STATE OF NEW YORK
PUBLIC SERVICE COMMISSION

CASE 24-G-0668 - Proceeding on Motion of the Commission as to the Rates, Charges, Rules and Regulations of Liberty Utilities (St. Lawrence Gas) Corp. for Gas Service.

CASE 24-G-0369 - Petition of Liberty Utilities (St. Lawrence Gas) Corp. for Approval to Implement Automated Meter Reading and Recover Associated Costs.

ORDER ADOPTING TERMS OF A JOINT PROPOSAL, ESTABLISHING GAS RATE PLAN AND AUTHORIZING IMPLEMENTATION OF AUTOMATED METER READING

Issued and Effective: January 22, 2026

TABLE OF CONTENTS

INTRODUCTION 5

BACKGROUND 8

NOTICE OF PROPOSED RULE MAKING AND PUBLIC COMMENTS 10

STATUTORY AND REGULATORY FRAMEWORK 12

THE JOINT PROPOSAL 14

Term and Make Whole Provision 14

Revenue Requirement Summary 15

Sales and Revenue Forecast 18

Operation and Maintenance Expenses 20

1. Direct Labor 20

2. Indirect Allocated Labor 24

3. Uncollectibles 26

4. Pension and OPEB 27

5. Greenhouse Gas Reduction/Hybrid Heating Program 28

6. Productivity Adjustment 29

7. Inflation 29

Depreciation 30

Amortization of Regulatory Deferrals 32

Taxes 33

Rate Base 35

1. Net Plant Reconciliation Mechanism 36

2. Earnings Base Capitalization Adjustment 37

3. Contribution in Aid of Construction 39

4. Capital Expenditures 39

Automated Meter Reading 42

Cost of Capital 45

1. Earnings Sharing Mechanism 48

Revenue Allocation and Rate Design 49

1. Merchant Function Charge & Delivery Revenue Adjustment 53
2. Revenue Decoupling Mechanism 54
3. Lost and Unaccounted for Gas 55
4. Interruptible Incentive Credit Mechanism 56
Gas Safety Metrics and Regulatory Goals 57
1. Timely Filings 57
2. Gas Safety Metrics 57
3. Pipeline Safety Management and Quality Control 61
4. Residential Methane Detector Pilot Program 62
5. First Responder Communication and Training 63
Customer Service 63
1. Customer Service Performance Indicators 64
2. Termination and Uncollectible Expenses 67
3. Low-Income Program 68
4. Outreach & Education 70
5. Levelized Payment Plan 72
6. Arrearage Management Program (AMP) 73
7. Language Access 74
8. Promotion of Natural Gas 75
9. Competitive Bidding for Goods and Services 76
CLCPA-Related Provisions and Environmental Goals 76
1. Behavioral Demand Response Program 79
2. Energy Efficiency 79
3. Greenhouse Gas Emissions Reporting 80
4. Green Tariff, RNG and Green Hydrogen 80
5. Main Extensions and NPAs 82

CONCLUSION 85

STATE OF NEW YORK
PUBLIC SERVICE COMMISSION

At a session of the Public Service Commission held in the City of Albany on January 22, 2026

COMMISSIONERS PRESENT:

Rory M. Christian, Chair
James S. Alesi
David J. Valesky
John B. Maggiore
Uchenna S. Bright
Denise M. Sheehan
Radina R. Valova

CASE 24-G-0668 - Proceeding on Motion of the Commission as to the Rates, Charges, Rules and Regulations of Liberty Utilities (St. Lawrence Gas) Corp. for Gas Service.

CASE 24-G-0369 - Petition of Liberty Utilities (St. Lawrence Gas) Corp. for Approval to Implement Automated Meter Reading and Recover Associated Costs.

ORDER ADOPTING TERMS OF A JOINT PROPOSAL, ESTABLISHING GAS RATE PLAN AND AUTHORIZING IMPLEMENTATION OF AUTOMATED METER READING

(Issued and Effective January 22, 2026)

BY THE COMMISSION:

INTRODUCTION

In this Order, the Commission approves the terms of a Joint Proposal, filed on August 29, 2025, establishing a three-year rate plan for gas delivery service by Liberty Utilities (St. Lawrence Gas) Corp. (the Company) for the period encompassing November 1, 2025, through October 31, 2028.[1] The

[1] Rate Year 1 (RY1) is from November 1, 2025, through October 31, 2026; Rate Year 2 (RY2) is from November 1, 2026, through October 31, 2027; and Rate Year 3 (RY3) is from November 1, 2027, through October 31, 2028.

Joint Proposal and supporting schedules are appended to this Order as Attachment A.

In summary, the Joint Proposal recommends a three-year Rate Plan that increases the Company's annual revenues from gas operations by $1.07 million in RY1; $1.09 million in RY2; and $1.12 million in RY3.[2] Excluding the effect of a make whole provision, monthly bill impacts during the Rate Plan term for the Company's residential service class (SC-1) are increases of $3.01 (3.4%) in RY1; $3.22 (3.5%) in RY2; and $3.58 (3.8%) in RY3.[3] The agreed return on equity (ROE) is 9.3%.[4] The primary rate drivers over the three-year Rate Plan include the amortization of regulatory deferrals, increased depreciation expense due to incremental capital spending, increased net utility plant due to incremental capital spending, implementation of automated meter reading (AMR), operation and maintenance (O&M) expenses (particularly labor and benefits), and property taxes.[5]

The Company, trial staff of the Department of Public Service (Staff), and Multiple Intervenors (MI)[6] signed the Joint Proposal (collectively, the Signatory Parties). The only other party to these proceedings, the Utility Intervention Unit of the New York State Department of State, Division of Consumer

[2] Joint Proposal, p. 10.

[3] Id., Appendix O.

[4] Id., p. 27.

[5] Company Statement in Support, p. 3; Hearing Exhibit 121 (Responses to ALJ Discovery Requests), pp. 3-5, 19-20.

[6] Multiple Intervenors is an unincorporated association of approximately 55 large industrial, commercial and institutional energy consumers with manufacturing and other facilities located throughout New York State (MI Statement in Support, p. 1).

Protection (UIU), authorized the Signatory Parties to state that it does not oppose the Joint Proposal.

For the reasons stated below, we adopt the terms of the Joint Proposal and supporting schedules as in the public interest. The terms of the Joint Proposal ensure the Company's continued provision of safe and reliable service at just and reasonable rates; fall within the range of potential litigated outcomes; and are consistent with the environmental, social, and economic policies of the Commission and the State, including New York's Climate Leadership and Community Protection Act (CLCPA). In addition, the Joint Proposal includes an earnings sharing mechanism and provides a multitude of benefits for customers, including rate stability, new reporting requirements and incentives to improve customer service performance metrics, the continuation of or increase in monthly bill discounts for low-income customers, the requirement that the Company grant a one-time per year reconnection waiver for low-income customers, enhanced outreach efforts targeting low-income and elderly customers and individuals in disadvantaged communities to boost enrollment in the low-income program, stricter reporting requirements for the Company's outreach and education activities to increase transparency regarding its efforts, and a new arrearage management program that offers forgiveness of up to $1,200 annually in arrears for certain low-income customers.[7] We therefore conclude that the Joint Proposal meets the public interest standard set forth in Public Service Law (PSL) §65(1).

[7] Joint Proposal, pp. 40-44; Staff Statement in Support, pp. 68-73; Company Statement in Support, pp. 66-70.

BACKGROUND

The Company provides gas service to approximately 17,000 customers in rural, northern New York.[8] On June 7, 2024, the Company filed a petition in Case 24-G-0369 seeking authorization to implement AMR throughout the Company's service territory and recovery of all costs associated with that implementation during the Company's next rate plan. On August 13, 2025, the Company filed a notice of impending settlement discussions. The parties incorporated the request for implementation of AMR in their settlement discussions in Case 24-G-0668. They seek resolution of all issues related to the AMR petition in the Joint Proposal, closure of Case 24-G-0369, and that all reporting and other requirements be subsumed into Case 24-G-0668.

On November 27, 2024, the Company filed revised tariff leaves proposing to increase its gas revenues. Specifically, the Company sought to increase its operating revenues by $2.17 million (6.12% of total revenues or 11.45% of delivery revenues) for the Rate Year beginning November 1, 2025, and ending on October 31, 2026.[9] The Company also filed testimony and exhibits proposing a one-year rate plan with the expectation that negotiating a multi-year plan could be required to meet the needs of all stakeholders in a fair and equitable manner. The historic test year supporting the Company's rate filing was the 12-month period ending June 30, 2024 (Historic Test Year).

On December 16, 2024, the Secretary to the Commission (Secretary) issued an initial Notice suspending the effective

[8] Company Statement in Support, p. 6. The Company is a subsidiary of Liberty Utilities Co. (LuCo), which is in turn a subsidiary of Algonquin Power & Utilities Corp., a Canadian corporation.

[9] Case 24-G-0668, Company's Cover Letter for Filing Rate Case (November 27, 2024, revised December 6, 2024), p. 2.

date of the rate filing through April 30, 2025.[10] The assigned Administrative Law Judges (ALJs) conducted technical and procedural conferences on January 2, 2025, and issued a ruling establishing a litigation schedule, including dates for the filing of testimony and commencement of an evidentiary hearing.[11] The Company filed corrections and updates to its testimony on February 28, 2025, Staff and UIU filed responsive testimony on April 1, 2025, and the Company filed rebuttal testimony on April 23, 2025.

Staff recommended a Rate Year revenue requirement decrease of $1.19 million, premised upon a 42.0% common equity ratio and an ROE of 9.25%.[12] In its rebuttal filing, the Company updated its requested base delivery revenue increase to $2.33 million. The Company's updated request reflected a common equity ratio of 48.0% and a ROE of 9.9%.[13]

Pursuant to the Commission's Settlement Rules and Guidelines, the Company filed a Notice of Impending Settlement Negotiations on April 29, 2025, and, relatedly, requested postponement of the evidentiary hearing and consented to an extension of the suspension period, subject to a "make-whole" provision. The Company subsequently agreed to similar extensions of the suspension period, again subject to a "make-whole" provision. The Commission ultimately suspended the

---

[10] Case 24-G-0668, Notice of Suspension of the Effective Date of Major Rate Changes and Initiation of Proceedings (issued December 16, 2024). On April 23, 2025, pursuant to PSL §66(12)(f), the Secretary issued a Notice of Further Suspension of the Effective Date of Major Rate Changes, extending the effective suspension period through October 30, 2025.

[11] Case 24-G-0668, Ruling on Schedule (issued January 3, 2025).

[12] Staff Statement in Support, p. 22.

[13] Id.

effective date of the proposed amendments through March 30, 2026.[14]

Settlement negotiations resulted in the filing of the Joint Proposal on August 29, 2025. Statements in Support of the Joint Proposal were filed by the Company, Staff, and MI. An evidentiary hearing on the Joint Proposal was conducted by the ALJs on November 19, 2025, to admit exhibits into evidence. Following the hearing, the ALJs determined that no post-hearing briefing on any issue was necessary before the Commission's consideration of the Joint Proposal and the resolution of this rate filing.

NOTICE OF PROPOSED RULE MAKING AND PUBLIC COMMENTS

Pursuant to the State Administrative Procedure Act (SAPA) §202(1), a Notice of Proposed Rulemaking was published in the State Register on February 5, 2025 (SAPA No. 24-G-0668SP1). Moreover, by Secretary's Notices, comments were solicited, due November 14, 2025. The Judges presided over two virtual public statement hearings, during which the only speaker was a representative of the Public Utility Law Project of New York, Inc. (PULP). Although PULP did not join these proceedings as a party, it expressed its concerns regarding the number of customers struggling to afford service even without a rate increase, whether the Company is filing collections activity reports, whether the Company's administrative fees are charged only to large energy service company customers, the adequacy of the discounts provided through the Company's tiered low-income program, and whether the levelized payment plan for residential customers differs in any meaningful way from the budget billing program currently used by the Company. PULP subsequently

[14] Case 24-G-0668, Order on Extension of Maximum Suspension Period on a Major Rate Filing (issued October 17, 2025).

submitted written comments reiterating the concerns raised during the public statement hearing, as well as additional comments that the Commission should reject any reinstitution of Positive Revenue Adjustments (PRAs) and that the Company should expand its language access services.

In addition to PULP's comments, the Commission's website contains approximately 70 comments filed in the rate proceeding.[15] Commenters are overwhelmingly opposed to the requested rate increases, mainly citing the current high level of unaffordability. In particular, commenters focused on the Company's statements in its revised petition that its requested revenue increase would result in an average monthly 11.3% bill increase for residential customers, with much lower increases proposed for commercial and industrial customers. Commenters questioned how an increase in rates on struggling residential customers could be justified in light of the Company's reported profits and executive compensation, with many suggesting the Company should cut costs internally rather than seek a rate increase. Another recurrent theme in the public comments is claims of ongoing billing errors, with customers stating that they sometimes do not receive bills at all or receive bills with a negative balance and then are overcharged on other bills.[16] Notably, the St. Lawrence County Deputy Clerk also submitted a resolution adopted by that County's Board of Legislators opposing the Company's requested rate increase and urging the

[15] An overwhelming majority of the comments were submitted prior to the filing of the Joint Proposal.

[16] The parties indicate that the percentage of adjusted bills in 2025 was 10.35%, which is slightly lower than the rate in the preceding three years. The parties anticipate that implementation of AMR, discussed in the Automated Meter Reading section of this Order, is expected to significantly reduce the number of adjusted bills (Hearing Exhibit 121 (Responses to ALJ Discovery Requests), pp. 13-14.)

Commission to reject the request in light of the financial burden on County residents caused by high levels of inflation.

STATUTORY AND REGULATORY FRAMEWORK

Pursuant to PSL §65(1), in establishing electric and gas rate plans, the Commission must find that the proposed rates assure the continuation of safe and adequate service at just and reasonable rates and produce a result that is in the public interest.[17] In evaluating what constitutes a reasonable rate, the Supreme Court of the United States has cautioned that, in order to avoid an unconstitutional taking of property dedicated to public service, utility rates must be set at a level that allows the utility an opportunity to earn a return on the value of its property that is comparable to the return available to other companies with a similar risk profile.[18] Thus, while the Commission is empowered to consider any factor it deems relevant in setting utility rates, it must in all cases give "due regard ... to a reasonable average return upon capital actually expended."[19]

As we evaluate the proposed rate plan in light of the requirements of the applicable statutes, we are mindful that

---

[17] Upon an application for a major change in rates, PSL §66(19)(c) also requires the Commission to review a utility's "compliance with the directions and recommendations made previously by the Commission, as a result of the most recently completed management and operations audit." No management and operations audits of the Company have been completed (Case 25-M-0515, Liberty Utilities (New York Water) Corp. and Liberty Utilities (St. Lawrence Gas) Corp. – Focused Operations Audit, Order Initiating a Focused Operations Audit (issued September 18, 2025), p. 2).

[18] Bluefield Waterworks & Improvement Co. v. Public Serv. Commn. of West Va., 262 U.S. 679, 692-693 (1923).

[19] Matter of Abrams v. Public Serv. Commn. of State of N.Y., 67 N.Y.2d 205, 212 (1986).

courts in New York will not disturb a rate set by the Commission unless the rate lacks a rational basis or reasonable support in the record.[20] The Commission will adopt the terms of a negotiated Joint Proposal only upon a finding that the terms, considered as a whole, meet the public interest standard in PSL §65(1). Factors to consider in evaluating whether that standard has been met include whether the Joint Proposal is consistent with the environmental, social, and economic policies of the Commission and the State; whether it falls within the range of reasonable outcomes that likely would have resulted in a fully litigated proceeding; and whether the record provides a rational basis for the Commission's adoption of it.[21] The Commission also must consider whether the Joint Proposal balances the protection of consumers with fairness to investors and the long-term viability of the utility. The individual, interrelated compromises negotiated by the parties will not be disturbed absent a demonstration that a challenged provision of the agreement is inconsistent with sound policy, outside the range of likely litigated outcomes, or contrary to the protection of ratepayers, fairness to investors and the long-term viability of the Company.[22]

Finally, CLCPA §7(2) requires State agencies to "consider whether their [administrative] ... decisions are inconsistent with or will interfere with the attainment of the

---

[20] See Matter of New York Tel. Co. v. Public Serv. Commn. of State of N.Y., 95 N.Y.2d 40, 48 (2000); Matter of Abrams, supra, at 212.

[21] Cases 90-M-0255 and 92-M-0138, Proceeding on Motion of the Commission Concerning its Procedures for Settlements and Stipulation Agreements, Opinion 92-2, Opinion, Order and Resolution Adopting Settlement Procedures and Guidelines (issued March 24, 1992) (Settlement Guidelines).

[22] Id.

established statewide greenhouse gas [GHG] emission limits established in" Environmental Conservation Law (ECL) Article 75. CLCPA §7(3) prohibits State agencies from issuing decisions that "disproportionately burden disadvantaged communities as identified pursuant to [ECL §75-0101(5)]" and requires prioritizing reductions of GHG emissions and co-pollutants in such disadvantaged communities. As the Commission has previously explained, however, the requirements of the CLCPA do not exist in a vacuum and must be balanced against the Commission's core mandate as defined by the Public Service Law, which is to act on behalf of the public in ensuring safe and adequate service at just and reasonable rates.[23]

THE JOINT PROPOSAL

Term and Make Whole Provision

The Joint Proposal establishes a three-year rate plan consisting of three successive individual Rate Years beginning November 1, 2025, and ending on October 31, 2028. The Company agrees that it will not file a new gas rate case for rates to become effective prior to November 1, 2028.[24] The three-year term of the proposed rate plan is typical for rate cases resolved through settlement and is reasonable because its length provides advantages for ratepayers that cannot be achieved through a fully litigated case, such as moderation of rate increases over multiple years.

Because this Order is being issued after November 1, 2025, a make-whole provision is warranted pursuant to which the Company will recover under-collections or refund over-collections in sales revenue resulting from the Company's

[23] Cases 22-E-0317 et al., NYSEG and RG&E – Rates, Order Adopting Joint Proposal (issued October 12, 2023), p. 55.

[24] Joint Proposal, p. 47.

agreement to extend the suspension period to accommodate settlement negotiations in these proceedings. The revenue differences will be recovered, with applicable surcharges and carrying charges, over the remaining months of RY1 and RY2, as detailed in Appendix B of the Joint Proposal.[25]

Revenue Requirement Summary

As explained above, the Company initially proposed an unmoderated one-year revenue requirement increase of approximately $2.17 million for gas delivery service.[26] The Joint Proposal provides that the Company’s unlevelized revenue requirements will increase by approximately $0.40 million in RY1, $1.88 million in RY2, and $1.65 million in RY3, corresponding to total revenue increases of 0.9%, 4.2% and 3.5%.[27]

The Joint Proposal further provides levelization to moderate the impact of the revenue increases, resulting in total revenue increases of 2.4% per year.[28] The levelized rates and charges in the Joint Proposal are designed to produce additional delivery revenue and, during the term of the rate plan, typical residential monthly bill impacts,[29] as follows:

---

[25] Id., p. 8 & Appendix B, Schedule 2.

[26] Case 24-G-0668, Company’s Letter for Filing Rate Case (November 27, 2024, revised December 6, 2024), at 2.

[27] Joint Proposal, pp. 9-10.

[28] Id. As of the date of the evidentiary hearing, the rate of inflation projected for RY1 is 2.76%. Thus, the revenue increases approximately track, but are slightly less than, the inflation rates projected in each Rate Year (id., p. 12; Evidentiary Hearing Transcript, p. 18).

[29] Joint Proposal, p. 10 and Appendix O, pp. 1-6. Minimum monthly charges are included in the bill impacts set forth above and are also further addressed in the Revenue Allocation and Rate Design Section of this Order.

	RY 1	RY 2	RY 3
Revenue Requirement Increase	$1.06 million	$1.09 million	$1.12 million
Delivery Revenue Percent Increase	5.8%	5.6%	5.5%
Average Monthly Bill Impact	$3.01	$3.22	$3.58
Average Percentage Monthly Bill Increase	3.4%	3.5%	3.8%

Given the cumulative nature of the rate increases – i.e., the RY1 increase will be in effect for all three years and the RY2 increase will be in effect for two years – the Joint Proposal would provide $6.50 million in incremental revenues during the plan.[30] The total bill impact on residential customers is an increase of approximately 10.7% over the course of the three-year rate plan,[31] which is less than the 11.3% bill increase initially proposed by the Company for RY1 alone.[32]

[30] Joint Proposal, p. 10.

[31] Id., Appendix O. Over the course of the rate plan and excluding the effect of a make-whole provision, the total bill increases on other service classes are 9.6% on SC-2 (commercial sales customers), 4.0% on SC-2L (large commercial sales customers) and 8.4% on SC-3 (industrial transport customers). The Company originally proposed a 1.9% total RY1 bill increase on SC-2, a 1.2% decrease on SC-2L and a 4.0% increase on SC-3 (Case 24-G-0668, Company's Cover Letter for Filing Rate Case (November 27, 2024, revised December 6, 2024), pp. 2-3.

[32] Case 24-G-0668, Company's Cover Letter for Filing Rate Case (November 27, 2024, revised December 6, 2024), p. 2.

Assuming a three-month make-whole period (i.e., November 1, 2025, through February 1, 2025), the estimated average residential monthly bill increases are $3.78 or 4.3% for RY1 and $3.24 or 3.5% for RY2.

Staff indicates that adjustments to operation and maintenance expenses ($0.52 million), amortization of deferrals ($0.33 million), rate base ($0.42 million) and increase of the common equity ratio from 42.00% to 48.00% ($0.16 million) were the main contributing factors to the difference between the Joint Proposal's recommendation of an unlevelized increase of $0.40 million in RY1 and Staff's litigation position that a decrease of $1.19 million was warranted.[33] As MI notes in its Statement in Support of the Joint Proposal, the increases in revenue requirement contained in the Joint Proposal are substantial but considerably reduced from the Company's initial proposal, compare favorably to the likely results of a litigated outcome, and are the reasonable product of compromise among the parties.[34] The increases will fund, among other things, capital projects required to upgrade aging infrastructure, implementation of AMR, customer protection initiatives, improvements to cybersecurity, and programs to enhance gas safety and reduce gas losses on the utility's system, and are consistent with the State's climate-related goals.

Although we recognize that the rate increases may present a hardship for some ratepayers, we find that the manner in which revenues will be collected will serve to ameliorate the rate impacts to some extent. Specifically, rates are levelized over the three-year term of the rate plan, and the increases

---

[33] Staff Statement in Support, p. 22.

[34] MI Statement in Support, pp. 2-3.

associated with the make-whole provision will be collected over the balance of RY1 and RY2.

The increases appropriately balance affordability concerns with the Commission's obligation to ensure that the Company has adequate revenue to deliver safe and reliable service, will be able to meet the regulatory and statutory requirements imposed on it, and is able to provide the Company's investors with the opportunity to earn a reasonable return. Moreover, as explained below, many elements of the revenue requirement represent a compromise of various litigated positions. These elements of the revenue requirement cannot be evaluated individually without the necessary context of the overall rate plan. In short, the record before us demonstrates that the parties worked collaboratively to ensure that the revenue increases proposed in the Joint Proposal are minimized to the extent possible in light of current economic conditions. Thus, we find no basis to upset the balance achieved by the Signatory Parties in negotiating the Company's future revenue requirements during the term of the Joint Proposal.

Sales and Revenue Forecast

Staff developed its own econometric models to forecast the Company's customers and sales, taking into account factors such as previous trends and seasonal patterns, which can affect yearly sales levels.[35] In addition, while the Company forecasted its gas sales using 30-year weather normalized monthly sales data, Staff based its forecast on a 10-year heating degree day average.[36] Staff forecasted 132 more customers and total sales volume 145,644 therms below the Company's forecast.[37] The gas

[35] Hearing Exhibit 80 (Staff Witness Gadomski Testimony (Forecasting and Inflation)), pp. 7-9.

[36] Id., pp. 12-13.

[37] Id., pp. 7-8.

sales forecasts reflected in Appendix C of the Joint Proposal are based on a 10-year average weather normalization, as recommended by Staff, and more closely align with Staff's forecast.[38] The use of a 10-year average weather normalization is more likely to reflect anticipated weather trends relevant to forecasted monthly sales and is consistent with previous rate cases.[39] As the Company notes, its agreement to use a 10-year period for weather normalization purposes represents a compromise on the part of the Company and, inasmuch as the forecasts reflect Staff's modeling improvements, we find that these consensus forecasts are reasonable.

In its Corrections and Updates filing, the Company Projected RY1 total operating revenue of $35.19 million, while Staff projected $35.03 million at current rates.[40] Appendix D to the Joint Proposal states that the total operating revenue in RY1 under current rates would be $35.03 million, reflecting Staff's recommended adjustments to the Company's Merchant Function Charge (MFC) and Delivery Revenue Adjustment (DRA) forecasts, which are based on an updated uncollectible rate. Staff also recommended excluding contributions in aid of construction (CIACs) from the Company's miscellaneous service revenue – and to use CIACs to reduce plant in service – to be consistent with the Uniform System of Accounts and to adjust gas cost revenue to match gas cost expense.[41] Appendix D also sets

---

[38] Joint Proposal, p. 10 & Appendix C; Hearing Exhibit 81 (Staff Witness Gadomski Exhibits (DGS-2)).

[39] Hearing Exhibit 80 (Staff Witness Gadomski Testimony (Forecasting and Inflation)), pp. 12-13.

[40] Hearing Exhibit 71 (Staff Revenue Allocation and Rate Design Panel Testimony), p. 10.

[41] Id., pp. 12-17. MFCs and DRAs are further discussed in the Revenue Allocation and Rate Design Section of this Order, and CIACs are discussed in the Rate Base Section.

forth the forecasts of the Company's base delivery revenues (excluding gross revenue taxes and gas costs) used to set rates for the three-year plan: $18.09 million in RY1, $19.30 million in RY2, and $20.56 million in RY3.[42] These figures largely reflect Staff's recommended sales forecast adjustments for SC-1 (residential), SC-2 (commercial), and SC-2L (large commercial).[43]

Operation and Maintenance Expenses

The Joint Proposal provides for total operation and maintenance (O&M) expenses of $7.44 million in RY1, $7.87 million in RY2, and $8.18 million in RY3.[44] Details regarding the Company's O&M Expenses are contained in Appendix A, Schedule 2 to the Joint Proposal. The significant or contested O&M expenses are discussed below.

1. Direct Labor

The Company originally projected a Rate Year total direct labor expense of $4.32 million.[45] Staff recommended adjusting direct labor expense to eliminate an incremental full-time employee (FTE) in the Company's labor expense forecast because the anticipated job duties were absorbed by an existing position, reducing the salary of the other incremental FTE to reflect the average salary for that grade level, and removing non-union management incentive compensation – totaling

---

[42] Base delivery revenue includes revenue associated with minimum charges, contract administration fees, and volumetric rates from firm and non-firm customers, as well as delivery revenues from customers taking service under negotiated contracts (id., pp. 10-11).

[43] Id., pp. 11-12; Joint Proposal, Appendix D.

[44] Joint Proposal, p. 11.

[45] Hearing Exhibit 73 (Staff Revenue Requirement Panel Testimony), p. 24. Direct labor expenses are those associated with employees directly employed by the Company (Hearing Exhibit 47 (Company Revenue Requirement Panel Testimony), p. 15).

approximately $531,000 – from the revenue requirement.[46] With respect to incentive compensation, Staff explained that Commission policy, as set forth in Case 10-E-0362, currently provides that incentive compensation may be recovered from ratepayers if a utility demonstrates – through, for example, the provision of a compensation study of similarly situated companies – that its total level of employee compensation, inclusive of incentive pay, is reasonable relative to peer companies and that the incentive compensation plan does not include performance targets that adversely affect ratepayer interests or are inconsistent with Commission policies.[47] Staff further opined that incentive targets should focus on improvements to customer service, reliability, safety, and the environment and not be primarily inclusive of financial

[46] Hearing Exhibit 73 (Staff Revenue Requirement Panel Testimony), pp. 15, 25-30. The adjustments to the FTE positions reduced the labor expense forecast by approximately $79,000.

[47] See Case 10-E-0362, Orange and Rockland Utilities, Inc. – Rates, Order Establishing Rates for Electric Service (issued June 17, 2011), pp. 39-41. In the alternative, a Company may demonstrate the reasonableness of an incentive compensation program by making an "affirmative demonstration that [an] above base pay incentive compensation program[] [is] designed to return quantifiable or demonstrable benefits to ratepayers in a financial sense or in terms of reliability, environmental impact, or customer service" (id., p. 38). The Commission has also ordered retention of an independent auditor to conduct focused assessments of the management compensation programs of New York utilities – including the Company – to identify best practices and improvement opportunities (Case 25-M-0043, In the Matter of a Focused Operations Audit to Examine Management Incentive Compensation Programs at Electric, Gas, and Water Utilities, Order Initiating an Operations Audit (issued February 13, 2025)), but no audit report or substantive orders have been issued in that proceeding thus far.

targets.[48] Although Staff concluded that a compensation study submitted by the Company demonstrated that its management compensation package, including incentive pay, is slightly below or within market competitive range,[49] Staff recommended removing incentive compensation in its entirety from the revenue requirement because the incentive compensation program is run by the Company's corporate parent – Algonquin Power & Utilities Corporation (Algonquin) – and predominantly focused on financial performance or performance unrelated to the Company's operations.[50]

In its rebuttal testimony, the Company agreed with Staff's recommendations regarding the incremental FTEs but disagreed with Staff's recommendation to remove incentive compensation. The Company asserted that its compensation package is already below market competitive range and would be well below that range if its incentive compensation package, which was supported by a comprehensive, market-based compensation study, was eliminated.[51] The Company argued that, among other things, Staff's primary objection to the incentive compensation plan – that certain performance metrics were inappropriate because they relate to the performance of Algonquin affiliates that are involved with other regulated industries – ignored the reality of, and economies of scale that

[48] Hearing Exhibit 73 (Staff Revenue Requirement Panel Testimony), p. 14.

[49] Id., pp. 15-18; Hearing Exhibits 50-52 (Company Revenue Requirements Panel Exhibits RR-3 & RR-4 (REDACTED and UNREDACTED)).

[50] Hearing Exhibit 73 (Staff Revenue Requirement Panel Testimony (REDACTED)), pp. 18-23.

[51] Hearing Exhibit 104(Company Revenue Requirement and Forecasting Panel Rebuttal Testimony (REDACTED)), pp. 7-12.

are derived from, having a regional and corporate workforce that provides services to multiple affiliates.[52]

The Joint Proposal reflects Staff's adjustments regarding the incremental employees and recommends $3.88 million of direct labor expense in RY1, which includes approximately $168,000 related to incentive compensation.[53] Subsequent to the filing of testimony and in response to the Commission's May 2025 Order in Case 23-W-0235,[54] Algonquin updated its incentive compensation program to reweight the performance scorecards comprising the program and to emphasize the performance of each operating subsidiary.[55] In light of the updated program, the forecast of direct labor incentive compensation expense appropriately reflects recovery of costs related solely to the performance of the Company's employees, to the benefit of the

---

[52] Id., p. 23.

[53] Joint Proposal, Appendix A, Schedule 2; Staff Statement in Support, p. 24.

[54] In Case 23-W-0235, Liberty Utilities (New York Water) Corp. – Rates, Order Denying Petition Seeking Approval of Cost Recovery and a Related Surcharge (issued May 15, 2025), p. 10, the Commission concluded that, while the compensation levels demonstrated in the proffered compensation study were potentially reasonable, the metrics and goals used in Algonquin's incentive compensation program were either primarily financial in nature or had no apparent relation to individual subsidiaries' operations and benefit to their customers. The Commission explained that Algonquin's incentive compensation program, which focused on the performance of Algonquin and its subsidiaries overall, created possible circumstances where an individual subsidiary's customers would be paying for incentive payouts that do not relate to service to the subsidiary's customers at all, or even rewarding performance contrary to Commission policies and ratepayers' interests (id. at 13).

[55] Staff Statement in Support, pp. 24-25; Hearing Exhibit 121 (Responses to ALJ Discovery Requests), p. 12.

Company's customers.[56] Staff asserts that cost recovery for the program is, therefore, now generally aligned with that approved for other utilities.[57] Moreover, the parties indicate that the individual and Company-wide targets set forth in the program are tied to the Company's operational performance in safety, reliability, customer service, and environmental-related areas, which have direct benefits for the Company's customers.[58]

We find that the inclusion of costs related to incentive compensation in direct labor expenses is reasonable in light of the Joint Proposal's limitation on recovery of costs to those that are related to incentive compensation program goals attributed to the performance of the Company. The parties do not dispute that the Company submitted a compensation study demonstrating that its overall management compensation levels, including incentive compensation, are reasonable relative to peer companies. Under these circumstances, the inclusion of expenses related to the revised incentive compensation plan does not adversely affect ratepayer interests and is consistent with current Commission policies.

2. Indirect Allocated Labor

The Company forecasted indirect allocated labor expense of $901,000 for the Rate Year.[59] Staff recommended three adjustments: (1) removing forecasted wage increases on the

---

[56] Hearing Exhibit 125 (Response to ALJ 030), pp. 1-2.

[57] Staff Statement in Support, pp. 24-25; Hearing Exhibit 121 (Responses to ALJ Discovery Requests), p. 12.

[58] Hearing Exhibit 121 (Responses to ALJ Discovery Requests), p. 12.

[59] Hearing Exhibit 73 (Staff Revenue Requirement Panel Testimony (REDACTED)), p. 35. Indirect allocated labor expense refers to indirect labor, overtime, and bonuses allocated to the Company in accordance with Algonquin's Cost Allocation Manual for services provided by Algonquin and its affiliates to its subsidiaries (id., p. 34).

ground that the Company's forecast, which assumed indirect allocated labor would track the projected direct labor increase, was not reliable, (2) removing any incentive compensation booked to this account consistent with the recommendation made regarding direct labor expense, and (3) a reduction consistent with Staff's recommendation to reduce cybersecurity capital costs by 22% in light of historical underspending.[60] These adjustments resulted in a forecasted indirect allocated labor expense of approximately $769,000 for the Rate Year.[61] In its rebuttal testimony, the Company disagreed with all of Staff's recommendations regarding indirect allocated labor.[62]

The Joint Proposal recommends an indirect allocated labor expense of approximately $837,000 for RY1.[63] Staff indicates that the agreed upon amount reflects a reduction in cybersecurity labor costs of 10% instead of 22%, and an addition of approximately $55,000 for incentive compensation.[64] With respect to incentive compensation, Staff argues that the Joint Proposal appropriately considers the Company's updated incentive compensation program and now reflects recovery of incentive compensation program goals attributed to the performance of corporate employees who achieve those operational targets that directly benefit the Company's customers.[65] Staff and the Company aver that the Joint Proposal does not allow cost recovery for any incentive compensation based on the performance of Algonquin's other affiliates; rather, the Joint Proposal

---

[60] Id., pp. 35-39.

[61] Id., p. 39.

[62] Hearing Exhibit 104 (Company Revenue Requirement Panel and Forecasting Panel Rebuttal Testimony (REDACTED)), pp. 25-26.

[63] Joint Proposal, Appendix A, Schedule 2.

[64] Staff Statement in Support, p. 25.

[65] Id.

provides cost recovery for incentive compensation based on meeting only those corporate targets that directly benefit the Company's customers.[66] Inasmuch as the amount of indirect allocated labor expense is a compromise and the incentive compensation program now better reflects Company's performance, this provision of the Joint Proposal is reasonable.

3. Uncollectibles

The Company developed its Rate Year forecast of uncollectible expense by taking a monthly average of actual net write-offs, annualizing that monthly average, and then dividing that annual amount by the adjusted Historic Test Year operating revenue, which resulted in an uncollectible rate of 1.31%. The Company then applied that percentage to the Rate Year operating revenue forecast at then-current rates, resulting in an uncollectible expense amount of $460,000.[67] Staff disagreed with the use of actual write-offs from January 2022 through June 2024 to calculate monthly average because the write-offs for certain months during that time frame were anomalously high due to the implementation of new software and excessive post-pandemic arrears.[68] Staff recommended using actual monthly net write-offs for the most recent period following the anomalous months, April 2024 to January 2025, which resulted in an uncollectible rate of 0.49% and an uncollectible expense amount of $171,647.[69] The Company generally agreed but asserted that the same

[66] Hearing Exhibit 121 (Responses to ALJ Discovery Requests), p. 12; Hearing Exhibit 125 (Response to ALJ 030), pp. 1-2.

[67] Hearing Exhibit 73 (Staff Revenue Requirement Panel Testimony (REDACTED) p. 43.

[68] Id., p. 46.

[69] Id., pp. 47-49.

uncollectible rate that was approved in the 2023 Rate Order, 0.50%, should be continued.[70]

The Joint Proposal recommends an uncollectibles expense of approximately $177,000, reflecting an uncollectible rate of 0.50%.[71] The increase above Staff's litigation position is de minimis and provides a reasonable forecast for uncollectibles.[72]

4. Pension and OPEB

The Company forecasted a Rate Year amount of negative $1.15 million and negative $1.35 million for pension and Other Post-Employment Benefits (OPEB) expenses, respectively.[73] Staff disagreed with the Company's forecast on the ground that the Company failed to apply the correct labor capitalization rate to the service cost component of its pension and OPEB expenses.[74] The Company applied capitalization rates of 17.58% and 34.57% to its pension and OPEB service cost components, while Staff used the same capitalization rate for employee benefits that applies to direct labor, 48.00%.[75] Use of the 48.00% capitalization rate resulted in Rate Year forecasts of negative $1.25 million and negative $1.36 million.[76] The Company disagreed with the use of

---

70 Hearing Exhibit 104 (Company Revenue Requirement Panel and Forecasting Panel Rebuttal Testimony (REDACTED)), p. 27.

71 Joint Proposal, p. 11 & Appendix A, Schedule 2.

72 Hearing Exhibit 73 (Staff Revenue Requirement Panel Testimony (REDACTED)), p. 47.

73 Id., p. 79.

74 Id., pp. 79-80. The Company's pension and OPEB expenses consist of five components: (1) service cost; (2) interest costs; (3) expected return on assets; (4) prior service cost amortizations; and (5) recognized net actuarial gains and losses (id., p. 77).

75 Id., p. 80.

76 Id., p. 81.

a 48.00% capitalization rate, arguing that its rates were based on the actual capital credits charged to the accounts at issue.[77] The Joint Proposal adopts Staff's position,[78] which, although it reflects a significant compromise on the Company's part in terms of revenue requirement dollars, is premised on proper pension and OPEB accounting.

5. Greenhouse Gas Reduction/Hybrid Heating Program

The Company initially proposed inclusion of $320,000 in O&M expenses for the Rate Year for its greenhouse gas reduction/hybrid heating program (GHG program).[79] The Company asserted that the program would promote, through the provision of monetary incentives that would cover 10-17% of total installation costs, the installation of hybrid heat pump systems for existing or prospective customers of the Company.[80] Over the term of a three-year rate plan, the proposed budget was $980,000.[81] Staff recommended removing the costs of the GHG program from the revenue requirement given the limited supporting information provided by the Company and the significant cost of the program to ratepayers.[82] In particular, Staff expressed concern that the Company had not assessed customer interest in the program, coordinated with local electric providers to assess the potential effect on the electric grid, or considered alternatives if customer interest

---

[77] Hearing Exhibit 104 (Company Revenue Requirement Panel and Forecasting Panel (REDACTED)), p. 33.

[78] Joint Proposal, Appendix A, Schedule 2.

[79] Hearing Exhibit 73 (Staff Revenue Requirement Panel Testimony (REDACTED)), p. 87.

[80] Hearing Exhibit 69 (Staff Policy Panel Testimony), pp. 17-18, 23.

[81] Id., p. 19.

[82] Id., pp. 26-27.

was less than projected given the minimal amount of the incentive compared to the total cost of heat-pump installation. Consistent with Staff's recommendation, the Joint Proposal does not reflect the costs of the GHG Program.[83]

6. Productivity Adjustment

The Commission's long-standing policy is to impute a productivity adjustment to capture unquantifiable and unidentified efficiencies and cost savings that could be realized in the Rate Year. Thus, Staff recommended applying a standard productivity adjustment of 1% of aggregate labor, payroll taxes and employee benefits.[84] Although the Company initially objected to the productivity adjustment as arbitrary, unwarranted and inappropriate,[85] it agreed to the application of the adjustment in the Joint Proposal.[86]

7. Inflation

Staff and the Company agreed that the most appropriate method to calculate the inflation rate is to use the latest available Blue Chip Economic Indicators forecasts of the Gross Domestic Product Price Index.[87] The forecasts are published by the United States Bureau of Economic Analysis and the Commission has traditionally used them to calculate inflation rates.[88] The

---

[83] Joint Proposal, p. 11.

[84] Hearing Exhibit 73 (Staff Revenue Requirement Panel Testimony (REDACTED)), pp. 90-91.

[85] Hearing Exhibit 104 (Company Revenue Requirement Panel and Forecasting Panel Testimony (REDACTED)), pp. 35-36.

[86] Joint Proposal, p. 12; Company's Statement in Support, p. 45.

[87] Hearing Exhibit 73 (Staff Revenue Requirement Panel Testimony (REDACTED)), pp. 90-91; Hearing Exhibit 80 (Staff Witness Gadomski Testimony (Forecasting and Inflation)), pp. 14-15; Hearing Exhibit 104 (Company Revenue Requirement Panel and Forecasting Panel Rebuttal Testimony (REDACTED)), p. 58.

[88] Staff Statement in Support, p. 28.

Joint Proposal reflects inflation rates of 6.58% for the historic test year through RY1 (July 1, 2024, through October 31, 2026), 2.40% for RY2, and 2.32% for RY3.[89]

Depreciation

The Joint Proposal reflects depreciation expense of approximately $2.20 million for RY1, $2.64 million for RY2, and $3.09 million for RY3.[90] Depreciation rates and factors, including average service life (ASL), net salvage value, and survivor curve type for specific plant accounts are set forth in Appendix E of the Joint Proposal.

The Company provided a depreciation study proposing changes to the types of survivor curves used in calculating depreciation – specifically, moving from sets of h-type curves to sets of Iowa-type curves for 11 distribution plant accounts and from h-type curves to square-type curves for six general plant accounts.[91] The depreciation study also proposed changes to the ASLs for five distribution plant accounts and three general plant accounts, as well as net salvage value changes for six distribution plant accounts and one general plant account.[92] Staff recommended using different survivor curves and/or ASLs for eight distribution plant accounts based on fit with observed data.[93] Staff also recommended changes to the net salvage value

[89] Joint Proposal, p. 12. At the evidentiary hearing, the parties indicated that the rate of inflation projected for RY1 is 2.76% (Evidentiary Hearing Transcript, p. 18).

[90] Joint Proposal, p. 12 & Schedule A, pp. 7, 17, 27.

[91] Hearing Exhibit 21 (Company Depreciation Panel Testimony), pp. 8-9; Hearing Exhibit 58 (Staff Depreciation Panel Testimony), pp. 11-12.

[92] Hearing Exhibit 58 (Staff Depreciation Panel Testimony), p. 12.

[93] Id., pp. 14-15.

for one additional distribution plant account.[94] Staff's recommended changes resulted in a reduction of approximately $358,000 from the Company's estimated depreciation expense for RY1.[95] Staff also recommended that the Company discontinue its current practice of individually depreciating each item in accounts 391.1 (Office Furniture and Equipment - Computers), 392 (Transportation Equipment), and 396 (Power-Operated Equipment) and to adopt the group depreciation methodology for those accounts similar to the depreciation methodology that is used for the Company's other plant accounts included in the depreciation study.[96]

The Company disagreed with certain of Staff's modifications to ASLs and net salvage values but agreed with the proposal to move from individually depreciating assets to group depreciation for accounts 391.1, 392, and 396.[97] The agreed upon depreciation rates in the Joint Proposal represent a compromise between the Staff and Company positions and move toward the ASLs and net salvage values indicated by the depreciation study.[98] Thus, the depreciation rates are adopted. In addition, the Joint Proposal reflects the parties' agreement to move from individually depreciating the assets in accounts 391.1, 392, and 396 to group depreciation, and the Joint Proposal's depreciation expense has been updated to reflect the plant in service balance forecast included herein. Thus, the depreciation expense provisions of the Joint Proposal are reasonable.

---

[94] Id., p. 18.

[95] Id., p. 6.

[96] Id., pp. 27-32.

[97] Company Depreciation Panel Rebuttal Testimony, pp. 1-2, 12.

[98] Staff Statement in Support, p. 30; Company Statement in Support, p. 46.

Amortization of Regulatory Deferrals

The Joint Proposal reflects the Signatory Parties' agreement to the amortization of certain regulatory deferrals over the rate period, as listed in Appendix I to the Joint Proposal.[99] The net amount of regulatory deferrals to be amortized is $309,829 in RY1, $459,937 in RY2, and $459,937 in RY3.[100] As set forth in Appendix I, the most significant regulatory deferrals to be amortized over the three-year rate plan and recovered via base delivery rates are expenses associated with this rate case of approximately $980,000 and costs of $889,000 incurred to date by the Company in preparing its long-term plan (LTP) as required by the Commission's May 2022 Order in Case 20-G-0131.[101] The Company's LTP was filed on January 31, 2025.[102]

The Joint Proposal also establishes an LTP surcharge, through which the Company will be eligible to recover the following deferred incremental costs related to the LTP – along with carrying charges – to the extent such costs are not included in the revenue requirement: (1) incremental costs to prepare and file annual LTP updates, (2) incremental costs to prepare and file future triennial LTPs, and (3) incremental costs associated with Commission authorized projects or programs

[99] Joint Proposal, p. 13.

[100] Id.

[101] Id. & Appendix I, p. 4; see Case 20-G-0131, Proceeding on Motion of the Commission in Regard to Gas Planning Procedures, Order Adopting Gas System Planning Process (issued May 12, 2022).

[102] Case 24-G-0630, In the Matter of a Review of the Long-Term Gas System Plan of Liberty Utilities (St. Lawrence Gas) Corp., Initial Gas Long-Term Plan (filed January 31, 2025).

associated with the LTP.[103] The LTP surcharge will be updated annually in a statement filed with the Secretary by October 1 each year and will be limited to an amount no greater than 2% of the Company's actual aggregate operating revenues for the 12-month period ending August 31.[104] The LTP Surcharge will include a reconciliation of the prior 12-month period's over-collection or under-collection.[105]

The provisions addressing amortization of regulatory deferrals and the LTP surcharge allow the Company to timely recover its Commission-authorized costs while providing near-term rate stability and predictability. In addition, the yearly LTP surcharge will save customers from paying the carrying charges on the associated deferred balances. Thus, the Joint Proposal's provisions are reasonable.

Taxes

The payroll taxes in the Joint Proposal reflect an adjustment to the Company's initial forecast to track the adjustments made to direct labor expenses, as set forth above.[106] The Joint Proposal provides that payroll taxes will be $404,856 in RY1, $414,780 in RY2, and $424,434 in RY3.[107]

The Joint Proposal also incorporates the property tax forecasts agreed upon by the Company and Staff: $3.06 million

---

[103] Joint Proposal, pp. 13-14. Incremental costs could include, for example, external consultant costs.

[104] Id., p. 14.

[105] Id.

[106] Staff Statement in Support, p. 32; Company Statement in Support, p. 49-50.

[107] Joint Proposal, p. 15.

in RY1, \$3.33 million in RY2, and \$3.62 million in RY3.[108] The Joint Proposal recommends a property tax reconciliation mechanism through which the Company will defer, for future refund to or recovery from customers, the difference between actual property tax expense and the forecasted amounts.[109] The difference will be deferred for collection or refund in the Company's next rate case and shared 90%/10% between customers and the Company, respectively.[110] The reconciliation and sharing arrangement is intended to acknowledge the difficulty and risk of forecasting property taxes, while providing the Company with an incentive in controlling or reducing property tax expense to the extent that it is able to do so.[111]

Finally, forecasted state and federal income taxes are set forth in Appendix A.[112] Income tax expense is reduced by regulatory liabilities for excess accumulated deferred income taxes (EADIT), which arose from the reduction of the Company's federal income tax rate by the 2017 Tax Cuts and Jobs Act.[113] Pursuant to the 2023 Rate Order, the value of the EADIT

---

[108] Id. As noted above, the Company has cited increasing property taxes as a significant driver of the approximately \$1.1 million revenue requirement increase needed each year. That assertion is confirmed by the year-over-year increases shown in the text above, as well as the increase in amount of property taxes forecasted as compared to the amount approved in the prior rate plan, which was \$2.42 million, \$2.65 million and \$2.90 million over the course of the three Rate Years ending October 31, 2025 (Case 21-G-0577, supra, Joint Proposal, pp. 12-13 (filed March 30, 2023)).

[109] Id.

[110] Id.

[111] Staff Statement in Support, p. 33; Company Statement in Support, p. 50.

[112] Joint Proposal, Appendix A, pp. 4, 15, 25.

[113] Id., p. 16; Hearing Exhibit 73 (Staff Revenue Requirement Panel Testimony (REDACTED)), p. 116.

regulatory liabilities are negative $963,111 for the Company's Legacy Area and $627,047 for its Expansion Area, and are to be amortized over 15 years and 38 years, respectively.[114] The Joint Proposal reflects the Company's position that the amortization balances to which the parties agreed in the 2023 Rate Order were grossed up for tax purposes and, thus, the proper amortized amount to be used to reduce income taxes in each Rate Year is $59,615.[115]

As the parties assert, the tax provisions of the Joint Proposal represent reasonable compromises between the parties and ensure that the Company's customers will receive the full benefit of past tax reductions and the vast majority of the benefit of any future property tax reductions that the Company is able to achieve.[116] Thus, these provisions are reasonable.

Rate Base

The Company originally proposed a rate base for RY1 of approximately $58.86 million, while Staff proposed approximately $45.60 million.[117] The Joint Proposal reflects the parties' compromise position that the 13-month average rate base will be approximately $50.62 million in RY1, $58.04 million in RY2, and $65.35 million in RY3.[118] The projected average plant-in-service

[114] Joint Proposal, p. 16; Hearing Exhibit 73(Staff Revenue Requirement Panel Testimony (REDACTED)), pp. 116-118. The Company's Legacy Area is comprised of certain communities in St. Lawrence County and a portion of Lewis County, while the Expansion Area is comprised of other communities in St. Lawrence County and a portion of Franklin County (Joint Proposal, p. 4; Hearing Exhibit 73 (Staff Revenue Requirement Panel Testimony (REDACTED)), p. 117).

[115] Joint Proposal, p. 16.

[116] Staff Statement in Support, pp. 32-34; Company Statement in Support, pp. 50-51.

[117] Company Statement in Support, pp. 51-52.

[118] Joint Proposal, p. 16.

balances for each Rate Year, which are calculated by adding the agreed-upon yearly capital expenditures to plant-in-service balance as of December 31, 2024, are $96.90 million for RY1, $107.06 million for RY2, and $117.52 million for RY3.[119] These figures reflect the capital spending levels necessary for the Company to continue to provide safe and reliable service.

1. Net Plant Reconciliation Mechanism

In its pre-filed testimony, Staff proposed that the Company continue its downward-only net plant reconciliation mechanism, which would defer, for the benefit of customers, the revenue requirement impact of a reduction in average net plant balance and depreciation expense if the Company underspends the expense amounts approved in this rate case proceeding.[120] Additionally, Staff recommended a separate, downward-only reconciliation for Plant Account 303 (Software/Cybersecurity) in light of allegedly conflicting and unreliable data provided by the Company with respect to its information technology capital expenditures.[121]

The Joint Proposal requires implementation of a net plant and depreciation reconciliation mechanism, pursuant to which the Company will reconcile, each Rate Year, its actual average net plant and depreciation expense revenue requirement to the target net plant and depreciation expense revenue requirement.[122] Although the Company opposed Staff's recommendation with respect to Account 303 in favor of a

[119] Id., p. 16 & Appendix A, pp. 6, 16, 26.

[120] Hearing Exhibit 65 (Staff Net Plant and Gas Infrastructure and Operations Panel Testimony), pp. 42-45.

[121] Id., pp. 13-15.

[122] Joint Proposal, p. 17 & Appendix F.

symmetrical reconciliation mechanism,[123] the Joint Proposal also recommends a separate downward-only net plant mechanism for that account, as well as for AMR expenses and the Oswegatchie Reinforcement Project.[124] For all reconciliation mechanisms, the year-over-year differences will carry forward and be summed at the end of RY3.[125] If the cumulative revenue requirement impact is negative, it will be deferred for the benefit of customers.[126] In contrast, no deferral will be permitted for a positive impact,[127] thus providing an incentive for the Company to control its capital spending. We agree with Staff that this provision protects customers in the event the Company underspends its capital budgets and, therefore, approve it.

2. Earnings Base Capitalization Adjustment

The Earnings Base Capitalization (EBCAP) adjustment is intended to align a utility's rate base with its interest-

[123] Hearing Exhibit 117 (Company Cybersecurity Panel Rebuttal Testimony (REDACTED), pp. 7-9.

[124] Joint Proposal, p.18; Evidentiary Hearing Transcript, pp. 10-11. AMR is further addressed in the Automated Meter Reading section of this Order. The Oswegatchie Reinforcement Project involves installation of an additional 1,850 feet of main across the Oswegatchie River in Calendar Year 2027 to increase reliability for approximately 400 customers, including a large hospital, two schools, and multiple businesses in the City of Ogdensburg (Hearing Exhibit 111 (Capital, Operations, Infrastructure, System Planning and Reliability, and Safety Panel Rebuttal Testimony)), p. 16).

[125] Joint Proposal, p. 17.

[126] Id.

[127] Id.

bearing capitalization dedicated to utility service.[128] The Joint Proposal contains an EBCAP adjustment that reduces rate base by $5.72 million in RY1.[129] This is significantly less than the reduction initially proposed by Staff in direct testimony in order to take into account a December 2024 equity infusion.[130] In light of (1) the increasing common equity ratios allowed in RY2 and RY3, (2) the Commission's recent order authorizing the issuance of securities in the long-term debt financing proceeding commenced by the Company,[131] (3) potential future equity infusions, and (4) forecasted positive retained earnings, the Joint Proposal reflects lesser EBCAP adjustments in RY2 ($4.29 million) and RY3 ($2.86 million).[132] The EBCAP adjustment in RY2 and RY3 is subject to a downward-only reconciliation.[133] The EBCAP adjustment amounts represent a reasonable compromise between Staff and the Company in consideration of the Company's

---

[128] Hearing Exhibit 73 (Staff Revenue Requirement Panel Testimony (REDACTED)), p. 123. Capitalization for the EBCAP represents funds provided by investors and customers to support utility operations, on which utilities pay a return. Generally, a differential between rate base and capitalization is due to variations in cash flow items not in rate base, such as non-interest-bearing liabilities (id., pp. 123-124).

[129] Joint Proposal, p. 19.

[130] Id.; Hearing Exhibit 73 (Staff Revenue Requirement Panel Testimony (REDACTED)), pp. 126-127; Staff Statement in Support, p. 36; Company Statement in Support, p. 53.

[131] Case 24-G-0687, Petition of Liberty Utilities (St. Lawrence Gas) Corp. for Authority to Incur Indebtedness for a Term in Excess of Twelve Months Pursuant to Section 69 of the Public Service Law, Order Authorizing Issuance of Securities (issued October 17, 2025). In its testimony, UIU opposed any deferral mechanisms associated with long-term debt because the petition in Case 24-G-0687 remained pending (Hearing Exhibit 98 (Testimony of Pooja Oberoi), p. 4). The Commission's Order resolved the petition.

[132] Joint Proposal, p. 19.

[133] Id.

December 2024 equity infusion, and ratepayers are protected in RY2 and RY3 with a downward-only reconciliation in the event that the EBCAP adjustment is larger than anticipated.

3. Contribution in Aid of Construction

Consistent with Staff's recommendation in its pre-filed testimony,[134] the Company performed a 10-year analysis to determine the amount of Contribution in Aid of Construction (CIAC) improperly booked as revenues.[135] The Joint Proposal requires the Company, on an ongoing basis, to modify its accounting treatment of CIACs, which the Company will book as a reduction to plant-in-service, rather than miscellaneous revenues.[136] The requirement that the Company book CIACs as a reduction of plant-in-service is consistent with the Uniform System of Accounts.[137]

4. Capital Expenditures

The Company proposed capital expenditure budgets by calendar year as follows: $6.91 million for 2025, $12.41 million for 2026, $14.54 million for 2027, and $8.05 million for 2028.[138] Staff calculated that the Company's budgets would result in capital expenditures of $11.02 million in RY1.[139] Staff recommended reducing the capital expenditure budgets to $5.30 million for 2025, $7.32 million for 2026, $10.66 million for 2027, and $5.87 million for 2028, resulting in a capital

[134] Hearing Exhibit 65 (Staff Net Plant and Gas Infrastructure and Operations Panel Testimony), pp. 39-42.

[135] Joint Proposal, p. 20.

[136] Id., pp. 19-20.

[137] Staff Statement in Support, p. 37.

[138] Hearing Exhibit 65 (Staff Net Plant and Gas Infrastructure and Operations Panel Testimony), p. 8.

[139] Id., p. 9.

expenditure budget of $7.23 million for RY1.[140] Staff's proposed budgets reflected the reduction of capital spending related to, among other things, cybersecurity, AMR, main extension projects, system redundancy projects, service installations related to new customers, tools and equipment.[141]

The Joint Proposal includes a capital budget of $6.06 million for RY1, $13.41 million for RY2, and $10.66 million in RY3.[142] The Joint Proposal also clarifies that the Company's capital expenditure budget for July 1, 2024, through October 31, 2025 – i.e., the historic test year through the end of the Rate Year immediately preceding RY1 – was $11.60 million.[143] At the evidentiary hearing, the parties testified that the Company's capital spending exceeded the amount approved in the 2023 Rate Order. The Company is not permitted to recover the revenue requirement effect of its spending in excess of the amount approved in the 2023 Rate Order for the period through October 31, 2025. However, the actual capital expenditures are reflected in the rate base as of November 1, 2025, and the Company will recover the revenue requirement effect of its actual, prudent, capital spending going forward.[144]

As explained in the AMR section of this Order, the Joint Proposal allows the Company to recover its RY2 capital expenditures related to AMR. In contrast, as discussed in the CLCPA section of this Order, the Joint Proposal does not include cost recovery for main extension projects in the capital

---

140 Id.

141 Id., pp. 11-12, 27.

142 Joint Proposal, p. 20.

143 Id.

144 Evidentiary Hearing Transcript, pp. 12-13; Hearing Exhibit 65 (Staff Net Plant and Gas Infrastructure and Operations Panel Testimony), p. 9.

expenditure budget; instead, the parties agreed to continue the process set forth in the 2023 Rate Order for approval of potential gas main extensions.[145] The Joint Proposal also reduced the amount of capital expenditures budgeted by the Company for cyber security software, service installations, tools and equipment.[146] With respect to cybersecurity, Staff recommended a 22% reduction to the Company's proposed capital expenditures based on historical underspending,[147] and the Joint Proposal reduced the Company's initial proposed capital budget by 10%.[148] Any additional incremental spending that may be required pursuant to Case 25-M-0302,[149] which the Commission commenced to consider expanding cybersecurity requirements, will be deferred and the Company may seek recovery of those costs in a future rate case, subject to Staff review.[150] To increase transparency in this regard, the Joint Proposal also establishes new reporting requirements detailing cybersecurity and physical security project spending and schedules for each project.[151]

The Joint Proposal also permits recovery for three gas system reliability projects performed in 2025 and, subject to

---

[145] 2023 Rate Order, pp. 34-36.

[146] Staff Statement in Support, p. 38.

[147] Hearing Exhibit 65 (Staff Net Plant and Gas Infrastructure and Operations Panel Testimony), p. 13.

[148] Staff Statement in Support, p. 40. As noted above, the Joint Proposal also adopts a downward-only reconciliation mechanism for cybersecurity software spending to protect customers from continued underspending.

[149] Case 25-M-0302, Proceeding on Motion of the Commission of the Rules and Regulations of the Public Service Commission, Contained in 16 NYCRR-Proposed Information Technology Cybersecurity Requirements, Order Instituting Proceeding to Establish Cybersecurity Rules for Information Technology (issued June 13, 2025).

[150] Joint Proposal, pp. 21-22.

[151] Id., pp. 26-27.

the downward-only reconciliation mechanism discussed above, the Oswegatchie Reinforcement Project in 2027.[152] This is a reduction from the six reliability projects initially proposed by the Company.[153] To address future reliability projects, the Joint Proposal requires the Company to work collaboratively with Staff and interested parties to develop criteria and standards that the Company will use in planning to support the need for reliability capital projects.[154] Similarly, the Company must work with Staff and interested parties to develop training standards to increase the number of employees qualified to perform emergency response and restoration operations.[155] By requiring the Company to develop reliability capital project criteria and standards and to increase the number of employees able to conduct restoration activities, this provision will result in greater transparency of proposed capital expenditures on future reliability projects and improvement of the Company's capability and speed in restoring outages.[156]

The Capital Expenditure provisions of the Joint Proposal ensure that the Company's investments in its gas system are necessary to provide customers with safe, adequate and reliable service. We accordingly find that the Joint Proposal's investment levels are reasonable.

Automated Meter Reading

In the Company's previous rate proceeding, Case 21-G-0577, it requested cost recovery for the implementation of an

---

[152] Staff Statement in Support, pp. 43-44; Hearing Exhibit 111 (Capital Operations Rebuttal Testimony), p. 16.

[153] Hearing Exhibit 1 (Company Capital, Operations, Gas Supply, and Safety Panel Testimony), pp. 11-12.

[154] Joint Proposal, p. 26.

[155] Id.

[156] Staff Statement in Support, p. 44.

AMR program. The proposed program consisted of costs related to the acquisition and installation of equipment attached to the installed meters that would allow the Company to read those meters via a passing vehicle,[157] as well as program administration costs, such as equipment and personnel to conduct monthly meter reading. The Joint Proposal adopted by the Commission's 2023 Rate Order denied recovery at that time but allowed the Company to petition the Commission during the rate plan for cost recovery.[158] The 2023 Rate Order required that any such petition contain a detailed plan on the AMR conversion including its customer and billing related impacts; a benefit/cost analysis demonstrating a ratio of 1.0 or greater; and an explanation of how the costs and benefits would be achieved by the proposed AMR program.

On June 7, 2024, the Company filed a Verified Petition seeking approval of its AMR implementation plan and cost recovery proposal. In the Verified Petition, the Company justified its AMR proposal by noting that it had been using a contractor to provide manual meter reads of all customers every other month, that the arrangement had resulted in estimated bills for the non-read months, that the contractor had recently retired, and that the Company had been using its existing staff

[157] Although the Company initially testified to plans in the previous rate proceeding to eventually implement a full Automated Meter Infrastructure (AMI) platform, on reconsideration, it determined that an AMR vehicle-read deployment properly balanced operations with the interests of the Company's customers (Case 24-G-0369, Liberty Utilities (St. Lawrence Gas) Corp. – Automated Meter Reading Implementation Petition, Verified Petition of Liberty Utilities (St. Lawrence Gas) Corp. for Approval to Implement Automated Meter Reading and Recover Associated Costs (filed June 7, 2024) (Verified Petition), p. 4 n. 8).

[158] Case 21-G-0577, supra, Joint Proposal (filed March 30, 2023), p. 17.

to continue the same practice of manual meter reading every second month with interim estimated bills. The Company indicated that it anticipated pressure to eliminate estimated bills via monthly reads for all customers. The Company explained that it had performed an options assessment that resulted in two viable scenarios: increasing staff and associated equipment to continue manual reads of the existing analog meters or replacing those analog meters with AMR-equipped digital meters and associated equipment.

Consistent with the 2023 Rate Order, the Verified Petition included a benefit-cost analysis demonstrating a ratio of 1.05. Additionally, the Company noted that between the two assessed options, the 20-year revenue requirement impact of implementing AMR totaled approximately $9.8 million compared to the impact of continuing an expanded employee manual read option at a cost of approximately $11.6 million for the same 20-year period. Finally, the Company provided the 2023 Rate Order's required detail on the achievement of benefits, explaining that the AMR proposal was likely to provide improved employee safety and customer service, reduced environmental and economic impacts, facilitating the statewide Integrated Energy Data Resource (IEDR) Initiative, and enable prospective compliance with potential legislative and regulatory prohibitions on estimated bills or, at the very least, address concerns that have been voiced underlying such potential changes of law.

On August 13, 2025, during the pendency of settlement negotiations on the current rate proceeding, the Company provided notice that the ongoing negotiations would include the contents of the Verified Petition. Such negotiations resulted in the Joint Proposal's inclusion of $4.12 million associated with AMR implementation in the Company's capital expenditure budget during RY2. Given the elements of the Verified Petition, such inclusion is reasonable, supported by the record and meets the criteria established by the Commission when it adopted the Company's previous rate plan.

Cost of Capital

The Company requested an overall after-tax rate of return of 7.27%.[159] The Company's requested rate of return was calculated using an ROE of 9.90%, a common equity ratio of 48.00%, a long-term debt ratio of 50.82% with a cost rate of 4.88%, and a customer deposits ratio of 1.18% with a cost rate of 3.00%.[160] Staff recommended an overall after-tax rate of return of 6.87%, which consisted of an ROE of 9.25%, a common equity ratio of 42.00%, a long-term debt ratio of 56.82% with a cost rate of 5.01%, and the same customer deposits ratio and cost rate as that requested by the Company.[161] Staff's recommendation lowered the revenue requirement impact by $366,000.[162] In its rebuttal testimony, the Company agreed that

---

[159] Hearing Exhibit 60 (Staff Finance Panel Testimony (REDACTED)), p. 7. A utility's rate of return is calculated through a weighted average of the individual cost components of its expected capitalization during the Rate Year (Id., pp. 9-10).

[160] Id., pp. 7, 23, 40, 51.

[161] Hearing Exhibit 60 (Staff Finance Panel Testimony (REDACTED)), pp. 7, 40, 47, 51. Customer deposits, while typically a very small component, are reflected in a utility's capitalization along with long-term debt and common equity because customer deposits are a permanent and generally stable source of capital employed by utilities. The cost rate for customer deposits is a non-controversial calculation that simply involves applying the interest rate that is currently prescribed by the Commission (id., pp. 10-11).

[162] Id., pp. 7-8. Staff indicated that a 10 basis point change in ROE is worth approximately $26,000 and a one percent change in the common equity ratio is worth approximately $33,000 (id., p. 8).

the cost of long-term debt should be 5.01%, rather than 4.88%,[163] leaving only the appropriate ROE and debt-to-equity ratio in contention.

The Joint Proposal recommends that the cost of capital during the term of the rate plan be based on a ROE of 9.30% in all three Rate Years and a common equity ratio of 46.00% in RY1, 47.00% in RY2, and 48.00% in RY3.[164] The common equity ratio is subject to downward reconciliation in RY2 and RY3.[165] Given the agreed-upon customer deposits ratio of 1.18%, the long-term debt ratio set forth in the Joint Proposal is 52.82% in RY1, 51.82% in RY2, and 50.82% in RY3. The Joint Proposal sets forth the projected weighted cost of capital after-tax as 6.97% in RY1, 7.01% in RY2, and 7.05% in RY3.[166]

It is well settled that a public service utility cannot be deprived of the fair opportunity to earn a reasonable return on its investments, and that such deprivation would be an unconstitutional confiscation of property.[167] As the Commission has previously recognized, a rate plan's ROE is the numerical representation of the constitutionally required fair opportunity for the Company's investors to earn a return on capital used in creating and maintaining the infrastructure dedicated to public utility service.[168] Staff recommended an ROE of 9.25% to permit

[163] Hearing Exhibit 119 (Cost of Capital Rebuttal Testimony), pp. 18, 41.

[164] Joint Proposal, pp. 27-28 & Appendix L.

[165] Id., pp. 27-28 & Appendix K.

[166] Id., pp. 28-29.

[167] Matter of New Rochelle Water Co. v Public Serv. Commn., 31 N.Y.2d 397, 407 (1972); Matter of Abrams v Public Serv. Commn., 67 N.Y.2d 205, 212-15 (1986).

[168] Cases 24-E-0461 et al., Central Hudson – Rates, Order Adopting Terms of a Joint Proposal and Establishing Gas Rate Plans (issued August 14, 2025), p. 39.

the Company a fair opportunity to earn a reasonable return on its investment. Although the agreed upon 9.30% ROE set forth in the Joint Proposal is slightly higher than that recommended by Staff, the increase appropriately reflects the additional business and financial risks inherent in a multi-year agreement, such as the risk that the actual cost of capital will increase during the three-year term of the rate plan or the risk of potentially higher operating costs than those forecasted.[169] Moreover, the 9.30% ROE is the product of compromise and much lower than the 9.90% rate sought by the Company.

The graduated equity ratio is closer to the Company's initially requested equity ratio of 48.00%, which is also the ratio approved in the 2023 Rate Order.[170] Nevertheless, we conclude that, like the ROE, the common equity ratio set forth in the Joint Proposal is reasonable and supported by the record.

In recommending an equity ratio of 42.00%, Staff noted that the Company's actual common equity ratio was 44.73% as of June 30, 2024, and 40.79% as of December 31, 2024.[171] Staff's primary concerns with continuing the 48.00% equity ratio were the Company's history of failing to maintain that common equity ratio despite committing to target it; that, as of the time of Staff's pre-filed testimony, the Company had failed to document that the December 2024 equity infusion of $11 million had

---

[169] Staff Statement in Support, pp. 47-48. Staff also notes that the 9.30% ROE in the Joint Proposal is lower than the ROEs approved by the Commission in recent multi-year rate plans.

[170] 2023 Rate Order, p. 12; Hearing Exhibit 60 (Staff Finance Panel Testimony (REDACTED)), p. 20. Under the rate plan approved in the 2023 Order, the Company's cost of capital rate of 6.66% was based on an ROE of 9.20%, a common equity ratio of 48.00%, a long-term debt ratio of 50.98%, and a customer deposits ratio of 1.02%.

[171] Hearing Exhibit 60 (Staff Finance Panel Testimony (REDACTED)), pp. 20-21.

actually occurred; and that the Company did not rely on an appropriate proxy group in calculating the common equity ratio.[172] The Company subsequently demonstrated that the equity infusion did, in fact, take place in December 2024,[173] and the downward-only reconciliation mechanism in the Joint Proposal is intended to incentivize the Company to effectively manage its capital structure to the agreed-upon common equity ratios and to protect ratepayers from paying for a common equity ratio that the Company may not achieve.[174] In addition, the Company's planned capital expenditures are increasing over the term of the rate plan, and the rising common equity ratio will provide a stronger equity base to allow the Company to finance its rising investment needs during the rate plan without the increased risk inherent in an over-reliance on debt.[175] The Joint Proposal employs a graduated rise to avoid a large immediate increase in customer bills.[176] Under the circumstances, we find that the Joint Proposal provides for a capital structure that will allow the Company to attract adequate capital to fund its anticipated investments, thereby ensuring the continued provision of safe and reliable service while providing predictability and minimizing rate impacts.

1. Earnings Sharing Mechanism

The Joint Proposal contains an Earnings Sharing Mechanism (ESM) to protect customers from excess earnings.[177] Under the terms of the ESM, the Company will be allowed to

---

[172] Id., pp. 27-43.

[173] Hearing Exhibit 120 (Company Cost of Capital Rebuttal Exhibits), Exh. JC-Rebuttal-1.

[174] Staff Statement in Support, p. 48.

[175] Id.

[176] Id.

[177] Joint Proposal, pp. 29-30.

retain any earnings it attains of up to 9.8%. Earnings greater than 9.8% but less than 10.3% are shared equally between the Company and customers. Earnings between 10.3% and 10.8% are shared 80.0% to customers and 20.0% to the Company. Lastly, earnings greater than 10.8% will be shared 90.0% to customers and 10.0% to the Company. The ESM calculations will be based on the lesser of the common equity ratios set forth in the Joint Proposal or the Company's actual common equity ratio for each Rate Year.[178] As the Commission has found, such ESM provisions provide customers, particularly during multi-year rate plans, with a share of efficiencies realized by the utility while providing the utility an incentive to find such efficiencies.[179] The ESM provision in the Joint Proposal strikes a fair balance among the interests of customers, investors, and the long-term soundness of the Company.

Revenue Allocation and Rate Design

Appendix N of the Joint Proposal sets forth the revenue allocation and rate design agreed upon by the Signatory Parties. With respect to revenue allocation, the Company submitted an embedded cost of service (ECOS) study to analyze whether the Company's revenues and costs are being allocated to the various service classes (SCs) in a manner that reflects the relative costs of providing service to each class – that is, whether the revenue from each SC covers its fair share of the costs.[180] Based on the ECOS study, the Company concluded that

[178] Id., p. 30.

[179] Case 23-G-0627, National Fuel Gas Distribution Corporation – Rates, Order Adopting Terms of a Joint Proposal and Establishing Gas Rate Plan with Minor Modifications (issued December 19, 2024), pp. 34-35.

[180] Hearing Exhibit 71 (Staff Revenue Allocation and Rate Design Panel Testimony), p. 17; Hearing Exhibit 23 (Company Embedded Cost of Service and Rate Design Panel Testimony), p. 6.

SC-1 (residential) and SC-2 (including SC-2L, commercial and large commercial) were over-contributing revenues to the system, while SC-3 (industrial) was under-contributing and deficient in covering its class-allocated costs.[181]

Although the Company proposed structuring rate increases that would move each SC closer to its overall cost of service, it also proposed limiting the revenue increase to each SC to no more than 200% or two times the system average increase, and that it would collect the resulting shortfall from SC-1.[182] Based upon the data in the ECOS study, Staff concluded that SC-1 was over-contributing to the system, SC-2 was essentially covering its costs, and SC-3 was vastly under-contributing.[183] Although Staff generally agreed that higher rate increases should be allocated to SCs that are under-contributing, it characterized the Company's proposal to allocate an increase of up to 200% as excessive.[184]

As set forth in Appendix N, the Joint Proposal adopts a revenue allocation of less than system average revenue increase for SC-1 for RY1 and RY2 and the system average increase for SC-1 in RY3; a system average increase for SC-2 and SC-2L for all three Rate Years; and an above system average increase for SC-3 for all three Rate Years.[185] This generally

[181] Hearing Exhibit 23 (Company Embedded Cost of Service and Rate Design Panel Testimony), pp. 15, 18; Hearing Exhibit 71 (Staff Revenue Allocation and Rate Design Panel Testimony), pp. 20-21.

[182] Hearing Exhibit 23 (Company Embedded Cost of Service and Rate Design Panel Testimony), pp. 19-21.

[183] Hearing Exhibit 71 (Staff Revenue Allocation and Rate Design Panel Testimony), p. 34.

[184] Id., p. 34.

[185] Joint Proposal, pp. 30-31 & Appendix N; Hearing Exhibit 121 (Responses to ALJ Discovery Requests), pp. 5-6.

tracks Staff's analysis of the results of the Company's ECOS study and Staff's recommendation to impose a limitation on the allocation of increases. The Joint Proposal also provides that the Company will evaluate SC-2 and SC-2L as two separate SCs in its next ECOS study in light of the vastly different rates and customer usage of those two classes.[186] MI states that one of its primary reasons for supporting the Joint Proposal is that the allocation of revenue and rate design contained therein are equitable and move rates closer to cost of service.[187] The agreed upon revenue allocation reduces the current cost of service and revenue imbalances between residential, commercial and industrial customers and, therefore, is reasonable.

Turning to rate design, the current rate structure provided for all SCs is a minimum charge with declining block delivery rates. There is also a demand charge for SC-3, and reserved transportation service customers in all SCs with annual throughput in excess of 50,000 therms are subject to a $125 per month contract administration charge.[188] Declining rates are applied to monthly therms based on three usage blocks for SC-1 and SC-3, and five usage blocks for the combined SC-2 and SC-

[186] Joint Proposal, p. 31; Hearing Exhibit 71 (Staff Revenue Allocation and Rate Design Panel Testimony), p. 29.

[187] MI Statement in Support, p. 2.

[188] Hearing Exhibit 71 (Staff Revenue Allocation and Rate Design Panel Testimony), pp. 37-38. In its public comments, PULP questioned whether the contract administration charge was imposed on all customers regardless of usage; the Joint Proposal clarifies that the charge is imposed only on customers that use over 50,000 therms annually and Staff avers that the charge is imposed only on transportation customers (Staff Statement in Support, p. 56).

2L.[189] In each SC, costs associated with the first usage block are recovered in the minimum monthly charge.[190]

The Company proposed maintaining this rate structure, increasing the minimum monthly charge for all SCs, and continuing its elimination of the current declining block rate structure in favor of flat rates, which would be one rate for any volume of gas consumption.[191] As relevant here, Staff agreed that the ECOS study supported higher minimum charges than those currently in place and that the block rates should be "flattened" in order to send the appropriate price signals to encourage energy efficiency and beneficial electrification by increasing the price associated with higher usage.[192] Staff recommended moving to a single volumetric rate for SC-1.[193]

The Joint Proposal reflects the rate design proposed by the Company and Staff, including moving to a single volumetric block rate for SC-1 by RY3.[194] The agreed-upon minimum monthly charges, as set forth in the Joint Proposal, are:

[189] Hearing Exhibit 71 (Staff Revenue Allocation and Rate Design Panel Testimony), pp. 36-37. As an example, the lowest usage block in SC-1 includes the first four therms, the second block includes the next 36 therms, and block three includes all usage in excess of 40 therms (id.).

[190] Id.

[191] Id., pp. 38-39. With declining block rates, customers are charged lower rates as usage increases.

[192] Id., pp. 39-43.

[193] Id., pp. 40-41.

[194] Joint Proposal, Appendix N, p. 2.

	Present	RY1	RY2	RY3
SC-1	$17	$18.50	$20	$21.50
SC-2	$28	$29.50	$31	$32.50
SC-2L	$190	$210	$220	$230
SC-3	$500	$550	$575	$600

The rate design reflects a balance of the CLCPA goals of promoting energy efficiency via block flattening, while minimizing rate impacts for larger customers. The multi-year, levelized rate plan permits the flattening of rate blocks and increasing minimum charges over multiple years, easing the bill impacts for rate payers in a way that would not be possible in a one-year rate case. The proposed changes to rate design also are reasonably crafted to better align with cost-of-service data and eliminate intra-class subsidies. We therefore find that both the revenue allocation and rate design proposed in the Joint Proposal are reasonable.

The Signatory Parties also resolved five additional "sub-issues" within the context of negotiations on revenue allocation and rate design that warrant discussion as follows.

1. Merchant Function Charge & Delivery Revenue Adjustment

The Merchant Function Charge (MFC) applies to sales customers in all SCs and permits the Company to recover, through a surcharge, costs associated with gas supply procurement, such as gas procurement salaries, gas control costs, carrying charges on gas in storage, and commodity-related uncollectible costs.[195] Similar costs are recovered from all transportation customers through the Delivery Revenue Adjustment (DRA).[196] Staff and the

[195] Hearing Exhibit 71 (Staff Revenue Allocation and Rate Design Panel Testimony), p. 43.

[196] Id., pp. 44-45.

Company agreed on the methodology used to calculate MFC and DRA revenues but Staff recommended updating the forecasted revenues based on an updated uncollectible rate.[197] Staff forecasted MFC revenues of approximately $308,000, or $101,000 less than the Company proposed, and DRA revenues of approximately $183,000 which is $33,000 less than the Company proposed.[198] The projected MFC and DRA revenues in the Joint Proposal track the amounts forecasted by Staff and reflect the updated revenue targets and uncollectible percentages consistent with the other provisions of the Joint Proposal.[199] The MFC and DRA provisions of the Joint Proposal reasonably use the most up-to-date information.

2. Revenue Decoupling Mechanism

The revenue decoupling mechanism (RDM) reconciles actual billed delivery service revenues to target revenues such that, if actual sales fall below the target level, the utility can recover the difference.[200] The RDM's purpose is to make utilities indifferent to energy efficiency measures that reduce usage and demand because revenue is no longer contingent on the volume of energy actually delivered.[201] The Joint Proposal continues the revenue decoupling mechanism established in the 2023 Rate Order for residential and commercial customers,[202] with targets established for delivery revenues for SC-1 and SC-2 (small and large commercial combined) at the following levels:

---

[197] Id., pp. 12-13, 44-45

[198] Id., p. 13.

[199] Joint Proposal, pp. 31-32 & Appendix P.

[200] Hearing Exhibit 71 (Staff Revenue Allocation and Rate Design Panel Testimony), pp. 45-46.

[201] Id., p. 45.

[202] Joint Proposal, pp. 32-33 & Appendix Q.

	RY1	RY2	RY3
SC-1	$10,783,883	$11,661,528	$12,382,359
SC-2	$4,763,826	$5,326,748	$5,760,339
Total	**$15,547,709**	**$16,988,276**	**$18,142,698**

3. Lost and Unaccounted for Gas

Lost and Unaccounted for (LAUF) gas is the disparity between the amount of gas metered into a distribution system and the amount of gas metered out of the system.[203] A LAUF incentive mechanism holds a utility accountable for those losses by limiting the amount of gas expense that the utility can recover.[204] Due to the inherent uncertainty and natural variability in gas measurement, a dead-band is established around the LAUF target.[205] For losses within the tolerance band, the utility is permitted to recover actual commodity costs; for losses beyond the upper dead-band, the utility will incur a penalty.[206]

The Company's current LAUF target is 0.156%, with an upper and lower dead-band of 0.865% and 0.000%.[207] Staff recommended that the Company's LAUF targets be updated based on the most recent five years of LAUF data.[208] The Joint Proposal adopts Staff's recommendation that the new target be set at 0.226%, with an upper and lower dead-band of 0.946% and

[203] Hearing Exhibit 71 (Staff Revenue Allocation and Rate Design Panel Testimony), p. 49.

[204] Id.

[205] Id.

[206] Id., p. 50.

[207] Id., p. 51. Because the lower dead-band is zero, the upper band is set at four standard deviations above the historical average.

[208] Id., pp. 51-52.

0.000%.[209] This provision of the Joint Proposal is reasonable inasmuch as the updated LAUF target and associated upper dead-band are calculated pursuant to the Commission's approved methodology and more accurately reflect the system's current performance.

4. Interruptible Incentive Credit Mechanism

The Interruptible Incentive Credit (IIC) mechanism reconciles the difference between actual delivery revenues from SC-4 (Interruptible Service) and the Rate Year target.[210] Under the prior rate plan, the first $100,000 of the difference between the target and the actual SC-4 delivery revenues received is shared between the Company and SC-1, SC-2 and SC-2L firm customers, with 15% going to the Company and 85% to the customers. All amounts in excess of $100,000 flow to those customers.[211] Staff recommended updating the annual IIC target to $847,243 based on its forecast for SC-4 delivery revenues, as well as including SC-3 in the IIC mechanism.[212] The Joint Proposal adopts Staff's recommendations and further provides that, if the Company does not file for new rates following RY3, the $847,243 target will continue.[213] Updating the IIC target is reasonable because it more accurately reflects forecasted amounts of SC-4 delivery service revenues anticipated during the

[209] Id., p. 52; Joint Proposal, p. 33 & Appendix R. In practice, the targets and upper dead-band mean that, for every 99,054 units delivered by the system, 100,000 must have been delivered to the city gate (Appendix R).

[210] Hearing Exhibit 71 (Staff Revenue Allocation and Rate Design Panel Testimony), p. 47.

[211] Id.

[212] Id., pp. 47-48.

[213] Joint Proposal, p. 33.

term of the rate plan, and a portion of the interruptible revenues offset the SC-3 cost of service in the ECOS study.[214]

Gas Safety Metrics and Regulatory Goals

1. Timely Filings

At Staff's recommendation, the Joint Proposal maintains a mechanism from the 2023 Rate Order pursuant to which the Company incurs a negative revenue adjustment (NRA) if it fails to comply with filing requirements.[215] Specifically, the Company will incur an NRA of three basis points for each instance of a missed filing deadline unless the Company has requested an extension or waiver of such deadline where the Secretary has the authority to extend the deadline.[216] This mechanism is reasonable because it incentivizes the Company to adhere to regulatory filing deadlines, an area in which its performance has been suboptimal in the past.[217]

2. Gas Safety Metrics

As Staff recommended in its initial testimony, the Joint Proposal maintains the performance metrics and associated revenue adjustments that were established in the 2023 Rate Order for emergency response, damage prevention, leak management, and pipeline safety regulatory compliance.[218] The Joint Proposal exposes the Company to a risk of incurring total NRAs of 138

---

[214] Hearing Exhibit 71 (Staff Revenue Allocation and Rate Design Panel Testimony), pp. 48-49.

[215] Joint Proposal, p. 34; Hearing Exhibit 73 (Staff Revenue Requirement Panel Testimony (REDACTED)), pp. 114-115. Over the course of the prior rate plan, the Company failed to timely request an extension or waiver 11 times, resulting in a regulatory liability of approximately $88,000 (id.).

[216] Joint Proposal, p. 34.

[217] Hearing Exhibit 73 (Staff Revenue Requirement Panel Testimony (REDACTED)), p. 115.

[218] Joint Proposal, p. 34; Hearing Exhibit 63 (Staff Gas Safety Panel Testimony), pp. 15, 29-30, 32, 38.

basis points annually for failing to meet the agreed-upon performance standards, and provides it with the opportunity to earn a maximum of 16 basis points annually in positive revenue adjustments (PRAs) for exceeding metric target levels.[219] Only the emergency response and damage prevention measures have associated PRAs.[220] The gas safety performance metrics, which are designed to encourage continuous improvement in safety performance, will remain in effect until changed by the Commission.[221]

Specifically, the emergency response metric requires the Company to respond to 75% of gas, leak, odor and emergency calls within 30 minutes, 90% within 45 minutes, and 95% within 60 minutes. Failure to meet these targets results in NRAs of nine, six and three basis points, respectively. Responding to greater than 85-90% of emergency calls within 30 minutes results in PRAs of three basis points and responding to greater than 90% of calls within 30 minutes results in PRAs of six basis points.[222] The Company's emergency response metric is consistent with that of other utilities across the State.[223]

The Joint Proposal maintains the damage prevention metric's targets for excavation damages per 1,000 calls and continues the associated revenue adjustments.[224] This metric is

---

[219] Joint Proposal, Appendix S; Hearing Exhibit 63 (Staff Gas Safety Panel Testimony), p. 11. The value of one basis point is $2,530 in RY1, $2,728 in RY2, and $3,137 in RY3 (Joint Proposal, Appendix T).

[220] Joint Proposal, Appendix S.

[221] Id., p. 34.

[222] Id., Appendix S; Hearing Exhibit 63 (Staff Gas Safety Panel Testimony), pp. 12-16. From 2019 through 2024, the Company met or exceeded the established minimum performance levels for the emergency response metric.

[223] Hearing Exhibit 63 (Staff Gas Safety Panel Testimony), p. 14.

[224] Id., pp. 16-30.

designed to prevent the uncontrolled release of natural gas caused by excavation damage to natural gas pipes.[225] Damages included in the calculation are those that occur due to the Company's improper locating of a facility or the Company, its contractors or a third-party excavator hitting a line. The targets, per 1,000 one-call tickets, are as follows:

Joint Proposal Targets	**NRA BPs**	**PRA BPs**
<1.70	N/A	10
<1.75	N/A	5
≥1.95 – 2.05	(5)	N/A
>2.05 - 2.40	(15)	N/A
>2.40	(27)	N/A

Staff's rationale for recommending no change to this metric was that no major operational changes have taken place in the Company's system between the issuance of the 2023 Rate Order and the date of the current rate filing.[226]

The Joint Proposal requires the Company to maintain a minimal leak backlog, with an NRA applied if the total leak

[225] Id., p. 16.

[226] Id., pp. 29-30. In 2023, the Company incurred an NRA of 27 basis points, worth approximately $70,000, for failing to meet its damage prevention performance targets. It agreed with Staff's recommendation to apply that amount to its residential methane detector program (id., pp. 25-26; Hearing Exhibit 111 (Capital, Operations, Infrastructure, System Planning and Reliability and Safety Panel Rebuttal Testimony), p. 4).

backlog exceeds the set threshold.[227] Specifically, the Company will be subject to an NRA of 18 basis points if its year-end total leak backlog exceeds four.[228] As with the damage prevention metric, Staff recommended no changes in light of the absence of any major operational changes in the Company's system since the issuance of the 2023 Rate Order.[229]

Finally, the metric for compliance with pipeline safety regulations continues the Company's exposure to a maximum NRA of 75 basis points for non-compliance with certain gas safety regulations, as identified by Staff field and records audits.[230] In each calendar year from 2026 through 2028, the Company will be subject to an NRA of one-half basis point or one basis point for exceeding specified high-risk violation thresholds, and one-quarter basis point for any "other risk" violations discovered during field audits and for greater than eight "other risk" violations discovered during record audits.[231] If the Company is found to have failed to comply with a single code section of either audit type (field or record) more than 10 times per calendar year, the Company must file a remediation plan with the Secretary.[232] The Joint Proposal further identifies procedures for the Company to cure record deficiencies and dispute or appeal Staff's conclusions as to

---

[227] Hearing Exhibit 63 (Staff Gas Safety Panel Testimony), pp. 30-33.

[228] Joint Proposal, Appendix S.

[229] Hearing Exhibit 63 (Staff Gas Safety Panel Testimony), p. 32. The Company has consistently met its leak management performance target from 2019 through 2023. The Company had a backlog of zero leaks in 2019, one leak in 2020, one leak in 2021, and zero leaks in 2022 and 2023 (id., p. 31).

[230] Id., pp. 33-44; Joint Proposal, pp. 35-36 & Appendix S.

[231] Id., Appendix S.

[232] Id., p. 36.

non-compliance.[233] Staff recommended continuing these target levels and associated NRAs because, among other things, the Company's current violation targets are the most stringent targets among all utilities in the State.[234]

The gas safety metric provisions of the Joint Proposal, which reflect the Company's and Staff's consistent litigation positions, are reasonably designed to promote quick response in emergency situations, prevent damage to underground Company facilities, reduce methane emissions, and motivate the Company to comply with safety-related regulations. Thus, we find that these provisions will improve the performance and reliability of the Company's gas system and promote public safety.

3. Pipeline Safety Management and Quality Control

Although Staff recommended that the Company be permitted to hire only one full-time employee (FTE), the Joint Proposal supports the addition of two FTEs.[235] One FTE, to be hired in RY1, will focus on the Pipeline Safety Management System (PSMS) Program, monitoring compliance with safety regulations and participating in continuous improvement efforts. Beginning in RY2, a second FTE will be hired to focus

[233] Id., Appendix S.

[234] Hearing Exhibit 63 (Staff Gas Safety Panel Testimony), pp. 38-39. Staff testified that in 2021 and 2022, the Company incurred total NRAs of 18 basis points, amounting to $35,460 owed to customers, in connection with violations of pipeline safety regulations. As with the NRA incurred due to the failure to meet damage prevention metrics, Staff recommended that this regulatory liability be applied towards the Company's residential methane detector program, and the Company agreed (id., pp. 37-38; Hearing Exhibit 111 (Capital, Operations, Infrastructure, System Planning and Reliability, and Safety Panel Rebuttal Testimony), p. 4).

[235] Joint Proposal, p. 36; Hearing Exhibit 63 (Staff Gas Safety Panel Testimony), pp. 52-56.

specifically on Quality Control and Quality Assurance (QA/QC) activities, supporting the Company's Quality Management System.[236] In its testimony, Staff objected that adding the second employee in RY1 was premature because, among other things, the Quality Management System was still in the development stage.[237] Adding these two FTEs will enhance the Company's ability to provide safe and adequate service, while delaying the hiring of the second FTE until RY2 prevents ratepayers from funding that position prematurely.

4. Residential Methane Detector Pilot Program

The Company will continue its Residential Methane Detector (RMD) Program, as recommended by Staff.[238] The cost of the program in RY1 – $105,201 – will be completely offset by the amortization of NRA funds incurred for prior non-compliance with pipeline safety regulations and failure to meet damage prevention targets.[239] The costs of the RMD program in RY2 and RY3 were adjusted for inflation. The Joint Proposal further provides that the Company must file a report with the Secretary within 60 days after the end of each Rate Year, indicating the number of RMD units offered to residential customers and the associated costs of deploying RMD units.[240] The continuation of this program is in the public interest because it improves gas

[236] Staff Statement in Support, pp. 61-62.

[237] Hearing Exhibit 111 (Rebuttal Testimony of Capital, Operations, Infrastructure, System Planning and Reliability and Safety Panel Rebuttal Testimony), p. 56.

[238] Joint Proposal, p. 36; Hearing Exhibit 63 (Staff Gas Safety Panel Testimony), pp. 49-52.

[239] Joint Proposal, p. 36.

[240] Id.

safety and minimizes the release of GHGs by facilitating more timely discovery and repair of any potential leaks.[241]

5. First Responder Communication and Training

Consistent with Staff's recommendation in its initial testimony, the Joint Proposal provides that the Company will continue its current practice of conducting one drill per year with fire department first responders, rotating the location of the drills among the three counties in the Company's service territory; the sessions will be open to any employee/volunteer from any of the three counties for all drills.[242] The Company will note, on its website, which fire departments participated in the training programs.[243] Conducting emergency drills with local first responders is critical to a more effective learning process and fostering communication and coordination between the Company's personnel and first responders in emergency situations.[244] This program enhances both reliability and public safety, and its continued inclusion in the Joint Proposal is reasonable.

Customer Service

The customer service provisions outlined in the Joint Proposal set forth a method for holding the Company financially accountable should it fail to supply adequate customer service, encourage meaningful progress on a plan to improve the Company's outreach to low-income customers, offer further protections for the Company's most vulnerable customers, and enhance relevant reporting requirements to increase transparency. These

[241] Hearing Exhibit 63 (Staff Gas Safety Panel Testimony), p. 52.

[242] Joint Proposal, p. 37; Hearing Exhibit 63 (Staff Gas Safety Panel Testimony), pp. 45-49.

[243] Joint Proposal, p. 37.

[244] Staff Statement in Support, p. 63.

provisions also reflect compromise among the parties and will provide significant benefits to the Company's customers.

1. Customer Service Performance Indicators

The Commission uses performance-based incentives – Customer Service Performance Indicators (CSPIs) – to align shareholder and ratepayer interests by imposing earnings consequences related to the quality of service that a utility provides to its customers.[245] The terms of the Joint Proposal continue the CSPIs currently in place under the 2023 Rate Order; namely, PSC Complaint Rate per 100,000 Customers and Overall Customer Satisfaction Rate.[246] Consistent with Staff's recommendation in pre-filed testimony, the Joint Proposal also imposes a new requirement that the Company credit a customer if it misses an appointment at the customer's premises.[247] The Company will continue to report CSPI data on a quarterly basis, but will break down by month the data for each of the two metrics, and include new reporting on call answer rates and adjusted bills.[248] The performance thresholds and associated NRAs for the two CSPI metrics are detailed in Appendix T of the Joint Proposal.

Turning to each specific metric, the PSC Complaint Rate metric tracks the annual average number of escalated complaints received per month, as reported by the Department's Office of Consumer Services, per 100,000 customers.[249] The Joint

[245] Hearing Exhibit 56 (Staff Consumer Services Panel Testimony), p. 6.

[246] Id., p. 8; Joint Proposal, p. 39.

[247] Hearing Exhibit 56 (Staff Consumer Services Panel Testimony), pp. 23-24; Joint Proposal, p. 40.

[248] Joint Proposal, p. 39 & Appendix W, pp. 1-2.

[249] Hearing Exhibit 56 (Staff Consumer Services Panel Testimony), pp. 8-9.

Proposal continues the targets and associated NRAs established in the 2023 Rate Order.[250] A complaint rate greater than or equal to 1.5 will result in an NRA of five basis points; a complaint rate greater than or equal to 2.0 will result in an NRA of 10 basis points; and a complaint rate greater than or equal to 2.5 will result in an associated NRA of 15 basis points.[251]

The Overall Customer Satisfaction Rate uses customer satisfaction surveys performed by an independent vendor to determine the percentage of customers satisfied with the service received from the Company.[252] The Joint Proposal continues the current targets and associated NRAs: a satisfaction rate equal to or less than 86% satisfaction will result in an NRA of five basis points; equal to or less than 85% will result in an NRA of 10 basis points; and equal or less than 84% will result in an NRA of 15 basis points.[253] Starting in RY1, the Company will switch from an annual survey to the transaction-based Qualtrics survey, which will be presented or emailed to each customer that completes a transaction with one of the Company's call center

[250] Id., pp. 9, 11; Joint Proposal, Appendix T.

[251] Joint Proposal, Appendix T. From 2022 through 2024, the Company's average monthly escalated complaint rate was 0.5 (Hearing Exhibit 56 (Staff Consumer Services Panel Testimony), p. 9).

[252] Hearing Exhibit 56 (Staff Consumer Services Panel Testimony), p. 9.

[253] Id., pp. 10-11; Joint Proposal, Appendix T. The Company's performance in 2022, 2023, and 2024 was 81%, 82%, and 88%, respectively. Thus, in 2022 and 2023, the Company incurred NRAs of 15 basis points worth approximately $36,000 (Hearing Exhibit 56 (Staff Consumer Services Panel Testimony), pp. 10-11). In its public comments, PULP objected to the Company's proposal to include PRAs in connection with this metric given the Company's recent performance. PRAs have not been included.

representatives.[254] The new survey vendor will allow for real-time data to improve customer service and will lead to a significant cost savings due to lower licensing fees.[255]

The Joint Proposal also incorporates Staff's recommendation that the Company implement a $25 credit for missed appointments, excluding same-day appointments and appointments missed due to circumstances beyond the Company's control, such as severe weather.[256] If the Company schedules an appointment at a customer's premises but fails to arrive as scheduled, the customer will receive a $25 credit in the next billing cycle.[257] The Joint Proposal further requires the Company to enhance its outreach materials and website to inform customers about this credit within 60 days of the issuance of an order in this proceeding, and to begin reporting on missed appointments within 60 days of the start of RY3.[258]

Although the Joint Proposal sets forth no targets or associated NRAs for failure to timely answer calls, it adopts Staff's recommendation that the Company be required to submit, as part of its CSPI reporting, a Call Answering Report, which will include the number of calls answered in less than 60 seconds, the number of adjusted bills, the reason for the adjusted bill, the number of delayed bills, and the reason for

---

[254] Joint Proposal, p. 39; Hearing Exhibit 56 (Staff Consumer Services Panel Testimony), pp. 14-15.

[255] Hearing Exhibit 56 (Staff Consumer Services Panel Testimony), p. 15; Hearing Exhibit 121 (Responses to ALJ Discovery Requests), p. 9.

[256] Joint Proposal, p. 40; Hearing Exhibit 56 (Staff Consumer Services Panel Testimony), pp. 22-26.

[257] Joint Proposal, p. 40.

[258] Id.

the delayed bills.[259] In addition, the Joint Proposal directs that the CSPI reporting include a Reconnection Report, which will set forth information on the number of shut-offs due to nonpayment, the number of reconnections completed for those service shut-offs, and the associated fees assessed for those reconnections.[260]

These provisions incentivize the Company to maintain a high level of customer service and address potential issues proactively. The continued use of these metrics, along with enhanced reporting, allows for increased transparency, consistent monitoring and evaluation of the Company’s performance. Therefore, these provisions are reasonable.

2. Termination and Uncollectible Expenses

The termination and uncollectible expense mechanism employs NRAs and PRAs to encourage utilities to identify and implement measures to reduce residential service terminations for non-payment while decreasing or maintaining the level of bad debt, or uncollectibles, for customers.[261] The mechanism was paused in the 2023 Rate Order due to the trailing effects of the moratorium on service terminations following the COVID-19 pandemic.[262] In its direct testimony, Staff recommended that the

[259] Id., Appendix W, p. 2; Hearing Exhibit 56 (Staff Consumer Services Panel Testimony), pp. 21-22.

[260] Joint Proposal, Appendix W, p. 2. Separate from the CSPI reporting, the Company must also submit a Collections Activity Report, which will be broken down by month and include information on, among other things, arrears greater than 60 days, final termination notices, information on deferred payment agreements, and uncollectibles (id.). This should resolve the concern expressed by PULP in its public comments that the Company was not filing Collection Activity Reports.

[261] Hearing Exhibit 56 (Staff Consumer Services Panel Testimony), p. 17.

[262] Id., pp. 8, 18; 2023 Rate Order, p. 27.

mechanism remain paused, as it is at all other utilities in the State.[263] Although the Company's collection practices and strategies are now fully functioning, Staff explained that there is insufficient relevant historical data to set appropriate targets for this mechanism given the pause on terminations from 2020 through 2022, as well as the institution of a new billing system in 2022 and 2023.[264] The Company disagreed, asserting that enough time has passed for the metric to be reintroduced.[265]

The Joint Proposal does not reinstate this mechanism.[266] Given the lack of recent data that could be used in setting targets for the mechanism, the continued pause is appropriate.

3. Low-Income Program

The Joint Proposal continues the Company's four-tiered bill discount program for eligible low-income customers.[267] The discounts are tiered based on the level of Home Energy

---

[263] Id., p. 18.

[264] Id., pp. 19-21. UIU agreed with Staff's position (Hearing Exhibit 98 (Testimony of Pooja Oberoi), pp. 8-9).

[265] Hearing Exhibit 115 (Company Customer Care Panel Rebuttal Testimony), p. 18.

[266] Joint Proposal, p. 40.

[267] Id., pp. 40-41.

Assistance Program (HEAP) benefits that customers receive.[268] The discounts set forth in the Joint Proposal reflect Staff's recommendation that the discounts for Tiers 2 and 3 be increased to move those tiers closer to the Commission's Energy Affordability Program goal of imposing only a 3% energy burden on gas-only low-income customers.[269]

For RY1, the monthly discounts set forth in the Joint Proposal are: $5 for customers receiving a regular HEAP benefit, $14.73 for those receiving a regular HEAP benefit plus one add-on, $39.50 for those receiving a regular HEAP benefit plus two add-ons, and $21.99 for those customers who receive a direct voucher from Social Services. For RY2, the monthly discounts are $5, $18.00, $42.50, and $21.99, respectively. For RY3, the monthly discounts are $5, $23.50, $45.50, and $21.99,

---

[268] Id. The participation level in the Company's low-income program consistently has been approximately 10% of the Company's customer base (Hearing Exhibit 56 (Staff Consumer Services Panel Testimony), p. 31; Hearing Exhibit 121 (Responses to ALJ Discovery Requests), pp. 9-10). Although the Company is not subject to the Commission's energy affordability policy because it has a customer base of less than 25,000 (Hearing Exhibit 56 (Staff Consumer Services Panel Testimony), p. 29), it is subject to the pause on disenrollment of customers from its low-income discount program that the Commission ordered – in response to the 2025 federal government shutdown – for utilities with energy affordability programs, as well as the requirement that the lookback period be extended to 18 months (Case 14-M-0565, Proceeding on Motion of the Commission to Examine Programs to Address Energy Affordability for Low Income Utility Customers, Order Pausing Customer Disenrollments in Utility Energy Affordability Programs (issued November 13, 2025), pp. 16, 21).

[269] Hearing Exhibit 56 (Staff Consumer Services Panel Testimony), pp. 33-35. The current energy burden of tiers 2 and 3 is 3.6% and 4.0%, respectively; Staff calculated that the adoption of its discount levels would reduce the burden on both tiers 2 and 3 to 3.4% (id.).

respectively.[270] The revenue requirement to fund the low-income program will be approximately $574,000 in RY1, $626,000 in RY2 and $706,000 in RY3.[271] The Joint Proposal continues the requirement that the Company track low-income discounts and reconcile actual discounts provided to customers to the associated low-income program budget amount, and continues current reporting requirements imposed upon the Company.[272] The Joint Proposal also incorporates Staff's recommendation that the Company continue to grant a one-time reconnection waiver for low-income customers whose service has been terminated.[273]

These recommendations for monthly low-income bill discounts are reasonable because they are consistent with the Commission's formula for setting low-income bill discounts for major energy utilities.[274] Continuing the waiver of the reconnection fee for customers enrolled in the low-income program is also reasonable, as it would continue to ease the financial burden on low-income customers.

4. Outreach & Education

The Joint Proposal requires the Company to continue its Outreach & Education (O&E) program with an increased focus

---

[270] Joint Proposal, p. 41.

[271] Id. The $574,000 rate allowance for RY1 represents an increase of $121,000 from the current allowance (Hearing Exhibit 56 (Staff Consumer Services Panel Testimony), p. 29; 2023 Rate Order, p. 29).

[272] Joint Proposal, pp. 41-42; (Hearing Exhibit 56 (Staff Consumer Services Panel Testimony), p. 37

[273] Joint Proposal, p. 42; Hearing Exhibit 56 (Staff Consumer Services Panel Testimony), p. 36.

[274] Staff Statement in Support, p. 70; Company Statement in Support, p. 67. The proposed monthly discounts are also consistent with PULP's recommendation in its public comments that the Company be subject to the Commission's energy affordability policy framework.

on targeting low-income or elderly customers and individuals in disadvantaged communities, as well as improvements in reporting requirements designed to correct prior errors identified by Staff.[275] The Company will develop and submit a single consolidated O&E budget and annual report using the Commission's template and will ensure that the "Energy Service Affordability" section of the template is completed fully.[276] In addition, the Joint Proposal requires the Company to promote clean energy information to all customers applying for new service and to develop a strategy to increase enrollment in its low-income program, including a more prominent focus on low-income customer engagement at outreach events, targeted communications, and increased collaboration with local agencies and organizations that serve those customers.[277] Within 120 days of the Commission issuing a rate order in this proceeding, the Company must file a plan detailing, among other things, how it plans to conduct O&E with respect to its AMR plan and how customers can opt out of receiving AMR meters.[278]

---

[275] Joint Proposal, pp. 42-43 & Appendix W, pp. 6-7; Hearing Exhibit 56 (Staff Consumer Services Panel Testimony), pp. 46-55.

[276] Joint Proposal, p. 42.

[277] Id., pp. 42-43. Although the parties have indicated that they are unable determine the total percentage of customers who may qualify for the Company's low-income program based on income (Hearing Exhibit 121 (Responses to ALJ Discovery Requests), p. 10), Staff stated in its initial testimony that the Company reported in 2024 that approximately 1,819 low-income customers are eligible for HEAP, over 12% of the Company's open residential accounts (Hearing Exhibit 56, Staff Consumer Services Panel Testimony), p. 54). However, Staff noted, the Company provided evidence that only 1,511 customers were enrolled in its low-income program in 2024, thus indicating a need for further outreach regarding the program (id., pp. 54-55).

[278] Joint Proposal, p. 43 & Appendix W, p. 7.

These provisions enhance O&E efforts in vulnerable communities and increase transparency into those efforts. The provisions are reasonable because they will ensure that O&E programs remain available to all of the Company's customers.

5. Levelized Payment Plan

The Joint Proposal stipulates that the Company will offer levelized payment plans to its residential customers and develop customer-facing messaging that clearly explains the levelized billing processes and procedures, within 30 days after issuance of a rate order in this proceeding.[279] As Staff recommended, the Joint Proposal provides that the messaging will explain the differences between the Company's current budget billing and a levelized payment plan, with an emphasis on how each plan reconciles payments against actual customer charges.[280] In that regard, the Company's current budget billing plan calculates a budget bill amount one time per year, in March, based on the prior 12-month average; at the end of the year, the Company reconciles the customer's budget bill payments with actual costs incurred and the customer pays the difference of any underpaid amounts or is credited for overpaid amounts.[281] The levelized payment plan sets bills based on monthly recalculations using the most recent 12-month usage data; this use of a rolling average may cause bills to fluctuate by up to

[279] Id., p. 43.

[280] Id.; Hearing Exhibit 56 (Staff Consumer Services Panel Testimony), pp. 60-63. In its public comments, PULP recommended that the parties seek clarity regarding the differences between the Company's current budget billing and the levelized payment plan. The required messaging should allay PULP's concerns, as well as confirm that the levelized payment plan complies with the requirements of 16 NYCRR §11.11.

[281] Hearing Exhibit 56 (Staff Consumer Services Panel Testimony), p. 60.

10% each month, but it does not result in an end-of-year reconciliation that could require customers to pay any underpaid amounts.[282]

These provisions of the Joint Proposal give Staff the opportunity to initially review the Company's messaging on the levelized payment plan and consult on any necessary improvements to assist in education of customers. Moreover, the levelized payment plan is meaningfully distinct from the Company's current budget billing plan. Therefore, the provisions are reasonable.

6. Arrearage Management Program (AMP)

The Joint Proposal directs the Company to launch an Arrearage Management Program (AMP) designed to support low-income residential customers who are behind on their utility bills.[283] Under the AMP, eligible customers will be placed on budget billing, and for each month that they make their full and timely budget payment, $100 of their arrears will be forgiven, up to $1,200 annually with no lifetime cap.[284] The program will be open to residential customers who have a minimum of $300 in arrears that are past due for 45 days or more and who are willing to enroll in the Company's budget billing program.[285] To address Staff's concern that participation in the AMP would render customers ineligible for Emergency HEAP benefits, the Joint Proposal provides that the Company will give customers a termination notice if an AMP payment is 20 days past due, allowing the customer to apply for Emergency HEAP; the Company will pause the customer's removal from the AMP program while the

[282] Id., pp. 61-62; Evidentiary Hearing Transcript, p. 17.

[283] Joint Proposal, p. 44 & Appendix U.

[284] Id., Appendix U, p. 1.

[285] Id., pp. 1-2.

customer applies for Emergency HEAP.[286] The Joint Proposal also incorporates Staff's recommendation for reporting on the AMP program, with annual reporting beginning 120 days after an issuance of an order in this proceeding.[287]

The Joint Proposal estimates the number of customers eligible for participation in the AMP at 232.[288] Including an initial information technology capital cost of $25,000, the projected cost of the program, to be recovered through the revenue requirements set forth in the Joint Proposal, is approximately $247,000.[289] The Joint Proposal provides that the differences between actual and estimated AMP expenses will be reconciled at the end of each Rate Year and deferred for recovery in a future proceeding.[290] Adoption of the AMP program will benefit low-income customers by providing them with a chance to pay off their arrears.[291]

7. Language Access

In its initial testimony, Staff recommended that the Company be required to make available to customers the Company's rights & responsibilities brochure, as well as materials

---

[286] Id., p. 2; Hearing Exhibit 56 (Staff Consumer Services Panel Testimony), pp. 42-46.

[287] Joint Proposal, p. 44 & Appendix W, p. 1.

[288] Id., p. 44.

[289] Id.

[290] Id.

[291] In its initial testimony, UIU generally supported the AMP but advocated for a standardized, state-wide program (Hearing Exhibit 98 (Testimony of Pooja Oberoi), p. 7). However, recognizing that this rate proceeding is likely to be decided before the issue of a state-wide AMP is resolved, UIU argued that the parties should focus on the most cost-effective way to implement the AMP, particularly with respect to information technology costs (id., p. 8). We find that the parties have done so, as reflected by the expenses set forth in the Joint Proposal.

pertaining to affordability programs, financial assistance and safety, in German, Pennsylvania German, Dutch, and Spanish.[292] The Company objected on the ground that Staff had not provided sufficient data that the Company's customers, in fact, spoke those languages and that it was not clear which materials Staff believed should be translated.[293]

The Joint Proposal includes provisions requiring the Company to translate specific materials into Spanish and German.[294] The materials to be translated include: Your Rights & Protections - Residential (brochure), Natural Gas Safety (brochure), Utility Service Interruption (brochure), Deferred Payment Agreements (DPA), and information on the Company's Low-Income Program.[295] These materials will be posted in Spanish and German on the Company's website.[296] These provisions are a reasonable compromise of the parties' litigation positions and will ensure that the Company's limited English proficiency customers have access to essential materials in the top two languages, other than English, that are spoken in the Company's service territory.[297]

8. Promotion of Natural Gas

The Joint Proposal incorporates Staff's recommendation that the Company be required to track and report in detail all expenses related to the promotion of natural gas (e.g., direct

---

[292] Hearing Exhibit 56 (Staff Consumer Services Panel Testimony), pp. 55-57. PULP supported Staff's position in its public comments.

[293] Hearing Exhibit 115 (Company Customer Care Panel Rebuttal Testimony), pp. 33-36.

[294] Joint Proposal, pp. 44-45.

[295] Id.

[296] Id.

[297] Staff Statement in Support, p. 73.

mail campaigns, digital marketing initiatives, paid media or social media) that are created solely to encourage natural gas conversions.[298] All such costs will be booked below-the-line (Account 426), meaning they are not recoverable from ratepayers.[299] This provision enhances transparency and prevents ratepayers from subsidizing the promotion of natural gas.

9. Competitive Bidding for Goods and Services

The Joint Proposal includes a process modification to reduce the cost threshold for when the Company is required to conduct competitive bidding for services. This provision will lead to cost savings, thereby reducing the associated recovery of costs from ratepayers.[300]

CLCPA-Related Provisions and Environmental Goals

As noted above, not only does the PSL require the Commission to find that the terms of the Joint Proposal produce just and reasonable rates and ensure safe and adequate service, the CLCPA also requires the Commission to find that adoption of the Rate Plan will not interfere with the attainment of the CLCPA's greenhouse gas emission (GHG) reduction goals.[301] If the adoption of the Rate Plan would be inconsistent with those goals, the Commission must adequately justify its action in adopting the Rate Plan and identify alternatives and GHG mitigation measures.[302] Additionally, the CLCPA requires that, in issuing administrative approvals and decisions, state agencies "shall not disproportionately burden disadvantaged

---

[298] Joint Proposal, p. 45; Hearing Exhibit 56 (Staff Consumer Services Panel Testimony), pp. 58-60

[299] Joint Proposal, p. 45.

[300] Id.

[301] PSL §65(1); CLCPA §7(2).

[302] CLCPA §7(2); Hearing Exhibit 69 (Staff Policy Panel Testimony), pp. 35-37.

communities."[303] The Commission has previously clarified that "the CLCPA does not preclude further investment in the gas system to ensure that the public continues to have safe, adequate and reliable gas service."[304]

As Staff argues, the Joint Proposal will contribute to the goals of the CLCPA by limiting the environmental impact of the utility service provided by the Company as it fulfills its legal obligation under the PSL to provide safe and adequate service to its customers and eligible applicants. Indeed, the Joint Proposal itself recites that its provisions are intended to be consistent with the objectives of the CLCPA and to maintain a balance between those objectives and the pre-existing and continuing obligations of utilities.[305] Specifically, as identified by Staff[306] and further explained below, the Joint Proposal requires the Company to implement a behavioral demand response program to reduce peak usage and to provide gas conservation messaging to its customers, including through its website;[307] mandates the filing of an annual report of GHG emissions, including information on the Company's upstream, local distribution and end-use GHG emissions;[308] permits the Company to seek review of any "Green Tariff" through which customers may purchase in-State renewable natural gas (RNG) and to seek authorization of any future proposed green hydrogen

---

[303] CLCPA §7(3); Hearing Exhibit 69 (Staff Policy Panel Testimony), p. 38.

[304] Cases 23-G-0225 et al., KEDNY/KEDLI – Rates, Order Approving Terms of Joint Proposal and Establishing Gas Rate Plans, With Minor Modifications and Corrections (issued August 15, 2024), p. 73.

[305] Joint Proposal, p. 47.

[306] Staff Statement in Support, pp. 10-16.

[307] Joint Proposal, pp. 37-38.

[308] Id., p. 37.

projects;[309] creates processes for ensuring that extension of service to applicants beyond what is required by 16 NYCRR Part 230 is undertaken only after the Commission authorizes cost recovery;[310] and requires the Company to modify its capital planning process to review, justify and document non-pipeline alternative (NPA) screening results and coordinate with electric utilities prior to customer solicitations to assess the feasibility of electrification.[311] As discussed above in the Gas Safety Section of this Order, the Company's leak management, emergency response, damage prevention and residential methane detector programs will result in reductions of methane emissions, further advancing the CLCPA's goals.[312]

In addition, adoption of the Joint Proposal will not disproportionately burden disadvantaged communities inasmuch as the only capital spending located within such a community involves either upgrades to the Company headquarters facilities or system reliability improvements that will benefit those communities,[313] and the Joint Proposal requires enhanced outreach efforts to benefit customers in disadvantaged communities, as discussed in the Customer Service section of this Order.

The specific provisions related to the Company's CLCPA and environmental goals are discussed as follows.

---

[309] Id., pp. 38-39.

[310] Id., pp. 22-24.

[311] Id., pp. 24-26.

[312] Id., pp. 35-36. Even assuming, arguendo, that we were to find that adoption of the Joint Proposal is inconsistent with the CLCPA's GHG reduction goals, we would find that adoption is justified as necessary for the continued legally required provision of safe, adequate, and reliable service to the Company's customers and that the Joint Proposal includes extensive GHG mitigation measures.

[313] Hearing Exhibit 69 (Staff Policy Panel Testimony), pp. 57-60.

1. Behavioral Demand Response Program

The Joint Proposal provides that the Company will continue its Behavioral Demand Response Program without modification.[314] Pursuant to the program, the Company requests that customers reduce usage during peak times.[315] This program helps benefit customers by lowering utility bills and creating reductions in the amount of natural gas consumed, which will result in reduced GHG emissions in furtherance of the CLCPA's emission reduction targets.[316]

2. Energy Efficiency

As Staff recommended, the Joint Proposal requires the Company to continue its programs encouraging conservation in various ways.[317] The Joint Proposal provides that, in addition to continuing to provide conservation messaging on its website, the Company will refer applicants for new natural gas service to the State Clean Heat Program for information about electrification options and available rebates.[318] The Joint Proposal directs the Company to provide a report to the Commission, no more than 60 days after the end of each Rate Year, detailing the number of new applicants for service it received and the energy efficiency programs for which information was made available to them.[319] In the event that a customer chose gas service notwithstanding awareness of available alternatives, the report must identify the customer's

[314] Joint Proposal, p. 37.

[315] Id., Hearing Exhibit 3 (Company CLCPA Panel Testimony), p. 20.

[316] Staff Statement in Support, p. 64.

[317] Joint Proposal, p. 38; Hearing Exhibit 56 (Staff Consumer Services Panel Testimony), pp. 57-58.

[318] Joint Proposal, p. 38; Staff Statement in Support, p. 65.

[319] Joint Proposal, p. 38.

rationale for that choice if the customer provides that information to the Company during the enrollment process.[320]

3. Greenhouse Gas Emissions Reporting

The Joint Proposal continues the Company's annual GHG emissions reporting, as required by the CLCPA Implementation Order and subsequent Commission direction.[321] This reporting, which details the Company's upstream, local distribution and end-use GHG emissions,[322] allows the Commission and stakeholders to observe trends in GHG emissions within the Company's service territory to identify future actions that may be necessary. Additionally, the Joint Proposal provides that the Company will file a report within 60 days of entering into a contract for RNG that includes the purchased volume and feedstocks, as well as other details.[323]

4. Green Tariff, RNG and Green Hydrogen

The Joint Proposal provides that the Company will seek independent Commission review and approval of any future Green Tariff.[324] For the purpose of this provision, "Green Tariff"

[320] Id. Although a customer may choose whether or not to disclose their reasons for choosing gas service over alternatives, we expect that the Company will ensure that it asks customers to provide those reasons during the enrollment process.

[321] Id., p. 37 & Appendix W, p. 5; Case 22-M-0149, Proceeding on Motion of the Commission Assessing Implementation of and Compliance with the Requirements and Targets of the Climate Leadership and Community Protection Act, Order on Implementation of the Climate Leadership and Community Protection Act (issued May 12, 2022) (CLCPA Implementation Order).

[322] Joint Proposal, Appendix W, p. 5.

[323] Id., p. 27 & Appendix W, p. 7.

[324] Id., p. 38.

means an “opt-in” Tariff that allows the Company’s customers to purchase RNG inclusive of environmental attributes.[325]

In addition, the Company receives RNG from several dairy farms in its service territory.[326] In its testimony, Staff explained that it is supportive of the Company pursuing RNG supply projects where the costs are not borne by ratepayers, as well as the discount negotiated by the Company on RNG supply in comparison to traditional gas supply.[327] Nevertheless, Staff recommended that the Commission not allow the Company to provide upfront ratepayer funding for any future RNG interconnections or projects, even if these costs are eventually reimbursed by the developer, and also recommended that the Commission require that any RNG be purchased at a discount as compared to the cost of traditional gas supply.[328] The Joint Proposal reflects Staff’s recommendations and further requires the Company to take receipt or delivery of purchased RNG directly onto the system only through either an on-system interconnection or an on-system injection point.[329]

The Joint Proposal also recommends requiring the Company to petition the Commission regarding any future “green

---

[325] Id.

[326] Hearing Exhibit 63 (Staff Gas Safety Panel Testimony), pp. 23-24. The developers of those projects fully reimbursed the Company for construction and interconnection costs (id.).

[327] Id., p. 25. In its direct testimony on the CLCPA, Staff also repeatedly emphasized that it recommended a shift to the purchase of in-state RNG, which would be purchased at a discount and result in a reduction of approximately 11,000 metric tons of carbon dioxide in 2026 alone, as compared to all delivery being sourced from Canada (Hearing Exhibit 69 (Staff Policy Panel Testimony), pp. 43-45, 52-53).

[328] Hearing Exhibit 63 (Staff Gas Safety Panel Testimony), pp. 25-26.

[329] Joint Proposal, p. 27.

hydrogen" project for which the Company will seek cost recovery. That is, the Company must receive authorization from the Commission on any filed proposal detailing the blending of hydrogen and natural gas before proceeding with such proposal.[330]

These provisions offer mechanisms pursuant to which the Company can propose innovative approaches to reducing GHG emissions, while protecting customers from subsidizing interconnection infrastructure associated with RNG and ensuring that the Company will not proceed with such proposals until they have been fully vetted by the Commission.

5. Main Extensions and NPAs

The Joint Proposal continues the process established in the 2023 Rate Order pursuant to which the Company must seek cost recovery for any subsequently proposed "Extension Cap-ex" projects to be funded by the Company.[331] Extension Cap-ex is defined in the Joint Proposal as "the Company's capital expenditures related to mains and services to add new applicants for gas service beyond that required under 16 NYCRR Part 230."[332] The capital budgets in the Joint Proposal do not include any capital spending for Extension Cap-ex projects.[333] The process set forth in the Joint Proposal enables the Commission to

[330] Id., p. 38. The reporting requirements associated with the purchase of RNG are set forth in the immediately preceding section on Greenhouse Gas Emissions Reporting.

[331] Id., pp. 22-23.

[332] Id., pp. 3-4. To the extent there are changes in law that impact 16 NYCRR Part 230, including implementation of the recently enacted Public Service Law §31(4-a), the Company will be required to abide by such changes and the revenue impacts of any such changes will fall under the section of the Joint Proposal that addresses Exogenous Events/Legislative, Regulatory and Related Actions.

[333] Staff Statement in Support, p. 40.

address the economic feasibility and consistency with the CLCPA of any such project prior to commencement of construction.[334]

Specifically, the Joint Proposal requires the Company to file a petition requesting Commission approval of any Extension Cap-ex Project at least 150 days before construction begins.[335] The petition must include: project cost estimates; prospective customer survey results with the potential customers' current energy type; projected natural gas and alternative energy costs; the number of both total potential new customers and committed customers; annual conversion estimates for the first five years; annual projected volumetric throughput for the first five years; annual projected revenue for the first seven years; information on the proposed project's consistency with attainment of statewide GHG emissions goals as articulated in the CLCPA; and information regarding consideration of any NPAs.[336] The Joint Proposal further provides that, upon filing, the petition will be noticed for public comment, allowing interested stakeholders to express their views on the proposal's merits and its consistency with the CLCPA, and Staff will conduct a thorough review of the petition.[337] The Commission would then be able to approve, reject, or modify the petition. In the event that the Commission granted the petition, recovery of the associated costs would be through a surcharge until the Company's base rates are next set.[338]

[334] Id., p. 41.

[335] Joint Proposal, p. 22.

[336] Id. The Joint Proposal specifies that RNG sourced within New York State will be reflected as appropriate in considering consistency with the CLCPA (id.).

[337] Id., p. 23.

[338] Id.

The Joint Proposal defines "Entitlement Cap-ex" projects as those involving "capital expenditures related to the portion of main and/or service to be made available to new applicants to the Company for gas service, without direct charge to the applicant, as required under 16 NYCRR Part 230."[339] For Entitlement Cap-ex projects designed to serve multiple customers and totaling more than 500 feet in length, the Joint Proposal mandates that the Company submit a report to the Commission detailing the project's cost and NPAs considered.[340] The report must also include documentation that potential customers received information regarding alternative heating options.[341]

Apart from the main extension processes described above, the Joint Proposal incorporates Staff's recommendations that the Company be required to revise its capital planning review and procedures to improve its opportunities to implement NPAs for areas of pressure concern.[342] Specifically, the Company must provide an annual report that proactively reviews projected areas of pressure concern that could arise in the following three years to assess NPA suitability and CLCPA-aligned emission reduction potential for those areas.[343] The Company must also coordinate with local electric providers to proactively address potential electric distribution issues due to increased electricity demand as a result of NPAs.[344] Finally, the Joint Proposal requires the Company to expand its capital planning process to include consideration and documentation of NPA

---

[339] Id., p. 3.

[340] Id., p. 24.

[341] Id.

[342] Id., pp. 24-26; Hearing Exhibit 67 (Staff Gas System Planning and Reliability Panel), pp. 16-19.

[343] Joint Proposal, pp. 24-25.

[344] Id., p. 25.

suitability and the Company's screening process for each capital project; each project's documentation of screening results will include a list of electrification measures and non-fossil fuel alternatives that the Company recommended to customers.[345]

The provisions in the Joint Proposal regarding main extensions and NPAs align with the State's regulatory and environmental policies by requiring consideration of NPAs to ameliorate the need for installation of additional gas main, increasing transparency, ensuring that the Company does not proceed with infrastructure expansion without proper consideration of alternatives and CLCPA goals, and memorializing standard practices for advanced capital project screening, including increased attention to NPA opportunities and coordinated energy planning with local electric providers. The detailed processes for project review, NPA consideration, and stakeholder engagement in these provisions create a framework for responsible infrastructure development that contributes toward CLCPA goals and are, therefore, reasonable.

CONCLUSION

Based on our thorough evaluation of the record in these proceedings, we adopt the terms of the Joint Proposal. The three-year Rate Plan provides for rates that are just and reasonable and, when considered in conjunction with the Rate Plan's other terms and conditions, satisfies the Commission's concern that, overall, the plan is in the public interest. In addition, we find that the adoption of the Joint Proposal will not interfere with the attainment of the CLCPA's GHG emission reduction goals or disproportionately burden disadvantaged communities.

[345] Id., pp. 25-26.

The Commission orders:

1. The rates, terms, conditions, and provisions of the Joint Proposal dated August 29, 2025, filed in these proceedings, and attached hereto as Attachment A, are adopted and incorporated herein to the extent consistent with the discussion herein as part of this Order.

2. Liberty Utilities (St. Lawrence Gas) Corp. is directed to file cancellation supplements, effective on not less than one day's notice, on or before January 27, 2026, cancelling the tariff amendments and supplements listed in Attachment B to this Order.

3. Liberty Utilities (St. Lawrence Gas) Corp. is directed to file, on not less than three days' notice, to take effect on February 1, 2026, on a temporary basis, such tariff changes as are necessary to effectuate the terms of this Order for Rate Year 1, the twelve-month period ending October 31, 2026, and to incorporate any tariff amendments that were previously approved by the Commission since the tariff amendments listed in Attachment B were filed, except for those related to the make-whole provisions adopted in this Order.

4. Liberty Utilities (St. Lawrence Gas) Corp. is directed to file, on not less than three days' notice, to take effect on February 1, 2026, on a temporary basis, such further tariff revisions as are necessary to effectuate the make-whole provisions adopted in this Order.

5. Liberty Utilities (St. Lawrence Gas) Corp. is directed to file, on not less than 30 days' notice, to take effect on November 1, 2026, on a temporary basis, such further tariff changes as are necessary to effectuate the terms of this Order for Rate Year 2, the twelve-month period ending October 31, 2027, as discussed in the body of this Order. The

amendments specified in the compliance filings shall not become effective on a permanent basis until approved by the Commission.

6. Liberty Utilities (St. Lawarence Gas) Corp. is directed to file, on not less than 30 days' notice, to take effect on November 1, 2027, on a temporary basis, such further tariff changes as are necessary to effectuate the terms of this Order for Rate Year 3, the twelve-month period ending October 31, 2028, as discussed in the body of this Order. The amendments specified in the compliance filings shall not become effective on a permanent basis until approved by the Commission.

7. Any party wishing to comment on the tariff amendments may do so by electronically filing its comments with the Secretary to the Commission and serving its comments upon all active parties within 14 days of service of the proposed amendments. The amendments specified in the compliance filings shall not become effective on a permanent basis until approved by the Commission.

8. The requirements of Public Service Law §66(12)(b) and Title 16 of the New York Codes, Rules and Regulations §720-8.1 that newspaper publication be completed prior to the effective date of the amendments for Rate Year 1 and to implement the make-whole provision are waived; provided however, that Liberty Utilities (St. Lawrence Gas) Corp. shall file with the Secretary of the Commission, no later than six weeks following the effective date of the amendments, proof that notice to the public of the changes set forth in the amendments has been published once a week for consecutive weeks in one or more newspapers having general circulation in the service territory and areas affected by the amendments. The requirements of Public Service Law §66(12)(b) and Title 16 of the New York Codes, Rules and Regulations §720-8.1 are not waived for tariff changes necessary to implement the rate plans

in Rate Years 2 and 3, or with respect to tariff filings in compliance with this Order made in subsequent years.

9. In the Secretary's sole discretion, the deadlines set forth in this Order may be extended. Any request for an extension must be in writing, must include a justification for the extension, and must be filed at least three days prior to the affected deadline.

10. These proceedings are continued.

By the Commission,

(SIGNED)

MICHELLE L. PHILLIPS
Secretary

Attachment A

NEW YORK STATE
PUBLIC SERVICE COMMISSION

Case 24-G-0668 – Proceeding on Motion of the Commission as to the Rates, Charges, Rules and Regulations of Liberty Utilities (St. Lawrence Gas) Corp. for Gas Service

---

Case 24-G-0369 – Petition of Liberty Utilities (St. Lawrence Gas) Corp. for Approval to Implement Automated Meter Reading and Recover Associated Costs

---

JOINT PROPOSAL

August 29, 2025

TABLE OF CONTENTS

Page

I. INTRODUCTION 2

II. DEFINITIONS 2

III. PROCEDURAL SUMMARY 5

- A. Automated Meter Reading Implementation and Recovery Petition 5
- B. Liberty SLG Rate Proceeding 5
- C. Settlement Negotiations 6

IV. APPROVAL OF THE JOINT PROPOSAL IS IN THE PUBLIC INTEREST 7

V. TERMS GOVERNING THE RATE CASE 8

- A. Term and Effective Date of Rate Changes 8
- B. Make Whole 8
- C. Rate Plan 9
  - 1. Summary of Overall Revenue Requirement 9
  - 2. Sales and Revenue 10
    - a) Gas Sales Forecast 10
    - b) Delivery Revenue 10
  - 3. Operation and Maintenance Expenses 11
    - a) Pensions and OPEB 11
    - b) Greenhouse Gas Reduction Program / Hybrid Heating Program 11
    - c) Productivity Adjustment 12
    - d) Inflation 12
  - 4. Depreciation 12
    - a) Depreciation Expense 12
    - b) Modifications to Depreciation 12
      - i. Group Depreciation 12
      - ii. Service Life Estimates / Annual Accrual Rates 13
  - 5. Amortization of Regulatory Deferrals 13
    - a) Long-Term Plan 13
      - i. LTP Surcharge 14
  - 6. Taxes Other Than Income Taxes 15

a) Payroll Taxes 15
b) Property Taxes 15
7. Income Taxes 15
a) Excess Accumualted Deferred Income Taxes 16
8. Rate Base 16
a) Plant in Service 16
b) Net Plant Reconciliation Mechanism 17
i. Excluded Projects 18
c) Accumulated Deferred Income Taxes 18
d) Excess Accumulated Deferred Income Taxes 19
e) Earnings Base Capitalization Adjustment 19
f) Contribution in Aid of Construction 19
g) Capital Expenditures 20
i. Projected Amounts 20
ii. Automated Meter Reading (AMR) 20
iii. Case 24-G-0369 – AMR Petition 21
iv. Plant Account 303 (Software/Cybersecurity) 21
v. Cybersecurity (Case 25-M-0302) 21
vi. Main Extensions 22
(a) Commission Review of Company-Funded Extension Capital Projects 22
(b) Non-Pipeline Alternative Consideration for Entitlement Capital Projects Regarding the CLCPA 24
vii. Emergency Planning Criteria for System Redundancy and Emergency Response Training 26
viii. Reporting 26
(a) Cybersecurity Reporting 26
(b) Physical Security Reporting 26
9. Renewable Natural Gas 27
10. Cost of Capital 27
a) Capital Structure, Return on Equity, and Cost Rates 27
b) Earnings Sharing Mechanism 29

D. Revenue Allocation and Rate Design....30
1. Revenue Allocation 30
2. Rate Design....31
3. Minimum Monthly Charges 31
4. Merchant Function Charge 31
5. Delivery Revenue Adjustment....32
6. Revenue Decoupling Mechanism 32
7. Lost and Unaccounted for Gas 33
8. Interruptible Incentive Credit Mechanism....33
9. Contract Administration Charge....34
E. Gas Safety, Regulatory, and Environmental/Climate Goals 34
1. Timely Filings....34
2. Gas Safety Metrics....34
a) Emergency Response....35
b) Damage Prevention....35
c) Leak Management 35
d) Compliance with Pipeline Safety Regulations 35
3. Additional Full-Time Employees in the Pipeline Safety Management System Program and Quality Control and Quality Assurance 36
4. Residential Methane Detector Pilot Program 36
5. First Responder Communication and Training....37
6. Behavioral Demand Response Program 37
7. Greenhouse Gas Emissions Reporting....37
8. Energy Efficiency 38
9. Green Tariff and Green Hydrogen....38
F. Customer Service 39
1. Customer Service Performance Indicators 39
a) Commission Complaint Rate....39
b) Overall Customer Satisfaction Rate....39
2. Missed Appointment Credit....40
3. Termination and Uncollectible Expenses 40
4. Low-Income Program....40
5. Outreach & Education 42
6. Levelized Payment Plan 43

7. Arrearage Management Plan 44
8. Language Access 44
9. Promotion of Natural Gas 45
10. Competitive Bidding for Goods and Services 45

G. Affiliate Code of Conduct 45
H. Omnibus Reporting Requirements 45
I. Exogenous Events / Legislative, Regulatory and Related Actions 46

VI. CLCPA-RELATED PROVISIONS 47

VII. GENERAL AND MISCELLANEOUS PROVISIONS 47

A. Restriction on Filing for Rate Increases During Term of Rate Plan 47
B. Provisions Not Separable 47
C. Provisions Not Precedent 48
D. Submission of the Proposal 48
E. Effect of Commission Adoption of Terms of this Proposal 49
F. Further Assurances 49
G. Execution 50
H. Entire Agreement 50

APPENDICES

Appendix A – Revenue Requirement

Appendix B – Levelization, Revenue Impacts, Make Whole, and Effectuating End of Rate Plan Impacts

Appendix C – Sales Forecast

Appendix D – Delivery Revenues

Appendix E – Depreciation Rate Factors

Appendix F – CapEx Budget, Net Plant Targets, Net Plant Tracker, and Other Capital Trackers

Appendix G – Automated Meter Reading Benefit Cost Analysis and Other Materials

Appendix H – Earnings Base Capitalization Reconciliation Mechanism

Appendix I – Amortization of Regulatory Deferrals

Appendix J – Extension Capital Project Recovery Mechanism

Appendix K – Common Equity Reconciliation Mechanism

Appendix L – Calculation of Capital Structure

Appendix M – Earnings Sharing Mechanism

Appendix N – Revenue Allocation and Rate Design

Appendix O – Customer Bill Impacts

Appendix P – Merchant Function Charge (MFC) & Delivery Rate Adjustment (DRA) Targets

Appendix Q – Revenue Decoupling Mechanism (RDM) Targets

Appendix R – Lost and Unaccounted for Gas Incentive Mechanism

Appendix S – Gas Safety Metrics

Appendix T – Customer Service Performance Indicators

Appendix U – Arrearage Management Program Materials

Appendix V – Affiliate Code of Conduct

Appendix W – Omnibus Reporting Requirements

NEW YORK STATE
PUBLIC SERVICE COMMISSION

Case 24-G-0668 – Proceeding on Motion of the Commission as to the Rates, Charges, Rules and Regulations of Liberty Utilities (St. Lawrence Gas) Corp. for Gas Service

---

Case 24-G-0369 – Petition of Liberty Utilities (St. Lawrence Gas) Corp. for Approval to Implement Automated Meter Reading and Recover Associated Costs

---

JOINT PROPOSAL

I. INTRODUCTION

This unopposed Joint Proposal (Joint Proposal or JP) is made as of August 29, 2025, by and among the following parties to the above-referenced proceedings: Liberty Utilities (St. Lawrence Gas) Corp. (Liberty SLG or the Company); Staff of the Department of Public Service (DPS Staff); and Multiple Intervenors (MI) (collectively, the Signatory Parties or Parties).[1] The only other party to this proceeding, the Utility Intervention Unit of the Division of Consumer Protection of the New York State Department of State (UIU), while not signing the Joint Proposal, has authorized the Signatory Parties to state that it will not oppose the Joint Proposal. This Joint Proposal settles all contested issues among the Signatory Parties in the above-captioned cases.

II. DEFINITIONS

As used in this Joint Proposal, the following terms have the following meanings:

---

[1] MI is an unincorporated association of approximately 55 large industrial, commercial, and institutional energy consumers with manufacturing and other facilities located throughout New York State, including in the Liberty SLG service territory.

MI and UIU are parties to Case 24-G-0668 but not Case 24-G-0369. Only the Company and DPS Staff are parties to Case 24-G-0369. Given the overlapping issues in Cases 24-G-0668 and 24-G-0369, they are referred to herein as a singular "case."

A. “Liberty SLG” or the “Company” means Liberty Utilities (St. Lawrence Gas) Corp.

B. “Rate Year 1” means November 1, 2025 through October 31, 2026.

C. “Rate Year 2” means November 1, 2026 through October 31, 2027.

D. “Rate Year 3” means November 1, 2027 through October 31, 2028.

E. Rate Year 1, Rate Year 2, and Rate Year 3 are collectively referred to as the “Rate Years” or the “Rate Plan,” and individually as a “Rate Year.”

F. “SC” means service classification.

G. “PSL” means the New York Public Service Law

H. “Commission” means the New York State Public Service Commission.

I. “Secretary” means the Secretary to the New York State Public Service Commission.

J. “CLCPA” means the New York State Climate Leadership and Community Protection Act.

K. “NYCRR” means the New York Codes, Rules and Regulations.

L. Main Extensions:

1. “Entitlement Cap-ex” means capital expenditures related to the portion of main and/or service to be made available to new applicants to the Company for gas service, without direct charge to the applicant, as required under 16 NYCRR Part 230.

2. “Extension Cap-ex” means the Company’s capital expenditures related to mains and services to add new applicants for gas service beyond that required under 16 NYCRR Part 230. The justification for inclusion in rate base is based on the economic analysis and

consistency with the CLCPA, subject to separate Commission approval, as set forth in Section V.C.8.g.vi.a, below.

3. "Extension Capital Project" means any capital project that includes Extension Cap-ex.

4. "Entitlement Capital Project" means any capital project that includes Entitlement Cap-ex, and not Extension Cap-ex.

M. "NRA" means negative revenue adjustment.

N. "PRA" means positive revenue adjustment.

O. "BP" means pre-tax basis point. One BP equals 1/100 of one percent or 0.01% of the return on common equity.

P. "2023 JP" means the Joint Proposal filed with the Commission on March 30, 2023, in Case 21-G-0577, and adopted by the Commission in the Order Adopting Terms of Joint Proposal and Establishing Gas Rate Plan (issued June 22, 2023).

Q. "Expansion Area" means the portion of the Company's service territory in the Towns of Winthrop, Brasher Falls, North Lawrence, Moira, Brushton, North Bangor, Malone, Burke, and Chateauguay (in Franklin and St. Lawrence Counties) served by the "Expansion Project" (as defined in the Joint Proposal adopted by the Commission on October 18, 2019, in Case 18-G-0133).

R. "Legacy Area" means the portion of the Company's service territory that is not the Expansion Area.

III. PROCEDURAL SUMMARY

A. Automated Meter Reading Implementation and Recovery Petition

On June 7, 2024, the Company initiated Case 24-G-0369 by filing with the Commission a verified petition seeking authorization to implement Automated Meter Reading (AMR) throughout the Company's service territory and allowing for recovery of all costs associated with that implementation during the Company's next rate plan. On August 13, 2025, Liberty SLG filed a notice of impending settlement discussions in Case 24-G-0369. The parties seek to resolve all issues in Case 24-G-0369 in the present rate case proceeding, and thus recommend the Commission close Case 24-G-0369, as all reporting and other requirements are to be subsumed into the instant proceeding in Case 24-G-0668.

B. Liberty SLG Rate Proceeding

On November 27, 2024, Liberty SLG filed revised tariff leaves. On November 29 and December 6, 2024, Liberty SLG filed testimonies, petition and exhibits as part of a one-year rate filing (the Rate Filing) requested to increase revenues from gas operations by $2,174,020 (or 4.86% of total revenues, or 11.62% of delivery revenues) to recover the revenue deficiency forecasted for Rate Year 1. The test year supporting Liberty SLG's Rate Filing is the 12-month period ending June 30, 2024 (Historic Test Year). The Company proposed a one-year rate plan with the expectation that negotiating a multi-year plan may meet the needs of all stakeholders in the most fair and equitable manner.

Following receipt of the Rate Filing, on December 16, 2024, the Commission suspended Liberty SLG's proposed tariff leaves through April 30, 2025. On April 23, 2025, the Commission further suspended the Company's proposed tariff leaves through October 30, 2025.

Administrative Law Judges (ALJs) Leah Soule Amyot and Ashley Moreno were appointed to preside over this case. Procedural and technical conferences were held remotely on January 2, 2025, after which, on January 3, 2025, ALJs Amyot and Moreno issued a Ruling on Schedule, which provided (among other things) for evidentiary hearings to begin on May 6, 2025. Two virtual public statement hearings were held on the afternoon and evening of February 13, 2025 (the only speaker was Theresa Hotte of the Public Utility Law Project).

Pursuant to the Ruling on Schedule, on February 28, 2025, Liberty SLG updated its Rate Filing (the Updated Filing) with additional testimony and exhibits. The Updated Filing presented the Company's updated calculation of the overall revenue requirement for Rate Year 1 based on the Test Year. The Updated Filing included an updated proposed revenue requirement increase for Rate Year 1 of $1,818,951, which represented a decrease of $355,069 from the $2,174,020 revenue requirement increase the Company proposed in its original Rate Filing. The Updated Filing adjusted the revenue requirement to account for changes and updates to data and inputs that emerged as part of the discovery process in this case.

On April 1, 2025, DPS Staff and UIU filed testimony and exhibits in response to the Company's Rate Filing and Updated Filing. On April 8, 2025, DPS Staff filed additional exhibits. On April 22, 2025, the Company filed rebuttal testimonies and exhibits (Rebuttal Filing). The Rebuttal Filing included an updated proposed revenue requirement increase for Rate Year 1 of $2,332,458, which represented an increase of $158,438 from the revenue requirement increase of $2,174,020 the Company proposed in its original Rate Filing.

Starting in November 2024, Liberty SLG responded to approximately 600 separately numbered interrogatories/document requests from DPS Staff or UIU.

C. Settlement Negotiations

On April 30, 2025, Liberty SLG filed with the Commission and served on all Parties a Notice of Impending Settlement Negotiations pursuant to 16 NYCRR § 3.9(a). In light of the

Parties' settlement negotiations, on May 1, 2025, ALJs Amyot and Moreno postponed the evidentiary hearing. Settlement negotiations began on May 7, 2025, and continued throughout June, July, and August 2025. On May 1, 2025, Liberty SLG requested and consented to an extension of the Suspension Date to December 29, 2025, subject to a make-whole provision for the period from October 31 to December 29, 2025. Pursuant to ALJs Amyot and Moreno's directive, on June 20, 2025, the Company requested and consented to an extension of the Suspension Date through February 27, 2026, subject to a make-whole provision, if necessary.

Between May and August 2025, the parties exchanged numerous settlement proposals and held more than a dozen settlement conferences and breakout sessions. Draft proposals were exchanged between settlement conferences. As a consequence of these negotiations, conferences, and exchange of proposals, an agreement in principle was reached among the Parties. That agreement in principle became the basis for this Joint Proposal. Drafts of this Joint Proposal and its appendices were subsequently exchanged and agreed to by the Signatory Parties, who present this document to the Commission for its consideration.

IV. APPROVAL OF THE JOINT PROPOSAL IS IN THE PUBLIC INTEREST

The Signatory Parties recommend that the Commission approve the terms of this Joint Proposal and the attached Appendices without modification.[2] The Signatory Parties have concluded that the terms and conditions herein resolve all issues in the rate case and the AMR petition in a manner that allows Liberty SLG to provide safe and adequate service at just and reasonable rates pursuant to PSL § 65. The Joint Proposal also contains provisions supportive of and in furtherance of the objectives of the CLCPA.

[2] Appendices A through W attached hereto are expressly incorporated by reference into this Joint Proposal.

V. TERMS GOVERNING THE RATE CASE

A. Term and Effective Date of Rate Changes

The term of this Joint Proposal is three years, commencing on November 1, 2025, and continuing through October 31, 2028.

The three successive 12-month periods, or Rate Years, ending on October 31 shall be referred to as "Rate Year 1," "Rate Year 2," and "Rate Year 3." The revenue requirement schedules demonstrating the respective revenue requirement increases are reflected in Appendix A. The provisions of Rate Year 3 will, unless otherwise specified herein, remain in effect until superseding rates and/or terms become effective.

Nothing herein precludes the Company from filing a new general gas rate case prior to October 31, 2028, for rates to be effective on or after November 1, 2028.

B. Make Whole

To the extent Commission approval of Rate Year 1 rates occurs after a date that would permit such rates to go into effect by November 1, 2025, the Company requested, and the Signatory Parties have agreed to, a make-whole provision whereby the Company will recover shortfalls and refund over-collections such that the Company and its customers would be in the same position had Rate Year 1 rates gone into effect on November 1, 2025.[3] The under-collected revenue resulting from the make whole provision will be recovered through a surcharge for the remainder of Rate Year 1 and Rate Year 2 as detailed in Appendix B. The amount to be recovered will be allocated to all firm service classes based on current revenues.

[3] Revenue adjustments will be calculated as the difference between: (1) sales revenues the Company would have billed at the new rates beginning November 1, 2025 and the date new rates actually go into effect; and (2) the same level of sales revenues at current rates. The revenue adjustments would include all applicable surcharges and carrying charges and would be subject to reconciliation in accordance with all applicable mechanisms, such as the Revenue Decoupling Mechanism (RDM).

C. Rate Plan

1. Summary of Overall Revenue Requirement

The Signatory Parties agree to the rate changes for the Company for the Rate Years defined in this Joint Proposal and Appendix A. As detailed in Appendix A, the revenue requirement, including the agreed upon revenue requirement increases (including delivery and non-delivery revenues, *e.g.*, commodity) for Rate Year 1 is $35,429,638; for Rate Year 2 is $37,545,273; and for Rate Year 3 is $39,446,781. The revenue requirement increases in gas delivery service in each of the Rate Years are:

Rate Year 1: $399,729

Rate Year 2: $1,876,203

Rate Year 3: $1,645,275

While the Signatory Parties worked to minimize the rate increases needed for safe and adequate service, they recognize that a significant increase in a particular Rate Year may place too much of a burden on ratepayers. To address this concern, the Signatory Parties propose to implement the annual revenue requirement increases to levelized total revenue impacts, and thus customer bill impacts. The resulting revenue requirement increases for each Rate Year are as follows:

Rate Year 1: $1,064,511

Rate Year 2: $1,093,427

Rate Year 3: $1,123,626

The calculation of the levelized amounts for each Rate Year is shown in Appendix B. The gas revenue increase and associated impacts are shown below:

Total Revenue Impacts (Non-Levelized)			
	Revenue Requirement Increase	Total Revenue %	Delivery %
RY1	$399,729	0.9%	2.2%
RY2	$1,876,203	4.2%	10.0%
RY3	$1,645,275	3.5%	7.9%
Total	**$6,596,868**		

Total Revenue Impacts (Levelized)			
	Revenue Requirement Increase	Total Revenue %	Delivery %
RY1	$1,064,511	2.4%	5.8%
RY2	$1,093,427	2.4%	5.6%
RY3	$1,123,626	2.4%	5.5%
Total	**$6,504,013**		

2. Sales and Revenue

a) Gas Sales Forecast

The overall gas sales forecasts associated with the revenue forecasts that underlie this Joint Proposal are set forth in Appendix C. A 10-year weather normalization was used in the preparation of these forecasts.

b) Delivery Revenue

The Signatory Parties agree to the base delivery revenues, including required base levelized revenue increases, shown in Appendix D for Rate Years 1, 2, and 3, which summarizes the agreed-upon total delivery and other revenues. As set forth in Appendix D, the Company's base delivery revenues (excluding gross revenue taxes and gas costs) will be as follows:

Rate Year 1: $18,089,726

Rate Year 2: $19,299,327

Rate Year 3: $20,555,888

3. Operation and Maintenance Expenses

The Signatory Parties agree on Rate Year 1 total operation and maintenance (O&M) expense of $7,443,651, Rate Year 2 total O&M expense of $7,870,664, and Rate Year 3 total O&M expense of $8,184,987. Appendix A, Schedule 2 provides additional detail regarding the Company's O&M expenses, and reflects adjustments to items including, but not limited to, incentive compensation, direct and indirect labor expenses, outside services, productivity, membership dues associated with organizations that participate in lobbying, uncollectibles and cybersecurity.

a) Pensions and OPEB

The Signatory Parties agree on adjustments that affect the Pensions and Other Post-Employment Benefits (OPEB) expenses, including reductions to Pensions and OPEB expense to reflect the capitalized portions of the service cost component of Pension and OPEB expenses. The Signatory Parties agree on a Pension amount for each Rate Year of negative $1,245,933, which includes negative $416,863 of Pension expense and negative $827,250 of amortization of the Pension deferral. The Signatory Parties agree on an OPEB amount for each Rate Year of negative $1,357,209, which includes negative $992,777 of OPEB expense and negative $364,432 of amortization of the Pension deferral.

b) Greenhouse Gas Reduction Program / Hybrid Heating Program

The Signatory Parties agree that the costs of the Greenhouse Gas Reduction Program / Hybrid Heating Program, as described in the Company's Initial Rate and Rebuttal Filings, are excluded from the revenue requirements presented in this Joint Proposal.

c) Productivity Adjustment

The Signatory Parties have agreed to the application of a 1% productivity adjustment to payroll and related personnel overheads. A productivity adjustment is reflected in the revenue requirement for each Rate Year.

d) Inflation

The Signatory Parties agree the inflation rates used for determining inflationary items in each Rate Year are as follows:

Historic Test Year through Rate Year 1: 6.584% (July 1, 2024 – October 31, 2026)

Rate Year 2: 2.396% (November 1, 2026 – October 31, 2027)

Rate Year 3: 2.323% (November 1, 2027 – October 31, 2028)

4. Depreciation

a) Depreciation Expense

As detailed in Appendix A, the revenue requirements underlying this Joint Proposal reflect depreciation expense for each Rate Year as follows:

Rate Year 1: $2,196,337

Rate Year 2: $2,637,394

Rate Year 3: $3,092,869

b) Modifications to Depreciation

i. Group Depreciation

The Company will move from individual asset rates to a group deprecation rate for plant Accounts 391.1, 392, and 396. The Company will reflect Accounts 391.1, 392, and 396 as group depreciation rates in its next depreciation study.

ii. Service Life Estimates / Annual Accrual Rates

For depreciation purposes, the Company will employ the depreciation factors (including average service life, net salvage, depreciation rate with net salvage, and curve type) as seen in Appendix E.

5. Amortization of Regulatory Deferrals

The revenue requirements underlying this Joint Proposal reflect the amortization of certain regulatory deferrals over the Rate Plan, as listed in Appendix I. The Signatory Parties agree on several adjustments that affect the amortization of regulatory deferrals. The total, net amount of regulatory deferrals to be amortized in each Rate Year is as follows:

Rate Year 1: $309,829

Rate Year 2: $459,937

Rate Year 3: $459,937

a) Long-Term Plan

The costs incurred by the Company to date to prepare the long-term plan (LTP) required by the Commission's Order Adopting Gas System Planning Process in Case 20-G-0131 (issued May 12, 2022), and filed by the Company on January 31, 2025, in Case 24-G-0630, will be amortized over a three-year period, reflected in revenue requirement, and recovered via base delivery rates. The Company will defer the following incremental costs related to completion of the LTP with carrying charges, calculated using the pre-tax weighted average cost of capital rate, to the extent they are not included in revenue requirement: (i) incremental costs to prepare and file annual LTP updates (*e.g.*, external consultant costs); (ii) incremental costs to prepare and file future triennial LTPs; and (iii) incremental costs associated with Commission authorized projects or programs.

i. LTP Surcharge

Any of the aforementioned incremental LTP costs will be eligible for recovery via an LTP Surcharge. The LTP Surcharge will be updated annually, will include costs incurred through August 31 (to be included in a statement filed with the Secretary by October 1), will take effect on November 1, and will be limited to an amount no greater than 2% of Liberty SLG's prior year's actual aggregate operating revenues (*i.e.*, including delivery and commodity revenues but excluding energy service company [ESCO] commodity revenues) for the 12-month period ending August 31.[4] The LTP Surcharge will include a reconciliation of the prior 12-month period's over-collection or under-collection. The prior 12-month period's over-collection or under-collection shall be booked to the Company's associated LTP deferral account and will accrue carrying charges consistent with the Company's other regulatory deferrals or the pre-tax weighted average cost of capital.

The allocation and recovery of external consultant costs shall be based on delivery revenues as shown in Appendix B, Schedule 2. The LTP Surcharge will be separately calculated for each SC on a dollar-per-therm basis (*i.e.*, the LTP Surcharge for SC 1, SC 2, SC 2L, and SC 3 will be calculated separately). The allocation and recovery of Commission authorized projects or programs costs associated with each LTP program and initiative will be addressed along with the corresponding proposals or other related future proceedings.

The Company's cover letter to the statement filed with the Secretary by October 1 of each year shall provide a narrative with any LTP costs incurred after a Commission order in Case 24-

[4] To the extent rates go into effect after November 1, 2025, then the LTP Surcharge will become effective upon the date new rates become effective, and would recover the associated costs through the remainder of Rate Year 1. The Company shall file tariff statements on not less than 30 days after Commision authorization of this Joint Proposal.

G-0630 or December 31, 2025 (whichever is sooner), which shall describe the process the Company used to procure services to ensure transparency, fairness, and cost-effectiveness to ratepayers. Deferred costs and those recovered through the LTP Surcharge remain subject to DPS Staff review, potential correction/revision, and reconciliation.

The Company shall file tariff statements for the LTP Surcharge on not less than 30 days notice prior to the effective date of November 1 of each year.

6. Taxes Other Than Income Taxes

a) Payroll Taxes

The Signatory Parties agree to an adjustment of Liberty SLG's presentation of payroll taxes to track adjustments to Direct Labor expense. The Signatory Parties agree on Payroll Tax expense for each Rate Year as follows:

Rate Year 1: $404,856

Rate Year 2: $414,780

Rate Year 3: $424,434

b) Property Taxes

Each Rate Year, the Company will reconcile actual property tax expense to the property tax expense amounts of $3,063,112 in Rate Year 1, $3,326,539 in Rate Year 2, and $3,616,500 in Rate Year 3. Any increase or decrease from the Rate Year targets for property taxes will be reconciled and shared 90% / 10% between customers and shareholders, respectively. The reconciliated property taxes will be deferred for collection/refund in the Company's next rate case.

7. Income Taxes

The State Income Tax and Federal Income Tax impacts of the agreed upon expense adjustments contained in this Joint Proposal are detailed in Appendix A.

a) Excess Accumualted Deferred Income Taxes

As determined in Case 21-G-0577, the valuation of the EADIT regulatory liability (which is grossed up for the income tax effect), resulted in a negative $963,111 for the Legacy Area and a negative $627,047 for the portion of Liberty SLG's service territory formerly referred to as the Expansion Area. Those amounts are to be amortized over 15 years and 38 years, respectively. In order for customers to receive the full revenue requirement impact of the amortization of EADIT, negative $47,427 and negative $12,189, respectively (or a total negative of $59,615), shall be amortized via the income tax calculation, and thus reduce current income tax expense. Amortizing this amount as a reduction to current income tax expense provides customers with the benefit of the appropriate revenue requirement impact of amortizing EADIT.

8. Rate Base

The Signatory Parties agree on adjustments that affect rate base, as detailed in Appendix A, Schedules 6 and 10. The Signatory Parties agree that the Company's 13-month average rate base for each Rate Year will be as follows:

Rate Year 1: $50,618,502

Rate Year 2: $58,040,867

Rate Year 3: $65,346,324

a) Plant in Service

The plant in service balances for each Rate Year were developed by beginning with the actual plant in service balance as of December 31, 2024, and adding agreed-upon capital expenditures. The projected average plant in service balances for each Rate Year are shown in Appendix A, Schedule 6.

b) Net Plant Reconciliation Mechanism

The Signatory Parties agree that Liberty SLG will continue its downward-only Net Plant Reconciliation Mechanisms (NPRM). Each Rate Year, the Company will reconcile its actual average net utility plant and depreciation expense revenue requirement, excluding the AMR Project, Plant Account 303 (Software/Cybersecurity), and the Oswegatchie Reinforcement Project (collectively, the Excluded Projects) to the target average net utility plant and depreciation expense, as demonstrated in Appendix F.

To calculate the deferral, and thus the associated revenue requirement impact, the average net utility plant will be calculated by applying the Company's pre-tax weighted average cost of capital in the respective Rate Years to the average net utility plant balance and adding the associated depreciation expense to the product.

The difference between the actual 13-month average net utility plant and depreciation expense revenue requirement separate from the Excluded Projects, and the target 13-month average net utility plant and depreciation expense revenue requirement separate from the Excluded Projects whether over or under the target, will carry forward each Rate Year and be summed at the end of the Rate Plan.

As illustrated in Appendix F, if at the end of Rate Year 3 the cumulative actual average net utility plant and depreciation expense revenue requirement is negative, the Company will defer the revenue requirement impact for the benefit of customers. However, if at the end of Rate Year 3 the cumulative actual average net utility plant and depreciation expense revenue requirement is positive, there will be no deferral. The net plant reconciliation mechanism separate from the Excluded Projects will apply to the Company's aggregate total average net plant and depreciation expense amounts combined, and not to individual components. The net plant target balances and reconciliation will not consider the impact of Accumulated Deferred Income Taxes (ADIT). The operation of this reconciliation mechanism is intended to operate in conjunction with, and not override, other individual reconciliation mechanisms contained herein. The net plant reconciliation mechanism separate from the Excluded Projects will not continue beyond Rate Year 3, unless the Company is below its respective target at the end of Rate Year 3, in which case the mechanisms will continue until the targets have been met.

i. Excluded Projects

The AMR Project, Plant Account 303 (Software/Cybersecurity), and the Oswegatchie Reinforcement Project, will each be subject to its own individual, separate, downward-only reconciliation mechanism.[5] To calculate the deferral for each individual Excluded Project, and thus the associated revenue requirement impact, the average net utility plant will be calculated by applying the Company's pre-tax weighted average cost of capital and adding the associated depreciation expense to the product. An example of how the Excluded Projects reconciliation mechanism functions is shown in Appendix F.

The target average net utility plant and depreciation expenses included in revenue requirement for the AMR Project, Plant Account 303, and the Oswegatchie Reinforcement Project are shown in Appendix F.

c) Accumulated Deferred Income Taxes

The Signatory Parties agree on adjustments that affect ADIT. The Signatory Parties agree on ADIT for each Rate Year as follows:

Rate Year 1: negative $2,002,924

Rate Year 2: negative $3,014,692

[5] Plant Account 303 (Software/Cybersecurity) shall be measured on an annual basis, and subject to a downward only NPRM. The AMR Project and Oswetgatchie Reinforcement Project will be measured independently, as these projects are slated to take place in the corresponding rate year.

Rate Year 3: negative $3,898,643

d) Excess Accumulated Deferred Income Taxes

The Signatory Parties agree the unamortized balance of EADIT for each rate year shall be as follows:

Rate Year 1: negative $1,309,348

Rate Year 2: negative $1,228,706

Rate Year 3: negative $1,147,996

e) Earnings Base Capitalization Adjustment

The Signatory Parties agree to an Earnings Base Capitalization (EBCAP) adjustment for Rate Year 1 of negative $5,716,733 measured as of January 31, 2025, to account for an equity infusion that took plance in December of 2024. In light of the Company managing to higher equity ratios throughout the rate plan, a pending long-term debt financing petition before the Commission, potential future equity infusions, and forecasted positive retained earnings, the Signatory parties agree to reflect a lesser EBCAP adjustment in Rate Year 2 and Rate Year 3 to more closely align rate base, and interest-bearing capitalization dedicated to providing gas utility service. More specifically, the EBCAP adjustment will be negative $4,287,654 for Rate Year 2, and negative $2,858,436 for Rate Year 3 – subject to a downward-only reconciliation. The Company shall measure the EBCAP downward only reconciliation using a 13-point average of actual earnings base, and actual capitalization devoted to providing utility service for the 12 months ending October 31, 2027 for Rate Year 2, and the 12 months ending October 31, 2028 for Rate Year 3. An example of the downward-only EBCAP reconciliation is included in Appendix H.

f) Contribution in Aid of Construction

The Signatory Parties agree that, starting in Rate Year 1 and on an annual basis thereafter, the Company will modify how it books Contribution in Aid of Construction (CIAC) from revenue to a reduction in plant-in-service. The Company performed a 10-year analysis to determine the amount of CIAC incorrectly booked as revenues, as such, the Company shall book a journal entry demonstrating the correct plant-in-service going forward, within 30 days of the Commission issuing an order setting rates in this proceeding.

g) Capital Expenditures

i. Projected Amounts

The Signatory Parties and Liberty SLG agree to capital expenditure budgets of $6,057,625 for capital expenditures anticipated to occur during Rate Year 1, $13,406,184 during Rate Year 2, and $10,662,178 during Rate Year 3 – as detailed in Appendix F.

The Signatory Parties and the Company agree on a capital expenditure budget of $11,598,937 for the time period from July 1, 2024, through October 31, 2025.

ii. Automated Meter Reading (AMR)

The Signatory Parties agree that capital expenditures associated with an AMR project implementation are included in Rate Year 2 of the Rate Plan. AMR costs during the Rate Plan will be capped at $4,122,296 (AMR Cap, included in Rate Year 2), subject to a downward-only reconciliation (separate from the overall net-plant downward reconciliation). The AMR Cap cost is exclusive of the AMR Software cost which is subject to the Plant Account 303 downward only reconciliation as explained in Section V.C.8.b.i. Additionally, the Company will file a report within 90 days after November 1, 2026, the start of Rate Year 2, benchmarking the progress of AMR. The report shall include, among other things, (1) purchase order receipt, (2) a full implementation schedule including delivery of units and installation of units, and (3) quarterly updates once installation begins until project completion. the Company cannot recover any AMR costs in excess of the AMR Cap in a future proceeding subject to the context of the rate request.

Residential customers who have, or are scheduled to have, automated meters installed by the Company on their premises may elect to opt out of an AMR equipped meter and, thereby, have their meters read manually, by completing an automated-meter opt-out form. The Company will post information and instructions for opting out of AMR metering on the Company's website, including notice and opt-out fees, as reflected in Appendix G.

iii. Case 24-G-0369 – AMR Petition

In Case 24-G-0369, Liberty SLG filed a petition seeking to implement AMR (AMR Petition), and recover the associated costs (i.e., return on and return of) in its next base rate case filing. In resolution of the issues related to the AMR Petition, the capital expenditures associated with implementation of AMR are included in this Rate Plan and are reflected in the Rate Year 2 capital expenditures budget in Appendix F. Accordingly, Liberty SLG shall recover the associated carrying charges, and depreciation expense associated with this investment, subject to the provisions identified in Section g.ii, above.

iv. Plant Account 303 (Software/Cybersecurity)

The Software and Cybersecurity capital projects forecasted throughout the Rate Plan shall be subject to a separate annual downward-only net plant reconciliation, as referenced in Sections V.C.8.a and 8.b, above.

v. Cybersecurity (Case 25-M-0302)

Cybersecurity capital projects shall be subject to a separate cumulative downward-only net plant reconciliation for Plant Account 303. For any additional incremental cybersecurity costs (separate and apart from the Company's traditional cybersecurity program reflected in rates) related to promulgation of new regulations (16 NYCRR Part 1200) pursuant to Case 25-M-0302, the Company will defer such additional costs, and seek review and recovery of those costs in a future rate case. To the extent DPS Staff finds such costs to be reasonable and accurate, Staff will support recovery of such costs in a future rate proceeding. The Company shall communicate with DPS Staff prior to and during any such project implementation and provide its reporting on an annual basis, as detailed in Section V.C.8.g.viii.a and Appendix W.

vi. Main Extensions

(a) Commission Review of Company-Funded Extension Capital Projects

The Company shall request Commission approval for rate recovery of any proposed Extension Capital Project(s) using the following process:

- At least 150 days before commencing construction on any Extension Capital Project in any Rate Year, the Company will file with the Secretary a petition requesting approval of the project, which must include the following information on the proposed project: (1) project cost estimates; (2) prospective customer survey results (with potential customers' current energy type); (3) projected natural gas and alternative energy costs; (4) number of both total potential new customers and committed customers; (5) annual conversion estimates for the first five years; (6) annual projected volumetric throughput for the first five years; (7) annual projected revenue for the first seven years; and (8) information on the proposed project's consistency with attainment of statewide greenhouse gas emissions limits established pursuant to the CLCPA (Renewable natural gas (RNG) sourced within New York State will be reflected as appropriate in considering consistency with the CLCPA); (9) information on consideration of non-pipe alternatives to the project; and (10) any other information the Company considers relevant (collectively, Extension Capital Project Petition).

- DPS Staff will review the Extension Capital Project Petition and request additional information from the Company as necessary to complete that review.
- After a timely review, the Commission will be able to approve, reject, or modify the proposed Extension Capital Project work for rate recovery. The standard for consideration of the Extension Capital Project Petition is whether the project(s) proposed in the Extension Capital Project Petition are (1) economically feasible under a prudent investment standard, and (2) not inconsistent with attainment of the statewide greenhouse gas emissions limits established pursuant to the CLCPA.
- After filing, an Extension Capital Project Petition will be promptly noticed for comments as required by SAPA. The parties intend to enable resolution of the Extension Capital Project Petition via Commission decision prior to the date construction is scheduled to commence as outlined in the Extension Capital Project Petition.
- Recovery of the revenue requirement (return on and return of) associated with the actual capital expenditures, capped at the total amount approved by the Commission for any approved Extension Cap-ex, once placed into service, including related property taxes, will be through a surcharge until Liberty SLG's base rates are next set, at which time the existing rate base being recovered through the surcharge will be included in rate base for base distribution rates. The revenue requirement associated with an approved Extension Capital Project will be calculated as shown in Appendix J. The actual revenue collected through the surcharge will be reconciled to the target revenue approved by the Commission on an annual basis.

(b) Non-Pipeline Alternative Consideration for Entitlement Capital Projects Regarding the CLCPA

For any Entitlement Capital Project to serve multiple customers totaling over 500 feet in length, the Company shall consider alternatives, including referring prospective customers to clean heat programs conducted by applicable electric utilities.

The Company will consult with DPS Staff prior to construction of Entitlement Capital Projects exceeding 500 feet. After such consultation, the Company will file a report with the Secretary at least 90 days prior to the start of construction, which shall include:

1) the cost of the proposed Entitlement Capital Project;
2) alternatives that were considered to the proposed Entitlement Capital Project;
3) documentation that the Company informed the potential customers to the proposed Entitlement Capital Project of alternatives to natural gas heating; and
4) information on the proposed Entitlement Capital Project's consistency with attainment of statewide greenhouse gas emissions limits established pursuant to the CLCPA.

In addition to those requirements, the Company will also implement the following concerning non-pipe alternatives (NPAs):

- The Company will revise its capital planning review and procedures to look a minimum of three years ahead at potential areas of its gas system that could lead to pressure concerns as a proactive analysis for improving applicability of NPAs that would help contribute toward CLCPA emission reduction goals. The Company will perform this three-year look ahead on an annual basis and include the results as part of its annual capital reporting process. The report shall include the following: a ranked list of all areas on the Company's gas system with pressure issues forecasted from this review;

hydraulic modeling that indicates the pressures of the identified areas and each pressure's percentage of Maximum Allowable Operating Pressure (MAOP); a street view map that locates the piping in the identified areas; a description of the methodology and/or criteria applied to forecast and prioritize pressure issues in the identified areas; and a detailed summary of NPA feasibility based on the screening criteria process the Company proposed in its August 10, 2022 filing in Case 20-G-0131, as supplemented and refined by its LTP and the LTP Annual Report filed in Case 24-G-0630 (the "NPA Suitability and Criteria Process"), for the identified areas that includes coordination with relevant electric providers.

- The Company will seek to coordinate with the applicable electric utility prior to customer solicitations of NPA electrification solutions to understand, to the extent possible, whether the electric utility's system has sufficient existing capacity to serve the customers in the solicitation. The Company will coordinate with local electric providers to proactively address potential electric distribution issues due to increased electricity demand as a result of NPA solutions. DPS Staff will assist in coordinating efforts with electric utilities that operate in Liberty SLG's service territory to the extent possible.
- The Company shall modify its capital budget process to ensure consideration and documentation of the NPA Suitability and Criteria Process. The Company will document the outcome of the NPA screening results and reasons for pursuing or not pursuing an NPA for each project or program, and that documentation will be included as part of the Company's project justification documentation. Each project's documentation of screening results shall also include a list of all alternatives the

Company recommended to customers and shall include a robust description of all available electrification measures and other non-fossil alternatives.

vii. Emergency Planning Criteria for System Redundancy and Emergency Response Training

The Company shall develop criteria and standards to establish when a secondary supply feed is necessary, which will include risk criteria of the associated distribution area being served. The Company shall incorporate training measures to increase the number of existing emergency response and restoration qualified staff to be capable and ready for future emergency response events. The Company will develop the planning and training standards collaboratively with DPS Staff and interested parties and file final criteria and procedures with the Secretary within 120 days from a Commission order setting rates in this proceeding.

viii. Reporting

The requirements set forth in Section V.C.7.f.iv of the 2023 JP regarding "Reporting" are superseded by the reporting requirements in this JP as outlined below and in Appendix W.

(a) Cybersecurity Reporting

The Company will file annual status and update reports with the Secretary no later than March 31 of each year detailing cybersecurity project spending and schedules for each project. These reports will highlight and explain any significant changes to cybersecurity projects including (but not limited to): alterations in major deadlines (such as acceptance tests or in-service dates), and changes in project scope, timelines, or budgets.

(b) Physical Security Reporting

The Company will file annual status and update reports detailing physical security project spending and schedules for each project. These reports will be filed with the Secretary no later than March 31 of the following calendar year and will highlight and explain any significant changes to physical projects, including (but not limited to): alterations in major deadlines (such as acceptance tests or in-service dates), and changes in project scope, timelines, or budgets.

9. Renewable Natural Gas

With respect to RNG, the Signatory Parties agree: (1) the Company will not provide upfront ratepayer funding for any future RNG interconnections or projects (regardless of whether those costs are eventually reimbursed by the developer); (2) the Company will purchase any RNG at a discount from the current published Dawn, Ontario Index price of natural gas (from Platt's Gas Daily Price Guide); and (3) the Company will only take receipt or delivery of purchased RNG directly onto the system through either (a) an on-system interconnection or (b) an on-system injection point for RNG that is not procured from an on-system interconnection. The Company will file the following information within 60 days of entering into a contract for RNG for each such contract: (1) purchase terms and conditions; (2) the total volume of RNG it purchased; (3) the supplier name(s) for purchased RNG; and (4) the feedstock(s) used to produce purchased RNG; and (5) documentation demonstrating that the RNG was purchased at a discount from the current published Dawn, Ontario Index price of natural gas (from Platt's Gas Daily Price Guide).

10. Cost of Capital

a) Capital Structure, Return on Equity, and Cost Rates

The cost of capital for the Company during the term of the Rate Plan shall be based on a return on equity (ROE) of 9.30% and a long-term debt cost rate of 5.01%.

The cost of capital for the Company during the term of the Rate Plan shall be based on a common equity ratio as follows:

- Rate Year 1: 46.00%, with no downward reconciliation.
- Rate Year 2: 47.00%, with a downward reconciliation to be implemented using a 13-point average to true-up the common equity ratio to 47.00% on a rate year basis.

- Rate Year 3: 48.00%, with a downward reconciliation to be implemented using a 13-point average to true-up the common equity ratio to 48.00% on a rate year basis.

For the purposes of the Rate Years 2 and 3 downward only reconciliation, the calculation shall use the Company's approved cost of debt, cost of customer deposits, customer deposits ratios, and cost of equity. An example of the common equity ratio downward-only reconciliation is included in Appendix K.

The Company's capital structure and overall cost of capital shall consist of the following components and cost rates for the term of the Rate Plan (as illustrated in Appendix L):

Rate Year 1				
	% of Capital	**Annual Cost**	**Weighted Cost After-Tax**	**Weighted Cost Pre-Tax**
Long Term Debt	52.82%	5.01%	2.65%	2.65%
Customer Deposits	1.18%	3.00%	0.04%	0.04%
Common Equity	46.00%	9.30%	4.28%	5.79%
Total	**100%**		**6.97%**	**8.48%**

Rate Year 2				
	% of Capital	**Annual Cost**	**Weighted Cost After-Tax**	**Weighted Cost Pre-Tax**
Long Term Debt	51.82%	5.01%	2.60%	2.60%
Customer Deposits	1.18%	3.00%	0.04%	0.04%
Common Equity	47.00%	9.30%	4.37%	5.92%
Total	**100%**		**7.01%**	**8.56%**

Rate Year 3				
	% of Capital	**Annual Cost**	**Weighted Cost After-Tax**	**Weighted Cost Pre-Tax**
Long Term Debt	50.82%	5.01%	2.55%	2.55%
Customer Deposits	1.18%	3.00%	0.04%	0.04%
Common Equity	48.00%	9.30%	4.46%	6.04%
Total	**100%**		**7.05%**	**8.63%**

The Signatory Parties agree that the Company will target the common equity ratio used to set rates throughout the term of the Rate Plan. Liberty SLG must submit its actual average common equity ratio for each Rate Year in its annual Earnings Sharing Mechanism compliance filings.

b) Earnings Sharing Mechanism

The Company shall be subject to an Earnings Sharing Mechanism (ESM), described below. An example of the ESM calculation is included in Appendix M.

Following each of Rate Year 1, Rate Year 2, and Rate Year 3, Liberty SLG will compute the earned rate of return on common equity for the preceding Rate Year. In the event Liberty SLG achieves a regulatory rate of return on its common equity above the allowed return on a 12-month basis, the Company shall share the earnings in excess of that return with its customers. The Company will share earnings as follows:

- From the allowed ROE up to and including the allowed ROE plus 50 bps, the Company retains 100%.
- Above the allowed ROE plus 50 bps up to and including the allowed ROE plus 100 bps, shared 50% customers / 50% Company.
- Above the allowed ROE plus 100 bps up to and including the allowed ROE plus 150 bps, shared 80% customers / 20% Company.

- Above the allowed ROE plus 150 bps, shared 90% customers / 10% Company.

The ESM calculations shall be based upon the lesser of a common equity ratio equal to 46.00% or the Company's actual average common equity ratio for Rate Year 1; 47.00% or the Company's actual average common equity ratio for Rate Year 2; and 48.00% or the Company's actual average common equity ratio for Rate Year 3. The calculation of such earnings will be on an annual basis for each Rate Year of the Rate Plan and will be done on a "per books" basis; that is, computed from the Company's books of account for each Rate Year. Any discrete incentives (*e.g.*, safety metrics) and revenue adjustments would not be included in the earned ROE calculation. Earnings for each Rate Year will be measured individually, and any overearnings that are owed to customers will be placed in a deferred credit account for future disposition to be determined by the Commission. The Company will file with the Secretary these computations of earnings no later than 90 days after the end of each Rate Year.

The ESM will continue beyond the Rate Plan until modified by the Commission. If new base rates do not become effective immediately after the end of the Rate Plan, or there is a "stub" period, the earnings in the stub period will be calculated and shared as described above. The stub period earnings will be calculated by adjusting the actual average rate base for that period by an operating income ratio factor. The operating income ratio factor will be calculated as the ratio of operating income during the same partial period in the previous Rate Year to the total operating income for that Rate Year. An example of the calculation for the stub period is shown in Appendix M.

D. Revenue Allocation and Rate Design

1. Revenue Allocation

The Signatory Parties agree on the provisions associated with the Company's revenue allocation as detailed in Appendix N and shown in the table below.

Service Class	Rate Year 1	Rate Year 2	Rate Year 3
SC 1	0.80	0.80	1.00
SC 2 / SC 2L	1.00	1.00	1.00
SC 3	1.20	1.20	1.20

The Signatory Parties agree to analyze SC2 and SC 2L separately in the next cost of service study performed in support of the Company's next rate filing.

2. Rate Design

The Signatory Parties agree on the rates for each of the Company's customer service classifications for each Rate Year as detailed in Appendix N. The resulting total monthly average and annual bill impacts calculated using the agreed upon rates are detailed in Appendix O.

3. Minimum Monthly Charges

The Signatory Parties agree to the following minimum monthly charges by customer service classification:

Service Class	Rate Year 1	Rate Year 2	Rate Year 3
SC 1	$18.50	$20.00	$21.50
SC 2	$29.50	$31.00	$32.50
SC 2L	$210.00	$220.00	$230.00
SC 3	$550.00	$575.00	$600.00

4. Merchant Function Charge

The Signatory Parties agree on the continuation of the Merchant Function Charge (MFC) for the commodity-related costs of natural gas service. The uncollectible cost component of the MFC will reflect an uncollectible rate of 0.50%. The MFC targets are shown in Appendix P and in the table below.

MFC Surcharge Component	Rate Years 1-3 Target
Gas Procurement Salary	$90,915
Uncollectibles*	$61,789
Gas Control	$97,917
Gas in Storage*	$59,086
Total	**$309,708**
*Figures shown are for illustrative purposes. Actual values will depend on actual costs/balances.	

5. Delivery Revenue Adjustment

The Signatory Parties agree on the continuation of the Delivery Revenue Adjustment (DRA). The uncollectible cost component of the DRA will reflect an uncollectible rate of 0.50%. The DRA revenue targets are shown in Appendix P and in the table below.

DRA Surcharge Component	Rate Years 1-3 Target
Gas Procurement Salary	$45,458
Uncollectibles*	$20,224
Gas Control	$97,917
Gas in Storage*	$19,389
Total	**$182,988**
*Figures shown are for illustrative purposes. Actual values will depend on actual costs/balances.	

6. Revenue Decoupling Mechanism

The Signatory Parties agree that the Company will continue its existing Revenue Decoupling Mechanism (RDM) applicable to residential and commercial service classes. The residential revenue target applies to delivery revenues from SC 1 and the commercial revenue target applies to all delivery revenues from SC 2 and SC 2L. Revenues from SC 3 and SC 4 are not included in the RDM. The RDM revenue targets for residential and commercial customers are shown in Appendix Q and in the table below.

Service Class	RY 1 Target	RY 2 Target	RY 3 Target
SC 1	$10,783,883	$11,661,528	$12,382,359
SC 2 and SC 2L	$4,763,826	$5,326,748	$5,760,339
Total	**$15,547,709**	**$16,988,276**	**$18,142,698**

7. Lost and Unaccounted for Gas

As shown in Appendix R, the Signatory Parties agree that the Company's Lost and Unaccounted for Gas (LAUF) incentive mechanism will include a target of 0.226%, an upper dead-band of 0.946%, and a lower dead-band of 0.0%. The Company will incorporate the LAUF target and dead-bands into its tariff.

8. Interruptible Incentive Credit Mechanism

The Signatory Parties agree that the Interruptible Incentive Credit Mechanism (IIC) shall be allocated to each customer service classification based on revenues. The IIC reconciles the difference between actual delivery revenue from SC 4 and the Rate Year Target – and it excludes any revenues related to gas costs. Actual delivery revenues are reconciled annually for the 12 months ending October 31 of each year. The first $100,000 of the difference between the interruptible delivery revenues received and the interruptible target will be shared 85% to all SC 1, SC 2 and 2 Large, and SC 3 firm customers and 15% to the Company. The balance of any difference above or below the first $100,000 is surcharged or refunded 100% to SC 1, SC 2 and 2 Large, and SC 3 customers. The IIC will continue to be allocated to each SC based on revenues. The targets are $847,243 for Rate Years 1, 2, and 3. If the Company does not file for new rates following Rate Year 3, the target will be set at $847,243 after Rate Year 3. Monthly targets are shown in Appendix D.

9. Contract Administration Charge

The Signatory Parties agree that the Company will continue to impose the $125 monthly contract administration charge only on customers that use over 50,000 therms annually.

E. Gas Safety, Regulatory, and Environmental/Climate Goals

1. Timely Filings

The Company shall incur an NRA of 3 BP for each instance in which the Company fails to make a filing by the relevant deadline specified by applicable statute, regulation, or Commission order, or fails to request an extension or waiver of such deadline, where an extension or waiver is possible, in a timely fashion.[6] An example of the calculation of the BP is detailed in Appendix T.

2. Gas Safety Metrics

The Signatory Parties agree that Liberty SLG will maintain its current targets and associated revenue adjustments with respect to gas safety performance metrics in the areas of emergency response, damage prevention, leak management, and pipeline safety regulatory compliance, which are detailed in Appendix S. The targets and associated revenue adjustments for all gas safety performance metrics will remain in effect until changed by the Commission.

---

[6] The Signatory Parties recognize that the Secretary may not have the authority to extend a particular deadline. Should the Company seek to rely on a request to the Secretary for an extension to demonstrate that it has met the requirements of this provision, the Company must demonstrate that the requested extension is one that the Secretary has authority to grant. The Approval of an extension request by the Secretary is conclusive evidence that the Secretary had the authority to grant the request.

For requests for extensions made to the Secretary, except as otherwise provided in the relevant requirement (*e.g.*, in the relevant Commission order or issuance from the Secretary), a timely request is understood to mean a request made in writing not less than three days in advance of the relevant deadline. For requests for extensions or waivers that would require Commission action, a timely request means a request in writing (*e.g.*, in the form of a petition) at a time that allows the Commission to act on the request prior to the relevant deadline.

a) Emergency Response

Emergency response relates to the amount of time it takes Company personnel to arrive on scene after receiving an emergency call. The Signatory Parties agree with maintaining the Company's current targets, which are responding to 75% of calls within 30 minutes, 90% of calls within 45 minutes, and 95% of calls within 60 minutes, consistent with the standard throughout New York State. As detailed in Appendix S, the Company will incur NRAs if it fails to meet those emergency response targets on an annual basis.

b) Damage Prevention

Damage prevention is associated with minimizing excavation damages to below ground facilities. Damage prevention targets are based on the total number of "damages" per 1,000 facility locate requests. Damages included in the calculation are those occurring as a result of the Company improperly locating a facility, the Company or its contractors hitting a line, or a third-party excavator hitting a line. The Signatory Parties agree to the damage prevention targets (expressed as overall damages per 1,000 locates) and associated NRAs and PRAs set forth in Appendix S.

c) Leak Management

Leak management relates to the Company's monitoring and repairing any new or existing leaks to its gas system. The Signatory Parties agreed to the safety-related leak management targets and associated NRAs set forth in Appendix S.

d) Compliance with Pipeline Safety Regulations

The Signatory Parties agree that the Company will incur NRAs for noncompliance with certain gas safety regulations contained in 16 NYCRR Part 255 and 261, as set forth in Appendix S.

For pipeline safety regulatory compliance, the number of non-compliances with each high risk and other risk code section may be capped at 10 per audit type (field or record). If the Company incurs greater than 10 instances of non-compliance of a single code section of either audit type (field or record) per calendar year, the Company shall file with the Secretary within 90 days of the date of the pipeline safety Staff's audit letter a remediation plan explaining the root cause of the Company's compliance deficiency and how the Company will address/resolve compliance issues going forward, including the dates by which the non-compliances will be brought into compliance or, where appropriate, when remedial actions will be taken to prevent future recurrence. Should the Company fail to timely file the remediation plan with the Secretary as required in the preceding sentence, or fail to comply with the provisions of its filed remediation plan, the non-compliances in excess of 10 shall be incorporated with the remainder of the non-compliances being considered under this measure.

3. Additional Full-Time Employees in the Pipeline Safety Management System Program and Quality Control and Quality Assurance

The Signatory Parties agree that the Company shall be allowed to recover the salary and benefits associated with two new full-time employees for the Pipeline Safety Management System program and Quality Control and Quality Assurance in Rate Year 2.

4. Residential Methane Detector Pilot Program

The Signatory Parties agree that the Company shall continue the Residential Methane Detector (RMD) Pilot Program in Rate Year 1, and throughout the rate plan. The cost of the program in Rate Year 1 of, $105,201, will be offset by the amortization of $105,201 of NRAs incurred for prior non-compliance with pipeline safety regulations and failure to meet damage prevention targets. The costs of the RMD program in Rate Year 2 and Rate Year 3 were adjusted for inflation. The Company shall file a report with the Secretary within 60 days after the end of each Rate Year. This report must indicate the number of RMD units offered to residential customers and the associated costs of deploying RMD units.

5. First Responder Communication and Training

The Signatory Parties agree that the Company will continue emergency drills with local first responders. The Company shall conduct one drill per year with fire department first responders, rotating the location of the drills among the three counties in the Company's service territory; the sessions will be open to any employee/volunteer from any of the three counties for all drills. The Company shall note which fire departments participated in the training programs on its website.

6. Behavioral Demand Response Program

The Company shall continue its Behavioral Demand Response program. Pursuant to the Behavioral Demand Response program, the Company requests that customers reduce usage during times of peak usage. The program benefits customers by lowering utility bills and creates a reduction in the amount of natural gas consumed, which results in proportionate reductions in carbon emissions and supports realization of the CLCPA's greenhouse gas emission reduction targets.

7. Greenhouse Gas Emissions Reporting

The Signatory Parties agree that the Company shall continue to provide annual reporting of its greenhouse gas (GHG) emissions as part of its requirements under Case 22-M-0149, *Proceeding on Motion of the Commission Assessing Implementation of and Compliance with the Requirements and Targets of the Climate Leadership and Community Protection Act*. Unless the Commission provides further guidance requiring specific reporting requirements during the term of its Rate Plan, the Company shall provide its upstream, local distribution, and end-use greenhouse gas emissions to the Secretary on or before April 15 of the subsequent year.

8. Energy Efficiency

The Company shall encourage gas conservation via messaging materials to its existing customers.

The Company will maintain and update the portion of its website that contain links to other entities and resources that can assist customers with reducing energy consumption and saving money on their bills.

The Company will refer its new gas applicants to the National Grid program manager for the New York State Clean Heat Program, including phone, email, and website contact information The New York State Energy Research and Development Authority maintains a list of utility contacts for the Clean Heat Program at the following link: https://cleanheat.ny.gov/contractors-contact/.

Within 60 days after the end of each Rate Year, the Company shall submit to the Secretary a report identifying the number of new applicants for service it received and the energy efficiency program(s) for which information was made available to those applicants. Of the applicants who were referred to other alternatives but ended up becoming a gas customer, the Company will identify the reason(s) why the customer ultimately decided to choose gas service instead of the other alternatives if that information was provided to the Company during the enrollment process.

9. Green Tariff and Green Hydrogen

For the purposes of this paragraph, "Green Tariff" means an "opt-in" tariff which allows Liberty SLG customers to purchase RNG inclusive of environmental attributes. If the Company desires to pursue a Green Tariff, the Company shall seek independent Commission review and approval of any future Green Tariff.

In addition, if the Company intends to pursue any future green hydrogen project for which the Company will seek cost recovery, it must submit a petition to the Commission regarding the project, including a detailed proposal regarding the safety and other aspect of blending hydrogen and natural gas. The Company shall not begin construction on any such project for which it will seek cost recovery without first receiving the Commission's authorization.

F. Customer Service

1. Customer Service Performance Indicators

As set forth in Appendix T, the Company's Customer Service Performance Indicators (CSPI) will include two metrics with performance thresholds and associated NRAs: the Commission Complaint Rate, and the Overall Customer Satisfaction Index. NRA amounts will be determined based on the equity ratio and rate base reflected in the revenue requirements for each rate year, as shown in Appendix A.

The Signatory Parties agree that the Company will continue CSPI reporting on a quarterly basis utilizing monthly data.

a) Commission Complaint Rate

The Company's Commission Complaint Rate performance will be the 12-month escalated complaints received per 100,000 customers as reported by the Department of Public Service Office of Consumer Services each year for the 12-month period ending in December, based on the number of complaints received.

b) Overall Customer Satisfaction Rate

An Overall Customer Satisfaction Index (OCSI) will be calculated based on the results of cumulative customer satisfaction surveys on an annual basis and will reflect the percentage of customers satisfied with the service they receive from the Company. The survey will be performed by Qualtrics starting in Rate Year 1. A survey will be presented or emailed to each customer that completes a transaction with one of the Company's call center representatives. The Company will not include any language pertaining to cost of service in the survey. As set forth in Appendix W, the Company will file the results of the survey quarterly.

2. Missed Appointment Credit

The Company will implement a $25 missed appointment credit beginning Rate Year 2. The credit will be issued to customers in their next billing cycle if the Company schedules an appointment at a customer's premises for a specific date and time but fails to arrive as scheduled. The Company will enhance its outreach materials and website to raise awareness of the $25 missed appointment credit, and will file the revised or new outreach materials within 60 days after issuance of an order setting rates in this proceeding.

The missed appointment credits will not apply to appointments made for the same day the customer requests service or if circumstances beyond the Company's control (*e.g.*, severe weather) prevent the Company from arriving as planned. The Company will track each missed appointment due to weather or other circumstances the Company asserts are beyond the Company's control.

The Company will track missed appointments on a monthly basis and provide monthly reports of missed appointments (including appointments missed because of severe weather or other circumstances beyond the Company's control) to the Secretary within 60 days of the start of Rate Year 3, and within 60 days of the end of the preceding Rate Year thereafter.

The costs of the missed appointment credit will be borne by the Company's shareholders and not ratepayers.

3. Termination and Uncollectible Expenses

The Company will not reinstate its Termination and Uncollectibles Incentive Mechanism.

4. Low-Income Program

The Signatory Parties agree that a four-tiered approach to providing bill discounts for the Company's low-income program shall be employed based on the Commission's recognition of varying levels of need that correlate with the Home Energy Assistance Program (HEAP) benefits.[7] The first tier will consist of all customers who receive a regular HEAP benefit and are classified by the Company as regular HEAP recipients. The second tier will consist of customers who receive the regular HEAP benefit with one add-on. The third tier will consist of customers who receive a regular HEAP benefit with two add-ons. The fourth tier will consist of customers who receive a direct voucher. Consistent with current rate design, the Company will implement the following bill discounts based on tiered eligibility for its low-income program.

	Estimated Number of Customers	Bill Discount RY1	Bill Discount RY2	Bill Discount RY3	Criteria
Tier 1	121	$5.00	$5.00	$5.00	Regular HEAP recipients
Tier 2	585	$14.73	$18.00	$23.50	Regular HEAP with one add-on recipient
Tier 3	973	$39.50	$42.50	$45.50	Regular HEAP with two add-on recipients
Tier 4	8	$21.99	$21.99	$21.99	Direct Voucher
Total	1,687	$573,977	$ 626, 123	$705,599	

The Signatory Parties agree the Low-Income Program will be funded, and reflected in the revenue requirement for each Rate Year as follows:

Rate Year 1: $573,977

Rate Year 2: $626,123

Rate Year 3: $705,599

The Company shall track low-income discounts and fully reconcile actual discounts provided to customers in any given rate year to the associated low-income program budget amount.

[7] Case 14-M-0565, *Proceeding on Motion of the Commission to Examine Programs to Address Energy Affordability for Low-Income Customers,* Order Adopting Low Income Program Modifications and Directing Utility Filings (issued May 20, 2016).

Any such deferral shall be addressed in a future rate proceeding and addressed in a manner to be determined by the Commission.

The Company shall file the annual low-income reports for each rate year that include the following information: (a) participant totals separated by tier; (b) new participants; (c) participant reconnection fee waiver; (d) participant arrears; (e) termination notices sent to participants; (f) amount budgeted and amount spent for the program; and (g) amount of participant uncollectibles. The Company shall file this report, within 30 days of the end of the preceding rate year with the Secretary .

The Company will grant a one-time per year waiver of its $32 reconnection fee for low-income customers.

5. Outreach & Education

The Signatory Parties agree that the Company will continue its Outreach & Education (O&E) program. The Signatory Parties agree that the Company shall develop and submit a single consolidated O&E budget and annual report using the Commission's Estimated Outreach & Education Budget Template (O&E Template).

In future filings, the Company will ensure that page 23 of the O&E Template, titled "Energy Service Affordability," is completed in full, rather than redirecting information to other sections.

The Company will enhance its outreach efforts targeting low-income, elderly customers, and individuals in disadvantaged communities. The Company will develop a comprehensive and tailored strategy addressing the unique needs of these customer groups. This strategy will be incorporated into the Company's annual O&E filing and will include measurable objectives and engagement approaches, such as community partnerships, multilingual communications, and enhanced participation in local events that reach these populations.

The Company agrees to continue to promote the New York Clean Energy Information to all customers applying for new service and include this information in the Company's O&E plan in a manner that does not increase costs associated with the O&E plan delivery.

Within 120 days of the Commission issuing an order establishing rates in this case, the Company will file an AMR O&E plan with the Secretary that will include the following: (a) the Company's plans on conducting outreach and education to customers; (b) information on how customers can opt-out of receiving AMR meters; (c) the Company's plans to test the AMR meters for accuracy; and (d) the timing and anticipated capability of reporting on the number of opt-outs and estimated bills.

The Company's O&E plan will include a detailed strategy to increase enrollment in its low-income program. Future filings will outline the specific actions the Company is taking to identify and reach eligible customers, including a more prominent focus on low-income customer engagement at outreach events, targeted communications, and collaborations with local agencies and organizations that serve income-eligible households.

6. Levelized Payment Plan

The Signatory Parties agree that the Company will offer levelized payment plans to its residential customers.

The Company will develop customer-facing messaging that clearly explains the levelized billing processes and procedures. This messaging will include a clear explanation of the differences between budget billing and a levelized payment plan, with emphasis on how each plan reconciles (or "trues up") payments against actual customer charges. This messaging will be submitted to DPS Staff for review 30 days after issuance of a Commission order in this proceeding. Thereafter, this shall be reported on a ongoing basis as part of the annual O&E filing in Case 17-M-0745, as reflected in Appendix W.

7. Arrearage Management Plan

The Company will implement an Arrearage Management Program (AMP) that offers arrearage forgiveness of up to $1,200 annually for eligible low-income customers pursuant to the AMP implementation plan included in Appendix U. The Company will report on overall AMP program performance as set forth in Appendix W. AMP costs for each Rate Year are set forth below:

	RY 1	RY 2	RY 3	
AMP Estimated Costs	$72,912	$72,912	$72,912	Based on outstanding balances for 232 eligible customers
Customer Communications	$1,000	$1,000	$1,000	
Total AMP Expense	**$73,912**	**$73,912**	**$73,912**	
IT Capital Costs	$25,000	$0	$0	Included in capital forecast

This Joint Proposal recommends recovery of the total AMP expense in each Rate Year through the revenue requirements set forth in this Joint Proposal. Any differences between actual and estimated AMP expenses will be reconciled at the end of each Rate Year and deferred for recovery in a future proceeding. The Company will only reconcile the amount of arrears forgiven and not the costs of customer communications.

8. Language Access

The Company will translate the materials listed below into the Spanish and German languages:

- Your Rights & Protections - Residential (brochure)
- Natural Gas Safety (brochure)
- Utility Service Interruption (brochure)
- Deferred Payment Agreements (DPA)

- Information on the Company's Low-Income Program

The above-listed materials will be posted to the Company's website with a note stating: "For German / Deutsch or Spanish / Español, visit (*insert webpage*)". The cost of translating the materials is $6,000 per year and will be a part of the annual O&E budget.

9. Promotion of Natural Gas

The Company will track and report all expenses related to the promotion of natural gas (*e.g.*, direct mail campaigns, digital marketing initiatives, or paid media or social media) that are created solely to encourage natural gas conversions. All such costs will be booked below-the-line (Account 426) and thus not recoverable from ratepayers. The Company agrees to track such costs in detail in the O&E budget template.

10. Competitive Bidding for Goods and Services

In order to ensure maximum value for its customers, the Company will conduct competitive bidding or solicitations for any products or services costing in excess of $350,000, including (but not limited to) any future LTP-related expenses.

G. Affiliate Code of Conduct

The most recent version of the Company's Affiliate Code of Conduct is provided in Appendix V. If the Company makes any changes to the substantive text of the Affiliate Code of Conduct, the Company will file the proposed changes with the Secretary at least 90 days prior to the effective date of such changes. The filing will specifically explain and identify each of the changes proposed.

H. Omnibus Reporting Requirements

Appendix W contains an omnibus list of the Company's reporting requirements to the Commission and DPS Staff on a going forward basis. Any reporting requirements from previous rate plans and the acquisition order (Case 08-G-1392, Case 15-G-0382 & 13-G-0076, Case 18-G-

0133 & 18-G-0140, and Case 21-G-0577) are terminated and replaced with reporting requirements as specified in this JP.

I. Exogenous Events / Legislative, Regulatory and Related Actions

The Signatory Parties recognize that any law, rule, regulation, order, or other requirement (or any repeal or amendment of an existing law, rule, regulation, order or other requirement) of the state, local or federal governments may result in a change in the Company's annual revenues, costs or expenses (including income or other federal or State tax expense, but excluding local property taxes) not anticipated in the forecasts on which the rates for the Rate Plan are based. If the Commission has not addressed or does not otherwise address the treatment of a legislative, accounting, regulatory, or government-mandated action (e.g., through consideration of a surcharge or deferred credit) via a generic or Company-specific proceeding, the Company will defer on its books of account the full change in revenues, costs or expenses if the change in Rate Year 1, Rate Year 2, or Rate Year 3 amounts to, or exceeds 3% of net income reflected in revenue requirement during Rate Year 1, Rate Year 2, or Rate Year 3, respectively. Any such deferrals are to be reflected in the next base rate case or in a manner to be determined by the Commission. No deferral for the benefit of the Company under this section will be authorized if the Company's earnings exceed an ROE of 9.3%.

In the event the Company meets the criteria to defer an amount incurred in excess of 3% due to a legislative, regulatory, and related action, Liberty SLG shall file a letter by March 31 after the rate year in which such expenses were incurred with the Secretary setting forth the rationale for the deferral. Any disagreement with the filing will be referred to the Commission for a decision or addressed in the Company's next base rate case.

VI. CLCPA-RELATED PROVISIONS

The Signatory Parties recognize that there is a need for the Commission to comply with applicable provisions of the CLCPA while, at the same time, ensuring compliance with the provisions of the PSL and other applicable requirements regarding the availability, cost, safety and reliability of gas service provided by local distribution companies such as Liberty SLG. The provisions of this Joint Proposal are intended to be consistent with the objectives of the CLCPA and to maintain a balance between those objectives and the pre-existing and continuing obligations of local distributions companies such as the Company. The Signatory Parties acknowledge that the objectives and obligations under the CLCPA are evolving and will require continued attention.

VII. GENERAL AND MISCELLANEOUS PROVISIONS

A. Restriction on Filing for Rate Increases During Term of Rate Plan

The Company agrees not to file for new base delivery rates to be effective prior to November 1, 2028. Nothing herein precludes the Company from filing a new general gas rate case prior to October 31, 2028, for rates to take effect on or after November 1, 2028. Notwithstanding the foregoing, nothing in the Joint Proposal shall prohibit the Commission (upon its own motion or upon motion of an interested party) from exercising its ongoing statutory authority to act on the level of the Company's rates in the event of unforeseen circumstances that, in the Commission's judgment, have such a substantial impact on the rate of return as to render the return on common equity devoted to the Company's gas operations, unreasonable, unnecessary, or inadequate for the provision of safe and adequate service.

B. Provisions Not Separable

The Signatory Parties intend this Joint Proposal to be a complete resolution of all the issues in Cases 24-G-0668 and 24-G-0369, and intend that the Company will file tariffs in a manner consistent with the terms of this Joint Proposal. The terms of this Joint Proposal are submitted as an integrated whole. In the event or to the extent that the Commission does not adopt the terms of this Joint Proposal in their entirety, the Signatory Parties shall be free to pursue their respective positions in this proceeding without prejudice. It is also understood that each provision of this Joint Proposal is in consideration and support of all the other provisions, and each provision is expressly conditioned upon acceptance by the Commission of this Joint Proposal in its entirety without change. Except as may be explicitly set forth herein, none of the Signatory Parties is deemed to have approved, agreed to, or consented to any principle, methodology, or interpretation of the law underlying or supposed to underlie any provision herein.

C. Provisions Not Precedent

The terms and provisions of this Joint Proposal apply solely to, and are binding only in the context of the purposes and results of this Joint Proposal. None of the terms or provisions of this Joint Proposal, including any methodology or principle utilized herein, and none of the positions taken herein by any Signatory Party may be referred to, cited, or relied upon by any other party in any fashion as precedent or otherwise in any other proceeding before this Commission or any other regulatory agency or before any court of law for any purpose other than furtherance of the purposes, results, and disposition of matters governed by this Joint Proposal. Concessions made by Signatory Parties on various issues included in this Joint Proposal do not preclude those parties from addressing such issues differently in other proceedings. This Joint Proposal shall not be construed, interpreted, or otherwise deemed in any respect to constitute an admission by any Signatory Party regarding any allegations, contentions, or issues raised in this proceeding or addressed in this Joint Proposal.

D. Submission of the Proposal

Each Signatory Party agrees to submit this Joint Proposal to the Commission, to support and request its adoption by the Commission, and not to take a position in this proceeding contrary to the agreements set forth herein or to assist another participant in taking such a contrary position in these proceedings. The Signatory Parties believe that the resolution of the issues, as set forth in this Joint Proposal, is just and reasonable and otherwise in accordance with the PSL, the Commission's regulations, and applicable Commission decisions and policies. The Signatory Parties believe this Joint Proposal satisfies the requirements of PSL § 65(1), as it enables Liberty SLG to continue to provide safe and adequate service at just and reasonable rates.

E. Effect of Commission Adoption of Terms of this Proposal

No provision of this Joint Proposal or the Commission's adoption of the terms of this Joint Proposal shall in any way abrogate or limit the Commission's statutory authority under the PSL. Any generic Commission action will take precedence over the recovery or procedures described in this Joint Proposal. The Signatory Parties recognize that any Commission adoption of the terms of this Joint Proposal does not waive the Commission's ongoing rights and responsibilities to enforce its orders and effectuate the goals expressed therein, nor the rights and responsibilities of Staff to conduct investigations or take other actions in furtherance of its duties and responsibilities.

F. Further Assurances

The Signatory Parties recognize that certain provisions of this Joint Proposal require that actions be taken in the future to fully effectuate this Joint Proposal. Accordingly, the Signatory Parties agree to cooperate with each other in good faith in taking such actions. In the event of any disagreement over the interpretation of this Joint Proposal or implementation of any of the provisions of this Joint Proposal, which cannot be resolved informally among the Signatory Parties, such disagreement shall be resolved in the following manner: (a) the Signatory Parties shall promptly convene a conference and in good faith attempt to resolve any such disagreement; and (b) if any such disagreement cannot be resolved by the Signatory Parties, any Signatory Party may petition the Commission for resolution of the disputed matter.

G. Execution

This Joint Proposal may be executed in one or more counterparts, all of which taken together shall constitute one and the same instrument which shall be binding upon each Signatory Party when it is executed in counterpart, filed with the Secretary of the Commission, and approved by the Commission.

H. Entire Agreement

This Joint Proposal, including all attachments, exhibits and appendices, if any, represents the entire agreement of the Signatory Parties with respect to the matters resolved herein.

[THE REST OF THIS PAGE INTENTIONALLY LEFT BLANK]

IN WITNESS WHEREOF, the Signatory Parties hereto have this day signed below as evidence of their agreement to be bound by the provisions of this Joint Proposal.

LIBERTY UTILITIES (ST. LAWRENCE GAS) CORP.

By: Jeffrey Greenblatt
Jeffrey Greenblatt, Esq.

Jeffrey D. Kuhn, Esq.
HARRIS BEACH MURTHA CULLINA PLLC

Date: August 29, 2025

STAFF OF THE DEPARTMENT OF PUBLIC SERVICE

By: ______________________________
Shauna Spinosa, Esq.

Date: August 29, 2025

MULTIPLE INTERVENORS

By: ______________________________
James King, Esq.
Melanie Franco, Esq.
COUCH WHITE, LLP

Date: August 29, 2025

IN WITNESS WHEREOF, the Signatory Parties hereto have this day signed below as evidence of their agreement to be bound by the provisions of this Joint Proposal.

LIBERTY UTILITIES (ST. LAWRENCE GAS) CORP.

By: ______________________________
Jeffrey Greenblatt, Esq.

Jeffrey D. Kuhn, Esq.
HARRIS BEACH MURTHA CULLINA PLLC

Date: August 29, 2025

STAFF OF THE DEPARTMENT OF PUBLIC SERVICE

By: Shauna Spinosa
Shauna Spinosa, Esq.

Date: August 29, 2025

MULTIPLE INTERVENORS

By: James King
James King, Esq.
Melanie Franco, Esq.
COUCH WHITE, LLP

Date: August 29, 2025

Liberty Utilities (St. Lawrence Gas) Corp.
PSC Case No. 24-G-0668
Statement of Operating Income
For the Rate Year Ending October 31, 2026
(Whole Dollars)

Schedule 1

	Rate Year Ending October 31, 2026	Adj. #	Staff Adjustments	Settlement Adjustments	Rate Year As Adjusted for Joint Proposal	Base Revenue Increase Required	Rate Year Ending October 31, 2026
Operating Revenues	$ 35,184,747	1	$ (154,838)	$ -	$ 35,029,909	$ 399,729	$ 35,429,638
Deductions							
Purchased Gas Costs	$ 16,238,574	2	$ 26,653	$ -	$ 16,265,227	$ -	$ 16,265,227
Revenue Taxes	462,907	3	(13)	-	462,894	3,998	466,892
Total Deductions	$ 16,701,481		$ 26,640	$ -	$ 16,728,121	$ 3,998	$ 16,732,118
Gross Margin	$ 18,483,266		$ (181,478)	$ -	$ 18,301,789	$ 395,731	$ 18,697,520
Total Operation & Maintenance Expenses	$ 8,352,034	4	$ (1,396,742)	$ 486,361	$ 7,441,652	$ 1,998	$ 7,443,651
Amortization of Regulatory Deferrals	250,970	5	(270,145)	329,004	309,829	-	309,829
Depreciation, Amort. & Loss on Disposition	3,578,389	6	(415,320)	99,059	3,262,128	-	3,262,128
Taxes Other Than Revenue & Income Taxes	2,974,809	7	472,400	20,759	3,467,968	-	3,467,968
Total Operating Revenue Deductions	$ 15,156,201		$ (1,609,807)	$ 935,183	$ 14,481,577	$ 1,998	$ 14,483,575
Operating Income Before Income Taxes	$ 3,327,065		$ 1,428,330	$ (935,183)	$ 3,820,212	$ 393,733	$ 4,213,945
Income Taxes							
State Income Taxes	$ 121,376	9	$ 102,070	$ (63,639)	$ 159,807	$ 25,593	$ 185,400
Federal Income Taxes	307,033	8	286,762	(170,670)	423,126	77,309	500,435
Total Income Taxes	$ 428,409		$ 388,833	$ (234,309)	$ 582,933	$ 102,902	$ 685,835
Operating Income After Income Taxes	$ 2,898,655		$ 1,039,497	$ (700,874)	$ 3,237,279	$ 290,831	$ 3,528,110
Rate Base	$ 57,926,280	10	$ (12,325,574)	$ 5,017,796	$ 50,618,502		$ 50,618,502
Rate of Return	5.00%				6.40%		6.97%

Liberty Utilities (St. Lawrence Gas) Corp.
PSC Case No. 24-G-0668
Operation and Maintenance Expenses
For the Rate Year Ending October 31, 2026
(Whole Dollars)

Schedule 2

	Rate Year Ending October 31, 2026	Adj. #	Staff Adjustments	Settlement Adjustments	Inflation Change	Revenue Increase	Rate Year As Adjusted for Joint Proposal
Operation & Maintenance Expenses:							
Departmental Items:							
Direct Labor	$ 4,320,669	**4a**	$ (609,580)	$ 168,272	$ -	$ -	$ 3,879,361
Direct Intercompany	492,468	**4b**	(23,003)		-		469,465
Indirect Allocated Labor	900,927	**4c**	(131,893)	68,025	-		837,059
Oper - Mains & Services Exp.	507,830	**4d**	(3,565)		8,332		512,597
Oper - Cust Install Exp	24,297				401		24,698
Oper - Meas & Reg Station Exp	37,990				628		38,617
Oper - Other Invoices	339,584				5,611		345,195
Maint - Maint of Mains	40,705				673		41,378
Maint - Other Invoices	(57,782)				(955)		(58,737)
Acct - Meter Reading Exp.	117,388				1,940		119,328
Billing & Collection Expenses	173,068	**4e**	(134,296)		641		39,413
Uncollectibles	459,513	**4f**	(287,866)	3,503	-	1,998	177,148
Acct-Other Invoices	436				7		443
Cust Rel - Informational Adv	-				-		-
Cust Rel - Other Invoices	18,091			6,000	299		24,390
Expenses - Informational Adv	7,546				125		7,671
Office Supplies and Exp	946,816	**4g**	(58,328)		14,681		903,169
Admin Exp and Admin Exp Transfer - Credit	(280,694)				(4,638)		(285,332)
Outside Services	459,234	**4h**	(253,659)	29,532	3,885		238,992
Indirect Allocation Intercompany	1,339,588	**4i**	(89,385)	80,144	20,974		1,351,321
Injuries & Damages	312,800	**4j**	(7,608)		5,043		310,235
Pension	(1,090,601)	**4k**	(155,332)	-	-		(1,245,933)
Health Insurance	972,822				16,074		988,897
Employee Benefits	(999,544)				(16,516)		(1,016,060)
OPEB's	(1,316,565)	**4l**	(40,644)	-	-		(1,357,209)
Other Employee Benefits	200,384	**4m**		77,422	4,590		282,397
Regulatory Commission Exp	207,090	**4n**	(13,998)		3,191		196,283
Maint of General Plant	163,647				2,704		166,351
Other Expenses	58,190	**4o**	(271,611)	56,812	(5,265)		(161,874)
Productivity	-	**4p**	(26,225)	(3,350)	-		(29,575)
Rents	(3,863)				(64)		(3,927)
Low Income Program	-	**4q**	573,977		-		573,977
Arrears Management Program	-	**4r**	73,912		-		73,912
Sub Total - Departmental	$ 8,352,034		$ (1,459,104)	$ 486,361	$ 62,361	$ 1,998	$ 7,443,651
TOTAL	**$ 8,352,034**		**$ (1,459,104)**	**$ 486,361**	**$ 62,361**	**$ 1,998**	**$ 7,443,651**

Liberty Utilities (St. Lawrence Gas) Corp.
PSC Case No. 24-G-0668
Taxes Other Than Income Taxes
For the Rate Year Ending October 31, 2026
(Whole Dollars)

Schedule 3

	Rate Year Ending October 31, 2026	Adj. #	Staff Adjustments	Settlement Adjustments	Rate Year As Adjusted for Joint Proposal
Taxes Other Than Income Taxes					
Payroll Tax	$ 428,969	**7a**	$ (44,872)	$ 20,759	$ 404,856
Property Tax	2,545,840	**7b**	517,272		3,063,112
Total Taxes Other Than Income Taxes	$ 2,974,809		$ 472,400	$ 20,759	$ 3,467,968

Liberty Utilities (St. Lawrence Gas) Corp.
PSC Case No. 24-G-0668
Income Taxes
For the Rate Year Ending October 31, 2026
(Whole Dollars)

Schedule 4

	Rate Year Ending October 31, 2026	Adj. #	Staff Adjustments	Settlement Adjustments	Rate Year As Adjusted for Joint Proposal
Operating Income Before Income Taxes	$ 3,327,065		$ 1,428,330	$ (935,183)	$ 3,820,212
Operating Income Adjustments:					
Interest Expense	$ (1,459,742)		$ 141,981	$ (43,876)	$ (1,361,638)
Taxable Income	$ 1,867,323		$ 1,570,311	$ (979,059)	2,458,574
State Income Tax Rate	6.50%		6.50%	6.50%	6.50%
Total State Income Taxes	$ 121,376	9	$ 102,070	$ (63,639)	$ 159,807
Federal Taxable Income before State Tax Deduction	$ 1,867,323		$ 1,570,311	$ (979,059)	$ 2,458,574
Adjust: State Tax Deduction	(121,376)		(102,070)	63,639	(159,807)
Income Subject to Federal Income Tax	$ 1,745,947		$ 1,468,240	$ (915,420)	$ 2,298,767
Federal Income Tax Rate	21%		21%	21%	21%
Federal Income Taxes	$ 366,649	8b	$ 308,330	$ (192,238)	$ 482,741
Adjust: Amortization of EADIT	(59,615)	8a	(21,568)	21,568	(59,615)
Total Federal Income Taxes	$ 307,033		$ 286,762	$ (170,670)	$ 423,126
Total Income Taxes	$ 428,409		$ 388,833	$ (234,309)	$ 582,933

Liberty Utilities (St. Lawrence Gas) Corp.
PSC Case No. 24-G-0668
Capital Structure
For the Rate Years Ending October 31, 2026, 2027 & 2028
(Whole Dollars)

Schedule 5

Staff Capital Structure RY3

	Total Annual Avg	Weighting Percent	Cost	Weighted Cost	Pre-Tax Weighted Cost
Long Term Debt	33,209,002	50.82%	5.01%	2.55%	2.55%
Short Term Debt	-	0.00%	0.00%	0.00%	0.00%
Customer Deposits	771,087	1.18%	3.00%	0.04%	0.04%
Common Equity	31,366,236	**48.00%**	**9.30%**	4.46%	6.04%
Total	$ 65,346,324	100.00%		7.05%	8.63%

Staff Capital Structure RY2

	Total Annual Avg	Weighting Percent	Cost	Weighted Cost	Pre-Tax Weighted Cost
Long Term Debt	30,076,777	51.82%	5.01%	2.60%	2.60%
Short Term Debt	-	0.00%	0.00%	0.00%	0.00%
Customer Deposits	684,882	1.18%	3.00%	0.04%	0.04%
Common Equity	27,279,208	**47.00%**	**9.30%**	4.37%	5.92%
Total	$ 58,040,867	100.00%		7.01%	8.56%

Staff Capital Structure RY1

	Total Annual Avg	Weighting Percent	Cost	Weighted Cost	Pre-Tax Weighted Cost
Long Term Debt	26,736,693	52.82%	5.01%	2.65%	2.65%
Short Term Debt	-	0.00%	0.00%	0.00%	0.00%
Customer Deposits	597,298	1.18%	3.00%	0.04%	0.04%
Common Equity	23,284,511	**46.00%**	**9.30%**	4.28%	5.79%
Total	$ 50,618,502	100.00%		6.97%	8.48%

Company Capital Structure

	Total Annual Avg	Weighting Percent	Cost	Weighted Cost	Pre-Tax Weighted Cost
Long Term Debt	29,438,135	50.82%	4.88%	2.48%	2.48%
Short Term Debt	-	0.00%	0.00%	0.00%	0.00%
Customer Deposits	683,530	1.18%	3.00%	0.04%	0.04%
Common Equity	27,804,614	48.00%	9.90%	4.75%	6.43%
Total	$ 57,926,280	100.00%		7.27%	8.95%

OTHER REVENUE REQUIREMENT INPUTS

Forecast Rate Year Rates To Apply To Rev Req	
Bad Debt % For Rev Req	**0.50%**
GRT Rate For Rev Req	**1.00%**
Federal Income Tax Rate	**21.00%**
NYS Income Tax Rate	**6.50%**

Liberty Utilities (St. Lawrence Gas) Corp.
PSC Case No. 24-G-0668
Summary of Rate Base
For the Rate Year Ending October 31, 2026
(Whole Dollars)

Schedule 6

	Rate Year Ending October 31, 2026	Adj. #	Staff Adjustments	Settlement Adjustments	Rate Year As Adjusted for Joint Proposal
Utility Plant	$ 97,947,596	**10a**	$ (2,683,662)	$ 1,639,852	$ 96,903,786
Depreciation Reserve	(41,061,557)	**10b**	128,479	179,088	(40,753,990)
Net Utility Plant	$ 56,886,040		$ (2,555,183)	$ 1,818,940	$ 56,149,796
Accumulated Deferred Income Taxes	$ (1,916,332)	**10c**	$ 86,077	$ (172,669)	$ (2,002,924)
Regulatory Liability Tax Reform	(1,309,348)	**10g**	-	-	(1,309,348)
Unamortized Deferrals	493,941	**10d**	(368,079)	620,273	746,135
Working Capital					
Materials and supplies	$ 559,627		$ -	$ -	$ 559,627
Prepayments	1,322,503		-	-	1,322,503
O&M Cash Allowance (1/8 O&M exp)	955,194	**10e**	(104,841)	19,232	869,585
Subtotal Working Capital	$ 2,837,324		$ (104,841)	$ 19,232	$ 2,751,715
Subtotal Avg. Before EBCAP Adj.	$ 56,991,625		$ (2,942,026)	$ 2,285,776	$ 56,335,375
Excess Earnings Base Adjustment	$ 934,654	**10f**	$ (9,383,547)	$ 2,732,020	$ (5,716,873)
Total Rate Base	**$ 57,926,280**		**$ (12,325,574)**	**$ 5,017,796**	**$ 50,618,502**

Liberty Utilities (St. Lawrence Gas) Corp.
PSC Case No. 24-G-0668
Depreciation and Amortization of Regulatory Deferrals
For the Rate Year Ending October 31, 2026
(Whole Dollars)

Schedule 7

	Rate Year Ending October 31, 2026	Adj. #	Staff Adjustments	Settlement Adjustments	Rate Year As Adjusted for Joint Proposal
Depreciation Expense	$ 2,512,598	**6**	$ (415,320)	$ 99,059	$ 2,196,337
Amortization Expense	1,065,791		-		1,065,791
Total Depreciation & Amortization Expense	$ 3,578,389		$ (415,320)	$ 99,059	$ 3,262,128
Summary of Amortization of Regulatory Deferrals					
Amortization of Regulatory Deferrals					
Rate Case Expense 24-G-0668	$ 422,678	**5a**	$ (200,527)	$ 104,562	$ 326,713
Other Regulatory Liability - Low Income 21-G-0577 Deferral	(68,885)	**5b**	34,443	(8,213)	(42,655)
EAP	(2,802)		-		(2,802)
Property Tax 21-G-0577 Deferral	(57,917)		-	(33,190)	(91,107)
NRAs CY 2023	(42,105)		-		(42,105)
Gas Safety PRA Deferral	-	**5c**	30,445	(30,445)	-
Gas Safety NRA Deferral	-	**5d**	(105,201)		(105,201)
Untimely Filing NRA Deferral	-	**5e**	(29,305)		(29,305)
LTP Deferral		**5f**	-	296,290	296,290
	$ 250,970		$ (270,145)	$ 329,004	$ 309,829

Liberty Utilities (St. Lawrence Gas) Corp.
PSC Case No. 24-G-0668
Interest Deduction
For the Rate Year Ending October 31, 2026
(Whole Dollars)

Schedule 8

	Rate Year Ending October 31, 2026	Staff Adjustments	Settlement Adjustments	Rate Year As Adjusted for Joint Proposal
Avg Rate Base Per Books	$ 56,991,625	$ (2,942,026)	$ 2,285,776	$ 56,335,375
Less: Excess Earnings Adj (EBCAP)	(934,654)	9,383,547	(2,732,020)	5,716,873
	$ 57,926,280	$ (12,325,574)	$ 5,017,796	$ 50,618,502
Weighted Cost of LTD Debt	2.48%	0.17%	0.00%	2.65%
Weighted Cost of Cust Deposits	0.04%	0.00%	0.00%	0.04%
	2.52%	0.17%	0.00%	2.69%
Total Income Tax Interest Deduction	**$ 1,459,742**	**$ (141,981)**	**$ 43,876**	**$ 1,361,638**

Liberty Utilities (St. Lawrence Gas) Corp.
PSC Case No. 24-G-0668
Working Capital
For the Rate Year Ending October 31, 2026
(Whole Dollars)

Schedule 9

Description	Rate Year Ending October 31, 2026	Staff Adjustments	Settlement Adjustments	Rate Year As Adjusted for Joint Proposal
Total O&M Expense	$ 8,352,034	$ (1,396,742)	$ 486,361	$ 7,441,652
Remove Major Non-Cash Items Included in O&M Expense:				
Uncollectibles	$ (459,513)	$ 287,866	(3,503)	$ (175,150)
Amortization of Regulatory Deferrals	(250,970)	270,145	(329,004)	(309,829)
Subtotal	$ (710,483)	$ 558,011	$ (332,507)	$ (484,978)
Add Major Cash Items Not Included in O&M Expense:				
Other	$ -	$ -	$ -	$ -
Subtotal	$ -	$ -	$ -	$ -
Total Adjustments	$ (710,483)	$ 558,011	$ (332,507)	$ (484,978)
Adjusted O&M Expense	$ 7,641,551	$ (838,731)	$ 153,854	$ 6,956,674
Departmental Cash Allowance - 1/8 (45 days)	$ 955,194	$ (104,841)	$ 19,232	$ 869,584

Liberty Utilities (St. Lawrence Gas) Corp.
PSC Case No. 24-G-0668
Summary of Adjustments
For the Rate Year Ending October 31, 2026
(Whole Dollars)

Schedule 10
Page 1 of 2

			Amount	Witness	Total
Adj. 1		**Operating Revenues**			
	a.	**Gas Revenue**			
	(1)	To reflect Staff's sales forecast	$ 84,399	Gadomski/SRARDP	
	(2)	To reflect Staff's update to the MFC/DRA	(122,936)	Gadomski/SRARDP	$ (38,537)
	b.	**Miscellaneous Service Revenue**			
		To remove CIAC per DPS-342	$ (116,301)	SRARDP	$ (116,301)
		Total adjustments to Operating Revenues		SRARDP	$ (154,838)
Adj. 2		**Purchased Gas Costs**			
		To reflect Staff's sales forecast	$ 26,653	SRARDP	$ 26,653
Adj. 3		**Revenue Taxes**			
		To reflect Staff's sales forecast	$ (13)	SRARDP	$ (13)
Adj. 4		**Operating and Maintenance Expenses**			
		Inflation			
		To update the general inflation factor to 5.877%	$ 34,975	SRRP/Gadomski	
		Joint Proposal - to update the general inflation factor to 6.58%	**27,386**	**Joint Proposal**	$ 62,361
	a.	**Direct Labor**			
	(1)	To adjust direct labor expense removing the analyst III position	$ (70,811)	SRRP	
	(2)	To adjust direct labor expense to adjust the analyst I position salary	(8,191)	SRRP	
	(3)	To adjust direct labor expense to remove incentive compensation	(530,578)	SRRP	
		Joint Proposal - to adjust incentive compensation to reflect the Company's modifications to its incentive compensation program	**168,272**	**Joint Proposal**	$ (441,308)
	b.	**Direct Intercompany**			
	(1)	To adjust direct intercompany expense to remove forecasted wage increases	$ (34,273)	SRRP	
	(2)	To adjust direct intercompany to remove incentive compensation	11,270	SRRP	(23,003)
	c.	**Indirect Allocated Labor**			
	(1)	To adjust indirect allocated labor to remove forecasted wage increases	$ (53,302)	SRRP	
	(2)	To adjust indirect allocated labor to remove incentive compensation	(55,345)	SRRP	
	(3)	To adjust indirect allocated labor to the reduce allocated labor tracking Staff's cybersecurity recommendation	(23,246)	SRRP	
		Joint Proposal -to reduce cybersecurity opex by 10%, tracking the reduction to cybersecurity capex	**12,680**	**Joint Proposal**	
		Joint Proposal - to remove Staff's adjustment related to incentive compensation	**55,345**	**Joint Proposal**	$ (63,868)
	d.	**Oper - Mains & Services Exp.**			
		To adjust oper - mains & services expense to remove membership due expense	$ (3,565)	SRRP	$ (3,565)
	e.	**Billing & Collection Expenses**			
		To adjust billing and collection expenses to remove non-reoccurring costs from a certain vendor	$ (134,296)	SRRP	$ (134,296)
	f.	**Uncollectibles**			
		To adjust uncollectibles to reflect Staff's net write-off rate	$ (287,866)	SRRP	
		Joint Proposal - to reflect a net write-off rate of 0.500%	**3,503**	**Joint Proposal**	$ (284,363)
		Cust Rel - Other Invoices			
		Joint Proposal - to reflect costs for language access	**$ 6,000**	**Joint Proposal**	$ 6,000
	g.	**Office Supplies and Expense**			
	(1)	To adjust Office and Supplies and Exp to remove membership dues from organizations that participate in lobbying	$ (11,622)	SRRP	
	(2)	To adjust office and Supplies and Exp to remove the costs associated with beverages	(21,676)	SRRP	
	(3)	To adjust office and Supplies and Exp to normalize bank fees	(15,069)	SRRP	
	(4)	To adjust office and Supplies and Exp to remove a misclassified expense	(9,961)	SRRP	$ (58,328)
	h.	**Outside Services**			
	(1)	To adjust Outside Services to remove the disallowed portion of prior rate case expenses	$ (134,296)	SRRP	
	(2)	To adjust Outside Services to remove non-reoccurring paving expenses	(77,422)	SRRP	
	(3)	To adjust Outside Services to remove normalize "consulting" costs	(41,941)	SRRP	
		Joint Proposal - to remove Staff adjustment (4h.2) to remove a misclassified expense, and reflect in proper cost element	**9,961**	**Joint Proposal**	
		Joint Proposal - to reflect 50% of Staff's consulting expense adjustment	**20,970**	**Joint Proposal**	
		Joint Proposal - to correct adjustment (4h.1) related to the disallowed portion of prior rate case expenses	**(1,399)**		$ (222,728)
	i.	**Indirect Allocation Intercompany**			
	(1)	To adjust indirect allocation intercompany to reduce O&M related to cybersecurity	$ (20,329)	SRRP	
	(2)	To adjust indirect allocation intercompany to remove incentive compensation	(69,056)	SRRP	
		Joint Proposal -to reduce cybersecurity opex by 10%, tracking the reduction to cybersecurity capex	**11,088**	**Joint Proposal**	
		Joint Proposal - to remove Staff's adjustment related to incentive compensation	**69,056**	**Joint Proposal**	$ (9,241)
	j.	**Injuries & Damages**			
	(1)	To adjust injuries and damages to normalize damage invoices	$ (7,608)	SRRP	$ (7,608)
	k.	**Pensions**			
	(1)	To adjust pension expense to apply a capitalization rate of 17.58% to the service cost component per DPS-574	$ (56,877)	SRRP	
	(2)	To adjust pension expense to apply the Company capitalization rate to the service cost component	(98,455)	SRRP	$ (155,332)
	l.	**OPEB's**			
	(1)	To OPEB expense to apply a capitalization rate of 34.57% to the service cost component per DPS-574	$ (29,270)	SRRP	
	(2)	To adjust OPEB expense to apply the capitalization rate of 48 percent to the service cost component	(11,374)	SRRP	$ (40,644)
	m.	**Other Employee Benefits**			
		Joint Proposal - to remove Staff's adjustment (4h.2) and reflect in proper cost element	**$ 77,422**		$ 77,422
	n.	**Regulatory Commission Expense**			
	(1)	To adjust regulatory commission expense to reflect the latest known billings	$ 12,450	SRRP	
	(2)	To adjust regulatory commission expense to reflect a refund	(26,449)	SRRP	$ (13,998)
	o.	**Other Expenses**			
	(1)	To remove the costs associated with the Greenhouse Gas Reduction Program	$ (56,812)	SGSP	
	(2)	To remove the costs associated with the PSMS Program	(320,000)	SPP	
	(3)	To adjust other expense to reflect the costs of Staff's proposed RMD program	105,201	SGSP	
		Joint Proposal - to reflect the cost of the Gas Safety FTE	**56,812**	**Joint Proposal**	$ (214,799)
	p.	**Productivity**			
		To reflect the Commission standard 1% productivity adjustment	$ (26,225)	SRRP	
		Joint Proposal - tracking staff's adjustments to labor and benefits	**(3,350)**	**Joint Proposal**	$ (29,575)
	q.	**Low Income Program**			
	(1)	To reflect the costs of the Low Income Program in base delivery rates	$ 486,204	SRRP	
	(2)	To update the costs of the Low Income Program to reflect Staff's recommendation	87,773	SCSP	$ 573,977

Liberty Utilities (St. Lawrence Gas) Corp.
PSC Case No. 24-G-0668
Summary of Adjustments
For the Rate Year Ending October 31, 2026
(Whole Dollars)

Schedule 10
Page 2 of 2

				Witness	
Adj. 4		**Operating and Maintenance Expenses (Continued)**			
	r.	**Arrears Management Program**			
		To reflect the costs of the Low Income Program in base delivery rates	$ 73,912	SCSP	$ 73,912
		Total Operating and Maintenance Expense Adjustment			$ (908,983)
Adj. 5		**Regulatory Deferrals**			
	a.	**Rate Case Expense 24-G-0668**			
	(1)	To adjust rate case expense to reduce total compensation study	$ (8,768)	SRRP	
	(2)	To adjust rate case expense to reduce depreciation study	(12,950)	SRRP	
	(3)	To adjust rate case expense to reduce allocated cost of service study	(16,694)	SRRP	
	(4)	To adjust rate case expense to reduce rate design study	(26,820)	SRRP	
	(5)	To adjust rate case expense to reduce cost of capital study	(34,725)	SRRP	
	(6)	To adjust rate case expense to reduce data collection costs	(5,833)	SRRP	
	(7)	To adjust rate case expense to reduce outside counsel costs	(94,737)	SRRP	
		Joint Proposal - to update rate case expense for most recent data	**104,562**	**Joint Proposal**	$ (95,965)
	b.	**Low Income 21-G-0577 Deferral**			
		To adjust the low income amortization to reflect the correct balance as of June 30, 2024	$ 34,443	SRRP	
		Joint Proposal - to adjust low income amortization to reflect the balance as of 3/31/2025	**(8,213)**	**Joint Proposal**	$ 26,230
	c.	**Gas Safety PRA Deferral**			
		To amortize Gas Safety PRA deferral over one-year	$ 30,445	SRRP/SGSP	
		Staff Settlement Offer #1 - to adjust PRA deferral to account for Staff error	**(30,445)**	**Error Correction**	$ -
	d.	**Gas Safety NRA Deferral**			
		To amortize Gas Safety NRA deferral over one-year to offset the costs of Staff's proposed RMD program	$ (105,201)	SRRP/SGSP	$ (105,201)
	e.	**Untimely Filing NRA Deferral**			
		To amortize the NRAs associated with the untimely filing deferral over a three-years	$ (29,305)	SRRP	$ (29,305)
	f.	**LTP Deferral**			
		Joint Proposal - to amortize deferred LTP costs over a 3-year period	**$ 296,290**	**Joint Proposal**	$ 296,290
	g.	**Property Tax Deferral**			
		Joint Proposal - to update the property tax deferral balance as of 3/31/2025	**$ (33,190)**		$ (33,190)
		Total Regulatory Deferral Adjustments			$ 92,049
Adj. 6		**Depreciation Expense**			
	(1)	To adjust depreciation expense tracking Staff's adjustments to gas utility plant, and to reflect Staff's depreciation rates	$ (327,714)	SNPGIOP	
	(2)	To adjust depreciation expense to reflect the amortization of depreciation reserve excess	(87,606)	SNPGIOP	
		Joint Proposal - to adjust depreciation expense to reflect the agreed upon depreciation rates and utility plant	**11,453**	**Joint Proposal**	
		Joint Proposal - to remove Staff's adjustment related to the amortization of the excess depreciation reserve	**87,606**	**Joint Proposal**	$ (316,261)
Adj. 7		**Taxes Other Than Revenue & Income Taxes**			
	a.	**Property Taxes**			
		To adjust property taxes to reflect correct calculation	$ 517,272	SRRP	$ 517,272
	b.	**Payroll Taxes**			
	(1)	To adjust payroll tax to reflect Staff's calculation	$ 18,220	SRRP	
	(2)	To adjust payroll tax tracking Staff's adjustment to direct labor expense	(63,092)	SRRP	
		Joint Proposal - to adjust payroll tax tracking adjustments to labor expenses	**20,759**	**Joint Proposal**	$ (24,113)
Adj. 8		**Federal Income Taxes**			
	(1)	To reflect Staff's adjustment to the amortization of excess accumulated deferred income taxes	$ (21,568)	SRRP	
	(2)	To adjust current federal income taxes, tracking staff's adjustments	116,092	SRRP	
		Joint Proposal - to remove Staff's adjustment related to the amortization of Excess ADIT	**21,568**	**Joint Proposal**	$ 116,092
Adj. 9		**State Income Taxes**			
		To adjust current state income taxes, tracking staff's adjustments	$ 38,431	SRRP	$ 38,431
		Total Current Income Tax Adjustments			$ 154,524
Adj. 10		**Rate Base**			
	a.	**Utility Plant**			
		To adjust Utility Plant to reflect Staff's forecast of plant additions	$ (2,683,662)	SNPGIOP	
		Joint Proposal - to adjust utility plant to reflect the agreed upon plant-in-service balances	**1,639,852**	**Joint Proposal**	$ (1,043,810)
	b.	**Accumulated Depreciation**			
		To adjust accumulated depreciation tracking Staff's forecast of plant additions	$ 128,479	SNPGIOP	
		Joint Proposal - to adjust accumulated depreciation tracking depreciation expense	**179,088**	**Joint Proposal**	$ 307,567
		Total Net Utility Plant Adjustment			$ (736,243)
	c.	**Accumulated Deferred Income Taxes (ADIT)**			
		To adjust ADIT tracking Staff's forecast of plant additions and amortization of deferrals	$ 86,077	SRRP	
		Joint Proposal - to adjust ADIT tracking depreciation expense and plant-in-service	**(172,669)**	**Joint Proposal**	$ (86,592)
	d.	**Unamortized Deferrals**			
		To adjust unamortized deferrals tracking amortization of regulatory deferrals (net of ADIT)	$ (368,079)	SRRP	
		Joint Proposal - to adjust the unamortized deferrals tracking amortization of regulatory deferrals	**620,273**	**Joint Proposal**	$ 252,194
	e.	**Working Capital**			
		To adjust working capital to reflect Staff's O&M adjustments	$ (104,841)	SRRP	
		Joint Proposal - to adjust working capital tracking adjustments to O&M expense	**19,232**	**Joint Proposal**	$ (85,609)
	f.	**Excess Earnings Base (EB/CAP)**			
		To reflect Historic Test Year calculation	$ (9,383,547)	SRRP	
		Joint Proposal - to adjust the EBCAP to reflect the December 2024 equity infusion, and measure as of 1/31/2025	**2,732,020**	**Joint Proposal**	$ (6,651,527)
		Total Rate Base Adjustments			$ (7,307,777)

Liberty Utilities (St. Lawrence Gas) Corp.
PSC Case No. 24-G-0668
Statement of Operating Income
For the Rate Years Ending October 31, 2027
(Whole Dollars)

Schedule 1

	Rate Year Ending October 31, 2026	Adj. #	Rate Year 2 Adjustments	Rate Year 2 As Adjusted for Joint Proposal	Revenue Increase	Rate Year Ending October 31, 2027
Operating Revenues	$ 35,429,638	1	$ 239,432	$ 35,669,070	$ 1,876,203	$ 37,545,273
Deductions						
Purchased Gas Costs	$ 16,265,227	2	$ 131,511	$ 16,396,738		$ 16,396,738
Revenue Taxes	466,892	3	2,394	469,286	18,762	488,048
Total Deductions	$ 16,732,118		$ 133,905	$ 16,866,023	$ 18,762	$ 16,884,785
Gross Margin	$ 18,697,520		$ 105,527	$ 18,803,047	$ 1,857,441	$ 20,660,488
Total Operation & Maintenance Expenses	$ 7,443,651	4	$ 417,633	$ 7,861,284	$ 9,380	$ 7,870,664
Amortization of Regulatory Deferrals	309,829	5	150,108	459,937	-	459,937
Depreciation, Amort. & Loss on Disposition	3,262,128	6	441,057	3,703,185	-	3,703,185
Taxes Other Than Revenue & Income Taxes	3,467,968	7	273,351	3,741,319	-	3,741,319
Total Operating Revenue Deductions	$ 14,483,575		$ 1,282,149	$ 15,765,725	$ 9,380	$ 15,775,105
Operating Income Before Income Taxes	$ 4,213,945		$ (1,176,623)	$ 3,037,322	$ 1,848,061	$ 4,885,383
Income Taxes						
State Income Taxes	$ 185,400	9	$ (87,573)	$ 97,828	$ 120,124	$ 217,952
Federal Income Taxes	500,435	8	(264,535)	235,900	362,867	598,767
Total Income Taxes	$ 685,835		$ (352,107)	$ 333,728	$ 482,991	$ 816,719
Operating Income After Income Taxes	$ 3,528,110		$ (824,515)	$ 2,703,594	$ 1,365,070	$ 4,068,664
Rate Base	$ 50,618,502	10	$ 7,422,365	$ 58,040,867		$ 58,040,867
Rate of Return	6.97%			4.66%		7.01%

Liberty Utilities (St. Lawrence Gas) Corp.
PSC Case No. 24-G-0668
Operation and Maintenance Expenses
For the Rate Year Ending October 31, 2027
(Whole Dollars)

Schedule 2

	Rate Year Ending October 31, 2026	Adj. #	Rate Year 2 Adjustments	Inflation	Rate Year 2 As Adjusted for Joint Proposal	Revenue Increase	Rate Year 2 After Increase
Operation & Maintenance Expenses:							
Departmental Items:							
Direct Labor	$ 3,879,361	**4a**	$ 119,091	$ -	$ 3,998,452	$ -	$ 3,998,452
Direct Intercompany	469,465	**4b**		-	469,465		469,465
Indirect Allocated Labor	837,059	**4c**		-	837,059		837,059
Oper - Mains & Services Exp.	512,597	**4d**		12,282	524,879		524,879
Oper - Cust Install Exp	24,698			592	25,290		25,290
Oper - Meas & Reg Station Exp	38,617			925	39,543		39,543
Oper - Other Invoices	345,195			8,271	353,466		353,466
Maint - Maint of Mains	41,378			991	42,369		42,369
Maint - Other Invoices	(58,737)			(1,407)	(60,144)		(60,144)
Acct - Meter Reading Exp.	119,328			2,859	122,187		122,187
Billing & Collection Expenses	39,413	**4e**		944	40,357		40,357
Uncollectibles	177,148	**4f**	1,197	-	178,345	9,380	187,725
Acct-Other Invoices	443			11	454		454
Cust Rel - Informational Adv	-			-	-		-
Cust Rel - Other Invoices	24,390			584	24,974		24,974
Expenses - Informational Adv	7,671			184	7,855		7,855
Office Supplies and Exp	903,169	**4g**		21,640	924,809		924,809
Admin Exp and Admin Exp Transfer - Credit	(285,332)			(6,837)	(292,169)		(292,169)
Outside Services	238,992	**4h**		5,726	244,718		244,718
Indirect Allocation Intercompany	1,351,321	**4i**	115,586	35,147	1,502,054		1,502,054
Injuries & Damages	310,235	**4j**		7,433	317,668		317,668
Pension	(1,245,933)	**4k**		-	(1,245,933)		(1,245,933)
Health Insurance	988,897			23,694	1,012,591		1,012,591
Employee Benefits	(1,016,060)			(24,345)	(1,040,404)		(1,040,404)
OPEB's	(1,357,209)	**4l**		-	(1,357,209)		(1,357,209)
Other Employee Benefits	282,397	**4m**		6,766	289,163		289,163
Regulatory Commission Exp	196,283	**4n**		4,703	200,985		200,985
Maint of General Plant	166,351			3,986	170,337		170,337
Other Expenses	(161,874)	**4o**	30,000	(3,160)	(135,033)		(135,033)
Productivity	(29,575)	**4p**	(1,283)	-	(30,858)		(30,858)
Rents	(3,927)			(94)	(4,021)		(4,021)
Low Income Program	573,977	**4q**	52,146	-	626,123		626,123
Arrears Management Program	73,912	**4r**		-	73,912		73,912
Sub Total - Departmental	$ 7,443,651		$ 316,737	$ 100,896	$ 7,861,284	$ 9,380	$ 7,870,664
TOTAL	**$ 7,443,651**		**$ 316,737**	**$ 100,896**	**$ 7,861,284**	**$ 9,380**	**$ 7,870,664**

Liberty Utilities (St. Lawrence Gas) Corp.
PSC Case No. 24-G-0668
Taxes Other Than Income Taxes
For the Rate Year Ending October 31, 2027
(Whole Dollars)

Schedule 3

	Rate Year Ending October 31, 2026	Adj. #	Rate Year 2 Adjustments	Rate Year 2 As Adjusted for Joint Proposal
Taxes Other Than Income Taxes				
Payroll Tax	$ 404,856	**7a**	$ 9,924	$ 414,780
Property Tax	3,063,112	**7b**	263,427	$ 3,326,539
Total Taxes Other Than Income Taxes	$ 3,467,968		$ 273,351	$ 3,741,319

Liberty Utilities (St. Lawrence Gas) Corp.
PSC Case No. 24-G-0668
Income Taxes
For the Rate Year Ending October 31, 2027
(Whole Dollars)

Schedule 4

	Rate Year Ending October 31, 2026	Adj. #	Rate Year 2 Adjustments	Rate Year 2 As Adjusted for Joint Proposal
Operating Income Before Income Taxes	$ 3,820,212		$ (1,176,623)	$ 3,037,322
Operating Income Adjustments:				
Interest Expense	$ (1,361,638)		$ (170,641)	$ (1,532,279)
Taxable Income	2,458,574		$ (1,347,264)	$ 1,505,043
State Income Tax Rate	6.50%		6.50%	6.50%
Total State Income Taxes	$ 159,807	**9**	$ (87,572)	$ 97,828
Federal Taxable Income before State Tax Deduction	$ 2,458,574		$ (1,347,264)	$ 1,505,043
Adjust: State Tax Deduction	(159,807)		87,572	(97,828)
Income Subject to Federal Income Tax	$ 2,298,767		$ (1,259,692)	$ 1,407,215
Federal Income Tax Rate	21%		21%	21%
Federal Income Taxes	$ 482,741	**8b**	$ (264,535)	$ 295,515
Adjust: Amortization of EADIT	(59,615)	**8a**	-	$ (59,615)
Total Federal Income Taxes	$ 423,126		$ (264,535)	$ 235,900
Total Income Taxes	$ 582,933		$ (352,107)	$ 333,728

Liberty Utilities (St. Lawrence Gas) Corp.
PSC Case No. 24-G-0668
Summary of Rate Base
For the Rate Year Ending October 31, 2027
(Whole Dollars)

Schedule 6

	Rate Year Ending October 31, 2026	Adj. #	Rate Year 2 Adjustments	Rate Year 2 As Adjusted for Joint Proposal
Utility Plant	$ 96,903,786	**10a**	$ 10,160,001	$ 107,063,787
Depreciation Reserve	(40,753,990)	**10b**	(3,032,481)	(43,786,471)
Net Utility Plant	$ 56,149,796		$ 7,127,520	$ 63,277,316
Accumulated Deferred Income Taxes	$ (2,002,924)	**10c**	$ (1,011,768)	$ (3,014,692)
Regulatory Liability Tax Reform	(1,309,348)	**10g**	80,642	(1,228,706)
Unamortized Deferrals	746,135	**10d**	(236,538)	509,597
Working Capital				
Materials and supplies	$ 559,627		$ -	$ 559,627
Prepayments	1,322,503		-	1,322,503
O&M Cash Allowance (1/8 O&M exp)	869,585	**10e**	33,291	902,876
Subtotal Working Capital	$ 2,751,715		$ 33,291	$ 2,785,006
Subtotal Avg. Before EBCAP Adj.	$ 56,335,375		$ 5,993,147	$ 62,328,522
Excess Earnings Base Adjustment	$ (5,716,873)	**10f**	$ 1,429,218	$ (4,287,654)
Total Rate Base	**$ 50,618,502**		**$ 7,422,365**	**$ 58,040,867**

Liberty Utilities (St. Lawrence Gas) Corp.
PSC Case No. 24-G-0668
Depreciation and Amortization of Regulatory Deferrals
For the Rate Year Ending October 31, 2027
(Whole Dollars)

Schedule 7

	Rate Year Ending October 31, 2026	Adj. #	Rate Year 2 Adjustments	Rate Year 2 As Adjusted for Joint Proposal
Depreciation Expense	$ 2,196,337	**6**	$ 441,057	$ 2,637,394
Amortization Expense	1,065,791			1,065,791
Total Depreciation & Amortization Expense	$ 3,262,128		$ 441,057	$ 3,703,185
Summary of Amortization of Regulatory Deferrals				
Amortization of Regulatory Deferrals				
Rate Case Expense 24-G-0668	$ 326,713	**5a**	$ -	$ 326,713
Other Regulatory Liability - Low Income 21-G-0577 Deferral	(42,655)	**5b**		(42,655)
EAP	(2,802)		2,802	0
Property Tax 21-G-0577 Deferral	(91,107)			(91,107)
NRAs CY 2023	(42,105)		42,105	-
Gas Safety PRA Deferral	-	**5c**	-	-
Gas Safety NRA Deferral	(105,201)	**5d**	105,201	-
Untimely Filing NRA Deferral	(29,305)	**5e**		(29,305)
LTP Deferral	296,290	**5f**		296,290
	$ 309,829		$ 150,108	$ 459,937

Liberty Utilities (St. Lawrence Gas) Corp.
PSC Case No. 24-G-0668
Interest Deduction
For the Rate Year Ending October 31, 2027
(Whole Dollars)

Schedule 8

	Rate Year Ending October 31, 2026	Rate Year 2 Adjustments	Rate Year 2 As Adjusted for Joint Proposal
Avg Rate Base Per Books	$ 56,335,375	$ 5,993,147	$ 62,328,522
Less: Excess Earnings Adj (EBCAP)	5,716,873	(1,429,218)	4,287,654
	$ 50,618,502	$ 7,422,365	$ 58,040,867
Weighted Cost of LTD Debt	2.65%	-0.05%	2.60%
Weighted Cost of Cust Deposits	0.04%	0.00%	0.04%
	2.69%	-0.05%	2.64%
Total Income Tax Interest Deduction	**$ 1,361,638**	**$ 170,641**	**$ 1,532,279**

Liberty Utilities (St. Lawrence Gas) Corp.
PSC Case No. 24-G-0668
Working Capital
For the Rate Year Ending October 31, 2027
(Whole Dollars)

Schedule 9

Description	Rate Year Ending October 31, 2026	Rate Year 2 Adjustments	Rate Year 2 As Adjusted for Joint Proposal
Total O&M Expense	$ 7,441,652	$ 419,632	$ 7,861,284
Remove Major Non-Cash Items Included in O&M Expense:			
Uncollectibles	$ (175,150)	(3,196)	$ (178,345)
Amortization of Regulatory Deferrals	(309,829)	(150,108)	(459,937)
Subtotal	$ (484,978)	$ (153,304)	$ (638,282)
Add Major Cash Items Not Included in O&M Expense:			
Other	$ -	$ -	$ -
Subtotal	$ -	$ -	$ -
Total Adjustments	$ (484,978)	$ (153,304)	$ (638,282)
Adjusted O&M Expense	$ 6,956,674	$ 266,328	$ 7,223,002
Departmental Cash Allowance - 1/8 (45 days)	$ 869,584	$ 33,291	$ 902,875

Liberty Utilities (St. Lawrence Gas) Corp.
PSC Case No. 24-G-0668
Summary of Adjustments
For the Rate Year Ending October 31, 2027
(Whole Dollars)

Schedule 10
Page 1 of 2

Adj. 1	**Operating Revenues**		
	Gas Revenue		
	To reflect RY2 sales forecast	$ 239,432	**$ 239,432**
Adj. 2	**Purchased Gas Costs**		
	To adjust purchased gas tracking RY2 sales forecast	$ 131,511	**$ 131,511**
Adj. 3	**Revenue Taxes**		
	To adjust revenue tax tracking RY2 sales forecast	$ 2,394	**$ 2,394**
Adj. 4	**Operating and Maintenance Expenses**		
	Inflation		
	To increase inflation pool items by a general inflation factor of 2.40%	$ 100,896	**$ 100,896**
a.	**Direct Labor**		
	To increase labor forecast by weighted average of wage increases	$ 119,091	**$ 119,091**
b.	**Indirect Allocation Intercompany**		
	To reflect RY2 cybersecurity O&M	$ 115,586	**$ 115,586**
c.	**Other Expenses**		
	To adjust RY2 Other Expenses for quality assurance costs	$ 30,000	**$ 30,000**
d.	**Productivity Expense**		
	To adjust productivity tracking Staff's forecast for labor and labor related expenses	$ (1,283)	**$ (1,283)**
e.	**Low Income Program**		
	To reflect RY2 Low Income Program forecast	$ 52,146	**$ 52,146**
	Total Operating and Maintenance Expense Adjustment		**$ 416,436**
Adj. 5	**Regulatory Deferrals**		
a.	**EAP**		
	To remove amortization of the EAP deferral	$ 2,802	**$ 2,802**
a.	**NRAs CY 2023**		
	To remove amortization of the NRAs CY 2023 Deferral	$ 42,105	**$ 42,105**
a.	**Gas Safety NRA Deferral**		
	To remove amortiation of the Gas Safety NRA Deferral	$ 105,201	**$ 105,201**
	Total Regulatory Deferral Adjustments		**$ 150,108**

Liberty Utilities (St. Lawrence Gas) Corp.
PSC Case No. 24-G-0668
Summary of Adjustments
For the Rate Year Ending October 31, 2027
(Whole Dollars)

Schedule 10
Page 2 of 2

Adj. 6	**Depreciation Expense**		
	To adjust depreciation expense tracking RY2 gas utility plant anad depreciation rates	$ 441,057	**$ 441,057**
Adj. 7	**Taxes Other Than Revenue & Income Taxes**		
	a. Property Taxes		
	To reflect RY2 Property Tax forecast	$ 263,427	**$ 263,427**
	b. Payroll Taxes		
	To reflect RY2 Payroll Tax forecast	$ 9,924	**$ 9,924**
Adj. 8	**Federal Income Taxes**		
	To adjust current Federal Income Taxes, tracking Staff's adjustments	$ (264,535)	**$ (264,535)**
Adj. 9	**State Income Taxes**		
	To adjust current State Income Taxes, tracking Staff's adjustments	$ (87,573)	**$ (87,573)**
	Total Current Income Tax Adjustments		**$ (352,107)**
Adj. 10	**Rate Base**		
	a. Utility Plant		
	To adjust RY2 utility plant-in-service	$ 10,160,001	**$ 10,160,001**
	b. Accumulated Depreciation		
	To adjust RY2 accumulated depreciation	$ (3,032,481)	**$ (3,032,481)**
	Total Net Utility Plant Adjustment		**$ 7,127,520**
	c. Accumulated Deferred Income Taxes (ADIT)		
	To adjust RY2 ADIT	$ (1,011,768)	**$ (1,011,768)**
	d. Unamortized Deferrals		
	To adjust RY2 unamortized deferral balance	$ (236,538)	**$ (236,538)**
	e. Working Capital		
	To adjust working capital to reflect Staff's O&M adjustments	$ 33,291	**$ 33,291**
	f. Excess Earnings Base (EB/CAP)		
	To adjust the RY1 EBCAP Adjustment by 25%	$ 1,429,218	**$ 1,429,218**
	g. **Regulatory Liability Tax Reform**		
	To adjust RY2 regulatory liability tax reform unamortized balance	$ 80,642	**$ 80,642**
	Total Rate Base Adjustments		**$ 7,422,365**

Liberty Utilities (St. Lawrence Gas) Corp.
PSC Case No. 24-G-0668
Statement of Operating Income
For the Rate Years Ending October 31, 2028
(Whole Dollars)

Schedule 1

	Rate Year Ending October 31, 2027	Adj. #	Rate Year 3 Adjustments	Rate Year 3 As Adjusted for Joint Proposal	Revenue Increase	Rate Year Ending October 31, 2028
Operating Revenues	$ 37,545,273	1	$ 256,233	$ 37,801,506	$ 1,645,275	$ 39,446,781
Deductions						
Purchased Gas Costs	$ 16,396,738	2	$ 141,062	$ 16,537,800		$ 16,537,800
Revenue Taxes	488,048	3	2,562	490,610	16,453	507,063
Total Deductions	$ 16,884,785		$ 143,624	$ 17,028,410	$ 16,453	$ 17,044,863
Gross Margin	$ 20,660,488		$ 112,609	$ 20,773,096	$ 1,628,822	$ 22,401,918
Total Operation & Maintenance Expenses	$ 7,870,664	4	$ 306,097	$ 8,176,761	$ 8,226	$ 8,184,987
Amortization of Regulatory Deferrals	459,937	5	-	459,937	-	459,937
Depreciation, Amort. & Loss on Disposition	3,703,185	6	455,475	4,158,660	-	4,158,660
Taxes Other Than Revenue & Income Taxes	3,741,319	7	299,615	4,040,934	-	4,040,934
Total Operating Revenue Deductions	$ 15,775,105		$ 1,061,187	$ 16,836,292	$ 8,226	$ 16,844,518
Operating Income Before Income Taxes	$ 4,885,383		$ (948,579)	$ 3,936,804	$ 1,620,596	$ 5,557,400
Income Taxes						
State Income Taxes	$ 217,952	9	$ (72,070)	$ 145,882	$ 105,339	$ 251,221
Federal Income Taxes	598,767	8	(217,707)	381,060	318,204	699,264
Total Income Taxes	$ 816,719		$ (289,777)	$ 526,941	$ 423,543	$ 950,484
Operating Income After Income Taxes	$ 4,068,664		$ (658,802)	$ 3,409,863	$ 1,197,053	$ 4,606,916
Rate Base	$ 58,040,867	10	$ 7,305,457	$ 65,346,324		$ 65,346,324
Rate of Return	7.01%			5.22%		7.05%

Liberty Utilities (St. Lawrence Gas) Corp.
Case 24-G-0668
Operation and Maintenance Expenses
For the Rate Year Ending October 31, 2028
(Whole Dollars)

Schedule 2

	Rate Year Ending October 31, 2027	Adj. #	Rate Year 3 Adjustments	Inflation	Rate Year 3 As Adjusted for Joint Proposal	Revenue Increase	Rate Year 3 After Increase
Operation & Maintenance Expenses:							
Departmental Items:							
Direct Labor	$ 3,998,452	**4a**	$ 115,537	$ -	$ 4,113,989	$ -	$ 4,113,989
Direct Intercompany	469,465	**4b**		-	469,465		469,465
Indirect Allocated Labor	837,059	**4c**		-	837,059		837,059
Oper - Mains & Services Exp.	524,879	**4d**		12,193	537,072		537,072
Oper - Cust Install Exp	25,290			587	25,877		25,877
Oper - Meas & Reg Station Exp	39,543			919	40,461		40,461
Oper - Other Invoices	353,466			8,211	361,677		361,677
Maint - Maint of Mains	42,369			984	43,354		43,354
Maint - Other Invoices	(60,144)			(1,397)	(61,542)		(61,542)
Acct - Meter Reading Exp.	122,187			2,838	125,026		125,026
Billing & Collection Expenses	40,357	**4e**		938	41,295		41,295
Uncollectibles	187,725	**4f**	1,282	-	189,008	8,226	197,234
Acct-Other Invoices	454			11	465		465
Cust Rel - Informational Adv	-			-	-		-
Cust Rel - Other Invoices	24,974			580	25,554		25,554
Expenses - Informational Adv	7,855			182	8,037		8,037
Office Supplies and Exp	924,809	**4g**		21,483	946,292		946,292
Admin Exp and Admin Exp Transfer - Credit	(292,169)			(6,787)	(298,956)		(298,956)
Outside Services	244,718	**4h**		5,685	250,403		250,403
Indirect Allocation Intercompany	1,502,054	**4i**	10,634.00	35,140	1,547,828		1,547,828
Injuries & Damages	317,668	**4j**		7,379	325,048		325,048
Pension	(1,245,933)	**4k**		-	(1,245,933)		(1,245,933)
Health Insurance	1,012,591			23,522	1,036,113		1,036,113
Employee Benefits	(1,040,404)			(24,169)	(1,064,573)		(1,064,573)
OPEB's	(1,357,209)	**4l**		-	(1,357,209)		(1,357,209)
Other Employee Benefits	289,163	**4m**		6,717	295,880		295,880
Regulatory Commission Exp	200,985	**4n**		4,669	205,654		205,654
Maint of General Plant	170,337			3,957	174,294		174,294
Other Expenses	(135,033)	**4o**		(3,137)	(138,170)		(138,170)
Productivity	(30,858)	**4p**	(1,245)	-	(32,103)		(32,103)
Rents	(4,021)			(93)	(4,115)		(4,115)
Low Income Program	626,123	**4q**	79,476	-	705,599		705,599
Arrears Management Program	73,912	**4r**		-	73,912		73,912
Sub Total - Departmental	$ 7,870,664		$ 205,684	$ 100,413	$ 8,176,761	$ 8,226	$ 8,184,987
TOTAL	**$ 7,870,664**		**$ 205,684**	**$ 100,413**	**$ 8,176,761**	**$ 8,226**	**$ 8,184,987**

Liberty Utilities (St. Lawrence Gas) Corp.
PSC Case No. 24-G-0668
Taxes Other Than Income Taxes
For the Rate Year Ending October 31, 2028
(Whole Dollars)

Schedule 3

	Rate Year Ending October 31, 2027	Adj. #	Rate Year 3 Adjustments	Rate Year 3 As Adjusted for Joint Proposal
Taxes Other Than Income Taxes				
Payroll Tax	$ 414,780	**7a**	$ 9,654	$ 424,434
Property Tax	3,326,539	**7b**	289,961	$ 3,616,500
Total Taxes Other Than Income Taxes	$ 3,741,319		$ 299,615	$ 4,040,934

Liberty Utilities (St. Lawrence Gas) Corp.
PSC Case No. 24-G-0668
Income Taxes
For the Rate Year Ending October 31, 2028
(Whole Dollars)

Schedule 4

	Rate Year Ending October 31, 2027	Adj. #	Rate Year 3 Adjustments	Rate Year 3 As Adjusted for Joint Proposal
Operating Income Before Income Taxes	$ 3,037,322		$ (948,579)	$ 3,936,804
Operating Income Adjustments:				
Interest Expense	$ (1,532,279)		$ (160,191)	$ (1,692,470)
Taxable Income	1,505,043		$ (1,108,770)	$ 2,244,335
State Income Tax Rate	6.50%		6.50%	6.50%
Total State Income Taxes	$ 97,828	**9**	$ (72,070)	$ 145,882
Federal Taxable Income before State Tax Deduction	$ 1,505,043		$ (1,108,770)	$ 2,244,335
Adjust: State Tax Deduction	(97,828)		72,070	(145,882)
Income Subject to Federal Income Tax	$ 1,407,215		$ (1,036,700)	$ 2,098,453
Federal Income Tax Rate	21%		21%	21%
Federal Income Taxes	$ 295,515	**8b**	$ (217,707)	$ 440,675
Adjust: Amortization of EADIT	(59,615)	**8a**	-	$ (59,615)
Total Federal Income Taxes	$ 235,900		$ (217,707)	$ 381,060
Total Income Taxes	$ 333,728		$ (289,777)	$ 526,941

Liberty Utilities (St. Lawrence Gas) Corp.
PSC Case No. 24-G-0668
Summary of Rate Base
For the Rate Year Ending October 31, 2028
(Whole Dollars)

Schedule 6

	Rate Year Ending October 31, 2027	Adj. #	Rate Year 3 Adjustments	Rate Year 3 As Adjusted for Joint Proposal
Utility Plant	$ 107,063,787	**10a**	$ 10,455,733	$ 117,519,520
Depreciation Reserve	(43,786,471)	**10b**	(3,474,624)	(47,261,095)
Net Utility Plant	$ 63,277,316		$ 6,981,109	$ 70,258,425
Accumulated Deferred Income Taxes	$ (3,014,692)	**10c**	$ (883,951)	$ (3,898,643)
Regulatory Liability Tax Reform	(1,228,706)	**10g**	80,710	(1,147,996)
Unamortized Deferrals	509,597	**10d**	(339,731)	169,866
Working Capital				
Materials and supplies	$ 559,627		$ -	$ 559,627
Prepayments	1,322,503		-	1,322,503
O&M Cash Allowance (1/8 O&M exp)	902,876	**10e**	38,102	940,978
Subtotal Working Capital	$ 2,785,006		$ 38,102	$ 2,823,108
Subtotal Avg. Before EBCAP Adj.	$ 62,328,522		$ 5,876,239	$ 68,204,761
Excess Earnings Base Adjustment	$ (4,287,654)	**10f**	$ 1,429,218	$ (2,858,436)
Total Rate Base	**$ 58,040,867**		**$ 7,305,457**	**$ 65,346,324**

Liberty Utilities (St. Lawrence Gas) Corp.
PSC Case No. 24-G-0668
Depreciation and Amortization of Regulatory Deferrals
For the Rate Year Ending October 31, 2028
(Whole Dollars)

Schedule 7

	Rate Year Ending October 31, 2027	Adj. #	Rate Year 3 Adjustments	Rate Year 3 As Adjusted for Joint Proposal
Depreciation Expense	$ 2,637,394	**6**	$ 455,475	$ 3,092,869
Amortization Expense	1,065,791			1,065,791
Total Depreciation & Amortization Expense	$ 3,703,185		$ 455,475	$ 4,158,660
Summary of Amortization of Regulatory Deferrals				
Amortization of Regulatory Deferrals				
Rate Case Expense 24-G-0668	$ 326,713	**5a**	$ -	$ 326,713
Other Regulatory Liability - Low Income 21-G-0577 Deferral	(42,655)	**5b**		(42,655)
EAP	0			0
Property Tax 21-G-0577 Deferral	(91,107)			(91,107)
NRAs CY 2023	-			-
Gas Safety PRA Deferral	-	**5c**		-
Gas Safety NRA Deferral	-	**5d**		-
Untimely Filing NRA Deferral	(29,305)	**5e**		(29,305)
LTP Deferral	296,290	**5f**		296,290
	$ 459,937		$ -	$ 459,937

Liberty Utilities (St. Lawrence Gas) Corp.
PSC Case No. 24-G-0668
Interest Deduction
For the Rate Year Ending October 31, 2028
(Whole Dollars)

Schedule 8

	Rate Year Ending October 31, 2027	Rate Year 3 Adjustments	Rate Year 3 As Adjusted for Joint Proposal
Avg Rate Base Per Books	$ 62,328,522	$ 5,876,239	$ 68,204,761
Less: Excess Earnings Adj (EBCAP)	4,287,654	(1,429,218)	$ 2,858,436
	$ 58,040,867	$ 7,305,457	$ 65,346,324
Weighted Cost of LTD Debt	0.00%	-0.05%	2.55%
Weighted Cost of Cust Deposits	0.00%	0.00%	0.04%
	0.00%	-0.05%	2.59%
Total Income Tax Interest Deduction	**$ -**	**$ 160,191**	**$ 1,692,470**

Liberty Utilities (St. Lawrence Gas) Corp.
PSC Case No. 24-G-0668
Working Capital
For the Rate Year Ending October 31, 2028
(Whole Dollars)

Schedule 9

Description	Rate Year Ending October 31, 2027	Rate Year 3 Adjustments	Rate Year 3 As Adjusted for Joint Proposal
Total O&M Expense	$ 7,861,284	$ 315,477	$ 8,176,761
Remove Major Non-Cash Items Included in O&M Expense:			
Uncollectibles	$ (178,345)	$ (10,662)	$ (189,008)
Amortization of Regulatory Deferrals	(459,937)	-	(459,937)
Subtotal	$ (638,282)	$ (10,662)	$ (648,944)
Add Major Cash Items Not Included in O&M Expense:			
Other	$ -	$ -	$ -
Subtotal	$ -	$ -	$ -
Total Adjustments	$ (638,282)	$ (10,662)	$ (648,944)
Adjusted O&M Expense	$ 7,223,002	$ 304,815	$ 7,527,817
Departmental Cash Allowance - 1/8 (45 days)	$ 902,875	$ 38,102	$ 940,977

Liberty Utilities (St. Lawrence Gas) Corp.
PSC Case No. 24-G-0668
Summary of Adjustments
For the Rate Year Ending October 31, 2028
(Whole Dollars)

Schedule 10
Page 1 of 2

Adj. 1	**Operating Revenues**		
	Gas Revenue		
	To reflect RY3 sales forecast	$ 256,233	**$ 256,233**
Adj. 2	**Purchased Gas Costs**		
	To adjust purchased gas tracking RY3 sales forecast	$ 141,062	**$ 141,062**
Adj. 3	**Revenue Taxes**		
	To adjust revenue tax tracking RY3 sales forecast	$ 2,562	**$ 2,562**
Adj. 4	**Operating and Maintenance Expenses**		
	Inflation		
	To increase inflation pool items by a general inflation factor of 2.23%	$ 100,413	**$ 100,413**
a.	**Direct Labor**		
	To increase labor forecast by weighted average of wage increases	$ 115,537	**$ 115,537**
b.	**Productivity Expense**		
	To reflect the Commission standard 1% productivity adjustment	$ (1,245)	**$ (1,245)**
c.	**Low Income Program**		
	To reflect RY3 Low Income Program Budget	$ 79,476	**$ 79,476**
d.	**Indirect Allocation Intercompany**		
	To reflect RY3 cybersecurity O&M	$ 10,634	**$ 10,634**
	Total Operating and Maintenance Expense Adjustment		**$ 304,815**

Liberty Utilities (St. Lawrence Gas) Corp.
PSC Case No. 24-G-0668
Summary of Adjustments
For the Rate Year Ending October 31, 2028
(Whole Dollars)

Schedule 10
Page 2 of 2

Adj. 6		**Depreciation Expense**		
		To adjust depreciation expense tracking RY3 gas utility plant anad depreciation rates	$ 455,475	**$ 455,475**
Adj. 7		**Taxes Other Than Revenue & Income Taxes**		
	a.	**Property Taxes**		
		To reflect RY3 Property Tax forecast	$ 289,961	**$ 289,961**
	b.	**Payroll Taxes**		
		To reflect RY3 Payroll Tax forecast	$ 9,654	**$ 9,654**
Adj. 8		**Federal Income Taxes**		
		To adjust RY3 Federal Income taxes tracking RY3 adjustments	$ (217,707)	**$ (217,707)**
Adj. 9		**State Income Taxes**		
		To adjust RY3 State Income taxes tracking RY3 adjustments	$ (72,070)	**$ (72,070)**
		Total Current Income Tax Adjustments		**$ (289,777)**
Adj. 10		**Rate Base**		
	a.	**Utility Plant**		
		To adjust Utility Plant to reflect RY3 forecast	$ 10,455,733	**$ 10,455,733**
	b.	**Accumulated Depreciation**		
		To adjust Accumulated Depreciation to reflect RY3 forecast	$ (3,474,624)	**$ (3,474,624)**
		Total Net Utility Plant Adjustment		**$ 6,981,109**
	c.	**Accumulated Deferred Income Taxes (ADIT)**		
		To adjust RY3 ADIT	$ (883,951)	**$ (883,951)**
	d.	**Unamortized Deferrals**		
		To adjust RY3 unamortized deferral balance	$ (339,731)	**$ (339,731)**
	e.	**Working Capital**		
		To adjust working capital to tracking RY3 O&M adjustments	$ 38,102	**$ 38,102**
	f.	**Excess Earnings Base (EB/CAP)**		
		To adjust the RY1 EBCAP Adjustment by 50%	$ 1,429,218	**$ 1,429,218**
	g.	**Regulatory Liability Tax Reform**		
		To adjust RY3 regulatory liability tax reform unamortized balance	$ 80,710	**$ 80,710**
		Total Rate Base Adjustments		**$ 7,305,457**

Rate Change Levelization Reconciliation
Levelization and Revenue Impact Summary
For the Rate Years Ending October 31, 2026, October 31, 2027, and October 31, 2028

Total Revenue Impacts - (Non-Levelized)

	Revenue Requirement Increase	Total Revenue %	Delivery %
RY1	$ 399,729	0.9%	2.2%
RY2	1,876,203	4.2%	10.0%
RY3	1,645,275	3.5%	7.9%
Total	$ 6,596,868		

Total Revenue Impacts - (Levelized - Interest)

	Revenue Requirement Increase	Total Revenue %	Delivery %
RY1	$ 1,064,511	2.4%	5.82%
RY2	1,093,427	2.4%	5.64%
RY3	1,123,626	2.4%	5.49%
Total	$ 6,504,013		

Interest $ (92,855)

Rate Change Levelization Reconciliation
Revenue Requirement levelization
For the Rate Years Ending October 31, 2026, October 31, 2027, and October 31, 2028

	Rate Year 1 TME 10/31/2026	Rate Year 2 TME 10/31/2027	Rate Year 3 TME 10/31/2028	Cumulative
Delievery Revenue	$ 18,301,789	$ 18,809,054	$ 20,778,684	
Commodity	16,265,227	16,396,738	16,537,800	
GRT	462,894	469,347	490,667	
ESCO Commodity	9,237,279	9,237,279	9,237,279	
Total Revenues Before Increase	$ 44,267,188	$ 44,912,417	$ 47,044,429	
Revenue Requirement	399,729	1,876,203	1,645,275	**$ 6,596,868**
Total Revenues Before Increase	44,267,188	44,912,417	47,044,429	
Pre-Levelization Total Revenue Increase %	0.9%	4.2%	3.5%	

Rate Change Levelization Reconciliation
Revenue Impact Levelization
For the Rate Years Ending October 31, 2026, October 31, 2027, and October 31, 2028

	Rate Year 1 TME 10/31/2026	Rate Year 2 TME 10/31/2027	Rate Year 3 TME 10/31/2028	Cumulative
Delievery Revenue	$ 18,301,789	$ 19,381,255	$ 20,490,409	
Commodity	16,265,227	16,396,738	16,537,800	
GRT	462,894	469,347	490,667	
ESCO Commodity	9,237,279	9,237,279	9,237,279	
Total Revenues Before Increase	$ 44,267,188	$ 45,484,618	$ 46,756,154	
Revenue Requirement	399,729	1,876,203	1,645,275	**6,596,868**
Total Revenue Before Revenue Requirement Increase	$ 44,267,188	$ 45,484,618	$ 46,756,154	
Levelization %	2.4%	2.4%	2.4%	
Delivery Rate Increase - Post Levelization	$ 1,079,467	$ 1,109,154	$ 1,140,161	**6,596,868**

Rate Change Levelization Reconciliation
Revenue Impact Levelization with Interest
For the Rate Years Ending October 31, 2026, October 31, 2027, and October 31, 2028

			Rate Year 1 TME 10/31/2026	Rate Year 2 TME 10/31/2027	Rate Year 3 TME 10/31/2028	Cumulative
Delievery Revenue			$ 18,301,789	$ 19,366,299	$ 20,459,727	
Commodity			16,265,227	16,396,738	16,537,800	
GRT			462,894	469,347	490,667	
ESCO Commodity			9,237,279	9,237,279	9,237,279	
Total Revenues Before Increase			$ 44,267,188	$ 45,469,662	$ 46,725,472	
Revenue Requirement			399,729	1,876,203	1,645,275	**6,504,013**
Interest	$	(92,855)				
Total Revenue Before Revenue Requirement Increase			$ 44,267,188	$ 45,469,662	$ 46,725,472	
Levelization %			2.4%	2.4%	2.4%	
Delivery Rate Increase - Post Levelization			$ 1,064,511	$ 1,093,427	$ 1,123,626	**6,504,013**

Rate Change Levelization Reconciliation
Revenue Levelization Interest Calculation
For the Rate Years Ending October 31, 2026, October 31, 2027, and October 31, 2028

	Rate Year 1 TME 10/31/2026	Rate Year 2 TME 10/31/2027	Rate Year 3 TME 10/31/2028	Cumulative
Delievery Revenue	$ 18,301,789	$ 19,366,299	$ 20,459,727	
Commodity	16,265,227	16,396,738	16,537,800	
GRT	462,894	469,347	490,667	
ESCO Commodity	9,237,279	9,237,279	9,237,279	
Total Revenues Before Increase	$ 44,267,188	$ 45,469,662	$ 46,725,472	
Revenue Requirement	399,729	1,876,203	1,645,275	**6,596,868**
Total Revenues Before Increase	44,267,188	45,469,662	46,725,472	
Pre-Levelization Revenue Increase %	0.9%	4.1%	3.5%	
Delievery Rate Increase - Post Levelization	$ 1,079,467	$ 1,109,154	$ 1,140,161	
Carrying Costs Calculation				
Starting Levelization Deferral	$ -	$ (691,662)	$ (627,086)	
Levelization Deferral	(679,738)	87,312	592,426	
Accrued Carrying Costs	(11,925)	(22,736)	(11,609)	
Ending Levelization Deferral	$ (691,662)	$ (627,086)	$ (46,269)	
Average Levelization Deferral	(339,869)	(648,006)	(330,873)	
Other Customer Capital Rate (interest) - 4.75%	4.75%	4.75%	4.75%	
Tax Rate	26.14%	26.14%	26.14%	
Accrued Carrying Costs	$ (11,925)	$ (22,736)	$ (11,609)	**(92,855)** Total Interest

Rate Change Levelization Reconciliation
Make Whole
For the Rate Years Ending October 31, 2026, October 31, 2027, and October 31, 2028

Rate Year 1 Levelized Revenue Requirement Increase $ 1,064,511

Make-Whole to be recovered through a surcharge

		% of Total Annual Revenue
New Rates Effective:	2/1/2026	
Rate Year Commencing:	11/1/2025	100.00%
Months Company to be Made-Whole	3 Months	35.41%

Amount Company to be Made-Whole, and recovered via surcharge **$ 376,902**

	SC1	SC2	SC2L	SC3	Total
Rate Year Surcharge Revenue per Service Class					
RY1 (2/1/2026-10/31/2027)	$ 90,756	$ 32,326	$ 7,935	$ 10,836	$ 141,853
RY2	$ 148,878	$ 54,607	$ 13,398	$ 18,166	$ 235,049
TOTAL	$ 239,634	$ 86,933	$ 21,332	$ 29,003	$ 376,902
Rate Year Volumes (Therms)					
RY1 (2/1/2026-10/31/2027)	9,505,883	8,356,481	5,702,015	20,795,231	44,359,610
RY2	15,167,845	13,103,596	9,151,835	28,836,075	66,259,351
Make Whole Surcharge ($/Therm)*					
RY1 (2/1/2026-10/31/2027)	$ 0.00955	$ 0.00387	$ 0.00139	$ 0.00052	
RY2	$ 0.00982	$ 0.00417	$ 0.00146	$ 0.00063	

Delivery Revenues**		RY1 (2/1/2026-10/31/2026)	RY2	Total
	SC1	$7,108,823	$11,661,528	$18,770,351
	SC2	$2,532,034	$4,277,325	$6,809,359
	SC2L	$621,528	$1,049,423	$1,670,951
	SC3	$848,810	$1,422,941	$2,271,751
	Total Sales	$11,111,195	$18,411,217	$29,522,412
		37.6%	62.4%	100%
Service Class % of Delivery Revenue**				
	SC1	64.0%	63.3%	
	SC2	22.8%	23.2%	
	SC2L	5.6%	5.7%	
	SC3	7.6%	7.7%	

*For illustrative purposes of how Make Whole Surcharge will be calculated
**How Make Whole was allocated amongst each Service Classification

Rate Change Levelization Reconciliation
Amount to Reflect in New Tariffs to Effectuate End of RY3
For the Rate Years Ending October 31, 2026, October 31, 2027, and October 31, 2028

Base Revenues Before Increase	RR Increase (Non Levelized	Total
$ 35,029,909	$ 399,729	
$ 35,669,070	$ 1,876,203	
$ 37,801,506	$ 1,645,275	**$ 39,446,781**

RY1 Base Revenues Before Increase	RR Increase (Non Levelized)	RY2 Sales	RY2 Base Revenues Before Increase	RR Increase (Non Levelized)	RY3 Sales	RY3 Base Revenues Before Increase	RY3 Base Revenues Before Increase	TOTAL REVENUE REQUIREMENT
$ 35,029,909	$ 399,729	$ 239,432	$ 35,669,070	$ 1,876,203	$ 256,233	$ 37,801,506	$ 1,645,275	**$ 39,446,781**

LEVELIZED

RY1 Base Revenues Before Increase	RY1 Levelized Increase	RY2 Sales Priced out at RY1 Rates	RY1 Levelized Revenue Requirement	RY2 Levelized Increase	RY3 Sales Priced out at RY2 Rates	RY3 Base Revenues Before Increase	RY3 Base Revenues Before Increase	TOTAL REVENUE REQUIREMENT
$ 35,029,909	$ 1,064,511	$ 247,559	$ 36,341,979	$ 1,093,427	$ 273,863	$ 37,709,269	$ 1,123,626	**$ 38,832,896**
							Difference	**$ 613,886**

Gas Sales Forecast

	Rate Year 1		Rate Year 2		Rate Year 3		Rate Year 4	
	Customers	Dth	Customers	Dth	Customers	Dth	Customers	Dth
SC1 Residential Sales General	272	5,176	265	5,043	257	4,898	257	4,898
SC1 Residential Sales Heat	15,202	1,464,496	15,324	1,464,646	15,447	1,464,796	15,447	1,464,796
SC1 Residential Transportation	65	47,870	66	47,096	67	46,511	67	46,511
SC1 Residential Total	15,539	1,517,542	15,656	1,516,785	15,771	1,516,205	15,771	1,516,205
SC2 Commercial Sales General	74	55,194	74	55,297	74	55,401	74	55,401
SC2 Commercial Sales Heat	1,660	592,673	1,695	605,281	1,732	618,821	1,732	618,821
SC2 Commercial Transportation	196	637,291	200	649,781	204	663,187	204	663,187
SC2 Commercial Total	1,930	1,285,157	1,969	1,310,360	2,010	1,337,409	2,010	1,337,409
SC2L Commercial Sales Heat	6	481,935	6	491,416	6	501,590	6	501,590
SC2L Commercial Sales Transportation	4	415,593	4	423,768	4	432,540	4	432,540
SC2L Commercial Total	10	897,528	10	915,183	10	934,130	10	934,130
SC2 Commercial Grand Total	1,940	2,182,685	1,979	2,225,543	2,020	2,271,539	2,020	2,271,539
SC3 Industrial Firm Sales	1	48,944	1	48,944	1	48,944	1	48,944
SC3 Industrial Firm Transportation	10	2,834,664	10	2,834,664	10	2,834,664	10	2,834,664
SC3 Industrial Total	11	2,883,608	11	2,883,608	11	2,883,608	11	2,883,608
SC4 Interruptible Sales	3	98,509	3	98,509	3	98,509	3	98,509
SC4 Interruptible Transportation	6	535,067	6	535,067	6	535,067	6	535,067
SC4 Interruptible Total	9	633,576	9	633,576	9	633,576	9	633,576
Cogeneration	2	280,055	2	280,055	2	280,055	2	280,055
TOTAL	17,501	7,497,466	17,656	7,539,567	17,814	7,584,983	17,814	7,584,983

Delivery Revenue

	Current Rates		Proposed Rates		Proposed Rates		Proposed Rates		Proposed Rates	
	Rate Year 4		Rate Year 1		Rate Year 2		Rate Year 3		Rate Year 4	
	Dth	Distribution Margin	Dth	Distribution Margin	Dth	Distribution Margin	Dth	Distribution Margin	Margin	Distribution Margin
Sales										
SC-1 Residential	1,469,672	$ 10,132,038	1,469,672	$ 10,742,706	1,469,689	$ 11,387,498	1,469,694	$ 12,095,475	1,469,694	$ 12,467,510
SC-2 Commercial	647,866	$ 2,208,838	647,866	$ 2,371,109	660,579	$ 2,574,939	674,222	$ 2,780,921	674,222	$ 2,864,036
SC-2L Commercial	481,935	$ 493,284	481,935	$ 529,523	491,416	$ 575,613	501,590	$ 621,741	501,590	$ 641,030
SC-3 Industrial Firm	48,944	$ 43,695	48,944	$ 47,481	48,944	$ 51,070	48,944	$ 53,661	48,944	$ 54,811
SC-4 Industrial Interruptible	98,509	$ 495,207	98,509	$ 495,207	98,509	$ 495,207	98,509	$ 495,207	98,509	$ 495,207
Total Sales	2,746,926	$ 13,373,062	2,746,926	$ 14,186,025	2,769,136	$ 15,084,328	2,792,959	$ 16,047,005	2,792,959	$ 16,522,594
Transportation										
SC-1 Residential	47,870	$ 247,769	47,870	$ 262,703	47,096	$ 274,030	46,511	$ 286,884	46,511	$ 295,343
SC-2 Commercial	637,291	$ 1,442,823	637,291	$ 1,548,819	649,781	$ 1,702,386	663,187	$ 1,845,026	663,187	$ 1,904,061
SC-2L Commercial	415,593	$ 403,075	415,593	$ 432,686	423,768	$ 473,809	432,540	$ 512,650	432,540	$ 528,220
SC-3 Industrial Firm	2,834,664	$ 1,165,584	2,834,664	$ 1,266,591	2,834,664	$ 1,371,871	2,834,664	$ 1,471,420	2,834,664	$ 1,526,654
SC-4 Industrial Interruptible	535,067	$ 352,037	535,067	$ 352,037	535,067	$ 352,037	535,067	$ 352,037	535,067	$ 352,037
Total Transportation	4,470,485	$ 3,611,288	4,470,485	$ 3,862,835	4,490,376	$ 4,174,134	4,511,969	$ 4,468,018	4,511,969	$ 4,606,314
Cogeneration	280,055	$ 40,866	280,055	$ 40,866	280,055	$ 40,866	280,055	$ 40,866	280,055	$ 40,866
Total	**7,497,466**	**$ 17,025,215**	**7,497,466**	**$ 18,089,726**	**7,539,567**	**$ 19,299,327**	**7,584,983**	**$ 20,555,888**	**7,584,983**	**$ 21,169,774**
MFC		$ 275,466		$ 309,708		$ 309,708		$ 309,708		$ 309,708
DRA		$ 215,589		$ 182,988		$ 182,988		$ 182,988		$ 182,988
Revenue Tax		$ 462,894		$ 462,894		$ 462,894		$ 462,894		$ 462,894
Total Surcharges		**$ 953,949**		**$ 955,590**		**$ 955,590**		**$ 955,590**		**$ 955,590**
Total Gas Costs		$ 16,265,227		$ 16,265,227		$ 16,396,738		$ 16,537,800		$ 16,537,800
487 - Forfeited Discounts		$ 181,791		$ 181,791		$ 181,791		$ 181,791		$ 181,791
488 - Misc. Service Revenues		$ 14,206		$ 14,206		$ 14,206		$ 14,206		$ 14,206
495 - Other Gas Revenue		$ 579,134		$ 579,134		$ 579,134		$ 579,134		$ 579,134
493 - Rents		$ 10,388		$ 10,388		$ 10,388		$ 10,388		$ 10,388
Total Misc. Revenue		**$ 17,050,746**		**$ 17,050,746**		**$ 17,182,257**		**$ 17,323,319**		**$ 17,323,319**
Total Revenue		**$ 35,029,909**		**$ 36,096,063**		**$ 37,437,174**		**$ 38,834,797**		**$ 39,448,683**

Depreciation Rates and Depreciation Factors

	DEPRECIABLE GROUP	Current Rate	Proposed Rate	Average Service Life	Net Salvage	Curve
	DISTRIBUTION PLANT					
374.00	LAND RIGHTS	1.43	1.43%	70	0%	SQ
375.00	STRUCTURES AND IMPROVEMENTS	2.50	2.63%	40	-5%	R4
376.10	MAINS - STEEL	1.66	1.86%	70	-30%	R3
376.20	MAINS - PLASTIC	1.84	1.86%	70	-30%	R3
378.00	MEASURING AND REGULATING STATION EQUIPMENT	2.00	2.18%	55	-20%	R3
380.10	SERVICES	2.17	2.33%	60	-40%	R2.5
380.20	SERVICES - PLASTIC	2.17	2.33%	60	-40%	R2.5
381.00	METERS	2.75	2.63%	40	-5%	R2.5
382.00	METER INSTALLATIONS	2.75	2.63%	40	-5%	R2.5
383.00	HOUSE REGULATORS	2.84	2.63%	40	-5%	R1
384.00	HOUSE REGULATOR INSTALLATIONS	2.70	2.50%	40	0%	R1
385.00	INDUSTRIAL MEASURING AND REGULATING STATION EQUIPMENT	2.38	2.33%	45	-5%	R1.5
387.00	OTHER EQUIPMENT	5.50	5.25%	20	-5%	R3
	GENERAL PLANT					
390.00	STRUCTURES AND IMPROVEMENTS	2.50	2.63%	40	-5%	R2.5
391.00	OFFICE FURNITURE AND EQUIPMENT	4.00	5.00%	20	0%	SQ
393.00	STORES EQUIPMENT	5.00	4.00%	25	0%	SQ
394.00	TOOLS, SHOP AND GARAGE EQUIPMENT	4.00	4.00%	25	0%	SQ
395.00	LABORATORY EQUIPMENT	4.00	5.00%	20	0%	SQ
397.00	COMMUNICATION EQUIPMENT	6.67	6.67%	15	0%	SQ
398.00	MISCELLANEOUS EQUIPMENT	5.00	5.00%	20	0%	SQ
	NONDEPRECIABLE AND NOT STUDIED PLANT					
301.00	ORGANIZATION	Indiv.	Indiv.	NA	NA	NA
302.00	FRANCHISES AND CONSENTS	Indiv.	Indiv.	NA	NA	NA
303.00	MISCELLANEOUS INTANGIBLE PLANT	Indiv.	Indiv.	NA	NA	NA
389.00	LAND	Indiv.	Indiv.	NA	NA	NA
391.10	OFFICE FURNITURE AND EQUIPMENT - COMPUTERS	Indiv.	20.00%	5	0%	TBD
392.00	TRANSPORTATION EQUIPMENT	Indiv.	8.20%	10	18%	TBD
396.00	POWER OPERATED EQUIPMENT	Indiv.	7.50%	10	25%	TBD

Liberty Utilities (St. Lawrence Gas) Corp
2025 Capital Budget

Calendar Year 2025 Capital Expenditure Budget

Appendix F
Schedule 1

2025 CAPEX Budget		Description	Jan-25	Feb-25	Mar-25	Apr-25	May-25	Jun-25	Jul-25	Aug-25	Sep-25	Oct-25	Nov-25	Dec-25	Total
303															
Computer Software	$873,000	Corporate IT	$72,750	$72,750	$72,750	$72,750	$72,750	$72,750	$72,750	$72,750	$72,750	$72,750	$72,750	$72,750	$873,000
	$200,000	IEDR	$16,667	$16,667	$16,667	$16,667	$16,667	$16,667	$16,667	$16,667	$16,667	$16,667	$16,667	$16,663	$200,000
	$72,344	PSMS			$18,086			$18,086			$18,086			$18,086	$72,344
	$62,600	Leak Survey Software			$15,650			$15,650			$15,650			$15,650	$62,600
	$28,000	Gas Planning Program			$7,000			$7,000			$7,000			$7,000	$28,000
374															
Easements	$57,200	Misc. Easements				$8,171	$8,171	$8,171	$8,171	$8,171	$8,171	$8,171			$57,200
376															
Mains	$416,783	Misc. Main Extensions					$69,464	$69,464	$69,464	$69,464	$69,464	$69,464			$416,783
	$1,424,102	NYS 310 8' Main (DOT mandated project)									$1,424,102				$1,424,102
	$71,515	Center St Culvert Repair - Mandated DOT Project						$71,515							$71,515
	$1,568,591	Croghan DOT Project							$1,568,591						$1,568,591
	$8,459	Reinforcement - Oburg Caroline St								$8,459					$8,459
	$26,532	Reinforcement - Potsdam Garden St									$26,532				$26,532
	$41,563	Reinforcement - Canton State St										$41,563			$41,563
378															
Measuring & Regulating Stations	$87,999	RTU						$66,000	$22,000						$87,999
	$0	Station Security Upgrades (Fencing)						$0	$0						$0
380															
Services	$703,722	1/2"-2"PE					$63,975	$95,962	$95,962	$95,962	$95,962	$95,962	$95,962	$63,975	$703,722
381															
Meters	$332,059	Meter Purchases for Inventory							$332,059						$332,059
383															
House Regulators	$24,750	Regulator Purchases for Inventory							$24,750						$24,750
382/384															
Meter/Regulator Installations	$77,697	Residential/Commercial Mtr Sets - Growth		$2,500	$2,500	$2,500	$2,500	$9,500	$9,500	$9,500	$9,500	$9,500	$9,500	$10,697	$77,697
	$213,100	Residential/Commercial Mtr Sets - Replacement	$15,258	$15,258	$25,258	$25,258	$25,258	$15,258	$15,258	$15,258	$15,258	$15,258	$15,258	$15,262	$213,100
385															
Ind. Measuring & Regulating Stations	$81,145	Industrial Mtr Sets						$20,286	$20,286	$20,286	$20,287				$81,145
390															
Building and Structures	$59,400	HVAC (5)					$59,400								$59,400
	$39,204	Parking lot Security Light Upgrade									$39,204				$39,204
	$90,525	Engineering Remodel (Floor and walls)		$90,525											$90,525
	$203,976	Boiler Upgrade					$203,976								$203,976
	$11,821	Lactation Room				$11,821									$11,821
391.1															
Computer Equipment	$5,280	APC Battery Backup					$5,280								$5,280
	$46,200	Printer upgrades							$46,200						$46,200
	$22,000	IT Equipment - Laptop/iPad replacements										$22,000			$22,000
394															
Tools & Work Equipment	$17,131	Waker Neuson Plate Tamper (GS)		$17,131											$17,131
	$66,000	Fusion Tools (scrapers, cold rings, machines, etc.) (GS)			$66,000										$66,000
	$66,000	Tapping/Stopping Equipment (valves, cutters, stoppers, machines) (GS)			$66,000										$66,000
	$22,000	Misc. tool replacement as needed (GS)						$11,000			$11,000				$22,000
	$48,400	HFI's (2) (RM)			$48,400										$48,400
	$15,990	GMI's (2) (RG)			$15,990										$15,990
	$7,606	PGM's (4) (RG)		$7,606											$7,606
	$6,975	Metal Detection (3) (RG)		$6,975											$6,975
	$0	Sewer Crawler								$0					$0
395															
Lab Equipment	$11,000	Calibration equipment							$11,000						$11,000
396															
Power Operated Heavy Equipment	$32,076	8x16 Utility Trailer			$32,076										$32,076
	$67,177	Stick Pipe Trailer				$67,177									$67,177
	$68,081	Attenuation Trailer						$68,081							$68,081
	7,278,001		**104,675**	**229,412**	**386,376**	**204,344**	**527,441**	**565,390**	**2,312,658**	**316,517**	**1,849,633**	**351,336**	**210,137**	**220,083**	**7,278,001**

Liberty Utilities (St. Lawrence Gas) Corp
2026 Capital Budget

Calendar Year 2026 Capital Expenditure Budget

2026 CAPEX Budget		Description	Jan-26	Feb-26	Mar-26	Apr-26	May-26	Jun-26	Jul-26	Aug-26	Sep-26	Oct-26	Nov-26	Dec-26	Total
303															
Computer Software	$844,000	Corporate IT	$70,333	$70,333	$70,333	$70,333	$70,333	$70,333	$70,333	$70,333	$70,333	$70,333	$70,333	$70,333	$844,000
	$250,000	IEDR	$20,833	$20,833	$20,833	$20,833	$20,833	$20,833	$20,833	$20,833	$20,833	$20,833	$20,833	$20,833	$250,000
	$25,365	AMR											$12,683	$12,683	$25,365
	$28,777	E Region Tech Services MOC Software						$28,777							$28,777
374															
Easements	$57,583	Misc. Easements	$4,799	$4,799	$4,799	$4,799	$4,799	$4,799	$4,799	$4,799	$4,799	$4,799	$4,799	$4,799	$57,583
376															
	$140,737	Heuvelton 6" Valve Replacement						$140,737							$140,737
	$419,577	Misc. Main Extensions (Entitlement)					$69,930	$69,930	$69,930	$69,930	$69,930	$69,930			$419,577
378															
Measuring & Regulating Stations	$88,589	RTU						$66,442	$22,147						$88,589
	$55,368	Station Upgrades - Paving						$27,684	$27,684						$55,368
	$221,474	Station Upgrades - Station Security Phase 1						$110,737	$110,737						$221,474
380															
Services	$805,046	1/2"-2"PE					$73,186	$109,779	$109,779	$109,779	$109,779	$109,779	$109,779	$73,186	$805,046
381															
Meters	$334,286	Meter Purchases for Inventory							$334,286						$334,286
	$2,002,609	AMR											$1,001,305	$1,001,305	$2,002,609
383															
House Regulators	$24,916	Regulator Purchases for Inventory							$24,916						$24,916
382/384															
Meter/Regulator Installations	$78,218	Residential/Commercial Mtr Sets - Growth	$6,518	$6,518	$6,518	$6,518	$6,518	$6,518	$6,518	$6,518	$6,518	$6,518	$6,518	$6,518	$78,218
	$214,528	Residential/Commercial Mtr Sets - Replacement	$17,877	$17,877	$17,877	$17,877	$17,877	$17,877	$17,877	$17,877	$17,877	$17,877	$17,877	$17,877	$214,528
385															
Ind. Measuring & Regulating Stations	$81,688	Industrial Mtr Sets			$20,422			$20,422			$20,422			$20,422	$81,688
390															
Building and Structures	$266,592	TBD - Building renovations and upgrades as needed			$66,648			$66,648			$66,648			$66,648	$266,592
391.1															
Computer Equipment	$73,972	TBD - Computer Hardware Replacement as needed			$18,493			$18,493			$18,493			$18,493	$73,972
	$224,312	AMR - IT Hardware											$112,156	$112,156	$224,312
392															
Transportation Equipment	$445,162	Ford Transit (3)			$445,162										$445,162
	$173,223	Truck						$173,223							$173,223
	$25,803	Sander for Truck #37 & Fisher Plow	$25,803												$25,803
	$483,802	Welding Truck										$483,802			$483,802
394															
Tools & Work Equipment	$290,562	TBD - Tool replacement as needed			$72,641			$72,641			$72,641			$72,641	$290,562
	$361,423	Sewer Cawler			$361,423										$361,423
395															
Lab Equipment	$11,074								$11,074						$11,074
396															
Power Operated Heavy Equipment	$166,643	T-24 Trailer (2)						$166,643							$166,643
	$13,439	York Rake w/hydraulic turn & remote kit									$13,439				$13,439
	$22,846	Kubota 74" Front Mount Snow blower									$22,846				$22,846
	$249,964	Ditchwitch Combo Trencher			$249,964										$249,964
	8,481,579		**146,164**	**120,361**	**1,355,114**	**120,361**	**263,476**	**1,192,516**	**830,913**	**300,069**	**514,558**	**783,871**	**1,356,283**	**1,497,894**	**8,481,579**

Calendar Year 2027 Capital Expenditure Budget

2027 CAPEX Budget		Description	Jan-27	Feb-27	Mar-27	Apr-27	May-27	Jun-27	Jul-27	Aug-27	Sep-27	Oct-27	Nov-27	Dec-27	Total
303															
Computer Software	$852,000	Corporate IT	$71,000	$71,000	$71,000	$71,000	$71,000	$71,000	$71,000	$71,000	$71,000	$71,000	$71,000	$71,000	$852,000
374															
Easements	$52,730	Misc. Easements	$4,394	$4,394	$4,394	$4,394	$4,394	$4,394	$4,394	$4,394	$4,394	$4,394	$4,394	$4,394	$52,730
376															
Mains	$0	Oswegatchie Main Replacement (System Reliability)						$0	$0						$0
Mains	$2,301,728	Winthrop Bridge Relay 8' Main (DOT mandated project)	$920,691	$920,691	$460,346										$2,301,728
	$384,216	Misc. Main Extensions (Entitlement)					$64,036	$64,036	$64,036	$64,036	$64,036	$64,036			$384,216
	$47,792	System Reliability						$23,896					$23,896		$47,792
378															
Measuring & Regulating Stations	$955,831	Station Painting					$159,305	$159,305	$159,305	$159,305	$159,305	$159,305			$955,831
	$95,583	Real time pressure monitors						$47,792	$47,792						$95,583
	$49,225	Station Upgrades - Paving						$24,613	$24,613						$49,225
	$196,901	Station Upgrades - Station Security Phase 2						$98,451	$98,451						$196,901
380															
Services	$737,198	1/2"-2"PE					$49,147	$122,866	$122,866	$122,866	$122,866	$122,866	$73,720		$737,198
381															
Meters	$306,113	Meter Purchases for Inventory							$306,113						$306,113
383															
House Regulators	$22,816	Regulator Purchases for Inventory							$22,816						$22,816
382/384															
Meter/Regulator Installations	$71,626	Residential/Commercial Mtr Sets - Growth	$5,969	$5,969	$5,969	$5,969	$5,969	$5,969	$5,969	$5,969	$5,969	$5,969	$5,969	$5,969	$71,626
	$196,448	Residential/Commercial Mtr Sets - Replacement	$16,371	$16,371	$16,371	$16,371	$16,371	$16,371	$16,371	$16,371	$16,371	$16,371	$16,371	$16,371	$196,448
	$1,870,010	AMR Installation					$311,668	$311,668	$311,668	$311,668	$311,668	$311,668			$1,870,010
385															
Ind. Measuring & Regulating Stations	$74,804	Industrial Mtr Sets			$18,701			$18,701			$18,701			$18,701	$74,804
390															
Building and Structures	$244,124	TBD - Building renovations and upgrades as needed			$61,031			$61,031			$61,031			$61,031	$244,124
391.1															
Computer Equipment	$67,738	TBD - Computer Hardware Replacement as needed			$16,934			$16,934			$16,934			$16,934	$67,738
392															
Transportation Equipment	$1,114,499	Vac Truck					$1,114,499								$1,114,499
	$159,662	Safety and Operations SUV (2)			$159,662										$159,662
	$271,763	Ford Transit (2)				$271,763									$271,763
	$317,247	Chevy Silverado (2)					$317,247								$317,247
394															
Tools & Work Equipment	$266,074	TBD - Tool replacement as needed			$66,519			$66,519			$66,519			$66,519	$266,074
395															
Lab Equipment	$10,140	Calibration equipment							$10,140						$10,140
396															
Power Operated Heavy Equipment	$152,598	Trailers (2)			$152,598										$152,598
	$189,408	Track loader Takeuchi			$189,408										$189,408
	11,008,275		**1,018,425**	**1,018,425**	**1,222,933**	**369,497**	**2,113,636**	**1,113,545**	**1,265,533**	**755,609**	**918,795**	**755,609**	**195,349**	**260,919**	**11,008,275**

Calendar Year 2028 Capital Expenditure Budget

2028 CAPEX Budget		Description	Jan-28	Feb-28	Mar-28	Apr-28	May-28	Jun-28	Jul-28	Aug-28	Sep-28	Oct-28	Nov-28	Dec-28	Total
303															
Computer Software	$900,000	Corporate IT	$75,000	$75,000	$75,000	$75,000	$75,000	$75,000	$75,000	$75,000	$75,000	$75,000	$75,000	$75,000	$900,000
374															
Easements	$64,277	Misc. Easements	$5,356	$5,356	$5,356	$5,356	$5,356	$5,356	$5,356	$5,356	$5,356	$5,356	$5,356	$5,356	$64,277
376															
Mains	$4,261,764	Oswegatchie Main Replacement (System Reliability)				$4,261,764									$4,261,764
	$0	Chateaugay Reinforcement – 4” Franklin to John St					$0								$0
	$468,354	Misc. Main Extensions (Entitlement)					$78,059	$78,059	$78,059	$78,059	$78,059	$78,059			$468,354
	$56,560	System Reliability						$28,280					$28,280		$56,560
378															
Measuring & Regulating Stations	$60,005	Station Upgrades - Paving						$30,002	$30,002						$60,005
	$240,020	Station Upgrades - Station Security Phase 3						$120,010	$120,010						$240,020
380															
Services	$898,633	1/2"-2"PE					$59,909	$149,772	$149,772	$149,772	$149,772	$149,772	$89,863		$898,633
381															
Meters	$373,147	Meter Purchases for Inventory							$373,147						$373,147
383															
House Regulators	$27,812	Regulator Purchases for Inventory							$27,812						$27,812
382/384															
Meter/Regulator Installations	$87,311	Residential/Commercial Mtr Sets - Growth	$7,276	$7,276	$7,276	$7,276	$7,276	$7,276	$7,276	$7,276	$7,276	$7,276	$7,276	$7,276	$87,311
	$239,467	Residential/Commercial Mtr Sets - Replacement	$19,956	$19,956	$19,956	$19,956	$19,956	$19,956	$19,956	$19,956	$19,956	$19,956	$19,956	$19,956	$239,467
385															
Ind. Measuring & Regulating Stations	$91,185	Industrial Mtr Sets			$22,796			$22,796			$22,796			$22,796	$91,185
390															
Building and Structures	$297,584	TBD - Building renovations and upgrades as needed			$74,396			$74,396			$74,396			$74,396	$297,584
391.1															
Computer Equipment	$82,572	TBD - Computer Hardware Replacement as needed			$20,643			$20,643			$20,643			$20,643	$82,572
392															
Transportation Equipment	$331,275	Ford Transit (2)			$331,275										$331,275
	$580,080	Chevy Silverado (3)				$580,080									$580,080
	$463,248	Int'l Weld/ Crew Truck										$463,248			$463,248
	$165,638	Van (Pool Vehicle)										$165,638			$165,638
	$97,313	Sales SUV					$97,313								$97,313
394															
Tools & Work Equipment	$324,341	TBD - Tool replacement as needed			$81,085			$81,085			$81,085			$81,085	$324,341
395															
Lab Equipment	$12,361	Calibration equipment							$12,361						$12,361
396															
Power Operated Heavy Equipment	$84,105	Trailers (3)			$84,105										$84,105
	$52,324	Welder (2)				$52,324									$52,324
	$188,566	2017 John Deere Excavator					$188,566								$188,566
	$265,953	Ditchwitch FX 60 Vacuum Excavator						$265,953							$265,953
	$6,032	Husqvarna Lawnmower			$6,032										$6,032
	$18,224	Sander			$18,224										$18,224
	10,738,150		**107,588**	**107,588**	**746,144**	**5,001,756**	**531,435**	**978,585**	**898,752**	**335,419**	**534,339**	**964,304**	**225,731**	**306,508**	**10,738,150**

Illustrative Net Plant Reconciliation Exclusive of Software, AMR, and Oswegatchie projects

Rate Year 1 Ending October 31, 2026

Line No.		Total Revenue Requirement Target	Total Gas Plant in Service (a)	Non-Interest Bearing CWIP (b)	Total Plant Including CWIP (c) = (a) + (b)	Reserve for Depreciation (d)	Gas Net Utility Plant in Service (e) = (c)+(d)	Gas Depreciation Expense (f)
1	Forecasted Net Plant	$ 8,023,631	$ 93,916,178	$ 2,987,608	$ 96,903,786	$ (40,753,990)	$ 56,149,796	$ 3,262,128 *
2	Less Plant Associated with Software	$ 1,875,187	$ 11,637,089	$ 96,595	$ 11,733,684	$ (1,562,072)	$ 10,171,612	$ 1,012,635
3	Less Plant Associated with AMR**		$ -	$ -	$ -	$ -	$ -	$ -
4	Less Plant Associated with Oswegatchie***		$ -	$ -	$ -	$ -	$ -	$ -
5								
6	Pre-Tax Weighted Average Cost of Capital						8.48%	
7								
8	Total Revenue Requirement Target****	$ 6,148,443					$ 3,898,950	$ 2,249,493
9								
10								
11								
12								
13								
14	Estimated Actual Results		$ 92,000,000	$ 2,000,000	$ 94,000,000	$ (38,000,000)	$ 56,000,000	$ 3,000,000 *
15	Estimated Software		$ 11,500,000	$ 90,000	$ 11,590,000	$ (1,600,000)	$ 9,990,000	$ 1,000,000
16	Estimated AMR		$ -	$ -	$ -	$ -	$ -	$ -
17	Estimated Oswegatchie							
18								
19	Pre-Tax WACC						8.48%	
20								
21	Total Revenue Requirement Actuals****	$ 5,901,648					$ 3,901,648	$ 2,000,000
22								
23	Actuals higher/(lower) than Target	$ (246,795)						
24	RY2 Higher/(lower) than Target	$ 286,506						
25	RY3 Higher/(lower) than Target	$ (205,008)						
26								
27	End of Rate Plan Total Reconciliation	$ (165,298)						
28								

29 * Depreciation Expense exclusive of capitalized portion of vehicles
30 ** Plant Associated with AMR is exclusive of AMR Software, which is included in the Software Plant above
31 *** Oswegatchie Main Replacement Plant will be removed similar to Lines 2 and 3 above when finalized
32 ****Targets and Actuals are reflected of total Net Plant less the excluded projects (Software, AMR, Oswegatchie)

Illustrative Net Plant Reconciliation

Rate Year 2 Ending October 31, 2027

Line No.		Total Revenue Requirement Target	Total Gas Plant in Service (a)	Non-Interest Bearing CWIP (b)	Total Plant Including CWIP (c) = (a) + (b)	Reserve for Depreciation (d)	Gas Net Utility Plant in Service (e) = (c)+(d)	Gas Depreciation Expense (f)	
1	Forecasted Net Plant	$ 9,119,723	$ 101,736,315	$ 5,327,472	$ 107,063,787	$ (43,786,472)	$ 63,277,316	$ 3,703,185	*
2	Less Plant Associated with Software	$ 2,104,653	$ 12,869,768	$ 77,315	$ 12,947,083	$ (2,674,849)	$ 10,272,234	$ 1,225,350	
3	Less Plant Associated with AMR**	$ 425,016	$ 2,226,921	$ 1,870,010	$ 4,096,931	$ (81,276)	$ 4,015,655	$ 81,276	
4	Less Plant Associated with Oswegatchie***								
5									
6	Pre-Tax Weighted Average Cost of Capital						8.56%		
7									
8	Total Revenue Requirement Target****	$ 6,590,054					$ 4,193,495	$ 2,396,559	
9									
10									
11									
12									
13									
14	Estimated Actual Results		$ 108,000,000	$ 7,932,000	$ 115,932,000	$ (38,000,000)	$ 77,932,000	$ 2,750,000	*
15	Estimated Software		$ 15,000,000	$ 90,000	$ 15,090,000	$ (1,600,000)	$ 13,490,000	$ 1,000,000	
16	Estimated AMR		$ 190,000	$ 3,910,000	$ 4,100,000	$ (15,000)	$ 4,085,000	$ 40,000	
17	Estimated Oswegatchie								
18									
19	Pre-Tax WACC						8.56%		
20									
21	Total Revenue Requirement Actuals****	$ 6,876,559					$ 5,166,559	$ 1,710,000	
22									
23	Actuals higher/(lower) than Target	$ 286,506							
24									
25									
26									
27									
28									

29 * Depreciation Expense exclusive of capitalized portion of vehicles
30 ** Plant Associated with AMR is exclusive of AMR Software, which is included in the Software Plant above
31 *** Oswegatchie Main Replacement Plant will be removed similar to Lines 2 and 3 above when finalized
32 ****Targets and Actuals are reflected of total Net Plant less the excluded projects (Software, AMR, Oswegatchie)

Illustrative Net Plant Reconciliation

Rate Year 3 Ending October 31, 2028

Line No.		Total Revenue Requirement Target	Total Gas Plant in Service (a)	Non-Interest Bearing CWIP (b)	Total Plant Including CWIP (c) = (a) + (b)	Reserve for Depreciation (d)	Gas Net Utility Plant in Service (e) = (c)+(d)	Gas Depreciation Expense (f)
1	Forecasted Net Plant	$ 10,221,962	$ 111,975,441	$ 5,544,080	$ 117,519,521	$ (47,261,095)	$ 70,258,425	$ 4,158,660
2	Less Plant Associated with Software	$ 2,260,198	$ 13,764,475	$ 74,167	$ 13,838,641	$ (3,858,858)	$ 9,979,783	$ 1,398,942
3	Less Plant Associated with AMR**	$ 473,113	$ 4,096,931	$ -	$ 4,096,931	$ (219,791)	$ 3,877,140	$ 138,515
4	Less Plant Associated with Oswegatchie***	$ 367,790	-	$ 4,261,764	$ 4,261,764	-	$ 4,261,764	-
5								
6	Pre-Tax Weighted Average Cost of Capital						8.63%	
7								
8	Total Revenue Requirement Target****	$ 7,120,862					$ 4,499,659	$ 2,621,202
9								
10								
11								
12								
13								
14	Estimated Actual Results		$ 115,000,000	$ 2,000,000	$ 117,000,000	$ (38,000,000)	$ 79,000,000	$ 2,750,000
15	Estimated Software		$ 10,500,000	$ 90,000	$ 10,590,000	$ (1,600,000)	$ 8,990,000	$ 1,000,000
16	Estimated AMR		$ 4,200,000	$ -	$ 4,200,000	$ (95,000)	$ 4,105,000	$ 140,000
17	Estimated Oswegatchie		$ 4,000,000	$ -	$ 4,000,000	$ (40,000)	$ 3,960,000	$ 40,000
18								
19								
20	Pre-Tax WACC						8.63%	
21								
22	Total Revenue Requirement Actuals****	$ 6,915,854					$ 5,345,854	$ 1,570,000
23								
24	Actuals higher/(lower) than Target	$ (205,008)						
25								
26								
27								
28								
29								
30	* Depreciation Expense exclusive of capitalized portion of vehicles							
31	** Plant Associated with AMR is exclusive of AMR Software, which is included in the Software Plant above							
32	*** Oswegatchie Main Replacement Plant will be removed similar to Lines 2 and 3 above when finalized							
33	****Targets and Actuals are reflected of total Net Plant less the excluded projects (Software, AMR, Oswegatchie)							

Net Plant Reconciliation and Excluded Project Targets

Rate Year 1 Targets

	Total Revenue Requirement Target	Gas Net Utility Plant in Service	Gas Depreciation Expense
Total Net Plant Exclusive of Software, AMR, Oswegatchie	$ 6,148,443	$ 3,898,950	$ 2,249,493
Net Plant Associated with Software	$ 1,875,187	$ 10,171,612	$ 1,012,635
Net Plant Associated with AMR	$ -	$ -	$ -
Net Plant Associated with Oswegatchie	$ -	$ -	$ -

Rate Year 2 Targets

	Total Revenue Requirement Target	Gas Net Utility Plant in Service	Gas Depreciation Expense
Total Net Plant Exclusive of Software, AMR, Oswegatchie	$ 6,590,054	$ 4,193,495	$ 2,396,559
Net Plant Associated with Software	$ 2,104,653	$ 10,272,234	$ 1,225,350
Net Plant Associated with AMR	$ 425,016	$ 4,015,655	$ 81,276
Net Plant Associated with Oswegatchie	$ -	$ -	$ -

Rate Year 3 Targets

	Total Revenue Requirement Target	Gas Net Utility Plant in Service	Gas Depreciation Expense
Total Net Plant Exclusive of Software, AMR, Oswegatchie	$ 7,120,862	$ 4,499,659	$ 2,621,202
Net Plant Associated with Software	$ 2,260,198	$ 9,979,783	$ 1,398,942
Net Plant Associated with AMR	$ 473,113	$ 3,877,140	$ 138,515
Net Plant Associated with Oswegatchie	$ 367,790	$ 4,261,764	$ -

2026-2027 Capital Budget - AMR

	2026 CAPEX Budget		Expenditure Type	Jan-26	Feb-26	Mar-26	Apr-26	May-26	Jun-26	Jul-26	Aug-26	Sep-26	Oct-26	Nov-26	Dec-26	Total
381	Residential ERT: 15,750 + inventory	$1,445,051	Non-Growth											$1,313,682	$131,368	$1,445,051
381	Commercial ERT: 1,954 + inventory	$251,355	Non-Growth											$228,505	$22,850	$251,355
381	Meters	$306,204	Non-Growth											$278,367	$27,837	$306,204
391.1	AMR Hardware	$224,312	Non-Growth											$203,920	$20,392	$224,312
303	AMR Software	$25,365	Non-Growth											$23,059	$2,306	$25,365

	2027 CAPEX Budget		Expenditure Type	Jan-27	Feb-27	Mar-27	Apr-27	May-27	Jun-27	Jul-27	Aug-27	Sep-27	Oct-27	Nov-27	Dec-27	Total
382	Installation & Implementation	$1,870,010	Non-Growth					$311,668	$311,668	$311,668	$311,668	$311,668	$311,668			$1,870,010
																-

Project Total	**$4,122,296**
	0

		Current Forecast 2026	Current Forecast 2027		Previous Forecast 2026	Previous Forecast 2027		Net Change 2026	Net Change 2027	
303	**AMR Software (A)**	20,052			24,000			(3,949)	-	
391.1	**AMR Hardware (B)**	177,322			128,490			48,832	-	
381	**Residential ERT: 15,750 + inventory (C)**	1,142,332			1,380,665			(238,333)	-	
381	**Commercial ERT: 1,954 + inventory (D)**	198,700			171,279			27,420	-	
381	**Meters**	242,058			0			242,058	-	
382	**Project Installation (E)**		1,022,360			1,022,360		-	-	
	Contingency 15%	267,070	153,354		170,443	102,236		96,626	51,118	
	Project Management & Supervision, Support		525,000			500,000		-	25,000	
	Clearing Allocations 10%	204,753	169,296		273,217	236,744		(68,464)	(67,448)	
		2,252,286	**1,870,010**		**2,148,095**	**1,861,340**		**104,191**	**8,670**	
				4,122,296			**4,009,435**			**112,861**
				(0)						
				(0)						
				(0)						

AMR Benefit Cost Analysis Support

OpEx - Labor		
	Monthly Manual Reads	Monthly AMR Reads
Minutes per read	2.75	1.20
# of Meter Reads per Year	212,448	212,448
Extra reads per year	12,000	3,000
FTE Hours per Year	10,287	4,309
# of FTEs	6	3
Hourly rate	$ 40.00	$ 40.00
Annual Labor OpEx	$ 411,488	$ 172,358

OpEx - Vehicle		
	Monthly Manual Reads	Monthly AMR Reads
# of Vehicles	6	3
Insurance per vehicle	$ 1,022	$ 1,022
Maintenance per vehicle	$ 2,763	$ 2,763
Fuel per vehicle	$ 6,300	$ 5,250
Annual Vehicle OpEx	$ 60,511	$ 27,105

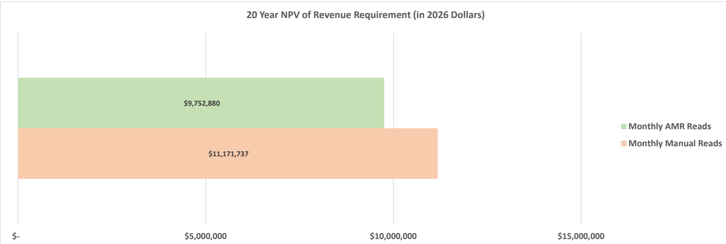
OpEx - Materials & Support		
	Monthly Manual Reads	Monthly AMR Reads
Uniforms: $1,720 per person	$ 11,352	$ 5,676
IT Support	$ 5,812	$ 19,180
Customer Service Support	$ 11,000	$ 2,200
Annual Materials & Support OpEx	$ 28,164	$ 27,056

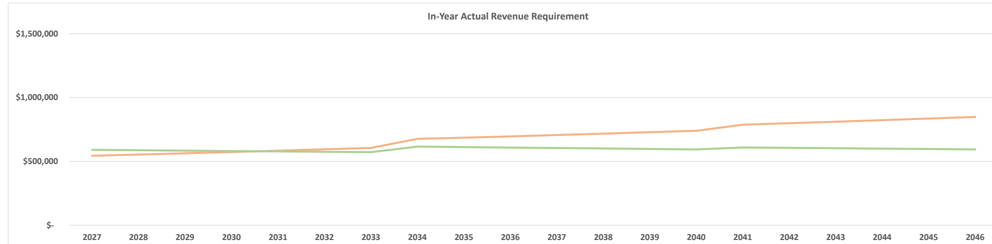
CapEx - Hardware & Software			
	Monthly Manual Reads	Monthly AMR Reads	Useful Life
Residential ERT: 15,750 + inventory	$ -	$ 1,313,682	
Commercial ERT: 1,954 + inventory	$ -	$ 228,505	
Meter Replacement	$ -	$ 278,367	
AMR Hardware	$ -	$ 203,920	
AMR Software		$ 23,059	
Total Material CapEx	$ -	$ 2,047,533	20

CapEx - Labor & Materials				
	Monthly Manual Reads	Monthly AMR Reads	Useful Life	
3rd Party Installation	$ -	$ 1,175,714		
Project Management & Supervision, Support, Clearing Allocations	$ -	$ 899,049		
Total Labor CapEx	$ -	$ 2,074,763	20	$ 4,122,296

CapEx - Vehicle [Note: First 3 vehicles will be supplied by existing fleet so only the incremental 3 vehicles for Maual 12mths will show up as immediate CapEx, all will show up in years 8 & 15 to refresh vehicles]			
	Monthly Manual Reads	Monthly AMR Reads	Useful Life
Standard Meter Reading Vehicle: $73,163 per vehicle	$ 241,438		
Total Vehicle CapEx	$ 241,438	$ -	7

CapEx - Tools & Supplies			
	Monthly Manual Reads	Monthly AMR Reads	Useful Life
Electronics: $927 per vehicle	$ 6,118	$ 3,059	5
Total Tools & Supplies CapEx	$ 6,730	$ 3,365	5





Debt	52.00%	**Equity**	48.00%	**Tax rate**	26.14%	**Inflation**	2.20%
Debt rate	2.21%	**Equity rate**	4.42%	**Pre-tax equity**	5.98%		
Vehicle replacement after fully depreciated: $73,163 per vehicle + inflation							
Electronics replacement after fully depreciated: $927 per employee + inflation							

		1	2	3	4	5	6	7	8	9	10
		2027	**2028**	**2029**	**2030**	**2031**	**2032**	**2033**	**2034**	**2035**	**2036**
Monthly AMR Meter Reads	**CapEx Additions**	$ 4,122,296	$ -	$ -	$ -	$ -	$ 3,169	$ -	$ 261,228	$ -	$ -
	Rate Base	$ 3,915,570	$ 3,708,843	$ 3,502,116	$ 3,295,390	$ 3,088,663	$ 2,885,083	$ 2,678,335	$ 2,695,496	$ 2,451,429	$ 2,207,362
	Accumulated Depreciation	$ 206,727	$ 413,453	$ 620,180	$ 826,907	$ 1,033,633	$ 1,240,382	$ 1,447,130	$ 1,691,197	$ 1,935,264	$ 2,179,331
	Depreciation Expense	$ 206,727	$ 206,727	$ 206,727	$ 206,727	$ 206,727	$ 206,749	$ 206,749	$ 244,067	$ 244,067	$ 244,067
	OpEx	$ 226,519	$ 231,503	$ 236,596	$ 241,801	$ 247,121	$ 252,557	$ 258,113	$ 263,792	$ 269,595	$ 275,526
	Cost of Debt	$ 44,998	$ 42,622	$ 40,246	$ 37,871	$ 35,495	$ 33,155	$ 30,779	$ 30,977	$ 28,172	$ 25,367
	ROE	$ 83,073	$ 78,687	$ 74,301	$ 69,915	$ 65,529	$ 61,210	$ 56,824	$ 57,188	$ 52,010	$ 46,831
	Taxes	$ 29,393	$ 27,841	$ 26,289	$ 24,737	$ 23,186	$ 21,657	$ 20,105	$ 20,234	$ 18,402	$ 16,570
	Revenue Requirement	$ 590,709	$ 587,379	$ 584,159	$ 581,051	$ 578,057	$ 575,328	$ 572,570	$ 616,257	$ 612,246	$ 608,362
NPV	**$ 9,752,880**										
Monthly Manual Meter Reads	**CapEx Additions**	$ 248,168					$ 6,338		$ 522,456		
	Rate Base	$ 212,453	$ 176,738	$ 141,024	$ 105,309	$ 69,594	$ 40,173	$ 4,414	$ 450,967	$ 375,062	$ 299,158
	Accumulated Depreciation	$ 35,715	$ 71,430	$ 107,144	$ 142,859	$ 178,574	$ 214,333	$ 250,091	$ 325,995	$ 401,900	$ 477,804
	Depreciation Expense	$ 35,715	$ 35,715	$ 35,715	$ 35,715	$ 35,715	$ 35,759	$ 35,759	$ 75,904	$ 75,904	$ 75,904
	OpEx	$ 500,163	$ 511,166	$ 522,412	$ 533,905	$ 545,651	$ 557,655	$ 569,924	$ 582,462	$ 595,276	$ 608,372
	Cost of Debt	$ 2,442	$ 2,031	$ 1,621	$ 1,210	$ 800	$ 462	$ 51	$ 5,183	$ 4,310	$ 3,438
	ROE	$ 4,507	$ 3,750	$ 2,992	$ 2,234	$ 1,477	$ 852	$ 94	$ 9,568	$ 7,957	$ 6,347
	Taxes	$ 1,595	$ 1,327	$ 1,059	$ 791	$ 522	$ 302	$ 33	$ 3,385	$ 2,815	$ 2,246
	Revenue Requirement	$ 544,421	$ 553,988	$ 563,798	$ 573,855	$ 584,164	$ 595,029	$ 605,860	$ 676,501	$ 686,263	$ 696,307
NPV	**$ 11,171,737**										

		11	12	13	14	15	16	17	18	19	20
		2037	**2038**	**2039**	**2040**	**2041**	**2042**	**2043**	**2044**	**2045**	**2046**
Monthly AMR Meter Reads	**CapEx Additions**	$ 3,533	$ -	$ -	$ -	$ 304,212	$ 3,939	$ -	$ -	$ -	$ -
	Rate Base	$ 1,966,756	$ 1,722,616	$ 1,478,476	$ 1,234,336	$ 1,288,268	$ 1,041,846	$ 791,484	$ 541,123	$ 290,761	$ 40,400
	Accumulated Depreciation	$ 2,423,471	$ 2,667,611	$ 2,911,750	$ 3,155,890	$ 3,406,170	$ 3,656,532	$ 3,906,893	$ 4,157,255	$ 4,407,616	$ 4,657,978
	Depreciation Expense	$ 244,140	$ 244,140	$ 244,140	$ 244,140	$ 250,280	$ 250,362	$ 250,362	$ 250,362	$ 250,362	$ 250,362
	OpEx	$ 281,588	$ 287,783	$ 294,114	$ 300,585	$ 307,198	$ 313,956	$ 320,863	$ 327,922	$ 335,136	$ 342,509
	Cost of Debt	$ 22,602	$ 19,796	$ 16,991	$ 14,185	$ 14,805	$ 11,973	$ 9,096	$ 6,219	$ 3,341	$ 464
	ROE	$ 41,727	$ 36,547	$ 31,367	$ 26,188	$ 27,332	$ 22,104	$ 16,792	$ 11,480	$ 6,169	$ 857
	Taxes	$ 14,764	$ 12,931	$ 11,098	$ 9,266	$ 9,671	$ 7,821	$ 5,941	$ 4,062	$ 2,183	$ 303
	Revenue Requirement	$ 604,820	$ 601,197	$ 597,710	$ 594,363	$ 609,285	$ 606,215	$ 603,054	$ 600,045	$ 597,191	$ 594,495
Monthly Manual Meter Reads	**CapEx Additions**	$ 7,066				$ 608,424	$ 7,879				
	Rate Base	$ 230,175	$ 154,125	$ 78,075	$ 2,025	$ 522,118	$ 441,503	$ 353,010	$ 264,516	$ 176,023	$ 87,530
	Accumulated Depreciation	$ 553,854	$ 629,903	$ 705,953	$ 782,003	$ 870,334	$ 958,827	$ 1,047,321	$ 1,135,814	$ 1,224,308	$ 1,312,801
	Depreciation Expense	$ 76,050	$ 76,050	$ 76,050	$ 76,050	$ 88,331	$ 88,493	$ 88,493	$ 88,493	$ 88,493	$ 88,493
	OpEx	$ 621,756	$ 635,435	$ 649,414	$ 663,702	$ 678,303	$ 693,226	$ 708,477	$ 724,063	$ 739,993	$ 756,272
	Cost of Debt	$ 2,645	$ 1,771	$ 897	$ 23	$ 6,000	$ 5,074	$ 4,057	$ 3,040	$ 2,023	$ 1,006
	ROE	$ 4,883	$ 3,270	$ 1,656	$ 43	$ 11,077	$ 9,367	$ 7,489	$ 5,612	$ 3,735	$ 1,857
	Taxes	$ 1,728	$ 1,157	$ 586	$ 15	$ 3,919	$ 3,314	$ 2,650	$ 1,986	$ 1,321	$ 657
	Revenue Requirement	$ 707,063	$ 717,683	$ 728,604	$ 739,833	$ 787,631	$ 799,474	$ 811,166	$ 823,194	$ 835,565	$ 848,286

		2027 Install Year	2028 1	2029 2	2030 3	2031 4	2032 5	2033 6	2034 7	2035 8	2036 9	2037 10	2038 11	2039 12	2040 13	2041 14	2042 15	2043 16	2044 17	2045 18	2046 19	Total	*WACC 7.01%* NPV
AMR Costs	CapEx	$ 4,122,296	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 4,122,296	$3,852,253
AMR Hardware & Software		$ 2,047,533																					
Project Installation, Management, Clearing Allocations		$ 2,074,763																					
AMR Savings	CapEx	$ 244,803	$ -	$ -	$ -	$ -	$ -	$ 3,834	$ -	$ 287,351	$ -	$ -	$ 4,275	$ -	$ -	$ -	$ 334,633	$ 4,767	$ -	$ -	$ -	$ 879,663	$503,906
Reduction in Vehicles		$ 241,438								$ 287,351							$ 334,633						
Reduction in Tools & Supplies		$ 3,365						$ 3,834					$ 4,275					$ 4,767					
AMR Savings	OpEx	$ -	$ 282,294	$ 291,222	$ 300,435	$ 309,944	$ 319,758	$ 329,887	$ 340,341	$ 351,130	$ 362,265	$ 373,758	$ 385,620	$ 397,864	$ 410,500	$ 423,543	$ 437,005	$ 450,900	$ 465,242	$ 480,045	$ 495,325	$ 7,207,079	$3,438,783
Reduction in Meter Reading Labor			$ 247,021	$ 255,173	$ 263,593	$ 272,292	$ 281,277	$ 290,560	$ 300,148	$ 310,053	$ 320,285	$ 330,854	$ 341,772	$ 353,051	$ 364,701	$ 376,737	$ 389,169	$ 402,012	$ 415,278	$ 428,982	$ 443,138		
Reduction in Vehicle O&M			$ 34,140	$ 34,891	$ 35,659	$ 36,443	$ 37,245	$ 38,065	$ 38,902	$ 39,758	$ 40,632	$ 41,526	$ 42,440	$ 43,374	$ 44,328	$ 45,303	$ 46,300	$ 47,318	$ 48,359	$ 49,423	$ 50,511		
Reduction in Meter Reading Materials & Support			$ 1,133	$ 1,158	$ 1,183	$ 1,209	$ 1,236	$ 1,263	$ 1,291	$ 1,319	$ 1,348	$ 1,378	$ 1,408	$ 1,439	$ 1,471	$ 1,503	$ 1,536	$ 1,570	$ 1,605	$ 1,640	$ 1,676		
Customer Value of Monthly Meter Reads																						$ -	$0
																						Benefit	$3,942,689
																						Cost	$3,852,253
	6.6%	$ (4,122,296)	$ 282,294	$ 291,222	$ 300,435	$ 309,944	$ 319,758	$ 333,721	$ 340,341	$ 638,481	$ 362,265	$ 373,758	$ 389,896	$ 397,864	$ 410,500	$ 423,543	$ 771,638	$ 455,666	$ 465,242	$ 480,045	$ 495,325	***B/C Ratio***	***1.023***

AMR Opt-Out Fees

Opt-Out	One-time Removal Fee	Monthly Meter Reading Fee
Customers who have received the AMR Module, but want it removed	$ 119.23	$ 9.63
Customers who opt-out of AMR, and do not receive a module	$ -	$ 9.63

AMR Meter Opt-Out Application Form

This application must be completed by customers choosing to opt-out of Advanced Metering Reading (AMR). Only residential customers may choose not to have an AMR meter. If you would like to speak with an AMR technical representative, please let us know.

It is important that you understand the costs and conditions of opting out of AMR metering. If you have not already done so, and would like to learn more about AMR, **please call Liberty at (800) 454-2201 before submitting this application**.

I understand that, by opting-out, I will not receive the benefits of AMR, including:

- Automated meter readings, which may mean that my meter read may be estimated.

I understand that, by opting-out, I will need to grant a Liberty representative access to my residence to conduct a manual meter read. I also agree to pay the following charges:

- Upon submission of the opt-out application form, **a monthly fee of $9.63** for a monthly manual meter read.
- Upon submission of the opt-out application form, if an AMR meter was previously installed, a **one-time change out fee of $119.23 per meter** will apply for a Customer who requests removal of the remote communications capability of an AMR meter, except as described in “Notice” in the General Rules, Regulation, Terms and Conditions in the Company’s tariff.

Additionally, I understand that Liberty has the right to install an AMR meter at its discretion if the company is **unable to obtain six consecutive actual meter reads**. At that time, the Company would stop charging the monthly opt-out fee. Alternatively, I may elect to relocate my meter(s) to an accessible area, at my expense.

Please return this completed form to Liberty:

Mail: Liberty
33 Stearns Street
Massena, NY 13662
Attn: Customer Service

Email: CustomerServiceNY@libertyutilities.com

Account Number:

Account Name:
Person listed on the Liberty account

Service Address:
Street
RM/FL/APT
City
Zip

Contact Information:
Tel
Cell
Email

By signing this application, I agree to the terms listed above and opt-out of receiving an AMR meter.

Print Name

Sign Name

Date

EBCAP Reconciliation - DOWNWARD ONLY
*For Illustsrative purposes only

	Rate Year 2 As Adjusted for Joint Proposal	RY2 (*Actual EBCAP Measurement) - EXAMPLE	Difference	RY2 Pre-Tax ROR	Deferral (booked as a regulatory liability)
Excess Earnings Base Adjustment	$ (4,287,654)	$ (5,088,839)	$ (801,185)	**8.56%**	$ (68,551)

*The EBCAP will be measured using a 13 point average of actual earnings base, and actual capitalization devoted to providing utility service for the Twelve Months Ending October 31, 2027 for RY2

EXAMPLE	**Rate Year 2 Ending October 31. 2027 (ACTUAL)**
Equity	$ 24,587,964
Debt	$ 25,615,879
Adjustments to Capitalization*	$ 3,154,897
Less: Non-Utility Assets	$ 551,000
Capitalization Dedicated to Utility Operations	$ 52,807,740
Earnings Base (Rate Base + CWIP)	$ 57,896,579
Excess Earnings Base	$ (5,088,839)

*Adjustments to capitalization include GAC & IIC (closed cycle) - net of 21% FIT and 6.5% SIT, Pension/OPEB Internal Reserve, and Gas in Storage

Capital Structure RY2

	Total Annual Avg	Weighting Percent	Cost	Weighted Cost	Pre-Tax Weighted Cost
Long Term Debt	30,076,777	51.82%	5.01%	2.60%	2.60%
Short Term Debt	-	0.00%	0.00%	0.00%	0.00%
Customer Deposits	684,882	1.18%	3.00%	0.04%	0.04%
Common Equity	27,279,208	47.00%	9.30%	4.37%	5.92%
Total	$ 58,040,867	100.00%		7.01%	8.56%

EBCAP Reconciliation - DOWNWARD ONLY
*For Illustsrative purposes only

	Rate Year 3 As Adjusted for Joint Proposal	RY3 (**Actual EBCAP Measurement) - EXAMPLE	Difference	RY3 Pre-Tax ROR	Deferral (booked as a regulatory liability)
Excess Earnings Base Adjustment	$ (2,858,436)	$ (4,740,239)	$ (1,881,803)	**8.63%**	$ (162,363)

*The EBCAP will be measured using a 13 point average of earnings base, and capitalization devoted to providing utility service for the Twelve Months Ending October 31, 2028 for RY3

EXAMPLE	**Rate Year 3 Ending October 31. 2028 (ACTUAL)**
Equity	$ 28,965,874
Debt	$ 29,587,446
Adjustments to Capitalization*	$ 3,154,897
Less: Non-Utility Assets	$ 551,000
Capitalization Dedicated to Utility Operations	$ 61,157,217
Earnings Base (Rate Base + CWIP)	$ 65,897,456
Excess Earnings Base	$ (4,740,239)

*Adjustments to capitalization include GAC & IIC (closed cycle) - net of 21% FIT and 6.5% SIT, Pension/OPEB Internal Reserve, and Gas in Storage

Capital Structure RY3

	Total Annual Avg	Weighting Percent	Cost	Weighted Cost	Pre-Tax Weighted Cost
Long Term Debt	33,209,002	50.82%	5.01%	2.55%	2.55%
Short Term Debt	-	0.00%	0.00%	0.00%	0.00%
Customer Deposits	771,087	1.18%	3.00%	0.04%	0.04%
Common Equity	31,366,236	48.00%	9.30%	4.46%	6.04%
Total	$ 65,346,324	100.00%		7.05%	8.63%

Forecast Rate Year Rates To Apply To Rev Req	
Bad Debt % For Rev Req	0.50%
GRT Rate For Rev Req	1.00%
Federal Income Tax Rate	21.00%
NYS Income Tax Rate	6.50%

Amortization of Regulatory Deferrals

Description	Rate Year 10/31/2026	Rate Year 2 10/31/2027	Rate Year 3 10/31/2028
Amortization of Regulatory Deferrals	$ 309,829	$ 459,937	$ 459,937
Unamortized Deferrals (net of ADIT)	$ 746,134	$ 509,597	$ 169,866

Amortization of Regulatory Deferrals

		LINK PERIOD															
Description	**6/30/2024**	**7/31/2024**	**8/31/2024**	**9/30/2024**	**10/31/2024**	**11/30/2024**	**12/31/2024**	**1/31/2025**	**2/28/2025**	**3/31/2025**	**4/30/2025**	**5/31/2025**	**6/30/2025**	**7/31/2025**	**8/31/2025**	**9/30/2025**	**10/31/2025**
Unamortized Deferrals	$ (869,259)	$ (956,247)	$ (913,962)	$ (871,678)	$ (829,393)	$ (787,109)	$ (744,825)	$ (702,540)	$ (660,256)	$ (617,971)	$ (575,687)	$ (533,403)	$ (491,118)	$ (448,834)	$ (406,549)	$ (364,265)	$ (321,984)
State Tax Effect @ 6.50%	56,502	62,156	59,408	56,659	53,911	51,162	48,414	45,665	42,917	40,168	37,420	34,671	31,923	29,174	26,426	23,677	20,929
Federal Tax Effect @ 21.00%	170,679	187,759	179,456	171,154	162,851	154,549	146,246	137,944	129,641	121,339	113,036	104,734	96,431	88,129	79,826	71,523	63,222
Net Unamortized Deferrals	$ (642,078)	$ (706,332)	$ (675,098)	$ (643,865)	$ (612,631)	$ (581,398)	$ (550,165)	$ (518,931)	$ (487,698)	$ (456,464)	$ (425,231)	$ (393,998)	$ (362,764)	$ (331,531)	$ (300,297)	$ (269,065)	$ (237,833)

	RATE YEAR 1												RY1 AVG
	11/30/2025	**12/31/2025**	**1/31/2026**	**2/28/2026**	**3/31/2026**	**4/30/2026**	**5/31/2026**	**6/30/2026**	**7/31/2026**	**8/31/2026**	**9/30/2026**	**10/31/2026**	**10/31/2026**
Unamortized Deferrals	$ 1,203,881	$ 1,178,062	$ 1,152,243	$ 1,126,424	$ 1,100,605	$ 1,074,786	$ 1,048,967	$ 1,023,148	$ 997,329	$ 971,510	$ 945,691	$ 919,872	$ 1,010,132
State Tax Effect @ 6.50%	(78,252)	(76,574)	(74,896)	(73,218)	(71,539)	(69,861)	(68,183)	(66,505)	(64,826)	(63,148)	(61,470)	(59,792)	(65,659)
Federal Tax Effect @ 21.00%	(236,382)	(231,312)	(226,243)	(221,173)	(216,104)	(211,034)	(205,965)	(200,895)	(195,826)	(190,756)	(185,686)	(180,617)	(198,339)
Net Unamortized Deferrals	$ 889,247	$ 870,176	$ 851,104	$ 832,033	$ 812,962	$ 793,891	$ 774,819	$ 755,748	$ 736,677	$ 717,606	$ 698,535	$ 679,463	$ 746,134

	RATE YEAR 2												RY2 AVG
	11/30/2026	**12/31/2026**	**1/31/2027**	**2/28/2027**	**3/31/2027**	**4/30/2027**	**5/31/2027**	**6/30/2027**	**7/31/2027**	**8/31/2027**	**9/30/2027**	**10/31/2027**	**10/31/2027**
Unamortized Deferrals	$ 881,544	$ 843,216	$ 804,888	$ 766,560	$ 728,232	$ 689,904	$ 651,576	$ 613,248	$ 574,920	$ 536,592	$ 498,264	$ 459,936	$ 689,904
State Tax Effect @ 6.50%	(57,300)	(54,809)	(52,318)	(49,826)	(47,335)	(44,844)	(42,352)	(39,861)	(37,370)	(34,878)	(32,387)	(29,896)	(44,844)
Federal Tax Effect @ 21.00%	(173,091)	(165,565)	(158,040)	(150,514)	(142,988)	(135,463)	(127,937)	(120,411)	(112,885)	(105,360)	(97,834)	(90,308)	(135,463)
Net Unamortized Deferrals	$ 651,153	$ 622,842	$ 594,530	$ 566,220	$ 537,909	$ 509,597	$ 481,287	$ 452,976	$ 424,665	$ 396,354	$ 368,043	$ 339,732	$ 509,597

	RATE YEAR 3												RY3 AVG
	11/30/2027	**12/31/2027**	**1/31/2028**	**2/29/2028**	**3/31/2028**	**4/30/2028**	**5/31/2028**	**6/30/2028**	**7/31/2028**	**8/31/2028**	**9/30/2028**	**10/31/2028**	**10/31/2028**
Unamortized Deferrals	$ 421,608	$ 383,280	$ 344,952	$ 306,624	$ 268,296	$ 229,968	$ 191,640	$ 153,312	$ 114,984	$ 76,656	$ 38,328	$ 0	$ 229,968
State Tax Effect @ 6.50%	(27,405)	(24,913)	(22,422)	(19,931)	(17,439)	(14,948)	(12,457)	(9,965)	(7,474)	(4,983)	(2,491)	-	(14,948)
Federal Tax Effect @ 21.00%	(82,783)	(75,257)	(67,731)	(60,206)	(52,680)	(45,154)	(37,628)	(30,103)	(22,577)	(15,051)	(7,526)	-	(45,154)
Net Unamortized Deferrals	$ 311,420	$ 283,110	$ 254,799	$ 226,487	$ 198,177	$ 169,866	$ 141,555	$ 113,244	$ 84,933	$ 56,622	$ 28,311	$ 0	$ 169,866

Amortization of Regulatory Deferrals

Line No.	Description	FERC Acct.	1/2 6/30/2023	TEST YEAR 7/31/2023	8/31/2023	9/30/2023	10/31/2023	11/30/2023	12/31/2023	1/31/2024	2/29/2024	3/31/2024	4/30/2024	5/31/2024	1/2 6/30/2024	Average
1	Unamortized Deferrals		$ (1,334,910)	$ (1,292,540)	$ (1,250,170)	$ (1,207,799)	$ (1,165,429)	$ (1,123,144)	$ (1,122,965)	$ (1,080,681)	$ (1,038,396)	$ (996,112)	$ (953,827)	$ (911,543)	$ (869,259)	$ (1,103,724)
2	State Tax Effect @ 6.50%		86,769	84,015	81,261	78,507	75,753	73,004	72,993	70,244	67,496	64,747	61,999	59,250	56,502	71,742
3	Federal Tax Effect @ 21.00%		298,553	289,076	279,600	270,124	260,648	251,191	251,151	241,694	232,237	222,780	213,324	203,867	170,679	245,859
4	Unamortized Deferrals (net of tax)		$ (949,588)	$ (919,449)	$ (889,309)	$ (859,168)	$ (829,028)	$ (798,949)	$ (798,821)	$ (768,743)	$ (738,663)	$ (708,585)	$ (678,504)	$ (648,426)	$ (642,078)	$ (786,123)
5	Amortization of Deferrals			(42,370)	(42,370)	(42,370)	(42,371)	(42,284)	(179)	(42,284)	(42,284)	(42,284)	(42,284)	(42,284)	(42,284)	(465,651)
6	Total Noncash Items			$ (42,370)	$ (42,370)	$ (42,370)	$ (42,371)	$ (42,284)	$ (179)	$ (42,284)	$ (42,284)	$ (42,284)	$ (42,284)	$ (42,284)	$ (42,284)	$ (465,651)

Line No.	Description	7/31/2024	8/31/2024	9/30/2024	10/31/2024	11/30/2024	12/31/2024	1/31/2025	Average
1	Unamortized Deferrals	$ (826,974)	$ (784,690)	$ (742,405)	$ (700,121)	$ (657,837)	$ (615,552)	$ (573,268)	$ (826,974)
2	State Tax Effect @ 6.50%	53,753	51,005	48,256	45,508	42,759	40,011	37,262	53,753
3	Federal Tax Effect @ 21.00%	162,376	154,074	145,771	137,469	129,166	120,864	112,561	172,478
4	Unamortized Deferrals (net of tax)	$ (610,845)	$ (579,611)	$ (548,378)	$ (517,144)	$ (485,912)	$ (454,677)	$ (423,445)	$ (600,743)
5	Amortization of Deferrals	(42,284)	(42,284)	(42,284)	(42,284)	(42,284)	(42,284)	(42,284)	(42,284)
6	Total Noncash Items	$ (42,284)	$ (42,284)	$ (42,284)	$ (42,284)	$ (42,284)	$ (42,284)	$ (42,284)	$ (42,284)

TEST YEAR

Description	Balance 6/30/23	Monthly Amortization	Annual Amortization	Balance 6/30/24
Risk Assessment Deferral	$ 268,387	$ (9,585)	$ (115,023)	$ 153,364
TSA	297	(74)	(892)	-
Performance Incentives Collections	2,000	(500)	(6,000)	-
Rate Case Expense 21-G-0577	941,374	(33,620)	(403,446)	537,928
Rate Case Expense 24-G-0668	-	-	-	-
Reg Assets Other - Int Rate True-Up	246,800	(8,814)	(105,772)	141,029
Deferred Regulatory Liability - Surcredit	259,002	(9,250)	(111,001)	148,001
Other Regulatory Liability - Low Income 21-G-0577 Deferral	(44,340)		-	(103,327)
EAP	(37,880)		-	(2,802)
Other Regulatory Liability - Low Income Rate	(495,480)	17,696	212,348	(283,131)
SRS/ILI	(428,287)	15,296	183,551	(244,735)
Current Regulatory Liability - Excess Earnings	(415,169)	14,828	177,931	(237,238)
Property Tax	(1,142,462)	40,802	489,627	(652,835)
Property Tax 21-G-0577 Deferral	(68,388)		-	(173,751)
Deferred Regulatory Liability - Gas Safety Performance Measures	(29,236)	1,044	12,530	(16,706)
Positive Benefit Adjustment	(388,888)	13,889	166,667	(222,221)
Un-Timely NRAs	(3,973)	993	11,919	-
SBC	1,332	(333)	(3,997)	-
NRAs CY 2023	-		-	(42,105)
Net Deferrals	**$ (1,334,910)**	**$ 42,370**	**$ 508,442**	**$ (998,531)**

1/ Adjusted to remove an accrual reversal originally booked in October 2023 that was corrected by the Company in December 2024.

LINK PERIOD

Description	Balance 7/1/2024	Monthly Amortization	Annual Amortization	Balance 10/31/25
Risk Assessment Deferral	$ 153,364	$ (9,585)	$ (153,364)	$ -
Rate Case Expense 21-G-0577	537,928	(33,620)	(537,928)	1
Rate Case Expense 24-G-0668	-	-	-	-
Reg Assets Other - Int Rate True-Up	141,029	(8,814)	(141,029)	-
Deferred Regulatory Liability - Surcredit	148,001	(9,250)	(148,001)	-
Other Regulatory Liability - Low Income 21-G-0577 Deferral	(103,327)	-	-	(127,966)
EAP	(2,802)	-	-	(2,802)
Other Regulatory Liability - Low Income Rate	(283,131)	17,696	283,131	-
SRS/ILI	(244,735)	15,296	244,735	-
Current Regulatory Liability - Excess Earnings	(237,238)	14,828	237,241	-
Property Tax	(652,835)	40,802	652,836	-
Property Tax 21-G-0577 Deferral	(173,751)	-	-	(273,320)
Deferred Regulatory Liability - Gas Safety Performance Measures	(16,706)	1,044	16,706	(0)
Positive Benefit Adjustment	(222,221)	13,889	222,222	-
NRAs CY 2023	(42,105)	-	-	(42,105)
Net Deferrals	**$ (998,531)**	**$ 42,284**	**$ 676,550**	**$ (446,192)**

RATE YEAR 1

Description	Balance 3/31/2025	Monthly Amortization	Rate Year 1 Amortization	Balance 10/31/26
Rate Case Expense 24-G-0668	980,140	(27,226)	(326,713)	$ 653,427
Other Regulatory Liability - Low Income 21-G-0577 Deferral	(127,966)	3,555	42,655	(85,311)
EAP	(2,802)	233	2,802	-
Property Tax 21-G-0577 Deferral	(273,320)	7,592	91,107	(182,214)
NRAs CY 2023	(42,105)	3,509	42,105	-
LTP Deferral	888,869	(24,691)	(296,290)	592,579
Gas Safety NRA Deferral	(105,201)	8,767	105,201	-
Untimely Filing NRA Deferral	(87,915)	2,442	29,305	(58,610)
Net Deferrals	**$ 1,229,700**	**$ (25,819)**	**$ (309,829)**	**$ 919,872**

RATE YEAR 2

	Balance 10/31/26	Monthly Amortization	Rate Year 2 Amortization	Balance 10/31/27
Rate Case Expense 24-G-0668	653,427	(27,226)	(326,713)	$ 326,713
Other Regulatory Liability - Low Income 21-G-0577 Deferral	(85,311)	3,555	42,655	(42,655)
EAP	-	-	-	-
Property Tax 21-G-0577 Deferral	(182,214)	7,592	91,107	(91,107)
NRAs CY 2023	-	-	-	-
LTP Deferral	592,579	(24,691)	(296,290)	296,290
Gas Safety NRA Deferral	-	-	-	-
Untimely Filing NRA Deferral	(58,610)	2,442	29,305	(29,305)
Net Deferrals	**$ 919,872**	**$ (38,328)**	**$ (459,937)**	**$ 459,936**

RATE YEAR 3

	Balance 10/31/27	Monthly Amortization	Rate Year 3 Amortization	Balance 10/31/28
Rate Case Expense 24-G-0668	326,713	(27,226)	(326,713)	$ -
Other Regulatory Liability - Low Income 21-G-0577 Deferral	(42,655)	3,555	42,655	-
EAP	-	-	-	-
Property Tax 21-G-0577 Deferral	(91,107)	7,592	91,107	-
NRAs CY 2023	-	-	-	-
LTP Deferral	296,290	(24,691)	(296,290)	-
Gas Safety NRA Deferral	-	-	-	-
Untimely Filing NRA Deferral	(29,305)	2,442	29,305	-
Net Deferrals	**$ 459,936**	**$ (38,328)**	**$ (459,937)**	**$ -**

Extension Capital Project Recovery Mechanism - Example

Description		Mains		Services		Meters		Total	
FERC Account		*376*		*380*		*381*			
Capital Spending *	$	1,000,000	$	200,000	$	50,000	$	1,250,000	
Deferred Tax Calculation									
Tax Method		MACRS20		MACRS20		MACRS20			
Tax Depreciation Rate		3.75%		3.75%		3.75%			
Tax Depreciation - Federal	$	37,500	$	7,500	$	1,875	$	46,875	
Tax Depreciation - State	$	37,500	$	7,500	$	1,875			
Book Depreciation Rate		1.72%		2.17%		2.75%			
Book Depreciation	$	17,200	$	4,340	$	1,375	$	22,915	
Tax over (under) Book - Federal	$	20,300	$	3,160	$	500	$	23,960	
Tax over (under) Book - State		20,300		3,160		500		23,960	
Deferred Taxes - Federal @ 21.00%		4,263		664		105		5,032	21.00%
Deferred Taxes - State @ 6.50%		1,320		205		33		1,557	6.50%
Deferred Tax Balance	$	5,583	$	869	$	138	$	6,589	
Rate Base Calculation									
Plant in Service	$	1,000,000	$	200,000	$	50,000	$	1,250,000	
Accumulated Depreciation		(17,200)		(4,340)		(1,375)		(22,915)	
Deferred Tax Balance		(5,583)		(869)		(138)		(6,589)	
Rate Base	$	977,218	$	194,791	$	48,488	$	1,220,496	
Revenue Requirement Calculation									
Return on Rate Base @ 8.22%	$	82,868	$	16,518	$	4,112	$	103,498	
Depreciation Expense		17,200		4,340		1,375	$	22,915	
Property Taxes (@ applicable rate)		5,000		1,000		250		6,250	
Annual Revenue Requirement	$	105,068	$	21,858	$	5,737	$	132,663	

Total Incremental Revenue Required	$	132,663
Current Revenue (before incremental revenue)	$	16,808,000
% Increase (to be applied to all distribution rates and charges)		0.79%

Rate of Return Calculation	Portion	After-Tax Cost	Pre-Tax WACC	Tax
Long-Term Debt	52.82%	5.01%	2.65%	
Customer Deposits	1.18%	3.00%	0.04%	
Common Equity	46.00%	9.30%	5.79%	26.14%
	100.00%		8.48%	

Disclaimer: The amounts contained in this example are hypothetical. The calculation will be reflective of actuals.

Liberty Utilities (St. Lawrence Gas) Corp.
Case 24-G-0668

Equity Ratio Reconciliation
For illustrative purposes only

	RY2 Revenue Requirement (Rates) **47%** 10/31/2026	Actual Equity Ratio (hypothetical) **46%** 10/31/2026	**Deferral***	RY3 Revenue Requirement (Rates) **48%** 10/31/2026	Actual Equity Ratio (hypothetical) **46%** 10/31/2026	**Deferral***
Rate Base	$ 58,043,044	$ 58,043,044		$ 65,341,792	$ 65,341,792	
Rate of Return	7.01%	6.97%		7.05%	6.97%	
Required Utility Operating Income	4,068,817	4,045,600		4,606,596	4,554,323	
Utility Operating Income Before Increase	2,704,062	2,704,062		3,409,970	3,409,970	
Under Operating Income	1,364,755	1,341,538		1,196,626	1,144,353	
Retention Factor	72.76%	72.76%		72.76%	72.76%	
Revenue Requirement	$ 1,875,770	$ 1,843,860	$ (31,910)	$ 1,644,688	$ 1,572,842	$ (71,846)

*Deferral Booked to a regulatory liability for future benefit to customers

	Retention Factor	Retention factor	Retention Factor	Retention factor
Revenues	100.00%	100.00%	100.00%	100.00%
Less: Revenue Taxes	1.00%	1.00%	1.00%	1.00%
Uncollectible Accounts	0.500%	0.5000%	0.500%	0.5000%
Total	98.50%	98.50%	98.50%	98.50%
Reciprocal of State Tax Rate	93.50%	93.50%	93.50%	93.50%
Net	92.10%	92.10%	92.10%	92.10%
Reciprocal of Federal Tax Rate	79.00%	79.00%	79.00%	79.00%
Retention Factor	72.76%	72.76%	72.76%	72.76%

	Capital Structure (set in rates) - RY2			**Actual Equity Ratio (46% - Example)**			**Capital Structure (set in rates) - RY3**			**Actual Equity Ratio (46% - Example)**		
	Ratios	Cost	Weighted Cost	Ratios	Cost	Weighted Cost	Ratios	Cost	Weighted Cost	Ratios	Cost	Weighted Cost
Long-Term Debt	51.82%	5.01%	2.60%	52.82%	5.01%	2.65%	50.82%	5.01%	2.55%	52.82%	5.01%	2.65%
Customer Deposits	1.18%	3.00%	0.04%	1.18%	3.00%	0.04%	1.18%	3.00%	0.04%	1.18%	3.00%	0.04%
Common Equity	**47.00%**	9.30%	4.37%	**46.00%**	9.30%	4.28%	**48.00%**	9.30%	4.46%	**46.00%**	9.30%	4.28%
Totals	100.00%		7.01%	100.00%		6.97%	100.00%		7.05%	100.00%		6.97%

Capital Structure

For the Rate Year Ending October 31, 2026
(Whole Dollars)

	Total Annual Avg	Weighting Percent	Cost	Weighted Cost	Pre-Tax Weighted Cost
Long Term Debt	$ 26,736,693	52.82%	5.01%	2.65%	2.65%
Short Term Debt	-	0.00%	0.00%	0.00%	0.00%
Customer Deposits	597,298	1.18%	3.00%	0.04%	0.04%
Common Equity	23,284,511	46.00%	9.30%	4.28%	5.79%
Total	$ 50,618,502	100.00%		6.97%	8.48%

For the Rate Year Ending October 31, 2027
(Whole Dollars)

	Total Annual Avg	Weighting Percent	Cost	Weighted Cost	Pre-Tax Weighted Cost
Long Term Debt	$ 30,076,777	51.82%	5.01%	2.60%	2.60%
Short Term Debt	-	0.00%	0.00%	0.00%	0.00%
Customer Deposits	684,882	1.18%	3.00%	0.04%	0.04%
Common Equity	27,279,208	47.00%	9.30%	4.37%	5.92%
Total	$ 58,040,867	100.00%		7.01%	8.56%

For the Rate Year Ending October 31, 2028
(Whole Dollars)

	Total Annual Avg	Weighting Percent	Cost	Weighted Cost	Pre-Tax Weighted Cost
Long Term Debt	$ 33,209,002	50.82%	5.01%	2.55%	2.55%
Short Term Debt	-	0.00%	0.00%	0.00%	0.00%
Customer Deposits	771,087	1.18%	3.00%	0.04%	0.04%
Common Equity	31,366,236	48.00%	9.30%	4.46%	6.04%
Total	$ 65,346,324	100.00%		7.05%	8.63%

Forecast Rate Year Rates To Apply To Rev Req	
Bad Debt % For Rev Req	0.5000%
GRT Rate For Rev Req	1.00%
Federal Income Tax Rate	21.00%
NYS Income Tax Rate	6.50%

Liberty Utilities (St. Lawrence Gas) Corp.
Earnings Sharing Calculation - Example
For The Rate Years Ending October 31, 2026, 2027, 2028, and stub period.

Earnings Sharing Mechanism (ESM) Tiers			
	Earnings	Customers	Company
Tier 1	Up to 9.80% (dead band)	0%	100%
Tier 2	Above 9.80% and up to 10.30%	50%	50%
Tier 3	Above 10.30% and up to 10.80%	80%	20%
Tier 4	Above 10.80%	90%	10%

Liberty Utilities (St. Lawrence Gas Corp.)
Earnings Sharing Calculation - Example
For The Rate Year Ending October 31, 2026

Net Inome	$ 3,600,000
Rate Base	50,606,861
Overall ROR	7.11%

	Weighting Percent	Cost	Weighted Cost	Pre-Tax Weighted Cost
Long Term Debt	52.82%	5.01%	2.65%	2.65%
Customer Deposits	1.18%	3.00%	0.04%	0.04%
Common Equity (see note below)	**46.00%**	**9.62%**	4.42%	5.99%
Total	100.00%		7.11%	8.68%

Note: Common equity ratio will be calculated at the lesser of actual average or 46.00%.

Calculation of Excess Earnings To Be Deferred

Allowed ROE in JP		9.30%
Actual Earned ROE		9.62%
ROE Basis Points above/(below) Threshold		32
Equity Earnings over/(under) Target	**$**	**73,714**

	BP	Total To Be Shared	Customer's Share	Company's Share
ROE 9.30% ≤ 9.80%, Customers 0% / Company 100%	32	$ 73,714	0	73,714
ROE above 9.80% ≤ 10.30%, Customers 50% / Company 50%	0	0	0	0
ROE above 10.30% ≤ 10.80%, Customers 80% / Company 20%	0	0	0	0
ROE above 10.80%, Customers 90% / Company 10%	0	0	0	0
Total Shared	**32**	**$ 73,714**	**$ 0**	**$ 73,714**
Combined Federal & State Income Tax Rate		26.135%	26.135%	26.135%
Amount Deferred		**$ 99,795**	**$ 0**	**$ 99,795**

Liberty Utilities (St. Lawrence Gas Corp.)
Earnings Sharing Calculation - Example
For The Rate Year Ending October 31, 2027

Net Inome	$ 4,300,000
Rate Base	58,031,770
Overall ROR	7.41%

	Weighting Percent	Cost	Weighted Cost	Pre-Tax Weighted Cost
Long Term Debt	51.82%	5.01%	2.60%	2.60%
Customer Deposits	1.18%	3.00%	0.04%	0.04%
Common Equity (see note below)	**47.00%**	**10.15%**	4.77%	6.46%
Total	100.00%		7.41%	9.10%

Note: Common equity ratio will be calculated at the lesser of actual average or 47.00%.

<u>Calculation of Excess Earnings To Be Deferred</u>

Allowed ROE in JP		9.30%
Actual Earned ROE		10.15%
ROE Basis Points above/(below) Threshold		85
Equity Earnings over/(under) Target	**$**	**231,393**

	BP	Total To Be Shared	Customer's Share	Company's Share
ROE 9.30% ≤ 9.80%, Customers 0% / Company 100%	50	$ 136,375	0	136,375
ROE above 9.80% ≤ 10.30%, Customers 50% / Company 50%	35	95,018	47,509	47,509
ROE above 10.30% ≤ 10.80%, Customers 80% / Company 20%	0	0	0	0
ROE above 10.80%, Customers 90% / Company 10%	0	0	0	0
Total Shared	**85**	**$ 231,393**	**$ 47,509**	**$ 183,884**
Combined Federal & State Income Tax Rate		26.135%	26.135%	26.135%
Amount Deferred		**$ 313,264**	**$ 64,319**	**$ 248,946**

Liberty Utilities (St. Lawrence Gas Corp.)
Earnings Sharing Calculation - Example
For The Rate Year Ending October 31, 2028

Net Inome	$ 4,800,000
Rate Base	65,340,396
Overall ROR	7.35%

	Weighting Percent	Cost	Weighted Cost	Pre-Tax Weighted Cost
Long Term Debt	50.82%	5.01%	2.55%	2.55%
Customer Deposits	1.18%	3.00%	0.04%	0.04%
Common Equity (see note below)	**48.00%**	**9.91%**	4.76%	6.44%
Total	100.00%		7.35%	9.03%

Note: Common equity ratio will be calculated at the lesser of actual average or 48.00%.

<u>Calculation of Excess Earnings To Be Deferred</u>

Allowed ROE in JP	9.30%
Actual Earned ROE	9.91%
ROE Basis Points above/(below) Threshold	61
Equity Earnings over/(under) Target	**$ 190,888**

	BP	Total To Be Shared	Customer's Share	Company's Share
ROE 9.30% ≤ 9.80%, Customers 0% / Company 100%	50	$ 156,817	0	156,817
ROE above 9.80% ≤ 10.30%, Customers 50% / Company 50%	11	34,072	17,036	17,036
ROE above 10.30% ≤ 10.80%, Customers 80% / Company 20%	0	0	0	0
ROE above 10.80%, Customers 90% / Company 10%	0	0	0	0
Total Shared	**61**	**$ 190,888**	**$ 17,036**	**$ 173,853**
Combined Federal & State Income Tax Rate		26.135%	26.135%	26.135%
Amount Deferred		**$ 258,429**	**$ 23,063**	**$ 235,365**

Liberty Utilities (St. Lawrence Gas Corp.)
Earnings Sharing Calculation - Example
For The Stub Period November 1, 2028 through April 30, 2029

Operating Income (For the 6-month period)	$ 3,978,000
Rate Base	70,000,000
Operating Income Ratio	77.51%
Rate Base As Adjusted	54,259,548
Overall ROR	7.33%

Monthly Operating Income		Ratio
November 2028	$ 555,000	10.81%
December 2028	625,000	12.18%
January 2029	811,000	15.80%
February 2029	777,000	15.14%
March 2029	655,000	12.76%
April 2029	555,000	10.81%
May 2029	333,000	6.49%
June 2029	222,000	4.33%
July 2029	111,000	2.16%
August 2029	111,000	2.16%
September 2029	155,000	3.02%
October 2029	222,000	4.33%
Total	$ 5,132,000	100.00%

	Weighting Percent	Cost	Weighted Cost	Pre-Tax Weighted Cost
Long Term Debt	50.82%	5.01%	2.55%	2.55%
Customer Deposits	1.18%	3.00%	0.04%	0.04%
Common Equity (see note below)	**48.00%**	**9.90%**	4.75%	6.43%
Total	100.00%		7.33%	9.01%

Note: Common equity ratio will be calculated at the lesser of actual average or 48.00%.

<u>Calculation of Excess Earnings To Be Deferred</u>

Allowed ROE in JP	9.30%
Actual Earned ROE	9.90%
ROE Basis Points above/(below) Threshold	60
Equity Earnings over/(under) Target	**$ 200,163**

	BP	Total To Be Shared	Customer's Share	Company's Share
ROE 9.30% ≤ 9.80%, Customers 0% / Company 100%	50	$ 168,000	0	168,000
ROE above 9.80% ≤ 10.30%, Customers 50% / Company 50%	10	32,163	16,081	16,081
ROE above 10.30% ≤ 10.80%, Customers 80% / Company 20%	0	0	0	0
ROE above 10.80%, Customers 90% / Company 10%	0	0	0	0
Total Shared	**60**	**$ 200,163**	**$ 16,081**	**$ 184,081**
Combined Federal & State Income Tax Rate		26.135%	26.135%	26.135%
Amount Deferred		**$ 270,984**	**$ 21,771**	**$ 249,213**

Disclaimer: The amounts (rate base, operating income ratios, earned ROE) contained in this stub period example are hypothetical. The calculation will be reflective of actual financial results.

Liberty Utilites (St. Lawrence Gas) Corp.

Revenue Allocation RY 1
Twelve-Months Ending in October 31, 2026

Revenue Increase	$1,064,511
Percent On Base Rate	6.60%

Service Classes	Allocation Factor	Revenue at Current Rates	Based Revenue Increase	Total Increase	% Increase	Revenue Target
SC No. 1 - Residential	0.80	$10,379,808	$547,777	$625,601	6.03%	$11,005,408
SC No. 2 - Small General Firm Service (Commercial)	1.00	$3,651,661	$240,888	$268,267	7.35%	$3,919,927
SC No. 2- Large Commercial	1.00	$896,359	$59,130	$65,850	7.35%	$962,209
SC No. 3 - Large General Firm Service (Industrial)	1.20	$1,209,279	$95,726	$104,793	8.67%	$1,314,072
Total		**$16,137,105**	**$943,521**	**$1,064,511**		**$17,201,616**

Revenue Allocation RY 2
Twelve-Months Ending in October 31, 2027

Revenue Increase	$1,093,427
Percent On Base Rate	6.31%

Service Classes	Allocation Factor	Revenue at Current Rates	Based Revenue Increase	Total	% Increase	Revenue Target
SC No. 1 - Residential	0.80	$11,026,477	$556,960	$635,051	5.76%	$11,661,528
SC No. 2 - Small General Firm Service (Commercial)	1.00	$3,996,675	$252,346	$280,651	7.02%	$4,277,325
SC No. 2- Large Commercial	1.00	$980,566	$61,912	$68,856	7.02%	$1,049,423
SC No. 3 - Large General Firm Service (Industrial)	1.20	$1,314,072	$99,563	$108,869	8.28%	$1,422,941
Total		**$17,317,790**	**$970,781**	**$1,093,427**		**$18,411,217**

Revenue Allocation RY 3
Twelve-Months Ending in October 31, 2028

Revenue Increase	$1,123,626
Percent On Base Rate	6.06%

Service Classes	Allocation Factor	Revenue at Current Rates	Based Revenue Increase	Total	% Increase	Revenue Target
SC No. 1 - Residential	1.00	$11,685,196	$708,029	$697,163	5.97%	$12,382,359
SC No. 2 - Small General Firm Service (Commercial)	1.00	$4,365,493	$264,514	$260,454	5.97%	$4,625,947
SC No. 2- Large Commercial	1.00	$1,070,522	$64,865	$63,870	5.97%	$1,134,391
SC No. 3 - Large General Firm Service (Industrial)	1.20	$1,422,941	$103,462	$102,139	7.18%	$1,525,080
Total		**$18,544,152**	**$1,140,870**	**$1,123,626**		**$19,667,778**

Revenue Allocation Stayout Period
Twelve-Months Ending in October 31, 2029

Revenue Increase	$613,886
Percent On Base Rate	3.12%

Service Classes	Allocation Factor	Revenue at Current Rates	Based Revenue Increase	Total	% Increase	Revenue Target
SC No. 1 - Residential	1.00	$12,382,359	$386,488	$380,494	3.07%	$12,762,853
SC No. 2 - Small General Firm Service (Commercial)	1.00	$4,625,947	$144,389	$142,149	3.07%	$4,768,097
SC No. 2- Large Commercial	1.00	$1,134,391	$35,408	$34,858	3.07%	$1,169,250
SC No. 3 - Large General Firm Service (Industrial)	1.20	$1,525,080	$57,122	$56,384	3.70%	$1,581,465
Total		**$19,667,778**	**$623,406**	**$613,886**		**$20,281,664**

Liberty Utilites (St. Lawrence Gas) Corp.

	Current Rates	Increase ($)	**Rate Year 1**	Increase ($)	**Rate Year 2**	Increase ($)	**Rate Year 3**	Increase ($)	**Stay-Out Period**
SC No. 1 - Residential									
Minimum Charge	$ 17.00	$ 1.5000	$ 18.50	$ 1.5000	$ 20.00	$ 1.5000	$ 21.50	$ -	$ 21.50
First 4 therms	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Next 36 therms	$ 0.5296	$ 0.0106	$ 0.5402	$ 0.0144	$ 0.5546	$ 0.0213	$ 0.5759	$ 0.0264	$ 0.6022
Over 40 therms	$ 0.4843	$ 0.0302	$ 0.5145	$ 0.0292	$ 0.5437	$ 0.0321	$ 0.5759	$ 0.0264	$ 0.6022
Contract Administration Charge*	$ 125.00	$ -	$ 125.00	$ -	$ 125.00	$ -	$ 125.00	$ -	$ 125.00
SC No. 2 - Commercial									
Minimum Charge	$ 28.00	$ 1.50	$ 29.50	$ 1.50	$ 31.00	$ 1.50	$ 32.50	$ -	$ 32.50
First 4 therms	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Next 66 therms	$ 0.4856	$ (0.0012)	$ 0.4844	$ 0.0362	$ 0.5207	$ 0.0325	$ 0.5532	$ 0.0206	$ 0.5737
Next 4,930 therms	$ 0.2786	$ 0.0242	$ 0.3028	$ 0.0227	$ 0.3254	$ 0.0203	$ 0.3457	$ 0.0129	$ 0.3586
Next 45,000 therms	$ 0.1686	$ 0.0149	$ 0.1835	$ 0.0137	$ 0.1972	$ 0.0123	$ 0.2095	$ 0.0078	$ 0.2173
Over 50,000 therms	$ 0.1686	$ 0.0149	$ 0.1835	$ 0.0137	$ 0.1972	$ 0.0123	$ 0.2095	$ 0.0078	$ 0.2173
Contract Adminstration Charge*	$ 125.00	$ -	$ 125.00	$ -	$ 125.00	$ -	$ 125.00	$ -	$ 125.00
SC No. 2 - Commercial Large									
Minimum Charge	$ 190.00	$ 20.00	$ 210.00	$ 10.00	$ 220.00	$ 10.00	$ 230.00	$ -	$ 230.00
First 4 therms	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Next 66 therms	$ 0.2856	$ 0.0110	$ 0.2966	$ 0.0026	$ 0.2992	$ 0.0181	$ 0.3173	$ 0.0100	$ 0.3273
Next 4,930 therms	$ 0.2856	$ 0.0110	$ 0.2966	$ 0.0026	$ 0.2992	$ 0.0181	$ 0.3173	$ 0.0100	$ 0.3273
Next 45,000 therms	$ 0.0959	$ 0.0043	$ 0.1002	$ 0.0086	$ 0.1088	$ 0.0066	$ 0.1154	$ 0.0037	$ 0.1190
Over 50,000 therms	$ 0.0671	$ 0.0100	$ 0.0771	$ 0.0066	$ 0.0837	$ 0.0051	$ 0.0887	$ 0.0028	$ 0.0916
Contract Adminstration Charge*	$ 125.00	$ -	$ 125.00	$ -	$ 125.00	$ -	$ 125.00	$ -	$ 125.00
SC No. 3 - Industrial									
Minimum Charge	$ 500.00	$ 50.00	$ 550.00	$ 25.00	$ 575.00	$ 25.00	$ 600.00	$ -	$ 600.00
Demand Charge (Per Mcf/D of Contract Volume)	$ 5.63	$ 0.37	$ 6.00	$ 0.25	$ 6.25	$ 0.25	$ 6.50	$ -	$ 6.50
Commodity Charge - First 10 therms	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Commodity Charge - First 12 times Contract Volume	$ 0.0080	$ 0.0130	$ 0.0210	$ (0.0094)	$ 0.0116	$ 0.0020	$ 0.0136	$ 0.0020	$ 0.0156
Commodity Charge - Excess therms	$ 0.0080	$ 0.0130	$ 0.0210	$ (0.0094)	$ 0.0116	$ 0.0020	$ 0.0136	$ 0.0020	$ 0.0156
Contract Adminstration Charge*	$ 125.00	$ -	$ 125.00	$ -	$ 125.00	$ -	$ 125.00	$ -	$ 125.00

* Applicable to customers with usage over 50,000 therms annually

RY1 Bill Impact Summary for SC-1 Residential, SC-2 Commercial, SC-2L Large Commercial, and SC-3 Industrial Rate Classes

Annual Average Heating Bills	Annual Average Therms	Annual Bill at Current Rates For an Average Heating Customer	Annual Bill at Proposed Rates For an Average Heating Customer	$ Change/Year	% Change/Year
SC-1 Sales	972	$1,046.44	$1,084.51	$38.06	3.6%
SC-1 Transport	972	$843.92	$883.49	$39.57	4.7%
SC-2 Sales	6,588	$4,896.51	$5,043.56	$147.05	3.0%
SC-2 Transport	6,588	$3,514.94	$3,676.06	$161.11	4.6%
SC-2L Sales	919,788	$450,215.85	$455,751.36	$5,535.51	1.2%
SC-2L Transport	919,788	$257,135.22	$264,672.49	$7,537.27	2.9%
SC-3 Transport	2,834,639	$389,902.42	$402,243.60	$12,341.18	3.2%

Levelized Monthly Bills	Levelized Monthly Average Therms	Monthly Bill at Current Rates For an Average Heating Customer	Monthly Bill at Proposed Rates For an Average Heating Customer	$ Change/Month	% Change/Month
SC-1 Sales	81	$87.58	$90.59	$3.01	3.4%
SC-1 Transport	81	$70.59	$73.77	$3.18	4.5%
SC-2 Sales	549	$408.04	$420.30	$12.25	3.0%
SC-2 Transport	549	$292.91	$306.34	$13.43	4.6%
SC-2L Sales	76,649	$37,674.17	$38,103.99	$429.82	1.1%
SC-2L Transport	76,649	$21,600.11	$22,193.59	$593.48	2.7%
SC-3 Transport	236,220	$32,491.87	$33,520.30	$1,028.43	3.2%

Gas costs used in the calculations above are reflective of the Company's August 2025 Gas Adjustment Clause Statement.

RY2 Bill Impact Summary for SC-1 Residential, SC-2 Commercial, SC-2L Large Commercial, and SC-3 Industrial Rate Classes

Annual Average Heating Bills	Annual Average Therms	Annual Bill at Current Rates For an Average Heating Customer	Annual Bill at Proposed Rates For an Average Heating Customer	$ Change/Year	% Change/Year
SC-1 Sales	972	$1,084.51	$1,124.56	$40.05	3.7%
SC-1 Transport	972	$883.49	$923.11	$39.62	4.5%
SC-2 Sales	6,588	$5,043.56	$5,220.48	$176.92	3.5%
SC-2 Transport	6,588	$3,676.06	$3,852.98	$176.92	4.8%
SC-2L Sales	919,788	$455,751.36	$462,664.51	$6,913.15	1.5%
SC-2L Transport	919,788	$264,672.49	$271,572.40	$6,899.91	2.6%
SC-3 Transport	2,834,639	$402,243.60	$412,840.09	$10,596.49	2.6%

Levelized Monthly Bills	Levelized Monthly Average Therms	Monthly Bill at Current Rates For an Average Heating Customer	Monthly Bill at Proposed Rates For an Average Heating Customer	$ Change/Month	% Change/Month
SC-1 Sales	81	$90.59	$93.80	$3.22	3.5%
SC-1 Transport	81	$73.77	$76.99	$3.22	4.4%
SC-2 Sales	549	$420.30	$435.04	$14.74	3.5%
SC-2 Transport	549	$306.34	$321.08	$14.74	4.8%
SC-2L Sales	76,649	$38,103.99	$38,690.80	$586.81	1.5%
SC-2L Transport	76,649	$22,193.59	$22,780.40	$586.81	2.6%
SC-3 Transport	236,220	$33,520.30	$34,403.34	$883.04	2.6%

Gas costs used in the calculations above are reflective of the Company's August 2025 Gas Adjustment Clause Statement.

RY3 Bill Impact Summary for SC-1 Residential, SC-2 Commercial, SC-2L Large Commercial, and SC-3 Industrial Rate Classes

Annual Average Heating Bills	Annual Average Therms	Annual Bill at Current Rates For an Average Heating Customer	Annual Bill at Proposed Rates For an Average Heating Customer	$ Change/Year	% Change/Year
SC-1 Sales	972	$1,124.56	$1,168.62	$44.06	3.9%
SC-1 Transport	972	$923.11	$966.86	$43.75	4.7%
SC-2 Sales	6,588	$5,220.48	$5,380.89	$160.41	3.1%
SC-2 Transport	6,588	$3,852.98	$4,013.39	$160.41	4.2%
SC-2L Sales	919,788	$462,664.51	$468,931.67	$6,267.16	1.4%
SC-2L Transport	919,788	$271,572.40	$277,829.46	$6,257.06	2.3%
SC-3 Transport	2,834,639	$412,840.09	$422,775.02	$9,934.92	2.4%

Levelized Monthly Bills	Levelized Monthly Average Therms	Monthly Bill at Current Rates For an Average Heating Customer	Monthly Bill at Proposed Rates For an Average Heating Customer	$ Change/Month	% Change/Month
SC-1 Sales	81	$93.80	$97.39	$3.58	3.8%
SC-1 Transport	81	$76.99	$80.57	$3.58	4.7%
SC-2 Sales	549	$435.04	$448.41	$13.37	3.1%
SC-2 Transport	549	$321.08	$334.45	$13.37	4.2%
SC-2L Sales	76,649	$38,690.80	$39,221.24	$530.44	1.4%
SC-2L Transport	76,649	$22,780.40	$23,310.83	$530.44	2.3%
SC-3 Transport	236,220	$34,403.34	$35,231.25	$827.91	2.4%

Gas costs used in the calculations above are reflective of the Company's August 2025 Gas Adjustment Clause Statement.

	MFC		DRA		Total	
Gas Procurement Salary	**$**	**136,373.25**	**$**	**136,373.25**		
		50.0%		25.0%		
	$	68,187	$	34,093		
Overhead		33.4%		33.4%		
	$	90,915	$	45,458	$	136,373
Uncollectibles	$	12,357,799	$	4,044,799		
		0.5%		0.5%		
Before revenue tax	$	61,789	$	20,224	$	82,013
Gas Control	$	293,165	$	293,165		
Overhead		33.4%		33.4%		
	$	97,917	$	97,917	$	195,834
CC on Gas in Storage	$	1,651,949	$	1,651,949		
Other Customer Provided Capital		4.8%		4.8%		
Sales Portion of Storage		75.3%		24.7%		
	$	59,086	$	19,389	$	78,475
Total	$	309,708	$	182,988	$	492,696
					$	**492,696**

MFC and DRA Summary

SC #1, 2 and 3 Sales and T Revenue	
Uncollectible Expense	
Uncollectible Rate	0.50%

* Amounts listed are for illustrative purposes. Targets will be set using known actual.
1) 50% is recovered through the MFC, 25% through DRA and 25% through base rates.
2) 1/3 is recovered through MFC, 1/3 through DRA and 1/3 in base rates.
3) The actual interest rate will be updated annually when rates go into effect

RDM Target Calculation

	Rate Year 1	Rate Year 2	Rate Year 3	Stay-Out Period
SC1 Residential (Sales and Transportation)				
RDM Target Revenue	$10,783,883	$11,661,528	$12,382,359	$12,762,853
SC2 & SC2L Commercial (Sales and Transportation)				
RDM Target Revenue	$4,763,826	$5,326,748	$5,760,339	$5,937,347

RDM Target Revenues by Month	Rate Year 1												
	25-Nov	**25-Dec**	**26-Jan**	**26-Feb**	**26-Mar**	**26-Apr**	**26-May**	**26-Jun**	**26-Jul**	**26-Aug**	**26-Sep**	**26-Oct**	**Total**
Rate Year 1													
Residential Sales													-
Residential Transportation													-
Total Residential	-	-	-	-	-	-	-	-	-	-	-	-	-
Commercial Sales													-
Commercial Transportation													-
Total Commercial	-	-	-	-	-	-	-	-	-	-	-	-	-

RDM Target Revenues by Month	Rate Year 2												
	26-Nov	**26-Dec**	**27-Jan**	**27-Feb**	**27-Mar**	**27-Apr**	**27-May**	**27-Jun**	**27-Jul**	**27-Aug**	**27-Sep**	**27-Oct**	**Total**
Rate Year 1													
Residential Sales													-
Residential Transportation													-
Total Residential	-	-	-	-	-	-	-	-	-	-	-	-	-
Commercial Sales													-
Commercial Transportation													-
Total Commercial	-	-	-	-	-	-	-	-	-	-	-	-	-

RDM Target Revenues by Month	Rate Year 3												
	27-Nov	**27-Dec**	**28-Jan**	**28-Feb**	**28-Mar**	**28-Apr**	**28-May**	**28-Jun**	**28-Jul**	**28-Aug**	**28-Sep**	**28-Oct**	**Total**
Rate Year 1													
Residential Sales													-
Residential Transportation													-
Total Residential	-	-	-	-	-	-	-	-	-	-	-	-	-
Commercial Sales													-
Commercial Transportation													-
Total Commercial	-	-	-	-	-	-	-	-	-	-	-	-	-

RDM Target Revenues by Month	Stay Out												
	28-Nov	**28-Dec**	**29-Jan**	**Feb-29**	**29-Mar**	**29-Apr**	**29-May**	**29-Jun**	**29-Jul**	**29-Aug**	**29-Sep**	**29-Oct**	**Total**
Rate Year 1													
Residential Sales													-
Residential Transportation													-
Total Residential	-	-	-	-	-	-	-	-	-	-	-	-	-
Commercial Sales													-
Commercial Transportation													-
Total Commercial	-	-	-	-	-	-	-	-	-	-	-	-	-

Lost And Unaccounted For Gas (LAUF)

The LAUF factor will be 1.00226 which requires non-sales customers to deliver an extra 23 units for every 10,000 to the city gate (system) and is a loss percentage of city gate receipts of 0.226% (approximate). The standard deviation of the loss percentage of city gate receipts is 0.180% as calculated from the last five years of data. Two standard deviations 0.360% is more than 0.226% and, thus Liberty SLG will be allowed to recover gas costs up to a loss percentage of 0.946% (four standard deviations), or for every 99,054 units delivered by the system, 100,000 units are delivered to the city gate.
Liberty SLG will be assessed a LAUF penalty of units in excess of the allowed recovery times the average cost of gas. The calculation of the average cost of gas is shown below as purchase units vary due to non-sales customers receipts-to-deliveries lag.
A System Performance Adjustment (SPA) will be refunded or surcharged to all customers, i.e., sales and non-sales customers, from each year's gas reconciliation. Refunds will occur when the loss percentage for that year is below 0.226% and surcharges will occur when the loss percentage for that year is above 0.226% with the Gas Adjustment Clause (GAC) refund/surcharge designed to recover the sales deliveries times the average cost of gas times the LAUF factor. Below are examples of how the GAC and SPA function for five different loss percentages. The sales deliveries, non-sale deliveries, and average cost of gas have been kept at 29 million therms, 43 million therms, and $0.63 per therm, respectively, for all examples.

Row	Calculation							
0		Actual LAUF	-0.215%	0.000%	0.143%	0.568%	0.716%	0.950%
1	Input	Sales Deliveries	29,000,000	29,000,000	29,000,000	29,000,000	29,000,000	29,000,000
2	Input	Non-Sales Deliveries	43,000,000	43,000,000	43,000,000	43,000,000	43,000,000	43,000,000
3	(1) + (2)	Total Deliveries	72,000,000	72,000,000	72,000,000	72,000,000	72,000,000	72,000,000
4	Input	City Gate Receipts	71,845,200	72,000,000	72,102,960	72,408,960	72,515,520	72,684,000
5	(2) * 1.00156	Non-Sales Receipts	43,067,080	43,067,080	43,067,080	43,067,080	43,067,080	43,067,080
6	(4) - (5)	Sales Receipts	28,778,120	28,932,920	29,035,880	29,341,880	29,448,440	29,616,920
7	Input	Commodity Costs	$ 18,130,216	$ 18,227,740	$ 18,292,604	$ 18,485,384	$ 18,552,517	$ 18,658,660
8	(7) / (6)	Commodity Cost per Therm	0.630000	0.630000	0.630000	0.630000	0.630000	0.630000
9	(3) / (.9914)	Maximum Allowed City Gate Receipts	72,624,571	72,624,571	72,624,571	72,624,571	72,624,571	72,624,571
10	(4) - (9) if (4) > (9) or 0	Disallowed Therm Recovery	-	-	-	-	-	59,429
11	(8) * (10)	Penalty	-	-	-	-	-	37,440
12	(7)	Commodity Costs	18,130,216	18,227,740	18,292,604	18,485,384	18,552,517	18,658,660
13	(11)	Penalty	-	-	-	-	-	37,440
14	(7) - (11)	Actual Commodity Cost Recoveries	18,130,216	18,227,740	18,292,604	18,485,384	18,552,517	18,621,220
15	(1) * (8) * 1.00156	Allowed Commodity Cost Recoveries	18,298,501	18,298,501	18,298,501	18,298,501	18,298,501	18,298,501
16	(0)*(3)*(8) if (0) < 0	LAUF Adjustment below 0	(97,524)					
17	(14) - (15) - (16)	SPA (Refund)/Surcharge from all Customers	(70,761)	(70,761)	(5,897)	186,883	254,016	322,719

Liberty SLG
Gas Safety Metrics

Leak Management

Leak Backlog Targets						
Metric	**Leak Types**	**Leak Backlog Targets**			**NRA (BPs)**	**PRA (BPs)**
		2026	**2027**	**2028**		
Year-end Leak Backlog	Total: Types 1, 2A, 2, and 3	4+	4+	4+	(18)	-

Emergency Response

	Emergency Response Time Targets					
Metric	**Response Time**	**Percent completed**			**NRA (BPS)**	**PRA (BPs)**
		2026	**2027**	**2028**		
Emergency Response	Within 30 minutes	<75	<75	<75	(9)	-
		>85 - 90	>85 - 90	>85 - 90	-	3
		>90	>90	>90	-	6
	Within 45 minutes	<90	<90	<90	(6)	-
	Within 60 minutes	<95	<95	<95	(3)	-

Damage Prevention

Damage Prevention Targets						
Metric	**Criteria**	**2026**	**2027**	**2028**	**NRA (BPs)**	**PRA (BPs)**
Damage Prevention (per 1,000 one-call tickets)	No-calls, Excavator Error, Company and Company Contractor Error, and Mismarks	>2.40	>2.40	>2.40	(27)	-
		>2.05 - 2.40	>2.05 - 2.40	>2.05 - 2.40	(15)	-
		≥1.95 - 2.05	≥1.95 - 2.05	≥1.95 - 2.05	(5)	-
		<1.75	<1.75	<1.75	-	5
		<1.70	<1.70	<1.70	-	10

Compliance Measure Procedures

Applicability

The compliance measure applies to instances of non-compliance (occurrences or violations) of certain gas pipeline safety-related regulations set forth below that are identified and included in the Staff's record and field audit letters. The categorization of instances of non-compliance as High Risk or Other Risk is for administrative purposes only.

The compliance measure covers the calendar years associated with the term of the rate plan set forth in the Joint Proposal, i.e., 2026, 2027 and 2028, and shall remain in effect thereafter until changed by the Commission in a subsequent Liberty SLG rate case.

Targets

Liberty SLG, herein referred to as the "operator" will incur negative revenue adjustments for each High Risk and Other Risk instance of non-compliance, as set forth in the following tables:

2026 through 2028 Field Audits		
Associated Risk	Target (Number of Instances of Non-Compliance)	Negative Revenue Adjustment (Basis Points per Instance of Non-Compliance)
High Risk	0-8	0.50
	Greater than 8	1
Other Risk	All Violations	0.25

For field audits, only actions performed or failures to take actions required to be performed by the operator in the calendar year the audit is conducted may constitute an instance of non-compliance under this measure.

2026 through 2028 Record Audits		
Associated Risk	Target (Number of Instances of Non-Compliance)	Negative Revenue Adjustment (Basis Points per Instance of Non-Compliance)
High Risk	0 to 4	0
High Risk	5 to 8	0.50
High Risk	Greater than 8	1.00
Other Risk	0 to 8	0
Other Risk	Greater than 8	0.25

For record audits, only documentation that the operator is required, but fails to generate during the calendar year prior to the calendar year in which the record audit is conducted, may constitute an instance of non-compliance under this measure. Unless it is a continuing violation from prior years, in which case it may also constitute an instance of non-compliance under this measure.

Field and Record Audits

On a calendar year basis, Staff conducts field and record audits to determine the operator's compliance with the pipeline safety regulations contained in 16 NYCRR Parts 10, 232, 255, 257, 258, 259, 261, 262, 293, 420, 733, and 753, 49 CFR Part 193, and the relevant statutory provisions in General Business Law and Public Service Law. At the conclusion of each audit, Staff will present its findings at a compliance meeting to the operator.

The operator shall have ten business days from the date of the compliance meeting to cure any identified document deficiency. Only official operator records, as defined in the operator's operating and maintenance procedures, shall be considered as a cure to a document deficiency. Staff shall provide the operator with the field and record audit letters. Only instances of non-compliance identified and included in Staff's field and record audit letters shall be considered for the compliance measure.

The field and record audit letters require, if applicable, that the operator respond within thirty days of the audit letter detailing what actions have and/or will be taken by the operator to remediate the instances of non-compliance and to address Staff's concerns, and to prevent future reoccurrences. The operator's response may also include any disputes related to the instance of non-compliance, including but not limited to, sufficient arguments regarding the appropriateness of applying a negative revenue adjustment. The operator shall provide its response to an audit letter to the Chief of Pipeline Safety.

In addition, the operator should address instances of non-compliance of a single regulation in excess of ten per record audit per calendar year through a remediation plan. The operator shall provide to the Chief of Pipeline Safety the remediation plan within ninety days of Staff's field or record audit letters. The remediation plan shall include, at a minimum, an analysis for the instances of non-compliance, and an explanation of how the instances of non-compliance will be resolved, including the dates by which the instances of non-compliance will be brought into compliance or, where appropriate, when remedial actions will be taken to prevent future recurrence.

Staff then will review and consider each instance of non-compliance for applicability with the compliance measure on a case-by-case basis. Instances of non-compliance subject to a separate penalty proceeding under Public Service Law §25 or §25-a, and instances of non-compliance for which sufficient arguments have been raised regarding the appropriateness of a negative revenue adjustment, will be excluded from consideration. Once reviewed and the circumstances considered, Staff shall file the negative revenue adjustment letter in Case 24-G-0668. Copies of the staff audit letters, and any operator responses, and any remediation plans will be submitted in Case 24-G-0668 when the negative revenue adjustment letter is submitted.

Negative Revenue Adjustments

The operator will incur negative revenues adjustments for each High Risk and Other Risk instance of non-compliance up to a combined maximum of seventy-five basis points per calendar year, as per the above targets.

The number of instances of non-compliance, for any applicable regulation, may be capped at ten per record audit per calendar year provided a remediation plan as described above is filed with the Chief of Pipeline Safety. If the operator files a remediation plan, it shall include, at a minimum, an analysis for the instances of non-compliance, and an explanation of how the non-compliance with the applicable regulation will be resolved, including the dates by which the instance of non-compliance will be brought into compliance or, where appropriate, when remedial actions will be taken to prevent future recurrence.

Remediation plans shall be filed with the Chief of Pipeline Safety within ninety days of Staff's field or record audit letters. If the operator fails to file a remediation plan or fails to comply with the provisions of its remediation plan, those instances of non-compliance in excess of ten shall be incorporated with the remainder of the instances of non-compliance being considered under this measure.

If the operator elects to dispute any instance of non-compliance or negative revenue adjustments, or to seek exclusions of certain non-compliances based on extenuating circumstances, the operator shall file a petition within sixty days of Staff's negative revenue adjustment letter in Case 24-G-0668. For those disputed items or exclusions, the operator will not incur a negative revenue adjustment until the Commission has issued a determination.

The operator does not waive its right to seek judicial appeal of any Commission determination under applicable law. Should the operator elect to seek judicial appeal of any Commission determination under applicable law, the operator will not incur a negative revenue adjustment until such time that the judicial review is complete, and a determination rendered.

If any instance of non-compliance is the subject of a separate penalty proceeding under Public Service Law §25 or §25-a, the instance of non-compliance shall not be considered for the compliance measure.

If an instance of non-compliance has a corresponding procedural instance of non-compliance under 16 NYCRR §255.603(d), non-compliance with both provisions shall be considered as a single instance of non-compliance for the compliance measure.

Risk Rankings

The pipeline safety regulations are contained in 16 NYCRR Parts 10, 232, 255, 257, 258, 259, 261, 262, 293, 420, 733, and 753, 49 CFR Part 193, and the relevant statutory provisions contained in General Business Law and Public Service Law. Set forth below are the High Risk and Other Risk pipeline safety regulations being considered for the compliance measure.

Title	Chapter	Subchapter	Part	Section	Subdivision	Description	Risk
16	III	C	255	5	(g)	Class Locations	High
16	III	C	255	14	(a)	Conversion to Service Subject to this Part	High
16	III	C	255	14	(b)	Conversion to Service Subject to this Part	Other
16	III	C	255	17	All	Preservation of Records	Other
16	III	C	255	18	(a),(c)	Notifications and Reports	High
16	III	C	255	53	All	Materials - General	High
16	III	C	255	65	All	Materials - Transportation of Pipe	High
16	III	C	255	67	(a),(b)	Records - Material Properties	High
16	III	C	255	103	All	Pipe Design - General	High
16	III	C	255	127	(a),(b)	Records - Pipe Design	High
16	III	C	255	143	All	Design of Pipeline Components - General Requirements	High
17	III	C	255	153	(e)	Components fabricated by welding	High
16	III	C	255	159	All	Design of Pipeline Components - Flexibility	High
16	III	C	255	161	All	Design of Pipeline Components - Supports and Anchors	High
16	III	C	255	163	All	Compressor Stations - Design and Construction	Other
16	III	C	255	165	All	Compressor Stations - Liquid Removal	Other
16	III	C	255	167	All	Compressor Stations - Emergency Shutdown	High
16	III	C	255	169	All	Compressor Stations - Pressure Limiting Devices	High
16	III	C	255	171	All	Compressor Stations - Additional Safety Equipment	Other
16	III	C	255	173	All	Compressor Stations - Ventilation	High
16	III	C	255	179	All	Valves on Pipelines to Operate at 125 PSIG (862 kPa) or More	High
16	III	C	255	181	All	Distribution Line Valves	High
16	III	C	255	183	All	Vaults - Structural Design Requirements	High
16	III	C	255	185	All	Vaults - Accessibility	Other
16	III	C	255	187	All	Vaults - Sealing, Venting, and Ventilation	Other
16	III	C	255	189	All	Vaults - Drainage and Waterproofing	High
16	III	C	255	190	All	Calorimeter or Calorimixer Structures	Other
16	III	C	255	191	All	Design Pressure of Plastic Fittings	Other
16	III	C	255	193	All	Valve Installation in Plastic Pipe	Other
16	III	C	255	195	All	Protection Against Accidental Overpressuring	High
16	III	C	255	197	All	Control of the Pressure of Gas Delivered from High Pressure Distribution Systems	High
16	III	C	255	199	All	Requirements for Design of Pressure Relief and Limiting Devices	High
16	III	C	255	201	All	Required Capacity of Pressure Relieving and Limiting Stations	High
16	III	C	255	203	All	Instrument, Control, and Sampling Piping and Components	Other
16	III	C	255	205	(a),(b)	Records - Pipeline Components	High
16	III	C	255	225	All	Qualification of Welding Procedures	High
16	III	C	255	227	All	Qualification of Welders	High
16	III	C	255	229	All	Limitations On Welders	Other
16	III	C	255	230	All	Quality Assurance Program	Other
16	III	C	255	231	All	Welding - Protection from Weather	High
16	III	C	255	233	All	Welding - Miter Joints	High
16	III	C	255	235	All	Preparation for Welding	High
16	III	C	255	237	All	Welding - Preheating	Other
16	III	C	255	239	All	Welding - Stress Relieving	Other
16	III	C	255	241	(a),(b)	Inspection and Test of Welds	High
16	III	C	255	241	(c)	Inspection and Test of Welds	Other
16	III	C	255	243	(a),(b),(c),(d),(e)	Nondestructive Testing - Pipeline to Operate at 125 PSIG (862 kPa) or More	High
16	III	C	255	243	(f)	Nondestructive Testing - Pipeline to Operate at 125 PSIG (862 kPa) or More	Other

Title	Chapter	Subchapter	Part	Section	Subdivision	Description	Risk
16	III	C	255	244	All	Welding Inspector	High
16	III	C	255	245	All	Welding - Repair or Removal of Defects	High
16	III	C	255	273	All	Joining of Materials other than by Welding - General	High
16	III	C	255	279	All	Joining of Materials other than by Welding - Copper Pipe	High
16	III	C	255	281	All	Joining of Materials other than by Welding - Plastic Pipe	High
16	III	C	255	283	All	Plastic Pipe - Qualifying Joining Procedures	Other
16	III	C	255	285	(a),(b),(d)	Plastic Pipe - Qualifying Persons to make Joints	High
16	III	C	255	285	(c),(e),(f)	Plastic Pipe - Qualifying Persons to make Joints	Other
16	III	C	255	287	All	Plastic Pipe - Inspection of Joints	Other
16	III	C	255	302	All	Notification Requirements	High
16	III	C	255	303	All	Compliance with Construction Standards	High
16	III	C	255	305	All	Inspection - General	High
16	III	C	255	307	All	Inspection of Materials	High
16	III	C	255	309	All	Repair of Steel Pipe	High
16	III	C	255	311	All	Repair of Plastic Pipe	High
16	III	C	255	313	(a),(b),(c)	Bends and Elbows	High
16	III	C	255	313	(d)	Bends and Elbows	Other
16	III	C	255	315	All	Wrinkle Bends in Steel Pipe	High
16	III	C	255	317	All	Protection from Hazards	Other
16	III	C	255	319	All	Installation of Pipe in a Ditch	Other
16	III	C	255	321	All	Installation of Plastic Pipe	High
16	III	C	255	323	All	Casing	Other
16	III	C	255	325	All	Underground Clearance	High
16	III	C	255	327	All	Cover	Other
16	III	C	255	353	All	Customer Meters and Regulators - Location	Other
16	III	C	255	355	All	Customer Meters and Regulators - Protection from Damage	Other
16	III	C	255	357	(a),(b),(c)	Customer Meters and Service Regulators - Installation	Other
16	III	C	255	357	(d)	Customer Meters and Service Regulators - Installation	High
16	III	C	255	359	All	Customer Meter Installations - Operating Pressure	Other
16	III	C	255	361	(a),(b),(c),(d)	Service Lines - Installation	Other
16	III	C	255	361	(e),(f),(g),(h),(i)	Service Lines - Installation	High
16	III	C	255	363	All	Service Lines - Valve Requirements	Other
16	III	C	255	365	(a),(c)	Service Lines - Location of Valves	Other
16	III	C	255	365	(b)	Service Lines - Location of Valves	High
16	III	C	255	367	All	Service Lines - General Requirements for Connections	Other
16	III	C	255	369	All	Service Lines - Connections to Cast Iron or Ductile Iron Mains	Other
16	III	C	255	371	All	Service Lines - Steel	Other
16	III	C	255	373	All	Service Lines - Cast Iron and Ductile Iron	Other
16	III	C	255	375	All	Service Lines - Plastic	Other
16	III	C	255	377	All	Service Lines - Copper	Other
16	III	C	255	379	All	New Service Lines not in Use	Other
16	III	C	255	381	All	Service Lines - Excess Flow Valve Performance Standards	Other
16	III	C	255	455	(a)	External Corrosion Control - Buried or Submerged Pipelines Installed after July 31, 1971	Other
16	III	C	255	455	(d),(e)	External Corrosion Control - Buried or Submerged Pipelines Installed after July 31, 1971	High
16	III	C	255	457	All	External Corrosion Control - Buried or Submerged Pipelines Installed before July 31, 1971	High
16	III	C	255	459	All	External Corrosion Control - Examination of Buried Pipeline when Exposed	Other
16	III	C	255	461	(a),(b),(d),(e),(f),(g)	External Corrosion Control - Protective Coating	Other

Title	Chapter	Subchapter	Part	Section	Subdivision	Description	Risk
16	III	C	255	461	(c)	External Corrosion Control - Protective Coating	High
16	III	C	255	463	All	External Corrosion Control - Cathodic Protection	High
16	III	C	255	465	(a),(e)	External Corrosion Control - Monitoring	High
16	III	C	255	465	(b),(c),(d),(f)	External Corrosion Control - Monitoring	Other
16	III	C	255	467	All	External Corrosion Control - Electrical Isolation	Other
16	III	C	255	469	All	External Corrosion Control - Test Stations	Other
16	III	C	255	471	All	External Corrosion Control - Test Leads	Other
16	III	C	255	473	All	External Corrosion Control - Interference Currents	Other
16	III	C	255	475	All	Internal Corrosion Control - General	Other
16	III	C	255	476	(a),(c)	Internal Corrosion Control - Design and Construction of Transmission Line	High
16	III	C	255	476	(d)	Internal Corrosion Control - Design and Construction of Transmission Line	Other
16	III	C	255	479	All	Atmospheric Corrosion Control - General	Other
16	III	C	255	481	All	Atmospheric Corrosion Control - Monitoring	Other
16	III	C	255	483	All	Remedial Measures - General	High
16	III	C	255	485	(a),(b)	Remedial Measures - Transmission Lines	High
16	III	C	255	485	(c)	Remedial Measures - Transmission Lines	Other
16	III	C	255	487	All	Remedial Measures - Distribution Lines other than Cast Iron or Ductile Iron Lines	Other
16	III	C	255	489	All	Remedial Measures - Cast Iron and Ductile Iron Pipelines	Other
16	III	C	255	490	All	Direct Assessment	Other
16	III	C	255	491	All	Corrosion Control Records	Other
16	III	C	255	493	All	In-Line Insepction of Pipelines	High
16	III	C	255	503	All	Test Requirements - General	Other
16	III	C	255	505	(a),(b),(c),(d)	Strength Test Requirements for Steel Pipelines to Operate at 125 PSIG (862 kPa) or More	High
16	III	C	255	505	(e),(h),(i)	Strength Test Requirements for Steel Pipelines to Operate at 125 PSIG (862 kPa) or More	Other
16	III	C	255	506	All	Transmission Lines - Spike Hydrostatic Pressure Test	High
16	III	C	255	507	All	Test Requirements for Pipelines to Operate at less than 125 PSIG (862 kPa)	Other
16	III	C	255	511	All	Test Requirements for Service Lines	Other
16	III	C	255	515	All	Environmental Protection and Safety Requirements	Other
16	III	C	255	517	All	Test Requirements - Records	Other
16	III	C	255	552	All	Upgrading / Conversion - Notification Requirements	Other
16	III	C	255	553	(a),(b),(c),(f)	Upgrading / Conversion - General Requirements	High
16	III	C	255	553	(d),(e)	Upgrading / Conversion - General Requirements	Other
16	III	C	255	555	All	Upgrading to a Pressure of 125 PSIG (862 kPa) or More in Steel Pipelines	High
16	III	C	255	557	All	Upgrading to a Pressure Less than 125 PSIG (862 kPa)	High
16	III	C	255	603	All	Operations - General Provisions	High
16	III	C	255	604	All	Operator Qualification	High
16	III	C	255	605	All	Essentials of Operating and Maintenance Plan	High
16	III	C	255	607	All	Verification of Pipeline Materials and Attributes - Onshore Steel Transmission Pipelines	High
16	III	C	255	609	All	Change in Class Location - Required Study	High
16	III	C	255	611	(a),(d)	Change in Class Location - Confirmation or Revision of Maximum Allowable Operating Pressure	Other
16	III	C	255	613	All	Continuing Surveillance	Other
16	III	C	255	614	All	Damage Prevention Program	High

Title	Chapter	Subchapter	Part	Section	Subdivision	Description	Risk
16	III	C	255	615	All	Emergency Plans	High
16	III	C	255	616	All	Customer Education and Information Program	High
16	III	C	255	619	All	Maximum Allowable Operating Pressure - Steel or Plastic Pipelines	High
16	III	C	255	621	All	Maximum Allowable Operating Pressure - High Pressure Distribution Systems	High
16	III	C	255	623	All	Maximum and Minimum Allowable Operating Pressure - Low Pressure Distribution Systems	High
16	III	C	255	624	All	Maximum Allowable Operating Pressure Reconfirmation - Onshore Steel Transmission Pipelines	High
16	III	C	255	625	(a),(b)	Odorization of Gas	High
16	III	C	255	625	(e),(f)	Odorization of Gas	Other
16	III	C	255	627	All	Tapping Pipelines Under Pressure	High
16	III	C	255	629	All	Purging of Pipelines	High
16	III	C	255	631	All	Control Room Management	High
16	III	C	255	632	All	Engineering Critical Assessment for Maximum Allowable Operating Pressure Reconfirmation - Onshore Steel Transmission Pipelines	High
16	III	C	255	705	All	Transmission Lines - Patrolling	High
16	III	C	255	706	All	Transmission Lines - Leakage Surveys	High
16	III	C	255	707	(a),(c),(d),(e)	Line Markers for Mains and Transmission Lines	Other
16	III	C	255	709	All	Transmission Lines - Record Keeping	Other
16	III	C	255	710	(b),(c),(d), (e),(f),(g)	Transmission Lines - Assessments Outside of High Consequence Areas	High
16	III	C	255	711	All	Transmission Lines - General Requirements for Repair Procedures	High
16	III	C	255	712	(a),(b),(d), (e),(f),(g)	Analysis of Predicated Failure Pressure	High
16	III	C	255	713	All	Transmission Lines - Permanent Field Repair of Imperfections and Damages	High
16	III	C	255	715	All	Transmission Lines - Permanent Field Repair of Welds	High
16	III	C	255	717	All	Transmission Lines - Permanent Field Repairs of Leaks	High
16	III	C	255	719	All	Transmission Lines - Testing of Repairs	High
16	III	C	255	721	(b)	Distribution Systems - Patrolling	Other
16	III	C	255	723	All	Distribution Systems -Leakage Surveys and Procedures	High
16	III	C	255	725	All	Test Requirements for Reinstating Service Lines	Other
16	III	C	255	726	All	Inactive Service Lines	Other
16	III	C	255	727	(b),(c),(d),(e),(f),(g)	Abandonment or Inactivation of Facilities	Other
16	III	C	255	729	All	Compressor Stations - Procedures for Gas Compressor Units	High
16	III	C	255	731	All	Compressor Stations - Inspection and Testing of Relief Devices	High
16	III	C	255	732	All	Compressor Stations - Additional Inspections	High
16	III	C	255	735	All	Compressor Stations - Storage of Combustible Materials	Other
16	III	C	255	736	All	Compressor Stations - Gas Detection	High
16	III	C	255	739	(a),(b)	Pressure Limiting and Regulating Stations - Inspection and Testing	High
16	III	C	255	739	(c),(d),(e),(f)	Pressure Limiting and Regulating Stations - Inspection and Testing	Other
16	III	C	255	740	(b)	Pressure regulating, limiting, and overpressure protection - Individual service lines directly connected to gathering or transmission pipelines	High
16	III	C	255	741	All	Pressure Limiting and Regulating Stations - Telemetering or Recording Gauges	Other

Title	Chapter	Subchapter	Part	Section	Subdivision	Description	Risk
16	III	C	255	743	(a),(b)	Pressure and Limiting and Regulating Stations - Testing of Relief Devices	High
16	III	C	255	743	(c)	Regulator Station MAOP	Other
16	III	C	255	744	All	Service Regulators and Vents - Inspection	Other
16	III	C	255	745	All	Transmission Line Valves	High
16	III	C	255	747	All	Valve Maintenance - Distribution Systems	Other
16	III	C	255	748	All	Valve Maintenance - Service Line Valves	Other
16	III	C	255	749	All	Vault Maintenance	Other
16	III	C	255	750	All	Launcher and Receiver Safety	High
16	III	C	255	751	All	Prevention of Accidental Ignition	High
16	III	C	255	753	All	Caulked Bell and Spigot Joints	Other
16	III	C	255	755	All	Protecting Cast Iron Pipelines	High
16	III	C	255	756	All	Replacement of Exposed or Undermined Cast Iron Piping	High
16	III	C	255	757	All	Replacement of Cast Iron Mains Paralleling Excavations	High
16	III	C	255	801	All	Reports of accidents	Other
16	III	C	255	803	All	Emergency Lists of Operator Personnel	Other
16	III	C	255	805	(a),(b),(e),(g),(h)	Leaks - General	Other
16	III	C	255	807	(a),(b),(c)	Leaks - Records	Other
16	III	C	255	807	(d)	Leaks - Records	High
16	III	C	255	809	All	Leaks - Instrument Sensitivity Verification	High
16	III	C	255	811	(b),(c),(d),(e)	Leaks - Type 1 Classification	High
16	III	C	255	813	(b),(c),(d)	Leaks - Type 2A Classification	High
16	III	C	255	815	(b),(c),(d)	Leaks - Type 2 Classification	High
16	III	C	255	817	All	Leaks - Type 3 Classification	Other
16	III	C	255	819	(a)	Leaks - Follow-Up Inspection	High
16	III	C	255	821	All	Leaks - Nonreportable Reading	High
16	III	C	255	823	(a),(b)	Interruptions of Service	Other
16	III	C	255	825	All	Logging and Analysis of Gas Emergency Reports	Other
16	III	C	255	829	All	Annual Report	Other
16	III	C	255	831	All	Reporting Safety-Related Conditions	Other
16	III	C	255	905	All	High Consequence Areas	High
16	III	C	255	907	All	General (IMP)	Other
16	III	C	255	909	All	Changes to an Integrity Management Program (IMP)	Other
16	III	C	255	911	All	Required Elements (IMP)	High
16	III	C	255	915	All	Knowledge and Training (IMP)	High
16	III	C	255	917	All	Identification of Potential Threats to Pipeline Integrity and Use of the Threat Identification in an Integrity Program (IMP)	High
16	III	C	255	919	All	Baseline Assessment Plan (IMP)	High
16	III	C	255	921	All	Conducting a Baseline Assessment (IMP)	High
16	III	C	255	923	All	Direct Assessment (IMP)	High
16	III	C	255	925	All	External Corrosion Direct Assessment (ECDA)(IMP)	High
16	III	C	255	927	All	Internal Corrosion Direct Assessment (ICDA)(IMP)	High
16	III	C	255	931	All	Confirmatory Direct Assessment (CDA)(IMP)	High
16	III	C	255	933	All	Addressing Integrity Issues (IMP)	High
16	III	C	255	935	All	Preventive and Mitigative Measures to Protect the High Consequence Areas (IMP)	High
16	III	C	255	937	All	Continual Process of Evaluation and Assessment (IMP)	High
16	III	C	255	939	All	Reassessment Intervals (IMP)	High
16	III	C	255	941	All	Low Stress Reassessment (IMP)	Other
16	III	C	255	945	All	Measuring Program Effectiveness (IMP)	Other
16	III	C	255	947	All	Records (IMP)	Other

Title	Chapter	Subchapter	Part	Section	Subdivision	Description	Risk
16	III	C	255	1003	All	General Requirements of a GDPIM Plan	High
16	III	C	255	1005	All	Implementation Requirements of a GDPIM Plan	High
16	III	C	255	1007	All	Required Elements of a GDPIM Plan	High
16	III	C	255	1009	All	Required Report when Compression Couplings Fail	High
16	III	C	255	1011	All	Records an Operator Must Keep (GDPIM)	Other
16	III	C	255	1015	All	GDPIM Plan Requirements for a Master Meter or a Small Liquefied Petroleum Gas (LPG) Operator	High
16	III	C	261	15	All	Operation and Maintenance Plan	High
16	III	C	261	17	(a),(c)	Leakage Survey	High
16	III	C	261	19	All	High Pressure Piping	Other
16	III	C	261	21	All	Carbon Monoxide Prevention	High
16	III	C	261	51	All	Warning Tag Procedures	High
16	III	C	261	53	All	HEFPA Liaison	High
16	III	C	261	55	All	Warning Tag Inspection	High
16	III	C	261	57	All	Warning Tag - Class A condition	High
16	III	C	261	59	All	Warning Tag - Class B condition	High
16	III	C	261	61	All	Warning Tag - Class C Condition	Other
16	III	C	261	63	All	Warning Tag - Action and Follow-Up	Other
16	III	C	261	65	All	Warning Tag Records	Other
49	I	D	193	2011	All	Reporting	Other
49	I	D	193	2017	All	Plans and Procedures	High
49	I	D	193	2019	All	Mobile and Temporary LNG Facilities	High
49	I	D	193	2057	All	Thermal Radiation Protection	High
49	I	D	193	2059	All	Flammable Vapor-Gas Dispersion Protection	High
49	I	D	193	2067	All	Wind Forces	High
49	I	D	193	2101	All	Design - Scope	High
49	I	D	193	2119	All	Design - Records	High
49	I	D	193	2155	All	Structural Requirements	High
49	I	D	193	2161	All	Design - Dikes	High
49	I	D	193	2167	All	Covered Systems	High
49	I	D	193	2173	All	Water Removal	High
49	I	D	193	2181	All	Impoundment Design and Capacity	High
49	I	D	193	2187	All	Nonmetallic Membrane Liner	High
49	I	D	193	2301	All	Construction - Scope	High
49	I	D	193	2303	All	Construction Acceptance	High
49	I	D	193	2304	All	Corrosion Control Overview	High
49	I	D	193	2321	All	Nondestructive Tests	High
49	I	D	193	2401	All	Equipment - Scope	High
49	I	D	193	2441	All	Equipment - Control Center	High
49	I	D	193	2445	All	Sources of Power	High
49	I	D	193	2501	All	Operations - Scope	High
49	I	D	193	2503	All	Operating Procedures	High
49	I	D	193	2505	All	Operations - Cooldown	High
49	I	D	193	2507	All	Monitoring Operations	High
49	I	D	193	2509	All	Emergency Procedures	High
49	I	D	193	2511	All	Personnel Safety	High
49	I	D	193	2513	All	Transfer Procedures	High
49	I	D	193	2515	All	Investigations of Failures	High
49	I	D	193	2517	All	Purging	High
49	I	D	193	2519	All	Communication Systems	High

Title	Chapter	Subchapter	Part	Section	Subdivision	Description	Risk
49	I	D	193	2521	All	Operating Records	Other
49	I	D	193	2603	All	Maintenance - General	High
49	I	D	193	2605	All	Maintenance Procedures	High
49	I	D	193	2607	All	Foreign Material	Other
49	I	D	193	2609	All	Support Systems	High
49	I	D	193	2611	All	Fire Protection	High
49	I	D	193	2613	All	Auxiliary Power Sources	High
49	I	D	193	2615	All	Isolating and Purging	High
49	I	D	193	2617	All	Maintenance - Repairs	High
49	I	D	193	2619	All	Control Systems	High
49	I	D	193	2621	All	Testing Transfer Hoses	High
49	I	D	193	2623	All	Inspecting LNG Storage Tanks	High
49	I	D	193	2625	All	Corrosion Protection	High
49	I	D	193	2627	All	Atmospheric Corrosion Control	Other
49	I	D	193	2629	All	External Corrosion Control - Buried or Submerged Components	Other
49	I	D	193	2631	All	Internal Corrosion Control	Other
49	I	D	193	2633	All	Interference Currents	Other
49	I	D	193	2635	All	Monitoring Corrosion Control	High
49	I	D	193	2637	All	Remedial Measures	High
49	I	D	193	2639	All	Maintenance Records	Other
49	I	D	193	2703	All	Design and Fabrication	Other
49	I	D	193	2705	All	Construction, Installation, Inspection, and Testing	High
49	I	D	193	2707	All	Operations and Maintenance	High
49	I	D	193	2709	All	Security	High
49	I	D	193	2711	All	Personnel Health	Other
49	I	D	193	2713	All	Training - Operations and Maintenance	High
49	I	D	193	2715	All	Training - Security	High
49	I	D	193	2717	All	Training - Fire Protection	High
49	I	D	193	2719	All	Training - Records	Other
49	I	D	193	2801	All	Fire Protection	High
49	I	D	193	2903	All	Security Procedures	High
49	I	D	193	2905	All	Protective Enclosures	High
49	I	D	193	2907	All	Protective Enclosure Construction	High
49	I	D	193	2909	All	Security Communications	High
49	I	D	193	2911	All	Security Lighting	High
49	I	D	193	2913	All	Security Monitoring	High
49	I	D	193	2915	All	Alternative Power Sources	High
49	I	D	193	2917	All	Warning Signs	Other

Customer Service Performance Indicators

PSC Complaint Rate (per 100K customers)	Proposed NRA BP	Equivalent Proposed NRA Amount For RY1	Equivalent Proposed NRA Amount For RY2	Equivalent Proposed NRA Amount For RY3
< 1.5	0	$ -	$ -	$ -
≥ 1.5	5	$ 17,387	$ 18,747	$ 21,555
≥ 2.0	10	$ 34,773	$ 37,494	$ 43,111
≥ 2.5	15	$ 52,160	$ 56,240	$ 64,666
Overall Customer Satisfaction Index				
> 86	0	$ -	$ -	$ -
≤ 86	5	$ 17,387	$ 18,747	$ 21,555
≤ 85	10	$ 34,773	$ 37,494	$ 43,111
≤ 84	15	$ 52,160	$ 56,240	$ 64,666

	Authorized **Case 24-G-0668** RY1	Authorized **Case 24-G-0668** RY2	Authorized **Case 24-G-0668** RY3	
Rate Base	$ 55,000,000	$ 58,040,867	$ 65,346,324	*a*
Equity Component	46.00%	47.00%	48.00%	*b*
Equity	$ 25,300,000	$ 27,279,208	$ 31,366,236	*c = a*b*
1 Basis Point = 0.01% or 0.0001	0.0001	0.0001	0.0001	*d = 0.01% or 0.0001*
$ value of 1 Basis Point*	$ 2,530	$ 2,728	$ 3,137	*e = c*d*
Retention Factor	72.76%	72.76%	72.76%	
Pre-Tax Basis Point Amount	$ 3,477	$ 3,749	$ 4,311	

Basis Point penalty applicable to the Rate Year in which the penalty occurred.
Basis point value based on the revenue requirement rate year listed above.

	Retention factor
Revenues	100.000%
Less: Revenue Taxes	1.000%
Uncollectible Accounts	0.500%
Total	98.500%
Reciprocal of State Tax Rate	93.500%
Net	92.098%
Reciprocal of Federal Tax Rate	79.000%
Retention Factor	72.757%

Bad Debt %	0.5000%
GRT Rate	1.00%
Federal Income Tax Rate	21.00%
NYS Income Tax Rate	6.50%
Tax Gross-up factor	1.35380

Arrearage Management Program (AMP) Implementation Plan

Liberty Utilities (St. Lawrence Gas) Corp. (Liberty SLG) proposes to launch an **Arrearage Management Program (AMP)** designed to support low-income residential customers who are behind on their utility bills. The AMP offers a structured path to reduce past-due balances through consistent, on-time payments.

Under the AMP, eligible customers will be placed on budget billing and, for each month they make their full and timely budget payment, $100 of their arrears will be forgiven. This can provide up to **$1,200 in annual forgiveness**, with **no lifetime cap** on total forgiveness. The program is designed not only to offer immediate financial relief, but also to encourage positive, long-term payment behaviors.

The AMP budget will be calculated in full compliance with NYPSC regulations and in accordance with HEFPA, as outlined in 16 NYCRR Section 11.11. The budget is based on 12 months of historical billing data for the customer's residence.

The AMP also aligns with assistance programs such as the Home Energy Assistance Program (HEAP), ensuring participants have the opportunity to seek and apply for aid before risking removal from the plan. Below is a detailed implementation plan:

Program Implementation Steps

1. **Customer Identification**
   - Following approval, SLG will identify customers who meet the following eligibility criteria:
     - Residential account
     - Enrolled in SLG's Low-Income Program
     - Arrearage balance of $300 or more
     - Past due for 45 days or longer
2. **Customer Outreach**
   - Eligible customers will be contacted by phone and then followed up with by mail to introduce and explain the AMP.
     - The mailed materials to include a description of the program's operation, a phone contact number for further information, a sample bill while on the program, and clarification that program participation is optional.
     - *Reference: AMP Eligibility Letter (attached)*

3. **Program Enrollment**
   - Upon opting in, the customer's arrears will be moved to a deferred balance, and they will be placed on a budget billing plan.
   - Their next bill will display:
     - The total deferred arrears eligible for forgiveness
     - The required monthly budget payment to maintain eligibility.
4. **Monthly Forgiveness Credit**
   - For each full, on-time monthly budget payment, a **$100 credit** will be applied to the deferred arrears balance.
5. **Missed Payment Follow-Up (1–15 Days Past Due)**
   - If a customer misses a budget payment, a courtesy reminder call will be placed within the first 15 days past due.
6. **Disconnection Notice (20 Days Past Due)**
   - On Day 20 of nonpayment, a **Disconnection Notice** will be issued.
     - The customer will have 45 days to make the missed payment to avoid removal from the AMP.
     - This notice serves as an official final termination warning, allowing time to apply for Emergency HEAP or other emergency assistance.
     - If the customer notifies SLG that they have applied for Emergency HEAP assistance, the AMP removal process will be paused until a decision is made.
     - *Reference: AMP Disconnection Notice (attached)*
7. **Application of Assistance Benefits**
   - If the customer receives HEAP (or similar) assistance:
     - Payments will be applied to any missed budget installments, to the oldest payments due first.
     - Remaining assistance funds will be credited to the account for future use.
     - Each budget payment covered by the assistance will trigger the corresponding $100 forgiveness credit.
     - A 30-day service protection will apply after the benefit is processed, in which the Company will pause collections activities on the account while the customer is awaiting receipt of a HEAP or assistance payment.
     - *Example:* If two payments are caught up via HEAP, **$200** in arrears will be forgiven.

8. **AMP Removal (65 Days Past Due)**
    - If no payment or assistance is received by Day 65, the customer will be removed from the AMP.
        - Customers may **reinstate the plan** by catching up on **all missed payments**. There is no limit to how many times a customer can be reinstated or the length of time in which customers may catch up on all missed payments.
        - Once removed, the account will resume the normal collections process based on its account type (e.g., Residential, Medical Hardship, Elderly/Protected status).

9. **Program Completion**
    - Once a customer has:
        - Paid all monthly budget installments (either personally or via assistance payments), and
        - All deferred arrears have been forgiven,
    - the customer will be notified by letter of their successful program completion.
        - The customer may choose to remain on budget billing or return to standard monthly billing.
        - *Reference: AMP Completion Letter (attached)*
    - Once the customer completes the program, the customer will not be eligible to enroll again, even at another location.

10. **Program Promotion**
    - SLG will dedicate a webpage on its external website to explain this program eligibility and benefits. The webpage will specifically include a program description and information on steps to maintain HEAP/Emergency HEAP while on AMP.
    - The AMP program will also be promoted through any customer assistance fairs that SLG holds in the future and may appear on bill messages, or in customer newsletters from time to time.

The AMP is designed to provide meaningful, achievable relief to customers in financial hardship, reduce write-offs, and promote responsible payment behavior. Implementation will include collaboration across billing, customer care, credit and collections, and regulatory compliance teams to ensure success.

Sample Eligibility Letter

Dear Customer,

According to our records, you may be eligible for a program that can assist with paying your past-due gas bill. Liberty now offers an Arrearage Management Program (AMP). To qualify for AMP, the following conditions must be met:

- You must be income eligible.
- Your account must be at least 45 days past due.
- Your account balance must be at least $300 past due.

AMP is an arrears forgiveness program that applies monthly credits to your past due balance.-Every month that you pay the budget amount by the due date, we will credit your account $100, with a maximum credit of $1,200 per year.

To remain enrolled, you must pay your pre-determined budget amount by the due date of your bill every month. Your monthly payment amount will be based on your historical usage projected over the term of your budget plan and will be recalculated and adjusted periodically based on your actual gas consumption and current rates to ensure the payment amount is sufficient to cover the charges accrued over the budget period.

Customers are only eligible for this program one time. If a payment defaults, you may be removed from the program.

Participation in this program is optional. If you would like to enroll, please fill out this form and return it to our office via mail or drop box.

For more information, please call 1-800-454-2201, Monday – Friday, 8 a.m. - 4:30 p.m.

Sincerely,

Liberty

AMP Enrollment Request

Name on Account ____________________________

Account Number __________________________

Signature ____________________________

Please mail this form to: Liberty - PO BOX 270 Massena, NY 13662

Liberty Energy and Water

33 Stearns St PO Box 270
Massena, NY 13662
800-454-2201

May 2, 2025

CUSTOMER NAME
STREET ADDRESS
CITY, STATE ZIP

Account#: 2000000000000
Past Due Amount: *AMP PAST DUE AMOUNT*

THIS IS A FINAL DISCONNECTION NOTICE. PLEASE REFER TO THIS NOTICE WHEN PAYING THIS BILL.

Your natural gas service may be shut off for non-payment of past-due bills. Shut off may occur on or after **June 16, 2025,** if payment is not made before this date. In order to avoid a shut off, please contact us as soon as possible at 800-454-2201 to make a payment. If you cannot pay the amount you owe in full, please contact us so we can try to work out a payment agreement you can afford. If payment, or a payment arrangement, has been recently made, please accept our thanks and disregard this notice.

This notice serves as an official final termination notice and allows you time to apply for Emergency HEAP or other emergency assistance. Please notify us if you have applied for Emergency HEAP or other emergency assistance, and the AMP removal process will be paused until a decision is made.

If your service is shut off, the past-due balance must be paid in full at an authorized payment agency prior to restoration of your services. If you are unable to pay the balance in full, you may be able to arrange a payment agreement. In addition, a reconnection charge and a new deposit will be assessed to your account.

If your service is disconnected for non-payment, your account will be billed a reconnect charge of $32.00 plus tax during normal business hours (8:00 a.m. to 4:00 p.m. Monday - Friday, excluding holidays) or $48.00 outside of normal business hours. To avoid the reconnect charge, please pay the amount due indicated on this notice; or contact a Liberty representative at 800-454-2201 to make acceptable arrangements. Please note that we cannot guarantee your service will be reconnected on the same day your payment is received. See reverse for payment options.

If you are having difficulty paying your past due amount, please contact us. To make a payment, inquire about your account, or arrange a payment plan, please call 800-454-2201.

Pay online at LibertyEnergyandWater.com, or return this portion with your payment. Please include your account number on your check and make payable to Liberty Utilities.

Account Number: 20000000000
Service Address: STREET ADDRESS

AMP Budget Amount Past Due	
Past Due Amount	**Amount Enclosed**

REMIT TO:

LIBERTY
PO BOX 75463
CHICAGO IL 60675-5463

CUSTOMER NAME
STREET ADDRESS
CITY, STATE ZIP

316520001084316300034801 39

Liberty

Payment Options

Liberty offers a variety of payment options available:

- Electronic bank drafts from your account or credit card payments can be made at www.libertyutilities.com.
- Credit card payments can also be made by calling the Liberty Customer Service Center at 800-454-2201 You can use the automated system 24/7 or speak with a Customer Service Representative Monday through Friday 8am to 430pm or visit our office at 33 Stearns St, Massena, NY 13662 to discuss your account and payment options.
- Authorized Payment Centers are listed on our website. If you'd like to make an in-person payment with cash, or checks at select locations, please take along your payment stub. Payments at *unauthorized* payment centers may cause delays in payment processing

If you call or visit us and we are unable to help you, you have the right to call the NYS Department of Public Service (DPS) for assistance. Their toll-free emergency HOTLINE number is listed below. You have important protections under the Home Energy Fair Practices Act (HEFPA). Highlights of your HEFPA protections appear below.

IMPORTANT NOTICE -- YOUR RIGHTS

Service termination: Your service will not be turned off before the scheduled disconnection date. We also cannot disconnect on Fridays, Saturdays, Sundays, holidays, the day before a holiday, during evening hours, or during a two- week period around Christmas and New Year's.

Restoring service: If your service is turned off, we will turn it back on if you pay the overdue bills or sign an installment payment agreement. You may later have to pay a deposit or reconnection fee, or both. However, you would be entitled to a payment plan for these also.

Payment plans: If you cannot pay the amount you owe in full, please contact us so we can try to work out an installment payment agreement you can afford. You may also wish to consider our levelized payment plan which evens out monthly payments throughout the year. If you wish, you can go on the plan when you sign the payment agreement.

Billing disputes: If you believe your bill is wrong, please contact us at the number above. Your service will not be turned off while we investigate your bill as long as you pay the amount not in dispute. If you disagree with our explanation, you may ask the DPS to review your billing dispute by contacting them online at www.dps.ny.gov/complaints, or by calling their toll free HELPLINE : (800) 342-3377 8:30 a.m. to 4:00 p.m. on business days. You may also write to: Consumer Services Division, Department of Public Service, Three Empire State Plaza, Albany, NY 12223-1350.

Emergency HOTLINE: If your service has been or is about to be shut off, you can also call the DPS toll-free HOTLINE at (800) 342-3355 for help. It is staffed from 7:30 a.m. to 7:30 p.m. on business days.

SPECIAL PROTECTIONS

Contact us immediately if any of the following apply:

Medical emergencies: If a medical doctor certifies that a medical emergency exists or that you require life support equipment, we must continue service for at least 30 days.

Elderly, blind, disabled: If everyone in your household is 62 or older, 18 or younger, or blind or disabled and we are unable to work out a payment plan, we will contact the Department of Social Services and continue service for 15 business days while your situation is reviewed.

Heat-related service in winter: If between November 1 and April 15 the loss of heat-related service is likely to cause a serious health or safety problem, we refer your case to Social Services and continue service during their review.

Public assistance and SSI: If you receive public assistance or SSI benefits, you may be able to prevent a shutoff by contacting both of us, at the number above, and the Department of Social Services at: (315) 379-2111 for St. Lawrence County, (315) 376-5400 for Lewis County, or (518) 483-6770 for Franklin County

Sample Bill

Account Activity for Your Water Service from 11/08/2024 - 12/09/2024
Rate: SC1 - General Water Service
Next Scheduled Meter Read Date: 01/09/2025
Point of Delivery ID:

Liberty

Meter Number	Read Type	Service Days	Billing Period	Current	Previous	100 Gallons Used	Usage
		32	11/8/24 - 12/9/24	17444	17371	73	73

What am I paying for?

Previous Balance as of 11/08/2024			$	245.00
Payment(s) Received as of 12/10/2024			$	-245.00
Balance Forward			**$**	**0.00**

Current Charges

WATER CHARGES	**QUANTITY USED**	**COST PER 100 GALLONS**		
Water Service Charge for Meter Size 5/8"			$	14.00
Water Usage Charge	30.00 CGL	$ 0.6123	$	18.37
Water Usage Charge	30.00 CGL	$ 0.8336	$	25.01
Water Usage Charge	13.00 CGL	$ 1.1969	$	15.56
CAP Discount			$	-14.00
TOTAL WATER CHARGES			**$**	**58.94**
OTHER CHARGES				
Make Whole Rate Surcharge			$	3.29
RAC/PTR Surcharge| 72.94 * 11.8000%			$	8.61
TOTAL OTHER CHARGES			**$**	**11.90**
TOTAL CURRENT CHARGES			**$**	**70.84**

Budget Arrears Management Program Information (AMP)

Arrears Management Program Start Date		01-NOV-2024
Your Current AMP Budget Installment is	**$**	**245.00**
Total Actual Charges to Date	$	598.79
Total AMP Budget Charges to Date	$	490.00
Total Company Contribution (AMP Forgiveness)	**$**	**-100.00**
Total Payments to Date	$	-245.00
Actual Account Balance if you come off Budget	$	253.79

Total Amount Due $ 245.00

Additional messages

A portion of your bill is a Special Franchise Tax, which are funds Liberty is required to collect that are used by the town and county to support various community initiatives. These taxes are passed through to local governments; Liberty does not profit from them. You can see the breakdown of how your bill is allocated at https://new-york-water.libertyutilities.com/all/residential/customer-service/understanding-my-bill.html.

Budget Arrears Management Program Information (AMP)

Arrears Management Program Start Date		01-NOV-2024
Your Current AMP Budget Installment is	**$**	**245.00**
Total Actual Charges to Date	$	598.79
Total AMP Budget Charges to Date	$	490.00
Total Company Contribution (AMP Forgiveness)	**$**	**-100.00**
Total Payments to Date	$	-245.00
Actual Account Balance if you come off Budget	$	253.79

Total Amount Due $ 245.00

Name	Version No.
SLG Affiliate Code of Conduct	1.2
	Next review date
	08/31/2026
Owner	Last approval date
Mark P. Murray, President	08/25/2025
Approver	
Jeffrey Greenblatt, Director, Legal Services	

Liberty Utilities (St. Lawrence Gas) Corp. Affiliate Code of Conduct

1. Purpose, Application and Corporate Statement

1.1 Purpose and Objectives of the Affiliate Code of Conduct ("Code")

The purpose of this Code is to establish parameters and standards for transactions, information sharing and the sharing of services and resources between Liberty Utilities (St. Lawrence Gas) Corp. ("SLG"), Affiliates and Representatives while permitting each party to achieve appropriate efficiencies and economies of scope and scale.

This Code will be reviewed and, as warranted, revised in each future rate proceeding for SLG and in any proceeding concerning a change in ownership of SLG or otherwise as needed by SLG.

Specifically, the Code is designed to meet the following objectives:

- Provide transparent and consistent guidance for SLG employees, Affiliates' employees and Representatives respecting Affiliate interactions,
- Create an awareness of compliance and ethics issues and accountabilities among SLG employees, Affiliates' employees and Representatives,
- To set standards that result in Affiliates and Customers being treated fairly and consistently and to prevent unduly preferential treatment,
- To set standards that result in Affiliates being treated fairly and that avoid cross- subsidizing Affiliate services or facilities,

- To protect and set standards for the use of confidential Customer information collected in the course of providing services and access to facilities,
- Avoid practices that could impede market competition that could occur between SLG and Affiliates and that may be detrimental to the interests of Customers.

1.2 Who This Code of Conduct Applies To

All employees (including managers, directors, full-time employees and part-time employees) and Representatives of SLG and all Affiliates' employees are expected to comply with all aspects of this Code.

The above objectives can only be realized through a demonstrated observance of and respect for the spirit and intent of this Code by all SLG employees, Representatives and Affiliates' employees to which it applies.

As this Code cannot address each specific issue that may arise, when necessary, employees and Representatives should be encouraged to seek additional guidance from their supervisor or others within SLG.

1.3 Definitions

1.3.1 Affiliate Activities – General business activities of an Affiliate relating to construction, operation, maintenance, generation, transportation, marketing, handling, storage of natural resources and energy such as oil, gas or electricity and facilities associated with the same.

1.3.2 Affiliates – An "affiliate" of SLG carrying out business in the United States or elsewhere, as defined by applicable federal, state or local laws, including, but not limited to New York State Public Service Law ("PSL") § 110(2). SLG's current and known Affiliates, both regulated and unregulated, and including SLG's Parent Company, are listed in the **Appendix**, along with a description of each Affiliates' service territory and operations.

1.3.3 "Average Total Capital" is defined as the sum of (i) Average Total Debt, (ii) common shareholder equity (excluding goodwill), and (iii) preferred stock. It is expected that, for any six-month period ending at the end of a quarter, SLG's Average Total Debt will not exceed 55 percent of its Average Total Capital, excluding any goodwill.

1.3.4 "Average Total Debt" is defined as an amount equal to (i) long-term debt, plus (ii) notes payable (including current maturities of long-term debt), minus the average daily balance of cash and cash equivalents appearing on SLG's consolidated balance sheet.

1.3.5 Code – This Affiliate Code of Conduct.

1.3.6 Compliance Officer – The individual tasked with the responsibilities specified in section 6.2 of this Code

1.3.7 Confidential Information – Any information of a proprietary, intellectual or similar nature relating to any current or potential Customer of SLG, which information has been obtained or compiled in the process of providing current or prospective services and which is not otherwise available to the public.

1.3.8 Customer(s) – Any current or potential person or organization to which SLG distributes natural gas.

1.3.9 Fair Market Value – The price reached in an open and unrestricted market between informed and prudent parties, acting at arm's length and under no compulsion to act. In determining the Fair Market Value, the seller may use any method that it believes is commercially reasonable in the circumstances.

1.3.10 For Profit Affiliate Services – Any service, provided by SLG to an Affiliate or vice versa, on a for-profit basis.

1.3.11 Fully Burdened Costs – The sum of direct costs plus a proportional share of indirect costs that may include a return on invested capital, which shall not exceed the weighted average costs of capital for SLG.

1.3.12 Information Services – Any computer systems including: computer services, databases, electronic storage services or electronic communication media, printing services or electronic communication media utilized by SLG or Affiliates relating to their respective Customers or respective operation.

1.3.13 Liberty Utilities (St. Lawrence Gas) Corp. - SLG is owned by its immediate parent company, Liberty Utilities Co. Liberty Utilities Co. is the subsidiary of its parent company, Algonquin Power & Utilities Corp. Both SLG and Liberty Utilities Co. are subsidiaries of their ultimate parent company, Algonquin Power & Utilities Corp.

1.3.14 Parent Company – The Parent Company of SLG refers to either or both of Liberty Utilities Co., SLG's direct Parent Company, and Algonquin Power & Utilities Corp., SLG's ultimate Parent Company.

1.3.15 PSC – The New York State Public Service Commission.

1.3.16 Regulated Affiliates – Affiliates whose tolls and tariffs are under the jurisdiction of the PSC or the equivalent of the PSC in another US state or elsewhere.

1.3.17 Representative – Contract workers, independent consultants, agents and any other entities that are not Affiliates, but who act on behalf of SLG.

1.3.18 Resources – Includes employees, intellectual property, materials, supplies, computer systems, equipment and facilities.

1.3.19 Senior Management Team – Employees designated as officers of SLG as determined by the Company's Board of Directors.

1.3.20 Services Agreement – An agreement entered into between SLG and one or more Affiliate for the provision of Shared Services and shall provide the following matters, as appropriate in the circumstances:

a. The type, quantity and quality of service,

b. Pricing, allocation or cost recovery provisions,

c. Confidentiality arrangements,

d. Apportionment of risk (including the risk of over or under provision of service),

e. Dispute resolution provisions, and

f. A representation by SLG and each Affiliate party to the agreement that the agreement complies with this Code.

1.3.21 Shared Core Corporate Services – SLG department functions that provide or receive shared strategic management and policy support to or from the corporate group of which SLG and Affiliates are members and may include, but are not limited to, legal, finance, tax, treasury, pensions, risk management, audit services, corporate planning, human resources, health and safety, communications, investor relations, trustee or public affairs.

1.3.22 Shared Customer Services – Any service provided to or from an Affiliate in relation to coordination and logistics, customer support services, legal and regulatory affairs, operation services, planning and analysis, system optimization, asset management, inventory management, facilities management and control center operations; the charges for such services shall be reimbursed on a Fully Burdened Cost basis.

1.3.23 Shared Services – Any service provided by SLG to an Affiliate or by an Affiliate to SLG, the charges for such services to be reimbursed on a Fully Burdened Cost basis.

1.3.24 SLG Services – Services provided by SLG to an Affiliate or Customer in relation to the distribution of Natural Gas including: interconnections; access to SLG facilities pipelines, lands, rights-of-way, leases, operations and maintenance, construction, regulatory services, technical and design; control center; and any other general services provided in relation to construction, operation, maintenance, removal, abandonment, deactivation or decommissioning of liquids pipeline.

1.3.25 Unregulated Affiliate Activities – General business activities of an Unregulated Affiliate relating to construction, operation, maintenance, generation, transportation, marketing, handling, storage of natural resources and energy, as well as the facilities associated with the same.

1.3.26 Unregulated Affiliate – An Affiliate that is not regulated by the PSC or the equivalent of the PSC in another US state or elsewhere.

1.4 Affiliate Code of Conduct Policy and Corporate Statement

SLG is committed to conducting its business in a socially responsible, legally compliant and ethical manner in accordance with a core set of corporate values, key components of the corporate values include operating with integrity, honesty, respect and transparency in all of its dealings with stakeholders. This commitment requires that SLG operates in compliance with both the letter and the spirit of the law. The interactions between SLG and Affiliates are governed by various legal and contractual provisions that are designed to ensure that these inter-affiliate interactions are appropriate and transparent.

2. Corporate Governance of SLG and Affiliates

2.1 Separate Operations

The commercial and business affairs of SLG should be managed and conducted independently from the commercial and business affairs of its Unregulated Affiliates, except as required to fulfill Shared Core Corporate Services and Shared Customer Services.

2.2 SLG Board of Directors

The SLG Board of Directors shall act as the board of directors for SLG. The SLG Board of Directors shall include an independent director who is a resident of the service area of SLG. For purposes of this requirement, "resident of the service area" may include the circumstance in which the personal residence of the director is within one of the counties in which SLG provides service, but not within the relevant service area; provided that the director's principal place of business or employment is within such service area. An Independent Director shall mean an individual who is not: (1) an officer or director of SLG's parent (2) an officer or director of any of SLG's Regulated Affiliates or (3) an officer or director of any of SLG's Unregulated Affiliates. Requirements (2) and (3) of the previous sentences shall not preclude the Independent Director from being an ex officio member of the Board of Directors of an SLG Regulated Affiliate or Unregulated Affiliate, solely by virtue of being a member of the SLG Board of Directors. Furthermore, no person holding any other position that could reasonably be considered to be detrimental to the interests of SLG or Affiliate Customers can be an SLG Director.

2.3 Separate Management

Subject to Sections 2.3 and 2.4, members of SLG's Senior Management Team must be separate from the managers of its Unregulated Affiliates. Subject to Sections 2.3 and 2.4, SLG may share management team members and managers with Regulated Affiliates.

2.4 Exception to Separate Management

SLG managers may also be managers of an Affiliate in order to perform Shared Core Corporate Services, Customer Shared Services, or Shared Services. However, this exception shall not allow an SLG officer in a commercial or business development role to be an officer of an Unregulated Affiliate that has or reasonably expects to have marketing functions and/or significant commercial or business development arrangements with SLG.

2.5 Guiding Principle

Notwithstanding sections 2.2 and 2.3, an individual shall not act both as a director or officer, or member of a management team of SLG and as a director, officer or member of a management team of any other Affiliate (thereby acting in a dual capacity) unless the individual is able to carry out his/her responsibilities in a manner that preserves the form, spirit and intent of this Code.

Specifically, an individual:

a. Shall not agree to act in a dual capacity if the individual, acting reasonably, determines that acting in a dual capacity could be detrimental to the interests of Customers, and

b. If or when acting in a dual capacity, shall abstain from engaging in any activity that the individual, acting reasonably, determines could be detrimental to the interests of Customers.

2.6 Accounting Separation

SLG must maintain separate financial records and books of accounts from those of its Affiliates. There shall be no cross -subsidization between SLG and any Affiliate.

2.7 Physical Separation

SLG must put appropriate measures in place to restrict access to SLG's Confidential Information by employees of Unregulated Affiliates with significant commercial and business development responsibilities.

Commercial and business development employees of an Unregulated Affiliate must be physically separated from SLG staff.

Where SLG provides services to an Unregulated Affiliate that operates in whole or in part as a producer, marketer, shipper or refiner, that Unregulated Affiliates' employees whose functions include commercial development, business development, marketing, producing, refining and shipping must be physically located in a separate building or complex for SLG's office that are used for its day-to-day operations.

2.8 Separation of Information Services

Subject to Section 2.11 where SLG shares Information Services with an Unregulated Affiliate, Confidential Information must be protected from unauthorized access by an Unregulated Affiliate and vice versa. Access to SLG and each Unregulated Affiliate's respective Information Services must include appropriate computer data management and data access protocols as well as contractual provisions regarding the breach of any access protocols. Compliance with the access protocols must be confirmed in writing every two years from the effective date of this Code by SLG through a review that complies with applicable federal, state and local laws.

2.9 Financial Transactions with Affiliates

SLG may participate in a money pool as a borrower or lender only if the other participants are regulated utilities, with the exception that Liberty Utilities Co. may participate, but only as a guarantor of loans made by that money pool and to provide funding to the money pool in the event that other participant-supplied funds on any given day are insufficient to meet the need for funds by the borrowing participants. SLG shall not participate in a money pool as a lender if any of the other participants are not regulated utilities. This does not preclude the unregulated affiliates of SLG in participating in a separate money pool that does not include SLG.

2.10 Sharing of Assets

The operation plant, assets and equipment of SLG shall be separated in ownership from that of its Affiliates. For the purposes of this section, operational plant, assets and equipment means, but is not limited to, any pipeline or portion thereof that is capable of being operated as a line for the transmission of gas or oil and includes all branches, extensions, tanks, reservoirs, storage facilities, pumps, racks and compressors.

2.11 Sharing Services Permitted

Where SLG determines that it is prudent in operating its business, it may obtain Shared Services, Shared Core Corporate Services, or Shared Customer Services from, or provide Shared Services or Shared Customer Services to, an Affiliate. SLG must periodically review the prudence of such sharing arrangements and make any adjustments necessary to ensure that each of SLG and their Affiliates bears its proportionate share of costs. If services are shared between SLG and an Affiliate, a Services Agreement must be put into place.

Employees providing Shared Customer Services will be required to undertake training in relation to protecting and using Confidential Information within a reasonable period of time of their commencing their job and annually, thereafter.

2.12 Sharing of Employees

SLG may share employees with an Affiliate on a Fully Burdened Cost recovery basis provided that the shared employees are able to carry out their responsibilities in a manner that is consistent with the spirit and intent of this Code. In particular, an employee must not be shared if it could reasonably be considered detrimental to the interests of SLG Customers or the Affiliate's Customers. If employees are shared, such employees must abstain from engaging in any activity that could reasonably be considered detrimental to the interests of SLG Customers or Affiliate's Customers.

Certain employees must not be shared. Unless they are providing Shared Corporate Services or Shared Customer Services, SLG may not share employees with an Unregulated Affiliate if that employee:

- Routinely participates in management level decision-making respecting the provision of SLG Services or Unregulated Affiliate Activities or how SLG Services or Unregulated Affiliate Activities and services are delivered,
- Routinely deals with or has direct contact with SLG or Unregulated Affiliate Customers, and
- Is routinely involved in senior commercial management of SLG or an Unregulated Affiliate's business.

Despite the above, for Shared Core Corporate Services or Shared Customer Services, Fully Burdened Costs may be applied where applicable. Cost allocation shall be applied in a reasonable manner to avoid cross subsidizations with respect to all Shared Core Corporate Services and Shared Customer Services. Such cost allocation shall be documented for audit purposes.

2.13 Occasional Services Permitted

Where SLG has otherwise acted prudently, it may receive or provide one-off, infrequent or occasional services to or from an Affiliate and such services shall be properly documented. For example, an employee of SLG may provide an Unregulated Entity with assistance resolving a database question, if needed. In the event that such occasional services become regular occurrences, SLG must enter into a Services Agreement with the Affiliate for Shared Services.

2.14 Emergency Services Permitted

In the event of an emergency, SLG may share services and resources with an Affiliate without a Services Agreement on a Fully Burdened Cost recovery basis.

2.15 Shared Services Employees

An employee or contractor to an Affiliate that, except in cases of emergency under section 2.14 of the Code, provides Shared Core Corporate Services, Shared Customer Services or Shared Services to SLG will, for purposes of the Code, be treated as if employed directly by SLG.

2.16 Debt Limits

If SLG's Average Total Debt does not exceed 55 percent for the most recent six- or three-month period ending at the end of a quarter, there will be no dividend restrictions. If SLG's Average Total Debt exceeds 55 percent for both the most recent three and six month periods, but does not exceed 57 percent in the most recent three or six month period, then SLG will be permitted to pay dividends up to an amount equal to but no greater than 50 percent of its net income for the previous twelve months ending at the end of a quarter until its Average Total Debt for the most recent six month period ending at the end of a quarter is less than or equal to 55 percent. In addition, absent a Commission order to the contrary, if during both the most recent six and three month period ending at the end of a quarter, SLG's Average Total Debt exceeds 57 percent, then SLG will not pay further dividends until the Average Total Debt is reduced to 55 percent or less over the most recent six months ending at the end of a quarter.

3. Transfer Pricing

3.1 For Profit Affiliate Services

Where SLG determines it is prudent to do so, it may obtain For Profit Affiliate Services from an Affiliate.

Prior to outsourcing to an Affiliate a service that SLG presently conducts itself, SLG shall undertake a prudent cost-benefit analysis over an appropriate timeframe in the circumstances. An Affiliate shall likewise undertake a prudent cost-benefit analysis over an appropriate timeframe in the circumstances, prior to outsourcing a service to SLG.

When SLG contracts to receive For Profit Affiliate Services it shall pay in accordance with any terms required pursuant to an order from the PSC or other applicable regulatory body or pay no more than the Fair Market Value of such services.

3.2 Asset Transfers

Assets transferred, mortgaged, leased or otherwise disposed of by SLG to an Affiliate must be at the higher of book value or fair market value of such assets or, where required, upon terms approved by the appropriate regulatory agency. If an asset is transferred, leased, sold or otherwise disposed of by SLG to an Affiliate, SLG shall notify **the Secretary of the Commission** not less than 90 days prior to such transfer. Assets transferred, mortgaged, leased or otherwise disposed of by an Affiliate to SLG must be at the lower of book value or fair market value of such assets or, where required, upon terms approved by the appropriate regulatory agency.

Where operational efficiencies between SLG and Affiliates can be obtained through the use of common facilities, combined purchasing power or through the use of other cost saving procedures, assets used in SLG and Affiliates' operations may be transferred between each other at net book value or other reasonable standard. All such transitions must be properly documented and accounted for in SLG and the Affiliates' respective accounting records.

4. Mitigation of Market Power and Equal Treatment of Representatives

SLG and its Affiliates shall conduct themselves in accordance with all applicable competition laws in the jurisdictions in which they conduct business.

SLG shall apply and enforce all tariff provisions in accordance with applicable legislation, regulatory orders, permits and licenses. Such tariff provisions shall be applied to Affiliates in the same manner as other Customers and/or prospective Customers in order to ensure no undue discrimination, preference or prejudice, except as approved by the appropriate regulatory agency. SLG shall not provide special rebates, rebates or different rates for like and contemporaneous service to Affiliates and Customers, except as approved by the appropriate regulatory agency.

SLG shall not favor any Affiliate with respect to access to information concerning services to Customers or scheduling of their transportation. All requests to SLG by an Affiliate for access to their respective services shall be processed and provided in accordance with this Code in the same manner as it would be processed or provided for any Customer.

SLG shall not condition or otherwise require any Customer to deal with an Affiliate in order to receive SLG transportation services.

SLG shall not explicitly or implicitly suggest that a Customer may receive an inappropriate advantage if that Customer also deals with an Affiliate.

Affiliates may not imply in any marketing material, other public documents or communications that Customers or potential Customers of the Affiliate may also receive preferential access to or service from SLG. If SLG becomes aware of any such inappropriate marketing material, public documents or communication, SLG shall:

- Immediately take reasonable steps to notify affected Customers or potential customers of the inaccurate information, and
- Take necessary steps to ensure that Affiliate is aware of this concern and to request that no further communications be made to suggest preferential access to or services from SLG.

There are no restrictions on any Affiliate using the same name, trade names, trademarks, service names, service marks or a derivative of a name of SLG, or in identifying itself as being affiliated with SLG. However, no non-SLG affiliate will be allowed to use the same name, trade names, trademarks, service names, service marks or a derivative of a name of SLG in any manner.

Affiliates are prohibited from giving any appearance that they represent SLG in matters involving the marketing of services by SLG or other Affiliates. If a customer requests information about securing any service or product offered within SLG's service territory by an Affiliate, SLG must offer to provide a list of all companies that are qualified and approved pursuant to governmental or SLG standards (including retail access standards) as providers of similar products or services within SLG's service territory.

5. Confidentiality

5.1 Release of SLG Information to Unregulated Affiliates

SLG must not provide any Affiliate who is a producer, refiner, marketer or shipper with information relating to the planning, operations, finances or strategy of SLG before such information is publicly available. In other words, subject to sections 2.1, 2.2, 2.4 and 2.12, SLG must take care that it does not disclose SLG information to any Affiliate who is a producer, refiner, marketer or shipper that it would not disclose to other Customers or potential Customers. This would include any Confidential Information and non-aggregated customer information gathered by SLG to generate annual supply forecasts for planning purposes.

Managers of SLG who are also managers of an Affiliate, as permitted by this Code, may disclose SLG planning, operational, financial and strategic information to the Affiliate to fulfill their responsibilities with respect to corporate governance, policy and strategic direction of an Affiliated entity, but only to the extent necessary and not for any other purpose.

5.2 No Release of Confidential Customer Information

SLG must not, without the Customer's prior written consent, use or disclose to an Affiliate any Confidential Information for the purpose of pursuing commercial or business development activities.

Where an Affiliate acquires specific Confidential Information, such information may not be used for commercial or business development activities without the Customer's consent. SLG may disclose Confidential Information for operational purposes, Shared Customer Services, emergencies or on an as- needed basis, to an Affiliate provided the Affiliate does not release the Confidential Information to any other entity without receiving the prior written consent of the Customer. SLG and its Affiliates seek to achieve operational efficiencies through the sharing of Resources. Where such Resource-sharing opportunities arise, SLG will:

- Not directly or indirectly disclose any Confidential Information provided to it by Customers unless:
    - It obtains consent for disclosure by the Customer,
    - The information is required for Shared Customer Services, Shared Corporate Services, emergency, operations purposes, or
    - The information is required by law.
- Implement reasonable measures to prevent any direct or indirect disclosure of any Customer proprietary or Confidential Information.

SLG and its Affiliates may respectively disclose Confidential Information when aggregated with the Confidential Information of other Customers in such a manner that an individual Customer's Confidential Information cannot be identified.

SLG employees whose primary job functions include commercial and business development services will be required to undertake training in relation to protecting and using Confidential Information within a reasonable period of time of their commencing their job and annually, thereafter.

6. Compliance Measures

6.1 Compliance Requirements

SLG is responsible for ensuring compliance with this Code.

SLG shall communicate the contents of this Code and any modifications to it from time to time to its employees, directors, managers, Representatives and Affiliates.

SLG shall make this Code available on its internal and external websites.

SLG shall appoint a compliance officer (the "Compliance Officer"). SLG shall ensure that the Compliance Officer has access to adequate resources to fulfill his or her responsibilities.

6.2 Responsibility of Compliance Officer

The responsibilities of the Compliance Officer with respect to this Code shall include:

- Providing guidance, advice and information to SLG for the purpose of ensuring compliance with this Code,
- Monitoring and documenting compliance with this Code by SLG, their employees, directors, managers, Representatives and Affiliates,
- Monitoring and documenting compliance with this Code by Affiliates with respect to the interactions of the Affiliates with SLG,
- Providing for the preparation and updating of a Compliance Report and Compliance Plan for SLG,
- Performing annual reviews of compliance with these Compliance Reports and Compliance Plans,
- Receiving and investigating internal and external disputes, complaints and inquires with respect to the application of and alleged non-compliance with this Code,
- Recommending measures to SLG to address events of non-compliance with the Code, and
- Maintaining and retaining for a period of seven years adequate records with respect to all aspects of the Compliance Officer's responsibility.

6.3 Communication of Code of Conduct Requirements

SLG shall communicate this Code as follows:

- On its internal and external websites, and
- Through orientation and training of all SLG employees, managers and directors.

6.4 Compliance Plan

SLG shall prepare a Compliance Plan and make it available on internal and external websites.

The Compliance Plan shall detail the measures, policies, procedures and monitoring mechanisms that SLG will employ to ensure full compliance with the provisions of this Code by their employees, directors, managers, Representatives and Affiliates. SLG shall review and update its Compliance

Plan annually.

6.5 Annual Compliance Report

The Compliance Report referenced in Section 6.2 shall be prepared annually and will include the following information prepared in respect to the period of time covered by the Compliance Report:

- A list of all Services Agreements entered into during the period covered by the Compliance Report,
- An overall assessment of compliance with the Code,
- An assessment of the effectiveness of the Compliance Plan and any recommendations for modifications, and
- In the event of any material non-compliance with this Code, a description of same and an explanation of all steps taken to correct such non-compliance.

SLG shall provide Department Staff with a copy of these annual Compliance Reports, upon request.

6.6 Dispute, Complaint and Inquiry Resolution

Disputes, complaints or inquiries from within SLG, an Affiliate, Customers of SLG or from a Representative respecting the application of, or alleged non-compliance with this Code, may be made verbally or submitted in writing to the Compliance Officer and may be made confidentially. The identity of any party making a submission to the Compliance Officer shall be kept confidential by the Compliance Officer unless the party otherwise agrees.

The Compliance Officer shall acknowledge all disputes, complaints or inquires in writing within five business days of receipt of the same.

The Compliance Officer shall respond to the dispute, complaint or inquiry within 25 business days of its receipt. The response shall include a description of the dispute, complaint or inquiry and the initial response of SLG or Affiliate to the issues identified in the submission. A final disposition of the dispute, complaint or inquiry shall be completed as expeditiously as possible in the circumstances and, in any event, within 90 days of receipt of the dispute, complaint or inquires, except where the party making the submission otherwise agrees.

All records of the Compliance Officer in relation to a dispute, complaint or inquiry shall be kept for a period of at least seven years. Compliance records shall be maintained in a manner sufficient to support a third-party independent audit of the state of compliance with this Code.

6.7 Non-Compliance

Any non-compliance with this Code by any employee, director, officer or Representative of SLG or an Affiliate with respect to the interactions of the Affiliate with SLG will be considered to be addressed pursuant to this Code.

Non-compliance with this Code by an employee, director, officer, Representative or SLG or an Affiliate may subject such individual to internal disciplinary action.

7. General Provisions

7.1 Interpretation

Headings are for convenience only and shall not affect the interpretation of this Code. Words importing the singular include the plural and vice versa. A reference to a statue, document or a provision of a document includes an amendment or supplement to, or a replacement of that statue, document or that provision of that document.

7.2 Coming into Force

This Code comes into effect upon closing of the Acquisition of SLG by Liberty Utilities Co. However, to the extent existing agreements or arrangements are in place between parties to whom this Code applies that do not conform with this Code, SLG shall use reasonable efforts to ensure that such agreements or arrangements are brought into compliance with this Code within 90 days after this Code comes into force.

7.3 Amendments to this Code

This Code may be reviewed and amended by SLG from time to time.

7.4 Authority of Regulators

This Code does not detract from, reduce or modify in any way the powers of SLG or Affiliates' respective regulators. Compliance with this Code does not eliminate the requirement for specific approval or filings where required by legislation, regulation or by a regulator's decisions, orders or directions.

[Type here]

Appendix
List of Affiliates

i. Affiliates Regulated by the NYS PSC:

	Name	Territory and Operations
a.	Liberty Utilities (New York Water) Corp.	New York Water is a utility regulated by the New York Public Service Commission that provides residential and non-residential metered and other water services to approximately 125,000 customers in Nassau, Putnam, Sullivan, Ulster, Washington and Westchester counties.

Affiliates Regulated by the Equivalent of the NYS PSC in other US states or Canadian Provinces:

	Name	Territory and Operations
a.	Liberty Utilities (Gas New Brunswick) Corp.	Gas New Brunswick is a utility regulated by the New Brunswick Energy and Utilities Board that provides natural gas to approximately 12,000 customers in 12 communities across New Brunswick and operates approximately 1,200 kilometers of natural gas distribution pipeline.
b.	Liberty Utilities (EnergyNorth Natural Gas) Corp.	EnergyNorth is a regulated natural gas utility providing natural gas distribution service in 30 communities covering five counties in New Hampshire. Its franchise service area includes the communities of Nashua, Manchester and Concord. It is regulated by the NHPUC.
c.	Liberty Utilities (Granite State Electric) Corp.	Granite State Electric, regulated by the NHPUC, provides distribution service in southern and northwestern New Hampshire, centered around operating centers in Salem in the south and Lebanon in the northwest. Granite State Electric's customer base consists of a mixture of residential, commercial and industrial customers. Granite State Electric is required to provide electric commodity supply for all customers who do not choose to take supply from a competitive supplier ("Default Service") in the New England power market and is allowed to fully recover its costs for the provision and administration of Default Service under the Default Service Adjustment Provision, as approved by the NHPUC. Granite State Electric must file with the NHPUC twice a year to adjust for market prices of power purchased and is also subject to limited FERC regulation.
d.	Liberty Utilities (New England Natural Gas Company) Corp.	New England Gas is a natural gas utility, regulated bythe MA DPU, providing natural gas distribution services in six communities located in the southeastern portion of Massachusetts. New England Gas customer base consists of a mixture of residential, commercial, and Industrial customers.
e.	Liberty Utilities (Peach State Natural Gas) Corp.	Peach State Gas is a Georgia PSC -regulated natural gas system providing natural gas distribution services in 13 communities covering six counties in Georgia. Its franchise service area includes the communities of Columbus, Gainesville, Waverly Hall, Oakwood, Hamilton, and Manchester. Peach State Gas' customer base consists of a mixture of residential, commercial, industrial and transportation customers.

[Type here]

	Name	Territory and Operations
f.	Liberty Utilities (CalPeco Electric) LLC	CalPeco Electric is a California PUC-regulated utility that provides electric distribution service to the Lake Tahoe basin and surrounding areas. The service territory, centered on a highly popular tourist destination, has a customer base spread throughout Alpine, El Dorado, Mono, Nevada, Placer, Plumas and Sierra Counties in northeastern California. CalPeco Electric's connection base is primarily residential. Its commercial connections consist primarily of ski resorts, hotels, hospitals, schools and grocery stores. The Corporation has entered into a multi-year services agreement with NV Energy that commenced in January 2016. On January 31, 2017, the Federal Energy Regulatory Commission authorized transactions between the Luning Solar Facility and CalPeco Electric pursuant to the services agreement with NV Energy. CalPeco Electric is also subject to FERC regulation.
g.	Liberty Utilities (Park Water) Corp.	Liberty Park Water owns and operates two California PUC-regulated water utilities engaged in the production, treatment, storage, distribution, and sale of water in Southern California. Its system is located in central Los Angeles.
h.	Liberty Utilities (Apple Valley Ranchos Water) Corp.	Liberty Utilities (Apple Valley Ranchos Water) Corp. (wholly-owned by Liberty Park Water) is a California PUC-regulated water utility which owns and operates the water system in Apple Valley.
i.	Liberty Utilities (Bella Vista Water) Corp.	The Liberty Utilities Bella Vista Water utility is located in Sierra Vista Arizona. All of Liberty Utilities water and wastewater utilities are generally subject to regulation by the public utility commissions of the states in which they operate. The respective public utility commissions have jurisdiction with respect to rate, service, accounting procedures, issuance of securities, acquisitions and other matters.
j.	Liberty Utilities (Gold Canyon Sewer) Corp.	The Liberty Utilities Gold Canyon Sewer utility is located in Avondale Arizona. All of Liberty Utilities water and wastewater utilities are generally subject to regulation by the public utility commissions of the states in which they operate. The respective public utility commissions have jurisdiction with respect to rate, service, accounting procedures, issuance of securities, acquisitions and other matters. Liberty Utilities (Entrada Del Oro Sewer) Corp. merged with this entity on May 31, 2023.
k.	Liberty Utilities (Litchfield Park Water & Sewer) Corp.	The LPSCo System, located in and around the city of Goodyear 15 miles west of Phoenix, Arizona has a service area that includes the City of Litchfield Park and sections of the cities of Goodyear and Avondale as well as portions of unincorporated Maricopa County. The wastewater system's Palm Valley Water Reclamation Facility has permitted treatment capacity of 6.5 million gallons per day.

[Type here]

	Name	Territory and Operations
l.	Liberty Utilities (Black Mountain Sewer) Corp.	The Liberty Utilities Black Mountain Sewer utility is located in Carefree Arizona. All of Liberty Utilities water and wastewater utilities are generally subject to regulation by the public utility commissions of the states in which they operate. The respective public utility commissions have jurisdiction with respect to rate, service, accounting procedures, issuance of securities, acquisitions and other matters.
m.	Liberty Utilities (Pine Bluff Water) Inc.	The Liberty Utilities Pine Bluff Water utility is located in Pine Bluff Arkansas. All of Liberty Utilities water and wastewater utilities are generally subject to regulation by the public utility commissions of the states in which they operate. The respective public utility commissions have jurisdiction with respect to rate, service, accounting procedures, issuance of securities, acquisitions and other matters.
n.	Liberty Utilities (Rio Rico Water & Sewer) Corp.	The Liberty Utilities Rio Rico Water & Sewer utility is located in Rio Rico Arizona. All of Liberty Utilities water and wastewater utilities are generally subject to regulation by the public utility commissions of the states in which they operate. The respective public utility commissions have jurisdiction with respect to rate, service, accounting procedures, issuance of securities, acquisitions and other matters.
o.	Liberty Utilities (Cordes Lakes Water) Corp.	Liberty Utilities Cordes Lakes is located in Cordes Lakes, AZ, and provides water service to approximately 1,500 Cordes Lakes residents. All of Liberty Utilities water and wastewater utilities are generally subject to regulation by the public utility commissions of the states in which they operate. The respective public utility commissions have jurisdiction with respect to rate, service, accounting procedures, issuance of securities, acquisitions and other matters
p.	Liberty Utilities (Missouri Water) LLC	The Liberty Utilities Missouri Water utility is located in Jackson Missouri. All of Liberty Utilities water and wastewater utilities are generally subject to regulation by the public utility commissions of the states in which they operate. The respective public utility commissions have jurisdiction with respect to rate, service, accounting procedures, issuance of securities, acquisitions and other matters.
q.	Liberty Utilities (Silverleaf Water) LLC	The Liberty Utilities Silverleaf Water utility is located in Wood County Texas. All of Liberty Utilities water and wastewater utilities are generally subject to regulation by the public utility commissions of the states in which they operate. The respective public utility commissions have jurisdiction with respect to rate, service, accounting procedures, issuance of securities, acquisitions and other matters.

[Type here]

	Name	Territory and Operations
r.	Liberty Utilities (Tall Timbers Sewer) Corp.	The Liberty Utilities Tall Timbers Sewer utility is located in Tyler Texas. All of Liberty Utilities water and wastewater utilities are generally subject to regulation by the public utility commissions of the states in which they operate. The respective public utility commissions have jurisdiction with respect to rate, service, accounting procedures, issuance of securities, acquisitions and other matters.
s.	Liberty Utilities (Woodmark Sewer) Corp.	The Liberty Utilities Woodmark Sewer utility is located in Smith County Texas. All of Liberty Utilities water and wastewater utilities are generally subject to regulation by the public utility commissions of the states in which they operate. The respective public utility commissions have jurisdiction with respect to rate, service, accounting procedures, issuance of securities, acquisitions and other matters.
t.	Liberty Utilities (Midstates Natural Gas) Corp.	Midstates Gas owns regulated natural gas utilities providing natural gas distribution services to approximately 190 communities in the states of Illinois, Iowa and Missouri, with a mix of residential, commercial, industrial and transportation customers. The franchise service area includes the communities of Virden, Vandalia, Harrisburg and Metropolis in Illinois, Keokuk in Iowa, and Butler, Kirksville, Canton, Hannibal, Jackson, Sikeston, Malden and Caruthersville in Missouri. The utilities in each of these states are regulated by their respective state PUCs.
u.	The Empire District Electric Company	Empire Electric is a vertically-integrated regulated electric utility with operations in parts of Missouri, Kansas, Oklahoma and Arkansas. The largest urban area served is the city of Joplin, Missouri, and its immediate vicinity. Empire Electric owns and operates Empire a wind generation facility, Ozark Beach hydro facility, Riverton, Energy Center and Stateline No. 1 natural gas-fired power generation facilities and a 40% interest in the Stateline combined cycle gas generation facility. Empire Electric is regulated by the Missouri Public Service Commission, Kansas Corporation Commission, Oklahoma Corporation Commission, Arkansas Public Service Commission, and the Federal Energy Regulatory Commission.
v.	The Empire District Gas Company	Empire District Gas provided regulated natural gas distribution services to customers in Missouri and is regulated by the Missouri Public Service Commission.

	Name	Territory and Operations
w.	Liberty Utilities (Tinker Transmission) LP	Tinker Transmission is an integral part of the transmission system of New Brunswick. The operations and rates are regulated by the New Brunswick Energy and Utilities Board. In total, the Tinker Transmission system connects 4 different entities: Perth Andover, the Northern Maine Independent System Administrator, Algonquin Tinker Gen Co and NB Power. Tinker Transmission delivers power directly to customers in Perth Andover and provides an interconnection between NB Power and Northern Maine through an interconnection at the New Brunswick/Maine border
x.	Liberty Utilities (Arkansas Water) Corp.	Arkansas Water is an amalgamation of the following previously unregulated utilities of Liberty Utilities (White Hall Sewer) Corp., Liberty Utilities (White Hall Water) Corp., and Liberty Utilities (Woodson-Hensley Water) Corp. located in Arkansas. In November 2019, Liberty Utilities filed an application with the Arkansas Public Utilities Commission requesting the CCN for Liberty Utilities Arkansas Water.
y.	Liberty Utilities (Beardsley Water) Corp.	Owner of water utility in Arizona.
z.	Suralis S.A.	Suralis S.A. (formerly ESSAL) is a vertically-integrated water and wastewater utility company in Southern Chile providing water and sewer services to approximately 238,300 customers. The utility operates 51 potable water production systems, 29 sewage plants, and 4,668 km of distribution and sewage networks covering 33 municipalities. Suralis is regulated by the Superintendence of Sanitary Services of Chile (Superintendencia de Servicios Sanitarios, or the SISS) and is also subject to the jurisdiction of the Chilean National Consumer Service ("SERNAC"), being Chile's consumer protection agency
aa.	Bermuda Electric Light Company Limited	BELCO is regulated by the Regulatory Authority of Bermuda. BELCO is sole provider of electricity transmission, distribution, and retail services to all customers in Bermuda and is a bulk generator of electricity on the island. BELCO provides service to approximately 38,300 customers.

ii. Unregulated Affiliates:

	Name	Territory and Operations
a.	Algonquin Power & Utilities Corp. ("Algonquin")	The Corporation owns and operates a diversified portfolio of regulated and non-regulated generation, distribution, and transmission utility assets. The Corporation's operations are organized across two primary North American business units consisting of: the Liberty Utilities Group, which primarily owns and operates a portfolio of regulated electric, natural gas, water distribution and wastewater collection utility systems, and transmission operations; and the Liberty Power Group. The Corporation provides strategic management, corporate governance, access to capital markets, and administrative services to its affiliates under an affiliate services agreement.
b.	Liberty Utilities (Canada) Corp.	This Corporation employs Canadian employees and provides corporate and business services to the affiliates of Algonquin under an affiliate services agreement.
c.	Liberty Utilities Service Corp.	This Corporation employs U.S. employees and consists of shared services employees that provides corporate and business services to the affiliates of Algonquin under an affiliate services agreement.
d.	Liberty Utilities Co.	This Corporation is a holding company that owns and operates regulated and unregulated gas, water, wastewater, and electric utilities in the U.S. This Corporation will from time to time arrange for services of non-affiliate experts, consultants, accountants and attorney in its provision of services under an affiliate service agreement. Also, under this service agreement, this Corporation arranges to provide financing for affiliates of Algonquin.
e.	Empire District Industries, Inc.	An unregulated Affiliate of the Empire District Electric Company located in Joplin Missouri, primarily engaged in providing fiber optic services in the Empire District service territory.
f.	Liberty Utilities (St. Lawrence Gas Service & Merchandising) Corp.	A direct, wholly owned subsidiary of Liberty Utilities (St. Lawrence Gas) Corp., and an unregulated business, primarily engaged in the rental of water heaters and other natural gas appliances to its customers in St. Lawrence County, Lewis County, Franklin County and Jefferson County in New York State.
g.	S.L.G. Communications Corp.	A direct, wholly owned Subsidiary of Liberty Utilities (St. Lawrence Gas) Corp., and an unregulated business, primarily to serve as a holding company for maintaining FCC licenses for two-way radio communications for the parent company.
h.	Liberty Utilities (Fox River Water) LLC	The Liberty Utilities Fox River Water unregulated utility is located at Sheridan Illinois.

	Name	Territory and Operations
i.	Liberty Utilities (Seaside Water) LLC	The Liberty Utilities Seaside Water unregulated utility is located at Seaside Resort in Texas.
j.	Liberty Utilities (Northwest Sewer) Corp.	The Liberty Utilities Northwest Sewer utility is located in Goodyear Arizona serving several HOA's in the area.
k.	Liberty Utilities (America) Co.	Holding company for U.S. regulated utilities assets of Algonquin.
l.	Liberty Utilities (America) Holdings, LLC	Holding company for U.S. regulated utilities assets of Algonquin.
m.	Liberty Utilities (America) Holdco Inc.	Holding company for U.S. regulated utilities assets of Algonquin.
n.	Liberty Utilities (Sub) Corp.	Holding company for certain U.S. regulated water and waste treatment assets of Algonquin.
o.	Liberty Energy Utilities (New Hampshire) Corp.	Holding company for New Hampshire regulated natural gas and electrical utility assets of Algonquin.
p.	Liberty Utilities (Project Developments) LLC	Holding company for Safe Harbor parts for future LUCo project use.
q.	Commonwealth Solar 1, LLC	Holding company for greenfield development assets in Kentucky.
r.	Liberty Utilities (Eastern Water Holdings) Corp.	This Corporation is a special purpose entity created to effectuate the acquisition Liberty Utilities (New York Water) Corp. (f/k/a New York American Water Company, Inc.) ("Liberty NYW")
s.	Mt. Ebo Sewage Works, Inc.	Mt. Ebo Sewer is an unregulated subsidiary of Liberty NYW.
t.	Western Water Holdings, LLC	Holding company for California, Park Water, and Apple Valley Ranchos Water utility assets.
u.	Liberty Utilities (Central) Co.	Holding company for The Empire District Electric Company utility.
v.	Liberty Utilities Energy Solutions Corp.	Holding company for compressed natural gas and liquefied natural assets of Algonquin.
w.	Liberty Utilities (Empire State Payco) LLC	Customer billing for utility customers in New York.
x.	Liberty RenGen Group Limited	Formerly AG Holdings Limited, a holding company providing non-regulated products and services in Bermuda that are generally complementary to the core services provided by its affiliate, BELCO. Liberty RenGen Group Limited's parent is Liberty Group Limited.
y.	Liberty Group Limited	Changed its name from Ascendant Group Limited in June 2021, is 100% indirectly owned by Algonquin and is the parent company of BELCO and Liberty RenGen Group Limited.

Version History

Version No.	Revision Date	Revised By	Description of Revisions
1.0	June 30, 2020	Carter Eady-Kissau	New Doc Transferred to New Template
1.1	March 10, 2023	Kimberly S. Baxter Jeffrey Greenblatt	Updated header for new logo, format, and director name Updated appendix "List of Affiliates" Moved definitions from Section 2.16 to Section 1.3 Minor housekeeping edits
1.2	August 25, 2025	Jeffrey Greenblatt	Updated Owner and Approver information Replaced Liberty Utilities East Region Board of Directors with SLG Board of Directors Updated appendix "List of Affiliates" Minor housekeeping edits

Omnibus Reporting Requirements

This Appendix W to the Joint Proposal dated August 29, 2025, in Case 24-G-0668 (Joint Proposal), sets forth all Liberty Utilities (St. Lawrence Gas) Corp.'s (the Company or Liberty SLG) reporting requirements to the New York State Public Service Commission (Commission) and/or the New York State Department of Public Service (DPS) on a going forward basis. Any reporting requirements from previous rate plans and/or Commission orders (including but not limited to, Cases 08-G-1392, 13-G-0076, 15-G-0382, 18-G-0133, 18-G-0140, and/or 21-G-0577) are terminated and replaced with the reporting requirements specified in the Joint Proposal or this Appendix W. In other words, the Company has no reporting requirements to the Commission or DPS other than those set forth in the Joint Proposal or this Appendix W.[1]

Report No.	Report Name	Report Description/Contents	Frequency	Due Date
1	AMP: Annual Budget vs. Actual Costs	With respect to the AMP, the Company will submit a report identifying any differences between actual and estimated costs, which will be reconciled at the end of each Rate Year and deferred for recovery in a future proceeding.	Annually	Within 120 days of the end of a Rate Year.
2	AMP Program Performance	The Company will report on overall AMP participation rates and effectiveness to ensure transparency and demonstrate the program's performance. This report will include: (1) number of participants and associated arrears forgiven; (2) number of customers disenrolled and reason why they were disenrolled, not Emergency HEAP related; (3) number of customers disenrolled for Emergency HEAP purposes; and (4) number of customers reinstated that received Emergency HEAP.	Annually	Within 120 days of the end of a Rate Year.
3	Customer Service Performance Indicators (CSPI)	As set forth in Appendix Q to the Joint Proposal, the Company's CSPI report will include two metrics broken down by month with performance threshold and associated NRAs: (1) the Commission Complaint Rate, and (2) the Overall Customer Satisfaction Index (OCSI). The Company's Commission Complaint Rate performance will be the 12-month escalated complaints received per 100,000 customers as reported by the DPS Office of Consumer Services each year for the 12-month period ending in December, based on the number of complaints received. An Overall Customer Satisfaction Index (OCSI) will be calculated based on the results of cumulative customer satisfaction surveys on an annual basis and will reflect the percentage of customers satisfied with the service they receive from the Company. The survey will be performed Qualtrics, starting in Rate Year1. A survey will be presented or emailed to each customer that	Quarterly	Within 30 days of the end of each quarter or reporting period.

[1] All capitalized terms not expressly defined in this Appendix W shall have the same meaning as given to such terms in the Joint Proposal. Unless expressly specified otherwise, all reporting requirements are subject to NRAs for potential untimely filings.

Report No.	Report Name	Report Description/Contents	Frequency	Due Date
		completes a transaction with the Company call center representatives.. The Company will not include any language pertaining to cost of service in the survey. The CSPI will also include a Call Answering Report, which will include the following information: 1. the number or calls answered under 60 seconds; 2. the number of adjusted bills; 3. the reasoning for the adjusted bill; 4. the number of delayed bills; and 5. the reasoning for delayed bill. The CSPI will also include a Reconnection Report, which will include the following information: 1. the number of shutoffs due to non-payment; 2. the number of reconnections completed for service shutoffs for non-payment; and 3. the associated amount of fees assessed for those reconnections.		
4	Annual Collections	The Company will submit a report on its collections broken down by month and including the following information: 1. Arrears Greater Than Sixty Days 2. Final Termination Notices This Month 3. Accounts Eligible for Field Action 4. Residential and Non- Residential Active DPA's at the Beginning of the Month 5. Residential and Non- Residential Deferred Payment Agreements Made 6. Residential and Non- Residential Deferred Payment Agreements Defaulted 7. Residential and Non- Residential Deferred Payment Agreements Satisfied 8. Residential and Non- Residential Active Deferred Payment Agreements at the End of the Month 9. Residential and Non-Residential Percent of Deferred Payment Agreement Greater Than 60 days 10. Uncollectibles This Month 11. Residential and Non-Residential Bankruptcies 12. Residential Final Bills Issued This Month 13. Residential Final Bills with Arrears This Month	Annual	Within 30 days of the end of each annual reporting period, starting within 120 days of the Commission issuing an order establishing rates in Case 24-G-0668.

Report No.	**Report Name**	**Report Description/Contents**	**Frequency**	**Due Date**
5	Low-Income Program	The Company will file an annual low-income program report that will include the following information on the previous Rate Year 1. participant totals separated by tier; 2. new participants; 3. participant reconnection fee waiver; 4. participant arrears; 5. termination notices sent to participants; 6. amount budgeted and actual spending for the program; and 7. amount of participant uncollectibles.	Annually	Within 30 days of the end of the preceding Rate Year.
6	Missed Appointment Credit	Beginning with the start of RY3, the Company will file a report that tracks on a monthly basis (1) all missed customer appointments and (2) missed customer appointments due to weather.	Annually	Within 60 days of the start of RY3, and within 60 days of the end of the preceding Rate Year thereafter.
7	Energy Efficiency	The Company will file a report identifying the number of new applicants for service the Company received and the energy efficiency program(s) for which information was made available to those applicants during the preceding Rate Year. Of the applicants who were referred to other alternatives but ended up becoming a gas customer, the Company will identify any reason(s) given by the customer for its decision to choose gas service instead of the other alternatives.	Annually	Within 90 days of the end of the preceding Rate Year.
8	Net Plant Reconciliation Mechanism (NPRM)	For each Rate Year, the Company will file a report reconciling its actual average net utility plant and depreciation expense revenue requirement to the target average net utility plant and depreciation expense revenue requirement. The difference between the actual average net utility plant and depreciation expense revenue requirement and the target average net utility plant and depreciation expense revenue requirement will carry forward each Rate Year and be summed at the end of the Rate Plan.	Annually	Within 90 days of the end of the preceding Rate Year.
9	Automated Meter Reading (AMR) Progress	The Company will file a report benchmarking the progress of the AMR project, which will include the following information: 1. purchase order receipts; and 2. a full implementation schedule, including delivery of units and installation of units.	Annually, with quarterly updates once AMR installation begins until project completion.	Within 90 days of the end of the preceding Rate Year, or within 30 days of the preceding quarter, as applicable.

Report No.	Report Name	Report Description/Contents	Frequency	Due Date
10	Three-Year Capital Investment Plan	The Company will file a three-year capital investment plan, which will include the following information: 1. a high-level schedule of major capital investments (estimated cost of $200,000 or above) by project and by plant account; and 2. a description of the capital projects, as well as details explaining any major shifts in the capital expenditure budget approved by the Commission.	Once	Within 30 days of the Commission issuing an order establishing rates in Case 24-G-0668.
11	Capital Budget Variances	The Company will file capital variance reports, which will include explanations for any individual project and plant account variances over 10% between the Commission approved budget and actual expenditures. The variance explanation will include a detailed explanation for the variance and any cost controlling strategies the Company used to avoid the variance if actual spending exceeds the budgeted amount. The variance reports will show a comparison of year-to-date budgeted amount as approved by the Commission and year-to-date actual spending by individual project and by plant account. The Company will meet with Staff to discuss each quarterly variance report within 45 days of filing each report.	Quarterly	Within 45 days of the end of the preceding quarter.
12	Physical Security Capital Project Spending	The Company will file a report detailing physical security capital spending and schedules for each project. The report will highlight and explain any significant changes to physical security capital projects, including (but not limited to) alterations in major deadlines (*e.g.*, acceptance tests or in-service dates), and changes in project scope, timelines, or budgets.	Annually	By March 31 of the subsequent calendar year.
13	Cybersecurity Capital Project Spending	The Company will file a report detailing cybersecurity capital spending and schedules for each project. The report will highlight and explain any significant changes to cybersecurity capital projects, including (but not limited to) alterations in major deadlines (*e.g.*, acceptance tests or in-service dates), and changes in project scope, timelines, or budgets. The report shall also include a downward-only reconciliation for Plant Account 303 for each year, with a cumulative reconciliation at the end of the Rate Plan.	Annually	Within 90 days of the end of the preceding Rate Year.
14	Capital Structure	The Company will file a report on its annual cost of debt, cost of customer deposits, customer deposit ratio, and cost of equity. The report shall include a downward only reconciliation of capital structure to be implemented using a 13-point average to true-up the common equity ratio to 47.00% in RY2 and 48.00% in RY3 on a Rate Year basis. The reconciliation will be calculated using the Commission-approved cost of debt, customer deposits, customer deposits ratios, and cost of equity for RY2 and RY3.	Annually	Within 90 days of the end of the preceding Rate Year.
15	Rate of Return / Return on Equity / Earning Sharing Mechanism	The Company will file a report computing its earned rate of return on common equity for the preceding Rate Year. In the event the Company achieves a regulatory rate of return on its common equity above the allowed return on a 12-month basis, the Company will share the earnings in excess of that return with the customers.	Annually	Within 90 days of the end of the preceding Rate Year.

Report No.	**Report Name**	**Report Description/Contents**	**Frequency**	**Due Date**
16	Entitlement Capital Projects	The Company will consult with DPS Staff prior to construction of Entitlement Capital Projects exceeding 500 feet. After such consultation and at least 90 days prior to the start of construction, the Company will file a report with the Secretary, which shall include: 1. the cost of the proposed Entitlement Capital Project; 2. alternatives that were considered to the proposed Entitlement Capital Project; 3. documentation that the Company informed the potential customers to the proposed Entitlement Capital Project of alternatives to natural gas heating; and 4. information on the proposed Entitlement Capital Project's consistency with attainment of statewide greenhouse gas emissions limits established pursuant to the CLCPA.	As needed	Within 90 days of consultation between the Company and DPS Staff.
17	Extension Capital Projects	At least 150 days before commencing construction on any Extension Capital Project in any Rate Year, the Company will file with the Secretary a petition requesting approval of the project, which must include the following information on the proposed project: 1. project cost estimates; 2. prospective customer survey results (with potential customers' current energy type); 3. projected natural gas and alternative energy costs; 4. number of both total potential new customers and committed customers; 5. annual conversion estimates for the first five years; 6. annual projected volumetric throughput for the first five years; 7. annual projected revenue for the first seven years; 8. information on the proposed project's consistency with attainment of statewide greenhouse gas emissions limits established pursuant to the CLCPA (Renewable natural gas (RNG) sourced within New York State will be reflected as appropriate in considering consistency with the CLCPA); 9. information on consideration of non-pipe alternatives to the project; and 10. any other information the Company considers relevant.	As needed	At least 150 days before commencing construction of any Extension Capital Project.
18	Greenhouse Gas (GHG) Emissions	The Company will provide annual GHG reporting as required in Case 22-M-0149. Unless the Commission provides further guidance, during the Rate Plan, the Company will provide its upstream, local distribution, and end-use GHG emissions.	Annually	By April 15 of the subsequent calendar year.
19	Natural Gas Promotion	The Company will track and report all expenses related to the promotion of natural gas, including direct mail campaigns, digital marketing initiatives, or paid media (including social media) created solely to encourage natural gas costs.	Annually	Within 90 days of the end of the preceding Rate Year.

Report No.	Report Name	Report Description/Contents	Frequency	Due Date
20	Non-Pipe Alternatives: Capital Planning and Screening	The Company will look a minimum of three years ahead at potential areas of its gas system that could lead to pressure concerns as a proactive analysis for improving applicability of NPAs that would help contribute toward CLCPA emission reduction goals. The Company will perform this three-year look ahead on an annual basis and inform Staff of the results in its annual capital reporting. The report shall include the following: 1. A ranked list of all areas on the Company's gas system with pressure issues forecasted from this review. 2. Hydraulic modeling that indicates the pressures of the identified areas and each pressure's percentage of Maximum Allowable Operating Pressure (MAOP). 3. A street view map that locates the piping in the identified areas. 4. A description of the methodology and/or criteria applied to forecast and prioritize pressure issues in the identified areas. 5. A detailed summary of NPA feasibility based on the screening criteria process the Company proposed in its August 10, 2022 filing in Case 20-G-0131, as supplemented and refined by its LTP and the LTP Annual Report filed in Case 24-G-0630 (the "NPA Suitability and Criteria Process"), for the identified areas that includes coordination with relevant electric providers.	Annually	May 31 of each year.
21	Outreach & Education (O&E) Budget and Annual Report	The Company will submit a single, consolidated O&E budget and annual report using the Commission's Estimated Outreach & Education Budge Template (O&E Template). The Company will ensure that page 23 of the O&E Template ("Energy Service Affordability") is completed in full, rather than redirecting information to other sections.	Annually	As part of the annual O&E reports filed in Case 17-M-0745 due by April 1 of each calendar year
22	O&E Plan	The Company will file an O&E Plan that will include the following elements: 1. Continue to promote the New York Clean Energy Information to all customers applying for new service and include this information in the Company's O&E plan in a manner that does not increase costs associated with the O&E plan delivery. 2. Detailed strategy to increase enrollment in the Company's low-income program. Future filings will outline the specific actions the Company is taking to identify and reach eligible customers, including a more prominent focus on low-income customer engagement at outreach events, targeted communications, and collaborations with local agencies and organizations that serve income-eligible households. 3. Strengthen efforts directed at low-income, elderly customers, and those in disadvantaged communities. The Company will develop a comprehensive and tailored strategy to address the unique needs of those customer groups. This strategy will include measurable	Annually	As part of the annual O&E reports filed in Case 17-M-0745 due by April 1 of each calendar year

Report No.	**Report Name**	**Report Description/Contents**	**Frequency**	**Due Date**
		objectives and engagement approaches, including community partnerships, multilingual communications, and enhanced participation in local events that reach these populations. 4. Initiatives to raise awareness of the $25 missed appointment credit. 5. Customer-facing messaging that clearly explains the levelized billing processes and procedures. This messaging will include a clear explanation of the differences between budget billing and a levelized payment plan, with emphasis on how each plan reconciles (or "trues up") payments against actual customer charges.		
23	AMR O&E Plan	The Company will file an AMR O&E Plan with the Secretary for Staff review that will include the following: 1. the Company's plans on conducting outreach and education to customers; 2. information on how customers can opt-out of receiving AMR meters; 3. the Company's plans to test the AMR meters for accuracy; and 4. the timing and anticipated capability of reporting on the number of opt-outs and estimated bills.	Once	Within 120 days of the Commission issuing an order establishing rates in Case 24-G-0668.
24	Residential Methane Detector (RMD) Program	The Company shall file a report indicating the number of RMD units offered to residential customers, and the cost associated with the deployment of RMD units.	Annually	Within 60 days of the end of the preceding Rate Year.
25	Renewable Natural Gas (RNG)	Within 60 days of entering into a contract for the purchase of RNG, the Company shall file a report with the following information: 1. purchase terms and conditions; 2. the total volume of RNG purchased; 3. the supplier name(s) for purchased RNG; 4. the feedstock(s) used to produce purchased RNG, and 5. documentation which demonstrates that the contract priced the purchased RNG at a discount of the Dawn, Ontario Index price of traditional natural gas supply (from Platt's Gas Daily Price Guide) at the time of purchase.	As needed	Within 60 days of entering into a contract for the purchase of RNG.
26	Annual Gas Safety Performance Measures	The Company shall file a report detailing its performance for all gas safety performance measures set forth in Appendix S to the Joint Proposal.	Annually	Within 90 days of the end of the preceding Calendar Year.
27	Compliance with Pipeline Safety	If the Company incurs greater than 10 instances of non-compliance of a single code section of either audit type (field or record) per calendar year, the Company shall file with the chief of gas safety	As needed	Within 90 days of the date of the

Report No.	Report Name	Report Description/Contents	Frequency	Due Date
	Regulations – Remediation Plan	section within 90 days of the date of the pipeline safety Staff's audit letter a remediation plan explaining the root cause of the Company's compliance deficiency and how the Company will address/resolve compliance issues going forward, including the dates by which the non-compliances will be brought into compliance or, where appropriate, when remedial actions will be taken to prevent future recurrence. Should the Company fail to timely file the remediation plan with the Secretary as required in the preceding sentence, or fail to comply with the provisions of its filed remediation plan, the non-compliances in excess of 10 shall be incorporated with the remainder of the non-compliances being considered under this measure.		pipeline safety Staff's audit letter.
28	Property Tax Reconciliation	The Company will file a letter with the Secretary showing the property tax reconciliation calculation described in Section V.C.6.b of the Joint Proposal, and will include all supporting workpapers for the calculation.	Annually	Within 120 days of the end of the preceding Rate Year.
29	Merchant Function Charge	The Company will file a report with the Secretary showing the Merchant Function Charge reconciliation calculation described in Section V.D.4 of the Joint Proposal, and will include all supporting workpapers for the calculation.	Annually	December 15 of each year.
30	Delivery Revenue Adjustment	The Company will file a report with the Secretary showing the Delivery Revenue Adjustment reconciliation calculation described in Section V.D.5 of the Joint Proposal, and will include all supporting workpapers for the calculation.	Annually	December 15 of each year.
31	Interruptible Incentive Credit	The Company will file a report with the Secretary showing the Interruptible Incentive Credit reconciliation calculation described in Section V.D.8 of the Joint Proposal, and will include all supporting workpapers for the calculation.	Annually	December 15 of each year.
32	Revenue Decoupling Mechanism Reconciliation	The Company will file a report with the Secretary showing the Revenue Decoupling Mechanism calculation described in Section V.D.6 of the Joint Proposal, and will include all supporting workpapers for the calculation.	Annually	December 15 of each year.
33	Long-Term Plan (LTP) Surcharge	The Company will file a report detailing any future costs authorized by the Commission resulting from the LTP process and/or program implementation, which costs will be eligible for deferral/surcharge, limited to an annual percentage cap (two percent of aggregate revenues), and subject to Staff review/confirmation.	Annually	December 15 of each year.
34	Exogenous Events	In the event of an exogenous event as defined in Section V.I of the Joint Proposal that meets the criteria to defer an amount incurred in excess of three percent due to a legislative, regulatory, and related action, Liberty SLG shall file a letter with the Secretary by March 31 after the calendar year in which such expenses were incurred setting forth the rationale for the deferral.	As needed	By March 31 subsequent to the calendar year in which an exogenous event

SUBJECT: Filing by LIBERTY UTILITIES (ST. LAWRENCE GAS) CORP.

Amendments to Schedule P.S.C. 1 - Gas

First Revised Leaves Nos. 8, 66, 67, 68
Second Revised Leaf No. 278.4
Third Revised Leaves Nos. 3, 269, 275, 284, 290, 314, 321
Fourth Revised Leaves Nos. 278.3, 278.5
Fifth Revised Leaves Nos. 268, 270, 283
Sixth Revised Leaves Nos. 274, 276, 285

Suspension Supplement Nos. 7, 8, 9