding Middlesex Water Company												
Mean										8.97%	10.01%	11.16%
Median										8.69%	9.61%	10.84%

Notes:
[1] Bloomberg Professional as of November 30, 2023
[2] Bloomberg Professional 90-day average as of November 30, 2023
[3] Equals [1]/[2]
[4] Equals [3] x (1 + 0.5 x [8])
[5] Value Line
[6] Yahoo! Finance
[7] Zacks
[8] Equals average of [5], [6], [7]
[9] Equals [3] x (1 + 0.5 x (min([5], [6], [7])) + (min([5], [6], [7])
[10] Equals [4] + [8]
[11] Equals [3] x (1 + 0.5 x (max([5], [6], [7])) + (max([5], [6], [7])

180-DAY CONSTANT GROWTH DCF

		[1]	[2]	[3]	[4]	[5]	[6]	[7]	[8]	[9]	[10]	[11]
Company		Annualized Dividend	Stock Price	Dividend Yield	Expected Dividend Yield	Value Line Projected EPS Growth Rate	Yahoo! Finance Projected EPS Growth Rate	Zacks Projected EPS Growth Rate	Average Projected EPS Growth Rate	Cost of Equity: Minimum Growth Rate	Cost of Equity: Mean Growth Rate	Cost of Equity: Maximum Growth Rate
Atmos Energy Corporation	ATO	$3.22	$113.07	2.85%	2.95%	7.00%	7.50%	7.30%	7.27%	9.95%	10.22%	10.45%
NiSource Inc.	NI	$1.00	$26.50	3.77%	3.93%	9.50%	8.30%	7.20%	8.33%	11.11%	12.26%	13.45%
Northwest Natural Gas Company	NWN	$1.95	$41.27	4.73%	4.83%	6.50%	2.80%	3.70%	4.33%	7.59%	9.16%	11.38%
ONE Gas, Inc.	OGS	$2.60	$72.99	3.56%	3.66%	6.50%	5.00%	5.00%	5.50%	8.65%	9.16%	10.18%
Spire, Inc.	SR	$2.88	$62.07	4.64%	4.80%	8.00%	n/a	5.60%	6.80%	10.37%	11.60%	12.83%
Eversource Energy	ES	$2.70	$66.71	4.05%	4.15%	6.00%	4.00%	5.00%	5.00%	8.13%	9.15%	10.17%
American States Water Company	AWR	$1.72	$84.55	2.03%	2.09%	6.50%	4.40%	6.30%	5.73%	6.48%	7.83%	8.60%
California Water Service Group	CWT	$1.04	$52.15	1.99%	2.08%	6.50%	10.80%	n/a	8.65%	8.56%	10.73%	12.90%
Middlesex Water Company	MSEX	$1.30	$73.90	1.76%	1.79%	5.00%	2.70%	n/a	3.85%	4.48%	5.64%	6.80%
SJW Group	SJW	$1.52	$68.60	2.22%	2.29%	6.50%	6.10%	n/a	6.30%	8.38%	8.59%	8.79%
Essential Utilities, Inc.	WTRG	$1.23	$38.42	3.20%	3.29%	7.50%	5.20%	5.60%	6.10%	8.48%	9.39%	10.82%
Mean										8.38%	9.43%	10.58%
Median										8.48%	9.16%	10.45%
Excluding Middlesex Water Company												
Mean										8.77%	9.81%	10.96%
Median										8.52%	9.28%	10.64%

Notes:
[1] Bloomberg Professional as of November 30, 2023
[2] Bloomberg Professional 180-day average as of November 30, 2023
[3] Equals [1]/[2]
[4] Equals [3] x (1 + 0.5 x [8])
[5] Value Line
[6] Yahoo! Finance
[7] Zacks
[8] Equals average of [5], [6], [7]
[9] Equals [3] x (1 + 0.5 x (min([5], [6], [7])) + (min([5], [6], [7])
[10] Equals [4] + [8]
[11] Equals [3] x (1 + 0.5 x (max([5], [6], [7])) + (max([5], [6], [7])

CAPITAL ASSET PRICING MODEL
CURRENT RISK FREE RATE AND VALUE LINE BETA

$$K = Rf + \beta\ (Rm - Rf)$$
$$K = Rf + 0.25 \times (Rm - Rf) + 0.75 \times \beta \times (Rm - Rf)$$

		[1]	[2]	[3]	[4]	[5]	[6]
Company	Ticker	Current 30-day average of 30-year U.S. Treasury bond yield	Beta (β)	Market Return (Rm)	Market Risk Premium (Rm − Rf)	CAPM ROE (K)	ECAPM ROE (K)
Atmos Energy Corporation	ATO	4.77%	0.85	12.56%	7.78%	11.39%	11.68%
NiSource Inc.	NI	4.77%	0.90	12.56%	7.78%	11.78%	11.97%
Northwest Natural Gas Company	NWN	4.77%	0.85	12.56%	7.78%	11.39%	11.68%
ONE Gas, Inc.	OGS	4.77%	0.85	12.56%	7.78%	11.39%	11.68%
Spire, Inc.	SR	4.77%	0.85	12.56%	7.78%	11.39%	11.68%
Eversource Energy	ES	4.77%	0.90	12.56%	7.78%	11.78%	11.97%
American States Water Company	AWR	4.77%	0.70	12.56%	7.78%	10.22%	10.81%
California Water Service Group	CWT	4.77%	0.70	12.56%	7.78%	10.22%	10.81%
Middlesex Water Company	MSEX	4.77%	0.75	12.56%	7.78%	10.61%	11.10%
SJW Group	SJW	4.77%	0.85	12.56%	7.78%	11.39%	11.68%
Essential Utilities, Inc.	WTRG	4.77%	1.00	12.56%	7.78%	12.56%	12.56%
Mean						11.28%	11.60%
Median						11.39%	11.68%

Notes:
[1] Bloomberg Professional 30-day average as of November 30, 2023
[2] Value Line
[3] Market Return
[4] Equals [3]-[1]
[5] Equals [1] + [2] x [4]
[6] Equals [1] + 0.25 x ([4]) + 0.75 x ([2] x [4])

CAPITAL ASSET PRICING MODEL
NEAR TERM PROJECTED RISK-FREE RATE AND VALUE LINE BETA

K = Rf + β (Rm − Rf)
K = Rf + 0.25 x (Rm - Rf) + 0.75 x β x (Rm − Rf)

		[1]	[2]	[3]	[4]	[5]	[6]
Company	Ticker	Near-term projected 30-year U.S. Treasury bond yield (Q1 2024 - Q1 2025)	Beta (β)	Market Return (Rm)	Market Risk Premium (Rm − Rf)	CAPM ROE (K)	ECAPM ROE (K)
Atmos Energy Corporation	ATO	4.48%	0.85	12.56%	8.08%	11.34%	11.65%
NiSource Inc.	NI	4.48%	0.90	12.56%	8.08%	11.75%	11.95%
Northwest Natural Gas Company	NWN	4.48%	0.85	12.56%	8.08%	11.34%	11.65%
ONE Gas, Inc.	OGS	4.48%	0.85	12.56%	8.08%	11.34%	11.65%
Spire, Inc.	SR	4.48%	0.85	12.56%	8.08%	11.34%	11.65%
Eversource Energy	ES	4.48%	0.90	12.56%	8.08%	11.75%	11.95%
American States Water Company	AWR	4.48%	0.70	12.56%	8.08%	10.13%	10.74%
California Water Service Group	CWT	4.48%	0.70	12.56%	8.08%	10.13%	10.74%
Middlesex Water Company	MSEX	4.48%	0.75	12.56%	8.08%	10.54%	11.04%
SJW Group	SJW	4.48%	0.85	12.56%	8.08%	11.34%	11.65%
Essential Utilities, Inc.	WTRG	4.48%	1.00	12.56%	8.08%	12.56%	12.56%
Mean						11.23%	11.56%
Median						11.34%	11.65%

Notes:
[1] Blue Chip Financial Forecasts, Vol. 42, No. 12, December 1, 2023, at 2
[2] Value Line
[3] Market Return
[4] Equals [3]-[1]
[5] Equals [1] + [2] x [4]
[6] Equals [1] + 0.25 x ([4]) + 0.75 x ([2] x [4])

CAPITAL ASSET PRICING MODEL
LONG-TERM PROJECTED RISK-FREE RATE AND VALUE LINE BETA

$$K = Rf + \beta\ (Rm - Rf)$$
$$K = Rf + 0.25 \times (Rm - Rf) + 0.75 \times \beta \times (Rm - Rf)$$

		[1]	[2]	[3]	[4]	[5]	[6]
Company	Ticker	Projected 30-year U.S. Treasury bond yield (2025 - 2029)	Beta (β)	Market Return (Rm)	Market Risk Premium (Rm − Rf)	CAPM ROE (K)	ECAPM ROE (K)
Atmos Energy Corporation	ATO	4.10%	0.85	12.56%	8.46%	11.29%	11.60%
NiSource Inc.	NI	4.10%	0.90	12.56%	8.46%	11.71%	11.92%
Northwest Natural Gas Company	NWN	4.10%	0.85	12.56%	8.46%	11.29%	11.60%
ONE Gas, Inc.	OGS	4.10%	0.85	12.56%	8.46%	11.29%	11.60%
Spire, Inc.	SR	4.10%	0.85	12.56%	8.46%	11.29%	11.60%
Eversource Energy	ES	4.10%	0.90	12.56%	8.46%	11.71%	11.92%
American States Water Company	AWR	4.10%	0.70	12.56%	8.46%	10.02%	10.65%
California Water Service Group	CWT	4.10%	0.70	12.56%	8.46%	10.02%	10.65%
Middlesex Water Company	MSEX	4.10%	0.75	12.56%	8.46%	10.44%	10.97%
SJW Group	SJW	4.10%	0.85	12.56%	8.46%	11.29%	11.60%
Essential Utilities, Inc.	WTRG	4.10%	1.00	12.56%	8.46%	12.56%	12.56%
Mean						11.17%	11.52%
Median						11.29%	11.60%

Notes:
[1] Blue Chip Financial Forecasts, Vol. 42, No. 12, December 1, 2023, at 14
[2] Value Line
[3] Market Return
[4] Equals [3]-[1]
[5] Equals [1] + [2] x [4]
[6] Equals [1] + 0.25 x ([4]) + 0.75 x ([2] x [4])

CAPITAL ASSET PRICING MODEL
CURRENT RISK FREE RATE AND BLOOMBERG BETA

$$K = Rf + \beta\ (Rm - Rf)$$
$$K = Rf + 0.25 \times (Rm - Rf) + 0.75 \times \beta \times (Rm - Rf)$$

		[1]	[2]	[3]	[4]	[5]	[6]
Company	Ticker	Current 30-day average of 30-year U.S. Treasury bond yield	Beta (β)	Market Return (Rm)	Market Risk Premium (Rm − Rf)	CAPM ROE (K)	ECAPM ROE (K)
Atmos Energy Corporation	ATO	4.77%	0.75	12.56%	7.78%	10.61%	11.10%
NiSource Inc.	NI	4.77%	0.81	12.56%	7.78%	11.09%	11.46%
Northwest Natural Gas Company	NWN	4.77%	0.71	12.56%	7.78%	10.26%	10.83%
ONE Gas, Inc.	OGS	4.77%	0.78	12.56%	7.78%	10.86%	11.28%
Spire, Inc.	SR	4.77%	0.77	12.56%	7.78%	10.78%	11.23%
Eversource Energy	ES	4.77%	0.81	12.56%	7.78%	11.05%	11.43%
American States Water Company	AWR	4.77%	0.65	12.56%	7.78%	9.87%	10.54%
California Water Service Group	CWT	4.77%	0.69	12.56%	7.78%	10.17%	10.76%
Middlesex Water Company	MSEX	4.77%	0.77	12.56%	7.78%	10.80%	11.24%
SJW Group	SJW	4.77%	0.81	12.56%	7.78%	11.05%	11.42%
Essential Utilities, Inc.	WTRG	4.77%	0.85	12.56%	7.78%	11.41%	11.69%
Mean						10.72%	11.18%
Median						10.80%	11.24%

Notes:
[1] Bloomberg Professional 30-day average as of November 30, 2023
[2] Bloomberg Professional
[3] Market Return
[4] Equals [3]-[1]
[5] Equals [1] + [2] x [4]
[6] Equals [1] + 0.25 x ([4]) + 0.75 x ([2] x [4])

CAPITAL ASSET PRICING MODEL
NEAR TERM PROJECTED RISK-FREE RATE AND BLOOMBERG BETA

K = Rf + β (Rm − Rf)
K = Rf + 0.25 x (Rm - Rf) + 0.75 x β x (Rm − Rf)

		[1]	[2]	[3]	[4]	[5]	[6]
Company	Ticker	Near-term projected 30-year U.S. Treasury bond yield (Q1 2024 - Q1 2025)	Beta (β)	Market Return (Rm)	Market Risk Premium (Rm − Rf)	CAPM ROE (K)	ECAPM ROE (K)
Atmos Energy Corporation	ATO	4.48%	0.75	12.56%	8.08%	10.54%	11.04%
NiSource Inc.	NI	4.48%	0.81	12.56%	8.08%	11.04%	11.42%
Northwest Natural Gas Company	NWN	4.48%	0.71	12.56%	8.08%	10.17%	10.77%
ONE Gas, Inc.	OGS	4.48%	0.78	12.56%	8.08%	10.80%	11.24%
Spire, Inc.	SR	4.48%	0.77	12.56%	8.08%	10.71%	11.17%
Eversource Energy	ES	4.48%	0.81	12.56%	8.08%	10.99%	11.38%
American States Water Company	AWR	4.48%	0.65	12.56%	8.08%	9.76%	10.46%
California Water Service Group	CWT	4.48%	0.69	12.56%	8.08%	10.08%	10.70%
Middlesex Water Company	MSEX	4.48%	0.77	12.56%	8.08%	10.74%	11.19%
SJW Group	SJW	4.48%	0.81	12.56%	8.08%	10.99%	11.38%
Essential Utilities, Inc.	WTRG	4.48%	0.85	12.56%	8.08%	11.36%	11.66%
Mean						10.65%	11.13%
Median						10.74%	11.19%

Notes:
[1] Blue Chip Financial Forecasts, Vol. 42, No. 12, December 1, 2023, at 2
[2] Bloomberg Professional
[3] Market Return
[4] Equals [3]-[1]
[5] Equals [1] + [2] x [4]
[6] Equals [1] + 0.25 x ([4]) + 0.75 x ([2] x [4])

CAPITAL ASSET PRICING MODEL
LONG-TERM PROJECTED RISK-FREE RATE AND BLOOMBERG BETA

$$K = Rf + \beta\ (Rm - Rf)$$
$$K = Rf + 0.25 \times (Rm - Rf) + 0.75 \times \beta \times (Rm - Rf)$$

		[1]	[2]	[3]	[4]	[5]	[6]
Company	Ticker	Projected 30-year U.S. Treasury bond yield (2025 - 2029)	Beta (β)	Market Return (Rm)	Market Risk Premium (Rm − Rf)	CAPM ROE (K)	ECAPM ROE (K)
Atmos Energy Corporation	ATO	4.10%	0.75	12.56%	8.46%	10.45%	10.97%
NiSource Inc.	NI	4.10%	0.81	12.56%	8.46%	10.97%	11.37%
Northwest Natural Gas Company	NWN	4.10%	0.71	12.56%	8.46%	10.06%	10.69%
ONE Gas, Inc.	OGS	4.10%	0.78	12.56%	8.46%	10.71%	11.17%
Spire, Inc.	SR	4.10%	0.77	12.56%	8.46%	10.63%	11.11%
Eversource Energy	ES	4.10%	0.81	12.56%	8.46%	10.92%	11.33%
American States Water Company	AWR	4.10%	0.65	12.56%	8.46%	9.63%	10.36%
California Water Service Group	CWT	4.10%	0.69	12.56%	8.46%	9.96%	10.61%
Middlesex Water Company	MSEX	4.10%	0.77	12.56%	8.46%	10.65%	11.13%
SJW Group	SJW	4.10%	0.81	12.56%	8.46%	10.92%	11.33%
Essential Utilities, Inc.	WTRG	4.10%	0.85	12.56%	8.46%	11.31%	11.62%
Mean						10.56%	11.06%
Median						10.65%	11.13%

Notes:
[1] Blue Chip Financial Forecasts, Vol. 42, No. 12, December 1, 2023, at 14
[2] Bloomberg Professional
[3] Market Return
[4] Equals [3]-[1]
[5] Equals [1] + [2] x [4]
[6] Equals [1] + 0.25 x ([4]) + 0.75 x ([2] x [4])

CAPITAL ASSET PRICING MODEL
CURRENT RISK FREE RATE AND LONG-TERM VALUE LINE BETA

$$K = Rf + \beta\ (Rm - Rf)$$
$$K = Rf + 0.25 \times (Rm - Rf) + 0.75 \times \beta \times (Rm - Rf)$$

		[1]	[2]	[3]	[4]	[5]	[6]
Company	Ticker	Current 30-day average of 30-year U.S. Treasury bond yield	Beta (β)	Market Return (Rm)	Market Risk Premium (Rm − Rf)	CAPM ROE (K)	ECAPM ROE (K)
Atmos Energy Corporation	ATO	4.77%	0.74	12.56%	7.78%	10.53%	11.04%
NiSource Inc.	NI	4.77%	0.74	12.56%	7.78%	10.51%	11.02%
Northwest Natural Gas Company	NWN	4.77%	0.70	12.56%	7.78%	10.22%	10.81%
ONE Gas, Inc.	OGS	4.77%	0.73	12.56%	7.78%	10.44%	10.97%
Spire, Inc.	SR	4.77%	0.73	12.56%	7.78%	10.46%	10.98%
Eversource Energy	ES	4.77%	0.74	12.56%	7.78%	10.56%	11.06%
American States Water Company	AWR	4.77%	0.69	12.56%	7.78%	10.14%	10.75%
California Water Service Group	CWT	4.77%	0.71	12.56%	7.78%	10.26%	10.83%
Middlesex Water Company	MSEX	4.77%	0.74	12.56%	7.78%	10.49%	11.01%
SJW Group	SJW	4.77%	0.76	12.56%	7.78%	10.65%	11.13%
Essential Utilities, Inc.	WTRG	4.77%	0.77	12.56%	7.78%	10.77%	11.21%
Mean						10.46%	10.98%
Median						10.49%	11.01%

Notes:
[1] Bloomberg Professional 30-day average as of November 30, 2023
[2] Source: LT Beta
[3] Market Return
[4] Equals [3]-[1]
[5] Equals [1] + [2] x [4]
[6] Equals [1] + 0.25 x ([4]) + 0.75 x ([2] x [4])

CAPITAL ASSET PRICING MODEL
NEAR-TERM PROJECTED RISK FREE RATE AND LONG-TERM VALUE LINE BETA

$$K = Rf + \beta\ (Rm - Rf)$$
$$K = Rf + 0.25 \times (Rm - Rf) + 0.75 \times \beta \times (Rm - Rf)$$

		[1]	[2]	[3]	[4]	[5]	[6]
Company	Ticker	Near-term projected 30-year U.S. Treasury bond yield (Q1 2024 - Q1 2025)	Beta (β)	Market Return (Rm)	Market Risk Premium (Rm − Rf)	CAPM ROE (K)	ECAPM ROE (K)
Atmos Energy Corporation	ATO	4.48%	0.74	12.56%	8.08%	10.46%	10.98%
NiSource Inc.	NI	4.48%	0.74	12.56%	8.08%	10.44%	10.97%
Northwest Natural Gas Company	NWN	4.48%	0.70	12.56%	8.08%	10.13%	10.74%
ONE Gas, Inc.	OGS	4.48%	0.73	12.56%	8.08%	10.36%	10.91%
Spire, Inc.	SR	4.48%	0.73	12.56%	8.08%	10.38%	10.92%
Eversource Energy	ES	4.48%	0.74	12.56%	8.08%	10.49%	11.00%
American States Water Company	AWR	4.48%	0.69	12.56%	8.08%	10.05%	10.68%
California Water Service Group	CWT	4.48%	0.71	12.56%	8.08%	10.17%	10.77%
Middlesex Water Company	MSEX	4.48%	0.74	12.56%	8.08%	10.42%	10.95%
SJW Group	SJW	4.48%	0.76	12.56%	8.08%	10.58%	11.07%
Essential Utilities, Inc.	WTRG	4.48%	0.77	12.56%	8.08%	10.70%	11.16%
Mean						10.38%	10.92%
Median						10.42%	10.95%

Notes:
[1] Blue Chip Financial Forecasts, Vol. 42, No. 12, December 1, 2023, at 2
[2] Source: LT Beta
[3] Market Return
[4] Equals [3]-[1]
[5] Equals [1] + [2] x [4]
[6] Equals [1] + 0.25 x ([4]) + 0.75 x ([2] x [4])

CAPITAL ASSET PRICING MODEL
LONG-TERM PROJECTED RISK FREE RATE AND LONG-TERM VALUE LINE BETA

$$K = Rf + \beta\ (Rm - Rf)$$
$$K = Rf + 0.25 \times (Rm - Rf) + 0.75 \times \beta \times (Rm - Rf)$$

		[1]	[2]	[3]	[4]	[5]	[6]
Company	Ticker	Projected 30-year U.S. Treasury bond yield (2025 - 2029)	Beta (β)	Market Return (Rm)	Market Risk Premium (Rm − Rf)	CAPM ROE (K)	ECAPM ROE (K)
Atmos Energy Corporation	ATO	4.10%	0.74	12.56%	8.46%	10.36%	10.91%
NiSource Inc.	NI	4.10%	0.74	12.56%	8.46%	10.34%	10.89%
Northwest Natural Gas Company	NWN	4.10%	0.70	12.56%	8.46%	10.02%	10.65%
ONE Gas, Inc.	OGS	4.10%	0.73	12.56%	8.46%	10.26%	10.83%
Spire, Inc.	SR	4.10%	0.73	12.56%	8.46%	10.27%	10.84%
Eversource Energy	ES	4.10%	0.74	12.56%	8.46%	10.39%	10.93%
American States Water Company	AWR	4.10%	0.69	12.56%	8.46%	9.93%	10.59%
California Water Service Group	CWT	4.10%	0.71	12.56%	8.46%	10.06%	10.69%
Middlesex Water Company	MSEX	4.10%	0.74	12.56%	8.46%	10.32%	10.88%
SJW Group	SJW	4.10%	0.76	12.56%	8.46%	10.48%	11.00%
Essential Utilities, Inc.	WTRG	4.10%	0.77	12.56%	8.46%	10.61%	11.10%
Mean						10.28%	10.85%
Median						10.32%	10.88%

Notes:
[1] Blue Chip Financial Forecasts, Vol. 42, No. 12, December 1, 2023, at 14
[2] Source: LT Beta
[3] Market Return
[4] Equals [3]-[1]
[5] Equals [1] + [2] x [4]
[6] Equals [1] + 0.25 x ([4]) + 0.75 x ([2] x [4])

HISTORICAL VALUE LINE BETA

		[1]	[2]	[3]	[4]	[5]	[6]	[7]	[8]	[9]	[10]	[11]
Company	Ticker	12/31/2013	12/31/2014	12/31/2015	12/31/2016	12/31/2017	12/31/2018	12/31/2019	12/31/2020	12/31/2021	12/31/2022	Average
Atmos Energy Corporation	ATO	0.80	0.80	0.80	0.70	0.70	0.60	0.60	0.80	0.80	0.80	0.74
NiSource Inc.	NI	0.85	0.85	NMF	NMF	0.60	0.50	0.55	0.85	0.85	0.85	0.74
Northwest Natural Gas Company	NWN	0.65	0.7	0.65	0.65	0.70	0.60	0.60	0.80	0.85	0.80	0.70
ONE Gas, Inc.	OGS	NA	NA	NA	0.70	0.70	0.65	0.65	0.80	0.80	0.80	0.73
Spire, Inc.	SR	0.65	0.7	0.7	0.70	0.70	0.65	0.65	0.85	0.85	0.85	0.73
Eversource Energy	ES			0.75	0.70	0.65	0.60	0.55	0.90	0.90	0.90	0.74
American States Water Company	AWR	0.65	0.7	0.7	0.75	0.80	0.70	0.65	0.65	0.65	0.65	0.69
California Water Service Group	CWT	0.6	0.7	0.75	0.75	0.80	0.70	0.70	0.65	0.70	0.70	0.71
Middlesex Water Company	MSEX	0.75	0.7	0.7	0.75	0.80	0.75	0.75	0.75	0.70	0.70	0.74
SJW Group	SJW	0.85	0.85	0.75	0.75	0.70	0.60	0.60	0.85	0.80	0.80	0.76
Essential Utilities, Inc.	WTRG	0.6	0.7	0.75	0.70	0.75	0.70	0.65	0.95	0.95	0.95	0.77
Mean		0.71	0.74	0.73	0.72	0.72	0.64	0.63	0.80	0.80	0.80	0.73

Notes:
[1] Value Line, December 26, 2013.
[2] Value Line, December 31, 2014.
[3] Value Line, December 30, 2015.
[4] Value Line, December 29, 2016.
[5] Value Line, December 28, 2017.
[6] Value Line, December 27, 2018.
[7] Value Line, December 26, 2019.
[8] Value Line, December 30, 2020.
[9] Value Line, December 29, 2021.
[10] Value Line, December 30, 2022.
[11] Average ([1] - [10])

MARKET RISK PREMIUM DERIVED FROM S&P 500 INDEX

[1] Estimate of the S&P 500 Dividend Yield	1.69%
[2] Estimate of the S&P 500 Growth Rate	10.78%
[3] S&P 500 Estimated Required Market Return	12.56%

Name	Ticker	[4] Shares Outst'g	[5] Price	[6] Market Capitalization	[7] Weight in Index	[8] Estimated Dividend Yield	[9] Cap-Weighted Dividend Yield	[10] Bloomberg Long-Term Growth Est.	[11] Cap-Weighted Long-Term Growth Est.
LyondellBasell Industries NV	LYB	324.362	95.1	30,846.83	0.11%	5.26%	0.01%	8.00%	0.01%
American Express Co	AXP	728.746	170.77	124,447.95	0.42%	1.41%	0.01%	14.01%	0.06%
Verizon Communications Inc	VZ	4204.102	38.33	161,143.23		6.94%			
Broadcom Inc	AVGO	469.426	925.73	434,561.73	1.48%	1.99%	0.03%	13.89%	0.21%
Boeing Co/The	BA	604.977	231.63	140,130.82				183.61%	
Caterpillar Inc	CAT	509.085	250.72	127,637.79	0.43%	2.07%	0.01%	20.00%	0.09%
JPMorgan Chase & Co	JPM	2891.008	156.08	451,228.53	1.54%	2.69%	0.04%	1.00%	0.02%
Chevron Corp	CVX	1887.749	143.6	271,080.76	0.92%	4.21%	0.04%	7.27%	0.07%
Coca-Cola Co/The	KO	4323.414	58.44	252,660.31	0.86%	3.15%	0.03%	6.51%	0.06%
AbbVie Inc	ABBV	1765.537	142.39	251,394.81	0.86%	4.35%	0.04%	0.19%	0.00%
Walt Disney Co/The	DIS	1830.316	92.69	169,651.99	0.58%	0.65%	0.00%	18.88%	0.11%
FleetCor Technologies Inc	FLT	72.204	240.5	17,365.06	0.06%			12.92%	0.01%
Extra Space Storage Inc	EXR	211.278	130.17	27,502.06	0.09%	4.98%	0.00%	1.10%	0.00%
Exxon Mobil Corp	XOM	4006.133	102.74	411,590.10		3.70%		45.59%	
Phillips 66	PSX	439.956	128.89	56,705.93	0.19%	3.26%	0.01%	15.21%	0.03%
General Electric Co	GE	1088.386	121.8	132,565.41		0.26%		22.50%	
HP Inc	HPQ	988.269	29.34	28,995.81	0.10%	3.76%	0.00%	3.00%	0.00%
Home Depot Inc/The	HD	995.262	313.49	312,004.68	1.06%	2.67%	0.03%	1.69%	0.02%
Monolithic Power Systems Inc	MPWR	47.912	548.72	26,290.27	0.09%	0.73%	0.00%	8.00%	0.01%
International Business Machines Corp	IBM	913.119	158.56	144,784.15	0.49%	4.19%	0.02%	2.77%	0.01%
Johnson & Johnson	JNJ	2407.279	154.66	372,309.77	1.27%	3.08%	0.04%	3.86%	0.05%
Lululemon Athletica Inc	LULU	121.425	446.8	54,252.69	0.18%			16.00%	0.03%
McDonald's Corp	MCD	725.342	281.84	204,430.39	0.70%	2.37%	0.02%	9.34%	0.07%
Merck & Co Inc	MRK	2534.023	102.48	259,686.68	0.88%	3.01%	0.03%	9.08%	0.08%
3M Co	MMM	552.317	99.07	54,718.05	0.19%	6.06%	0.01%	4.00%	0.01%
American Water Works Co Inc	AWK	194.705	131.84	25,669.91	0.09%	2.15%	0.00%	8.00%	0.01%
Bank of America Corp	BAC	7913.732	30.49	241,289.69		3.15%		-5.00%	
Pfizer Inc	PFE	5646.413	30.47	172,046.20		5.38%		50.40%	
Procter & Gamble Co/The	PG	2356.886	153.52	361,829.14	1.23%	2.45%	0.03%	7.51%	0.09%
AT&T Inc	T	7150.02	16.57	118,475.83	0.40%	6.70%	0.03%	3.36%	0.01%
Travelers Cos Inc/The	TRV	228.399	180.62	41,253.43	0.14%	2.21%	0.00%	15.33%	0.02%
RTX Corp	RTX	1437.901	81.48	117,160.17	0.40%	2.90%	0.01%	8.61%	0.03%
Analog Devices Inc	ADI	496.262	182.5199	90,577.69	0.31%	1.88%	0.01%	4.50%	0.01%
Walmart Inc	WMT	2692.234	155.69	419,153.91	1.43%	1.46%	0.02%	3.00%	0.04%
Cisco Systems Inc	CSCO	4063.476	48.38	196,590.97	0.67%	3.22%	0.02%	10.00%	0.07%
Intel Corp	INTC	4216	44.7	188,455.20		1.12%		-1.82%	
General Motors Co	GM	1369.481	31.6	43,275.60		1.14%		-4.65%	
Microsoft Corp	MSFT	7432.262	378.91	2,816,158.39	9.59%	0.79%	0.08%	15.72%	1.51%
Dollar General Corp	DG	219.476	131.12	28,777.69		1.80%		-2.50%	
Cigna Group/The	CI	292.62	262.88	76,923.95	0.26%	1.87%	0.00%	9.80%	0.03%
Kinder Morgan Inc	KMI	2222.774	17.57	39,054.14	0.13%	6.43%	0.01%	2.00%	0.00%
Citigroup Inc	C	1913.882	46.1	88,229.96		4.60%		-9.70%	
American International Group Inc	AIG	702.04	65.81	46,201.25	0.16%	2.19%	0.00%	10.00%	0.02%
Altria Group Inc	MO	1768.647	42.04	74,353.92	0.25%	9.32%	0.02%	4.50%	0.01%
HCA Healthcare Inc	HCA	267.661	250.48	67,043.73	0.23%	0.96%	0.00%	7.56%	0.02%
International Paper Co	IP	346.017	36.94	12,781.87		5.01%		-2.00%	
Hewlett Packard Enterprise Co	HPE	1283	16.91	21,695.53	0.07%	3.08%	0.00%	3.03%	0.00%
Abbott Laboratories	ABT	1736.059	104.29	181,053.59	0.62%	1.96%	0.01%	3.27%	0.02%
Aflac Inc	AFL	584.38	82.71	48,334.07	0.16%	2.42%	0.00%	8.04%	0.01%
Air Products and Chemicals Inc	APD	222.208	270.55	60,118.37	0.20%	2.59%	0.01%	12.55%	0.03%
Royal Caribbean Cruises Ltd	RCL	256.235	107.46	27,535.01					
Hess Corp	HES	307.152	140.56	43,173.29	0.15%	1.25%	0.00%	13.00%	0.02%
Archer-Daniels-Midland Co	ADM	533.381	73.73	39,326.18		2.44%		-7.07%	
Automatic Data Processing Inc	ADP	411.305	229.92	94,567.25	0.32%	2.44%	0.01%	16.00%	0.05%
Verisk Analytics Inc	VRSK	144.987	241.43	35,004.21	0.12%	0.56%	0.00%	12.15%	0.01%
AutoZone Inc	AZO	17.634	2609.93	46,023.51	0.16%			13.72%	0.02%
Linde PLC	LIN	484.89	412.4952	200,014.80	0.68%	1.24%	0.01%	14.00%	0.10%
Avery Dennison Corp	AVY	80.531	194.5	15,663.28	0.05%	1.67%	0.00%	7.00%	0.00%
Enphase Energy Inc	ENPH	136.551	101.02	13,794.38				28.59%	
MSCI Inc	MSCI	79.091	520.85	41,194.55	0.14%	1.06%	0.00%	14.48%	0.02%
Ball Corp	BALL	315.301	55.29	17,432.99	0.06%	1.45%	0.00%	10.30%	0.01%
Axon Enterprise Inc	AXON	74.934	229.87	17,225.08					
Ceridian HCM Holding Inc	CDAY	156.127	68.9	10,757.15					
Carrier Global Corp	CARR	839.047	51.96	43,596.88	0.15%	1.42%	0.00%	10.80%	0.02%
Bank of New York Mellon Corp/The	BK	769.073	48.32	37,161.61	0.13%	3.48%	0.00%	10.00%	0.01%
Otis Worldwide Corp	OTIS	409.259	85.79	35,110.33	0.12%	1.59%	0.00%	9.00%	0.01%
Baxter International Inc	BAX	507.324	36.08	18,304.25		3.22%		-1.17%	
Becton Dickinson & Co	BDX	290.405	236.18	68,587.85		1.61%		-2.02%	
Berkshire Hathaway Inc	BRK/B	1308.414	360	471,029.04					
Best Buy Co Inc	BBY	217.638	70.94	15,439.24	0.05%	5.19%	0.00%	2.93%	0.00%
Boston Scientific Corp	BSX	1464.983	55.89	81,877.90	0.28%			12.10%	0.03%
Bristol-Myers Squibb Co	BMY	2034.758	49.38	100,476.35	0.34%	4.62%	0.02%	9.92%	0.03%
Brown-Forman Corp	BF/B	310.136	58.74	18,217.39	0.06%	1.48%	0.00%	6.42%	0.00%
Coterra Energy Inc	CTRA	752.192	26.25	19,745.04		3.05%		55.04%	
Campbell Soup Co	CPB	297.622	40.18	11,958.45	0.04%	3.68%	0.00%	2.81%	0.00%
Hilton Worldwide Holdings Inc	HLT	256.44	167.52	42,958.83	0.15%	0.36%	0.00%	17.09%	0.03%
Carnival Corp	CCL	1119.445	15.06	16,858.84					
Qorvo Inc	QRVO	97.346	96.5	9,393.89	0.03%			10.04%	0.00%
UDR Inc	UDR	328.928	33.4	10,986.20	0.04%	5.03%	0.00%	6.08%	0.00%
Clorox Co/The	CLX	124.059	143.35	17,783.86	0.06%	3.35%	0.00%	11.53%	0.01%
Paycom Software Inc	PAYC	60.228	181.66	10,941.02	0.04%	0.83%	0.00%	15.19%	0.01%
CMS Energy Corp	CMS	291.764	56.76	16,560.52	0.06%	3.44%	0.00%	7.75%	0.00%
Colgate-Palmolive Co	CL	823.372	78.77	64,857.01	0.22%	2.44%	0.01%	7.21%	0.02%

		[4]	[5]	[6]	[7]	[8]	[9]	[10]	[11]
Name	Ticker	Shares Outst'g	Price	Market Capitalization	Weight in Index	Estimated Dividend Yield	Cap-Weighted Dividend Yield	Bloomberg Long-Term Growth Est.	Cap-Weighted Long-Term Growth Est.
EPAM Systems Inc	EPAM	57.7	258.19	14,897.56	0.05%			4.87%	0.00%
Comerica Inc	CMA	131.873	45.22	5,963.30	0.02%	6.28%	0.00%	10.63%	0.00%
Conagra Brands Inc	CAG	477.968	28.29	13,521.71	0.05%	4.95%	0.00%	0.84%	0.00%
Airbnb Inc	ABNB	434.745	126.34	54,925.68	0.19%			18.20%	0.03%
Consolidated Edison Inc	ED	344.924	90.11	31,081.10	0.11%	3.60%	0.00%	4.88%	0.01%
Corning Inc	GLW	853.175	28.49	24,306.96	0.08%	3.93%	0.00%	1.57%	0.00%
Cummins Inc	CMI	141.745	224.16	31,773.56	0.11%	3.00%	0.00%	9.15%	0.01%
Caesars Entertainment Inc	CZR	215.711	44.72	9,646.60				110.92%	
Danaher Corp	DHR	738.927	223.31	165,009.79		0.48%		-7.03%	
Target Corp	TGT	461.662	133.81	61,774.99	0.21%	3.29%	0.01%	0.15%	0.00%
Deere & Co	DE	288.001	364.41	104,950.44	0.36%	1.48%	0.01%	3.96%	0.01%
Dominion Energy Inc	D	836.773	45.34	37,939.29		5.89%		-0.72%	
Dover Corp	DOV	139.89	141.16	19,746.87	0.07%	1.45%	0.00%	10.00%	0.01%
Alliant Energy Corp	LNT	252.719	50.57	12,780.00	0.04%	3.58%	0.00%	6.26%	0.00%
Steel Dynamics Inc	STLD	161.816	119.13	19,277.14		1.43%		-13.17%	
Duke Energy Corp	DUK	771	92.28	71,147.88	0.24%	4.44%	0.01%	6.06%	0.01%
Regency Centers Corp	REG	184.576	62.78	11,587.68	0.04%	4.27%	0.00%	4.64%	0.00%
Eaton Corp PLC	ETN	399.3	227.69	90,916.62	0.31%	1.51%	0.00%	15.00%	0.05%
Ecolab Inc	ECL	285.14	191.73	54,669.89	0.19%	1.11%	0.00%	16.00%	0.03%
Revvity Inc	RVTY	123.407	88.9	10,970.88		0.31%		-26.69%	
Emerson Electric Co	EMR	570.1	88.9	50,681.89	0.17%	2.36%	0.00%	12.01%	0.02%
EOG Resources Inc	EOG	583.15	123.07	71,768.27	0.24%	2.96%	0.01%	17.83%	0.04%
Aon PLC	AON	200.216	328.49	65,768.95	0.22%	0.75%	0.00%	11.58%	0.03%
Entergy Corp	ETR	211.456	101.41	21,443.75	0.07%	4.46%	0.00%	6.22%	0.00%
Equifax Inc	EFX	123.217	217.71	26,825.57	0.09%	0.72%	0.00%	12.33%	0.01%
EQT Corp	EQT	411.332	39.96	16,436.83		1.58%		20.04%	
IQVIA Holdings Inc	IQV	182.5	214.1	39,073.25				-13.67%	
Gartner Inc	IT	77.949	434.84	33,895.34	0.12%			7.35%	0.01%
FedEx Corp	FDX	251.42	258.83	65,075.04	0.22%	1.95%	0.00%	14.50%	0.03%
FMC Corp	FMC	124.759	53.66	6,694.57		4.32%		-4.00%	
Brown & Brown Inc	BRO	284.598	74.74	21,270.85	0.07%	0.70%	0.00%	11.00%	0.01%
Ford Motor Co	F	3932.102	10.26	40,343.37		5.85%		-2.52%	
NextEra Energy Inc	NEE	2023.714	58.51	118,407.51	0.40%	3.20%	0.01%	8.10%	0.03%
Franklin Resources Inc	BEN	494.584	24.8	12,265.68		4.84%		-9.00%	
Garmin Ltd	GRMN	191.331	122.24	23,388.30	0.08%	2.39%	0.00%	5.60%	0.00%
Freeport-McMoRan Inc	FCX	1433.977	37.32	53,516.02		1.61%		-15.66%	
Dexcom Inc	DXCM	386.374	115.52	44,633.92				30.59%	
General Dynamics Corp	GD	272.897	246.97	67,397.37	0.23%	2.14%	0.00%	10.40%	0.02%
General Mills Inc	GIS	581.279	63.66	37,004.22	0.13%	3.71%	0.00%	8.00%	0.01%
Genuine Parts Co	GPC	140.197	132.78	18,615.36	0.06%	2.86%	0.00%	9.49%	0.01%
Atmos Energy Corp	ATO	148.496	113.81	16,900.33	0.06%	2.83%	0.00%	7.25%	0.00%
WW Grainger Inc	GWW	49.634	786.19	39,021.75		0.95%			
Halliburton Co	HAL	895.052	37.03	33,143.78		1.73%		24.14%	
L3Harris Technologies Inc	LHX	189.54	190.81	36,166.13	0.12%	2.39%	0.00%	3.50%	0.00%
Healthpeak Properties Inc	PEAK	547.074	17.32	9,475.32	0.03%	6.93%	0.00%	1.24%	0.00%
Insulet Corp	PODD	69.828	189.09	13,203.78				41.08%	
Catalent Inc	CTLT	180.272	38.85	7,003.57	0.02%			9.24%	0.00%
Fortive Corp	FTV	351.434	68.98	24,241.92	0.08%	0.46%	0.00%	8.68%	0.01%
Hershey Co/The	HSY	149.885	187.92	28,166.39	0.10%	2.54%	0.00%	9.00%	0.01%
Synchrony Financial	SYF	413.804	32.36	13,390.70		3.09%			
Hormel Foods Corp	HRL	546.481	30.59	16,716.85	0.06%	3.69%	0.00%	1.08%	0.00%
Arthur J Gallagher & Co	AJG	215.9	249	53,759.10	0.18%	0.88%	0.00%	14.11%	0.03%
Mondelez International Inc	MDLZ	1360.896	71.06	96,705.27	0.33%	2.39%	0.01%	9.17%	0.03%
CenterPoint Energy Inc	CNP	629.432	28.27	17,794.04	0.06%	2.83%	0.00%	8.02%	0.00%
Humana Inc	HUM	123.111	484.86	59,691.60	0.20%	0.73%	0.00%	12.32%	0.03%
Willis Towers Watson PLC	WTW	103.26	246.3	25,432.94	0.09%	1.36%	0.00%	11.19%	0.01%
Illinois Tool Works Inc	ITW	300.886	242.21	72,877.60	0.25%	2.31%	0.01%	3.91%	0.01%
CDW Corp/DE	CDW	133.96	210.88	28,249.48	0.10%	1.18%	0.00%	13.10%	0.01%
Trane Technologies PLC	TT	227.557	225.41	51,293.62	0.17%	1.33%	0.00%	13.29%	0.02%
Interpublic Group of Cos Inc/The	IPG	383.004	30.74	11,773.54	0.04%	4.03%	0.00%	5.71%	0.00%
International Flavors & Fragrances Inc	IFF	255.279	75.38	19,242.93	0.07%	4.30%	0.00%	5.50%	0.00%
Generac Holdings Inc	GNRC	61.432	117.07	7,191.84	0.02%			5.00%	0.00%
NXP Semiconductors NV	NXPI	257.763	204.08	52,604.27		1.99%		34.00%	
Kellanova	K	342.52	52.54	17,996.00	0.06%	4.26%	0.00%	1.69%	0.00%
Broadridge Financial Solutions Inc	BR	117.647	193.82	22,802.34		1.65%			
Kimberly-Clark Corp	KMB	337.941	123.73	41,813.44	0.14%	3.81%	0.01%	9.64%	0.01%
Kimco Realty Corp	KIM	619.892	19.32	11,976.31	0.04%	4.97%	0.00%	4.35%	0.00%
Oracle Corp	ORCL	2739.376	116.21	318,342.88	1.08%	1.38%	0.01%	14.45%	0.16%
Kroger Co/The	KR	719.316	44.27	31,844.12	0.11%	2.62%	0.00%	4.21%	0.00%
Lennar Corp	LEN	250.152	127.92	31,999.44	0.11%	1.17%	0.00%	1.00%	0.00%
Eli Lilly & Co	LLY	949.307	591.04	561,078.41		0.76%		21.47%	
Bath & Body Works Inc	BBWI	227.381	32.62	7,417.17	0.03%	2.45%	0.00%	6.51%	0.00%
Charter Communications Inc	CHTR	147.92	400.13	59,187.23	0.20%			12.31%	0.02%
Loews Corp	L	223.251	70.29	15,692.31		0.36%			
Lowe's Cos Inc	LOW	575.113	198.83	114,349.72		2.21%		20.20%	
Hubbell Inc	HUBB	53.622	300	16,086.60		1.63%			
IDEX Corp	IEX	75.626	201.68	15,252.25	0.05%	1.27%	0.00%	11.00%	0.01%
Marsh & McLennan Cos Inc	MMC	493.072	199.42	98,328.42	0.33%	1.42%	0.00%	11.53%	0.04%
Masco Corp	MAS	224.501	60.55	13,593.54	0.05%	1.88%	0.00%	4.36%	0.00%
S&P Global Inc	SPGI	316.8	415.83	131,734.94	0.45%	0.87%	0.00%	13.66%	0.06%
Medtronic PLC	MDT	1329.654	79.27	105,401.67	0.36%	3.48%	0.01%	4.33%	0.02%
Viatris Inc	VTRS	1199.671	9.18	11,012.98		5.23%		-2.58%	
CVS Health Corp	CVS	1286.897	67.95	87,444.65	0.30%	3.56%	0.01%	6.99%	0.02%
DuPont de Nemours Inc	DD	430.042	71.54	30,765.20	0.10%	2.01%	0.00%	11.43%	0.01%
Micron Technology Inc	MU	1098.034	76.12	83,582.35		0.60%		-11.00%	
Motorola Solutions Inc	MSI	165.968	322.87	53,586.09	0.18%	1.21%	0.00%	10.82%	0.02%
Cboe Global Markets Inc	CBOE	105.556	182.19	19,231.25	0.07%	1.21%	0.00%	10.21%	0.01%
Laboratory Corp of America Holdings	LH	84.9	216.91	18,415.66		1.33%		-32.45%	
Newmont Corp	NEM	1152.492	40.19	46,318.65	0.16%	3.98%	0.01%	11.58%	0.02%
NIKE Inc	NKE	1224.013	109.9	134,519.03	0.46%	1.35%	0.01%	16.07%	0.07%
NiSource Inc	NI	413.415	25.64	10,599.96	0.04%	3.90%	0.00%	7.65%	0.00%
Norfolk Southern Corp	NSC	226.136	218.16	49,333.83	0.17%	2.48%	0.00%	0.73%	0.00%

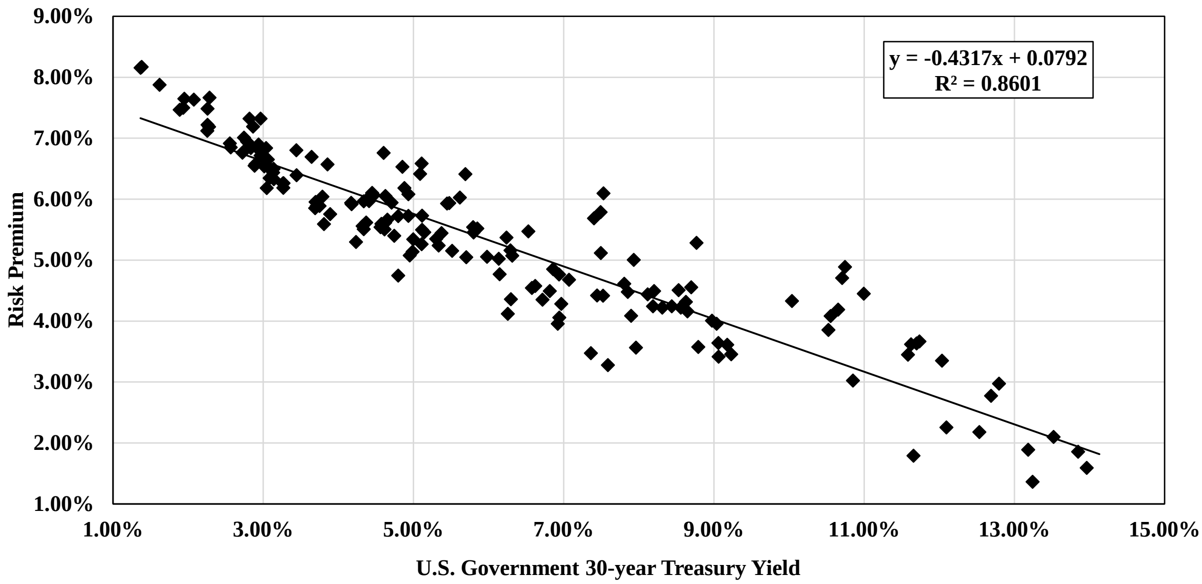
		[4]	[5]	[6]	[7]	[8]	[9]	[10]	[11]
Name	Ticker	Shares Outst'g	Price	Market Capitalization	Weight in Index	Estimated Dividend Yield	Cap-Weighted Dividend Yield	Bloomberg Long-Term Growth Est.	Cap-Weighted Long-Term Growth Est.
Principal Financial Group Inc	PFG	238.412	73.83	17,601.96	0.06%	3.63%	0.00%	8.98%	0.01%
Eversource Energy	ES	349.086	59.41	20,739.20	0.07%	4.54%	0.00%	5.21%	0.00%
Northrop Grumman Corp	NOC	150.793	475.16	71,650.80	0.24%	1.57%	0.00%	2.53%	0.01%
Wells Fargo & Co	WFC	3631.64	44.59	161,934.83	0.55%	3.14%	0.02%	13.41%	0.07%
Nucor Corp	NUE	245.839	169.97	41,785.25		1.20%		-10.84%	
Occidental Petroleum Corp	OXY	880.371	59.15	52,073.94		1.22%			
Omnicom Group Inc	OMC	197.934	80.63	15,959.42	0.05%	3.47%	0.00%	4.72%	0.00%
ONEOK Inc	OKE	582.551	68.85	40,108.64	0.14%	5.55%	0.01%	6.93%	0.01%
Raymond James Financial Inc	RJF	208.607	105.15	21,935.03		1.71%			
PG&E Corp	PCG	2133.508	17.17	36,632.33	0.12%	0.23%	0.00%	6.26%	0.01%
Parker-Hannifin Corp	PH	128.476	433.18	55,653.23	0.19%	1.37%	0.00%	15.28%	0.03%
Rollins Inc	ROL	484.038	40.74	19,719.71	0.07%	1.47%	0.00%	14.86%	0.01%
PPL Corp	PPL	737.089	26.12	19,252.76	0.07%	3.68%	0.00%	4.20%	0.00%
ConocoPhillips	COP	1187.408	115.57	137,228.74	0.47%	0.50%	0.00%	6.00%	0.03%
PulteGroup Inc	PHM	215.595	88.42	19,062.91	0.06%	0.90%	0.00%	2.04%	0.00%
Pinnacle West Capital Corp	PNW	113.312	74.94	8,491.60	0.03%	4.70%	0.00%	5.95%	0.00%
PNC Financial Services Group Inc/The	PNC	398.341	133.96	53,361.76	0.18%	4.63%	0.01%	12.87%	0.02%
PPG Industries Inc	PPG	235.8	141.99	33,481.24	0.11%	1.83%	0.00%	12.91%	0.01%
Progressive Corp/The	PGR	585.041	164.03	95,964.28		0.24%		39.34%	
Veralto Corp	VLTO	246.308	77.25	19,027.29					
Public Service Enterprise Group Inc	PEG	499.111	62.43	31,159.50	0.11%	3.65%	0.00%	5.47%	0.01%
Robert Half Inc	RHI	105.895	81.98	8,681.27	0.03%	2.34%	0.00%	1.26%	0.00%
Cooper Cos Inc/The	COO	49.524	336.92	16,685.63	0.06%	0.02%	0.00%	7.54%	0.00%
Edison International	EIX	383.568	66.99	25,695.22	0.09%	4.40%	0.00%	4.80%	0.00%
Schlumberger NV	SLB	1423.421	52.04	74,074.83		1.92%		33.41%	
Charles Schwab Corp/The	SCHW	1771.682	61.32	108,639.54	0.37%	1.63%	0.01%	3.60%	0.01%
Sherwin-Williams Co/The	SHW	255.966	278.8	71,363.32	0.24%	0.87%	0.00%	10.90%	0.03%
West Pharmaceutical Services Inc	WST	73.99	350.76	25,952.73	0.09%	0.23%	0.00%	5.80%	0.01%
J M Smucker Co/The	SJM	106.133	109.73	11,645.97	0.04%	3.86%	0.00%	5.95%	0.00%
Snap-on Inc	SNA	52.78	274.69	14,498.14	0.05%	2.71%	0.00%	4.85%	0.00%
AMETEK Inc	AME	230.799	155.23	35,826.93	0.12%	0.64%	0.00%	6.36%	0.01%
Southern Co/The	SO	1091.515	70.98	77,475.73	0.26%	3.94%	0.01%	5.05%	0.01%
Truist Financial Corp	TFC	1333.668	32.14	42,864.09	0.15%	6.47%	0.01%	16.00%	0.02%
Southwest Airlines Co	LUV	596.115	25.57	15,242.66	0.05%	2.82%	0.00%	10.15%	0.01%
W R Berkley Corp	WRB	257.872	72.55	18,708.61	0.06%	0.61%	0.00%	13.00%	0.01%
Stanley Black & Decker Inc	SWK	153.311	90.9	13,935.97	0.05%	3.56%	0.00%	9.00%	0.00%
Public Storage	PSA	175.829	258.76	45,497.51	0.15%	4.64%	0.01%	3.77%	0.01%
Arista Networks Inc	ANET	311.1	219.71	68,351.78	0.23%			19.72%	0.05%
Sysco Corp	SYY	504.372	72.17	36,400.53	0.12%	2.77%	0.00%	13.00%	0.02%
Corteva Inc	CTVA	704.88	45.2	31,860.58	0.11%	1.42%	0.00%	16.17%	0.02%
Texas Instruments Inc	TXN	908.204	152.71	138,691.83	0.47%	3.41%	0.02%	10.00%	0.05%
Textron Inc	TXT	196.005	76.66	15,025.74	0.05%	0.10%	0.00%	11.73%	0.01%
Thermo Fisher Scientific Inc	TMO	386.372	495.76	191,547.78		0.28%		-5.00%	
TJX Cos Inc/The	TJX	1139.677	88.11	100,416.94	0.34%	1.51%	0.01%	6.38%	0.02%
Globe Life Inc	GL	94.119	123.13	11,588.87		0.73%			
Johnson Controls International plc	JCI	680.32	52.8	35,920.90	0.12%	2.80%	0.00%	13.36%	0.02%
Ulta Beauty Inc	ULTA	48.562	425.99	20,686.93	0.07%			6.41%	0.00%
Union Pacific Corp	UNP	609.597	225.27	137,323.92	0.47%	2.31%	0.01%	11.00%	0.05%
Keysight Technologies Inc	KEYS	174.6	135.89	23,726.39	0.08%			1.81%	0.00%
UnitedHealth Group Inc	UNH	924.925	551.09	509,716.92	1.74%	1.36%	0.02%	13.40%	0.23%
Blackstone Inc	BX	710.545	112.37	79,843.94	0.27%	2.85%	0.01%	7.63%	0.02%
Marathon Oil Corp	MRO	585.247	25.43	14,882.83	0.05%	1.73%	0.00%	8.00%	0.00%
Bio-Rad Laboratories Inc	BIO	24.059	304.92	7,336.07	0.02%			4.00%	0.00%
Ventas Inc	VTR	402.381	45.84	18,445.15	0.06%	3.93%	0.00%	8.02%	0.01%
VF Corp	VFC	388.883	16.73	6,506.01	0.02%	2.15%	0.00%	3.10%	0.00%
Vulcan Materials Co	VMC	132.873	213.56	28,376.36		0.81%		23.22%	
Weyerhaeuser Co	WY	730.001	31.35	22,885.53		2.42%			
Whirlpool Corp	WHR	54.853	108.9	5,973.49		6.43%		-2.33%	
Williams Cos Inc/The	WMB	1216.499	36.79	44,755.00	0.15%	4.87%	0.01%	3.50%	0.01%
Constellation Energy Corp	CEG	319.382	121.04	38,658.00		0.93%		26.33%	
WEC Energy Group Inc	WEC	315.435	83.62	26,376.67	0.09%	3.73%	0.00%	6.41%	0.01%
Adobe Inc	ADBE	455.3	611.01	278,192.85	0.95%			17.33%	0.16%
AES Corp/The	AES	669.629	17.21	11,524.32	0.04%	3.86%	0.00%	10.12%	0.00%
Expeditors International of Washington Inc	EXPD	145.389	120.34	17,496.11		1.15%		-16.00%	
Amgen Inc	AMGN	535.178	269.64	144,305.40	0.49%	3.16%	0.02%	4.88%	0.02%
Apple Inc	AAPL	15552.752	189.95	2,954,245.24	10.06%	0.51%	0.05%	13.00%	1.31%
Autodesk Inc	ADSK	213.764	218.43	46,692.47	0.16%			12.48%	0.02%
Cintas Corp	CTAS	101.854	553.25	56,350.73	0.19%	0.98%	0.00%	11.84%	0.02%
Comcast Corp	CMCSA	4015.635	41.89	168,214.95	0.57%	2.77%	0.02%	9.26%	0.05%
Molson Coors Beverage Co	TAP	200.955	61.54	12,366.77	0.04%	2.66%	0.00%	12.99%	0.01%
KLA Corp	KLAC	135.932	544.62	74,031.29	0.25%	1.06%	0.00%	9.93%	0.03%
Marriott International Inc/MD	MAR	293.691	202.7	59,531.17	0.20%	1.03%	0.00%	17.38%	0.04%
Fiserv Inc	FI	600.186	130.61	78,390.29	0.27%			14.08%	0.04%
McCormick & Co Inc/MD	MKC	251.291	64.83	16,291.20	0.06%	2.59%	0.00%	7.01%	0.00%
PACCAR Inc	PCAR	523.076	91.82	48,028.84	0.16%	1.18%	0.00%	12.00%	0.02%
Costco Wholesale Corp	COST	442.741	592.74	262,430.30	0.89%	0.69%	0.01%	13.06%	0.12%
Stryker Corp	SYK	379.895	296.33	112,574.29	0.38%	1.01%	0.00%	7.62%	0.03%
Tyson Foods Inc	TSN	285.231	46.84	13,360.22		4.18%		46.71%	
Lamb Weston Holdings Inc	LW	144.927	100.03	14,497.05	0.05%	1.12%	0.00%	13.32%	0.01%
Applied Materials Inc	AMAT	836.534	149.78	125,296.06	0.43%	0.85%	0.00%	5.50%	0.02%
American Airlines Group Inc	AAL	653.541	12.43	8,123.51				54.64%	
Cardinal Health Inc	CAH	246.468	107.08	26,391.79	0.09%	1.87%	0.00%	13.32%	0.01%
Cincinnati Financial Corp	CINF	156.908	102.79	16,128.57	0.05%	2.92%	0.00%	18.21%	0.01%
Paramount Global	PARA	610.704	14.37	8,775.82		1.39%		-20.36%	
DR Horton Inc	DHI	333.184	127.67	42,537.60	0.14%	0.94%	0.00%	1.70%	0.00%
Electronic Arts Inc	EA	268.966	138.01	37,120.00	0.13%	0.55%	0.00%	10.32%	0.01%
Fair Isaac Corp	FICO	24.714	1087.6	26,878.95				22.00%	
Fastenal Co	FAST	571.413	59.97	34,267.64		2.33%			
M&T Bank Corp	MTB	165.96	128.17	21,271.09	0.07%	4.06%	0.00%	11.59%	0.01%
Xcel Energy Inc	XEL	551.816	60.84	33,572.49	0.11%	3.42%	0.00%	6.12%	0.01%
Fifth Third Bancorp	FITB	681.017	28.95	19,715.44		4.84%		25.00%	
Gilead Sciences Inc	GILD	1246.042	76.6	95,446.82	0.33%	3.92%	0.01%	2.10%	0.01%

Name	Ticker	[4] Shares Outst'g	[5] Price	[6] Market Capitalization	[7] Weight in Index	[8] Estimated Dividend Yield	[9] Cap-Weighted Dividend Yield	[10] Bloomberg Long-Term Growth Est.	[11] Cap-Weighted Long-Term Growth Est.
Hasbro Inc	HAS	138.764	46.41	6,440.04		6.03%		-3.49%	
Huntington Bancshares Inc/OH	HBAN	1448.075	11.26	16,305.32		5.51%		-7.69%	
Welltower Inc	WELL	556.094	89.1	49,547.98	0.17%	2.74%	0.00%	10.96%	0.02%
Biogen Inc	BIIB	144.898	234.08	33,917.72	0.12%			0.87%	0.00%
Northern Trust Corp	NTRS	207.036	79.25	16,407.60	0.06%	3.79%	0.00%	5.93%	0.00%
Packaging Corp of America	PKG	89.624	168.01	15,057.73	0.05%	2.98%	0.00%	5.00%	0.00%
Paychex Inc	PAYX	361.232	121.97	44,059.47	0.15%	2.92%	0.00%	7.00%	0.01%
QUALCOMM Inc	QCOM	1113	129.05	143,632.65	0.49%	2.48%	0.01%	11.61%	0.06%
Ross Stores Inc	ROST	338.632	130.38	44,150.84	0.15%	1.03%	0.00%	10.00%	0.02%
IDEXX Laboratories Inc	IDXX	83.052	465.82	38,687.28	0.13%			17.98%	0.02%
Starbucks Corp	SBUX	1136.7	99.3	112,874.31	0.38%	2.30%	0.01%	17.41%	0.07%
KeyCorp	KEY	936.26	12.39	11,600.26	0.04%	6.62%	0.00%	7.08%	0.00%
Fox Corp	FOXA	247.227	29.54	7,303.09	0.02%	1.76%	0.00%	6.24%	0.00%
Fox Corp	FOX	235.581	27.66	6,516.17	0.02%	1.88%	0.00%	6.24%	0.00%
State Street Corp	STT	308.584	72.82	22,471.09	0.08%	3.79%	0.00%	6.92%	0.01%
Norwegian Cruise Line Holdings Ltd	NCLH	425.425	15.27	6,496.24					
US Bancorp	USB	1557.012	38.12	59,353.30	0.20%	5.04%	0.01%	7.50%	0.02%
A O Smith Corp	AOS	122.828	75.36	9,256.32		1.70%			
Gen Digital Inc	GEN	640.715	22.08	14,146.99	0.05%	2.26%	0.00%	12.98%	0.01%
T Rowe Price Group Inc	TROW	223.47	100.13	22,376.05		4.87%		-4.09%	
Waste Management Inc	WM	402.775	170.99	68,870.50	0.23%	1.64%	0.00%	10.05%	0.02%
Constellation Brands Inc	STZ	183.663	240.49	44,169.11	0.15%	1.48%	0.00%	9.75%	0.01%
DENTSPLY SIRONA Inc	XRAY	211.86	31.75	6,726.56	0.02%	1.76%	0.00%	7.93%	0.00%
Zions Bancorp NA	ZION	148.149	35.63	5,278.55		4.60%		-9.73%	
Alaska Air Group Inc	ALK	128.053	37.81	4,841.68	0.02%			3.56%	0.00%
Invesco Ltd	IVZ	449.554	14.27	6,415.14		5.61%		-0.68%	
Intuit Inc	INTU	279.936	571.46	159,972.23	0.54%	0.63%	0.00%	18.96%	0.10%
Morgan Stanley	MS	1641.312	79.34	130,221.69	0.44%	4.29%	0.02%	3.64%	0.02%
Microchip Technology Inc	MCHP	541.045	83.44	45,144.79		2.10%		-1.00%	
Chubb Ltd	CB	407.99	229.43	93,605.15	0.32%	1.50%	0.00%	15.50%	0.05%
Hologic Inc	HOLX	240.003	71.3	17,112.21				-8.76%	
Citizens Financial Group Inc	CFG	466.223	27.27	12,713.90		6.16%		-10.63%	
O'Reilly Automotive Inc	ORLY	59.162	982.38	58,119.57	0.20%			11.39%	0.02%
Allstate Corp/The	ALL	261.687	137.87	36,078.79		2.58%		50.02%	
Equity Residential	EQR	379.724	56.84	21,583.51	0.07%	4.66%	0.00%	4.75%	0.00%
BorgWarner Inc	BWA	235.055	33.69	7,919.00	0.03%	1.31%	0.00%	4.33%	0.00%
Keurig Dr Pepper Inc	KDP	1398.336	31.57	44,145.47	0.15%	2.72%	0.00%	6.85%	0.01%
Host Hotels & Resorts Inc	HST	705.4	17.47	12,323.34		4.12%			
Incyte Corp	INCY	224.109	54.34	12,178.08				36.36%	
Simon Property Group Inc	SPG	326.247	124.89	40,744.99	0.14%	6.09%	0.01%	1.71%	0.00%
Eastman Chemical Co	EMN	118.564	83.83	9,939.22	0.03%	3.77%	0.00%	4.75%	0.00%
AvalonBay Communities Inc	AVB	142.015	172.94	24,560.07	0.08%	3.82%	0.00%	6.27%	0.01%
Prudential Financial Inc	PRU	361	97.78	35,298.58	0.12%	5.11%	0.01%	10.47%	0.01%
United Parcel Service Inc	UPS	723.257	151.61	109,652.99	0.37%	4.27%	0.02%	1.64%	0.01%
Walgreens Boots Alliance Inc	WBA	863.915	19.94	17,226.47	0.06%	9.63%	0.01%	0.25%	0.00%
STERIS PLC	STE	98.8	200.94	19,852.87		1.04%			
McKesson Corp	MCK	133.062	470.56	62,613.65	0.21%	0.53%	0.00%	10.04%	0.02%
Lockheed Martin Corp	LMT	248.099	447.77	111,091.29	0.38%	2.81%	0.01%	7.04%	0.03%
Cencora Inc	COR	199.433	203.37	40,558.69	0.14%	1.00%	0.00%	9.04%	0.01%
Capital One Financial Corp	COF	380.847	111.66	42,525.38		2.15%		-6.30%	
Waters Corp	WAT	59.127	280.61	16,591.63	0.06%			4.44%	0.00%
Nordson Corp	NDSN	57.014	235.34	13,417.67		1.16%			
Dollar Tree Inc	DLTR	217.872	123.59	26,926.80	0.09%			7.77%	0.01%
Darden Restaurants Inc	DRI	120.315	156.47	18,825.69	0.06%	3.35%	0.00%	10.45%	0.01%
Evergy Inc	EVRG	229.583	51.04	11,717.92	0.04%	5.04%	0.00%	4.82%	0.00%
Match Group Inc	MTCH	271.812	32.38	8,801.27				43.48%	
Domino's Pizza Inc	DPZ	34.881	392.89	13,704.40	0.05%	1.23%	0.00%	13.97%	0.01%
NVR Inc	NVR	3.179	6155.39	19,567.98				-4.57%	
NetApp Inc	NTAP	206.031	91.39	18,829.17	0.06%	2.19%	0.00%	7.40%	0.00%
Old Dominion Freight Line Inc	ODFL	109.114	389.06	42,451.89	0.14%	0.41%	0.00%	5.83%	0.01%
DaVita Inc	DVA	91.3	101.46	9,263.30				21.67%	
Hartford Financial Services Group Inc/The	HIG	300.77	78.16	23,508.18	0.08%	2.41%	0.00%	7.00%	0.01%
Iron Mountain Inc	IRM	291.99	64.15	18,731.16	0.06%	4.05%	0.00%	4.00%	0.00%
Estee Lauder Cos Inc/The	EL	232.305	127.69	29,663.03	0.10%	2.07%	0.00%	13.86%	0.01%
Cadence Design Systems Inc	CDNS	272.062	273.27	74,346.38	0.25%			18.56%	0.05%
Tyler Technologies Inc	TYL	42.124	408.84	17,221.98					
Universal Health Services Inc	UHS	61.007	137.48	8,387.24	0.03%	0.58%	0.00%	9.41%	0.00%
Skyworks Solutions Inc	SWKS	159.955	96.93	15,504.44		2.81%		-7.11%	
Quest Diagnostics Inc	DGX	112.435	137.23	15,429.46		2.07%		-1.27%	
Rockwell Automation Inc	ROK	114.673	275.44	31,585.53	0.11%	1.82%	0.00%	12.16%	0.01%
Kraft Heinz Co/The	KHC	1226.539	35.11	43,063.78	0.15%	4.56%	0.01%	4.03%	0.01%
American Tower Corp	AMT	466.165	208.78	97,325.93	0.33%	3.10%	0.01%	10.93%	0.04%
Regeneron Pharmaceuticals Inc	REGN	107.129	823.81	88,253.94	0.30%			4.00%	0.01%
Amazon.com Inc	AMZN	10334.031	146.09	1,509,698.59				86.99%	
Jack Henry & Associates Inc	JKHY	72.828	158.69	11,557.08	0.04%	1.31%	0.00%	7.06%	0.00%
Ralph Lauren Corp	RL	39.752	129.38	5,143.11	0.02%	2.32%	0.00%	10.38%	0.00%
Boston Properties Inc	BXP	156.939	56.93	8,934.54	0.03%	6.89%	0.00%	2.82%	0.00%
Amphenol Corp	APH	598.31	90.99	54,440.23	0.19%	0.97%	0.00%	4.04%	0.01%
Howmet Aerospace Inc	HWM	411.744	52.6	21,657.73		0.38%		20.41%	
Pioneer Natural Resources Co	PXD	233.309	231.64	54,043.70		5.53%		-3.00%	
Valero Energy Corp	VLO	340.453	125.36	42,679.19		3.25%		35.66%	
Synopsys Inc	SNPS	152.053	543.23	82,599.75	0.28%			16.68%	0.05%
Etsy Inc	ETSY	119.746	75.81	9,077.94	0.03%			2.74%	0.00%
CH Robinson Worldwide Inc	CHRW	116.651	82.05	9,571.21	0.03%	2.97%	0.00%	5.00%	0.00%
Accenture PLC	ACN	664.787	333.14	221,467.14	0.75%	1.55%	0.01%	10.00%	0.08%
TransDigm Group Inc	TDG	55.314	962.87	53,260.19	0.18%			15.56%	0.03%
Yum! Brands Inc	YUM	280.308	125.55	35,192.67	0.12%	1.93%	0.00%	11.93%	0.01%
Prologis Inc	PLD	923.862	114.93	106,179.46	0.36%	3.03%	0.01%	8.00%	0.03%
FirstEnergy Corp	FE	573.815	36.94	21,196.73		4.44%		-0.33%	
VeriSign Inc	VRSN	102.1	212.2	21,665.62	0.07%			11.50%	0.01%
Quanta Services Inc	PWR	145.285	188.31	27,358.62	0.09%	0.17%	0.00%	8.00%	0.01%
Henry Schein Inc	HSIC	130.585	66.73	8,713.94	0.03%			3.44%	0.00%

Name	Ticker	[4] Shares Outst'g	[5] Price	[6] Market Capitalization	[7] Weight in Index	[8] Estimated Dividend Yield	[9] Cap-Weighted Dividend Yield	[10] Bloomberg Long-Term Growth Est.	[11] Cap-Weighted Long-Term Growth Est.
Ameren Corp	AEE	262.475	77.59	20,365.44	0.07%	3.25%	0.00%	7.11%	0.00%
ANSYS Inc	ANSS	86.873	293.36	25,485.06	0.09%			10.77%	0.01%
FactSet Research Systems Inc	FDS	37.988	453.46	17,226.04	0.06%	0.86%	0.00%	10.45%	0.01%
NVIDIA Corp	NVDA	2470	467.7	1,155,219.00		0.03%		50.82%	
Sealed Air Corp	SEE	144.436	33.38	4,821.27	0.02%	2.40%	0.00%	0.01%	0.00%
Cognizant Technology Solutions Corp	CTSH	501.413	70.38	35,289.45	0.12%	1.65%	0.00%	12.00%	0.01%
Intuitive Surgical Inc	ISRG	352.072	310.84	109,438.06	0.37%			11.57%	0.04%
Take-Two Interactive Software Inc	TTWO	170.068	158.2	26,904.76				58.00%	
Republic Services Inc	RSG	314.637	161.84	50,920.85	0.17%	1.32%	0.00%	9.97%	0.02%
eBay Inc	EBAY	519	41.01	21,284.19	0.07%	2.44%	0.00%	0.32%	0.00%
Goldman Sachs Group Inc/The	GS	326.112	341.54	111,380.29	0.38%	3.22%	0.01%	7.71%	0.03%
SBA Communications Corp	SBAC	107.887	246.96	26,643.77	0.09%	1.38%	0.00%	8.00%	0.01%
Sempra	SRE	629.328	72.87	45,859.13	0.16%	3.27%	0.01%	5.49%	0.01%
Moody's Corp	MCO	183	364.96	66,787.68	0.23%	0.84%	0.00%	14.08%	0.03%
ON Semiconductor Corp	ON	430.698	71.33	30,721.69	0.10%			3.72%	0.00%
Booking Holdings Inc	BKNG	34.89	3125.7	109,055.67	0.37%			15.00%	0.06%
F5 Inc	FFIV	59.707	171.19	10,221.24	0.03%			5.45%	0.00%
Akamai Technologies Inc	AKAM	150.832	115.53	17,425.62					
Charles River Laboratories International Inc	CRL	51.297	197.08	10,109.61	0.03%			9.00%	0.00%
MarketAxess Holdings Inc	MKTX	37.905	240.12	9,101.75		1.20%			
Devon Energy Corp	DVN	640.7	44.97	28,812.28		6.85%		51.35%	
Bio-Techne Corp	TECH	158.15	62.9	9,947.64	0.03%	0.51%	0.00%	4.50%	0.00%
Alphabet Inc	GOOGL	5918	132.53	784,312.54	2.67%			16.65%	0.44%
Teleflex Inc	TFX	46.993	225.69	10,605.85	0.04%	0.60%	0.00%	7.00%	0.00%
Netflix Inc	NFLX	437.68	473.97	207,447.19				30.96%	
Allegion plc	ALLE	87.788	106.09	9,313.43	0.03%	1.70%	0.00%	5.93%	0.00%
Agilent Technologies Inc	A	292.123	127.8	37,333.32	0.13%	0.74%	0.00%	8.00%	0.01%
Warner Bros Discovery Inc	WBD	2438.566	10.45	25,483.01				91.04%	
Elevance Health Inc	ELV	234.959	479.49	112,660.49	0.38%	1.23%	0.00%	10.85%	0.04%
Trimble Inc	TRMB	248.768	46.4	11,542.84					
CME Group Inc	CME	359.99	218.36	78,607.42	0.27%	2.02%	0.01%	11.10%	0.03%
Juniper Networks Inc	JNPR	318.868	28.45	9,071.79	0.03%	3.09%	0.00%	7.96%	0.00%
BlackRock Inc	BLK	148.762	751.23	111,754.48	0.38%	2.66%	0.01%	6.72%	0.03%
DTE Energy Co	DTE	206.109	104.11	21,458.01	0.07%	3.66%	0.00%	7.00%	0.01%
Nasdaq Inc	NDAQ	576.965	55.84	32,217.73	0.11%	1.58%	0.00%	2.68%	0.00%
Celanese Corp	CE	108.855	138.66	15,093.83	0.05%	2.02%	0.00%	2.27%	0.00%
Philip Morris International Inc	PM	1552.406	93.36	144,932.62	0.49%	5.57%	0.03%	9.19%	0.05%
Salesforce Inc	CRM	968	251.9	243,839.20				21.67%	
Ingersoll Rand Inc	IR	404.797	71.43	28,914.65	0.10%	0.11%	0.00%	14.00%	0.01%
Huntington Ingalls Industries Inc	HII	39.723	237.02	9,415.15		2.19%		40.00%	
Roper Technologies Inc	ROP	106.822	538.25	57,496.94		0.56%		-1.00%	
MetLife Inc	MET	740.19	63.63	47,098.29	0.16%	3.27%	0.01%	9.17%	0.01%
Tapestry Inc	TPR	229.186	31.67	7,258.32	0.02%	4.42%	0.00%	11.00%	0.00%
CSX Corp	CSX	1976.131	32.3	63,829.03	0.22%	1.36%	0.00%	6.39%	0.01%
Edwards Lifesciences Corp	EW	606.5	67.71	41,066.12	0.14%			9.23%	0.01%
Ameriprise Financial Inc	AMP	101.196	353.51	35,773.80	0.12%	1.53%	0.00%	15.82%	0.02%
Zebra Technologies Corp	ZBRA	51.36	236.98	12,171.29					
Zimmer Biomet Holdings Inc	ZBH	208.981	116.31	24,306.58	0.08%	0.83%	0.00%	7.12%	0.01%
CBRE Group Inc	CBRE	304.793	78.96	24,066.46					
Camden Property Trust	CPT	106.771	90.26	9,637.15	0.03%	4.43%	0.00%	6.17%	0.00%
Mastercard Inc	MA	930.438	413.83	385,043.16	1.31%	0.55%	0.01%	17.35%	0.23%
CarMax Inc	KMX	158.668	63.94	10,145.23	0.03%			16.34%	0.01%
Intercontinental Exchange Inc	ICE	572.364	113.84	65,157.92	0.22%	1.48%	0.00%	8.66%	0.02%
Fidelity National Information Services Inc	FIS	592.484	58.64	34,743.26	0.12%	3.55%	0.00%	5.51%	0.01%
Chipotle Mexican Grill Inc	CMG	27.445	2202.25	60,440.75				25.41%	
Wynn Resorts Ltd	WYNN	112.946	84.42	9,534.90		1.18%		153.24%	
Live Nation Entertainment Inc	LYV	230.325	84.22	19,397.97					
Assurant Inc	AIZ	52.591	168.02	8,836.34	0.03%	1.71%	0.00%	14.60%	0.00%
NRG Energy Inc	NRG	225.764	47.84	10,800.55		3.16%			
Regions Financial Corp	RF	930.065	16.68	15,513.48	0.05%	5.76%	0.00%	0.99%	0.00%
Monster Beverage Corp	MNST	1040.441	55.15	57,380.32				21.32%	
Mosaic Co/The	MOS	326.835	35.89	11,730.11	0.04%	2.23%	0.00%	7.00%	0.00%
Baker Hughes Co	BKR	1006.234	33.75	33,960.40	0.12%	2.37%	0.00%	16.00%	0.02%
Expedia Group Inc	EXPE	133.325	136.18	18,156.20	0.06%			17.50%	0.01%
CF Industries Holdings Inc	CF	191.057	75.15	14,357.93		2.13%		46.00%	
Leidos Holdings Inc	LDOS	137.506	107.32	14,757.14	0.05%	1.42%	0.00%	8.12%	0.00%
APA Corp	APA	306.719	36	11,041.88	0.04%	2.78%	0.00%	0.72%	0.00%
Alphabet Inc	GOOG	5725	133.92	766,692.00	2.61%			16.65%	0.43%
First Solar Inc	FSLR	106.844	157.78	16,857.85				43.22%	
TE Connectivity Ltd	TEL	310.779	131	40,712.05		1.80%			
Discover Financial Services	DFS	250.058	93	23,255.39		3.01%		56.16%	
Visa Inc	V	1580.68	256.68	405,728.94	1.38%	0.81%	0.01%	14.32%	0.20%
Mid-America Apartment Communities Inc	MAA	116.688	124.48	14,525.32	0.05%	4.50%	0.00%	1.77%	0.00%
Xylem Inc/NY	XYL	241.078	105.13	25,344.53		1.26%			
Marathon Petroleum Corp	MPC	379.697	149.19	56,647.00		2.21%			
Advanced Micro Devices Inc	AMD	1615.499	121.16	195,733.86				30.65%	
Tractor Supply Co	TSCO	108.114	203.01	21,948.22	0.07%	2.03%	0.00%	3.81%	0.00%
ResMed Inc	RMD	147.092	157.73	23,200.82		1.22%			
Mettler-Toledo International Inc	MTD	21.684	1091.93	23,677.41	0.08%			5.01%	0.00%
Jacobs Solutions Inc	J	126.024	127.18	16,027.73	0.05%	0.82%	0.00%	12.31%	0.01%
Copart Inc	CPRT	960.231	50.22	48,222.80					
VICI Properties Inc	VICI	1034.532	29.89	30,922.16	0.11%	5.55%	0.01%	7.09%	0.01%
Fortinet Inc	FTNT	767.91	52.56	40,361.35	0.14%			15.03%	0.02%
Albemarle Corp	ALB	117.353	121.27	14,231.40	0.05%	1.32%	0.00%	18.79%	0.01%
Moderna Inc	MRNA	381.284	77.7	29,625.77				-29.33%	
Essex Property Trust Inc	ESS	64.183	213.46	13,700.50	0.05%	4.33%	0.00%	5.71%	0.00%
CoStar Group Inc	CSGP	408.363	83.04	33,910.46	0.12%			20.00%	0.02%
Realty Income Corp	O	723.924	53.96	39,062.94	0.13%	5.69%	0.01%	0.68%	0.00%
Westrock Co	WRK	256.469	41.17	10,558.83	0.04%	2.94%	0.00%	4.20%	0.00%
Westinghouse Air Brake Technologies Corp	WAB	179.159	116.56	20,882.77	0.07%	0.58%	0.00%	12.86%	0.01%
Pool Corp	POOL	38.679	347.32	13,433.99		1.27%		-5.49%	
Western Digital Corp	WDC	324.243	48.31	15,664.18				-11.96%	

		[4]	[5]	[6]	[7]	[8]	[9]	[10]	[11]
Name	Ticker	Shares Outst'g	Price	Market Capitalization	Weight in Index	Estimated Dividend Yield	Cap-Weighted Dividend Yield	Bloomberg Long-Term Growth Est.	Cap-Weighted Long-Term Growth Est.
PepsiCo Inc	PEP	1374.864	168.29	231,375.86	0.79%	3.01%	0.02%	8.70%	0.07%
Diamondback Energy Inc	FANG	178.985	154.41	27,637.07		8.73%		21.94%	
Palo Alto Networks Inc	PANW	315.3	295.09	93,041.88				30.00%	
ServiceNow Inc	NOW	205	685.74	140,576.70					
Church & Dwight Co Inc	CHD	246.382	96.63	23,807.89	0.08%	1.13%	0.00%	5.95%	0.00%
Federal Realty Investment Trust	FRT	81.618	95.59	7,801.86	0.03%	4.56%	0.00%	5.77%	0.00%
MGM Resorts International	MGM	341.583	39.44	13,472.03					
American Electric Power Co Inc	AEP	515.176	79.55	40,982.25	0.14%	4.42%	0.01%	4.83%	0.01%
SolarEdge Technologies Inc	SEDG	56.811	79.38	4,509.66				27.00%	
Invitation Homes Inc	INVH	611.958	33.36	20,414.92	0.07%	3.12%	0.00%	3.15%	0.00%
PTC Inc	PTC	119.245	157.36	18,764.39	0.06%			19.31%	0.01%
JB Hunt Transport Services Inc	JBHT	103.143	185.27	19,109.30		0.91%		27.00%	
Lam Research Corp	LRCX	131.792	715.92	94,352.53	0.32%	1.12%	0.00%	5.44%	0.02%
Mohawk Industries Inc	MHK	63.682	88.31	5,623.76				-3.08%	
Pentair PLC	PNR	165.299	64.54	10,668.40	0.04%	1.36%	0.00%	6.22%	0.00%
GE HealthCare Technologies Inc	GEHC	455.243	68.46	31,165.94	0.11%	0.18%	0.00%	12.70%	0.01%
Vertex Pharmaceuticals Inc	VRTX	257.683	354.81	91,428.51	0.31%			13.38%	0.04%
Amcor PLC	AMCR	1445.343	9.48	13,701.85	0.05%	5.27%	0.00%	1.33%	0.00%
Meta Platforms Inc	META	2219.607	327.15	726,144.43				24.05%	
T-Mobile US Inc	TMUS	1156.475	150.45	173,991.66		1.73%		38.46%	
United Rentals Inc	URI	67.781	476.02	32,265.11	0.11%	1.24%	0.00%	17.87%	0.02%
Honeywell International Inc	HON	659.251	195.92	129,160.46	0.44%	2.20%	0.01%	7.69%	0.03%
Alexandria Real Estate Equities Inc	ARE	173.775	109.4	19,010.99	0.06%	4.53%	0.00%	5.28%	0.00%
Delta Air Lines Inc	DAL	643.463	36.93	23,763.09		1.08%		30.85%	
Seagate Technology Holdings PLC	STX	209.184	79.1	16,546.45	0.06%	3.54%	0.00%	6.11%	0.00%
United Airlines Holdings Inc	UAL	328.017	39.4	12,923.87				46.54%	
News Corp	NWS	191.385	23.04	4,409.51		0.87%			
Centene Corp	CNC	534.201	73.68	39,359.93	0.13%			8.43%	0.01%
Martin Marietta Materials Inc	MLM	61.807	464.59	28,714.91		0.64%		21.60%	
Teradyne Inc	TER	152.879	92.23	14,100.03	0.05%	0.48%	0.00%	7.82%	0.00%
PayPal Holdings Inc	PYPL	1078.14	57.61	62,111.65	0.21%			6.26%	0.01%
Tesla Inc	TSLA	3178.921	240.08	763,195.35	2.60%			11.00%	0.29%
Arch Capital Group Ltd	ACGL	373.172	83.69	31,230.76	0.11%			10.00%	0.01%
Dow Inc	DOW	701.397	51.75	36,297.29		5.41%		-4.72%	
Everest Group Ltd	EG	43.39	410.55	17,813.76		1.71%		37.66%	
Teledyne Technologies Inc	TDY	47.185	402.96	19,013.67	0.06%			8.03%	0.01%
News Corp	NWSA	380.67	22.04	8,389.97		0.91%			
Exelon Corp	EXC	994.299	38.51	38,290.45	0.13%	3.74%	0.00%	4.00%	0.01%
Global Payments Inc	GPN	260.389	116.44	30,319.70	0.10%	0.86%	0.00%	13.33%	0.01%
Crown Castle Inc	CCI	433.689	117.28	50,863.05	0.17%	5.34%	0.01%	7.00%	0.01%
Aptiv PLC	APTV	282.862	82.84	23,432.29	0.08%			11.44%	0.01%
Align Technology Inc	ALGN	76.589	213.8	16,374.73					
Illumina Inc	ILMN	158.8	101.95	16,189.66				-51.00%	
Kenvue Inc	KVUE	1914.995	20.44	39,142.50		3.91%			
Targa Resources Corp	TRGP	222.976	90.45	20,168.18	0.07%	2.21%	0.00%	15.00%	0.01%
Bunge Global SA	BG	161.429	109.87	17,736.20		2.41%		-5.00%	
LKQ Corp	LKQ	267.598	44.53	11,916.14		2.69%			
Zoetis Inc	ZTS	459.114	176.67	81,111.67	0.28%	0.85%	0.00%	10.91%	0.03%
Digital Realty Trust Inc	DLR	302.846	138.78	42,028.97	0.14%	3.52%	0.01%	6.80%	0.01%
Equinix Inc	EQIX	93.883	815.01	76,515.58	0.26%	2.09%	0.01%	16.67%	0.04%
Las Vegas Sands Corp	LVS	764.491	46.12	35,258.32		1.73%			
Molina Healthcare Inc	MOH	58.3	365.56	21,312.15	0.07%			11.24%	0.01%

Notes:
[1] Equals sum of Col. [9]
[2] Equals sum of Col. [11]
[3] Equals ([1] x (1 + (0.5 x [2]))) + [2]
[4] Bloomberg Professional as of November 30, 2023
[5] Bloomberg Professional as of November 30, 2023
[6] Equals [4] x [5]
[7] Equals weight in S&P 500 based on market capitalization [6] if Growth Rate >0% and ≤20%
[8] Bloomberg Professional, as of November 30, 2023
[9] Equals [7] x [8]
[10] Value Line, as of November 30, 2023
[11] Equals [7] x [10]



SUMMARY OUTPUT

Regression Statistics	
Multiple R	0.9274291
R Square	0.8601248
Adjusted R Square	0.8593020
Standard Error	0.0054192
Observations	172

ANOVA

	df	*SS*	*MS*	*F*	*Significance F*
Regression	1	0.03070	0.03070	1,045.36873	0.00000
Residual	170	0.00499	0.00003		
Total	171	0.03569			

	Coefficients	*Standard Error*	*t Stat*	*P-value*	*Lower 95%*	*Upper 95%*	*Lower 95.0%*	*Upper 95.0%*
Intercept	0.0792	0.00	86.91	0.0000	0.0774	0.0810	0.0774	0.0810
U.S. Govt. 30-year Treasury	(0.4317)	0.01	(32.33)	0.0000	(0.4581)	(0.4054)	(0.4581)	(0.4054)

	[7]	[8]	[9]
	U.S. Govt. 30-year Treasury	Risk Premium	ROE
Current 30-day average of 30-year U.S. Treasury bond yield [4]	4.77%	5.86%	10.63%
Blue Chip Near-Term Projected Forecast (Q1 2024 - Q1 2025) [5]	4.48%	5.98%	10.46%
Blue Chip Long-Term Projected Forecast (2025-2029) [6]	4.10%	6.15%	10.25%
AVERAGE			10.45%

Notes:
[1] Regulatory Research Associates, rate cases through November 30, 2023
[2] Source: S&P Capital IQ Pro, quarterly bond yields are the average of each trading day in the quarter
[3] Equals Column [1] − Column [2]
[4] Source: S&P Capital IQ Pro, 30-day average as of November 30, 2023
[5] Source: Blue Chip Financial Forecasts, Vol. 42, No. 12, December 1, 2023, at 2
[6] Source: Blue Chip Financial Forecasts, Vol. 42, No. 12, December 1, 2023, at 14.
[7] See notes [4], [5] & [6]
[8] Equals 0.079161 + (-0.431626 x Column [7])
[9] Equals Column [7] + Column [8]

BOND YIELD PLUS RISK PREMIUM

	[1]	[2]	[3]
Quarter	Authorized Natual Gas ROE	U.S. Govt. 30-year Treasury	Risk Premium
1980.1	13.45%	11.66%	1.79%
1980.2	14.38%	10.52%	3.85%
1980.3	13.87%	10.85%	3.02%
1980.4	14.35%	12.10%	2.25%
1981.1	14.71%	12.53%	2.18%
1981.2	14.61%	13.24%	1.36%
1981.3	14.86%	14.13%	0.72%
1981.4	15.70%	13.85%	1.86%
1982.1	15.55%	13.96%	1.59%
1982.2	15.62%	13.52%	2.10%
1982.3	15.77%	12.79%	2.97%
1982.4	15.63%	10.75%	4.89%
1983.1	15.41%	10.71%	4.71%
1983.2	14.84%	10.65%	4.19%
1983.3	15.24%	11.62%	3.62%
1983.4	15.40%	11.74%	3.66%
1984.1	15.39%	12.04%	3.35%
1984.2	15.07%	13.18%	1.89%
1984.3	15.46%	12.69%	2.77%
1984.4	15.33%	11.70%	3.63%
1985.1	15.03%	11.58%	3.45%
1985.2	15.44%	11.00%	4.45%
1985.3	14.64%	10.55%	4.08%
1985.4	14.37%	10.04%	4.33%
1986.1	14.05%	8.77%	5.28%
1986.2	13.28%	7.49%	5.79%
1986.3	13.09%	7.40%	5.69%
1986.4	13.62%	7.53%	6.09%
1987.1	12.61%	7.49%	5.11%
1987.2	13.04%	8.53%	4.51%
1987.3	12.70%	9.06%	3.64%
1987.4	12.69%	9.23%	3.46%
1988.1	12.94%	8.63%	4.31%
1988.2	12.48%	9.06%	3.41%
1988.3	12.79%	9.18%	3.61%
1988.4	12.98%	8.97%	4.00%
1989.1	12.99%	9.04%	3.96%
1989.2	13.25%	8.70%	4.55%
1989.3	12.56%	8.12%	4.44%
1989.4	12.94%	7.93%	5.00%
1990.1	12.68%	8.44%	4.24%
1990.2	12.81%	8.65%	4.16%
1990.3	12.36%	8.79%	3.57%
1990.4	12.78%	8.56%	4.22%
1991.1	12.69%	8.20%	4.49%
1991.2	12.53%	8.31%	4.22%
1991.3	12.43%	8.19%	4.24%
1991.4	12.33%	7.85%	4.48%
1992.1	12.42%	7.81%	4.61%
1992.2	11.98%	7.90%	4.09%
1992.3	11.87%	7.45%	4.42%
1992.4	11.94%	7.52%	4.42%
1993.1	11.75%	7.07%	4.68%
1993.2	11.71%	6.86%	4.85%
1993.3	11.39%	6.32%	5.07%
1993.4	11.16%	6.14%	5.02%
1994.1	11.12%	6.58%	4.54%
1994.2	10.84%	7.36%	3.47%
1994.3	10.87%	7.59%	3.28%
1994.4	11.53%	7.96%	3.56%
1995.2	11.00%	6.94%	4.06%

1995.3	11.07%	6.72%	4.35%
1995.4	11.61%	6.24%	5.37%
1996.1	11.45%	6.29%	5.16%
1996.2	10.88%	6.92%	3.95%
1996.3	11.25%	6.97%	4.28%
1996.4	11.19%	6.62%	4.57%
1997.1	11.31%	6.82%	4.49%
1997.2	11.70%	6.94%	4.76%
1997.3	12.00%	6.53%	5.47%
1997.4	10.92%	6.15%	4.77%
1998.2	11.37%	5.85%	5.52%
1998.3	11.41%	5.48%	5.93%
1998.4	11.69%	5.11%	6.58%
1999.1	10.82%	5.37%	5.44%
1999.2	11.25%	5.80%	5.45%
1999.4	10.38%	6.26%	4.12%
2000.1	10.66%	6.30%	4.36%
2000.2	11.03%	5.98%	5.05%
2000.3	11.33%	5.79%	5.54%
2000.4	12.10%	5.69%	6.41%
2001.1	11.38%	5.45%	5.93%
2001.2	10.75%	5.70%	5.05%
2001.4	10.65%	5.30%	5.35%
2002.1	10.67%	5.52%	5.15%
2002.2	11.64%	5.62%	6.03%
2002.3	11.50%	5.09%	6.41%
2002.4	11.01%	4.93%	6.08%
2003.1	11.38%	4.85%	6.53%
2003.2	11.36%	4.60%	6.76%
2003.3	10.61%	5.11%	5.50%
2003.4	10.84%	5.11%	5.73%
2004.1	11.06%	4.88%	6.18%
2004.2	10.57%	5.34%	5.24%
2004.3	10.37%	5.11%	5.26%
2004.4	10.66%	4.93%	5.73%
2005.1	10.65%	4.71%	5.94%
2005.2	10.54%	4.47%	6.07%
2005.3	10.47%	4.42%	6.05%
2005.4	10.32%	4.65%	5.66%
2006.1	10.68%	4.63%	6.05%
2006.2	10.60%	5.14%	5.46%
2006.3	10.34%	5.00%	5.34%
2006.4	10.14%	4.74%	5.40%
2007.1	10.52%	4.80%	5.72%
2007.2	10.13%	4.99%	5.14%
2007.3	10.03%	4.95%	5.08%
2007.4	10.12%	4.61%	5.50%
2008.1	10.38%	4.41%	5.97%
2008.2	10.17%	4.57%	5.59%
2008.3	10.55%	4.45%	6.10%
2008.4	10.34%	3.64%	6.69%
2009.1	10.24%	3.44%	6.80%
2009.2	10.11%	4.17%	5.94%
2009.3	9.88%	4.32%	5.56%
2009.4	10.31%	4.34%	5.97%
2010.1	10.24%	4.62%	5.61%
2010.2	9.99%	4.37%	5.62%
2010.3	10.43%	3.86%	6.57%
2010.4	10.09%	4.17%	5.92%
2011.1	10.10%	4.56%	5.54%
2011.2	9.85%	4.34%	5.51%
2011.3	9.65%	3.70%	5.95%
2011.4	9.88%	3.04%	6.84%
2012.1	9.63%	3.14%	6.50%
2012.2	9.83%	2.94%	6.89%
2012.3	9.75%	2.74%	7.01%

2012.4	10.06%	2.86%	7.19%
2013.1	9.57%	3.13%	6.44%
2013.2	9.47%	3.14%	6.33%
2013.3	9.60%	3.71%	5.89%
2013.4	9.83%	3.79%	6.04%
2014.1	9.54%	3.69%	5.85%
2014.2	9.84%	3.44%	6.39%
2014.3	9.45%	3.27%	6.18%
2014.4	10.28%	2.96%	7.32%
2015.1	9.47%	2.55%	6.91%
2015.2	9.43%	2.88%	6.55%
2015.3	9.75%	2.96%	6.79%
2015.4	9.68%	2.96%	6.71%
2016.1	9.48%	2.72%	6.76%
2016.2	9.42%	2.57%	6.85%
2016.3	9.47%	2.28%	7.19%
2016.4	9.67%	2.83%	6.84%
2017.1	9.60%	3.05%	6.55%
2017.2	9.47%	2.90%	6.57%
2017.3	10.14%	2.82%	7.32%
2017.4	9.70%	2.82%	6.88%
2018.1	9.68%	3.02%	6.66%
2018.2	9.43%	3.09%	6.34%
2018.3	9.71%	3.06%	6.65%
2018.4	9.53%	3.27%	6.26%
2019.1	9.55%	3.01%	6.54%
2019.2	9.73%	2.78%	6.94%
2019.3	9.95%	2.29%	7.67%
2019.4	9.74%	2.26%	7.48%
2020.1	9.35%	1.89%	7.46%
2020.2	9.55%	1.38%	8.17%
2020.3	9.52%	1.37%	8.15%
2020.4	9.50%	1.62%	7.87%
2021.1	9.71%	2.07%	7.63%
2021.2	9.48%	2.26%	7.22%
2021.3	9.43%	1.93%	7.50%
2021.4	9.59%	1.95%	7.65%
2022.1	9.38%	2.25%	7.12%
2022.2	9.23%	3.05%	6.18%
2022.3	9.52%	3.26%	6.26%
2022.4	9.65%	3.89%	5.75%
2023.1	9.64%	3.75%	5.89%
2023.2	9.40%	3.81%	5.59%
2023.3	9.53%	4.23%	5.30%
2023.4	9.54%	4.80%	4.75%
AVERAGE	11.37%	6.08%	5.29%
MEDIAN	10.83%	5.22%	5.50%

SIZE PREMIUM CALCULATION

Proxy Group Market Capitalization and Market-to-Book Ratio

Company	Ticker	[1] Market Capitalization ($ billions)	[2] Market-to-Book Ratio
Atmos Energy Corporation	ATO	$ 16.45	1.53
NiSource Inc.	NI	$ 10.55	1.74
Northwest Natural Gas Company	NWN	$ 1.36	1.10
ONE Gas Inc.	OGS	$ 3.42	1.28
Spire, Inc.	SR	$ 3.08	1.15
Eversource Energy	ES	$ 19.54	1.25
American States Water Company	AWR	$ 2.93	3.83
California Water Service Group	CWT	$ 2.87	2.04
Middlesex Water Company	MSEX	$ 1.14	2.75
SJW Group	SJW	$ 2.00	1.65
Essential Utilities, Inc.	WTRG	$ 9.27	1.60
Median		$ 3.08	1.60

Elizabethtown Gas Company		
Test Year Rate Base ($millions)	[3]	$ 1,729.6
Company Proposed Common Equity Ratio	[4]	57.00%
Implied Common Equity ($millions)	[5]	$ 985.9
Implied Market Capitalization ($millions)	[6]	$ 1,576.0
Market Capitalization of Proxy Group (median) ($millions)	[7]	$ 3,078.5
As % of Proxy Group Market Capitalization (median)	[8]	51.2%

Kroll Cost of Capital Navigator -- Size Premium

Breakdown of Deciles 1-10		[9] Market Capitalization of Largest Company ($ millions)	[10] Size Premium
1-Largest		$ 2,203,381	-0.26%
2		$ 31,317	0.45%
3		$ 12,324	0.57%
4		$ 5,916	0.58%
5		$ 3,770	0.93%
6		$ 2,365	1.16%
7		$ 1,389	1.37%
8		$ 782	1.18%
9		$ 374	2.15%
10-Smallest		$ 218	4.83%
Elizabethtown Gas Company Implied Market Capitalization	[6]	$ 1,576	1.16%
Proxy Group Market Capitalization (median)	[7]	$ 3,078	0.93%
Size Premium	[11]		0.23%

Notes:
[1]-[2] S&P Capital IQ Pro, equals 30-day average as of November 30, 2023
[3] Data provided by the Company
[4] Requested by the Company
[5] Equals [3] x [4]
[6] Equals [5] x median market-to-book ratio of proxy group
[7] Equals median market capitalization of proxy group x 1000
[8] Equals [6] / [7]
[9]-[10] Kroll Cost of Capital Navigator - Size Premium: Annual Data as of 12/31/2022
[11] Size Premium of Elizabethtown Gas Company less Size Premium of Proxy Group

2024-2028 CAPITAL EXPENDITURES AS A PERCENTAGE OF 2022 NET PLANT

($ Millions)

		[1]	[2]	[3]	[4]	[5]	[6]	[7]
		2022	2024	2025	2026	2027	2028	2024-2028 Cap. Ex. / 2022 Net Plant
Atmos Energy Corporation	ATO							
Capital Spending per Share			$ 18.70	$ 20.10	$ 21.50	$ 21.50	$ 21.50	
Common Shares Outstanding			$ 155.00	$ 162.50	$ 170.00	$ 170.00	$ 170.00	
Capital Expenditures			$ 2,898.50	$ 3,266.25	$ 3,655.00	$ 3,655.00	$ 3,655.00	99.36%
Net Plant		$ 17,240						
NiSource Inc.	NI							
Capital Spending per Share			$ 6.55	$ 6.65	$ 6.75	$ 6.75	$ 6.75	
Common Shares Outstanding			$ 420.00	$ 430.00	$ 440.00	$ 440.00	$ 440.00	
Capital Expenditures			$ 2,751.00	$ 2,859.50	$ 2,970.00	$ 2,970.00	$ 2,970.00	73.18%
Net Plant		$ 19,843						
Northwest Natural Gas Company	NWN							
Capital Spending per Share			$ 7.75	$ 7.63	$ 7.50	$ 7.50	$ 7.50	
Common Shares Outstanding			$ 38.00	$ 40.00	$ 42.00	$ 42.00	$ 42.00	
Capital Expenditures			$ 294.50	$ 305.00	$ 315.00	$ 315.00	$ 315.00	49.59%
Net Plant		$ 3,114						
ONE Gas, Inc.	OGS							
Capital Spending per Share			$ 11.95	$ 12.23	$ 12.50	$ 12.50	$ 12.50	
Common Shares Outstanding			$ 55.50	$ 56.25	$ 57.00	$ 57.00	$ 57.00	
Capital Expenditures			$ 663.23	$ 687.66	$ 712.50	$ 712.50	$ 712.50	61.97%
Net Plant		$ 5,629						
Spire, Inc.	SR							
Capital Spending per Share			$ 12.85	$ 12.60	$ 12.35	$ 12.35	$ 12.35	
Common Shares Outstanding			$ 53.00	$ 54.00	$ 55.00	$ 55.00	$ 55.00	
Capital Expenditures			$ 681.05	$ 680.40	$ 679.25	$ 679.25	$ 679.25	63.30%
Net Plant		$ 5,370						
Eversource Energy	ES							
Capital Spending per Share			$ 11.25	$ 10.88	$ 10.50	$ 10.50	$ 10.50	
Common Shares Outstanding			$ 355.00	$ 357.50	$ 360.00	$ 360.00	$ 360.00	
Capital Expenditures			$ 3,993.75	$ 3,887.81	$ 3,780.00	$ 3,780.00	$ 3,780.00	53.23%
Net Plant		$ 36,113						
American States Water Co	AWR							
Capital Spending per Share			$ 5.25	$ 4.75	$ 4.25	$ 4.25	$ 4.25	
Common Shares Outstanding			$ 37.00	$ 37.25	$ 37.50	$ 37.50	$ 37.50	
Capital Expenditures			$ 194.25	$ 176.94	$ 159.38	$ 159.38	$ 159.38	48.43%
Net Plant		$ 1,754						
California Water Service Group	CWT							
Capital Spending per Share			$ 6.15	$ 6.30	$ 6.45	$ 6.45	$ 6.45	
Common Shares Outstanding			$ 52.00	$ 51.00	$ 50.00	$ 50.00	$ 50.00	
Capital Expenditures			$ 319.80	$ 321.30	$ 322.50	$ 322.50	$ 322.50	52.59%
Net Plant		$ 3,059						
Middlesex Water Company	MSEX							
Capital Spending per Share			$ 5.45	$ 5.73	$ 6.00	$ 6.00	$ 6.00	
Common Shares Outstanding			$ 17.90	$ 17.95	$ 18.00	$ 18.00	$ 18.00	
Capital Expenditures			$ 97.56	$ 102.76	$ 108.00	$ 108.00	$ 108.00	56.95%
Net Plant		$ 921						
SJW Group	SJW							
Capital Spending per Share			$ 8.25	$ 8.50	$ 8.75	$ 8.75	$ 8.75	
Common Shares Outstanding			$ 30.00	$ 30.00	$ 30.00	$ 30.00	$ 30.00	
Capital Expenditures			$ 247.50	$ 255.00	$ 262.50	$ 262.50	$ 262.50	49.04%
Net Plant		$ 2,630						
Essential Utilities, Inc.	WTRG							
Capital Spending per Share			$ 4.25	$ 4.05	$ 3.85	$ 3.85	$ 3.85	
Common Shares Outstanding			$ 277.00	$ 281.00	$ 285.00	$ 285.00	$ 285.00	
Capital Expenditures			$ 1,177.25	$ 1,138.05	$ 1,097.25	$ 1,097.25	$ 1,097.25	50.37%
Net Plant		$ 11,131						
Elizabethtown Gas Company	ETG							
Capital Expenditures [8]			$ 280.60	$ 282.14	$ 294.27	$ 300.17	$ 299.41	75.07%
Net Plant [9]		$ 1,940						

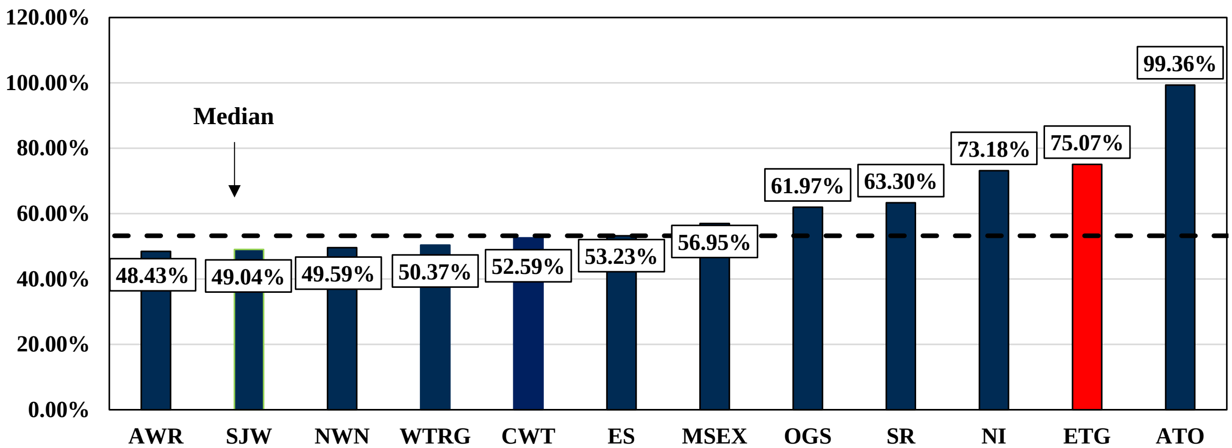
Notes:

[1] - [6] Value Line Reports, November 24, 2023, November 10, 2023, October 6, 2023

[7] Equals (Column [2] + [3] + [4] + [5] + [6]) / Column [1]

[8] Provided by the Company

[9] Provided by the Company



Projected CAPEX/2022 Net Plant

	Company	Ticker	Projected CAPEX / 2022 Net Plant
1	American States Water Co	AWR	48.43%
2	SJW Group	SJW	49.04%
3	Northwest Natural Gas Company	NWN	49.59%
4	Essential Utilities, Inc.	WTRG	50.37%
5	California Water Service Group	CWT	52.59%
6	Eversource Energy	ES	53.23%
7	Middlesex Water Company	MSEX	56.95%
8	ONE Gas, Inc.	OGS	61.97%
9	Spire, Inc.	SR	63.30%
10	NiSource Inc.	NI	73.18%
11	Elizabethtown Gas Company	ETG	75.07%
12	Atmos Energy Corporation	ATO	99.36%
	Proxy Group Median		53.23%
	Elizabethtown Gas as % of Median		1.41

Notes:
Schedule 11, pg. 1 col. [7]

COMPARATIVE REGULATORY RISK ASSESSMENT

Company	Ticker	State	Utility Type	Future Test Year	Revenue Stabilization or Decoupling	Infrastructure Cost Recovery Mechanism
American States Water Co						
	AWR	California	Water	Fully Forecast	Full	Yes
	AWR	California	Electric	Fully Forecast	Full	Yes
Atmos Energy Corporation						
	ATO	Colorado	Gas	Historical	No	Yes
	ATO	Kansas	Gas	Historical	Partial	Yes
	ATO	Kentucky	Gas	Fully Forecast	Partial	Yes
	ATO	Louisiana	Gas	Historical	FRP	No
	ATO	Mississippi	Gas	Historical	FRP	Yes
	ATO	Tennessee	Gas	Historical	FRP	No
	ATO	Texas	Gas	Historical	FRP	Yes
	ATO	Virginia	Gas	Historical	Partial	Yes
California Water Service Group						
	CWT	California	Water	Fully Forecast	Full	Yes
	CWT	Hawaii	Water	Fully Forecast	No	No
	CWT	New Mexico	Water	Historical	No	No
	CWT	Washington	Water	Historical	No	Yes
Essential Utilities, Inc.						
	WTRG	Pennsylvania	Water	Fully Forecast	No	Yes
	WTRG	Pennsylvania	Gas	Fully Forecast	No	Yes
	WTRG	Ohio	Water	Partially Forecast	No	Yes
	WTRG	Illinois	Water	Fully Forecast	Full	Yes
	WTRG	Texas	Water	Historical	No	Yes
	WTRG	New Jersey	Water	Partially Forecast	No	Yes
	WTRG	North Carolina	Water	Historical	No	Yes
	WTRG	Indiana	Water	Fully Forecast	No	Yes
	WTRG	Virginia	Water	Historical	No	Yes
	WTRG	Kentucky	Gas	Fully Forecast	Partial	Yes
	WTRG	West Virginia	Gas	Historical	No	No
Eversource Energy						
	ES	Connecticut	Electric	Fully Forecast	Full	Yes
	ES	Connecticut	Gas	Fully Forecast	Full	Yes
	ES	Connecticut	Water	Fully Forecast	Full	Yes
	ES	Massachusetts	Electric	Historical	Full	Yes
	ES	Massachusetts	Gas	Historical	Full	Yes
	ES	Massachusetts	Water	Historical	No	Yes
	ES	New Hampshire	Electric	Historical	Partial	Yes
	ES	New Hampshire	Water	Historical	No	Yes
Middlesex Water Company						
	MSEX	New Jersey	Water	Partially Forecast	No	Yes
	MSEX	Delaware	Water	Historical	No	Yes
	MSEX	Pennsylvania	Water	Fully Forecast	No	No

COMPARATIVE REGULATORY RISK ASSESSMENT

Company	Ticker	State	Utility Type	Future Test Year		Revenue Stabilization or Decoupling		Infrastructure Cost Recovery Mechanism	
NiSource Inc.									
	NI	Indiana	Electric	Fully Forecast		Partial		Yes	
	NI	Indiana	Gas	Fully Forecast		No		Yes	
	NI	Kentucky	Gas	Fully Forecast		Partial		Yes	
	NI	Maryland	Gas	Partially Forecast		Partial		Yes	
	NI	Ohio	Gas	Partially Forecast		SFV		Yes	
	NI	Pennsylvania	Gas	Fully Forecast		Partial		Yes	
	NI	Virginia	Gas	Historical		Partial		Yes	
Northwest Natural Gas Company									
	NWN	Oregon	Gas	Fully Forecast		Partial		Yes	
	NWN	Washington	Gas	Historical		No		No	
ONE Gas, Inc.									
	OGS	Kansas	Gas	Historical		Partial		Yes	
	OGS	Oklahoma	Gas	Historical		FRP		No	
	OGS	Texas	Gas	Historical		FRP		Yes	
SJW Group									
	SJW	California	Water	Fully Forecast		No		Yes	
	SJW	Connecticut	Water	Fully Forecast		Full		Yes	
	SJW	Maine	Water	Historical		No		Yes	
	SJW	Texas	Water	Historical		No		No	
Spire, Inc.									
	SR	Alabama (AL)	Gas	Fully Forecast		FRP		No	
	SR	Alabama (Gulf)	Gas	Fully Forecast		FRP		No	
	SR	Mississippi	Gas	Historical		FRP		No	
	SR	Missouri	Gas	Partially Forecast		Partial		Yes	
Proxy Group Totals				Historical	27	Full	10	Yes	44
				Fully Forecast	23	Partial	13	No	12
				Partially Forecast	6	FRP	9		
						SFV	1		
						No	23		
				Full/Partial Forecast	51.8%		58.9%	CCRM	78.6%
Elizabethtown Gas		New Jersey	Gas	Partially Forecast		Partial		Yes	

COMPARISON OF RRA JURISDICTIONAL RANKINGS

		[1]	[2]
		RRA	
	Operation State	Rank	Numeric Rank
Atmos Energy Corporation	Colorado	Average/1	4
	Kansas	Below Average/1	7
	Kentucky	Average/2	5
	Louisiana (PSC)	Average/2	5
	Mississippi	Above Average/3	3
	Tennessee	Above Average/3	3
	Texas (RRC)	Average/1	4
	Virginia	Average/2	5
NiSource Inc.	Indiana	Average/1	4
	Kentucky	Average/2	5
	Maryland	Below Average/2	8
	Ohio	Average/2	5
	Pennsylvania	Above Average/2	2
	Virginia	Average/2	5
Northwest Natural Gas Company	Oregon	Average/2	5
	Washington	Average/3	6
ONE Gas, Inc.	Kansas	Below Average/1	7
	Oklahoma	Average/3	6
	Texas (RRC)	Average/1	4
Spire, Inc.	Alabama	Above Average/1	1
	Missouri	Average/3	6
	Mississippi	Above Average/3	3
Eversource	Connecticut	Below Average/2	8
	Massachusetts	Average/2	5
	New Hampshire	Average/2	5
American States Water Co	California	Average/1	4
California Water Service Group	California	Average/1	4
	Hawaii	Average/2	5
	New Mexico	Below Average/1	7
	Washington	Average/3	6
Middlesex Water Company	New Jersey	Below Average/1	7
	Delaware	Average/2	5
	Pennsylvania	Above Average/2	2
SWJ Group	California	Average/1	4
	Connecticut	Below Average/2	8
	Maine	Average/3	6
	Texas	Average/3	6
Essential Utilities, Inc.	Pennsylvania	Above Average/2	2
	Ohio	Average/2	5
	Illinois	Average/3	6
	Texas	Average/3	6
	New Jersey	Below Average/1	7
	North Carolina	Above Average/3	3
	Indiana	Average/1	4
	Virginia	Average/2	5
	Kentucky	Average/2	5
	West Virginia	Below Average/1	7
Proxy Group Average		Average/2	5
Elizabethtown Gas Company	New Jersey	Below Average/1	7

Notes
[1] State Regulatory Evaluations, Regulatory Research Associates, December 4, 2023.
[2] AA/1= 1, AA/2= 2, AA/3= 3, A/1= 4, A/2= 5, A/3=6, BA/1= 7, BA/2= 8, BA/3= 9

COMPARISON OF S&P JURISDICTIONAL RANKINGS

		[1]	[2]
		S&P	
	Operation State	Rank	Numeric Rank
Atmos Energy Corporation	Colorado	Very Credit Supportive	3
	Kansas	Highly Credit Supportive	2
	Kentucky	Most Credit Supportive	1
	Louisiana (PSC)	Highly Credit Supportive	2
	Mississippi	Very Credit Supportive	3
	Tennessee	Highly Credit Supportive	2
	Texas (RRC)	Highly Credit Supportive	2
	Virginia	Highly Credit Supportive	2
NiSource Inc.	Indiana	Highly Credit Supportive	2
	Kentucky	Most Credit Supportive	1
	Maryland	Very Credit Supportive	3
	Ohio	Very Credit Supportive	3
	Pennsylvania	Highly Credit Supportive	2
	Virginia	Highly Credit Supportive	2
Northwest Natural Gas Company	Oregon	More Credit Supportive	4
	Washington	Very Credit Supportive	3
ONE Gas, Inc.	Kansas	Highly Credit Supportive	2
	Oklahoma	Very Credit Supportive	3
	Texas (RRC)	Highly Credit Supportive	2
Spire, Inc.	Alabama	Most Credit Supportive	1
	Missouri	Very Credit Supportive	3
	Mississippi	Very Credit Supportive	3
Eversource	Connecticut	More Credit Supportive	4
	Massachusetts	Highly Credit Supportive	2
	New Hampshire	Highly Credit Supportive	2
American States Water Co	California	More Credit Supportive	4
California Water Service Group	California	More Credit Supportive	4
	Hawaii	More Credit Supportive	4
	New Mexico	Credit Supportive	5
	Washington	Very Credit Supportive	3
Middlesex Water Company	New Jersey	More Credit Supportive	4
	Delaware	Very Credit Supportive	3
	Pennsylvania	Highly Credit Supportive	2
SWJ Group	California	More Credit Supportive	4
	Connecticut	More Credit Supportive	4
	Maine	Highly Credit Supportive	2
	Texas	Very Credit Supportive	3
Essential Utilities, Inc.	Pennsylvania	Highly Credit Supportive	2
	Ohio	Very Credit Supportive	3
	Illinois	Very Credit Supportive	3
	Texas	Very Credit Supportive	3
	New Jersey	More Credit Supportive	4
	North Carolina	Highly Credit Supportive	2
	Indiana	Highly Credit Supportive	2
	Virginia	Highly Credit Supportive	2
	Kentucky	Most Credit Supportive	1
	West Virginia	Very Credit Supportive	3
Proxy Group Average		Highly Credit Supportive / Very Credit Supportive	2.68
Elizabethtown Gas Company	New Jersey	More Credit Supportive	4

Notes

[1] Source: North American Utility Regulatory Jurisdictions: Some Notable Developments, November 10, 2023
[2] Most= 1, Highly= 2, Very= 3, More= 4, Credit Supportive= 5

CAPITAL STRUCTURE ANALYSIS

COMMON EQUITY RATIO [1]

Proxy Group Company	Ticker	2022	2021	2020	3-yr Avg.
American States Water Company	AWR	60.78%	59.68%	56.75%	59.07%
Atmos Energy Corporation	ATO	60.01%	59.88%	58.31%	59.40%
California Water Service Group	CWT	50.88%	48.85%	52.23%	50.65%
Essential Utilities, Inc.	WTRG	57.80%	55.09%	55.36%	56.08%
Eversource Energy	ES	56.37%	54.75%	55.63%	55.58%
Middlesex Water Company	MSEX	61.42%	59.01%	59.21%	59.88%
NiSource Inc.	NI	54.17%	54.85%	54.43%	54.48%
Northwest Natural Gas Company	NWN	51.21%	49.57%	47.44%	49.41%
ONE Gas, Inc.	OGS	58.23%	61.09%	60.04%	59.79%
SJW Group	SJW	53.78%	52.06%	56.76%	54.20%
Spire, Inc.	SR	54.32%	55.46%	58.61%	56.13%

Proxy Group				
MEAN	56.27%	55.48%	55.89%	55.88%
LOW	50.88%	48.85%	47.44%	49.41%
HIGH	61.42%	61.09%	60.04%	59.88%

COMMON EQUITY RATIO - UTILITY OPERATING COMPANIES

Company Name	Ticker	2022	2021	2020	3-yr Avg.
Golden State Water / Bear Valley	AWR	60.78%	59.68%	56.75%	59.07%
Atmos Energy Corporation	ATO	60.01%	59.88%	58.31%	59.40%
California Water Service	CWT	50.41%	48.11%	51.34%	49.95%
New Mexico Water Service Water Division	CWT		69.19%	67.06%	68.12%
New Mexico Water Service Sewer Division	CWT		62.89%	59.47%	61.18%
Washington Water Service	CWT	62.87%	65.96%	71.93%	66.92%
Hawaii Water Service Pukalani Division	CWT	65.87%	65.58%	64.56%	65.34%
Aqua Pennsylvania Water	WTRG		54.32%	51.14%	52.73%
Aqua Pennsylvania Wastewater	WTRG		98.06%	97.07%	97.57%
Peoples Natural Gas Company	WTRG	58.85%	57.75%	61.48%	59.36%
Peoples Gas Company	WTRG	67.48%	55.97%	79.59%	67.68%
Aqua Ohio Water	WTRG	54.03%	52.11%	64.62%	56.92%
Aqua Ohio Wastewater	WTRG	74.40%	73.67%	72.82%	73.63%
Aqua Illinois	WTRG	56.55%	57.99%	54.57%	56.37%
Aqua Texas	WTRG		49.91%	50.17%	50.04%
Aqua New Jersey, Inc. Water	WTRG	55.74%	53.19%	50.28%	53.07%
Aqua New Jersey, Inc. Wastewater	WTRG	100.00%	100.00%	100.00%	100.00%
Aqua North Carolina	WTRG	50.21%	48.75%	50.62%	49.86%
Aqua Virginia	WTRG	47.83%	48.83%	55.23%	50.63%
Delta Natural Gas Company	WTRG	58.51%	54.49%	56.93%	56.64%
Peoples Gas of WV	WTRG	58.78%	47.74%	48.44%	51.65%
Connecticut Light and Power Company	ES	57.03%	54.86%	55.42%	55.77%
Yankee Gas Company	ES	61.62%	61.12%	61.97%	61.57%
Aquarion Water Company CT	ES	55.94%	57.55%	58.76%	57.42%
NSTAR Electric Company	ES	55.89%	55.10%	54.95%	55.32%
NSTAR Gas Company	ES	55.96%	55.54%	55.54%	55.68%
Aquarion Water Company MA	ES	86.93%	85.64%	96.04%	89.54%
Eversource Gas of MA	ES	53.20%	52.25%	68.65%	58.03%
Public Service Company of NH	ES	53.77%	49.10%	48.66%	50.51%
Aquarion Water Company NH	ES	75.26%	59.74%	58.81%	64.60%
Middlesex Water Company	MSEX	61.15%	58.76%	59.03%	59.65%
Pinelands Water	MSEX	100.00%	100.00%	100.00%	100.00%
Pinelands WW	MSEX	100.00%	100.00%	100.00%	100.00%
Northern Indiana Public Service Company LLC	NI	56.92%	58.59%	58.01%	57.84%
Columbia Gas of Kentucky, Inc.	NI	54.91%	53.87%	54.68%	54.49%
Columbia Gas of Maryland, Inc.	NI	51.96%	55.26%	54.95%	54.06%
Columbia Gas of Ohio, Inc.	NI	50.67%	50.79%	50.45%	50.64%
Columbia Gas of Pennsylvania, Inc.	NI	56.64%	56.05%	55.68%	56.12%
Columbia Gas of Virginia, Inc.	NI	44.25%	44.52%	43.69%	44.15%
Northwest Natural Gas Company	NWN	51.21%	49.57%	47.44%	49.41%
Kansas Gas Service Company, Inc.	OGS	58.37%	61.37%	60.33%	60.02%
Oklahoma Natural Gas Company	OGS		60.99%	59.85%	60.42%
Texas Gas Service Company, Inc.	OGS	58.13%	60.98%	59.99%	59.70%
San Jose Water	SJW	53.20%	50.25%	54.02%	52.49%
CT Water	SJW	54.61%	52.66%	59.12%	55.46%
Maine Water Co.	SJW	53.92%	57.59%	60.15%	57.22%
Canyon Lake Water Service Company	SJW		59.64%	74.05%	66.85%
Spire Alabama Inc.	SR	61.18%	58.51%	64.20%	61.30%
Spire Gulf Inc.	SR	51.61%	49.48%	40.55%	47.21%
Spire Mississippi Inc.	SR		100.00%	100.00%	100.00%
Spire Missouri Inc.	SR	51.46%	53.96%	56.68%	54.03%

Notes:

[1] Ratios are weighted by actual common capital, preferred equity, and long-term debt of Operating Subsidiaries.

[2] Electric, Natural Gas and Water operating subsidiaries where data was unable to be obtained for 2022, 2021 and 2020 were removed from the analysis.

CAPITAL STRUCTURE ANALYSIS

LONG-TERM DEBT RATIO [1]

Proxy Group Company	Ticker	2022	2021	2020	3-yr Avg.
American States Water Company	AWR	39.22%	40.32%	43.25%	40.93%
Atmos Energy Corporation	ATO	39.99%	40.12%	41.69%	40.60%
California Water Service Group	CWT	49.12%	51.15%	47.77%	49.35%
Essential Utilities, Inc.	WTRG	42.20%	44.91%	44.64%	43.92%
Eversource Energy	ES	43.11%	44.67%	43.74%	43.84%
Middlesex Water Company	MSEX	38.26%	40.66%	40.43%	39.78%
NiSource Inc.	NI	45.83%	45.15%	45.57%	45.52%
Northwest Natural Gas Company	NWN	48.79%	50.43%	52.56%	50.59%
ONE Gas, Inc.	OGS	41.77%	38.91%	39.96%	40.21%
SJW Group	SJW	46.22%	47.94%	43.24%	45.80%
Spire, Inc.	SR	45.68%	44.54%	41.39%	43.87%
Proxy Group					
MEAN		43.65%	44.44%	44.02%	44.04%
LOW		38.26%	38.91%	39.96%	39.78%
HIGH		49.12%	51.15%	52.56%	50.59%

LONG-TERM DEBT RATIO - UTILITY OPERATING COMPANIES

Company Name	Ticker	2022	2021	2020	3-yr Avg.
Golden State Water / Bear Valley	AWR	39.22%	40.32%	43.25%	40.93%
Atmos Energy Corporation	ATO	39.99%	40.12%	41.69%	40.60%
California Water Service	CWT	49.59%	51.89%	48.66%	50.05%
New Mexico Water Service Water Division	CWT		30.81%	32.94%	31.88%
New Mexico Water Service Sewer Division	CWT		37.11%	40.53%	38.82%
Washington Water Service	CWT	37.13%	34.04%	28.07%	33.08%
Hawaii Water Service Pukalani Division	CWT	34.13%	34.42%	35.44%	34.66%
Aqua Pennsylvania Water	WTRG		45.68%	48.86%	47.27%
Aqua Pennsylvania Wastewater	WTRG		1.94%	2.93%	2.43%
Peoples Natural Gas Company	WTRG	41.15%	42.25%	38.52%	40.64%
Peoples Gas Company	WTRG	32.52%	44.03%	20.41%	32.32%
Aqua Ohio Water	WTRG	45.97%	47.89%	35.38%	43.08%
Aqua Ohio Wastewater	WTRG	25.60%	26.33%	27.18%	26.37%
Aqua Illinois	WTRG	43.45%	42.01%	45.43%	43.63%
Aqua Texas	WTRG		50.09%	49.83%	49.96%
Aqua New Jersey, Inc. Water	WTRG	44.26%	46.81%	49.72%	46.93%
Aqua New Jersey, Inc. Wastewater	WTRG	0.00%	0.00%	0.00%	0.00%
Aqua North Carolina	WTRG	49.79%	51.25%	49.38%	50.14%
Aqua Virginia	WTRG	52.17%	51.17%	44.77%	49.37%
Delta Natural Gas Company	WTRG	41.49%	45.51%	43.07%	43.36%
Peoples Gas of WV	WTRG	41.22%	52.26%	51.56%	48.35%
Connecticut Light and Power Company	ES	41.82%	43.93%	43.30%	43.02%
Yankee Gas Company	ES	38.38%	38.88%	38.03%	38.43%
Aquarion Water Company CT	ES	44.06%	42.45%	41.24%	42.58%
NSTAR Electric Company	ES	43.68%	44.42%	44.52%	44.21%
NSTAR Gas Company	ES	44.04%	44.46%	44.46%	44.32%
Aquarion Water Company MA	ES	13.07%	14.36%	3.96%	10.46%
Eversource Gas of MA	ES	46.80%	47.75%	31.35%	41.97%
Public Service Company of NH	ES	46.23%	50.90%	51.34%	49.49%
Aquarion Water Company NH	ES	24.73%	40.26%	41.18%	35.39%
Middlesex Water Company	MSEX	38.53%	40.91%	40.62%	40.02%
Pinelands Water	MSEX	0.00%	0.00%	0.00%	0.00%
Pinelands WW	MSEX	0.00%	0.00%	0.00%	0.00%
Northern Indiana Public Service Company LLC	NI	43.08%	41.41%	41.99%	42.16%
Columbia Gas of Kentucky, Inc.	NI	45.09%	46.13%	45.32%	45.51%
Columbia Gas of Maryland, Inc.	NI	48.04%	44.74%	45.05%	45.94%
Columbia Gas of Ohio, Inc.	NI	49.33%	49.21%	49.55%	49.36%
Columbia Gas of Pennsylvania, Inc.	NI	43.36%	43.95%	44.32%	43.88%
Columbia Gas of Virginia, Inc.	NI	55.75%	55.48%	56.31%	55.85%
Northwest Natural Gas Company	NWN	48.79%	50.43%	52.56%	50.59%
Kansas Gas Service Company, Inc.	OGS	41.63%	38.63%	39.67%	39.98%
Oklahoma Natural Gas Company	OGS		39.01%	40.15%	39.58%
Texas Gas Service Company, Inc.	OGS	41.87%	39.02%	40.01%	40.30%
San Jose Water	SJW	46.80%	49.75%	45.98%	47.51%
CT Water	SJW	45.39%	47.34%	40.88%	44.54%
Maine Water Co.	SJW	46.08%	42.41%	39.85%	42.78%
Canyon Lake Water Service Company	SJW		40.36%	25.95%	33.15%
Spire Alabama Inc.	SR	38.82%	41.49%	35.80%	38.70%
Spire Gulf Inc.	SR	48.39%	50.52%	59.45%	52.79%
Spire Mississippi Inc.	SR		0.00%	0.00%	0.00%
Spire Missouri Inc.	SR	48.54%	46.04%	43.32%	45.97%

Notes:
[1] Ratios are weighted by actual common capital, preferred equity, and long-term debt of Operating Subsidiaries.
[2] Electric, Natural Gas and Water operating subsidiaries where data was unable to be obtained for 2022, 2021 and 2020 were removed from the analysis.

CAPITAL STRUCTURE ANALYSIS

PREFERRED EQUITY RATIO [1]

Proxy Group Company	Ticker	2022	2021	2020	3-yr Avg.
American States Water Company	AWR	0.00%	0.00%	0.00%	0.00%
Atmos Energy Corporation	ATO	0.00%	0.00%	0.00%	0.00%
California Water Service Group	CWT	0.00%	0.00%	0.00%	0.00%
Essential Utilities, Inc.	WTRG	0.00%	0.00%	0.00%	0.00%
Eversource Energy	ES	0.53%	0.58%	0.63%	0.58%
Middlesex Water Company	MSEX	0.32%	0.33%	0.35%	0.33%
NiSource Inc.	NI	0.00%	0.00%	0.00%	0.00%
Northwest Natural Gas Company	NWN	0.00%	0.00%	0.00%	0.00%
ONE Gas, Inc.	OGS	0.00%	0.00%	0.00%	0.00%
SJW Group	SJW	0.00%	0.00%	0.00%	0.00%
Spire, Inc.	SR	0.00%	0.00%	0.00%	0.00%
Proxy Group					
MEAN		0.08%	0.08%	0.09%	0.08%
LOW		0.00%	0.00%	0.00%	0.00%
HIGH		0.53%	0.58%	0.63%	0.58%

PREFERRED EQUITY RATIO - UTILITY OPERATING COMPANIES

Company Name	Ticker	2022	2021	2020	3-yr Avg.
Golden State Water / Bear Valley	AWR	0.00%	0.00%	0.00%	0.00%
Atmos Energy Corporation	ATO	0.00%	0.00%	0.00%	0.00%
California Water Service	CWT	0.00%	0.00%	0.00%	0.00%
New Mexico Water Service Water Division	CWT		0.00%	0.00%	0.00%
New Mexico Water Service Sewer Division	CWT		0.00%	0.00%	0.00%
Washington Water Service	CWT	0.00%	0.00%	0.00%	0.00%
Hawaii Water Service Pukalani Division	CWT	0.00%	0.00%	0.00%	0.00%
Aqua Pennsylvania Water	WTRG		0.00%	0.00%	0.00%
Aqua Pennsylvania Wastewater	WTRG		0.00%	0.00%	0.00%
Peoples Natural Gas Company	WTRG	0.00%	0.00%	0.00%	0.00%
Peoples Gas Company	WTRG	0.00%	0.00%	0.00%	0.00%
Aqua Ohio Water	WTRG	0.00%	0.00%	0.00%	0.00%
Aqua Ohio Wastewater	WTRG	0.00%	0.00%	0.00%	0.00%
Aqua Illinois	WTRG	0.00%	0.00%	0.00%	0.00%
Aqua Texas	WTRG		0.00%	0.00%	0.00%
Aqua New Jersey, Inc. Water	WTRG	0.00%	0.00%	0.00%	0.00%
Aqua New Jersey, Inc. Wastewater	WTRG	0.00%	0.00%	0.00%	0.00%
Aqua North Carolina	WTRG	0.00%	0.00%	0.00%	0.00%
Aqua Virginia	WTRG	0.00%	0.00%	0.00%	0.00%
Delta Natural Gas Company	WTRG	0.00%	0.00%	0.00%	0.00%
Peoples Gas of WV	WTRG	0.00%	0.00%	0.00%	0.00%
Connecticut Light and Power Company	ES	1.15%	1.20%	1.28%	1.21%
Yankee Gas Company	ES	0.00%	0.00%	0.00%	0.00%
Aquarion Water Company CT	ES	0.00%	0.00%	0.00%	0.00%
NSTAR Electric Company	ES	0.42%	0.48%	0.52%	0.47%
NSTAR Gas Company	ES	0.00%	0.00%	0.00%	0.00%
Aquarion Water Company MA	ES	0.00%	0.00%	0.00%	0.00%
Eversource Gas of MA	ES	0.00%	0.00%	0.00%	0.00%
Public Service Company of NH	ES	0.00%	0.00%	0.00%	0.00%
Aquarion Water Company NH	ES	0.01%	0.01%	0.01%	0.01%
Middlesex Water Company	MSEX	0.32%	0.33%	0.36%	0.34%
Pinelands Water	MSEX	0.00%	0.00%	0.00%	0.00%
Pinelands WW	MSEX	0.00%	0.00%	0.00%	0.00%
Northern Indiana Public Service Company LLC	NI	0.00%	0.00%	0.00%	0.00%
Columbia Gas of Kentucky, Inc.	NI	0.00%	0.00%	0.00%	0.00%
Columbia Gas of Maryland, Inc.	NI	0.00%	0.00%	0.00%	0.00%
Columbia Gas of Ohio, Inc.	NI	0.00%	0.00%	0.00%	0.00%
Columbia Gas of Pennsylvania, Inc.	NI	0.00%	0.00%	0.00%	0.00%
Columbia Gas of Virginia, Inc.	NI	0.00%	0.00%	0.00%	0.00%
Northwest Natural Gas Company	NWN	0.00%	0.00%	0.00%	0.00%
Kansas Gas Service Company, Inc.	OGS	0.00%	0.00%	0.00%	0.00%
Oklahoma Natural Gas Company	OGS		0.00%	0.00%	0.00%
Texas Gas Service Company, Inc.	OGS	0.00%	0.00%	0.00%	0.00%
San Jose Water	SJW	0.00%	0.00%	0.00%	0.00%
CT Water	SJW	0.00%	0.00%	0.00%	0.00%
Maine Water Co.	SJW	0.00%	0.00%	0.00%	0.00%
Canyon Lake Water Service Company	SJW		0.00%	0.00%	0.00%
Spire Alabama Inc.	SR	0.00%	0.00%	0.00%	0.00%
Spire Gulf Inc.	SR	0.00%	0.00%	0.00%	0.00%
Spire Mississippi Inc.	SR		0.00%	0.00%	0.00%
Spire Missouri Inc.	SR	0.00%	0.00%	0.00%	0.00%

Notes:
[1] Ratios are weighted by actual common capital, preferred equity, and long-term debt of Operating Subsidiaries.
[2] Electric, Natural Gas and Water operating subsidiaries where data was unable to be obtained for 2022, 2021 and 2020 were removed from the analysis.

Company's Long-Term Debt
BEFORE Refinancing

Tranche	Coupon	Maturity	Principal	Annual Interest
Debt Tendered With Acquisition				
4.02% Series 2018A due 2028	4.02%	12/20/2028	$ 50,000,000	$ 2,010,000
4.22% Series 2018A due 2033	4.22%	12/20/2033	$ 55,000,000	$ 2,321,000
4.29% Series 2018A due 2038	4.29%	12/20/2038	$ 141,000,000	$ 6,048,900
4.37% Series 2018A due 2048	4.37%	12/20/2048	$ 200,000,000	$ 8,740,000
4.52% Series 2018A due 2058	4.52%	12/20/2058	$ 75,000,000	$ 3,390,000
2.84% Series 2019A due 2029	2.84%	9/27/2029	$ 33,000,000	$ 937,200
2.84% Series 2019A due 2029	2.84%	10/29/2029	$ 26,000,000	$ 738,400
2.94% Series 2019A due 2031	2.94%	11/26/2031	$ 25,000,000	$ 735,000
2.94% Series 2019A due 2031	2.94%	12/27/2031	$ 30,000,000	$ 882,000
3.28% Series 2020A due 2050	3.28%	11/10/2050	$ 72,200,000	$ 2,368,160
3.38% Series 2020B due 2060	3.38%	11/10/2060	$ 41,400,000	$ 1,399,320
2.260% Series 2020A-1, Tranche A due 2031	2.26%	6/15/2031	$ 39,000,000	$ 881,400
3.360% Series 2020A-1, Tranche C due 2051	3.36%	6/15/2051	$ 42,800,000	$ 1,438,080
CIC Debt Before Equity Refinancing	**3.84%**		$ 830,400,000	$ 31,889,460
Long-Term Debt Refinanced with Equity			$ (140,400,000)	$ (5,391,715)
CIC Debt After Equity Refinancing			$ 690,000,000	$ 26,497,745
Debt Not Tendered With Acquisition				
Series 2018A-3 due 2038	4.29%	12/20/2038	$ 9,000,000	$ 386,100
Series 2019 A-1 due 2029	2.84%	9/27/2029	$ 7,000,000	$ 198,800
Series 2019 A-2 due 2029	2.84%	10/29/2029	$ 9,000,000	$ 255,600
Series 2019 A-4 due 2031	2.94%	12/27/2031	$ 15,000,000	$ 441,000
Series 2020 A-1, Tranche A due 2050	3.28%	11/10/2050	$ 2,800,000	$ 91,840
Series 2020 A-1, Tranche B due 2060	3.38%	11/10/2060	$ 8,600,000	$ 290,680
Series 2020 A-2, Tranche A due 2031	2.26%	6/15/2031	$ 11,000,000	$ 248,600
Series 2020 A-2, Tranche B due 2041	3.08%	6/15/2041	$ 25,000,000	$ 770,000
Series 2020 A-2, Tranche C due 2051	3.36%	6/15/2051	$ 7,200,000	$ 241,920
Total	**3.09%**		$ 94,600,000	$ 2,924,540
TOTAL @ 10/31/23	**3.75%**		$ 784,600,000	$ 29,422,285

Company's Long-Term Debt
AFTER Refinancing

Tranche	Coupon	Maturity	Principal	Annual Interest
Debt Tendered With Acquisition				
4.99% due 2026	4.99%	6/1/2026	$ 50,000,000	$ 2,495,000
4.97% due 2028	4.97%	6/1/2028	$ 125,000,000	$ 6,212,500
5.04% due 2030	5.04%	6/1/2030	$ 100,000,000	$ 5,040,000
5.21% due 2033	5.21%	6/1/2033	$ 150,000,000	$ 7,815,000
5.31% due 2035	5.31%	6/1/2035	$ 125,000,000	$ 6,637,500
5.41% due 2038	5.41%	6/1/2038	$ 90,000,000	$ 4,869,000
5.52% due 2043	5.52%	6/1/2043	$ 50,000,000	$ 2,760,000
Refinanced Debt			$ 690,000,000	$ 35,829,000
Debt Not Tendered With Acquisition				
Series 2018A-3 due 2038	4.29%	12/20/2038	$ 9,000,000	$ 386,100
Series 2019 A-1 due 2029	2.84%	9/27/2029	$ 7,000,000	$ 198,800
Series 2019 A-2 due 2029	2.84%	10/29/2029	$ 9,000,000	$ 255,600
Series 2019 A-4 due 2031	2.94%	12/27/2031	$ 15,000,000	$ 441,000
Series 2020 A-1, Tranche A due 2050	3.28%	11/10/2050	$ 2,800,000	$ 91,840
Series 2020 A-1, Tranche B due 2060	3.38%	11/10/2060	$ 8,600,000	$ 290,680
Series 2020 A-2, Tranche A due 2031	2.26%	6/15/2031	$ 11,000,000	$ 248,600
Series 2020 A-2, Tranche B due 2041	3.08%	6/15/2041	$ 25,000,000	$ 770,000
Series 2020 A-2, Tranche C due 2051	3.36%	6/15/2051	$ 7,200,000	$ 241,920
			$ 94,600,000	$ 2,924,540
TOTAL @ 10/31/23	4.94%		$ 784,600,000	$ 38,753,540
Projected New Long-Term Debt Issuance	6.23%		$ 100,000,000	$ 6,226,800
Proforma Interest After Refinancing	**5.08%**		**$ 884,600,000**	**$ 44,980,340**

Assessment of the Company's Long-Term Debt Cost

Tranche	Issue Date	Coupon	Maturity	Principal
4.99% due 2026	5/18/2023	4.99%	6/1/2026	$ 50,000,000
4.97% due 2028	5/18/2023	4.97%	6/1/2028	$ 125,000,000
5.04% due 2030	5/18/2023	5.04%	6/1/2030	$ 100,000,000
5.21% due 2033	5/18/2023	5.21%	6/1/2033	$ 150,000,000
5.31% due 2035	5/18/2023	5.31%	6/1/2035	$ 125,000,000
5.41% due 2038	5/18/2023	5.41%	6/1/2038	$ 90,000,000
5.52% due 2043	5/18/2023	5.52%	6/1/2043	$ 50,000,000
Actual 30-day Avg. Moody's Baa-rated Utility Bond Yield as of Issue Date		5.55%		
Projected New Long-Term Debt Issuance 6/1/24	6/1/2024	6.23%		$ 100,000,000
Estimated 30-day Avg. Moody's Baa-rated Utility Bond Yield as of Issue Date		6.17%		

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. GR24__________

DIRECT TESTIMONY

OF

TIMOTHY S. LYONS

Cash Working Capital

On Behalf Of
Elizabethtown Gas Company

Exhibit P-8

February 29, 2024

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ELIZABETHTOWN GAS COMPANY
DIRECT TESTIMONY OF
TIMOTHY S. LYONS

I. INTRODUCTION AND QUALIFICATIONS

Q. PLEASE STATE YOUR NAME AND BUSINESS ADDRESS.

A. My name is Timothy S. Lyons. My business address is 3 Speen Street, Suite 150, Framingham, Massachusetts 01701.

Q. 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 Consulting Services 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"), whose parent company is South Jersey Utilities, Inc. which is 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 – Schedules supporting the Lead-Lag Study.

II. OVERVIEW OF TESTIMONY

Q. PLEASE DEFINE THE TERM "CASH WORKING CAPITAL" AS A RATE BASE COMPONENT.

A. The term "cash 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: (1) operations and maintenance ("O&M") expenses, including labor and non-labor expenses; (2) federal and state income taxes; and (3) taxes other than income taxes.

Q. HOW WAS THE COMPANY'S CASH WORKING CAPITAL REQUIREMENT DETERMINED?

A. The Company's CWC requirement was determined by applying the results of the lead-lag study to forecast 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 forecast post-test year adjusted expenses to derive the CWC requirement, which is included in the Company's rate base.

III. <u>LEAD-LAG STUDY APPROACH</u>

Q. PLEASE DESCRIBE THE DATA USED IN THE LEAD-LAG STUDY.

A. The lead-lag study was based on data from the period October 1, 2022 through September 30, 2023. The data included customer meter reading and billing schedules, O&M expenses, federal and state income taxes, and taxes other than income 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 through February 2023 to remove amounts related to bad debt created by COVID-19. Those amounts were addressed separately by the Board in the 2023 Merger Order[1].

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 58.65 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, including regular payroll expenses and variable compensation expenses; (3) retirement savings plan expenses; (4) group insurance; (5) uncollectible expenses; (6) service company (affiliate) charges; and (7) other O&M expenses.

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[1] *I/M/O the Merger of South Jersey Industries, Inc. and Boardwalk Merger Sub, Inc.*, BPU Docket No. GM22040270, Order dated January 25, 2023 ("2023 Merger Order")

Q. HOW WERE LEAD DAYS FOR PURCHASED GAS EXPENSES DERIVED?

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 FOR REGULAR PAYROLL EXPENSES DERIVED?

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 2022 through December 2022 performance period to the March 9, 2023 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 October 1, 2022 through September 30, 2023 divided by uncollectible expenses over the same period. Similar to the collection lag, the monthly reserve account for uncollectible expenses reflects an adjustment through February 2023 to remove amounts related to bad debt created by COVID-19. Those amounts were addressed separately by the Board in the 2023 Merger Order.

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 Services 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 October 1, 2022 through September 30, 2023. 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 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 October 1, 2022 through September 30, 2023. 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 study 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 NEW JERSEY 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.[2] 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. A zero-expense lead was also assigned to interest payments on long-term debt which is also consistent with the Board's practice.[3]

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.[4] 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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2 *See* "Order Adopting Initial Decision with Modifications and Clarifications," BPU Docket No. ER12111052, March 26, 2015, at 14.

3 *See* "Order Adopting Initial Decision with Modifications and Clarifications," BPU Docket No. ER12111052, March 26, 2015, at 14.

4 *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.[5]

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 CWC 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 items for which

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[5] *See* "Order Adopting Initial Decision with Modifications and Clarifications," BPU Docket No. ER12111052, March 26, 2015, at 13.

they were withheld. Therefore, miscellaneous employee deductions are deducted from the CWC 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 $50,475,720.

Q. ARE THE RESULTS OF THIS LEAD-LAG STUDY REASONABLE?

A. Yes, the study provides an accurate assessment of the Company's actual CWC requirements. The resulting CWC requirement should be included in the Company's rate base.

Q. DOES THIS CONCLUDE YOUR TESTIMONY?

A. Yes, it does.

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 and evidence before 26 state regulatory commissions and 3 Canadian regulatory boards. 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			
Cook Inlet Natural Gas Storage Alaska, LLC	7/21	Docket No. U-21-058	Sponsored testimony supporting the lead-lag study/cash working capital requirement for a general rate case proceeding.
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.
Arizona Corporation Commission			
Southwest Gas Corporation	12/21	Docket No. G-01551A-21-0368	Sponsored testimony supporting class cost of service, rate design and bill impact analysis for a general rate case proceeding.
Arkansas Public Service Commission			
Liberty Utilities (The Empire District Electric Company)	2/23	Docket No. 22-085-U	Sponsored testimony supporting the class cost of service, rate design, bill impact studies, and revenue decoupling for a general rate case proceeding.
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			
Bear Valley Electric Service, Inc.	10/22	Application No. 22-08-010	Sponsored testimony supporting marginal cost study, rate design and bill impact analysis for a general rate case proceeding.
Liberty Utilities (CalPeco Electric)	5/21	Application No. 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	Application No. 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.
Delaware Public Service Commission			
Artesian Water Company	04/23	Docket No. 23-0601	Sponsored testimony supporting the cost of service, rate design and bill impact studies for a general rate case proceeding.
Illinois Commerce Commission			
Ameren Illinois Company d/b/a Ameren Illinois	1/23	Docket No. 22-0487	Sponsored testimony supporting a Multi-Year Integrated Grid Plan (Grid Plan). Prepared research and analysis evaluating the reasonableness of the Grid Plan through comparison to how other electric utilities have responded to the changing energy landscape.
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			

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MANAGEMENT CONSULTANTS

Sponsor	Date	Docket No.	Subject
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.
Kentucky Public Service Commission			
Bluegrass Water Utility (Central States Water Company)	02/23	Case No. 2022-00432	Sponsored testimony supporting the rate design and bill impact studies for a general rate case proceeding.
Maine Public Utilities Commission			
Northern Utilities, Inc. d/b/a Unitil	05/23	Docket No. 2023-00051	Sponsored testimony supporting the cost of service, rate design and bill impact studies for a general rate case proceeding.
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			
The Potomac Edison Company (FirstEnergy)	03/23	Case No. 9695	Sponsored testimony supporting the class cost of service, rate design, bill impact and lead-lag studies for a general rate case proceeding.
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.
Massachusetts Department of Public Utilities			
Berkshire Gas Company, Eversource Energy, Liberty Utilities, National Grid, and Unitil	03/22	Docket No. DPU 20-80	Sponsored report that summarizes research, findings, and recommendations for regulatory mechanisms, methodologies, and policies that support Massachusetts's achievement of its net zero climate goal by 2050. The regulatory designs were informed by the results of quantitative and qualitative analysis of decarbonization pathways to achieve the Commonwealth's climate goals.
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.
Eversource Energy, National Grid, and Unitil	02/20	Docket No. DPU 19-55	Sponsored report that summarizes research and evaluation of funding approaches for infrastructure modifications that interconnect Distributed Generation (DG) projects.
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.

Sponsor	Date	Docket No.	Subject
Michigan Public Service Commission			
Lansing Board of Water & Light and Michigan State University	04/23	Docket No. U-21308	Sponsored testimony evaluating Consumer Energy's class cost of service and rate design proposals.
Lansing Board of Water & Light and Michigan State University	04/20	Docket No. U-20650	Sponsored testimony evaluating Consumer Energy's class 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 class cost of service and rate design proposals.
Midland Cogeneration Ventures, LLC	09/18	Docket No. U-18010	Sponsored testimony evaluating Consumer Energy's class cost of service and rate design proposals.
Minnesota Public Utilities Commission			
Northern States Power Company (XcelEnergy)	10/21	Docket No. E002/GR-21-630	Sponsored testimony supporting a Return on Equity (ROE)adjustment mechanism that would allow the Company to symmetrically adjust its ROE to reflect significant changesin financial market conditions.
Missouri Public Service Commission			
Confluence Rivers Utility Operating Company	12/22	Case No. WR-2023-0006/ SR-2023-0007	Sponsored testimony supporting the rate design and bill impact studies for a general rate case proceeding.
The Empire District Gas Company	08/21	Docket No. GR-2021-0320	Sponsored testimony supporting the class 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 class 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 class 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.
Liberty Utilities (Midstates Natural Gas)	09/17	Docket No. GR-2018-0013	Sponsored testimony supporting the class 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 class 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 class 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.
Nevada Public Utilities Commission			
Southwest Gas Corporation	09/23	Docket No. 23-09012	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	09/21	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.

Sponsor	Date	Docket No.	Subject
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 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.
New Jersey Board of Public Utilities			
Jersey Central Power and Light Company (FirstEnergy)	03/23	Docket No. ER23030144	Sponsored testimony supporting the class cost of service and Lead/Lag studies for a general rate case proceeding.
South Jersey Gas Company	04/22	Docket No. GR22040253	Sponsored testimony supporting the Lead/Lag study for a general rate case proceeding.
Elizabethtown Gas Company	12/21	Docket No. GR21121254	Sponsored testimony supporting the Lead/Lag study for a general rate case proceeding.
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.
New Mexico Public Regulation Commission			
New Mexico Gas Company, Inc.	9/23	Case No. 23-00255-UT	Sponsored testimony supporting the class cost of service, rate design, bill impact and weather normalization adjustment mechanisms for a general rate case proceeding.
Corporation Commission of Oklahoma			
The Empire District Electric Company	02/21	Cause No. PUD 202100163	Sponsored testimony supporting the class cost of service, rate design, bill impact and Lead/Lag studies for a general rate case proceeding. The proposed rate design included a three-year phase-in of the proposed rate increase.
The Empire District Electric Company	03/19	Cause No. PUD 201800133	Sponsored testimony supporting the class 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 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.

Sponsor	Date	Docket No.	Subject
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 – West Texas, North Texas, and Borger/ Skellytown Service Areas	06/22	Case No. 00009896	Sponsored testimony supporting the Lead/Lag study for a general rate case proceeding.
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.
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			

Sponsor	Date	Docket No.	Subject
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	3/23	Case No. PUR-2023-00002	Sponsored testimony supporting the Lead/Lag study for the 2023 triennial review of base rates, terms, and conditions.
Rappahannock Electric Cooperative	10/22	Case No. PUR-2022-00160	Sponsored report and studies related to revenue requirements, class cost of service, rate design, and bill impact analysis for a streamlined application to increase base rates.
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.
West Virginia Public Service Commission			
Monongahela Power Company and The Potomac Edison Company (FirstEnergy)	06/23	Case No. 23-0460-E-42T	Sponsored testimony supporting the class cost of service, rate design, bill impact and lead-lag studies for a general rate case proceeding.
Nova Scotia Utility and Review Board			
Nova Scotia Power	01/22	Matter No. M10431	Sponsored evidence supporting the cash working capital requirement and lead/Lag study for a general rate case proceeding.
Ontario Energy Board			
Toronto Hydro-Electric System Limited	11/23	EB-2023-0195	Sponsored evidence supporting proposed Rate Framework.
Ontario Energy Association	01/21	Docket No. EB-2020-0133	Sponsored evidence regarding policies and ratemaking treatment related to COVID-19 costs in U.S. and Canadian regulatory jurisdictions. The evidence was used to support Ontario Energy Association's response to Staff's proposals
Commission of Canada Energy Regulator			
Trans-Northern Pipelines, Inc.	06/23	Docket No. RH-001-2023	Sponsored evidence related to application for approval of incentive tolls.

Elizabethtown Gas Company
Lead-Lag Study For The Period October 1, 2022 Through September 30, 2023
Working Capital Requirement
Summary

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	**Gas Costs and O&M Expenses**								
2	Purchased Gas Costs	$ 179,633,352	$ 492,146	58.65	A	(40.22)	B	18.43	$ 9,070,251
3	Regular Payroll	24,492,837	67,104	58.65	A	(9.92)	C	48.73	3,269,978
4	Variable Compensation	1,246,356	3,415	58.65	A	(251.29)	C	(192.64)	(657,866)
5	Pension/ OPEB	4,233,062	11,597	58.65	A	-		58.65	680,164
6	Retirement Savings Plan	1,539,868	4,219	58.65	A	(23.59)	C	35.06	147,918
7	Group Insurance	4,386,354	12,017	58.65	A	(42.91)	C	15.74	189,148
8	Uncollectible Expense	10,021,812	27,457	58.65	A	(274.24)	C	(215.59)	(5,919,455)
9	Service Company Charges	27,583,019	75,570	58.65	A	(42.88)	C	15.77	1,191,739
10	Other Third-Party O&M Expenses	18,031,303	49,401	58.65	A	(39.15)	C	19.50	963,320
11	Total Gas Costs and O&M Expenses	$ 271,167,963				.			$ 8,935,197
12	**Income Taxes**								
13	Excess Deferred Tax Amortization	$ (2,385,594)	$ (6,536)	58.65		-		58.65	$ (383,336)
14	Federal Income Taxes (21.00%)	30,238,213	82,844	58.65	A	(37.00)	D	21.65	1,793,573
15	State Income Tax (9.00%)	14,240,917	39,016	58.65	A	(37.00)	D	21.65	844,696
16	Total Income Taxes	$ 42,093,536							$ 2,254,933
17	**Taxes Other Than Income Taxes**	$ 5,600,492	$ 15,344	58.65	A	(17.82)	E	40.83	$ 626,496
18	**Depreciation Expense**	$ 73,787,250	$ 202,157	58.65	A	-		58.65	$ 11,856,508
19	**Amortization Expense**	$ 3,402,945	$ 9,323	58.65	A	-		58.65	$ 546,794
20	**Interest Expense**								
21	Interest on Long-Term Debt	34,164,877	$ 93,602	58.65	A	-	F	58.65	$ 5,489,757
22	Interest on Short-Term Debt	-	-	58.65	A	-	F	58.65	-
23	Interest on Customer Deposits	184,353	505	58.65	A	(250.43)	F	(191.78)	(96,849)
24	Total Interest Expense	$ 34,349,230							$ 5,392,908
25	**Return**	$ 120,576,379	$ 330,346	58.65	A	-		58.65	$ 19,374,793
26	**Other Adjustments**								
27	Incidental collections								$ 1,985,982
28	Employee deductions								(497,891)
29	Total Other Adjustments								$ 1,488,091
30	**Total**	$ 550,977,795	$ 547,847						$ 50,475,720

Elizabethtown Gas Company
Lead-Lag Study For The Period October 1, 2022 Through September 30, 2023
Revenue and Collection Lag
Revenue Lag

Line	Description	Revenue Lag	Reference
1	Service Lag	15.21	
2	Billing Lag	1.45	WP A-1
3	Collection Lag	42.00	WP A-2
4	Composite Revenue Lag	58.65	

Elizabethtown Gas Company
Lead-Lag Study For The Period October 1, 2022 Through September 30, 2023
Purchased Gas

Line	Month	Production Period Begin	Production Period End	Invoice	Settlement	Expense	Midpoint	(Lead)/Lag Days	Dollar Days	Composite (Lead)/Lag Days
1	October 2022	10/01/22	10/31/22	11/15/22	11/25/22	$ 15,616,014	(15.50)	(40.50)	$ (632,448,559)	
2	November 2022	11/01/22	11/30/22	12/15/22	12/25/22	15,584,636	(15.00)	(40.00)	(623,385,450)	
3	December 2022	12/01/22	12/31/22	01/15/23	01/25/23	18,380,944	(15.50)	(40.50)	(744,428,231)	
4	January 2023	01/01/23	01/31/23	02/15/23	02/25/23	27,500,591	(15.50)	(40.50)	(1,113,773,952)	
5	February 2023	02/01/23	02/28/23	03/15/23	03/25/23	16,475,501	(14.00)	(39.00)	(642,544,546)	
6	March 2023	03/01/23	03/31/23	04/15/23	04/25/23	16,495,410	(15.50)	(40.50)	(668,064,114)	
7	April 2023	04/01/23	04/30/23	05/15/23	05/25/23	10,035,124	(15.00)	(40.00)	(401,404,958)	
8	May 2023	05/01/23	05/31/23	06/15/23	06/25/23	11,603,981	(15.50)	(40.50)	(469,961,231)	
9	June 2023	06/01/23	06/30/23	07/15/23	07/25/23	10,363,337	(15.00)	(40.00)	(414,533,475)	
10	July 2023	07/01/23	07/31/23	08/15/23	08/25/23	9,052,064	(15.50)	(40.50)	(366,608,611)	
11	August 2023	08/01/23	08/31/23	09/15/23	09/25/23	9,280,217	(15.50)	(40.50)	(375,848,804)	
12	September 2023	09/01/23	09/30/23	10/15/23	10/25/23	9,241,860	(15.00)	(40.00)	(369,674,391)	
13	Total		Total			$ 169,629,680			$ (6,822,676,321)	(40.22)

Elizabethtown Gas Company
Lead-Lag Study For The Period October 1, 2022 Through September 30, 2023
O&M Expenses

Line	Description	(Lead)/Lag Days	Ref.
1	Operations and Maintenance Expenses		
2	Regular Payroll	(9.92)	C-1
3	Variable Compensation	(251.29)	C-4
4	Retirement Savings Plan	(23.59)	C-5
5	Group Insurance	(42.91)	C-6
6	Uncollectible Expenses	(274.24)	C-7
7	Service Company Charges	(42.88)	C-8
8	Other Third-Party O&M Expenses	(39.15)	C-9

Elizabethtown Gas Company
Lead-Lag Study For The Period October 1, 2022 Through September 30, 2023
Income Taxes

Line	Description	(Lead)/Lag Days	Ref.
1	Current Federal Income Taxes	(37.00)	D-1
2	State Income Tax	(37.00)	D-2

Elizabethtown Gas Company
Lead-Lag Study For The Period October 1, 2022 Through September 30, 2023
Taxes Other Than Income Taxes

Line	Description	Expense	Percent	(Lead)/Lag Days	Reference	Dollar Days
1	Payroll Taxes - Regular Payroll					
2	FICA	$ 12,753,746	98.13%	(23.97)	E-1	$ (305,659,656)
3	Federal Unemployment	17,724	0.14%	(30.08)	E-2	(533,115)
4	State Unemployment	225,870	1.74%	(30.36)	E-3	(6,857,942)
5	Total Payroll Taxes - Regular Payroll	$ 12,997,340	100.00%	(24.09)		$ (313,050,713)
6	Property Taxes	$ 1,205,759		49.77	E-4	$ 60,005,813
7	Taxes Other Than Income Taxes (Lead)/Lag Days	$ 14,203,099		(17.82)		$ (253,044,899)

Elizabethtown Gas Company
Lead-Lag Study For The Period October 1, 2022 Through September 30, 2023
Interest Expense

Line	Description	(Lead)/Lag Days	Ref.
1	Interest Expense		
2	Interest on Long-Term Debt	0.00	
3	Interest on Short-Term Debt	0.00	
4	Interest on Customer Deposits	(250.43)	F-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
BPU DOCKET NO. GR__________

DIRECT TESTIMONY

OF

DANE A. WATSON, PE CDP

On Behalf Of
Elizabethtown Gas Company

Exhibit P-9

February 29, 2024

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LIST OF SCHEDULES

SCHEDULE DAW-1	Elizabethtown Gas Company Depreciation Rate Study at December 31, 2022
SCHEDULE DAW-2	Dane Watson List of Testimony Appearances

Exhibit P-9

ELIZABETHTOWN GAS COMPANY
DIRECT TESTIMONY OF
DANE A. WATSON

I. INTRODUCTION

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

A. My name is Dane A. Watson, and my business address is 101 E. Park Blvd, 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").

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 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.

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[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 numerous regulatory commissions across North America and have performed more than 300 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. <u>PURPOSE OF DIRECT TESTIMONY</u>

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 which in turn is owned by IIF US Holding 2, LP ("IIF"), a private equity fund, 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 2022.

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 a decrease 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, 2022, I recommend an annualized depreciation expense for Elizabethtown of approximately $62.2 million. This represents a decrease of approximately $636 thousand over the annualized depreciation expense calculated on year-end 2022 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, 2022, 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 since the previous depreciation study, which was conducted in 2021 and was used to develop the existing approved depreciation rates. Specifically, the Distribution function has seen the most dramatic increase in investment, which correlates with the focus of the Company's Infrastructure Investment Program ("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 reflect the Company's recent and specific retirement experience for assets more accurately. Lastly, both the Company's statistical data and field experience indicate that the accounts 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, 2022.

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 2022 in Docket No. GR21121254.

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, 2022.

Q. IN DEVELOPING THE PROPOSED DEPRECIATION RATES, DID YOU CONSIDER THE COMPANY'S CURRENT ASSET ACCOUNTING AND OPERATIONAL 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 decreasing and is primarily influenced by the small increase in lives, there has been a decrease in removal cost, and an increase in salvage for transportation equipment. Elizabethtown plans to continue focusing on 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 decreasing by approximately $636 thousand annually. This decrease is computed by applying the existing account rates to the investment balances at the study date of December 31, 2022, 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
Comparison of Rates and Expense

Description	Plant Balance 12/31/2022	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]
Manufactured Gas	$ 61,423	4.39%	$ 2,696	4.39%	$ 2,696	$ -
Other Storage	69,613,034	2.51%	1,745,332	2.65%	1,844,870	99,538
Transmission	24,642,773	2.18%	536,455	2.00%	492,540	(43,915)
Distribution	1,851,040,503	2.27%	42,059,979	2.19%	40,602,247	(1,457,732)
General Depreciated	157,098,791	9.59%	15,060,985	10.02%	15,734,587	673,602
General Amortized (after retirements)	25,407,548	13.31%	3,381,561	13.53%	3,436,481	54,920
Reserve True Amortized 3 Years					37,688	37,688
Total Study Plant In Service	$ 2,127,864,072	2.95%	$ 62,787,008	2.92%	$ 62,151,109	$ (635,899)
(excludes Intangibles and Land)						

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, 2022.

A. Service Lives

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 Distribution Account 380 Services, is 60 years. The Company has a low-pressure program nearing completion and a vintage replacement program that is expected to continue for another 10 years. The Company is also replacing a number of services based on increasing load requirements. This information in conjunction with the analysis supported a life decrease operationally but not to the level indicated in the life analysis. As a result, this study recommends moving down by five years to a 55-year life.

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 1.5 years (June 2024) from the study date. At the completion of the IIP, the average service life of some of the accounts is expected to eventually move longer because the Company has replaced 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, 3 accounts had an increase in life, 3 accounts had a decrease in life, 36 accounts remained the same, and there are 8 accounts where no comparison can be made.

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 base rate cases since 2009. Specifically, the Company has amortized Accounts 391X (except 391.20), 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 <u>current</u> cost of salvage or removal whereas the retirement amount is the <u>original</u> 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 (2022) would have had an installed cost of $11.53 in 1949[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). However, a correct removal cost calculation would show a negative 434 percent removal cost for that asset ($50/$11.53). Inflation from the time of installation of the asset until the time of its removal

[2] Using the Handy-Whitman Bulletin No. 198, G-1, line 44, $11.53 = $500 x 30/1301.

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.

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 -434% removal cost rate accurately reflects the cost necessary to remove the asset 73 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 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.

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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. 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 2022. In that analysis, 2- through 10-year averages were calculated and evaluated. A 3-year average and 5-year average amount were 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.

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]

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[4] F.K. Wolf and W.C. Fitch, *Depreciation Systems*, pp. 260-267 (1994).
[5] NARUC, *Public Utility Depreciation Practices,* pp. 157-164 (1996).

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. The Company can fall 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 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 BPU Docket No. GR21121254. However, it is important to note that the amounts were established pursuant to a settlement agreement.

Q. WHAT PLANT ACCOUNTS SEE THE MOST REMOVAL COSTS?

A. There are six accounts that 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 (Distribution 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 also 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 $1,145 in the annual accrual amount; Distribution Mains, I recommend including $2,685,106 in the annual accrual amount; and for Distribution Services, I recommend including $4,483,483 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 near 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 $7,328,944. General Plant Transportation Accounts exhibit positive net salvage of $129,592. The total amount of net salvage (salvage less cost of removal) included in the depreciation rate accrual is a negative $7,222,967. 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. CONCLUSION

Q. PLEASE SUMMARIZE THE CONCLUSIONS YOU HAVE REACHED AS A RESULT OF YOUR ANALYSIS.

A. The depreciation study and analysis performed under my supervision fully 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, 2022

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, 2022 ("Study"). To determine depreciation rates, the following process occurred: 1) historic data through December 31, 2022 and judgment are used to estimate life and net salvage amounts are 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, 2022 are used to compute the proposed depreciation accrual. The total proposed decrease that results from depreciation expense in this Study is approximately $636 thousand based on plant balances as of December 31, 2022.

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. GR21121254. 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, 2022, as follows: no change for Manufactured Gas, an increase of nearly $100 thousand for Other

Storage, a decrease of nearly $44 thousand for Transmission, a decrease of nearly $1.5 million for Distribution, and an increase of $766 thousand for General. The total proposed change in depreciation and amortization expense is a decrease of nearly $636 thousand.

For Manufactured Gas, Storage, Transmission, Distribution, and General accounts (excluding Intangibles), there are 3 accounts that have increasing lives and 3 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, 10 accounts experienced negative net salvage (removal cost) charges, for a total of $7,352,559. 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, $129,592 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, 2022
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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, 2022. Historical data at December 31, 2022, 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.

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 300,000 residential, commercial, and industrial customers in parts of Union, Middlesex, Sussex, Warren, Hunterdon, Morris, and Mercer 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 $62.2 million based on Elizabethtown's depreciable investment for the plant balances as of December 31, 2022. This reflects a decrease of $0.6 million as compared to the equivalent annual depreciation expense of $62.8 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 $1.8 million. The proposed depreciation rates for Transmission translate into an annual depreciation expense of $493 thousand. The proposed depreciation rates for Distribution translate into an annual depreciation expense of $40.6 million. The proposed depreciation rates for General Plant translate into an annual depreciation expense of $19.2 million. The changes in proposed depreciation expense are primarily due to increases in the life for Transmission Mains, decreased cost of removal in the Transmission and Distribution Plant function, in General Plant the reduction in life for Account 394, 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

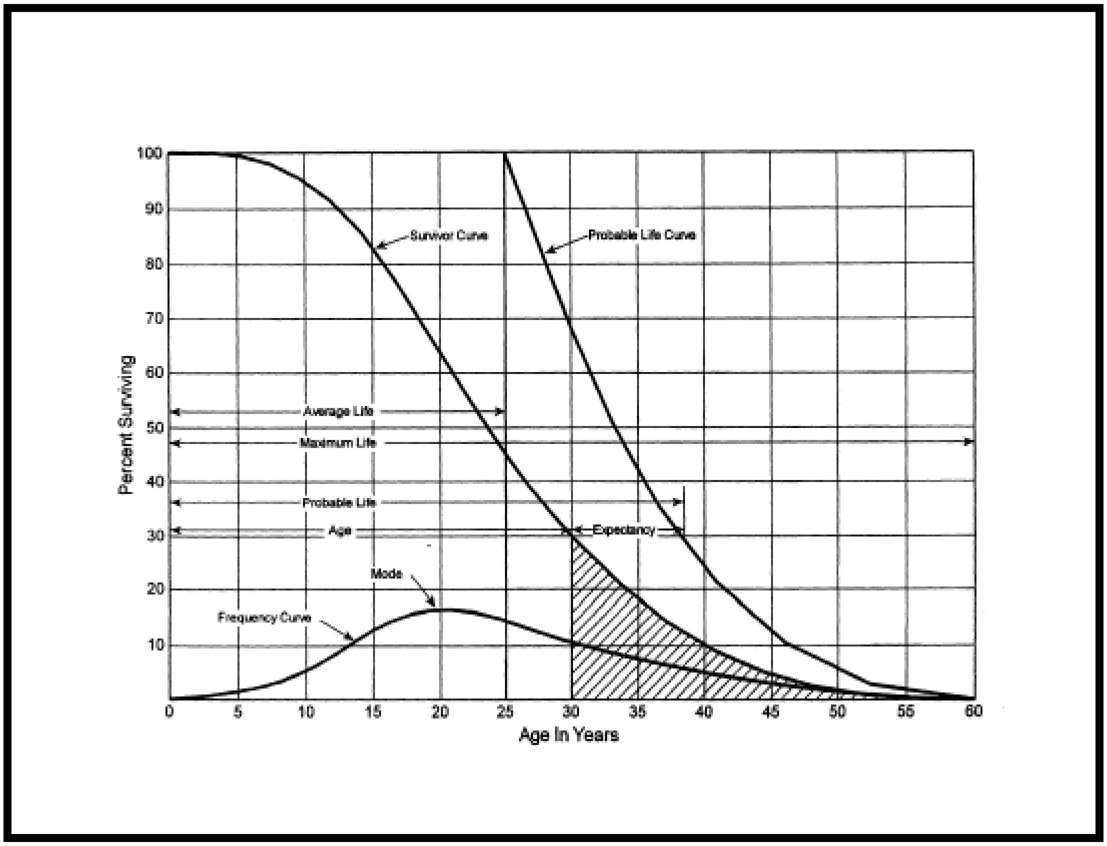
[1] Function or function group refers to different categories of plant. Specifically, the functions analyzed in this study are: Manufactured Gas Production, Other Storage, Transmission, Distribution, and General.

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.

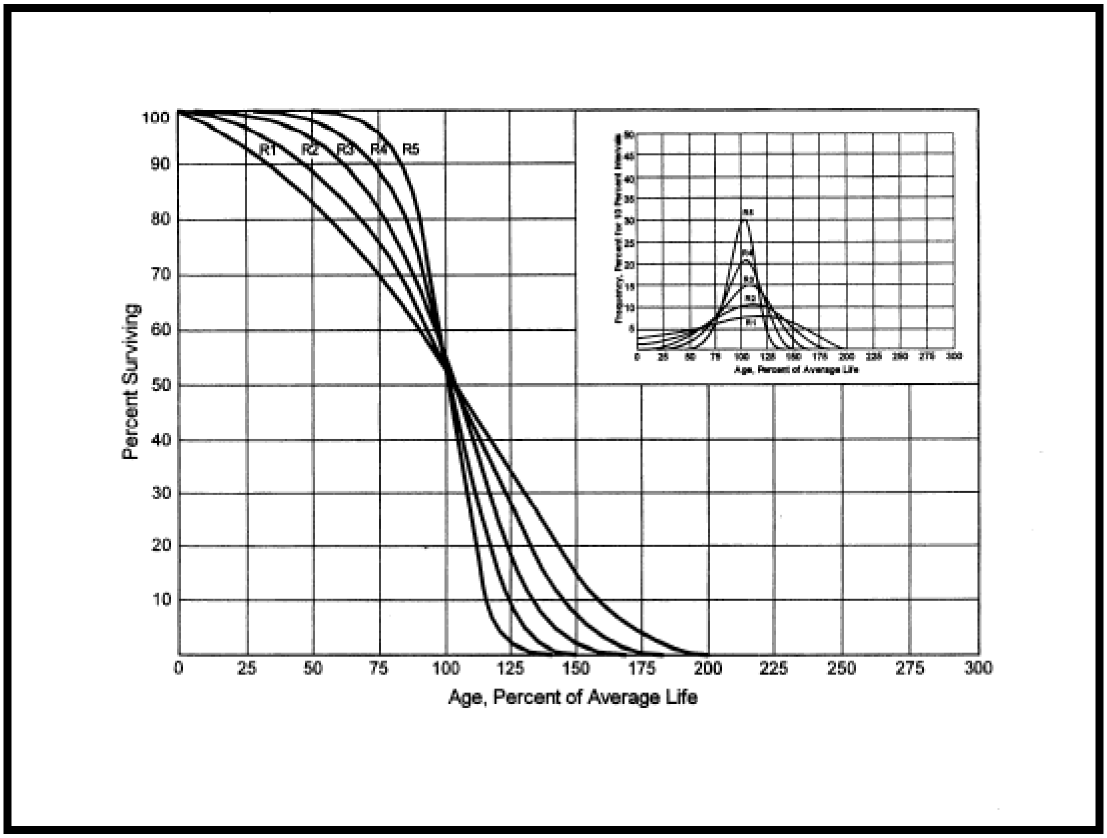
The actuarial analysis is used for each account within a functional group where sufficient data is available. Judgment is used to some degree on all accounts.

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. GR21121254, 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, 2022, 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. Phases 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).

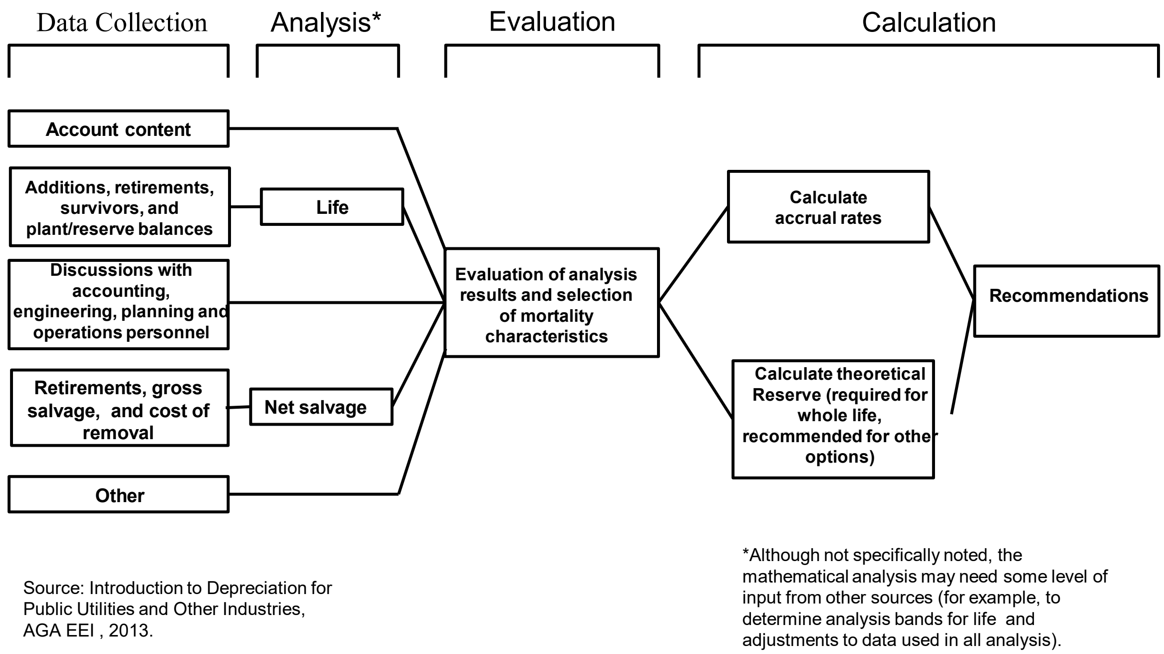


Figure 1

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, 2022, 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.

$$\textit{Annual Depreciation Expense} = \frac{\textit{Original Cost–Allocated Book Reserve–(Original Cost * Net Salvage \%)}}{\textit{Average Remaining Life}}$$

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, 2022, 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.

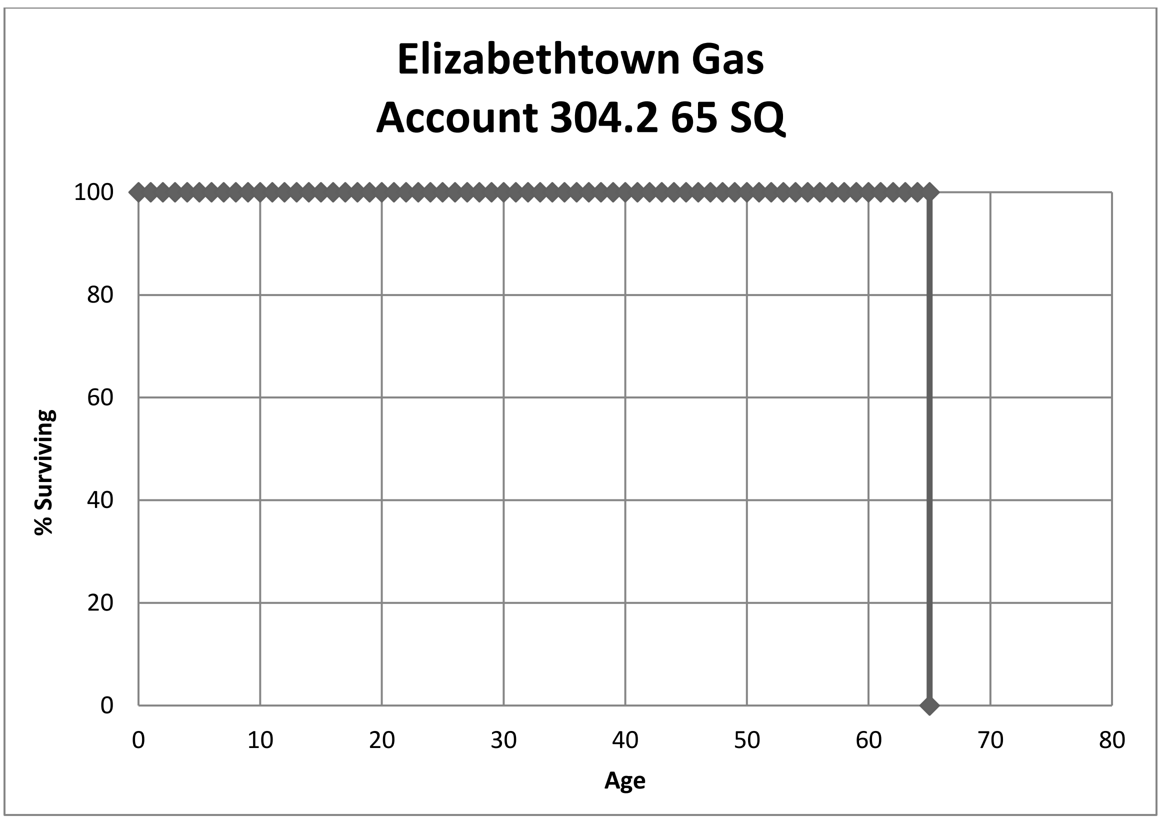
For each account on the overall band (*i.e.*, placement from earliest vintage year available for each account through 2022), the survivor curves underlying the depreciation rates stipulated and approved in Docket No. GR21121254 were used as a starting point. Using the same average life, various dispersion 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, 2022, 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.

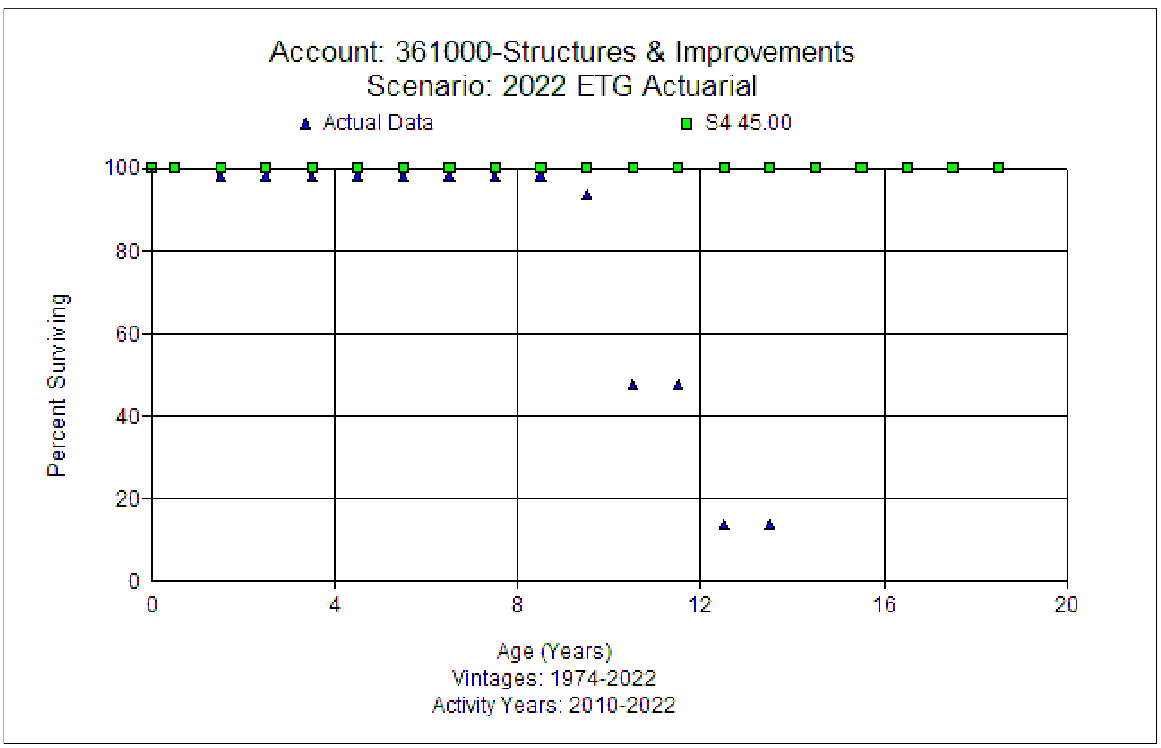


B. Other Storage Plant

Storage Accounts, FERC Accounts 361.00–363.40

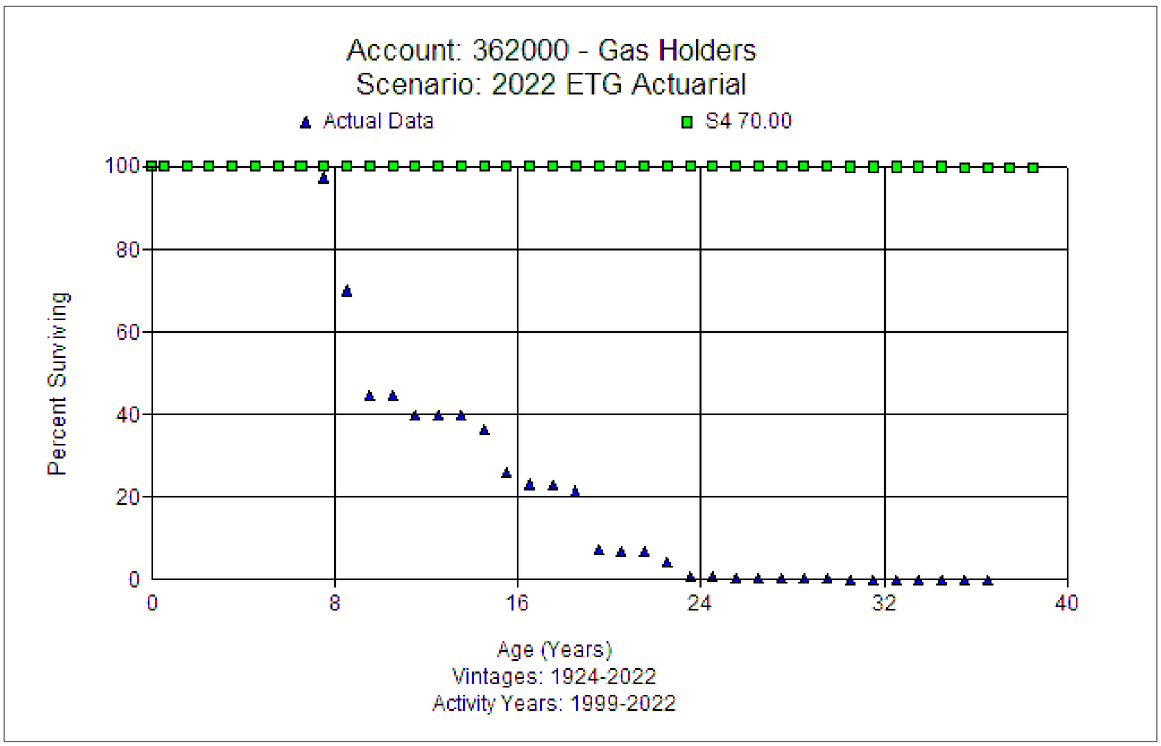
<u>FERC Account 361.00 Structures and Improvements 45 S4</u>

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, 2022, there was approximately $6.3 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 operationally 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.



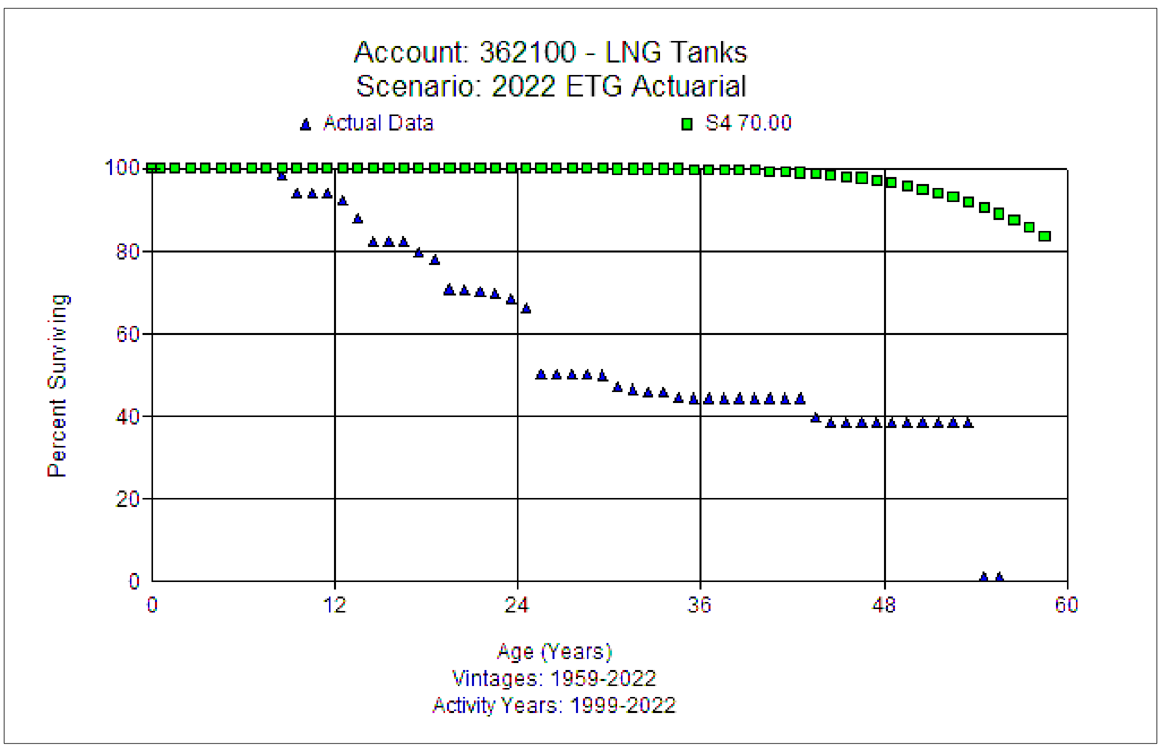
FERC Account 362.00 Gas Holders – Natural Gas 70 S4

This account includes the cost of natural gas holders (tanks) used in the storage function. At December 31, 2022, the balance is $379 thousand. The current approved life for this account is 65 years with the S4. The prior study included the transfer of assets from the natural gas holder to LNG. Some assets remain. The analysis is not reflective of Company expectations going forward for these assets. The same life used for Account 362.10, 70 S4, is proposed.



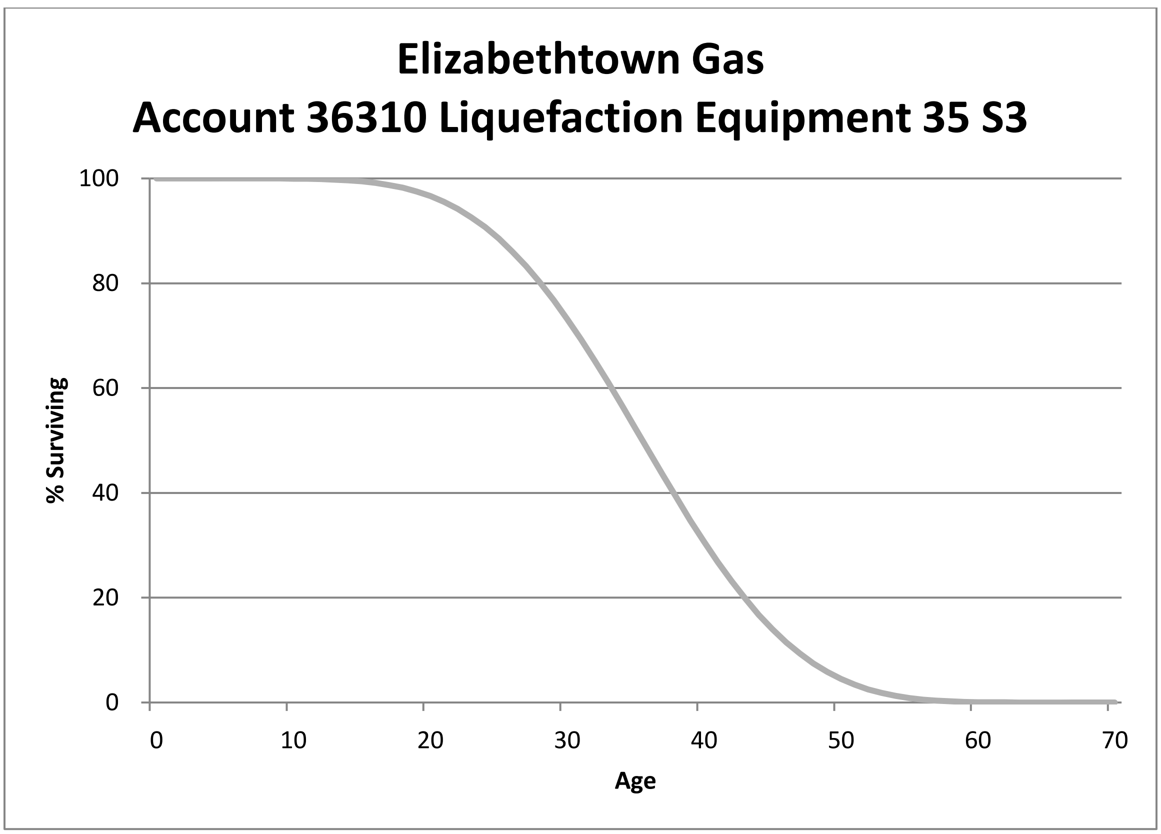
FERC Account 362.10 Gas Holders – LNG 70 S4

This account includes the cost of LNG holders (tanks), piping, valves, and other miscellaneous equipment used in the storage function. At December 31, 2022, there was approximately $3.2 million in this account. 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.



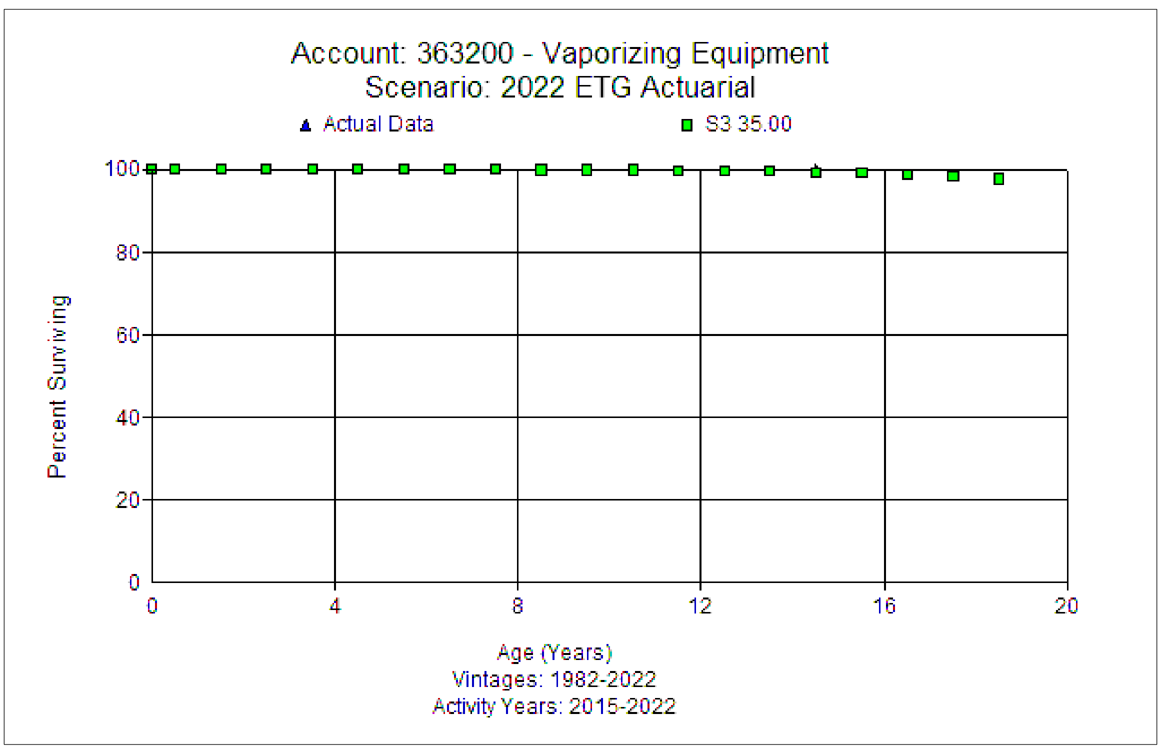
FERC Account 363.10 Liquefaction Equipment 35 S3

This account consists of liquefaction equipment, boiler, piping, and pump equipment associated with the LNG plant. There is approximately $50.3 million in this account at December 31, 2022. This is a new account. Discussions with Company personnel indicated the new equipment came online in June 2022. The old equipment was retired. Company personnel indicated there is a mix of assets with varying lives, but the majority of the investment is in the cold box, and it would last 35 years or more. The electrical components would have a shorter life. Overall, a 35-year life is still operationally reasonable. Based on the type of assets, discussion with Company personnel, and expectations, the Study recommends the 35 S3 dispersion pattern. A representative graph of the life of the account is shown in the curve below.



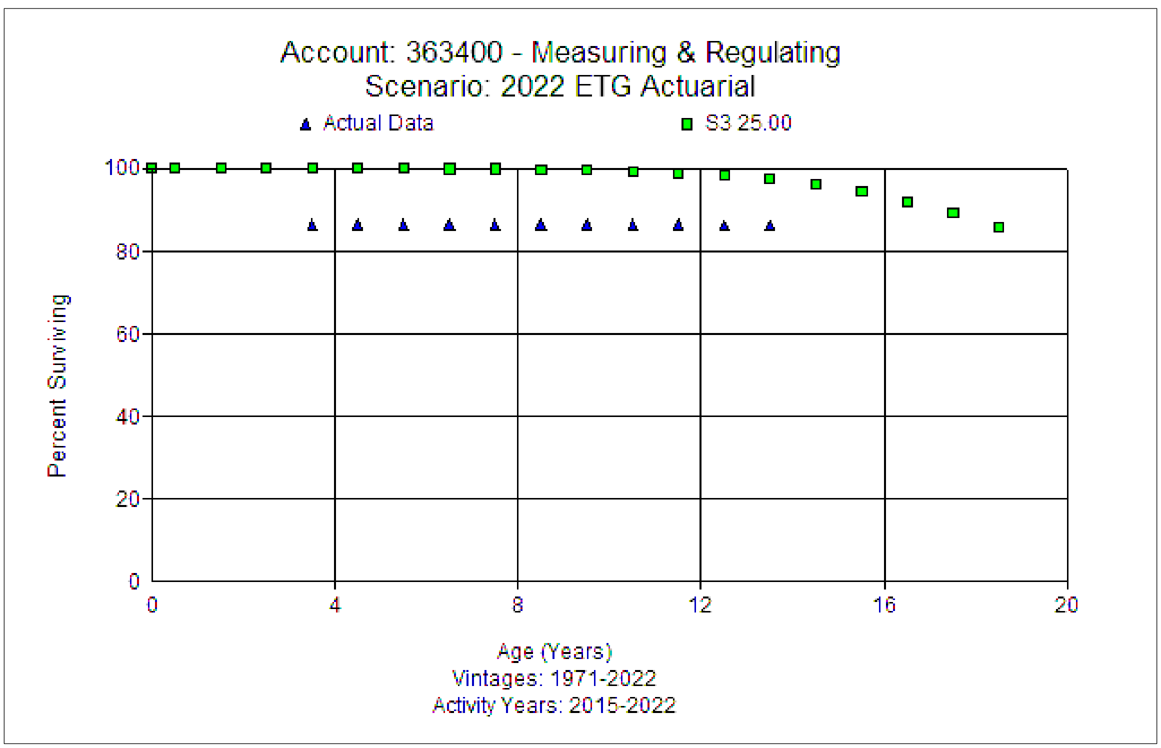
FERC Account 363.20 Vaporizing Equipment 35 S3

This account consists of vaporizers, boiler, piping, and pump equipment associated with the LNG plant. There is approximately $6.4 million in this account at December 31, 2022. The approved life for this account is 35 years with the S3 dispersion. Discussions with Company personnel indicated that units were replaced in 1992 with stainless and controls were changed also. However, the 1992 equipment and 2005 controls are being replaced and will be in service by June of 2024. The boil off compressor is included in this account. Company personnel indicated a 35-year life is still operationally reasonable. Based on the type of assets, discussion with Company personnel, historical replacement cycle 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 $3 million in this account. The approved life for this account is 25 years with the S3 dispersion. The average age of retirements is 22 years, and the average age of surviving assets is about 7 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. The mix of assets in this account would likely still support the approved 25 year life. 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.

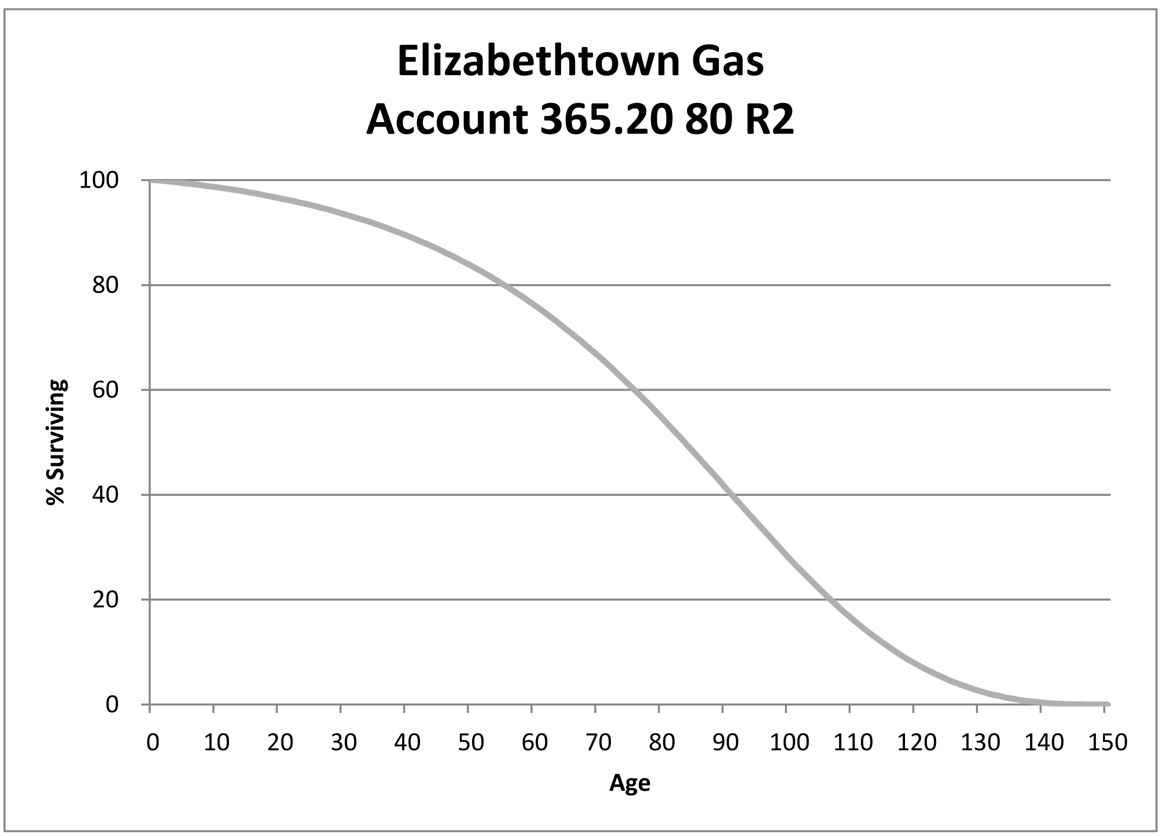


C. Transmission Plant

Transmission Accounts, FERC Accounts 365.20–371.0

<u>FERC Account 365.20 Rights of Way 80 R2</u>

This account includes the cost of rights of way, and associated legal fees and recording costs related to 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 be at least equal or exceed the life of mains. Based on the 73 year life recommendation for Account 367, Mains in this Study, the Study retains the 80-year life and R2 dispersion. A representative graph of the life of the account is shown in the curve below.

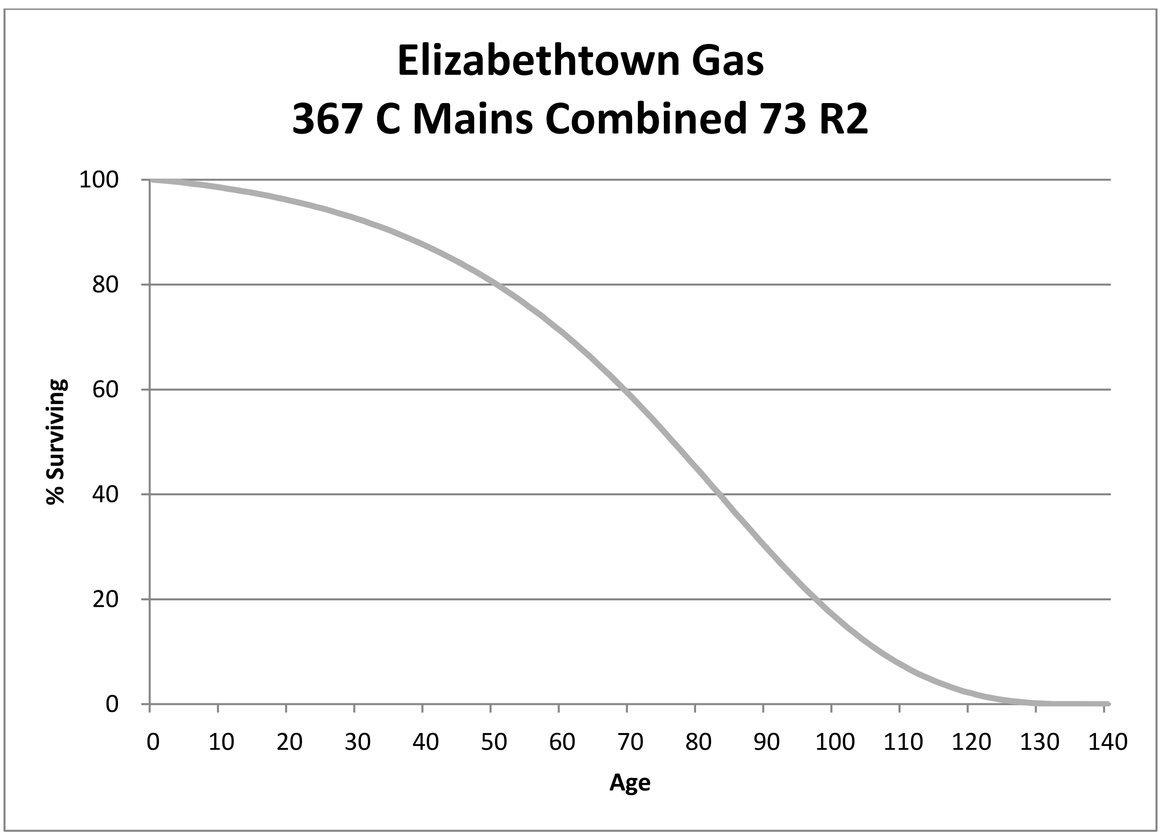


FERC Account 367 Mains - All 73 R2

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 $15.6 million as of December 31, 2022. The approved life is 71 R2.

Discussions with Company personnel indicated 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, 8.35 years, is relatively young for this type of asset. There has been limited retirement activity, which occurred in 2021. Based on type of assets and expectations, this Study moves the life slightly longer to 73 R2. A representative graph of the life of the account is shown in the curve below.

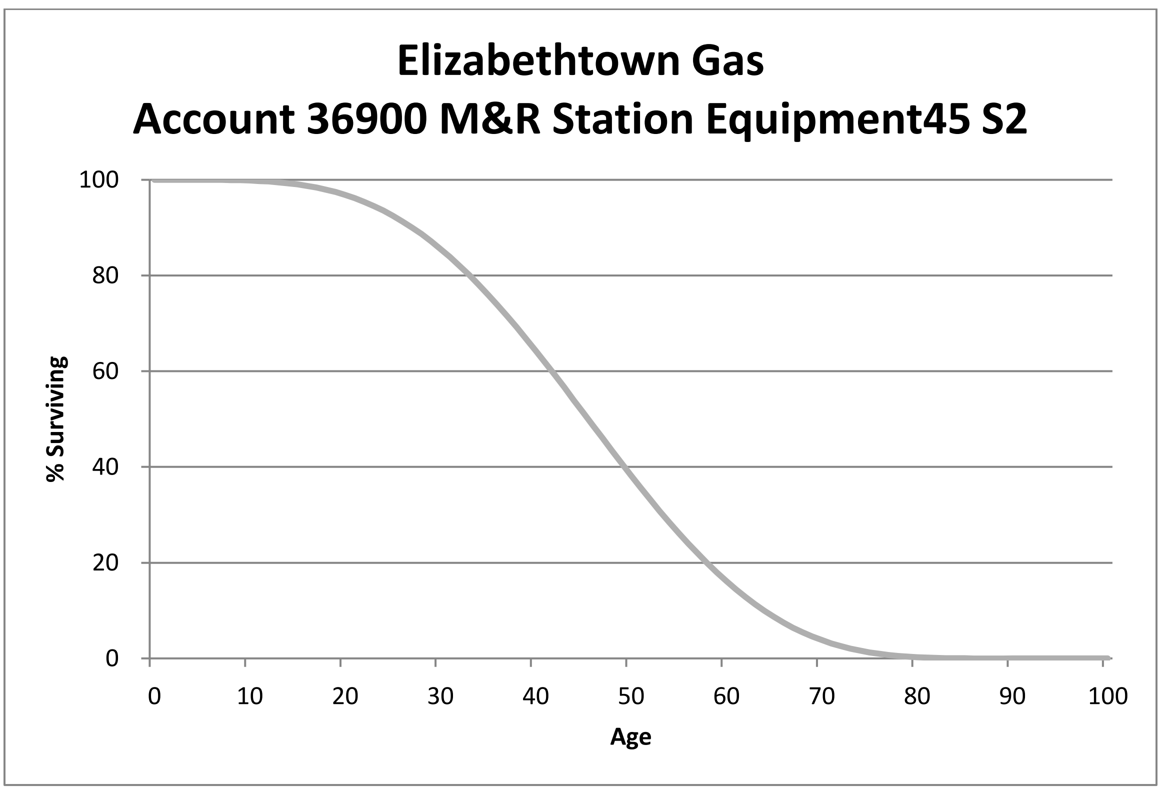


<u>FERC Account 369.00 M&R Station Equipment 45 S2</u>

This account includes measuring equipment, gauges, piping, and valves associated with the transmission system. There is approximately $8.6 million in this account. The approved life for this account is 45 S2. Only $8 thousand of the $8.6 million in assets has a vintage before 2008.

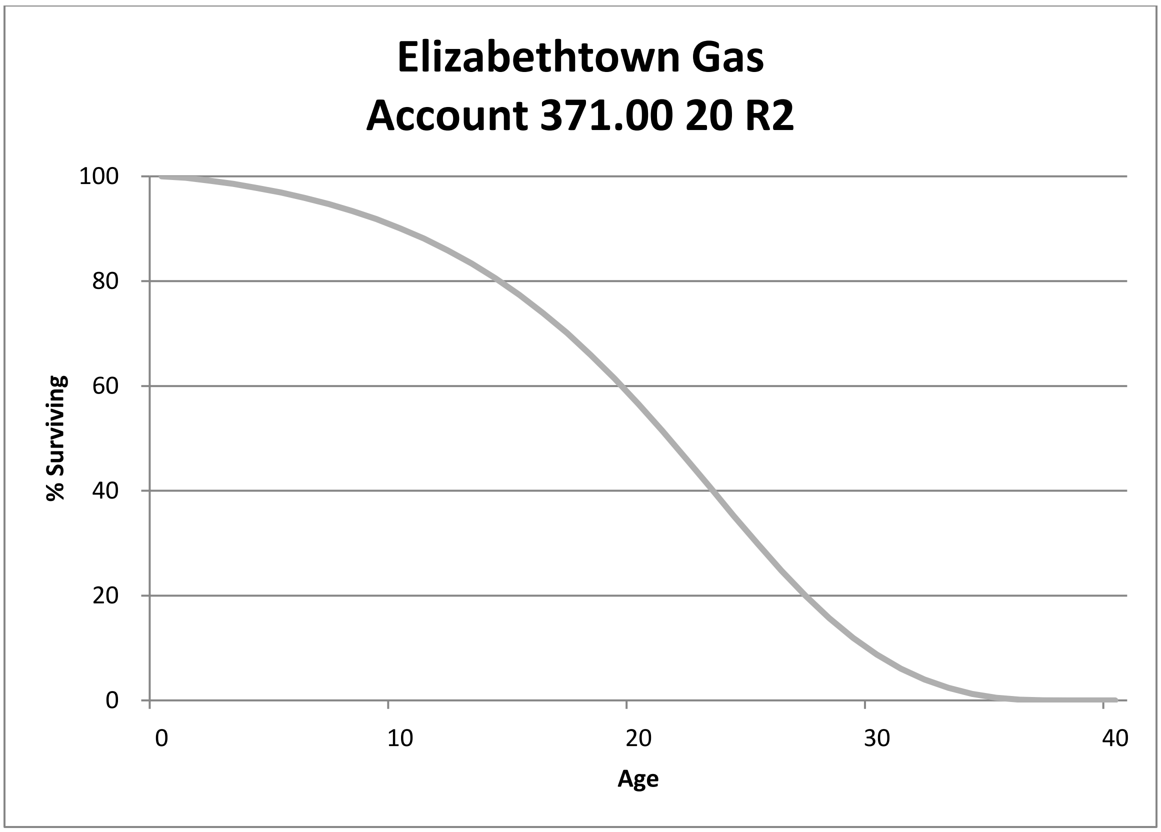
Discussions with Company personnel indicated there are two transmission stations, which connect the 3rd party take points to the Company's transmission system: Warren Glen and New Village. The Company has just started to replace SCADA equipment and electronics. The Company believes the operational characteristics of these stations are similar to assets in Account 379 City Gates and operationally, they would expect a similar life.

Overall, there has not been enough retirement activity for life analysis. Based on the type of assets and Company expectations, this Study recommends retaining a 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 4 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 20 R2. A representative graph of the life of the account is shown in the curve below.

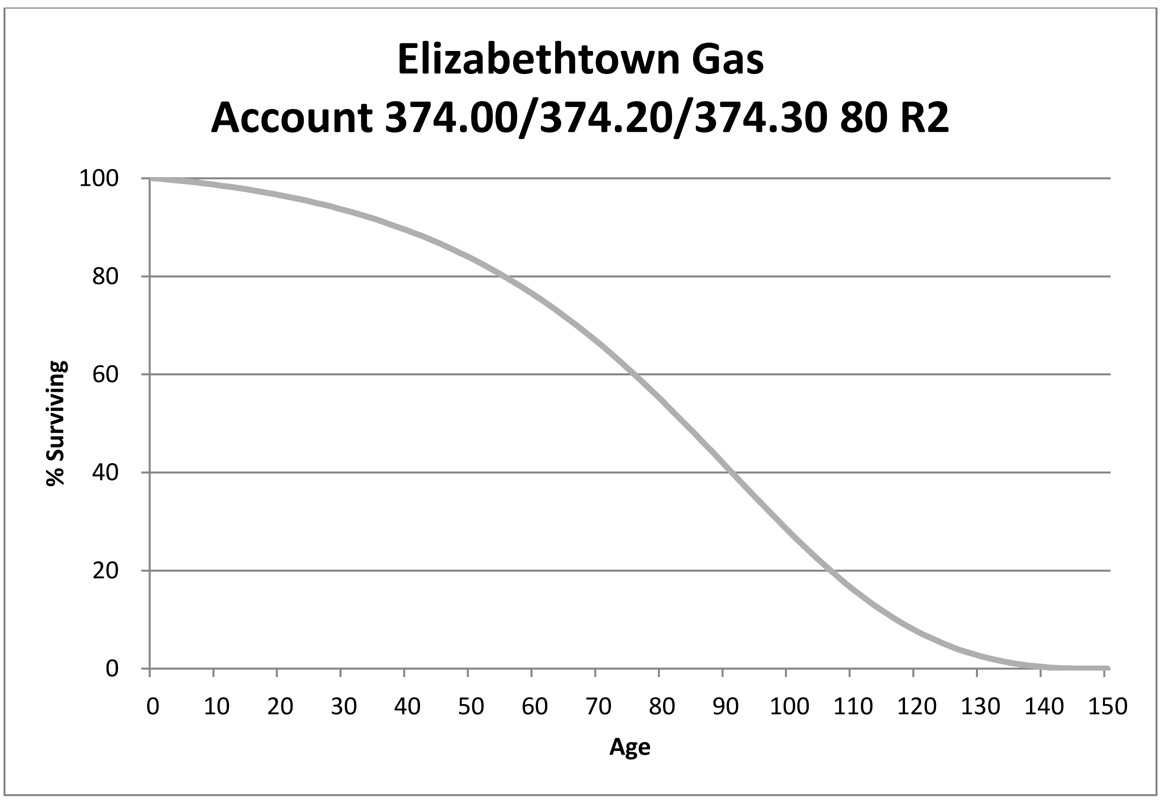


D. Distribution Plant

Distribution Plant Accounts, FERC Accounts 374.10–387.00

<u>FERC Account 374.00/374.20/374.30 Land Rights and Right of Way 80 R2</u>

These accounts include the cost of land rights used in connection with distribution operations. There is approximately $3 million in these accounts. The approved life for these accounts are 80 R2. There have been very limited retirements recorded and few are expected in intermediate 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.

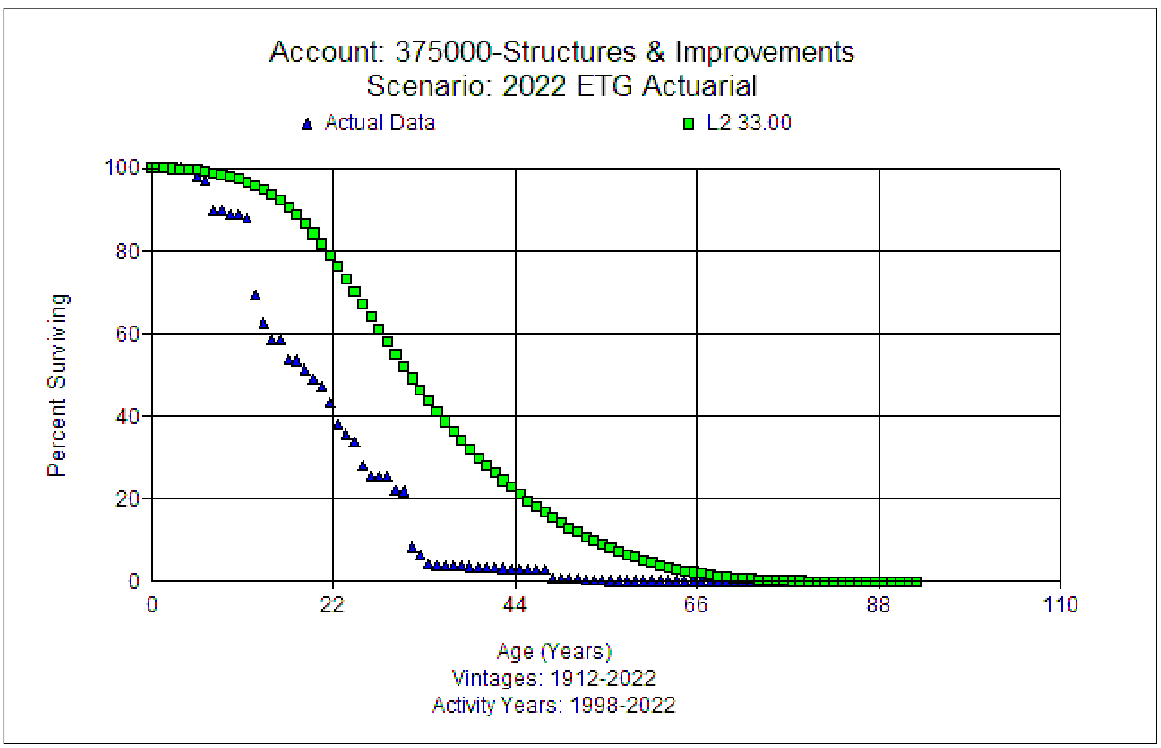


FERC Account 375.00 Structures and Improvements 33 L2

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 $6 million in this account. The approved life for this account is 33 L2. Currently there are no assets with a vintage older than 2001 and $5.1 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 L2 dispersion pattern. The observed life table versus the proposed is graphed for this account below.



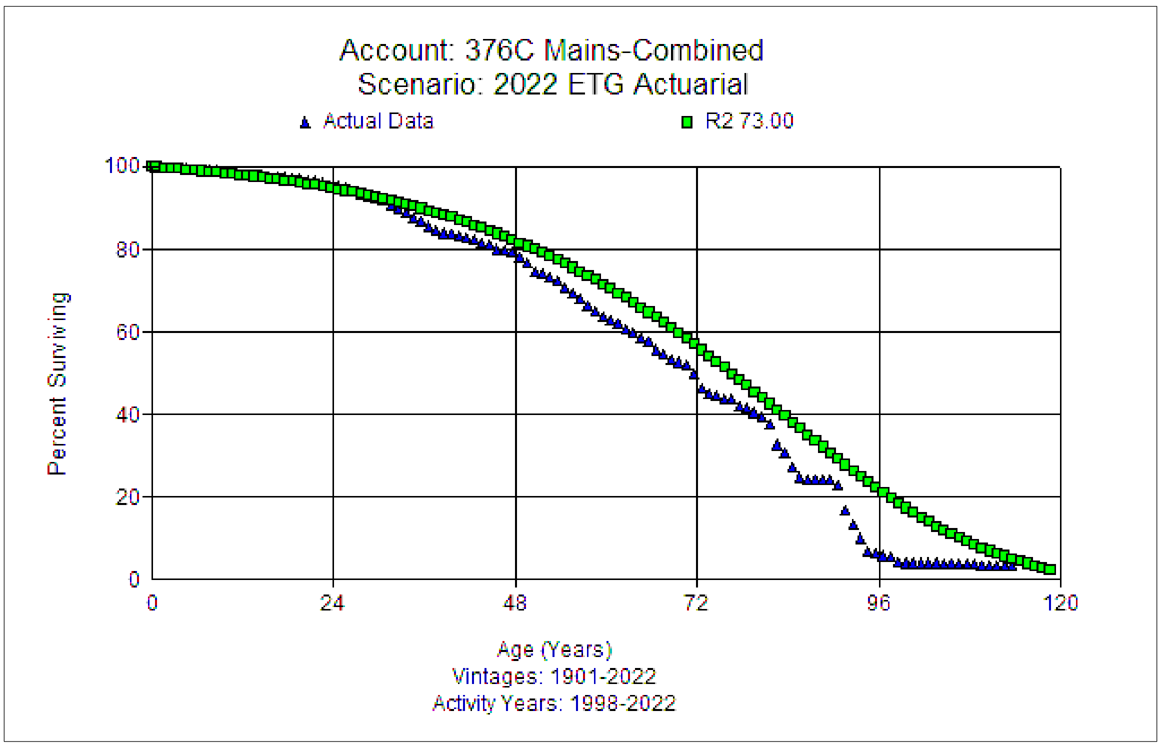
<u>FERC Account 376.00 Mains – All 73 R2</u>

This account consists of all distribution mains, which comprise cast iron, steel, and plastic. There is approximately $1 billion of investment in this account. The approved curve for this account is the 73 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 June 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 – Aldyl-A but there is not a lot of the early generation plastic on the system. Company personnel believe the current life of 73 years is operationally reasonable.

In the life analysis, the full band observed life table continues to indicate a lower life. The 67 R2 is a better fit than the approved 73 R2. A mid-placement band of 1953-2022, which drops to around 40 percent surviving has a great fit at 63 R2.5. 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 73 R2 in the full band, is a reasonably good fit considering all the information and drops to nearly zero percent, providing a full curve.

Based on the analysis, along with the Company's plans to finish replacing vintage pipe, as well as any early vintage plastic on the system, the Study recommends retention of 73 R2 at this time. The observed life table versus the proposed is graphed for this account below.



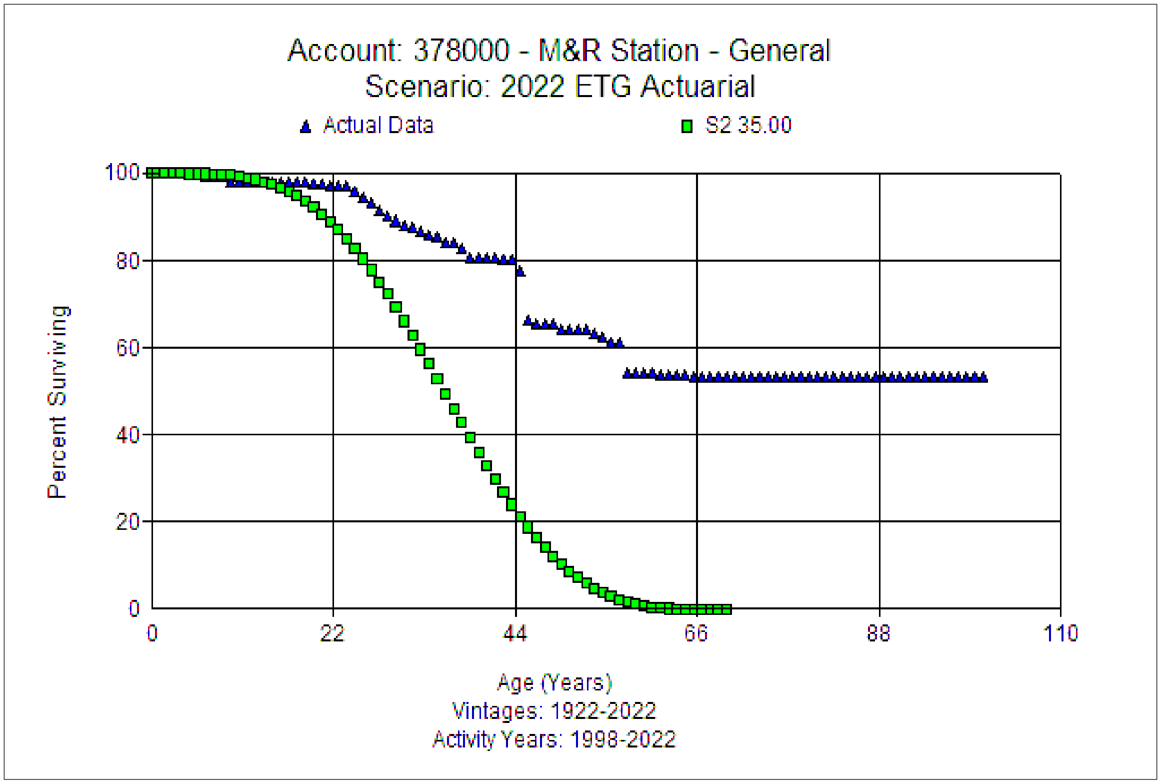
<u>FERC Account 378.00 Measuring & Regulating Equipment 35 S2</u>

This account consists primarily of valves, regulators, and heaters. There is approximately $19 million of investment in this account at December 31, 2022. The approved curve for this account is the 35 S2.

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 being on a low-pressure system. The Company indicated from 2020-2034 they have already retired 11, 10, 18 and 41 stations respectively. Once the low-pressure system is replaced, they will revert back to a traditional retirement through replacement of 3-5 stations per year.

A driver of retirements for DRS is due to capacity changes which can 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. 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 that operationally, an average life of 35 years for the DRS account is reasonable.

The life analysis indicates a very long life. Company information indicates a number of retirements have been recorded recently, as noted above. The current plans to continue replacing approximately 180 DRS due to low pressure systems would suggest not changing the life at this time. Understanding the life analysis and considering Company input and expectations, this Study recommends retention of the existing 35 S2 at this time. The observed life table versus the proposed is graphed for this account below.

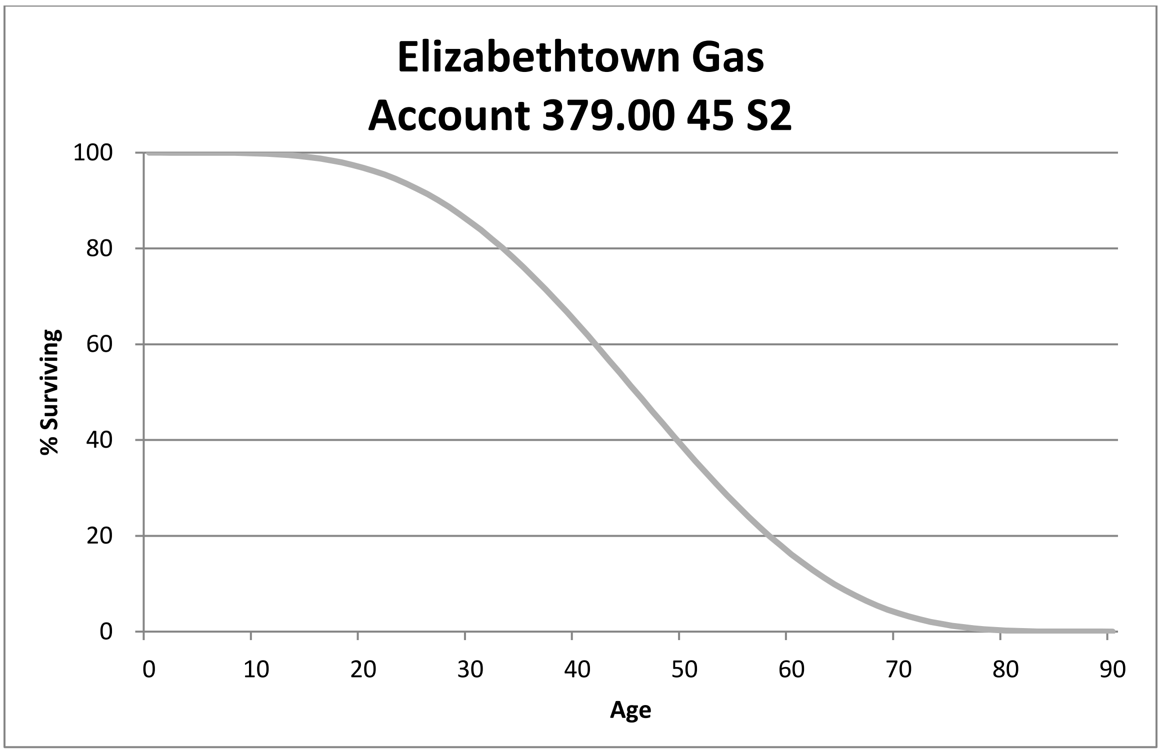


<u>FERC Account 379.00 M&R - City Gate Equipment 45 S2</u>

This account consists primarily of valves, regulators, and heaters used at receipt points on the distribution system. There is approximately $22 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, inspected more often, and mostly in buildings. 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 but there are other assets that would have a shorter life in many cases. Regulators may be changed with different flow rates. The Company believes the existing 45-year life is operationally reasonable.

No retirements have been recorded. The average age of the surviving balance is nearing 28 years. 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.

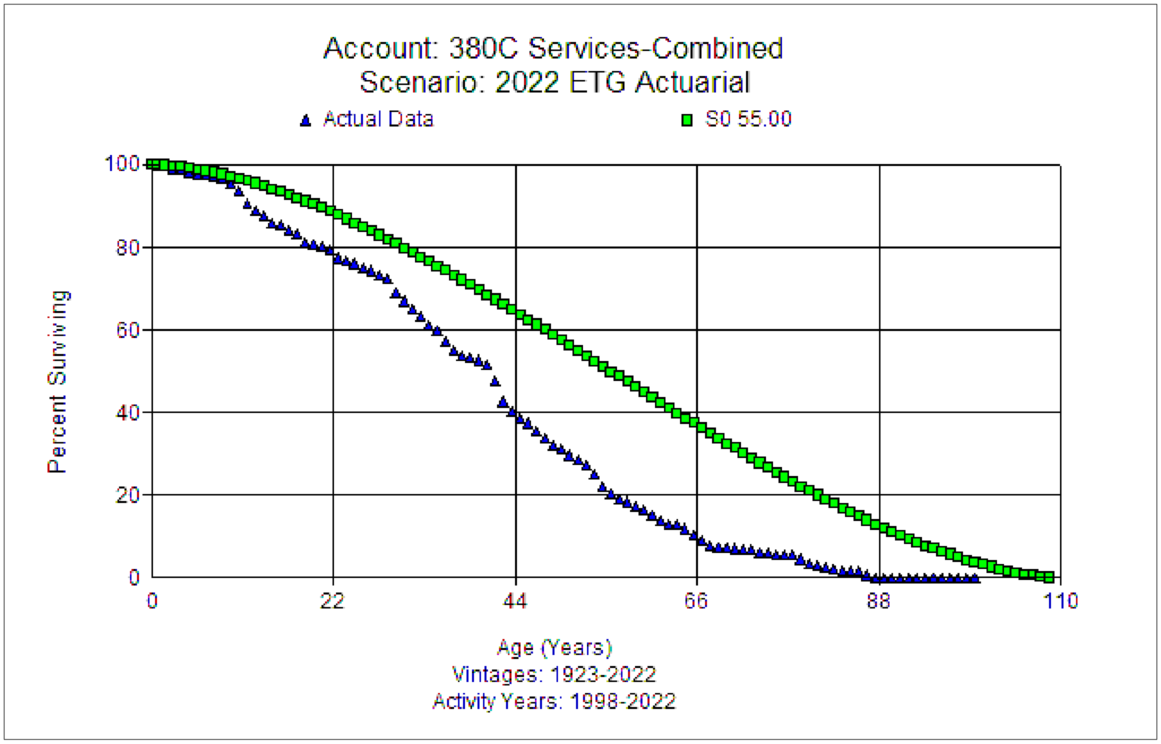


FERC Account 380.00 Services - All 55 S0

This account consists of steel, plastic, and some copper services. There is approximately $564.5 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 10 years.

Discussions with Company personnel indicated there are approximately 227 thousand services, with around 35 thousand services targeted in the proposed IIP 2 filing made in December 2023. BPU approval is not expected until mid to late 2024 and the number may be lower. 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. Moving the life incrementally down to 55 years would be operationally reasonable.

The analysis indicates a much shorter life than existing. In the full band 39 S0 is an excellent fit. In a more recent placement band (1973-2022), a 36 R1.5 is a good fit. As noted above, as the IIP is completed and older services are replaced with newer ones, the shorter life indication is expected to move back closer to a 50-60 year range. Factoring in IIP, the type of assets, the analysis, and Company expectations, this Study proposes moving to a 55 S0 dispersion pattern at this time. The observed life table versus the proposed is graphed for this account below.



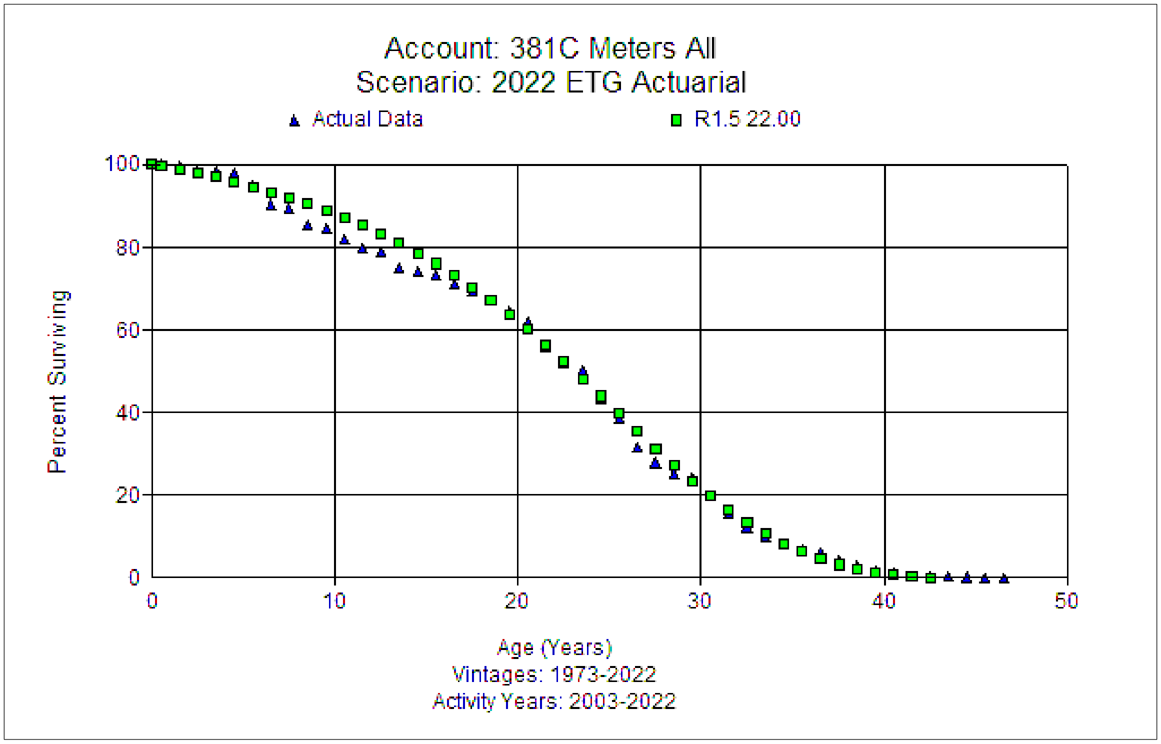
Account: 380C Services-Combined
Scenario: 2022 ETG Actuarial
Actual Data
S0 55.00
Percent Surviving
100
80
60
40
20
0
0
22
44
66
88
110
Age (Years)
Vintages: 1923-2022
Activity Years: 1998-2022

FERC Account 381.00 Meters – All 22 R1.5

This account includes the cost of meters and related equipment used in measuring gas to customers. The current investment is approximately $116 million. The approved curve for this account is the 23 R1. The Company currently uses Itron ERTs (100G).

Discussions with Company personnel indicated that the Company is using 100G and is 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 15-20 year life on the ERTs based on the battery life. 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 more operationally reasonable due to the practice of changing meters with ERTs.

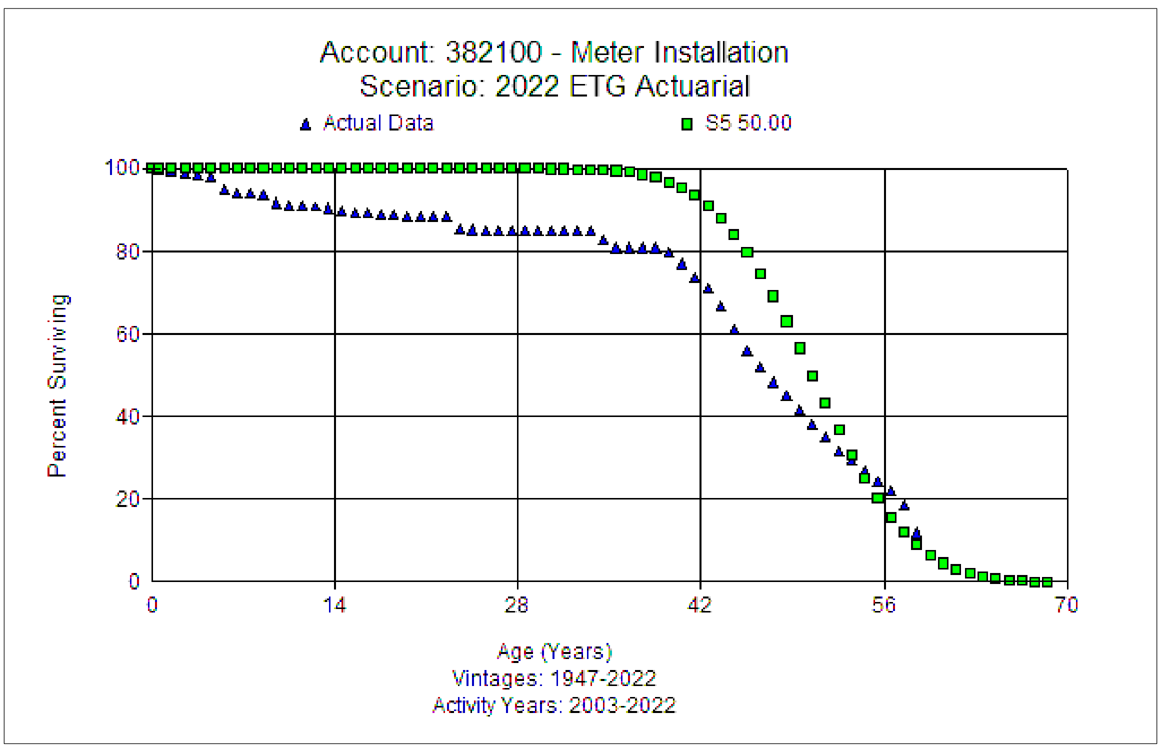
The life analysis supports the Company's expectations of a shorter life. This is not surprising with the move to more technological assets and the life of the batteries associated with these assets. Indications across the bands indicate best fits to be 21-22 years with generally R1 or R1.5 dispersions. These support a decrease from the existing 28 year life and a slightly different dispersion pattern. This Study recommends decreasing the life to 22 years and moving to the R1.5 dispersion pattern. The observed life table versus the proposed is graphed for this account below.


Account: 381C Meters All
Scenario: 2022 ETG Actuarial
Actual Data
R1.5 22.00
Percent Surviving
100
80
60
40
20
0
0
10
20
30
40
50
Age (Years)
Vintages: 1973-2022
Activity Years: 2003-2022

FERC Account 382.10 Meter Installations 50 S5

This account includes the cost of installation of meters. There is approximately $68.7 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. The analysis does provide best fits across the bands with different lives and dispersion patterns. However, based on the analysis and Company input, this Study recommends retention of the 50 S5 at this time. The observed life table versus the proposed is graphed for this account below.

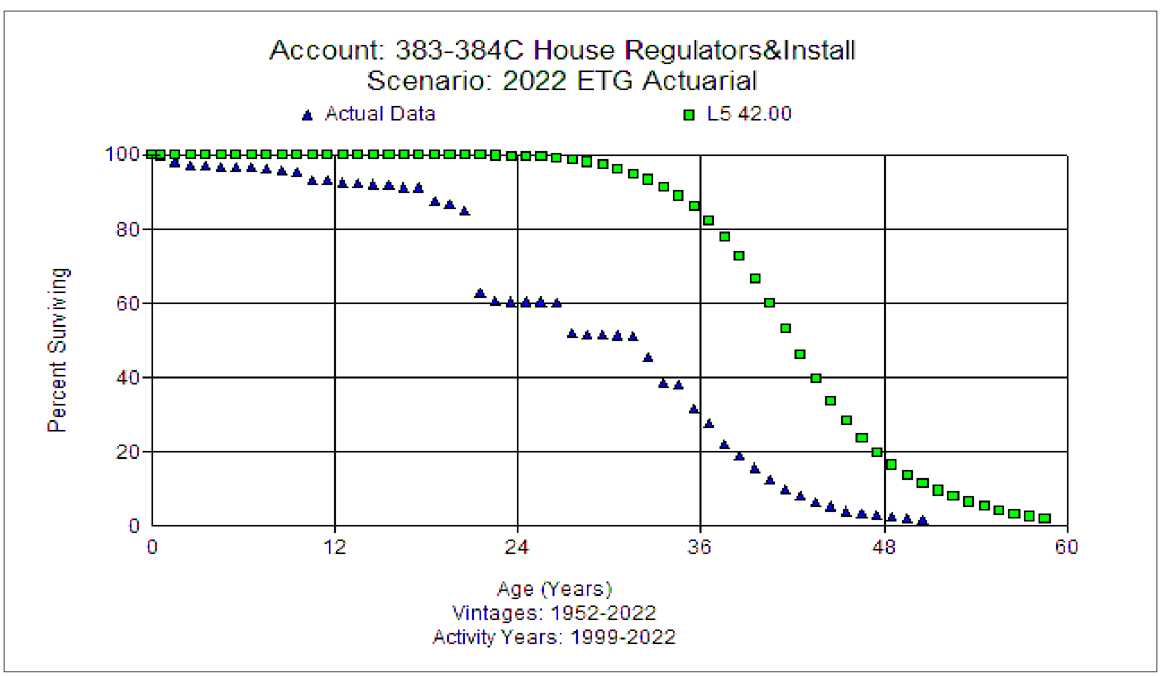


FERC Account 383.00 House Regulators 42 L5

This account includes the cost of house regulators. There is approximately $9.8 million of investment in this account. 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 combined analysis is consistently fitting a life below the existing. Some of this could be attributed to the IIP activity. The Company believes Accounts 383-384 would have a shorter operational life than Account 382. A much shorter life than reasonable is suggested by the analysis. Although a shorter life is suggested by the analysis, based on Company input and the characteristics of assets in this combined account, this Study recommends retention of the 42 L5 at this time. The observed life table versus the proposed is graphed for this account below.

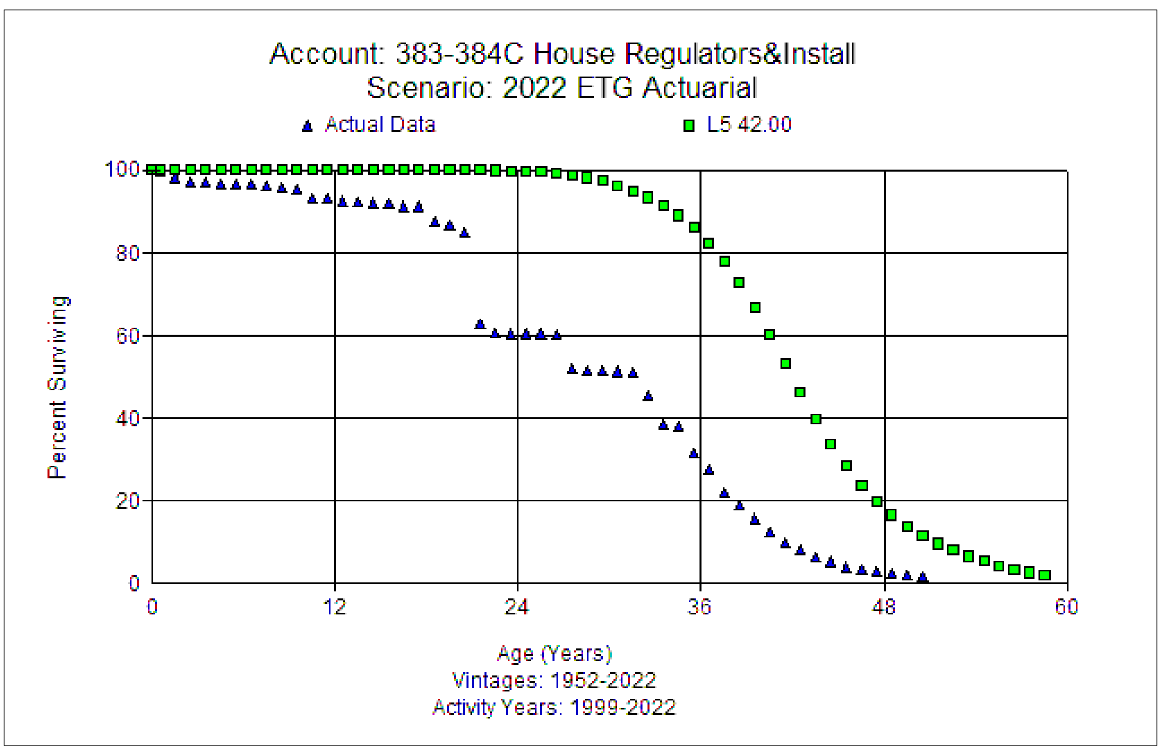


<u>FERC Account 384.00 House Regulator Installations (42 L5)</u>

This account includes the cost of installing house regulating equipment. The current balance is $2.8 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 combined analysis is consistently fitting a life below the existing. Some of this could be attributed to the IIP activity. The Company believes Accounts 383-384 would have a shorter operational life than Account 382. A much shorter life than reasonable is suggested by the analysis. Although a shorter life is suggested by the analysis, based on Company input and the characteristics of assets in this combined account, this Study recommends retention of the 42 L5 at this time. The observed life table versus the proposed is graphed for this account below.

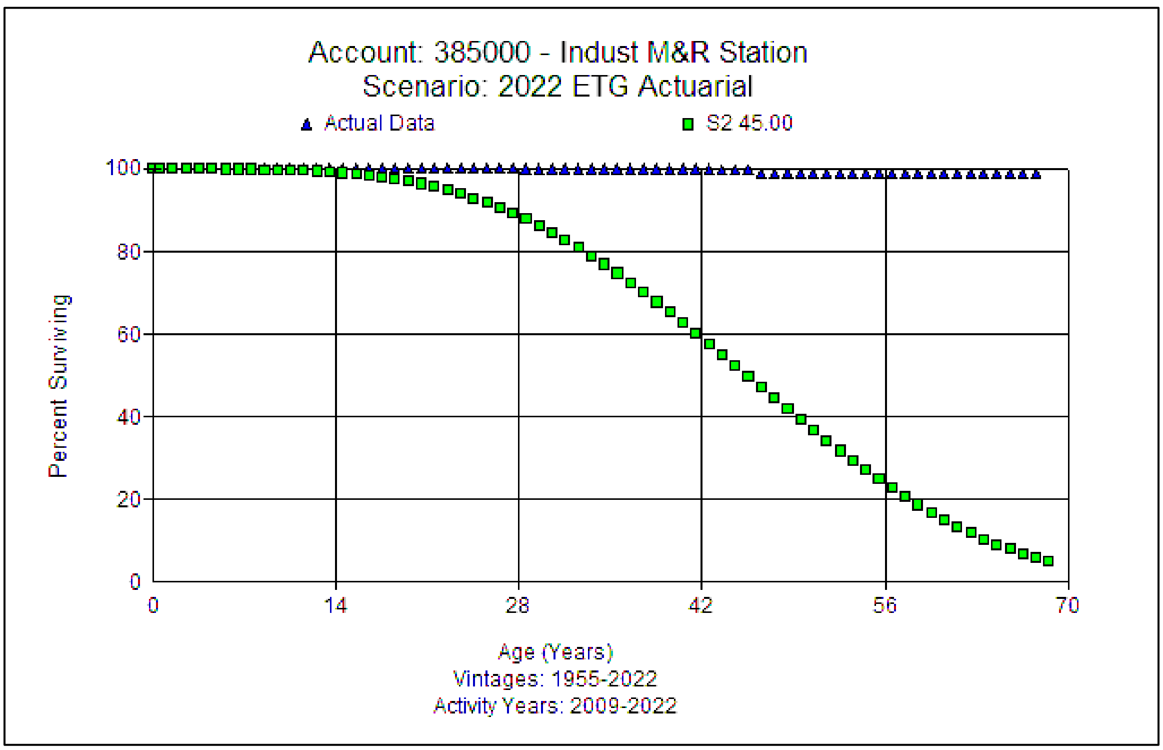


<u>FERC Account 385.00 Industrial Meter & Regulator Equipment (45 S2)</u>

This account includes the cost of measuring and regulating equipment used in industrial stations. The current balance is $15.9 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 27 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.

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 recommends retaining a 45-year life with an S2 dispersion. The observed life table versus the proposed is graphed for this account below.

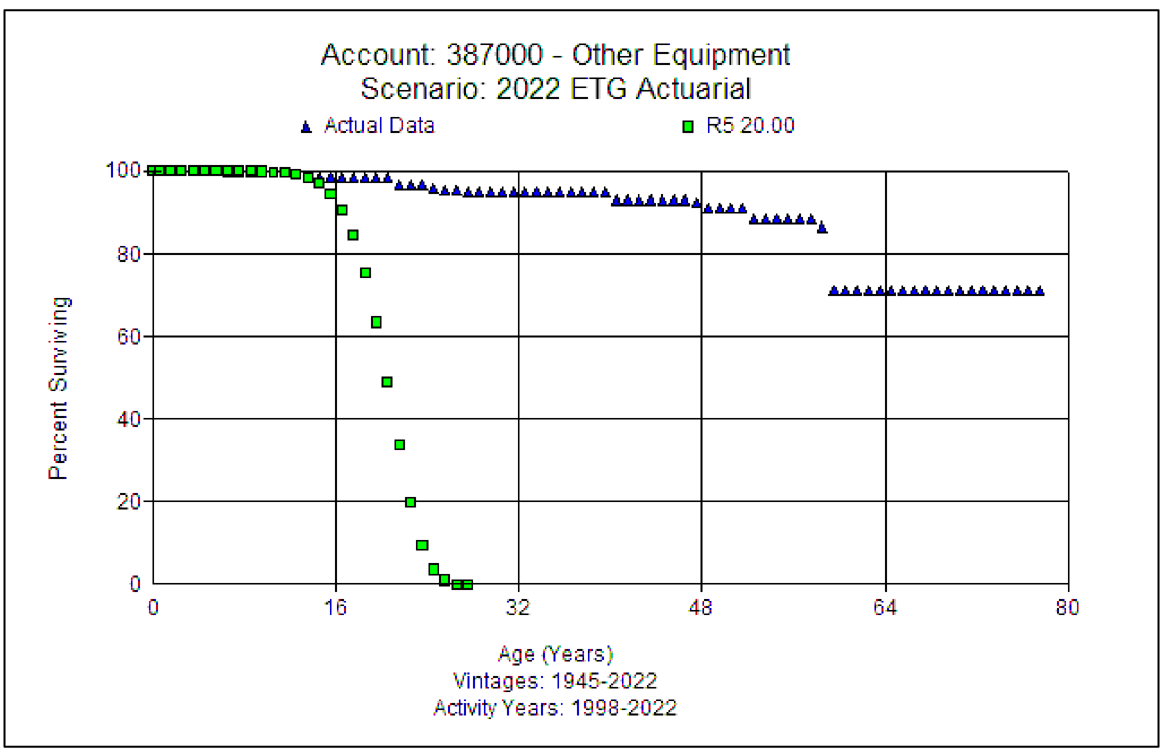


<u>FERC Account 387.00 Other Equipment (20 R5)</u>

This account includes the cost of equipment used in conjunction with providing distribution service. The current balance is $3.9 million. The approved life is a 20 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 16 years, and the average age of retirements is around 20 years. Many of the assets recorded here are now electronic in nature and would not be expected to have a life much longer than existing.

The analysis in the full band produces a good fit with 67 R45, but the OLT only drops to 71% (demonstrating a lack of statistical validity) and the life 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, this Study proposes retaining the life of 20 years and 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

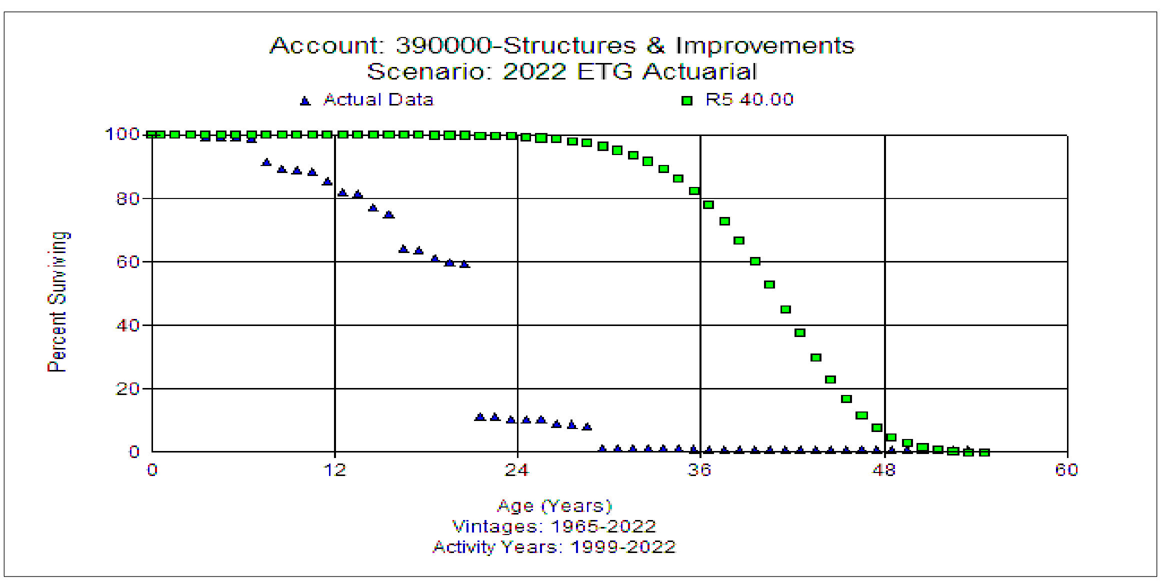
GENERAL PLANT DEPRECIATED

<u>FERC Account 390.00 Structures & Improvements (40 R5)</u>

This account generally includes the cost of structures and improvements used for utility service. Currently, there is about $26.1 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. Green Lane is now Elizabethtown's headquarters. At New Village, they have had two material projects this year. In Layfette, they were leasing a building but in 2022-2023 they purchased land and built a divisional building. Overall, there have been a number of renovations and new additions. The Company believes a 40-year life is operationally reasonable.

The life analysis fits indicate a life range of 10-20 years, which is not rational for the structures (although it may be reasonable for some of the smaller short-lived assets in the account). Based on the type of 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 Enterprise Systems 10 SQ

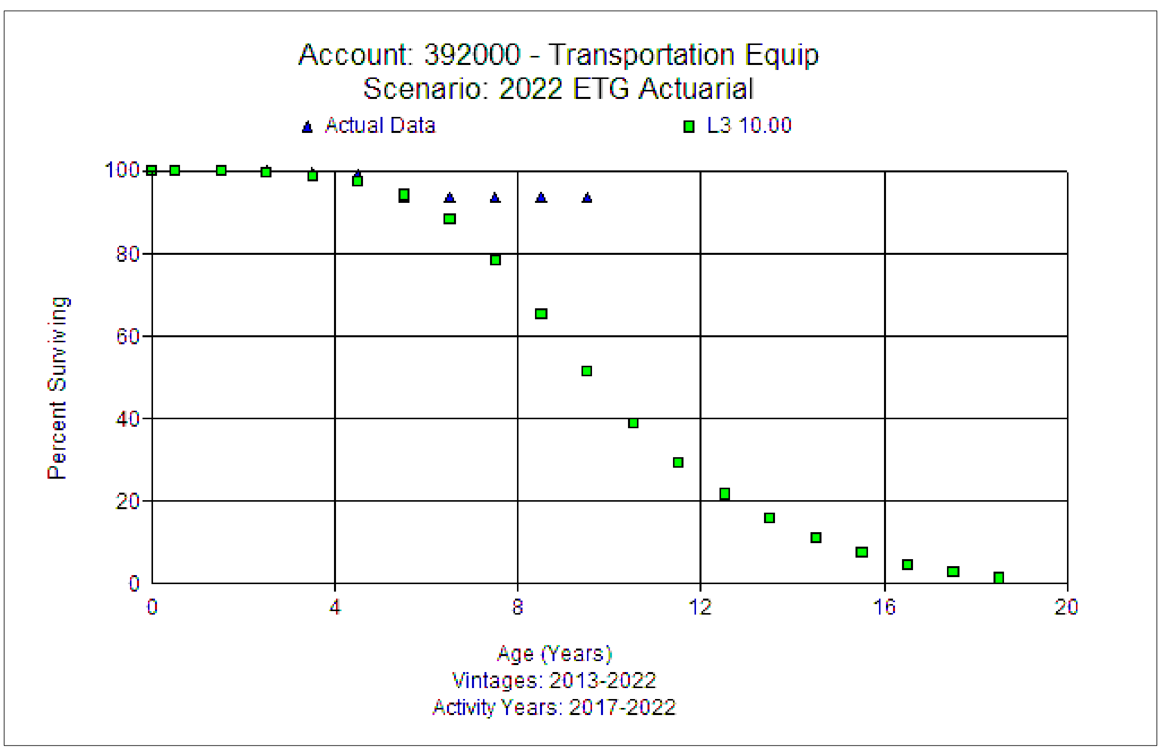
This account consists of large enterprise software systems used for general utility service. There is approximately $107.1 million in this account. The existing parameter is 10 SQ. Discussions with Company personnel indicated they moved to their own systems in 2020, which included 34 different systems. The large platform systems, like Oracle would retain a 10 year life. However, there is some expectation that technology and the Cloud could shorten the life to as low as 7 years. Based upon those discussions five new accounts will be established to reflect the changing needs of computer hardware and software, smaller application software and large enterprise systems and upgrades. For now, based on Company input and judgment, this Study recommends retaining the 10 SQ for this account, which is a depreciable, not amortized, asset at this time. No graph is provided.

FERC Account 392.00 Transportation Equipment 10 L3

This account consists of converted record and a mix of vehicles. used with transportation equipment in performing various distribution and general company operations. The life parameter is 10 L3. There is approximately $4.7 million in this account. There have some retirements and all assets have been added since 2013 and the average age of the investment is 4 years.

Discussions with Company personnel indicated they have a “new fleet” policy, which means they replace quicker to maintain a reliable fleet. However, in the current market with supply chain issues this approach is not always feasible. 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 retaining the existing 10 L3. The observed life table versus the proposed is graphed below for this account.

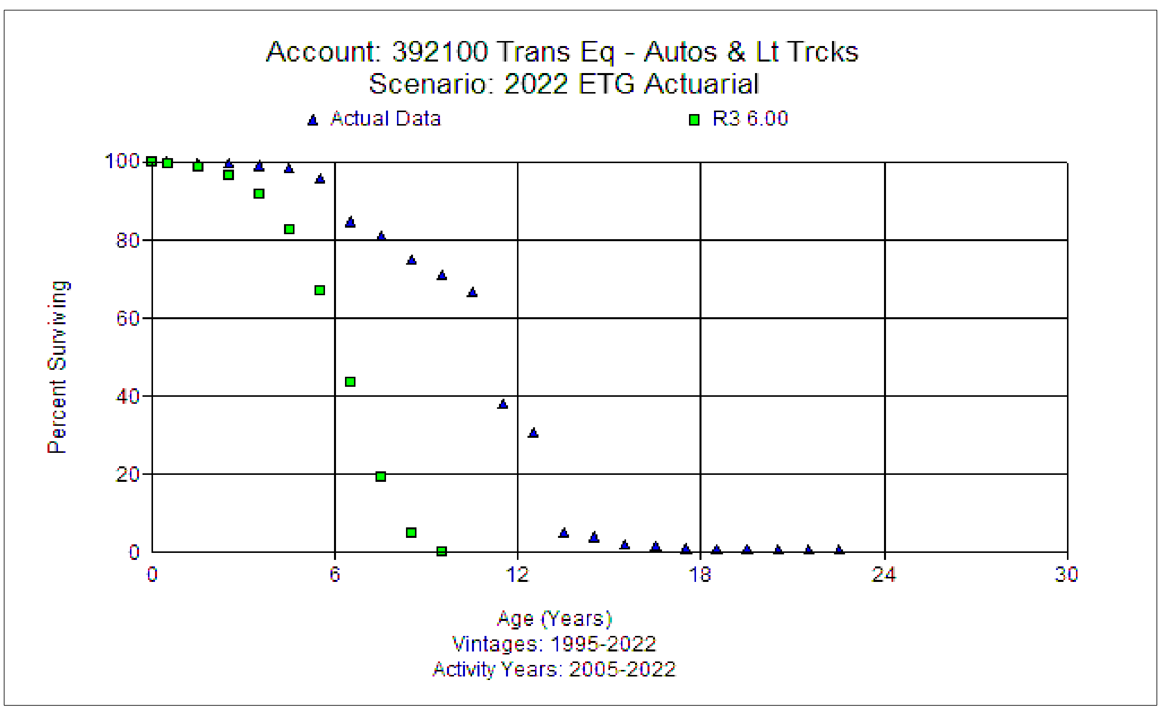


FERC Account 392.10 Autos & Light Trucks 6 R3

This account consists of autos and light duty trucks, meter reading trucks, and other related equipment used in performing various distribution and general company operations. The approved curve for this account is the 6 R3. There is approximately $4.6 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. 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. Additionally, there has been supply chain issues on getting new equipment.

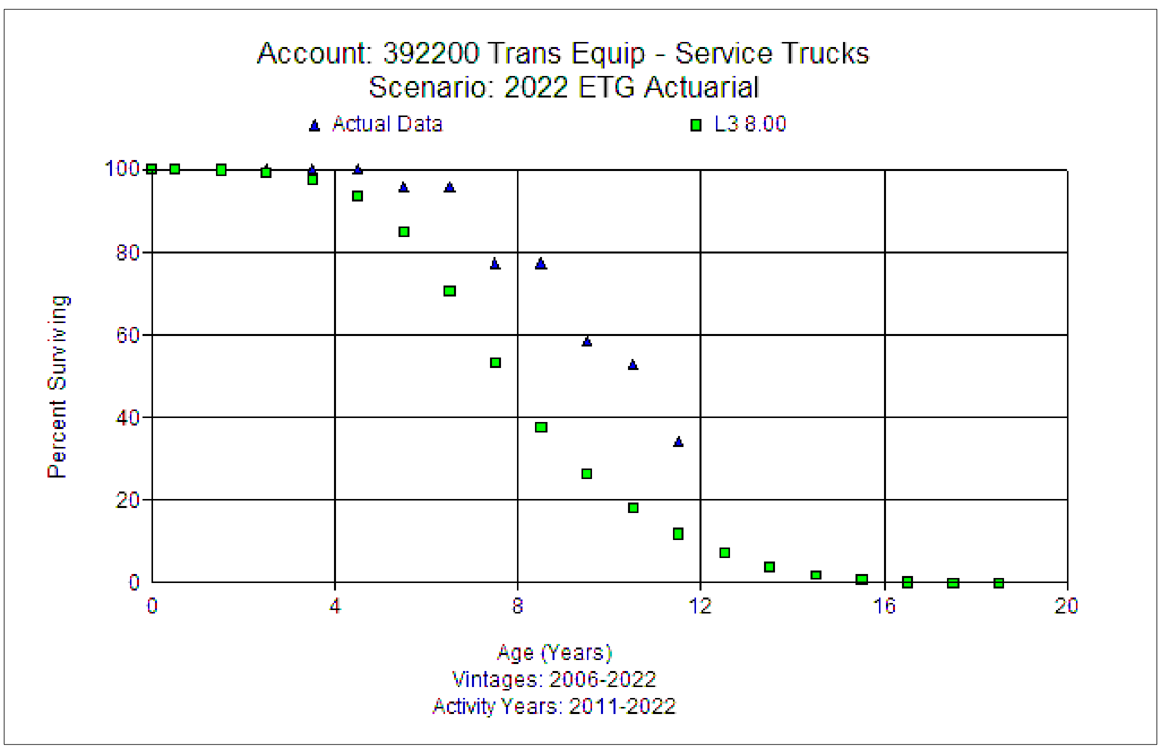
The analysis does indicate a longer life than what Company expectations are for this type of vehicles. The best fits across the bands analyzed are 8-11 years. However, considering past delays, Company policy and expectations, type of assets and use, the Study recommends retaining the life of 6 R3 curve. 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 $2.4 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 a life of 10 years, which is consistent with the other transportation accounts exhibiting a longer life due to supply chain issues. The Study recommendation is to retain the approved 8 L3. The observed life table versus the proposed is graphed for this account below.

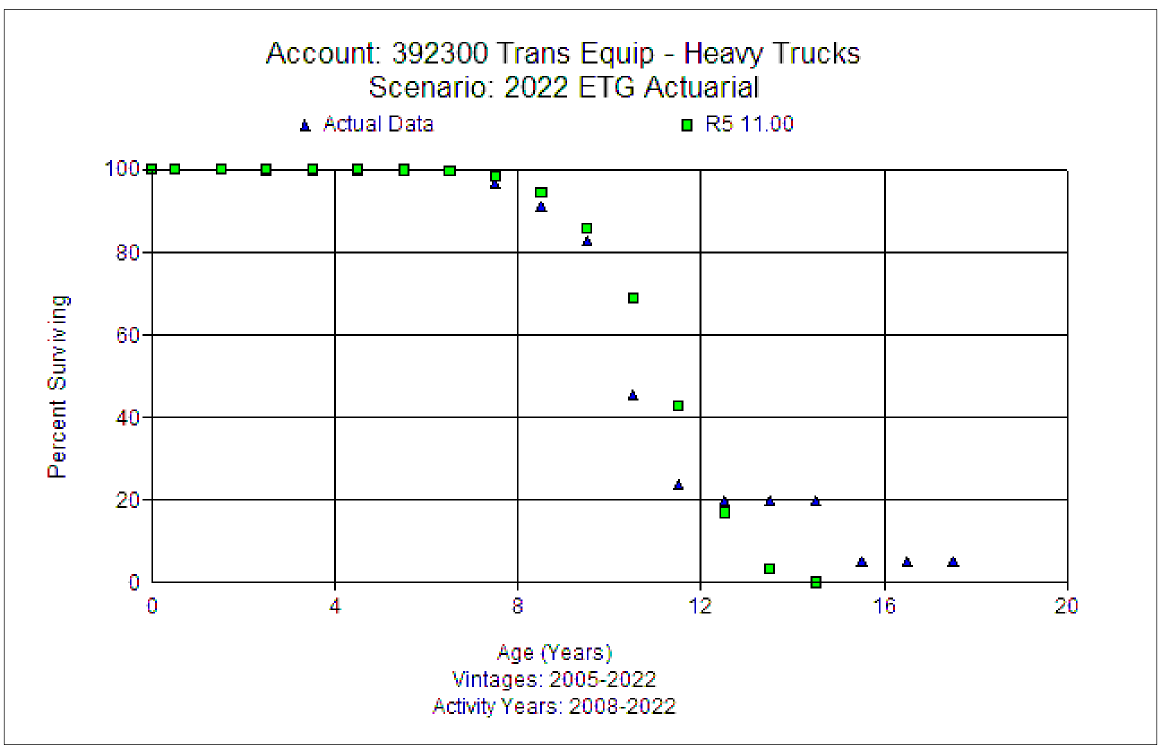


FERC Account 392.30 Heavy Trucks 11 R5

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 11 R5. There is approximately $5.3 million in this account.

The current average age of surviving assets is nearly 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 and recent supply chain issues. For this particular class they expect a life between 10-12 years.

The life analysis indications show a good fit with an 11-year R5 dispersion pattern. This supports the Company's life cycle target replacement and "new fleet" policy. Based on the type of assets, expected use, the target range for replacement, and judgment, the Study recommendation is to retain the 11 R5. The observed life table versus the proposed is graphed for this account below.

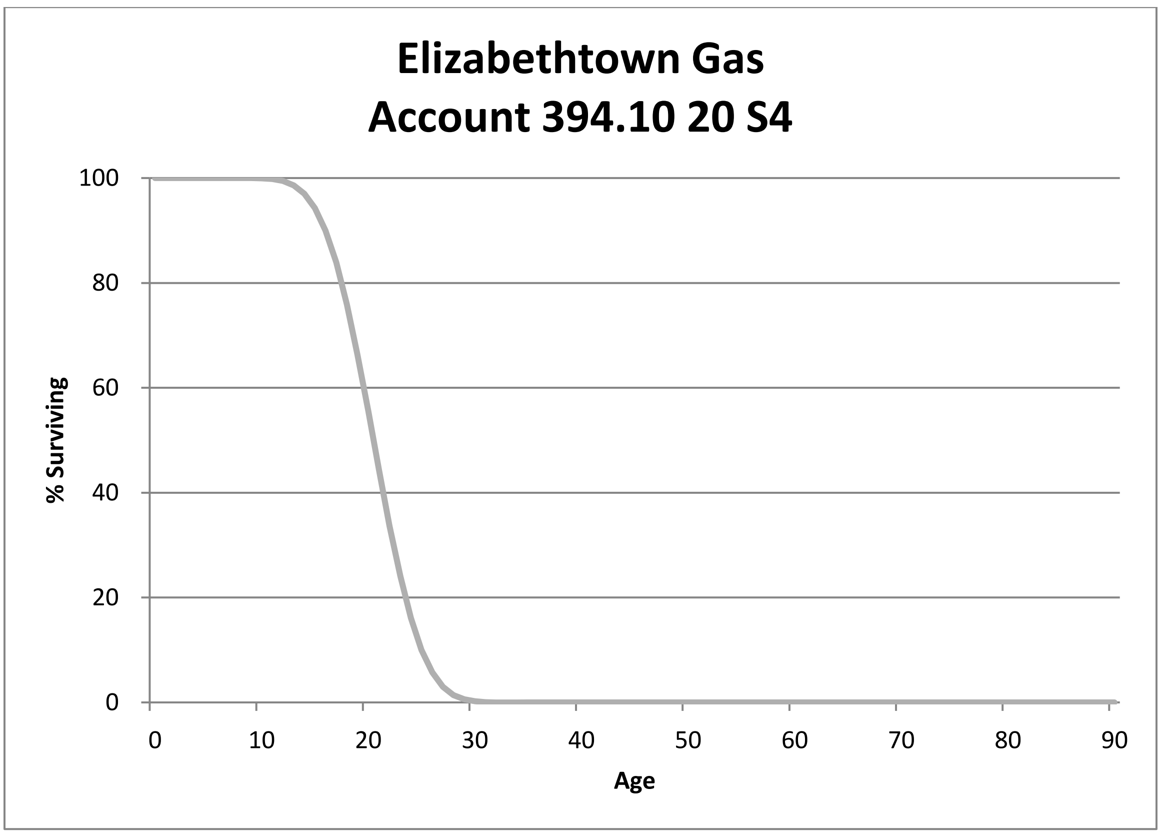


FERC Account 394.10 Natural Gas Vehicle Stations 20 S4

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, compressors have around a 20 year life, and the tanks would have a longer life than 20 years. Some of the electrical would be replaced sooner than 20 years, but overall, 20 years remains operationally reasonable.

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.

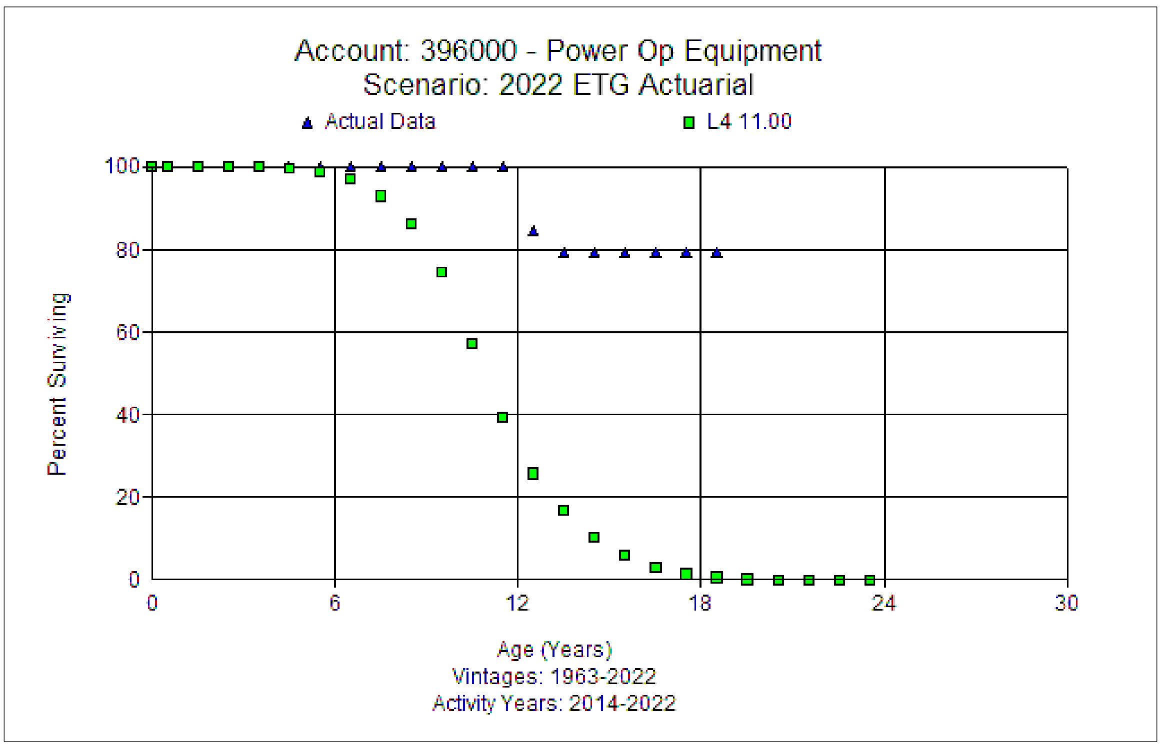


FERC Account 396.00 Power Operated Equipment 11 L4

This account consists primarily of forklifts, backhoes, and other miscellaneous equipment. The existing life parameter is 11 L4. There is approximately $1.9 million in this account.

Discussions with Company personnel indicated a life between 8-10 years for a backhoe and around 10-12 years for generators is reasonable. The supply chain also impacts the lives of these assets as well.

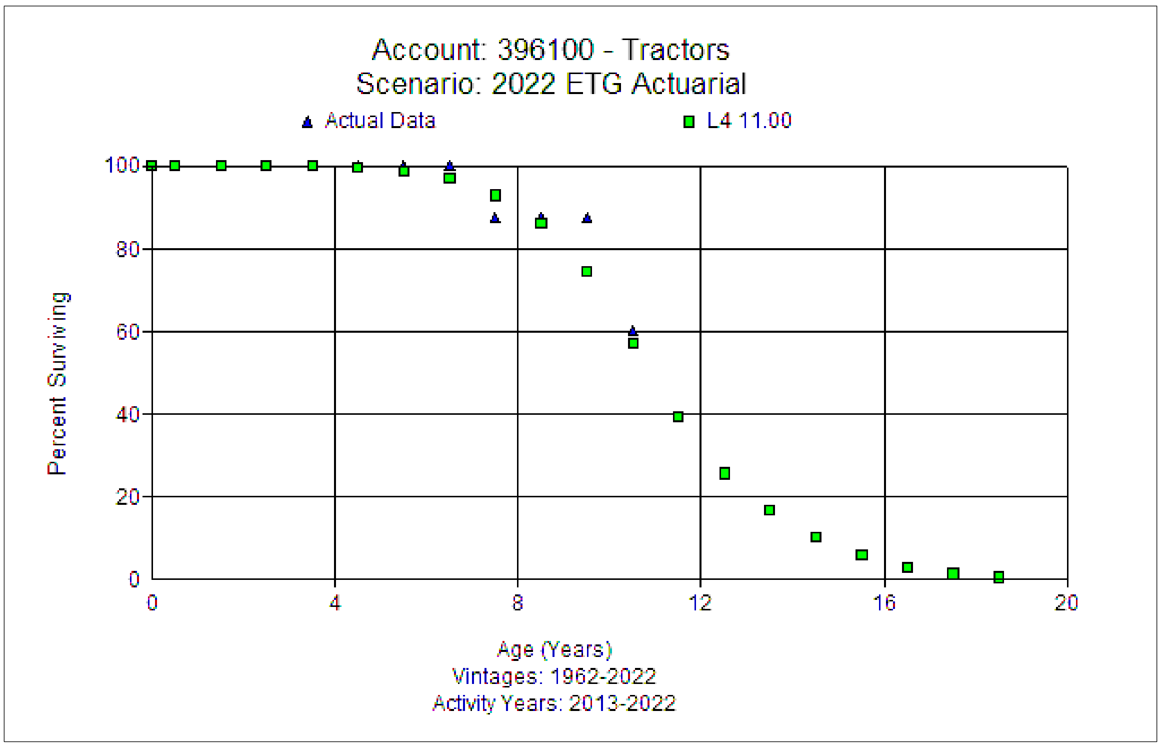
Based on type of assets, the analysis indications, and Company expectations, this Study recommends retaining the existing 11 L4. The observed life table versus the proposed is graphed for this account below.



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 11 L4. There is approximately $2.2 million in this account.

The life analysis indicates a good fit with the existing 11 L4. Based on type of assets, analysis indications, and Company expectations, this Study recommends retaining the 11 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.

<u>FERC Account 391.00 Office Furniture and Equipment 20 SQ</u>

This account consists of office furniture and equipment used for general utility service. There is approximately $957 thousand in this account. The approved curve for this account is the 20 SQ and is retained.

<u>FERC Account 391.10 Computer Equipment 5 SQ</u>

This account consists of personal computer ("PC") equipment, printers, and peripherals used for general utility service. There is approximately $5.1 million in this account. The approved curve for this account is the 5 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 but can get delayed at times. This Study recommends retaining 5 SQ and amortization accounting.

<u>FERC Account 391.11 Computer Equipment and Software 5 SQ</u>

This account consists of personal computer software used for general utility service. There is approximately $4.7 million in this account. The existing parameter is 5 SQ. Discussions with Company personnel indicated the refresh cycle for this group is similar to Account 391.10 above. Target refresh cycle for PC/Laptop equipment and software is closer to 4 years but can get delayed at times. Based on judgment, this Study recommends retaining the 5 SQ and 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 $3.5 million in this account. The existing parameter is 6 SQ. Discussions with Company personnel indicated the lifecycle of servers is between 5-7 years. Based on judgment, this Study recommends retention of 6 SQ and amortization accounting.

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 15 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 $542 million in this account. The approved life and curve for this account is 18 SQ. Based on discussions with Company personnel, many of these assets are now electronic in nature and will not last beyond 15 years. This Study recommends moving to a 15 SQ and retaining amortization accounting.

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 and amortization accounting is retained if future additions are recorded.

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 $4.2 million in this account. The approved life and curve are a 10 SQ. The Company believes that 10 years is long. Some assets would have a longer life than network type equipment. They refreshed the system after the purchase from Southern. Network equipment is expected to have a life of 7 years. Most of the routers put in service in 2018 are now being upgraded to enhance the resiliency of the system. Cellular equipment will likely be retired with the upgrade in 2020 from 3G to 4G. Technology is a big driver and forces accelerated changes in electronic assets in the account. However, for now, this Study recommends retention of the 10 SQ and amortization accounting.

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 $1.9 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 (2022) would have had an installed cost of $11.53 in 1949[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 434 percent removal cost for that asset ($50/$11.53). 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

4 Using the Handy-Whitman Bulletin No. 198, G-1, line 44, $11.53 = $500 x 30/1301.

analyzed over periods varying from one to 10 years. These calculations are found 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. GR21121254 was a 3-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 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 (0 percent)

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.

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. 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 $21,163. This Study recommends adding $1,145 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 $33,475. This Study recommends adding $22,471 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 negative net salvage amount is $2,659,609. This Study recommends adding $2,685,106 to the annual accrual for negative net salvage (3 year cost of removal expenditures are $2,782,856) 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 $65,124. This Study recommends adding $21,276 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 $12,255. This Study recommends adding $27,934 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 $5,903,383. This Study recommends adding $4,483,483 to the annual accrual for negative net salvage (3 year cost of removal expenditures are $4,537,571) 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 $31,881. This Study recommends adding $30,744 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 net salvage amount is $0. This Study recommends adding $18,406 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 negative net salvage is $112. 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 negative net salvage is $83,939. This Study recommends adding $61,995 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 $183. This Study recommends an amount of $78,178, 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 $41,919. This Study recommends an amount of $39,443, 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 $13,616. This Study recommends an amount of $3,000, 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 $11,150. This Study recommends an amount of $8,971, 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.

FERC Account 396.10 Power Operated - Tractors

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 zero. This Study does not reflect any net salvage amount for this account.

GENERAL PLANT AMORTIZED

FERC Account 391.00 Office Furniture and Equipment

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.

FERC Account 391.10 Computer Equipment

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.

FERC Account 391.11 Computer Equipment and Software

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 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. This Study does not reflect any net salvage amount for this account.

APPENDIX A - Depreciation Rate Calculations

ELIZABETHTOWN GAS
COMPUTATION OF DEPRECIATION ACCRUAL RATE
AT DECEMBER 31, 2022

Account	Description	Plant In Service 12/31/2022	Book Depreciation 12/31/2022	Net Salvage %	Gross Salvage Amount	Unaccrued Balance	Remaining Life	Life Accrual Amount	Life Accrual Rate	3-Year COR Accrual Amount	COR Rate	Total (Life and COR) Accrual Amount	Total (Life and COR) Accrual Rate
	PRODUCTION PLANT												
304.2	Land Rights	61,423	33,825	0%		27,598	10.24	2,696	4.39%	0		2,696	4.39%
	Total Production	**61,423**	**33,825**			**27,598**		**2,696**	**4.39%**	**0**		**2,696**	**4.39%**
	STORAGE PLANT												
361.00	Structures & Improvements	6,280,274	806,626	0%		5,473,648	40.74	134,344	2.14%	0		134,344	2.14%
362.00	Gas Holders - Natural Gas	378,876	114,551	0%		264,324	67.50	3,916	1.03%	0		3,916	1.03%
362.10	Gas Holders - LNG	3,237,323	2,657,922	0%		579,401	26.64	21,752	0.67%	0		21,752	0.67%
363.10	Liquefaction Equipment	50,305,489	676,609	0%		49,628,880	34.50	1,438,518	2.86%	0		1,438,518	2.86%
363.20	Vaporization Equipment	6,394,121	2,096,194	0%		4,297,927	29.82	144,124	2.25%	0		144,124	2.25%
363.40	M&R Equipment	3,016,952	1,158,583	0%		1,858,368	18.15	102,393	3.39%	0		102,393	3.39%
	Total Storage	**69,613,034**	**7,510,485**			**62,102,549**		**1,845,047**	**2.65%**	**0**		**1,845,047**	**2.65%**
	TRANSMISSION PLANT												
365.20	Rights Of Way	367,325	8,222	0%	0	359,103	42.55	8,439	2.30%	0		8,439	2.30%
367.00	Mains - All	15,621,398	131,709	0%	0	15,489,690	65.75	235,586	1.51%	1,145	0.01%	236,730	1.52%
369.00	M&R Equipment	8,598,040	121,921	0%	0	8,476,119	38.34	221,094	2.57%	22,471	0.26%	243,565	2.83%
371.00	Other Equipment	56,010	1,345	0%	0	54,665	16.47	3,319	5.93%	0		3,319	5.93%
	Total Transmission	**24,642,773**	**263,196**			**24,379,577**		**468,438**	**1.90%**	**23,615**		**492,053**	**2.00%**
	DISTRIBUTION PLANT												
374.00	Land Right and Rights of Way (All)	2,958,294	794,359	0%	0	2,163,935	58.80	36,800	1.24%	0		36,800	1.24%
375.00	Structures & Improvements	5,966,851	1,085,170	0%	0	4,881,681	27.31	178,758	3.00%	0		178,758	3.00%
376.00	Mains - All	1,019,557,004	150,848,692	0%	97,750	868,610,562	62.30	13,943,068	1.37%	2,782,856	0.27%	16,725,924	1.64%
378.00	M&R Stations General	18,964,657	11,299,251	0%	0	7,665,406	14.41	532,078	2.81%	21,276	0.11%	553,354	2.92%
379.00	M&R Stations City Gate	22,007,665	11,641,493	0%	0	10,366,173	21.29	486,941	2.21%	27,934	0.13%	514,876	2.34%
380.00	Services - All	564,508,501	76,058,492	0%	54,088	488,395,921	47.36	10,312,640	1.83%	4,537,571	0.80%	14,850,211	2.63%
381.00	Meters - All	116,047,708	28,098,279	0%	0	87,949,429	16.20	5,429,567	4.68%	30,744	0.03%	5,460,311	4.71%
382.00	Meter Installation	68,680,461	13,821,700	0%	0	54,858,761	40.08	1,368,695	1.99%	18,406	0.03%	1,387,101	2.02%
383-384	House Regulators and Installation	12,624,637	2,096,269	0%	0	10,528,367	34.89	301,761	2.39%	61,995	0.49%	363,756	2.88%
385.00	Industrial M&R Equipment	15,870,575	8,653,290	0%	0	7,217,284	20.79	347,087	2.19%	0		347,087	2.19%
387.00	Other Equipment	3,854,149	2,314,912	0%	0	1,539,237	8.28	185,975	4.83%	0		185,975	4.83%
	Total Distribution	**1,851,040,503**	**306,711,908**		**151,838**	**1,544,176,757**		**33,123,369**	**1.79%**	**7,480,782**		**40,604,151**	**2.19%**
										7,328,944	NS		
	GENERAL PLANT - DEPRECIATED												
390.00	Structures & Improvements	26,074,060	3,626,616	0%	0	22,447,444	31.19	719,810	2.76%	0		719,810	2.76%
391.20	Enterprise Systems	107,089,900	19,658,251	0%	0	87,431,649	7.48	11,684,524	10.91%	0		11,684,524	10.91%
392.00	Transportation Equipment	4,747,767	1,562,086	0%	78,178	3,107,503	6.61	469,772	9.89%	0		469,772	9.89%
392.10	Auto & Light Trucks	4,642,778	2,187,220	0%	39,443	2,416,115	2.09	1,155,834	24.90%	0		1,155,834	24.90%
392.20	Service Trucks	2,420,925	1,030,412	0%	3,000	1,387,513	2.98	464,932	19.20%	0		464,932	19.20%
392.30	Heavy Trucks	5,318,388	1,667,763	0%	8,971	3,641,654	5.74	634,658	11.93%	0		634,658	11.93%

ELIZABETHTOWN GAS
COMPUTATION OF DEPRECIATION ACCRUAL RATE
AT DECEMBER 31, 2022

Account	Description	Plant In Service 12/31/2022	Book Depreciation 12/31/2022	Net Salvage %	Gross Salvage Amount	Unaccrued Balance	Remaining Life	Life Accrual Amount	Life Accrual Accrual Rate	3-Year COR Accrual Amount	COR Rate	Total (Life and COR) Accrual Amount	Total (Life and COR) Accrual Accrual Rate
394.10	Natural Gas Vehicle Stations	2,721,905	616,159	0%	0	2,105,746	12.97	162,387	5.97%	0		162,387	5.97%
396.00	Power Operated Equipment	1,873,839	599,170	0%	0	1,274,669	5.70	223,487	11.93%	0		223,487	11.93%
396.10	Power Operated - Tractors	2,209,230	396,136	0%	0	1,813,093	8.22	220,468	9.98%	0		220,468	9.98%
	Total General Depreciated	**157,098,791**	**31,343,814**		**129,592**	**125,625,385**		**15,735,871**	**10.02%**	**0**		**15,735,871**	**10.02%**
GENERAL PLANT - AMORTIZED (After AR 15 Retirements)													
391.00	Office Furniture And Equipment	956,553	293,816	0%	0	662,737		47,828	5.00%	0		47,828	5.00% *
391.10	Computer Equipment and Software	5,071,181	862,246	0%	0	4,208,936		1,014,236	20.00%	0		1,014,236	20.00% *
391.11	Computer Software	4,651,301	1,204,372	0%	0	3,446,929		930,260	20.00%	0		930,260	20.00% *
391.12	Computer Hardware	3,542,226	2,887,703	0%	0	654,523		590,371	16.67%	0		590,371	16.67% *
391.50	Individual Equipment	0	0	0%	0	0		0	0.00%	0		0	0.00% *
393.00	Stores Equipment	60,377	21,333	0%	0	39,044		2,415	4.00%	0		2,415	4.00% *
394.00	Tools, Shop, & Garage Equipment	4,947,746	1,964,374	0%	0	2,983,372		329,850	6.67%	0		329,850	6.67% *
395.00	Laboratory Equipment	0	0	0%	0	0		0	5.00%	0		0	5.00% *
397.00	Communication Equipment	4,246,601	1,721,071	0%	0	2,525,531		424,660	10.00%	0		424,660	10.00% *
398.00	Miscellaneous Equipment	1,931,564	839,420	0%	0	1,092,144		96,578	5.00%	0		96,578	5.00% *
	Total General Amortized	**25,407,548**	**9,794,334**		**0**	**15,613,214**		**3,436,198**	**13.52%**	**0**		**3,436,198**	**13.52%**
	Annual Reserve True Up Amortized (3 Years)							**37,688**					
	Total General Depreciated & Amortized	**182,506,339**	**41,138,148**		**129,592**	**141,238,599**		**19,209,757**	**10.53%**	**0**		**19,172,069**	**10.50%**
	Total Plant Depreciated and Amortized	**$ 2,127,864,072**	**$ 355,657,563**		**$ 281,430**	**$ 1,771,925,079**		**$ 54,649,306**	**2.57%**	**$ 7,504,397**		**$ 62,116,016**	**2.92%**
	Total Net Salvage in Rates									**$ (7,222,967)**			

*Denotes a whole life rate is proposed.

ELIZABETHTOWN GAS
COMPUTATION OF AMORTIZATION ACCRUAL RATE
AT DECEMBER 31, 2022

GENERAL PLANT - AMORTIZED		Plant	Book	Theoretical		Reserve	Amortize	Assets to Retire
		Balance	Reserve	Reserve	Reserve	Recovery	Reserve	Greater Than
Account	Description	12/31/2022	12/31/2022	12/31/2022	(Deficit)/Surplus	Period (Yrs)	(Deficit)/Surplus	ASL
391.00	Office Furniture And Equiq	956,552.99	293,816.31	278,418.47	15,397.84	3	5,132.61	-
391.10	Computer Equip	5,071,181.23	862,245.62	1,120,596.61	(258,350.99)	3	(86,117.00)	-
391.11	Computer Equip & Software	4,651,300.76	1,204,371.85	1,037,607.36	166,764.49	3	55,588.16	-
391.12	Computer Hardware	3,542,225.63	2,887,702.75	2,690,873.11	196,829.64	3	65,609.88	-
393.00	Stores Equip	60,377.05	21,333.24	20,528.20	805.04	3	268.35	-
394.00	Tools Shop & Garage Equip	5,444,066.40	2,460,694.60	2,829,467.66	(368,773.06)	3	(122,924.35)	496,320.84
395.00	Laboratory Equip	-	-	-	-			-
397.00	Communication Equip	4,246,601.14	1,721,070.62	1,604,773.64	116,296.98	3	38,765.66	-
398.00	Miscellaneous Equip	1,931,563.76	839,420.09	821,453.52	17,966.57	3	5,988.86	-
	Total General Amortized	25,903,868.96	10,290,655.08	10,403,718.56	(113,063.48)		(37,687.83)	496,320.84

ELIZABETHTOWN GAS
COMPUTATION OF AMORTIZATION ACCRUAL RATE
AT DECEMBER 31, 2022

After Retirements of Assets With Age > Average Service Life

Account	Description	Plant Balance 12/31/2022	Book Reserve 12/31/2022	Proposed Life	Annual Amortization	Accrual For Reserve Deficit/ (Surplus)	Total Amortization	Annual Amortization %
391.00	Office Furniture And Equip	956,552.99	293,816.31	20	47,827.65			5.00%
391.00	Office Furniture And Equip					(5,132.61)		
391.00	Total						42,695.04	
391.10	Computer Equip	5,071,181.23	862,245.62	5	1,014,236.25			20.00%
391.10	Computer Equip					86,117.00		
391.10	Total						1,100,353.24	
391.11	Computer Equip & Software	4,651,300.76	1,204,371.85	5	930,260.15			20.00%
391.11	Computer Equip & Software					(55,588.16)		
391.11	Total						874,671.99	
391.12	Computer Hardware	3,542,225.63	2,887,702.75	6	590,370.94			16.67%
391.12	Computer Hardware					(65,609.88)		
391.12	Total						524,761.06	
393.00	Stores Equip	60,377.05	21,333.24	25	2,415.08			4.00%
393.00	Stores Equip					(268.35)		
393.00	Total						2,146.73	
394.00	Tools, Shop, & Garage Equip	4,947,745.56	1,964,373.76	15	329,849.70			6.67%
394.00	Tools, Shop, & Garage Equip					122,924.35		
394.00	Total						452,774.06	
395.00	Laboratory Equip	-	-	20	-			5.00%
395.00	Laboratory Equip							
395.00	Total						-	
397.00	Communication Equip	4,246,601.14	1,721,070.62	10	424,660.11			10.00%
397.00	Communication Equip					(38,765.66)		
397.00	Total						385,894.45	
398.00	Miscellaneous Equip	1,931,563.76	839,420.09	20	96,578.19			5.00%
398.00	Miscellaneous Equip					(5,988.86)		
398.00	Total						90,589.33	
	Total General Amortized After Ret	25,407,548.12	9,794,334.24		3,436,198.07	37,687.83	3,473,885.90	
	AR 15 Retirements	496,320.84	496,320.84					

APPENDIX B - Depreciation Expense Comparison

Elizabethtown Gas
Comparison of Depreciation Expense
Comparison of Existing and Proposed Depreciation Accrual Rates
Depreciation Study as of December 31, 2022

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	4.39%	2,696	4.39%	2,696	-
	Total Production	61,423	4.39%	2,696	4.39%	2,696	-
	STORAGE PLANT						
360.00	Land and Land Rights	68,417	0.00%	-	0.00%	-	-
361.00	Structures and Improvements	6,280,274	1.99%	124,977	2.14%	134,398	9,420
362.00	Gas Holders-Natural Gas	378,876	0.47%	1,781	1.03%	3,902	2,122
362.10	Gas Holders-LNG	3,237,323	0.47%	15,215	0.67%	21,690	6,475
363.10	Liquefaction Equipment	50,305,489	2.69%	1,353,218	2.86%	1,438,737	85,519
363.20	Vaporizing Equipment	6,394,121	2.69%	172,002	2.25%	143,868	(28,134)
363.40	Measuring & Regulating Equip	3,016,952	2.59%	78,139	3.39%	102,275	24,136
	Total Storage (Excl Land Rights)	69,613,034	2.51%	1,745,332	2.65%	1,844,870	99,538
	TRANSMISSION PLANT						
365.11	Land	263,454	0.00%	-	0.00%	-	-
365.20	Rights of Way	367,325	2.56%	9,404	2.30%	8,448	(955)
367.00	Transmission-Mains	15,621,398	1.73%	270,250	1.52%	237,445	(32,805)
369.00	Measuring & Regulating Equip	8,598,040	2.95%	253,642	2.83%	243,325	(10,318)
371.00	Other Equipment	56,010	5.64%	3,159	5.93%	3,321	162
	Total Transmission (Excl Land)	24,642,773	2.18%	536,455	2.00%	492,540	(43,915)
	DISTRIBUTION PLANT						
374.00	Land and Land Rights	1,376,838	1.22%	16,797	1.24%	17,073	275
374.10	Land	893,795	0.00%	-	0.00%	-	-
374.20	Land Rights	879,052	1.22%	10,724	1.24%	10,900	176
374.30	Rights of Way	702,404	1.22%	8,569	1.24%	8,710	140

Elizabethtown Gas
Comparison of Depreciation Expense
Comparison of Existing and Proposed Depreciation Accrual Rates
Depreciation Study as of December 31, 2022

			Existing		Proposed		Change in
			Annual Accrual		Annual Accrual		Depreciation
Account	**Description**	**Plant Balance**	**Rate**	**Amount**	**Rate**	**Amount**	**Expense**
(a)	**(b)**	**(c)**	**(d)**	**(e)**	**[f]**	**[g]**	**[h]**
375.00	Structures & Improvements	5,966,851	3.00%	179,006	3.00%	179,006	-
376.00	Mains	1,019,557,004	1.67%	17,026,602	1.64%	16,720,735	(305,867)
378.00	M&R Station Equip - General	18,964,657	2.91%	551,872	2.92%	553,768	1,896
379.00	M&R Equipment - City Gate	22,007,665	2.10%	462,161	2.34%	514,979	52,818
380.00	Services	564,508,501	2.93%	16,540,099	2.63%	14,846,574	(1,693,526)
381.00	Meters	116,047,708	4.27%	4,955,237	4.71%	5,465,847	510,610
382.00	Meter Installations	68,680,461	1.93%	1,325,533	2.02%	1,387,345	61,812
383.00	House Regulators	9,783,968	3.19%	312,109	2.88%	281,778	(30,330)
384.00	Regulator Installations	2,840,669	3.19%	90,617	2.88%	81,811	(8,806)
385.00	Industrial M&R Station Equipment	15,870,575	2.51%	398,351	2.19%	347,566	(50,786)
387.00	Other Equipment	3,854,149	4.73%	182,301	4.83%	186,155	3,854
	Total Distribution (Excl Land)	1,851,040,503	2.27%	42,059,979	2.19%	40,602,247	(1,457,732)
GENERAL PLANT - DEPRECIATED							
389.00	Land and Land Rights	25,149	0.00%	-	0.00%	-	-
390.00	Structures & Improvements	26,074,060	2.69%	701,392	2.76%	719,644	18,252
391.20	Enterprise Systems	107,089,900	10.25%	10,976,715	10.91%	11,683,508	706,793
392.00	Transportation Equip	4,747,767	11.20%	531,750	9.89%	469,554	(62,196)
392.10	Autos & Light Trucks	4,642,778	26.73%	1,241,015	24.90%	1,156,052	(84,963)
392.20	Service Trucks	2,420,925	16.55%	400,663	19.20%	464,818	64,155
392.30	Heavy Trucks	5,318,388	12.27%	652,566	11.93%	634,484	(18,083)
394.10	Natural Gas Vehicle Stations	2,721,905	5.58%	151,882	5.97%	162,498	10,615
396.00	Power Operated Equipment	1,873,839	10.59%	198,440	11.93%	223,549	25,109
396.10	Power Operated Equipment Tractors	2,209,230	9.35%	206,563	9.98%	220,481	13,918
	Total General Depreciated (excl Land)	157,098,791	9.59%	15,060,985	10.02%	15,734,587	673,602

Elizabethtown Gas
Comparison of Depreciation Expense
Comparison of Existing and Proposed Depreciation Accrual Rates
Depreciation Study as of December 31, 2022

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	956,553	5.00%	47,828	5.00%	47,828	-
391.10	Computer Equipment and Software	5,071,181	20.00%	1,014,236	20.00%	1,014,236	-
391.11	Computer Software	4,651,301	20.00%	930,260	20.00%	930,260	-
391.12	Computer Hardware	3,542,226	16.67%	590,489	16.67%	590,489	-
393.00	Stores Equipment	60,377	4.00%	2,415	4.00%	2,415	-
394.00	Tools, Shop, Garage Equipment	4,947,746	5.56%	275,095	6.67%	330,015	54,920
395.00	Laboratory Equipment	-	5.00%	-	5.00%	-	-
397.00	Communication Equipment	4,246,601	10.00%	424,660	10.00%	424,660	-
398.00	Misc. Equipment	1,931,564	5.00%	96,578	5.00%	96,578	-
	Total General Amortized	25,407,548	13.31%	3,381,561	13.53%	3,436,481	54,920
	Reserve True Up Amortized Annual (3 Years)			-		37,688	37,688
	Total General Plant	182,506,339	10.11%	18,442,547	10.52%	19,208,756	766,209
	TOTAL DEPRECIABLE PLANT IN SERVICE (excludes Intangibles and Land)	$ 2,127,864,072	2.95%	$ 62,787,008	2.92%	$ 62,151,109	$ (635,900)
TBD	PC, Laptop, Toughbook Equipment *				25.00%		
TBD	PC, Laptop, Non-Enterprise Software *				25.00%		
TBD	Network/Server Hardware *				16.67%		
TBD	Network/Server Software *				16.67%		
TBD	Major Software Systems (Upgrades) *				20.00%		

*Denotes new accounts to be set up for new additions for Computer/Network Assets

APPENDIX C - Depreciation Parameter Comparison

Elizabethtown Gas Company
Depreciation Study as of December 31, 2022
Comparison of Existing and Proposed Parameters

			APPROVED 2019 STUDY				PROPOSED			
Account	Description	Balance	Life	Curve	3 Year Net Salvage Amount	COR Rate	Life	Curve	3 Year Net Salvage Amount	COR Rate
MANUFACTURED GAS PLANT										
304.20	Land Rights	61,423	65	SQ	-		65	SQ		
311.00	Liquefied Petroleum Gas Equipment	-	35	S3	-		35	S3		
320.40	Other Equipment	-	15	L1	-		15	L1		
	Total Manufactured Gas Plant	61,423			-				-	
OTHER STORAGE PLANT										
361.00	Structures & Improvements	6,280,274	45	S4	-		45	S4		
362.00	Gas Holders-Natural Gas	378,876	65	S4	-		70	S4		
362.10	Gas Holders-LNG	3,237,323	65	S4	-		70	S4		
362.10	Liquefaction Equipment	50,305,489					35	S3		
363.20	Vaporizing Equipment	6,394,121	35	S3	-		35	S3		
363.40	M&R Equipment	3,016,952	25	S3	-		25	S3		
	Total Other Storage Plant	69,613,034			-					
TRANSMISSION PLANT										
365.20	Rights of Way	367,325	80	R2	-		80	R2		
367 C	Mains-Combined	15,621,398	71	R2	(21,163)	0.15%	73	R2	(1,145)	0.01%
369.00	M&R Equipment	8,598,040	45	S2	(33,475)	0.39%	45	S2	(22,471)	0.26%
371.00	Other Equipment	56,010	20	R2	-		20	R2		
	Total Transmission Plant	24,642,773			(54,637)				(23,615)	
DISTRIBUTION PLANT										
374.00	Land and Land Rights	1,376,838	80	R2	-		80	R2		
374.20	Land Rights	879,052	80	R2	-		80	R2		

Elizabethtown Gas Company
Depreciation Study as of December 31, 2022
Comparison of Existing and Proposed Parameters

			APPROVED 2019 STUDY				PROPOSED			
Account	Description	Balance	Life	Curve	3 Year Net Salvage Amount	COR Rate	Life	Curve	3 Year Net Salvage Amount	COR Rate
374.30	Rights of Way	702,404	80	R2	-		80	R2		
375.00	Structures & Improvements	5,966,851	33	L2	-		33	L2		
376 Comb	Mains - Combined	1,019,557,004	73	R2	(2,659,609)	0.32%	73	R2	(2,685,106)	0.27%
378.00	M&R Station Equip - General	18,964,657	35	S2	(65,124)	0.36%	35	S2	(21,276)	0.11%
379.00	M&R Equipment - City Gate	22,007,665	45	S2	(12,255)	0.06%	45	S2	(27,934)	0.13%
380 Comb	Services-Combined	564,508,501	60	S0	(5,903,383)	1.28%	55	S0	(4,483,483)	0.80%
381.00	Meters	116,047,708	23	R1	(31,881)	0.02%	22	R1.5	(30,744)	0.03%
382.10	Meter Installations	68,680,461	50	S5	0		50	S5	(18,406)	0.03%
383.00	House Regulators	9,783,968	42	L5	(112)	0.87%	42	L5	(112)	0.49%
384.00	Regulator Installations	2,840,669	42	L5	(83,939)	0.87%	42	L5	(61,883)	0.49%
385.00	Industrial M&R Station Equipment	15,870,575	45	S2	-		45	S2		
387.00	Other Equipment	3,854,149	20	R5			20	R5		
	Total Distribution Plant	1,851,040,503			(8,756,304)				(7,328,944)	
GENERAL PLANT										
390.00	Structures & Improvements	26,074,060	40	R5	-		40	R5		
391.00	Office Furniture & Equipment	956,553	20	SQ	-		20	SQ		
391.10	Computer Equipment	5,071,181	5	SQ	-		5	SQ		
391.11	Computer Equipment and Software	4,651,301	5	SQ	-		5	SQ		
391.12	Computer Hardware	3,542,226	6	SQ	-		6	SQ		
391.20	Enterprise Systems	107,089,900	10	SQ	-		10	SQ		
TBD	PC, Laptop, Toughbook Equipment	*					4	SQ		
TBD	PC, Laptop, Non-Enterprise Software	*					4	SQ		
TBD	Network/Server Hardware	*					6	SQ		
TBD	Network/Server Software	*					6	SQ		

Elizabethtown Gas Company
Depreciation Study as of December 31, 2022
Comparison of Existing and Proposed Parameters

			APPROVED 2019 STUDY				PROPOSED			
Account	**Description**	**Balance**	**Life**	**Curve**	**3 Year Net Salvage Amount**	**COR Rate**	**Life**	**Curve**	**3 Year Net Salvage Amount**	**COR Rate**
TBD	Major Software Systems (Upgrades)	*					5	SQ		
392.00	Transportation Equipment	4,747,767	10	L3	183		10	L3	78,178	
392.10	Auto & Light Trucks	4,642,778	6	R3	41,919		6	R3	39,443	
392.20	Service Trucks	2,420,925	8	L3	13,616		8	L3	3,000	
392.30	Heavy Trucks	5,318,388	11	R5	11,150		11	R5	8,971	
393.00	Stores Equipment	60,377	25	SQ	-		25	SQ		
394.00	Tools, Shop, & Garage Equipment	5,444,066	18	SQ			15	SQ		
394.10	Natural Gas Vehicle Equipment	2,721,905	20	S4	-		20	S4		
395.00	Laboratory Equipment	-	20	SQ	-		20	SQ		
396.00	Power Operated Equipment	1,873,839	11	L4	-		11	L4		
396.10	Power Operated Equipment Tractors	2,209,230	11	L4	-		11	L4	-	
396.20	Power Operated Equip Compressors	-	N/A		-					
397.00	Communication Equipment	4,246,601	10	SQ	-		10	SQ		
398.00	Miscellaneous Equipment	1,931,564	20	SQ			20	SQ		
	Total General Plant	183,002,660			66,868	Salvage			129,592	Salvage
	Total Study Balance	2,128,360,393			(8,810,942)	COR			(7,352,559)	COR
Total Net Salvage Amount Included in Annual Accrual					$ (8,744,073)	Net Salvage			$ (7,222,967)	

APPENDIX D - Net Salvage Analysis

Elizabethtown Gas
Depreciation Study as of December 31, 2022
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
304	2021	-	0	0	0	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA
304	2022	-	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

Elizabethtown Gas
Depreciation Study as of December 31, 2022
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 %
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
305	2021	-	0	0	0	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA
305	2022	-	0	0	0	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA
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
311	2021	-	-	0	0	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA
311	2022	-	-	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%

Elizabethtown Gas
Depreciation Study as of December 31, 2022
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 %
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%
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%
320	2021	173,509	0	0	0	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
320	2022	-	0	0	0	NA	0.00%	0.00%	0.00%	0.00%	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%
361	2021	-	0	0	0	NA	NA	NA	NA	NA	NA	0.00%	0.00%	0.00%	0.00%
361	2022	-	0	0	0	NA	NA	NA	NA	NA	NA	NA	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%			

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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%
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	2021	-	0	0	0	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA
362	2022	-	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%
362.1	2021	-	0	0	0	NA	NA	NA	NA	NA	NA	0.00%	0.00%	0.00%	0.00%
362.1	2022	-	0	0	0	NA	NA	NA	NA	NA	NA	NA	0.00%	0.00%	0.00%

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362 Combi	1999	512,454	0	104,703	(104,703)	-20.43%									
362 Combi	2000	-	0	0	0	NA	-20.43%								
362 Combi	2001	-	0	0	0	NA	NA	-20.43%							
362 Combi	2002	-	0	0	0	NA	NA	NA	-20.43%						
362 Combi	2003	-	0	0	0	NA	NA	NA	NA	-20.43%					
362 Combi	2004	-	0	0	0	NA	NA	NA	NA	NA	-20.43%				
362 Combi	2005	-	0	0	0	NA	NA	NA	NA	NA	NA	-20.43%			
362 Combi	2006	-	0	0	0	NA	NA	NA	NA	NA	NA	NA	-20.43%		
362 Combi	2007	-	0	0	0	NA	NA	NA	NA	NA	NA	NA	NA	-20.43%	
362 Combi	2008	-	0	0	0	NA	NA	NA	NA	NA	NA	NA	NA	NA	-20.43%
362 Combi	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 Combi	2010	-	0	0	0	NA	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
362 Combi	2011	-	0	0	0	NA	NA	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
362 Combi	2012	-	0	0	0	NA	NA	NA	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
362 Combi	2013	-	0	0	0	NA	NA	NA	NA	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
362 Combi	2014	-	0	0	0	NA	NA	NA	NA	NA	0.00%	0.00%	0.00%	0.00%	0.00%
362 Combi	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 Combi	2016	-	0	0	0	NA	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
362 Combi	2017	-	0	0	0	NA	NA	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
362 Combi	2018	-	0	0	0	NA	NA	NA	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
362 Combi	2019	-	0	0	0	NA	NA	NA	NA	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
362 Combi	2020	-	0	0	0	NA	NA	NA	NA	NA	0.00%	0.00%	0.00%	0.00%	0.00%
362 Combi	2021	-	0	0	0	NA	NA	NA	NA	NA	NA	0.00%	0.00%	0.00%	0.00%
362 Combi	2022	-	0	0	0	NA	NA	NA	NA	NA	NA	NA	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%

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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%
363.2	2021	10,060,650	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	2022	-	0	0	0	NA	0.00%	0.00%	0.00%	0.00%	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
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%
363.4	2021	-	0	0	0	NA	NA	NA	NA	NA	NA	0.00%	0.00%	0.00%	0.00%
363.4	2022	375,629	0	0	0	0.00%	0.00%	0.00%	0.00%	0.00%	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	

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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	-	0	0	0	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA
367C	2021	4,435,634	0	3,434	(3,434)	-0.08%	-0.08%	-0.08%	-1.51%	-1.51%	-1.55%	-1.82%	-5.31%	-5.31%	-5.31%
367C	2022	-	0	0	0	NA	-0.08%	-0.08%	-0.08%	-1.51%	-1.51%	-1.55%	-1.82%	-5.31%	-5.31%
5 year		887,127	0	13,384	(13,384)										
3 year		1,478,545	0	1,145	(1,145)										
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							
369	2021	-	0	16,804	(16,804)	NA	NA	NA	NA						
369	2022	-	0	50,609	(50,609)	NA	NA	NA	NA	NA					
5 year		-	0	33,567	(33,567)										
3 year		-	0	22,471	(22,471)										
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

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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%
371	2021	-	0	0	0	NA	NA	NA	NA	NA	NA	0.00%	0.00%	0.00%	0.00%
371	2022	-	0	0	0	NA	NA	NA	NA	NA	NA	NA	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
374 C	2021	-	0	0	0	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA
374 C	2022	-	0	0	0	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA
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%		

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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%
375	2021	143,494	0	0	0	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
375	2022	-	0	0	0	NA	0.00%	0.00%	0.00%	0.00%	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%
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%
376 C	2021	4,114,822	145,400	4,115,261	(3,969,861)	-96.48%	-81.14%	-89.19%	-85.52%	-81.72%	-91.47%	-94.61%	-89.37%	-81.25%	-84.44%
376 C	2022	4,818,263	147,850	2,482,417	(2,334,567)	-48.45%	-70.57%	-67.87%	-76.62%	-76.02%	-73.95%	-81.94%	-84.85%	-81.61%	-75.03%
5 year		3,758,002	58,650	2,915,301	(2,856,651)										
3 year		3,956,229	97,750	2,782,856	(2,685,106)										

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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	0	0	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA
378	2016	-	0	0	0	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA
378	2017	-	0	0	0	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA
378	2018	(292)	0	0	0	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
378	2019	-	0	0	0	NA	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
378	2020	-	0	0	0	NA	NA	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
378	2021	1,994,845	0	62,664	(62,664)	-3.14%	-3.14%	-3.14%	-3.14%	-3.14%	-3.14%	-3.14%	-3.14%	-3.14%	-3.14%
378	2022	26,423	0	1,164	(1,164)	-4.41%	-3.16%	-3.16%	-3.16%	-3.16%	-3.16%	-3.16%	-3.16%	-3.16%	-3.16%
5 year		404,195	0	12,766	(12,766)										
3 year		673,756	0	21,276	(21,276)										
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
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

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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
379	2021	-	0	0	0	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA
379	2022	-	0	83,803	(83,803)	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA
5 Year		-	-	24,113	(24,113)										
3 Year		-	-	27,934	(27,934)										
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%
380 C	2021	12,272,733	0	4,765,866	(4,765,866)	-38.83%	-34.75%	-57.08%	-62.09%	-60.65%	-69.10%	-75.37%	-78.00%	-77.40%	-75.94%
380 C	2022	9,004,256	0	5,075,786	(5,075,786)	-56.37%	-46.25%	-40.63%	-56.91%	-60.95%	-59.86%	-66.94%	-72.21%	-74.50%	-74.09%
5 Year		9,040,101	37,023	5,547,383	(5,510,361)										
3 Year		11,035,257	54,088	4,537,571	(4,483,483)										

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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%					
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%
381 C	2021	4,669,997	0	4,900	(4,900)	-0.10%	-1.02%	-0.64%	-0.53%	-0.42%	-0.40%	-0.35%	-0.34%	-0.34%	-0.34%
381 C	2022	1,310,983	0	0	0	0.00%	-0.08%	-0.89%	-0.59%	-0.49%	-0.40%	-0.38%	-0.34%	-0.33%	-0.33%
5 Year		4,066,788	0	20,109	(20,109)										
3 Year		3,447,200	0	30,744	(30,744)										
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%

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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%
382	2021	1,800,956	0	33,659	(33,659)	-1.87%	-1.87%	-1.85%	-1.82%	-1.81%	-1.61%	-1.61%	-1.61%	-1.61%	-1.53%
382	2022	1,121,300	0	21,560	(21,560)	-1.92%	-1.89%	-1.89%	-1.88%	-1.86%	-1.86%	-1.72%	-1.72%	-1.72%	-1.72%
5 Year		594,136	0	11,044	(11,044)										
3 Year		974,298	0	18,406	(18,406)										
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%
383	2021	-	0	0	0	NA	NA	-163.20%	-47.40%	-28.15%	-0.39%	-0.39%	-0.39%	-0.39%	-0.39%
383	2022	308,005	0	0	0	0.00%	0.00%	-0.11%	-0.11%	-0.11%	-0.11%	-0.09%	-0.09%	-0.09%	-0.09%
5 Year		61,743	0	67	(67)										
3 Year		102,668	0	112	(112)										

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384	1999	-	0	0	0	NA	NA	NA	-0.11%	-0.11%	-0.11%	-0.11%	-0.09%	-0.09%	-0.09%
384	2000	-	0	0	0	NA	NA	NA	NA	-0.11%	-0.11%	-0.11%	-0.11%	-0.09%	-0.09%
384	2001	-	0	0	0	NA	NA	NA	NA	NA	-0.11%	-0.11%	-0.11%	-0.11%	-0.09%
384	2002	-	0	0	0	NA	NA	NA	NA	NA	NA	-0.11%	-0.11%	-0.11%	-0.11%
384	2003	-	0	0	0	NA	NA	NA	NA	NA	NA	NA	-0.11%	-0.11%	-0.11%
384	2004	-	0	0	0	NA	NA	NA	NA	NA	NA	NA	NA	-0.11%	-0.11%
384	2005	-	0	0	0	NA	NA	NA	NA	NA	NA	NA	NA	NA	-0.11%
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
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
384	2021	-	0	1,062	(1,062)	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA
384	2022	434,764	0	0	0	0.00%	-0.24%	-42.70%	-58.16%	-58.16%	-58.16%	-58.16%	-58.16%	-58.16%	-58.16%
5 Year		86,953	0	50,576	(50,576)										
3 Year		144,921	0	61,883	(61,883)										
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%

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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%
383-384	2021	-	0	1,062	(1,062)	NA	NA	-122474.14%	-35574.44%	-21127.15%	-295.20%	-295.20%	-292.40%	-292.39%	-292.34%
383-384	2022	742,769	0	0	0	0.00%	-0.14%	-25.04%	-34.08%	-34.06%	-34.04%	-30.56%	-30.56%	-30.53%	-30.53%
5 Year		148,696	0	50,643	(50,643)										
3 Year		247,590	0	61,995	(61,995)										
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
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%
385	2021	-	0	0	0	NA	NA	NA	NA	NA	NA	0.00%	0.00%	0.00%	0.00%
385	2022	-	0	0	0	NA	NA	NA	NA	NA	NA	NA	0.00%	0.00%	0.00%

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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%
387	2021	-	0	0	0	NA	NA	NA	NA	NA	NA	-24.02%	-186.69%	-186.69%	-186.69%
387	2022	-	0	0	0	NA	NA	NA	NA	NA	NA	NA	-24.02%	-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%					
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%

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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%
390	2021	276,091	0	0	0	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
390	2022	-	0	0	0	NA	0.00%	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%
39100	2021	-	0	0	0	NA	NA	NA	NA	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
39100	2022	-	0	0	0	NA	NA	NA	NA	NA	0.00%	0.00%	0.00%	0.00%	0.00%
39110	1999	-	0	0	0	NA									
39110	2000	-	0	0	0	NA	NA								
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				

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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%
39110	2021	969,911	0	0	0	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
39110	2022	-	0	0	0	NA	0.00%	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%
39111	2021	-	0	0	0	NA	NA	NA	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
39111	2022	-	0	0	0	NA	NA	NA	NA	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%
39112	2021	-	0	0	0	NA	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
39112	2022	-	0	0	0	NA	NA	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

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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%
0	2021	-	0	0	0	NA	NA	NA	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
0	2022	-	0	0	0	NA	NA	NA	NA	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
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
0	2021	-	0	0	0	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA
0	2022	-	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	

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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%
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%
0	2021	-	0	0	0	NA	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
0	2022	-	0	0	0	NA	NA	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%					
39200	2021	133,410	23,718	0	23,718	17.78%	17.78%	15.58%	15.94%	16.09%	26.66%				
39200	2022	-	210,817	0	210,817	NA	175.80%	175.80%	154.05%	154.41%	154.56%	165.13%			
5 Year		30,449	47,017	0	47,017										
3 Year		44,470	78,178	0	78,178										
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%

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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%
39210	2021	665,599	118,330	0	118,330	17.78%	17.78%	17.78%	17.45%	17.29%	6.77%	7.22%	7.37%	6.64%	6.64%
39210	2022	97,535	0	0	0	0.00%	15.51%	15.51%	15.51%	16.32%	16.41%	6.68%	7.13%	7.28%	6.57%
5 Year		299,193	48,817	0	48,817										
3 Year		254,378	39,443	0	39,443										

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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					
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%
39220	2021	50,619	8,999	0	8,999	17.78%	17.78%	17.78%	45.82%	43.25%	30.55%	27.51%	27.51%	22.18%	22.18%
39220	2022	-	0	0	0	NA	17.78%	17.78%	17.78%	45.82%	43.25%	30.55%	27.51%	27.51%	22.18%
5 Year		21,756	9,969	0	9,969										
3 Year		16,873	3,000	0	3,000										

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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%
39230	2021	151,385	26,913	0	26,913	17.78%	17.78%	17.78%	8.18%	13.20%	12.89%	12.89%	12.89%	12.89%	12.89%
39230	2022	92,061	0	0	0	0.00%	11.06%	11.06%	11.06%	7.28%	12.40%	12.48%	12.48%	12.48%	12.48%
5 Year		165,918	12,073	0	12,073										
3 Year		81,149	8,971	0	8,971										
39240	1999	-	0	0	0	NA									
39240	2000	-	0	0	0	NA	NA								
39240	2001	-	0	0	0	NA	NA	NA							
39240	2002	230,545	0	0	0	0.00%	0.00%	0.00%	0.00%						
39240	2003	-	0	0	0	NA	0.00%	0.00%	0.00%	0.00%					
39240	2004	-	0	0	0	NA	NA	0.00%	0.00%	0.00%	0.00%				
39240	2005	-	0	0	0	NA	NA	NA	0.00%	0.00%	0.00%	0.00%			
39240	2006	-	0	0	0	NA	NA	NA	NA	0.00%	0.00%	0.00%	0.00%		
39240	2007	-	0	0	0	NA	NA	NA	NA	NA	0.00%	0.00%	0.00%	0.00%	
39240	2008	-	0	0	0	NA	NA	NA	NA	NA	NA	0.00%	0.00%	0.00%	0.00%
39240	2009	-	0	0	0	NA	NA	NA	NA	NA	NA	NA	0.00%	0.00%	0.00%
39240	2010	-	0	0	0	NA	NA	NA	NA	NA	NA	NA	NA	0.00%	0.00%
39240	2011	-	0	0	0	NA	NA	NA	NA	NA	NA	NA	NA	NA	0.00%
39240	2012	-	0	0	0	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA
39240	2013	-	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 %
39240	2014	-	0	0	0	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA
39240	2015	-	0	0	0	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA
39240	2016	-	0	0	0	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA
39240	2017	-	0	0	0	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA
39240	2018	-	0	0	0	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA
39240	2019	-	0	0	0	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA
39240	2020	-	0	0	0	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA
39240	2021	-	0	0	0	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA
39240	2022	-	0	0	0	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA
5 Year		0	0	0	0										
3 Year		0	0	0	0										
39250	1999	203,643	0	0	0	0.00%									
39250	2000	-	0	0	0	NA	0.00%								
39250	2001	-	0	0	0	NA	NA	0.00%							
39250	2002	1,955,549	0	0	0	0.00%	0.00%	0.00%	0.00%						
39250	2003	-	0	0	0	NA	0.00%	0.00%	0.00%	0.00%					
39250	2004	766,946	0	0	0	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%				
39250	2005	-	0	0	0	NA	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%			
39250	2006	-	0	0	0	NA	NA	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%		
39250	2007	-	0	0	0	NA	NA	NA	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	
39250	2008	-	0	0	0	NA	NA	NA	NA	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
39250	2009	-	0	0	0	NA	NA	NA	NA	NA	0.00%	0.00%	0.00%	0.00%	0.00%
39250	2010	-	0	0	0	NA	NA	NA	NA	NA	NA	0.00%	0.00%	0.00%	0.00%
39250	2011	-	0	0	0	NA	NA	NA	NA	NA	NA	NA	0.00%	0.00%	0.00%
39250	2012	-	0	0	0	NA	NA	NA	NA	NA	NA	NA	NA	0.00%	0.00%
39250	2013	-	0	0	0	NA	NA	NA	NA	NA	NA	NA	NA	NA	0.00%
39250	2014	-	0	0	0	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA
39250	2015	-	0	0	0	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA
39250	2016	-	0	0	0	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA
39250	2017	-	0	0	0	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA
39250	2018	-	0	0	0	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA
39250	2019	-	0	0	0	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA
39250	2020	-	0	0	0	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA
39250	2021	-	0	0	0	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA
39250	2022	-	0	0	0	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA
5 Year		0	0	0	0										
3 Year		0	0	0	0										

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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 %
392 All	1999	203,643	0	0	0	0.00%									
392 All	2000	-	0	0	0	NA	0.00%								
392 All	2001	-	0	0	0	NA	NA	0.00%							
392 All	2002	2,186,094	23,991	0	23,991	1.10%	1.10%	1.10%	1.00%						
392 All	2003	-	0	0	0	NA	1.10%	1.10%	1.10%	1.00%					
392 All	2004	766,946	20,637	0	20,637	2.69%	2.69%	1.51%	1.51%	1.51%	1.41%				
392 All	2005	158,460	18,570	0	18,570	11.72%	4.24%	4.24%	2.03%	2.03%	2.03%	1.91%			
392 All	2006	657,243	64,311	0	64,311	9.78%	10.16%	6.54%	6.54%	3.38%	3.38%	3.38%	3.21%		
392 All	2007	14,647	10,887	0	10,887	74.33%	11.19%	11.29%	7.16%	7.16%	3.66%	3.66%	3.66%	3.47%	
392 All	2008	500,593	0	0	0	0.00%	2.11%	6.41%	7.05%	5.45%	5.45%	3.23%	3.23%	3.23%	3.08%
392 All	2009	521,644	0	0	0	0.00%	0.00%	1.05%	4.44%	5.06%	4.37%	4.37%	2.88%	2.88%	2.88%
392 All	2010	72,868	0	0	0	0.00%	0.00%	0.00%	0.98%	4.26%	4.87%	4.25%	4.25%	2.84%	2.84%
392 All	2011	1,264,863	0	0	0	0.00%	0.00%	0.00%	0.00%	0.46%	2.48%	2.94%	2.89%	2.89%	2.25%
392 All	2012	-	0	0	0	NA	0.00%	0.00%	0.00%	0.00%	0.46%	2.48%	2.94%	2.89%	2.89%
392 All	2013	963,143	0	0	0	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.33%	1.88%	2.26%	2.33%
392 All	2014	446,064	44,234	0	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	0	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	0	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	0	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	0	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	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	0	0	NA	0.00%	14.37%	16.15%	8.45%	8.71%	8.76%	8.02%	8.02%	7.22%
392 All	2021	1,001,013	177,960	0	177,960	17.78%	17.78%	17.45%	15.79%	16.61%	9.33%	9.54%	9.55%	8.81%	8.81%
392 All	2022	189,596	210,817	0	210,817	111.19%	32.65%	32.65%	32.15%	22.79%	21.41%	11.12%	11.25%	11.20%	10.35%
5 Year		517,316	117,876	0	117,876										
3 Year		396,869	129,592	0	129,592										
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

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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%
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%
393	2021	-	0	0	0	NA	NA	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
393	2022	-	0	0	0	NA	NA	NA	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%

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 %
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%
394	2021	701	0	0	0	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	1.93%	0.58%	0.58%
5 Year		20,871	0	0	0										
3 Year		350	0	0	0										

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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 %
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
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%
395	2021	-	0	0	0	NA	NA	NA	NA	NA	NA	NA	NA	0.00%	0.00%
395	2022	-	0	0	0	NA	NA	NA	NA	NA	NA	NA	NA	NA	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

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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%
39600	2021	-	0	0	0	NA	NA	NA	NA	NA	0.00%	0.00%	0.00%	0.00%	0.00%
39600	2022	-	0	0	0	NA	NA	NA	NA	NA	NA	0.00%	0.00%	0.00%	0.00%
5 Year		0	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			
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%
39610	2021	-	0	0	0	NA	NA	NA	NA	0.00%	11.34%	11.34%	10.66%	8.15%	8.15%
39610	2022	-	0	0	0	NA	NA	NA	NA	NA	0.00%	11.34%	11.34%	10.66%	8.15%
5 Year		0	0	0	0										
3 Year		0	0	0	0										

Elizabethtown Gas
Depreciation Study as of December 31, 2022
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 %
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%
39620	2021	-	0	0	0	NA	NA	NA	NA	NA	NA	0.00%	0.00%	0.00%	0.00%
39620	2022	-	0	0	0	NA	NA	NA	NA	NA	NA	NA	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%						
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%

Elizabethtown Gas
Depreciation Study as of December 31, 2022
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	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%
397	2021	-	0	0	0	NA	NA	NA	NA	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
397	2022	81,392	0	0	0	0.00%	0.00%	0.00%	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%
398	2021	57,427	0	0	0	0.00%	0.00%	-73.40%	-99.84%	-115.16%	-182.19%	-67.78%	-66.34%	-18.55%	-18.55%
398	2022	7,651	0	0	0	0.00%	0.00%	0.00%	-64.77%	-88.10%	-106.71%	-171.99%	-66.32%	-64.93%	-18.44%
5 Year		13,016	0	11,467	(11,467)										
3 Year		21,693	0	0	0										

Dane Watson Testimony Appearances

Asset Location	Commission	Docket (If Applicable	Company	Year	Description
Missouri	Missouri Public Service Commission	GR-2024-0106	Liberty Utilities Mid States Gas	2024	Gas Depreciation Study
Pennsylvania	Pennsylvnia Public Utility Commission	R-2024-3045193	Veolia Pennsylvania	2024	WasteWater Depreciation Study
Pennsylvania	Pennsylvnia Public Utility Commission	R-2024-3045192	Veolia Pennsylvania	2024	Water Depreciation Study
Arkansas	Arkansas Public Service Commission	23-079-U	Summit Utilities Arkansas	2024	Gas Depreciation Study
Colorado	Colorado Public Utilities Commission	23A-0632G	Atmos Energy	2023	Gas Clean Heat Plan
Illinois	Illinois Commerce Commission	24-0043	Liberty Mid States Gas-Illinois	2023	Gas Depreciation Study
Oklahoma	Oklahoma Corporation Commission	2023-00087	Oklahoma Gas & Electric	2023	Electric Depreciation Study
Michigan	Michigan Public Service Commission	21513	Upper Peninsula Power Company	2023	Electric Depreciation Study
Texas	Public Utility Commission of Texas	55867	Lower Colorado River Authority	2023	Electric Depreciation Study
Texas	Railroad Commission of Texas	Case No. OS-23-00015513	CenterPoint Texas Gas	2023	Gas Depreciation Study
Nevada	Public Utility Commission of Nevada	23-090-12	Southwest Gas	2023	Gas Depreciation Study - Nevada Division
Louisiana	Public Service Commission of Louisiana	36959	Entergy Louisiana	2023	Electric Depreciation Study
Texas	Railroad Commission of Texas	13758	Atmos Energy - APT	2023	Gas Depreciation Study
Florida	Florida Public Service Commission	20230023	Peoples Gas System	2023	Gas Depreciation Study
Texas	Public Utility Commission of Texas	54565	Central States Water Resources (CSWR Texas)	2023	Water Depreciation Study
New York	New York State Public Service Commission	23-W-0111	Veolia New York	2023	Water Depreciation Study
Arkansas	Arkansas Public Service Commission	22-085-U	Empire District Electric Company	2023	Electric Depreciation Study
Texas	Public Utility Commission of Texas	54634	Southwestern Public Service Company	2023	Electric Technical Update
Louisiana	Louisiana Public Service Commission	U-36923	Cleco	2023	Electric Depreciation study
Arkansas	Arkansas Public Service Commission	22-085-U	Liberty Empire Electric Arkansas	2023	Electric Depreciation Study
Florida	Florida Public Service Commission	20220219	People Gas System	2022	Gas Depreciation Study
Michigan	Michigan Public Service Commission	U-21329	Michigan Gas Utilities Corporation	2022	Gas Depreciation Study
New Mexico	New Mexico Public Regulation Commission	22-00270-UT	Public Service of New Mexico	2022	Electric Depreciation Study

Dane Watson Testimony Appearances

Asset Location	Commission	Docket (If Applicable	Company	Year	Description
New Mexico	New Mexico Public Regulation Commission	22-00286-UT	Southwestern Public Service Company	2022	Electric Technical Update
Michigan	Michigan Public Service Commission	U-21294	SEMCO Gas	2022	Gas Depreciation Study
Arkansas	Arkansas Public Service Commission	22-064-U	Liberty Pine Bluff Water	2022	Water Depreciation Study
Colorado	Colorado Public Utilities Commission	22AL-0348G	Atmos Energy	2022	Gas Depreciation Study
New York	FERC	ER22-2581-000	New York Power Authority	2022	Electric Transmission and General Depreciation Study
South Carolina	South Carolina Public Service Commission	2022-89-G	Piedmont Natural Gas	2022	Natural Gas Depreciation Study
Alaska	Regulatory Commission of Alaska	U-22-034	Chugach Electirc Association	2022	Electric Depreciation Study
Georgia	Georgia Public Service Commission	44280	Georgia Power Company	2022	Electric Depreciation Study
Texas	Public Utility Commission of Texas	53719	Entergy Texas	2022	Electric Depreciation Study
California	California Public Utilities Commission	A22-005-016	San Diego Gas and Electric	2022	Electirc Gas and Common Depreciation Study
California	California Public Utilities Commission	A22-005-015	Southern California Gas	2022	Gas Depreciation Study
Colorado	Colorado Public Utilities Commission	22AL-0046G	Public Service of Colorado	2022	Gas Alternatives to Climate Goals
Texas	Public Utility Commission of Texas	53601	Oncor Electric Delivery	2022	Electric Depreciation Study
New Jersey	New Jersey Board of Public Utilities	GR2222040253	South Jersey Gas	2022	Gas Depreciation Study
Oklahoma	Coporation Commission of Oklahoma	PUD 202100163	Empire District Electric Company	2022	Electric Depreciation Study
Michigan	Michigan Public Service Commission	U-21176	Consumers Gas	2021	Gas Depreciation Study
New Jersey	New Jersey Board of Public Utilities	GR21121254	Elizabethtown Natural Gas	2021	Gas Depreciation Study
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

Dane Watson Testimony Appearances

Asset Location	Commission	Docket (If Applicable	Company	Year	Description
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
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

Dane Watson Testimony Appearances

Asset Location	Commission	Docket (If Applicable	Company	Year	Description
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
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

Dane Watson Testimony Appearances

Asset Location	Commission	Docket (If Applicable	Company	Year	Description
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
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

Dane Watson Testimony Appearances

Asset Location	Commission	Docket (If Applicable	Company	Year	Description
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
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

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Asset Location	Commission	Docket (If Applicable	Company	Year	Description
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
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

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Asset Location	Commission	Docket (If Applicable	Company	Year	Description
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
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

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Asset Location	Commission	Docket (If Applicable	Company	Year	Description
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
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

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Asset Location	Commission	Docket (If Applicable	Company	Year	Description
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
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

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Asset Location	Commission	Docket (If Applicable	Company	Year	Description
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
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

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Asset Location	Commission	Docket (If Applicable	Company	Year	Description
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
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

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Asset Location	Commission	Docket (If Applicable	Company	Year	Description
Texas	Public Utility Commission of Texas	11735	TXU	1993	Electric Depreciation Study