STATE OF NEW YORK
PUBLIC SERVICE COMMISSION

CASE 24-E-0060 - Proceeding on Motion of the Commission as to the Rates, Charges, Rules and Regulations of Orange and Rockland Utilities, Inc. for Electric Service.

CASE 24-G-0061 - Proceeding on Motion of the Commission as to the Rates, Charges, Rules and Regulations of Orange and Rockland Utilities, Inc. for Gas Service.

ORDER ADOPTING TERMS OF A JOINT PROPOSAL AND ESTABLISHING ELECTRIC AND GAS RATE PLANS

Issued and Effective: March 20, 2025

Table of Contents

INTRODUCTION.. 5
BACKGROUND.. 6
NOTICE OF PROPOSED RULE MAKING...................................... 9
STATUTORY AND REGULATORY FRAMEWORK.................................. 10
THE JOINT PROPOSAL... 11
A. Term 11
B. Revenue Requirements, Revenue Allocation, and Rate Design 12
1. Revenue Requirements 12
a. Electric 12
b. Gas 13
2. Rate Drivers 14
3. Revenue Allocation and Rate Design 15
4. Rate Mitigation 16
5. Sales Forecasts 18
a. Electric Revenue Forecasts 18
b. Gas Revenue Forecasts 18
6. Electric Provisions 19
a. Market Supply Charge/Energy Cost Adjustment 19
b. Revenue Decoupling Mechanism 19
c. Other Charges 20
7. Gas Provisions 20
a. Gas Supply Charge/Monthly Gas Adjustment 20
b. Revenue Decoupling Mechanism 21
c. Base Rate Imputations 21
d. Lost and Unaccounted for Gas 22
C. Capital Structure, Cost of Capital, and Disposition of Excess Earnings 24
D. Capital Expenditures, Reconciliations, and Deferrals 27
1. Capital Expenditures 27
2. Net-Plant Reconciliations 29
3. Non-Wires Alternative (NWA) and NPA Adjustment Mechanisms 30
4. Non-Plant Reconciliations and Deferrals 30

E. Additional Accounting Provisions 34
1. Productivity 34
2. Depreciation Rates and Reserves 35
3. Interest on Deferred Costs 36
4. Property Tax Refunds and Credits 36
5. Income Taxes and Cost of Removal 37
6. Common Expenses/Plant Allocation 37
7. Legislative Lobbying 38
F. Performance Metrics 38
1. Electric Reliability Performance Mechanism 38
2. Gas Safety Performance Metrics 39
G. Additional Electric and Gas Programs 44
1. Pomona BESS Expansion 45
2. Little Tor Substation Project 45
3. West Point Upgrade Project 46
4. Additional Reporting Requirements 47
5. AMI NGDs 47
6. NPAs 48
7. Fusion Re-Dig Program 49
H. Customer Service 50
1. Customer Service 50
2. Extreme Cold and Heat Provisions 53
Discussion of PULP's Opposition to the Extreme Heat and Cold Provisions 53
a. Extreme Cold Provisions 54
b. Extreme Heat Events 56
c. Extreme Weather Reporting 58
Discussion of the Village's Opposition to Certain Customer Service Provisions 59
I. Electric and Gas Low Income Affordability Programs 62
J. Earnings Adjustment Mechanisms 66
K. CLCPA 69
L. Management Audit 72
M. Make-Whole Provision 74

CONCLUSION.. 74

STATE OF NEW YORK
PUBLIC SERVICE COMMISSION

At a session of the Public Service Commission held in the City of Albany on March 20, 2025

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-E-0060 - Proceeding on Motion of the Commission as to the Rates, Charges, Rules and Regulations of Orange and Rockland Utilities, Inc. for Electric Service.

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ORDER ADOPTING TERMS OF A JOINT PROPOSAL AND ESTABLISHING ELECTRIC AND GAS RATE PLANS

(Issued and Effective March 20, 2025)

BY THE COMMISSION:

INTRODUCTION

In this Order, the Commission approves a Joint Proposal establishing three-year rate plans for electric and gas delivery service provided by Orange and Rockland Utilities, Inc. (Company) for the period encompassing January 1, 2025, to December 31, 2027.

The Company, trial staff of the Department of Public Service (Staff), and the Utility Intervention Unit of the New York State Department of State (UIU) signed the Joint Proposal (collectively the Signatory Parties). The Public Utility Law Project (PULP) and the Village of Kiryas Joel (Village) oppose the Joint Proposal, New York Geothermal Energy Organization (NY Geothermal) takes a neutral position, and the Municipal Intervenors[1] take no position.

As more fully discussed throughout this Order, we approve and adopt the terms of the Joint Proposal as it is in the public interest. We find that 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 or otherwise provide benefits to ratepayers that would not have been achieved in a fully litigated proceeding; 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). As discussed more fully below, the Joint Proposal offers multi-year rate certainty for the Company and its customers, includes an earnings sharing mechanism, and provides a multitude of customer benefits.

BACKGROUND

Pursuant to Public Service Law (PSL) §66(12), the Company filed amendments to its electric and gas tariff schedules on January 26, 2024, proposing to increase its annual electric and gas delivery revenues for the rate year beginning January 1, 2025. More specifically, the Company sought an increase in electric delivery revenues of approximately $18.1 million and an increase in gas delivery revenues of approximately $14.4 million. According to the Company, these

[1] The Municipal Intervenors include Rockland County; the Towns of Haverstraw, Clarkstown, Orangetown, Ramapo, Stony Point, Rockland Green; and the Rockland County Sewer District No. 1.

proposed increases in revenues would increase the average residential customer's monthly total electric bill by $8.26 (or 6.0%) and the monthly total gas bill by $12.73 (or 8.1%).[2] In its filings, the Company asserted that the proposed revenue increases largely were driven by necessary enhancements to the Company's infrastructure that will ensure the Company is able to provide safe and reliable service and increase resiliency, as well as to support beneficial electrification, distributed energy resources, and the development of large-scale renewables and storage. The Company indicated in its filings that its electric investments would address anticipated growth in multifamily homes, large commercial and industrial facilities, and data centers; foster electrification of buildings and transportation; and better meet customers' increased expectations regarding system reliability, resiliency, and faster restoration of service after outages caused by storms. As for its natural gas investments, the Company's filings noted that its proposals would assist in maintaining safety and reliability and support decarbonization through reductions in gas usage in furtherance of the CLCPA's goals.

By Secretary's Notice dated February 15, 2024, the Commission suspended the Company's rate filings and initiated these proceedings to examine the Company's proposals.[3] The assigned Administrative Law Judges (Judges) conducted a

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[2] The bill impact calculated by the Company is for an electric residential customer using 550 kilowatt-hour (kWh) per month and a gas residential customer using 100 centum cubic feet per month.

[3] Notice of Suspension of the Effective Date of Major Rate Changes and Initiation of Proceedings (issued February 15, 2024). On June 7, 2024, 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 December 30, 2024.

procedural and technical conference and subsequently issued a ruling establishing a litigation schedule, including dates for the filing of testimony and the commencement of an evidentiary hearing.[4] Pursuant to that ruling, the Company filed various updates to its initial filings in April 2024; Staff, PULP, and UIU filed initial testimony in May 2024; and the Company and Staff filed rebuttal testimony in June 2024.

Pursuant to the Commission's Settlement Rules and Guidelines, the Company filed a Notice of Impending Settlement Negotiations on June 10, 2024, 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 through and including April 29, 2025, again subject to a "make-whole" provision. The Commission issued an order on November 14, 2024, extending the maximum suspension period of the tariff leaves through April 29, 2025.[5] A Settlement Judge was assigned to the case in August 2024 to ensure the expedient and efficient scheduling and conduct of ongoing settlement discussions, a requirement imposed by the Judges in their ruling postponing the originally scheduled evidentiary hearing on the Company's filed tariff leaves.[6]

Settlement negotiations ultimately resulted in the filing of the Joint Proposal on November 8, 2024. Statements in Support of the Joint Proposal were filed by the Company, Staff,

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[4] Ruling on Schedule (issued February 22, 2024).

[5] Order on Extension of Maximum Suspension Period of Major Rate Filings (issued November 14, 2024).

[6] Ruling on Schedule and Settlement Judge (issued August 28, 2024); Ruling Postponing Evidentiary Hearing (issued June 12, 2024).

and UIU, Statements in Opposition were filed by the Village and PULP, and a Statement of Neutrality was filed by NY Geothermal. An evidentiary hearing on the Joint Proposal was conducted by the Judges on November 21, 2024, to admit nearly 300 exhibits into evidence and to allow cross examination of a joint panel consisting of witnesses from Staff and the Company. Post-hearing briefs were filed by the Company, Staff, PULP, and UIU. Post-hearing reply briefs were filed by the Company, Staff, PULP, the Village, and the Municipal Intervenors.

NOTICE OF PROPOSED RULE MAKING

Pursuant to the State Administrative Procedure Act (SAPA) §202(1), Notices of Proposed Rulemaking were published in the State Register on May 1, 2024, for both the electric and gas rate filings [SAPA Nos. 24-E-0060SP1 and 24-G-0061SP1, respectively]. The deadline for submission of comments pursuant to the Notices was July 1, 2024. Moreover, in a Notice Soliciting Comments and Announcing In-Person Public Statement Hearings, comments were solicited, due November 29, 2024. In addition, the Judges presided over three Public Statement Hearings held within the Company’s service territory.

At the Public Statement Hearings, eight people provided spoken comments. Speakers commented on concerns regarding affordability and the discrepancy between commodity costs and delivery costs, noting that there is very little people can do to control or lower their delivery charges. Commenters also expressed the belief that ratepayers, who are also taxpayers, are being squeezed on all sides by policy decisions at the state level regarding environmental and energy issues.

In addition to the foregoing, the Commission’s website catalogues approximately 57 comments filed in the electric and gas proceedings. Comments expressed near unanimous opposition to any rate increase, mainly citing the cost of energy at the Company's existing rates, with many commenters expressing concerns over affordability. Other topics mentioned included a need for fewer electricity outages and for increased reliability, storm hardening, and improved resiliency; the amount or percentage of the delivery charges on customer bills relative to the energy commodity component; and the lack of any noticeable change in monthly bills after undertaking individual household conservation measures.

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. In the context of a negotiated Joint Proposal, the Commission will adopt its terms upon a finding that, as a whole, it meets the public interest standard in PSL §65(1). Applying the Commission's Settlement Guidelines, the Joint Proposal must meet the public interest standard after the Commission's consideration of the following factors: whether the Joint Proposal balances the protection of consumers with fairness to investors and the long-term viability of the utility; whether it is consistent with the environmental, social, and economic policies of the Commission and the State; whether it falls within the range of reasonable likely outcomes that would have resulted in a fully litigated proceeding; and whether the record provides a rational basis for the Commission's adoption of it.[7]

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[7] 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).

These factors and considerations in the context of a negotiated settlement "are themselves elements of the public interest standard."[8]

In addition, upon the application for a major change in rates, PSL §66(19)(c) requires the Commission to review the electric and gas corporation's "compliance with the directions and recommendations made previously by the Commission, as a result of the most recently completed management and operations audit."

Finally, CLCPA §7(2) requires State agencies to consider whether their administrative approvals and decisions are inconsistent with or will interfere with the attainment of the established statewide greenhouse gas (GHG) emission limits under Environmental Conservation Law (ECL) Article 75.[9] In addition, CLCPA §7(3) prohibits State agency approvals and decisions from disproportionately burdening disadvantaged communities identified under ECL §75-0101(5) and requires prioritization of the reduction of GHG emissions and co-pollutants in such communities. Our CLCPA analysis necessarily includes consideration of the Commission's core mandate to ensure safe and adequate service at just and reasonable rates, and we evaluate the Joint Proposal holistically rather than through its individual components.

THE JOINT PROPOSAL

A. Term

The Joint Proposal establishes a three-year rate plan consisting of three successive individual rate years beginning on January 1, 2025, and ending on December 31, 2027. Rate year

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[8] Id.

[9] ECL art. 75, L. 2019, ch. 106.

1 (RY1) matches the calendar year (January 1 to December 31) 2025, rate year 2 (RY2) consists of the calendar year 2026, and rate year 3 (RY3) consists of the calendar year 2027.

B. Revenue Requirements, Revenue Allocation, and Rate Design

1. Revenue Requirements

a. Electric

The Joint Proposal recommends the Commission adopt an electric operations revenue requirement decrease of $13.0 million in RY1, followed by a RY2 increase of $24.8 million and a RY3 increase of $44.0 million. The three rate years have been shaped in the Joint Proposal's rate plan for the electric operations to not include any delivery charge changes in RY1, with rates implementing equal revenue requirement increases of $17.7 million in both RY2 and RY3. The RY2 and RY3 monetary increases represent a 2.3% total revenue requirement impact in both years. However, because the Company's expiring 2022 Rate Plan[10] included the use of temporary sur-credits to address that plan's levelized revenue requirement increases, customers will experience the equivalent of a 1.3% total revenue requirement impact in RY1 due to the loss of that credit.[11]

[10] See Cases 21-E-0074 et al., Orange and Rockland Rates, Order Adopting Terms of Joint Proposal and Establishing Electric and Gas Rate Plans (issued April 14, 2022) (2022 Rate Plan).

[11] A similar sur-credit is included in the Joint Proposal for RY3 to make up for the Joint Proposal's shaping of the electric revenue requirement increase to moderate bill impacts and its resulting lower base delivery rate revenues that would result at the end of RY3. To make up the difference, RY3 base rates are increased by $38.1 million, but customers are provided a credit of $20.4 million. Thus, when the credit expires at the end of RY3, electric base rates will be set at the correct level that would have resulted had the Joint Proposal not included the shaping mechanism.

The following table shows the average monthly bill impacts for a typical residential customer, exclusive of any potential make-whole provision, and including the effect of the expiration of the temporary sur-credits from the 2022 Rate Plan.[12]

Electric	**Rate Year 1**	**Rate Year 2**	**Rate Year 3**
Avg. Monthly Bill Impact ($)	$3.50	$4.93	$5.33
Avg. Monthly Bill Impact (%)	2.4%	3.3%	3.5%

b. Gas

For gas, the Joint Proposal includes revenue requirement increases of $3.6 million in RY1, $18.0 million in RY2, and $16.5 million in RY3. The amounts have been levelized as an increase of $10.4 million in each of the three rate years. The monetary revenue requirement increased amounts represent a 3.4% impact on the Company's gas total revenue requirement in RY1, a 3.3% impact in RY2, and a 3.1% impact in RY3. As the expiring 2022 Rate Plan for gas also included a final rate year sur-credit, customers will experience an additional 1.6% RY1 impact in addition to the 3.4% impact due to the Joint Proposal's RY1 revenue requirement increase.[13]

[12] The average total monthly bill impacts shown are for a typical electric customer using 600 kWh per month.

[13] As with the electric operations rate plan, shaping the revenue increases for gas across the Joint Proposal's three rate years would otherwise result in a base rate deficiency compared to the revenue requirement increases being applied without the bill impact moderating effect of levelization. Accordingly, the Company will record a base rate RY3 revenue increase of $17.2 million and apply a $6.8 million credit that will expire with the rate year.

The following table shows the average monthly bill impacts for a typical residential gas heating customer, exclusive of any potential make-whole provision, and including the effect of the expiration of the temporary sur-credits from the 2022 Rate Plan.[14]

Gas	**Rate Year 1**	**Rate Year 2**	**Rate Year 3**
Avg. Monthly Bill Impact ($)	$9.58	$5.99	$6.79
Avg. Monthly Bill Impact (%)	6.1%	3.5%	3.6%

2. Rate Drivers

A main driver of the requested revenue requirement increases for electric and gas is the continued need to upgrade, rebuild, and invest in the Company’s infrastructure. Additional drivers include higher financing costs and a decrease in projected net sales revenue for the Company’s gas business.

The Joint Proposal reflects electric capital along with operations and maintenance (O&M) spending for programs that will support safe and reliable service, including additional substations, increased resiliency efforts against climate change impacts, and the replacement of aging infrastructure. Another driver is the need to address the increasing impact of storms in the Company’s service territory through an increase in major storm funding.

Drivers of the gas rate increases include capital and O&M spending to improve system reliability through the replacement of aging infrastructure, including leak-prone pipe.

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[14] The average total monthly bill impacts shown are for a typical residential gas heating customer using 100 centum cubic feet per month.

The Joint Proposal also recommends the continuation and development of various pipeline safety programs.

3. Revenue Allocation and Rate Design

The revenue allocation proposed in the Joint Proposal does not use or reflect any single embedded cost of service (ECOS) study sponsored by any party.[15] Rather, the Signatory Parties agreed to an allocation of revenue increases for individual customer classes. Notably, the Joint Proposal provides for updated electric customer charges that are intended to better align with the customer-related costs, such as meter and service-related costs as well as customer care costs.

The Company initially proposed to increase the electric residential service classification (SC) 1 customer charge and gas SC1 minimum charge, a proposal that was opposed by PULP and Staff. Under the terms of the Joint Proposal, electric SC1 customers will not see an increase of the customer charge in RY1 and increases in the customer charge would be phased in over the subsequent two rate years.[16] As for gas customers, the Joint Proposal provides for updated minimum charges that are more aligned with the Company's costs. As with electric SC1 customers, gas SC1 customers will see no increases to the minimum charge in RY1 and increases will be phased in over the subsequent two rate years to mitigate bill impacts.[17]

No party opposes or otherwise takes issue with the agreed-upon revenue allocation or rate design provisions of the Joint Proposal. UIU, which was opposed to the Company's initial ECOS studies and overall revenue allocation proposals, supports the terms in the Joint Proposal, stating that the compromise

[15] Joint Proposal, p. 40.

[16] Id., Appendix 17.

[17] Id., Appendix 18.

approach to revenue allocation used by the Signatory Parties "achieves fair, just, and reasonable rates."[18] UIU highlights that the Joint Proposal requires the Company, as part of its next rate filing, to provide interested parties an overview of its proposed ECOS study and rate design proposals, including "an explanation of the differences in the ECOS studies filed pursuant to this [Joint] Proposal, [and] a more detailed explanation of the purpose of each file and cross-references of the underlying data sources."[19] According to UIU, this will help parties in the Company's future rate case avoid confusion and further the parties' understanding of the Company's ECOS models.[20]

We find that both the electric and gas revenue allocations and rate designs recommended in the Joint Proposal are just and reasonable and in the public interest. The proposed revenue allocations and rate design are supported by the ECOS studies, are more reasonable than what could have been achieved by using any one ECOS methodology, and fairly allocate revenue requirements among the service classes consistent with cost-of-service principles. We also find that the rate design and revenue allocation provisions are within the range of reasonable outcomes had the cases been fully litigated.

4. Rate Mitigation

The rate increases provided in the Joint Proposal are intended to be mitigated through several provisions. Notably, while the Joint Proposal recommends changes to the Company's

[18] UIU Statement in Support, p. 3.

[19] Joint Proposal, pp. 40-41. As with this case, in the next rate case, the Company will again provide alternative electric and gas ECOS studies that exclude transmission and distribution components from customer-related costs.

[20] UIU Statement in Support, p. 3.

electric delivery service rates and charges designed to produce a reduction of $13.1 million in revenues on an annual basis in RY1,[21] it also recommends keeping base rates unchanged in RY1, which provides rate stability and results in zero impact on total revenue for electric in RY1.[22] As mentioned above, the Joint Proposal also includes no increase to the electric SC1 customer charge in RY1 and phased-in increases to customer charges for SC1 in RY2 and RY3, to mitigate bill impacts.[23] Additionally, the proposed partially levelized electric base rate changes mitigate the bill impact that will occur in calendar year 2028.[24]

For gas, the Joint Proposal also recommends phasing in the base rate changes, which equally spreads the gas revenue increases over the three years of the rate plan.[25] The Joint Proposal also includes no increase to the gas SC1 RY1 minimum charge and phased-in increases to the minimum charges for SC1 in RY2 and RY3, to mitigate bill impacts.[26]

The Joint Proposal includes limits such that each electric service class received a delivery revenue increase that was no more than 1.25 times but at least 0.5 times the system average delivery revenue increase for each rate year.[27] For gas, each service class received a delivery revenue increase that was

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[21] Joint Proposal, p. 5.

[22] Id., p. 6. The zero impact does not include the expiration of credits from prior cases. See n. 11, supra.

[23] Id., Appendix 17, Schedule 5, p. 1; Schedule 6, p. 1; Schedule 7, p. 1.

[24] Staff Statement in Support, pp. 19-20; p. 20 n. 39.

[25] Joint Proposal, p. 9.

[26] Id., Appendix 18, Schedule 5, p. 1; Schedule 6, p. 1; Schedule 7, p. 1.

[27] Id., Appendix 17, p. 1.

no more than 1.25 times but at least 0.75 times the system average delivery revenue increase for each rate year.[28]

The electric and gas revenue requirements in the Joint Proposal also contain an escalating productivity adjustment, detailed below.[29] The Joint Proposal's productivity adjustment is consistent with the position Staff advanced in its testimony and with the Commission's practice to use the productivity adjustment to capture unidentified and/or unquantifiable productivity gains, efficiencies, and cost savings.[30]

We find that these provisions of the Joint Proposal will reasonably mitigate overall rate impacts over the three-year Rate Plans and provide rate stability, while assuring the Company's continued ability to provide safe and adequate service.

5. Sales Forecasts

a. Electric Revenue Forecasts

The Joint Proposal reflects electric revenues of $613.8 million in RY1, $630.3 million in RY2, and $642.2 million in RY3, based on a total annual megawatt-hour (MWh) delivery volume of 3.9 million MWh for RY1, 3.9 million MWh for RY2, and 4.0 million MWh for RY3.[31]

b. Gas Revenue Forecasts

The Joint Proposal reflects gas revenues of $294.6 million in RY1, $308.5 million in RY2, and $322.6 million in RY3, based on deliveries of between 23.8 million and 24.2

[28] Id., Appendix 18, p. 1.

[29] Id., p. 37.

[30] Hearing Exhibit 172 (Staff Accounting Panel Testimony), p. 27.

[31] Joint Proposal, p. 7; Appendix 4, pp. 1-4.

million thousand cubic feet (Mcf).[32] The gas revenues include delivery and commodity revenues as well as revenue taxes.[33]

6. Electric Provisions

a. Market Supply Charge/Energy Cost Adjustment

The Joint Proposal provides for the Company's continued recovery of all prudently incurred electric supply and electric supply-related costs, including purchase power costs, through the Market Supply Charge (MSC) and Energy Cost Adjustment (ECA) mechanisms.[34] This reflects the conclusion that these mechanisms are the preferred alternative for recovering certain costs or incentives provided for in the Joint Proposal because the amounts to be recovered are either currently unknown, subject to a cap, or would otherwise be subject to reconciliation.[35] We expect the Company to continue to strategically plan to minimize supply cost fluctuations and to timely and effectively communicate with customers and interested stakeholders in advance of significant supply cost price increases and resulting bill impacts.

b. Revenue Decoupling Mechanism

The Joint Proposal allows the Company to continue to implement a Revenue Decoupling Mechanism (RDM) for the term of the electric rate plan, as set forth in the Company's electric tariff and modified by Appendix 20.[36] If the Company does not file for new base delivery rates to take effect within 15 days upon the expiration of RY3, the RDM will remain in effect and the delivery revenue targets effective January 1, 2028, will

[32] Id., Appendix 5.

[33] Id., Appendix 5.

[34] Id., p. 7.

[35] Company Statement in Support, p. 21.

[36] Joint Proposal, pp. 7-8, Appendix 20.

continue but will be restated to reflect the expiration of the temporary credit that is being collected through the ECA in RY3.[37]

c. Other Charges

The Joint Proposal provides that if the Company is or will be subject to governmental or regional transmission organization transmission and/or generation-related charges, costs, or credits not listed in or otherwise covered by the then-effective MSC or ECA tariff language -- such as those that may be imposed by the Federal Energy Regulatory Commission, the Environmental Protection Agency, or the New York Independent System Operator -- the Company may make a tariff filing with the Commission providing for recovery from customers of such charges and/or costs, or application of credits, through the MSC, ECA, and/or comparable adjustment mechanism and may include the charges, costs, and/or credits applicable to the period prior to the effective date of the tariff amendment.[38]

7. Gas Provisions

a. Gas Supply Charge/Monthly Gas Adjustment

The Joint Proposal continues the Company's recovery of all prudently incurred gas supply and gas supply-related costs through the Gas Supply Charge (GSC) and Monthly Gas Adjustment clause (MGA).[39] Costs associated with balancing assets will continue to be recovered from all SC 1, 2, and 6 customers through a common cents per centum cubic feet component in the MGA.[40] The Company will file monthly statements reflecting the

[37] Id., pp. 7-8, Appendix 20. The electric RDM targets for each rate year are detailed in Schedule 1 to Appendix 20.

[38] Id., p. 8.

[39] Id., p. 10.

[40] Id., pp. 10-11.

costs, charges, and/or credits covered by the GSC, MGA, and Weighted Average Cost of Transportation adjustment mechanisms.[41]

b. Revenue Decoupling Mechanism

The Joint Proposal allows the Company to continue to implement a RDM for the term of the gas rate plan, as set forth in the Company's gas tariff and modified by Appendix 20.[42] If the Company does not file for new base delivery rates to take effect within 15 days upon the expiration of RY3, the RDM will remain in effect and the delivery revenue targets effective January 1, 2028, will continue but will be restated to reflect the expiration of the temporary credit that is being collected through the MGA in RY3.[43]

c. Base Rate Imputations

The Joint Proposal sets the base rate imputation at approximately $4.5 million in all three Rate Years.[44] These revenue imputations reflect (1) interruptible benefits[45] of $4.8 million (Interruptible Benefits Imputation) and (2) $0 for net benefits associated with the delivery of gas to electric generating facilities previously owned by the Company in each rate year (Power Generation Imputation).

The Joint Proposal provides that any positive or negative variances between the actual revenue margin and the Interruptible Benefits Imputation, during each Rate Year that

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[41] Id., p. 11, n. 15.

[42] Id., p. 11, Appendix 20.

[43] Id., p. 11, Appendix 20. The gas RDM targets for each RY are detailed in Schedule 2 to Appendix 20.

[44] Id., p. 11.

[45] Interruptible benefits are total interruptible (SC8) and firm withdrawable (SC9) revenues, minus any associated gas costs and revenue tax surcharge revenues. Joint Proposal, p. 11, n. 16.

the gas rate plan is effective, will be shared on an 80% customer/20% Company basis, and the 80% customer over-/under-recovery will be credited to/recovered from customers as applicable through the MGA. One hundred percent of any positive or negative variances between the actual revenue margin and the Power Generation Imputation, during each Rate Year the gas rate plan is effective, will be credit to/recovered from customers as applicable through the MGA.

d. Lost and Unaccounted for Gas

The Joint Proposal sets the lost and unaccounted for (LAUF) gas target, dead bands, and factor of adjustment (FAO). The FAO will be updated November 1 of each RY, based on the average of the FAOs for the previous five 12-month periods ending August 31.[46] This provision is consistent with our prior rate orders for the Company and is reasonably designed to address the necessary calculations for determining LAUF.

Discussion of PULP's Opposition

PULP's Statement in Opposition argues that many of the Company's customers are already struggling to pay their bills, the Joint Proposal envisions significant bill impacts for each of the next three rate years, and that the Joint Proposal should be modified to produce lower bill impacts for customers.[47] PULP also recommends that fixed charges be frozen to help customers afford their bills.[48]

The Company counters that PULP fails to provide any specific recommendations as to which programs or projects should

[46] Joint Proposal, pp. 12-14, Appendix 10 (illustrative calculation of LAUF and dead band target, illustrative calculation of line loss incentive/penalty, and illustrative calculation of System Performance Adjustment mechanism).

[47] PULP Statement in Opposition, pp. 2-4.

[48] Id., p. 6.

be modified to achieve those bill impacts and provides no evidence or analysis on the consequences to the Company's ability to provide safe and reliable service associated with such modifications.[49] The Company also argues that, in evaluating a utility rate settlement, the Commission must view the proposed settlement as a whole, and the Signatory Parties arrived at the Joint Proposal only after several months of negotiations. The Company asserts that the agreement overall balances "a complicating array of factors (and result[s] in reasonable total bill impacts of 0% to 3.4% annually during the rate plan)." According to the Company, PULP does not provide evidence to justify "undermining that balance."[50] The Company also argues that any shortfall in the revenue recovered through the customer charge would increase the revenue to be recovered through the per kWh usage charges and, thus, freezing the customer charge would shift the allocation to other customers.[51] Staff also opposes PULP's arguments.[52] PULP's Post-Hearing Reply brief did not address any of the Company's or Staff's counterarguments.[53]

We find that the revenue requirement terms proposed in the Joint Proposal compare favorably with the likely result of a litigated outcome. We also find that the rate mitigation, revenue forecasting, and other provisions underlying the Joint

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49 Company Post-Hearing Brief, p. 2.

50 Id.

51 Id.

52 Staff Post-Hearing Brief, pp. 3-5.

53 In their Post-Hearing Brief, the Rockland Municipal Intervenors raised, for the first time, the issue of bill impacts (p. 4). The Rockland Municipal Intervenors did not oppose the Joint Proposal. In any event, their argument regarding bill impacts is unavailing for the same reasons that PULP's arguments are unavailing.

Proposal's electric and gas rate plans are reasonable. Notably, the Joint Proposal sets forth various rate mitigation measures designed to reduce the rate impact of the proposed electric and gas rate plans. We agree with the Company and Staff that many elements of the revenue requirement represent a compromise of various litigated positions and therefore cannot be evaluated individually in a vacuum. We also agree that PULP fails to justify upsetting the balance achieved by the Signatory Parties after months of negotiations. Accordingly, based on the record before us, we find that these provisions of the Joint Proposal will assure safe and adequate service at just and reasonable rates.

C. Capital Structure, Cost of Capital, and Disposition of Excess Earnings

The Joint Proposal includes an allowed return on equity (ROE) of 9.75 percent and a capital structure that incorporates a common equity ratio of 48 percent for both the Company's electric and gas businesses.[54] The Joint Proposal also includes an earnings-sharing mechanism (ESM) pursuant to which ratepayers will share in a portion of the Company's annual earnings that exceed 10.25 percent.[55] Under the ESM, earnings above 10.25 percent, but less than or equal to 10.75 percent, would be shared equally between ratepayers and the Company. Earnings above 10.75 percent, but less than or equal to 11.25 percent, would be shared 75 percent/25 percent between ratepayers and the Company, respectively. Earnings above 11.25 percent would be shared 90 percent/10 percent between ratepayers and the Company, respectively. The Company will defer the ratepayers' share of excess earnings for the benefit of ratepayers. For any of the Company's shared earnings, the

[54] Joint Proposal, p. 14, and Appendices 1 and 2.

[55] Id., p. 15.

Company would use 50 percent of its portion to reduce regulatory asset balances associated with Site Investigation and Remediation (SIR) or other deferred costs, should the shared portion exceed SIR balances.[56]

The opportunity for a utility to earn a fair return on its prudently incurred infrastructure investments used to serve the public is a fundamental requirement of a rate order.[57] The 9.75 percent ROE in the Joint Proposal is the product of compromise and falls within the bounds of the 10.3 percent ROE proposed by the Company and the 9.5 percent ROE recommended by Staff.[58] Further, the proposed ROE is reasonable given the economic environment at the time the revenue requirement in the Joint Proposal was agreed upon. In July 2024, the Commission adopted a 9.5 percent ROE for Central Hudson Gas & Electric Corporation in a litigated rate order.[59] The Commission also adopted a three-year rate plan containing a 9.7 percent ROE for National Fuel Gas Distribution Corporation in December 2024.[60]

PULP argues that the Joint Proposal's 9.75 percent ROE is not in the public interest because it is "fixed" over the three-year term of the rate plan.[61] PULP argues that the Commission's use of a fixed ROE may harm ratepayers and requests that the Commission modify the Joint Proposal to include an

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[56] Id., p. 17.

[57] Case 23-G-0627, National Fuel Gas – Rates, Order Adopting Terms of a Joint Proposal and Establishing Gas Rate Plan with Minor Modifications (issued December 19, 2024) (2024 NFG Rate Order), pp. 30–31.

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

[59] Cases 23-E-0418 et al., Central Hudson Gas & Electric Corporation – Rates, Order Establishing Rates for Electric and Gas Service (issued July 18, 2024), p. 71.

[60] Case 23-G-0627, supra, 2024 NFG Rate Order, pp. 30–31.

[61] PULP Statement in Opposition, pp. 4-5.

annual process to prescribe a fixed ROE for a single year, after which the Company would be subject to "equitable sharing" of any overearnings. Finally, PULP requests that the Commission modify the Joint Proposal to require a study during the rate plan, absent a change to PULP's requested annual ROE update, to determine what the benefit or harm to ratepayers would have been under an annual update scenario.[62]

For the reasons stated in several of the Commission's recent rate orders rejecting PULP's similar requests, we disagree with PULP's position and decline to modify the Joint Proposal as requested.[63] As noted in previous rate orders, PULP's arguments fail to account for the benefits that utility customers receive through a fixed ROE and that utilities must manage their business in a manner beneficial to customers of the utility and its investors to receive the return prescribed in the allowed ROE. Moreover, incorporating a fixed ROE in a settlement was an issue that was specifically considered by the Commission, and thoroughly vetted by interested parties, including PULP, when the Commission adopted the Settlement Guidelines. The Commission stated that the "disposition of rate of return and rate design issues can be integral to parties' agreement to the terms of a settlement and the comments persuasively argue that these issues should not be treated differently from all other terms of a settlement."[64] We see no

[62] Id.

[63] Case 23-G-0627, supra, 2024 NFG Rate Order, pp. 31–32; Cases 22-E-0317, NYSEG and RG&E – Rates, Order Adopting Joint Proposal (issued October 12, 2023), pp. 27-29; Cases 22-E-0064 et al., Consolidated Edison Company – Rates, Order Adopting Terms of Joint Proposal and Establishing Electric and Gas Rate Plans with Additional Requirements (issued July 20, 2023), pp. 76-77.

[64] Cases 92-M-0138 et al., supra, Settlement Guidelines, p. 23.

reason to depart from that position and find that the Commission's 1992 expectation has been proven time and again in the numerous rate cases that have been brought to the Commission as settled joint proposals since.

A fixed ROE in a multi-year rate plan promotes the public interest by providing predictability and stability that protects ratepayer interests against the volatility of frequent rate changes. It also supports utilities' credit ratings, allowing the companies to borrow money on more favorable terms and, in turn, keep rates lower. Finally, it incentivizes utilities to continue to strive for cost efficiencies and productivity gains that ultimately benefit ratepayers by leading to lower costs that will be reflected in future rates.

Accordingly, we find that the Joint Proposal's 9.75 percent ROE is reasonable, given the overall financial market conditions at the time the agreement was reached, and is inextricably a part of such agreement. We determine that the agreed-upon ROE is fair, given the increased financial and business risks inherent in setting rates over a multi-year period. The Joint Proposal incorporates a return that is expected to allow the Company to attract adequate capital to fund its anticipated investments, ensuring the continued provision of safe and reliable service in the Company's service territory and, as such, is in the public interest.

D. Capital Expenditures, Reconciliations, and Deferrals

1. Capital Expenditures

The Joint Proposal provides for an electric capital investment of $313.9 million in RY1, $351.6 million in RY2, and $316.4 million in RY3.[65] Programs supported by these investments include expansion of the existing Pomona Battery Energy Storage

[65] Joint Proposal, Appendices 8 and 9.

System from 3 megawatts (MW)/12 MWh to 3MW/18MWh; funding for the West Point Project, which will upgrade the electric service for the United States Military Academy and the Company's customers in Highland Falls; and funding for various transmission projects.

The Joint Proposal provides for a gas capital investment of $117.7 million in RY1, $124.2 million in RY2, and $108.8 million in RY3. These investments will support the Main Replacement Program, which prioritizes replacing the riskiest gas mains with plastic or protected steel, as well as other distribution system upgrades and reliability enhancements. Consistent with the CLCPA, non-pipe alternatives (NPAs) may be considered for some of the projects.

The Joint Proposal also recognizes that the Company applied for federal funding under the Infrastructure Investment and Jobs Act (IIJA). If the Company receives any funding under the IIJA, the Company will sur-credit the carrying charge associated with the decrease in program or project cost through the ECA.

Capital expenditure reporting requirements are detailed in Appendix 19 to the Joint Proposal and largely remain unchanged from the 2022 Rate Plan. Moving forward, however, the Company will be required to provide more details in its presentation of its capital expenditures. Specifically, the Company must present its capital budget by project or program category, rather than as a total expenditure amount, and the Company will be required to provide a narrative for each project that includes project design and permitting or construction status. These details will permit the Commission and Staff to better monitor the progress of the Company's programs and projects, and the amounts allocated to each.

From the record, we see that in these proceedings the participating parties thoroughly examined the Company's proposed capital expenditures. The budgets reflected in the Joint Proposal fall within the range of possible outcomes that could have resulted following a fully litigated case and represent a reasonable compromise that will allow the Company to continue to provide safe and reliable service to its customers.

2. Net-Plant Reconciliations

The Joint Proposal continues the reconciliation mechanisms set in the 2022 Rate Plan, including the downward-only reconciliation for electric and gas net plant.[66] The downward-only reconciliation mechanism is intended to incent the Company to adhere to the plant budgets in the Rate Plan by setting net plant targets and requiring the Company to defer for customer benefit the revenue requirement impact amount associated with net plant investment that is not made. The calculation of such an amount will be made on a cumulative basis. By allowing for this measure to be calculated on a total three-year cumulative basis, the Company retains the flexibility to modify the type, timing, nature, and scope of its capital programs and projects as unforeseen demands and situations occur influencing the timing of specific projects. This approach serves the Company's ability to efficiently manage and operate its electric and gas businesses, while protecting customers from under-spending in a manner that would not otherwise be captured through traditional ratemaking. The reconciliation mechanisms are reasonable and support our finding that the Joint Proposal is in the public interest.

[66] Joint Proposal, pp. 17-22, Appendix 8.

3. Non-Wires Alternative (NWA) and NPA Adjustment Mechanisms

The Joint Proposal continues the provisions in the 2022 Rate Plan addressing costs incurred by the Company for implementing new NWA and NPA projects. Specifically, to the extent that a new NWA or a new NPA displaces a capital project reflected in the average electric or gas net plant in service balance, the appropriate balance will be reduced to exclude the anticipated net plant amount associated with the displaced project. In addition, the Joint Proposal provides a financial incentive for the Company to successfully implement NWA projects that avoid cost overruns. The continuation of these provisions, which may provide societal and environmental benefits, also benefits customers by treating the Company's investments in NWA and NPA the same as if the investments were in traditional capital projects, reducing the incentive for the Company to prefer traditional capital projects over NWA or NPA. Given that the NWA and NPA provisions of the Joint Proposal provide benefits by potentially reducing the long-term impacts of adding traditional infrastructure, we find that they are reasonable and support a finding that the Joint Proposal serves the public interest.

4. Non-Plant Reconciliations and Deferrals

a. Pensions and Other Post-Employment Benefits (OPEBs)

The Joint Proposal continues, without modification or opposition, the provisions of the 2022 Rate Plan relating to reconciliation of the Company's OPEBs costs, in accordance with the Commission's Pension Policy Statement.[67]

b. Major Storm Reserves

The Joint Proposal largely continues the storm reserve framework established in the 2022 Rate Plan, with minor modifications. Specifically, the Joint Proposal increases the storm allowance to $12.6 million in RY1, $12.9 million in RY2, and $13.2 million in RY3.[68] All incremental major storm costs above $200,000 are chargeable to the major storm reserve. In addition, the Joint Proposal allows the Company to charge pre-staging and mobilization costs between $100,000 and $1.9 million to the major storm reserve.[69] The Joint Proposal specifies that all major storm costs are subject to Staff's review. Finally, the Company anticipates a storm reserve deficiency at the start of RY1 of approximately $81.9 million. As such, the Joint Proposal includes recovery of previously incurred major storm expenses at a rate of $19.1 million annually.

These terms permit the Company to be appropriately prepared to respond to major storm events while providing a financial incentive to the Company to ensure that its preparations are reasonably developed to avoid unnecessary costs

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[67] Id., pp. 24-25, Appendices 6 and 7. See Case 91-M-0890, Matter of the Development of a Statement of Policy Concerning the Accounting and Ratemaking Treatment for Pensions and Post-Retirement Benefits Other Than Pensions, Statement of Policy and Order Concerning the Accounting and Ratemaking Treatment for Pensions and Post-Retirement Benefits Other Than Pensions (issued September 7, 1993) (Pension Policy Statement).

[68] Joint Proposal, p. 28, Appendix 6.

[69] This increases the upper limit from $1.75 million set in the 2022 Rate Plan. Unchanged from the 2022 Rate Plan is the provision that permits the Company to charge 85 percent of such costs that exceed $1.9 million to the major storm reserve, with the remaining 15 percent expensed in the year that the cost occurred.

to ratepayers. The terms of the Joint Proposal in this regard are reasonable and consistent with past practice.

c. Combined Uncollectable Expenses and Late Payment Charge Reconciliation

Due to the uncertainties in the forecasts because of the COVID pandemic, the 2022 Rate Plan permitted the Company to reconcile its actual revenues for electric and gas late payment charges with the levels included in base rates once the variance equates or exceeds five basis points of return on common equity.[70] Similarly, the Company also was permitted to defer 100 percent of the difference between its actual uncollectable expense reserve and the level reflected in base rates each year for the period between January 1, 2020, through December 31, 2024, once the variance equals or exceeds five basis points of return on common equity.[71] The Company proposed to continue this mechanism unchanged, alleging that its arrears and write-off balances were "still significantly elevated" compared to pre-pandemic levels, thereby rendering the forecast of such figures "untenable."[72]

In response, Staff posited that the Company's elevated arrears balances after October 2023 were due primarily to the Company's implementation of its new customer service billing

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[70] Legislation enacted in 2021 extended the COVID-related moratorium on utility terminations and the ban on utility late fees until July 2022 for residential and small business utility customers. See L. 2021, ch. 106.

[71] These figures are calculated on an annual basis and applied separately for gas and electric service. 2022 Rate Plan, Joint Proposal, Appendix 9.

[72] Hearing Exhibit 1 (Company Accounting Panel Testimony), pp. 59-60. The Company reports that its arrears balance as of December 31, 2023, was $26 million, an increase of 86 percent over its pre-pandemic baseline of $14 million, and that since February 2020 the number of customers in arrears increased by 8,300 to 26,000. Id.

system, rather than any difficulties related to forecasting arrears due to the pandemic.[73] Staff therefore recommended that, rather than continuing the uncollectable expenses and late payment reconciliations unchanged, as the Company proposed, the reconciliations should be discontinued completely.[74]

The Joint Proposal provides that once an annual threshold is met – set at $900,000 for electric and $500,000 for gas – the Company is permitted to defer for reconciliation 100 percent of the variation between its actual uncollectable expenses and late payment charges and the levels of uncollectable expenses and late payment charges provided for in base rates.[75] The Joint Proposal specifies that, if the Company under-collects, deferring the costs at issue cannot put the Company in an over-earnings position. If the deferral of costs would put the Company in an over-earnings position, then the Company will expense the costs above the Company's authorized ROE. Any recovery from or refund to customers will be made via surcharge or sur-credit, subject to separate annual surcharge caps for gas and electric that are limited to no more than 0.5 percent total bill impact per commodity.[76]

The Joint Proposal's treatment of the Company's uncollectable expenses and late payment charges falls within the range of outcomes that could have been reached as a result of

[73] Hearing Exhibit 172 (Staff Accounting Panel Testimony), pp. 117-126. Notably, immediately prior to implementation of the new system, the Company "paused all collection activities", consistent with industry best practices, "to stabilize the system and validate that billing as well as payment application processes were working correctly." Id., p. 120. Collections for commercial and residential customers did not recommence until April and May 2024, respectively.

[74] Id., p. 126.

[75] This is to be calculated separately for electric and gas.

[76] Joint Proposal, pp. 32-33.

litigation and supports the public interest by setting annual thresholds for which the Company is responsible before amounts are deferred for recovery from its customers, while also providing the Company with an incentive to be proactive in its arrears collection activities. The surcharge/sur-credit cap and mechanism also support the public interest by ensuring that the annual bill impact to customers is held to a reasonable level and that any refunds due to customers can be timely made, rather than deferring the amounts to the next rate case, thereby minimizing the effect of regulatory lag.

E. Additional Accounting Provisions

1. Productivity

The Company proposed a one percent productivity adjustment intended to capture cost savings associated with unidentified/unquantifiable productivity gains and other efficiencies realized during the Rate Year.[77] Staff recommended a 1.5 percent adjustment based on the Company's proposed hiring activities and information technology (IT) investments.[78] The Joint Proposal provides for an escalating productivity adjustment with a one percent adjustment reflected in revenue requirements for RY1, a 1.25 percent adjustment for RY2, and a 1.5 percent adjustment for RY3. This outcome appropriately recognizes increasing productivity gains resulting from RY1 IT investments and will capture unidentified productivity in the later rate years.

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[77] Hearing Exhibit 1 (Company Accounting Panel Testimony), pp. 41-43; Hearing Exhibit 108 (Company Accounting Panel Update Testimony); Hearing Exhibit 110 (Company Accounting Panel Update Exhibit AP-E3); Hearing Exhibit 115 (Company Accounting Panel Update Exhibit AP-G3).

[78] Hearing Exhibit 172, supra, pp. 27-28.

2. Depreciation Rates and Reserves

In its initial rate filings, the Company proposed new average service lives for five electric and eleven gas accounts, and one common account, as well as new net salvage percentages for nine electric and three gas accounts. The Company also proposed to shorten the service lives of several gas accounts by up to 15 years based on anticipated CLCPA impacts.[79] Staff countered with several different average service lives and different net salvage percentages but stated that depreciation impacts related to CLCPA compliance should be addressed more generically in Case 20-G-0131.[80]

Appendix 11 of the Joint Proposal provides average service lives, net salvage factors, and life tables used in calculating the depreciation reserve and establishing related revenue requirements for electric and gas service. According to Staff and the Company, the depreciation figures and methods in the Joint Proposal represent a compromise approach.[81] The Company further comments that notwithstanding its compromise, it believes its position regarding shortened service lives will better serve customer interests. The Company acknowledges that its recommended approach would increase short-term depreciation costs but claims it would lower overall, long-term costs. The

[79] Hearing Exhibit 32 (Company Depreciation Panel Exhibit DP-E2); Hearing Exhibit 33 (Company Depreciation Panel Exhibit DP-G2); Hearing Exhibit 29 (Company Depreciation Panel Testimony), pp. 10, 26-27, 53.

[80] Hearing Exhibit 186 (Staff Depreciation and Net Plant Panel Testimony), pp. 19-20. See Case 20-G-0131, Proceeding on Motion of the Commission in Regard to Gas Planning Procedures (Generic Gas Planning Proceeding).

[81] Staff Statement in Support, p. 44; Company Statement in Support, p. 31.

Company also expresses concern about the progress of the depreciation issue in the Generic Gas Planning Proceeding.[82]

The proposed depreciation figures contained in Appendix 11 of the Joint Proposal are reasonable and designed to balance the concerns raised by the Company with the potential for rate shock. While we note the Company's concerns, we continue to believe that the issue is better dealt with on a statewide basis in the generic proceeding. Further, we disagree that progress in that proceeding is anything but measured, thoughtful, and steady.

3. Interest on Deferred Costs

The Joint Proposal requires the Company to record on its books various credits and debits that are to be charged or refunded to customers. Except where otherwise specified in the Joint Proposal or by Commission order, the Company will accrue interest on these book amounts, net of federal and state income taxes, at the Other Customer-Provided Capital Rate published annually by the Commission.[83] As noted by Staff, these variances are short-term in nature and a short-term carrying charge rate is appropriate and reasonable. Longer-term items, including the Company's existing regulatory assets and liabilities, are carried at the Company's rate of return, which is appropriate given the impacts these long-term items have on the Company's financing requirements.[84]

4. Property Tax Refunds and Credits

Treatment of property tax refunds and credits in the Joint Proposal is consistent with the 2022 Rate Order. Specifically, the Joint Proposal recommends that any property

[82] Company Statement in Support, p. 32.

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

[84] Staff Statement in Support, p. 32.

tax refunds, including credits against tax payments or similar forms of tax reductions the Company receives resulting from its efforts will be shared 86 percent/14 percent between customers and shareholders, net of costs, to achieve the refund or credit. The Joint Proposal does change the existing treatment of refunds and credits by specifically requiring that the deferral and retention of property tax refunds and credits remain subject to an annual filing of its efforts to reduce its property tax burden.[85]

The sharing and reporting provisions provide an appropriate incentive for the Company to minimize property tax liabilities for specific properties as well as to seek broader taxation changes to the mutual benefit of the Company and its customers and are adopted.

5. Income Taxes and Cost of Removal

The Joint Proposal acknowledges the ongoing audit directed by the Commission to investigate the Company's income tax accounting in Case 18-M-0013 (COR Audit).[86] The Joint Proposal further recognizes that the final, non-appealable Commission-ordered findings in the COR Audit are binding on the instant proceedings.[87]

6. Common Expenses/Plant Allocation

The Joint Proposal proposes common expenses and common plant, other than intangible common plant (software), will be allocated according to the following percentages: 66.93% electric operations and 33.07% gas operations. Annual revenue

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[85] Joint Proposal, p. 38. The report was filed in the Consolidated Edison Company of New York, Inc. (Con Edison) electric base rate Case 22-E-0064.

[86] Case 18-M-0013, Matter of a Focused Operations Audit to Investigate the Income Tax Accounting of Certain New York State Utilities.

[87] Joint Proposal, p. 39.

impacts resulting from any Commission directed changes to common allocation percentages for electric and/or gas service prior to the next base rate case will be deferred for future recovery from or credit to customers.[88]

7. Legislative Lobbying

No part of the revenue requirements underlying the Joint Proposal include membership fees for any organization that engages in legislative lobbying.[89]

F. Performance Metrics

1. Electric Reliability Performance Mechanism

The Joint Proposal continues the electric reliability performance metrics (ERPM) under the Company's existing electric rate plan, which the Company and Staff agreed to in testimony.[90] Subject to exclusions for system interruptions caused by major storms, strikes, catastrophic events and incidents beyond the Company's control involving generation or the bulk transmission system, the Company will be subject to a System Average Interruption Frequency Index (SAIFI) target of 1.20 and a Customer Average Interruption Duration Index (CAIDI) target of 1.85 hours.[91]

The Joint Proposal increases the negative revenue adjustments (NRAs) applicable for each target missed during a calendar year, from 20 basis points to 30 basis points, as Staff recommended in testimony.[92] The Company will credit to customers any NRAs it incurs. The NRAs will be returned to customers

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[88] Id., pp. 39-40.

[89] Id., p. 40.

[90] Hearing Exhibit 204 (Staff Electric Resilience, Reliability, and Vegetation Management Panel Testimony), p. 106.

[91] Joint Proposal, Appendix 13, pp. 1-2.

[92] Id.; Hearing Exhibit 204, supra, pp. 106-108.

through the Energy Cost Adjustment (ECA) mechanism over a 12-month period starting June 1 and will be subject to Staff audit and full reconciliation.[93] The Company also will file annual reports on its performance on the ERPM on March 31 following each Rate Year.

The ERPM terms of the Joint Proposal are unopposed, fall within the range of likely litigated outcomes, align the Company with other similarly situated New York utilities, and are reasonable.

2. Gas Safety Performance Metrics

The Joint Proposal contains gas safety performance metrics for leak prone pipe (LPP) replacement/removal, leak management, emergency response, damage prevention, and gas safety regulations performance.[94] With the exception of the emergency response and LPP replacement/removal metrics, for which existing targets will continue, the Joint Proposal requires the Company to satisfy more stringent gas safety performance targets. All metrics have associated NRAs for failure to meet targets, while only the emergency response and damage prevention metrics have associated positive revenue adjustments (PRAs) for exceeding targets.[95] The Company will report its annual performance on gas safety metrics no later than 60 days after the end of each calendar year. The pipeline safety performance measures align the Company's gas safety performance metrics with other utilities and ensure the Company will continue to provide safe and reliable gas service while further reducing methane emissions in support of CLCPA goals.

[93] Joint Proposal, pp. 45-46.

[94] Id., p. 45, Appendix 14.

[95] The Joint Proposal provides that NRAs for gas safety performance metrics shall not exceed 150 basis points in any one rate year. Joint Proposal, Appendix 14, p. 1, n. 1.

a. LPP Removal/Replacement

The Joint Proposal continues the current three-year cumulative LPP removal/replacement target of 66 miles, which will apply to calendar years 2025-2027. The Company also will continue to be subject to an NRA of 7.5 basis points for failing to meet that cumulative target. In addition, the Joint Proposal continues minimum LPP replacement targets of 20 miles per year in 2025, 2026, and 2027, subject to the same NRA levels now applicable.[96] Specifically, the Company will be subject to NRAs of 15 basis points for failing to meet the minimum targets in 2025 and 2026, and 7.5 basis points for failing to meet the minimum target in 2027. The Joint Proposal discontinues the PRAs of up to 10 basis points that the Company could earn under the 2022 Rate Plan for exceeding annual LPP removal targets. The Company will count bare steel and aldyl plastic for this metric, as well as ineffectively coated steel that is in the top five percent riskiest pipe for that year. The Company also may request Staff's consent to include, on a case-by-case basis, other ineffectively coated steel and vintage plastic pipe, with proper justification.[97]

In testimony, the Company sought a two-mile reduction in annual LPP removal/replacement targets, while Staff sought a

[96] The 20-mile annual target will remain in effect unless and until changed by the Commission, but the 66-mile cumulative target will not continue beyond 2027. Joint Proposal, Appendix 14, n. 2.

[97] Joint Proposal, Appendix 14, p. 5. At the beginning of each calendar year, the Company also is required to provide a list of the top five percent of the riskiest pipe in its system and an explanation of any such pipe it does not plan to replace in that calendar year. Id., p. 11.

two-mile annual increase and a 72-mile cumulative target.[98] The Joint Proposal reasonably continues the current LPP removal/replacement targets, which fall within the range of targets likely to have resulted from litigation. We agree with Staff that the LPP targets and associated NRAs will ensure continued public safety and foster the State's climate goals by reducing fugitive methane emissions.

b. Leak Management

Under the Joint Proposal, the leak management targets (types 1, 2, and 2A) for each calendar year from 2025-2027 are reduced to less than or equal to 10 from the current annual targets of less than or equal to 20.[99] The Company will be subject to NRAs of 10 basis points in each year in which the repairable leak backlog exceeds 10. Year-end total leak backlog (types 1, 2, 2A, and 3), are reduced from the current target of less than or equal to 50 to a target in 2025 of less than or equal to 30 and then to a target in both 2026 and 2027 of less than or equal to 25. The Company will be subject to five basis points in NRAs for failing to meet those total leak backlog targets. The leak management targets adopt the targets Staff proposed in testimony and discontinue PRAs for the metric. The targets are reasonable, will further reduce methane emissions, and will continue to promote public safety.

c. Emergency Response

The emergency response targets and NRAs remain unchanged from the 2022 Rate Plan. This metric requires the Company to respond within 30 minutes to gas leak or odor calls for at least 75 percent of the calls for calendar years 2025,

[98] Hearing Exhibit 64 (Company Gas Infrastructure and Operations Panel Testimony), pp. 95-97; Hearing Exhibit 256 (Staff Pipeline Safety Panel Exhibit SPSP-2).

[99] Joint Proposal, Appendix 14, pp. 1-2.

2026 and 2027; to respond within 45 minutes for at least 90 percent of the calls during those years; and to respond within 60 minutes to at least 95 percent of the calls during those years.[100] The Company will be subject to NRAs of 12 basis points for failing to meet the 30-minute target, eight basis points for failing to meet the 45-minute target, and five basis points for failing to meet the 60-minute target. The Joint Proposal continues to allow the Company to earn PRAs of up to six basis points, at two basis point increments, starting at the existing 91 percent PRA response in 2025, and increasing to a 92 percent response rate in both 2025 and 2026.[101] The emergency response metric appropriately rewards the Company for superior performance and penalizes it for inadequate performance.

The Joint Proposal contains a typical provision allowing the Company to seek to exclude from the metric "[g]as leak and odor calls resulting from such events as mass odor complaints involving ten or more odor calls received within a two-hour period resulting from major weather-related occurrences or major equipment failure not caused by the Company."[102] The Company must provide Staff with an informational filing within two weeks or 10 business days from the conclusion of such event. Staff will respond whether it consents or does not consent to the requested exclusion. If Staff does not provide a response within 90 days, the Company may file a request for an exclusion with the Commission.

d. Damage Prevention

The damage prevention metric under the Joint Proposal is more stringent than the existing metric and requires all

[100] Id., pp. 3-4.

[101] Id., p. 9.

[102] Id., p. 3.

damages to be tracked in accordance with the guidelines in the Annual Gas Safety Performance Measures report. NRAs of 5, 10 and 20 basis points will apply if the total damages to the Company's gas facilities by any party equal or exceed 1.95, 2.35, and 2.40, respectively, per 1,000 one-call tickets for each calendar year from 2025-2027.[103] From 2025-2027, the Company can earn PRAs in each calendar year for successfully reducing the number of total damages to its facilities per 1,000 one-call ticket to 1.15 to less than 1.35 to earn five basis points, 1.05 to less than 1.15 to earn 10 basis points, and less than 1.05 to earn 15 basis points.[104]

The Joint Proposal continues to allow the Company to average the current and prior year total damage numbers in calculating its performance.[105] For example, if the Company uses this option, it could calculate its total damage performance for 2025 by averaging its total damage performance for 2024 and 2025.

The damage prevention metric is reasonable and will improve public safety by imposing more stringent performance targets to the Company's total number of damages per 1,000 one-call tickets and by providing an incentive for the Company to further reduce the total number of damages.

e. Gas Safety Regulations Performance

The Joint Proposal lists the gas safety regulations to which this metric applies and categorizes them as "high" risk or "other" risk violations.[106] Only those violations of pipeline safety regulations identified in Staff's field audit and record

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[103] Id., pp. 4-5.

[104] Id., p. 10.

[105] Id., p. 4, n. 7.

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

audit letters are counted. In each calendar year from 2025-2027, 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 exceeding other-risk violation thresholds. In addition, the Joint Proposal limits the NRAs that may be assessed against this metric to 75 basis points per calendar year. Appendix 14 to the Joint Proposal also contains information about the Company's ability to cure certain document deficiencies, the way that 10 or more violations of any one code section will be treated, and procedures for the Company to dispute and appeal Staff's final audit results.

The gas safety regulations performance metric reduces the number of violations at which the Company will be subject to NRAs as compared to the Company's current metric targets. The metric is reasonable and appropriately incentivizes the Company to minimize violations of gas safety regulations.

G. Additional Electric and Gas Programs

The Joint Proposal provides funding to continue or expand existing electric and gas programs, including Reforming the Energy Vision (REV) Demonstration Projects, the Pomona Battery Energy Storage System (BESS), the Little Tor Substation Project, Advanced Metering Infrastructure-Enabled Natural Gas Detectors (AMI NGD), NPAs, and the Fusion Re-Dig Program.[107] In addition, the Joint Proposal includes funding for new programs or projects, such as the West Point Project, as well as

[107] Joint Proposal, p. 46. REV Demonstration Costs will continue to be reconciled in accordance with the Track One REV Order. Case 14-M-0101, Proceeding on Motion of the Commission in Regard to Reforming the Energy Vision, Order Adopting Regulatory Policy Framework and Implementation Plan (issued February 26, 2015), pp. 116-117.

establishing new reporting for Vegetation Management and Pole Replacement activities.

1. Pomona BESS Expansion

The Company initially sought funding through 2029 for 11 BESS projects and 10 incremental full-time equivalents (FTEs) for its Distributed Resource Integration (DRI) group to manage them.[108] This proposal was opposed by Staff due to, among other reasons, the Company's failure to conduct a benefit-cost analysis (BCA) with respect to any of the proposed projects.[109]

The Signatory Parties agreed upon a provision in the Joint Proposal to expand the current Pomona BESS from its existing 3MW/12MWh to 3MW/18MWh. Funding in RY2 of $7.2 million in capital expenditures is included in the Joint Proposal to enable this expansion, which will include the addition of six FTEs and three incremental FTEs to support battery energy storage matters.[110] Notably, the Company did perform a BCA for the expansion of the Pomona BESS, which it has been successfully operating since December 2020. As demonstrated by the BCA, the associated societal cost of the proposed expansion is expected to be outweighed by the associated societal benefit gained.[111] The expansion of this BESS benefits customers by addressing a reliability concern during peak load days and system events.

2. Little Tor Substation Project

The Company initially requested $18.5 million to construct the Little Tor Substation in New City, New York. This

[108] Hearing Exhibit 40 (Company Electric Infrastructure and Operations Panel [EIOP] Testimony), pp. 128-136; Hearing Exhibit 42 (Company Exhibit EIOP-2); Hearing Exhibit 213 (Staff Exhibit SESP-1).

[109] Hearing Exhibit 212 (Staff Energy Sustainability Panel Testimony), p. 40.

[110] Joint Proposal, p. 46.

[111] Staff Statement in Support, Appendix B.

project was first proposed by the Company in 2007 to address system reliability and design standards, but the project has been delayed by litigation between the Company and the Town of Clarkstown regarding permitting issues.[112] While Staff acknowledges the need for this project, it opposed including any funding for the project while the litigation remained pending.[113]

The Joint Proposal provides for funding of $125,000 in each rate year to develop the Little Tor Substation Project and permits the Company to file a petition during the Rate Plan to seek recovery of additional costs. This approach balances the uncertainty of the timeline for construction of the project, which is dependent upon a court decision, with the Company's need to nevertheless continue to develop it, thereby ensuring that the Company could immediately commence work on the project should it receive a favorable outcome in court.

3. West Point Upgrade Project

Staff supported the Company's proposed West Point Upgrade Project, which will be a joint undertaking with the United States Military Academy (USMA) to upgrade the Company's existing 34.5 kilovolt (kV) transmission system between the Harriman substation and the Highland Falls and West Point substations to 69kV.[114] The project is designed to help maintain system reliability and resiliency by accommodating expected load growth in the area and ensuring that future renewable resources can be integrated. The existing 34.5kV transmission loop is designated "at risk" and, as such, is not expected to be capable

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[112] Hearing Exhibit 40, supra, pp. 80-81.

[113] Hearing Exhibit 166 (Staff EIOP Panel Testimony), pp. 19-20.

[114] Hearing Exhibit 40, supra, p. 94; Hearing Exhibit 44 (Company Exhibit EIOP-1).

of continuing to meet increasing demand under normal conditions.[115]

The Joint Proposal allows recovery of expected costs to the Company of $19.9 million in RY1, $13.1 million in RY2, and $6.0 million in RY3.[116] Because the USMA is a contract customer of the Company that has an existing project cost-sharing provision, the proposed amounts reflect a cost-sharing allocation for the project of 29% to the Company and 71% to the USMA, based upon the actual demand ratio on load that occurred in 2021.[117] Given the demonstrated need for this upgrade, this approach is reasonable.

4. Additional Reporting Requirements

The Joint Proposal includes provisions requiring additional reporting by the Company regarding its Vegetation Management and Pole Replacement programs.[118] The Company will expand its Vegetation Management reporting activity to track spending and progress, with specific location information, and to provide quarterly and annual reports. For its Pole Replacement program, the agreed to begin reporting annually its spending and the number of poles replaced on a Rate Year basis. These enhanced reporting requirements will benefit Staff and other parties in future rate cases with a more detailed understanding of the Company's activities with respect to these programs.

5. AMI NGDs

The Company agreed to install approximately 30,000 AMI NGDs during the term of the Rate Plan, in continuation of its

[115] Hearing Exhibit 166, supra, p. 30.

[116] Joint Proposal, p. 47.

[117] Id., p. 47.

[118] Id., pp. 48-49.

existing AMI NGD program.[119] The Joint Proposal requires the Company to file an annual report detailing, among other things, the number of AMI NGDs installed in the Rate Year, the cost to install the AMI NGDs, the number of alarm alerts received by the Company in the Rate Year, and the actions taken in response.[120] The use of AMI NGDs benefits ratepayers by providing the Company with a way to detect dangerous and potentially deadly gas leaks, which can cause significant injury and damage to persons and property. This provision is an important public safety aspect of the Joint Proposal.

6. NPAs

In initial testimony, the Company stated that it had identified several NPA projects in the Generic Gas Planning Proceeding that could potentially reduce GHG emissions.[121] The Company stated that it was following the processes established by the Commission in the generic proceeding regarding capital project screening and NPA suitability criteria.[122] According to the Company, it has been pursuing NPA projects as a substitute for "some LPPs, gas expansion, and new service projects," including the electrification of 11 customers using farm taps, and the electrification of one residential and two commercial customers to allow for the retirement of a leak-prone gas main in a disadvantaged community.[123] Staff expressed concerns that

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[119] Id., p. 49.

[120] Id.

[121] Hearing Exhibit 64 (Company Gas Infrastructure and Operations Panel [GIOP] Testimony), p. 17; Hearing Exhibit 65 (Company Exhibit GIOP-1). See Case 20-G-0131, supra.

[122] Hearing Exhibit 64, supra, pp. 36-37. See Case 20-G-0131, supra, Order Adopting Gas System Planning Process (issued May 12, 2022).

[123] Hearing Exhibit 64, supra, p. 38. Hearing Exhibit 12 (Company CLCPA Panel Testimony), pp. 42-43.

the Company's proposed NPA projects were too limited in scope and would not be implemented in a satisfactory time frame.[124]

The Joint Proposal requires the Company to continue to explore NPA solutions to defer or replace the need for traditional gas infrastructure projects and sets forth a methodology for the Company to report on all future NPA activity. Absent Commission action in the Generic Gas Planning Proceeding, new NPA projects that arise during the Rate Plan will remain subject to the screening and suitability criteria the Company proposed in the generic proceeding, including the Company's proposed societal cost test (SCT) to assess the cost effectiveness of new NPAs.[125] In addition, to promote expansion of the Company's NPA program, the Joint Proposal requires the Company to convene a technical conference within one year of the date of this Order to update the parties to these proceedings with respect to the Company's NPA program, provide insight as to the future direction of the program, and provide the parties with the opportunity to provide feedback to the Company.

7. Fusion Re-Dig Program

The Joint Proposal anticipates the Company's continued compliance with the Order issued in Case 14-G-0212 with respect to inspections of plastic pipe fusion joints.[126] In accordance with that Order, for any plastic fusion that is determined to require removal and replacement, the Company will continue to

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[124] Hearing Exhibit 247 (Staff Gas Supply and Reliability Panel Testimony), pp. 24-25.

[125] Joint Proposal, pp. 50-51.

[126] Id., p. 53. See Case 14-G-0212, Proceeding on Motion of the Commission to Investigate the Practices of Qualifying Persons to Perform Plastic Fusions on Natural Gas Facilities, Order Requiring Local Distribution Companies to Follow and Complete Remediation Plans as Modified by this Order and to Implement New Inspection Protocols (issued May 15, 2015).

charge the contractor who initially performed the defective work to pay for the replacement, including site remediation and restoration costs. The continuation of this program enhances public safety at no cost to the Company's customers and is therefore reasonable.

H. Customer Service

1. Customer Service

The Joint Proposal's terms include the continuation and enhancement of various programs in support of the Company's provision of customer service. By its agreement, the Company is required to continue its outreach and education activities and annual reporting on its customer education efforts,[127] its efforts to provide same-day electric service reconnection for residential customers whose service was disconnected for non-payment but then become eligible for reconnection, to quarterly report data regarding its reconnection efforts,[128] to waive the reconnection charge for electric customers with remote connect/disconnect capable meters whose service was shut off for non-payment or tampering-related reasons where the Company is able to reconnect service remotely,[129] and to exclude any residential termination and uncollectible metric that would offer the Company a positive revenue adjustment.[130]

The Joint Proposal also contains various provisions regarding the Company's investment in IT enhancements designed to improve the customer experience. The Joint Proposal authorizes funding for a Customer Analytics Reporting and Engagement (CARE) Program designed to improve customers' digital

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[127] Joint Proposal, p. 57.

[128] Id., pp. 57-58.

[129] Id., p. 62.

[130] Id., p. 61.

experience, facilitate decision making, encourage participation in energy efficiency initiatives and clean energy programs, and establishes a downward-only reconciliation of any unspent program costs.[131] The Joint Proposal also continues several programs that the Company shares with its affiliate, Con Edison, including the Digital Customer Experience (DCX) program to refine and enhance the Company's core digital platform;[132] the Data Analytics Program, designed to develop data analytics use cases to identify business operations efficiencies and cost savings, and improve customer understanding and support for the Company's program offerings;[133] replacement of its legacy retail access system to allow the Company and energy service providers "to better manage and exchange information involving electric and gas retail commodity customers";[134] and enhancement of its new Customer Service System with hardware and software upgrades that will allow it to accommodate new regulatory requirements and meet customer service expectations.[135] In addition, the Joint Proposal imposes reporting requirements for the CARE, DCX, and Data Analytics Program to allow the Commission and interested parties to monitor the Company's progress.

Two other customer-service-related technology improvements are included in the Joint Proposal, both of which are identified as enhancing customer project management: the replacement of the Company's legacy Customer and Project Management Platform (NUCON) and the implementation of a New Business Services (NBS) Training Platform.[136] The Company

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[131] Id., pp. 59-60.

[132] Id., p. 59.

[133] Id., p. 60; Staff Statement in Support, p. 77.

[134] Joint Proposal, p. 61.

[135] Id., p. 61.

[136] Id., pp. 60-61.

justified the need for these improvements by citing to its increasing number of complex customer construction projects, especially those related to electric vehicle charging, large solar and energy storage, and commercial and industrial customers, recognizing that its existing system lacks certain features and functions that result in manual processes that encumber the process.[137] The NUCON replacement project will implement a new system to manage customer construction projects to connect new services or upgrade existing services with technology that will "support and enhance communication, collaboration and execution among the Company and stakeholders across project lifecycle."[138] The Joint Proposal also includes a NBS Training Platform "designed to accelerate employee effectiveness and proficiency, improve knowledge transfer, reduce training costs and enable the Company's NBS group to improve knowledge and skills essential to supporting customer construction projects."[139]

The Signatory Parties contend that the customer service provisions of the Joint Proposal represent significant benefits to the Company's operations and customers while also recognizing that they represent a series of compromises from the Signatory Parties' litigation positions.[140] No party opposes the provisions discussed above.

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[137] Company Statement in Support, pp. 41-42. See Hearing Exhibit 22 (Company Customer Service Panel Testimony) and Hearing Exhibit 23 (Company Exhibit CSP-1).

[138] Joint Proposal, p. 60.

[139] Id., p. 61.

[140] UIU Statement in Support, p. 5; UIU Initial Brief, p. 4; Company Statement in Support, pp. 39-42; Staff Statement in Support, pp. 71-79.

2. Extreme Cold and Heat Provisions

The Joint Proposal requires the Company to expand its protections for residential customers related to extreme cold and hot weather conditions.[141] Specifically, the Company shall not schedule residential service terminations for non-payment on days when "the heat index is forecasted to reach 93 degrees Fahrenheit or higher" and, between November 1 and April 15, "on days when high temperatures, factoring in wind chill, are forecasted to be 32 degrees Fahrenheit or lower."[142] These protections differ from those established in the 2022 Rate Plan by recognizing the impact of wind chill and the heat index on the "feels like" temperature experienced by customers and not limiting the protection to days on which the actual temperature reached the identified thresholds.[143] The Joint Proposal also requires the Company to establish a voluntary moratorium on winter termination for customers that are elderly, blind, or disabled.[144]

Discussion of PULP's Opposition to the Extreme Heat and Cold Provisions

PULP proposes modifications to the customer service provisions of the Joint Proposal contending that the provisions regarding extreme heat and cold weather protections are insufficient. PULP also requests that the Commission modify the Joint Proposal to require the Company's submission of additional reports.

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141 Joint Proposal, pp. 58-59.

142 Id., pp. 58-59. The terms also require the Company to suspend residential service terminations in extreme hot weather one calendar day before any day when the heat index is forecasted to reach 93 degrees Fahrenheit.

143 Cases 21-E-0074 et al., O&R Rates, supra, 2022 Rate Plan Order, p. 121.

144 Joint Proposal, pp. 58-59.

a. Extreme Cold Provisions

With respect to extreme cold weather, PULP argues that, despite the inclusion of language requiring the consideration of the wind chill, the additional inclusion of the phrase "high temperature" will result in fewer days of protection for customers than in the 2022 Rate Plan.[145] According to PULP, the 2022 Rate Plan provided extreme cold protections on days during which the actual temperature was predicted to fall below freezing at any point in the day – not just the high temperature. To remedy this perceived limitation, PULP requests that the language in the Joint Proposal be modified to state that residential service terminations shall not be scheduled "on days when the local weather forecast – factoring in wind chill – predicts below-freezing temperatures (i.e., 32 degrees Fahrenheit or less)."[146] This language reiterates the cold weather protection in the 2022 Rate Plan and includes the heightened protection proposed in the Joint Proposal to consider the wind chill factor's impact on the base temperature reading. PULP claims that its proposed language modification will protect ratepayer interests, eliminate confusion, and clarify what protections the Company's customers can expect to receive during the Rate Plan.[147] The Rockland Municipal Intervenors support PULP's request.[148]

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[145] PULP Statement in Opposition; PULP Post-Hearing Brief, p. 4.

[146] PULP Statement in Opposition, p. 11; PULP Post-Hearing Brief, p. 4. The language requested by PULP mirrors the language used in the 2022 Rate Plan but adds "factoring in wind chill."

[147] PULP Statement in Opposition, pp. 10-11; PULP Post-Hearing Brief, p. 4; PULP Post-Hearing Reply Brief, pp. 2-5.

[148] Rockland Municipal Intervenors Post-Hearing Reply Brief, p. 6.

The Company and Staff both contend that, despite the minor language differences in the last Joint Proposal and this Joint Proposal, there is in effect no change in application of the extreme cold temperature threshold between the existing Rate Plan and what is proposed in the Joint Proposal, and believe that the cold weather protections in the Joint Proposal benefit residential customers' health and safety during cold weather conditions.[149] They refer to the testimony presented by the Company to explain the Company has a long-standing policy to use a forecasted high temperature in applying the cold weather protections.[150] The Company characterizes PULP's assertion that the Joint Proposal would "roll back" the number of days during which residential customers would be protected as "disingenuous."[151] It contends that PULP's interpretation of the language in the 2022 Rate Plan Joint Proposal is undercut by its own witness's testimony that advocated for cold weather protections based upon the expected wind chill's impact to the forecasted high temperature, which is consistent with the language of this Joint Proposal.[152] The Company and Staff both consider the language incorporating wind chill, rather than only the actual air temperature, to be an expansion of protections for customers[153] and highlight the testimony of the Company's

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149 Company Statement in Support, pp. 39-40; Staff Statement in Support, pp. 73-74.

150 Company Post-Hearing Brief, pp. 6-7; Staff Post-Hearing Brief, p. 8, Tr. 45-47.

151 Company Post-Hearing Brief, p. 6.

152 Id., p. 7, citing Hearing Exhibit 272 (Direct Testimony of William Yates, p. 41).

153 Company Statement in Support, p. 40; Company Post-Hearing Brief, p. 6; Staff Post-Hearing Brief, p. 8.

witness that the inclusion of wind chill increases the probability of protections being triggered.[154]

It is evident that the parties here did not share an interpretation of the cold weather protection language included in the 2022 Rate Plan and, as a result, the language included in the Joint Proposal was intended to provide clarification for the Rate Plan moving forward. Contrary to PULP's view, we find that the language included in the Joint Proposal is consistent with the Company's past practice and does not represent a dilution of protections offered to residential customers, which appears to have been the understanding of PULP's witness as well. As such, we find that the Joint Proposal's terms represent an expansion of protections due to the inclusion of a requirement that wind chill must be considered, and that those cold weather protections are reasonable, protective of human health and safety, and in the public interest.

b. Extreme Heat Events

With respect to extreme heat days, PULP states that it is supportive of any change to the Company's policies that result in stronger customer protections, but the extreme heat protections included in the Joint Proposal are not substantive enough to offset the negative impacts resulting from the proposed rate increases.[155] PULP suggests that the Joint Proposal be modified by the Commission "to lower the heat index threshold to 90 degrees, and to extend the suspension on terminations for non-payment for two days following a day when the heat index reaches 90 degrees."[156] PULP argues that adoption of these changes would more closely align the Company with other

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[154] Transcript (Tr.) 51-52.

[155] PULP Statement in Opposition, p. 7.

[156] Id.

extreme heat protections of similarly situated utilities in New York, "including its sister Company, Con Edison."[157]

The Company and Staff urge the Commission to reject PULP's proposed modification. They claim that the Joint Proposal's extreme heat protections are more protective than existing ones – whereas the 2022 Rate Plan suspended residential service terminations when the heat index is forecasted at 95 degrees for two or more consecutive days and/or when the heat index is forecasted at 100 degrees Fahrenheit or more for one or more consecutive days,[158] the Joint Proposal suspends residential service terminations when the heat index is forecasted to reach 93 degrees Fahrenheit or higher and, additionally, precludes terminations the prior calendar day.[159] The Company argues that, while PULP may favor different protections, that is not sufficient justification to disrupt the balance of the Joint Proposal, the terms of which represent a "significant compromise", and characterizes "PULP's single-issue arguments" as being "at odds with the Commission's Settlement Guidelines and the complex task of developing overall rate plans."[160] The Company and Staff both reject PULP's comparison to Con Edison because the territories are dissimilar – Con Edison's territory is a densely urban area where heat-island effects are expected, whereas the Company's territory is far less densely populated and heat-island effects are not a factor.[161]

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[157] Id.

[158] Cases 21-G-0073 et al., supra; Joint Proposal, p. 35.

[159] Company Statement in Support, pp. 40; Staff Statement in Support, pp. 73-74.

[160] Company Statement in Support, pp. 40; Company Post-Hearing Brief, p. 6.

[161] Company Post-Hearing Brief, p. 6, n. 9; Staff Post-Hearing Brief, p. 7.

The Commission recently instituted a proceeding aiming to examine best utility practices regarding customer protections associated with extreme heat events, and to identify improvements that may be warranted to standardize customer protections across utilities to the extent practicable.[162] As stated in the Extreme Heat Protections Order, electric customer protections associated with extreme heat have been considered in the context of individual rate proceedings and are not uniform.[163] Therefore, we decline to modify the Joint Proposal in this case. If during this Rate Plan the Commission adopts uniform standards in the Extreme Heat Protections proceeding and those protections are more protective than what is included herein, the more protective terms will be effectuated. For now, examining the provisions that are currently before us, we find that the Joint Proposal enhances customer protections compared to the 2022 Rate Plan, advances our policy goals and that of the State in protecting New York residents from the impacts of extreme heat conditions and is in the public interest.

c. Extreme Weather Reporting

Finally, PULP requests that Commission modify the Joint Proposal to require the Company to file annual reports providing the number of extreme weather days the utility experienced.[164] Citing testimony elicited during the evidentiary hearing explaining that that the Company tracks and provides such information to Staff, PULP opines that the public filing of that information would "ensure that all interested parties have

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[162] Case 24-M-0586, Proceeding on Motion of the Commission for the Establishment of Extreme Heat Protections, Practices and Procedures, Order Instituting Proceeding (issued January 23, 2025) (Extreme Heat Protections Order).

[163] Extreme Heat Protections Order, supra, pp. 7-9.

[164] PULP Post-Hearing Brief, p. 4.

access to the same information," suggesting that it may be of use in considering existing or new policy design.[165]

As for PULP's request for annual reporting regarding extreme weather days, the Company states that, considering that the information already is available to parties through the discovery process, it would be inappropriate to impose a reporting obligation merely to relieve a party from discovery in a future proceeding.[166] For its part, Staff states that it often requests such information from the utilities, concurs with the Company that that such information is available to parties through discovery, but states that it does not object to the Commission directing a formal filing at the conclusion of each rate year.[167]

Given that PULP and all interested parties to rate proceedings can request data pertaining to extreme weather events and protections within the context of discovery, we are unpersuaded by PULP's contentions and decline to modify the Joint Proposal to impose an annual reporting requirement.

Discussion of the Village's Opposition to Certain Customer Service Provisions

The Village opposes the Joint Proposal contending that it does not "adequately address the Company's ongoing failure to timely provide service to new applicants."[168] The Village explains that "because of its unique demographic characteristics" with its population growing "much faster than the national average or the surrounding areas," it is expecting a significant increase in the number of new housing units in the

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165 Id., p. 5.

166 Company Post-Hearing Reply Brief, p. 2.

167 Staff Letter Reply Brief, pp. 1-2.

168 Village Statement in Opposition, p. 1.

Village.[169] It alleges that housing growth in the Village "has been stymied because applicants for new electric and gas service are facing significant delays in obtaining service." The Village acknowledges that the Joint Proposal's terms include provisions intended to expedite the processing of new connection requests, including the replacement of the NUCON system with a new system; the implementation of a modernized NBS system to accelerate employee training; and additional employees within the NBS group,[170] but it nevertheless argues that these provisions are insufficient to "address the problem in the near term." Citing various Commission and State policies, as well as the PSL and its implementing regulations, the Village requests that the Commission modify the Joint Proposal to "require uniform, reasonable, and enforceable timeframes for new service application processing," including deadlines for "1. review of newly submitted applications for completeness; 2. identification and notification of applicant of any deficiencies; 3. interconnection design for complete applications; 4. final design to include proposed construction schedule; 5. installation and energization per agreed schedule; and 6. an expedited dispute resolution process."[171]

The Company urges the Commission to reject the Village's proposal, stating that not only has the Village failed to recommend any timeframes for each of the new service application processing steps it recommends, but also that the record is devoid of information on the topic and, further, requiring a modification of the Joint Proposal would disturb the interrelated compromises negotiated by the parties. The Company

[169] Id., p. 2.

[170] Id., pp. 3-4.

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

adds that "[t]he parties to these proceedings have not considered or investigated the additional resources that the Company would require to implement" changes on territory-wide basis that would be necessary "to avoid instituting an undue preference for new service requests in the Village."

As an initial matter, the Village has not provided sufficient evidence to establish that there are unreasonable delays in the Company's provision of new service connections, either in the service territory generally or specifically in the Village. Similarly, its contention that the Company is violating existing laws is unsupported by record evidence. Moreover, we agree with the Company that the record lacks support for establishing new service application timing requirements in the context of this proceeding because the record does not contain any evidence regarding the appropriateness of any timeframe for processing new service applications or the feasibility, costs, and benefits of establishing such timeframes.

As the Village acknowledges, the Joint Proposal contains many provisions designed to improve customer service and to improve the processing of new connection requests. While the Village views these provisions as insufficient, we disagree. The terms of the Joint Proposal will enhance the new service connection process and we find that, in so doing, the terms of the Joint Proposal support the policy goals of both the State and this Commission by, among other things, streamlining processes for interconnecting new residential properties and subdivisions. To the extent that the Village has concerns with the new-service application process, the Village should avail itself of the existing remedy for all customers – the Department's complaint process – rather than seek to create a specialized remedy within the context of an individual rate case proceeding.[172]

I. Electric and Gas Low Income Affordability Programs

The Joint Proposal states that the Company's Energy Affordability Program (EAP) will continue to provide bill discounts to eligible customers consistent with the Commission's August 2021 Order in the EAP Proceeding.[173] Based on the current number of customers receiving discounts, the estimated annual rate allowances for the bill discount credits – which are subject to symmetrical deferral – are approximately $14.5 million and $7.2 million in RY1 for electric and gas credits, respectively.[174] The Company will also continue its reconnection fee waiver program for any customer enrolled in the Company's EAP.[175] The Joint Proposal requires the Company to update its EAP discounts following the issuance of a rate order in these cases, to file new discount amounts via tariff statements as part of its RY1 compliance filing, and to adjust discounts via further tariff statement filed by November of each year in the EAP Proceeding.[176] Although all qualifying customers will be accepted into the program,[177] the Company will adjust benefit

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[172] The Village acknowledged that developers are aware they can contact the Department for assistance but simply choose not to do so. Village Statement in Opposition, p. 5.

[173] Joint Proposal, p. 62; See Case 14-M-0565, Energy Affordability Proceeding, Order Adopting Energy Affordability Policy Modifications and Directing Utility Filings (issued August 12, 2021) (2021 EAP Order).

[174] Joint Proposal, p. 62.

[175] Id., p. 63.

[176] Id.; 2021 EAP Order, pp. 41, 44. In addition, the Company is subject to both annual and monthly reporting requirements on its EAP.

[177] Company Statement in Support, p. 43.

levels to align the annual rate allowance to the EAP budget cap of two percent of total Company revenue.[178]

In opposition to the Joint Proposal, PULP argues that the proposed rate increases will disproportionately impact EAP customers unless discounts are increased and, further, estimates that only 34 percent of the Company's eligible customers are enrolled in the EAP.[179] PULP notes that the Company's Customer Service Panel provided direct testimony forecasting that the Company would reach its two-percent program expenditure cap in RY2 and RY3.[180] PULP therefore requests that the Joint Proposal be modified to lower the bill impacts for customers or, at the very least, to require the Company to conduct enhanced outreach to identify potentially eligible households and enroll them in the EAP during the Rate Plan, so that they may receive an additional level of protection from rate increases.[181] As in its direct testimony, PULP proposes that the Company identify those customers eligible for enrollment in the EAP by leveraging census data, indicators of past financial need in utility account histories, and data on Disadvantaged Communities (DACs) compiled by the Climate Action Council to conduct community-level interventions and enroll as many customers as possible in the EAP.[182]

The Company responds that PULP fails to provide specific recommendations as to which programs or projects should

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[178] Staff Statement in Support, p. 80.

[179] PULP Statement in Opposition, p. 3; PULP Post-Evidentiary Hearing Brief, pp. 5-6.

[180] PULP Statement in Opposition, p. 4; Hearing Exhibit 22 (Company's Customer Service Panel Testimony), p. 74.

[181] PULP Statement in Opposition, p. 4; PULP Post-Hearing Brief, pp. 6-7.

[182] PULP Post-Hearing Brief, pp. 6-7; Hearing Exhibit 272 (Direct Testimony of William Yates), pp. 21-23.

be modified to reduce bill impacts to customers or to analyze the consequences of any modifications on the Company's ability to provide safe and reliable service. Similarly, the Company argues, PULP provides no detail on its proposed enhanced outreach, such as when it would be implemented, what the cost would be, and whether it would require incremental hiring. The Company maintains that, if the Commission wishes to require an enhanced outreach campaign, it should do so on a generic basis within the EAP Proceeding and authorize recovery through a surcharge.[183]

Staff emphasizes its belief that all eligible customers should be afforded the benefits of EAPs but points to the Commission's directive that issues implicating all utility EAPs be determined and addressed on a generic, state-wide basis in the EAP Proceeding, rather than in the context of individual rate proceedings.[184] Staff maintains that such generic issues include the two percent program expenditure cap and EAP enrollment outreach, and avers that the topic of enhancing outreach was raised in the Commission's EAP Working Group by PULP and will be considered by all interested stakeholders this year. With respect to this Joint Proposal, Staff notes that the impacts on the Company's EAP customers cannot be evaluated at this time because the Company will modify the EAP discounts to reflect the increased rate impacts once the Commission has issued its rate order.

Finally, Staff argues that the proposed increases to the customer charge in the Joint Proposal are reasonable because the current customer charge is below the demonstrated cost to serve and that the overall rate increases are modest,

[183] Company Post-Hearing Brief, pp. 2-3; Company Post-Hearing Reply Brief, pp. 2-3.

[184] 2021 EAP Order, pp. 38-39.

particularly with the Joint Proposal's shaping of the annual amounts, and as compared to the increases likely to result from a one-year litigated rate plan.[185]

We find that the EAP provisions in the Joint Proposal are in the public interest and consistent with the Commission's EAP Orders and policies. The terms of the Joint Proposal will ensure that low-income participants receive a discount to provide financial relief from their energy bills, within the framework and budget cap previously established by the Commission in the EAP Proceeding. As the Company argues, PULP provides no details in proposing that bill impacts to EAP participants be mitigated. In any event, as we have previously explained, proposals to limit bill impacts to EAP participants, the exploration of alternate sources of EAP funding and consideration of changes to the budget cap should be addressed in the context of the EAP Proceeding to ensure standardization and eliminate inequities among EAP participants throughout the state.[186] Similarly, while utilities are free to voluntarily expand their outreach efforts, the EAP Working Group is considering the topic of enhancing outreach to the population covered by EAPs statewide. Given Staff's assurances that all interested stakeholders will have the opportunity in 2025 to address outreach enhancement in the context of the EAP Working Group's efforts, we conclude that unilateral modification of the Joint Proposal to address the issue outside that context is not appropriate at this time.

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[185] Staff Post-Hearing Brief, pp. 3-5; Staff Post-Hearing Reply Brief, p. 2.

[186] Cases 23-G-0225 et al., KeySpan Gas East Corporation and The Brooklyn Union Gas Company, d/b/a National Grid NY for Gas Service – Rates, Order Approving Joint Proposal with Minor Modification and Correction (issued August 15, 2024), p. 143.

J. Earnings Adjustment Mechanisms

As recommended by both the Company and Staff, the Joint Proposal sets forth six earnings adjustment mechanisms (EAMs): (1) solar distributed energy resource (DER) utilization MW (based on third-party solar installations of five MW or less); (2) storage DER utilization MW (based on electric energy storage installations of five MW or less, excluding NWAs and company-owned storage); (3) electric vehicle (EV) adoption (based on estimated tons of lifetime CO2 reduced as a result of incremental EV registrations); (4) demand response (based on the amount of operationally available load relief measured in a given rate year compared to that available in the prior rate year); (5) residential managed charging (based on enrollment in the Company's SmartCharge NY program, which encourages avoidance of charging during peak hours and decreased peak coincident demand); and (6) commercial managed charging (same for commercial charging station demand coincident with the site's substation peak during the summer period).[187] The Company is required to file an annual EAM report on a calendar-year basis, with reports due by June 30th of the following year.[188] Incentives will continue to be recovered through the EAM Surcharge component of the Company's ECA Mechanism.[189]

The corresponding dollar values for the EAMs established in the Joint Proposal, as well as the details about each EAM measurement, achievement standard, target level, and applicable basis points, are set forth in Appendix 16 to the Joint Proposal. The targets and incentive levels reflect a reasonable compromise between the positions advocated by Staff

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[187] Joint Proposal, pp. 64-65, Appendix 16; Company Statement in Support, pp. 43-44.

[188] Joint Proposal, Appendix 16, p. 14.

[189] Id., p. 64.

and the Company. In its initial testimony, the Company proposed that the total annual maximum financial incentive should be 84 basis points across the six EAM categories, while Staff recommended that the Company be provided with the opportunity to earn an annual maximum of 35 basis points, as compared to the 33 basis points allowed under the Company's prior rate plan.[190] The Joint Proposal provides that if the Company attained the highest metric levels for all six EAMs, it would earn 45 basis points worth approximately $3.9 million in RY1, 51 basis points worth approximately $4.7 million in RY2, and 53.5 basis points worth approximately $5.8 million in RY3.[191] The three-year targets for each metric approximately track Staff's proposals in its initial testimony.[192]

EAMs are not related to traditional basic service, but are incentive measures designed to promote new performance expectations that may run counter to both conventional methods of operation and a utility's implicit financial incentives

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[190] Hearing Exhibit 36 (Company Earning Adjustment Mechanisms [EAM] Panel Testimony), p. 19; Hearing Exhibit 196 (Staff Exhibit SEAMP-2) and Hearing Exhibit 198 (Staff Exhibit SEAMP-4). In Case 14-M-0101, supra, Order Adopting a Ratemaking and Utility Revenue Model Policy Framework (issued May 19, 2016), pp. 68, the Commission established 100 basis points as the maximum annual EAM incentive that utilities may earn. Staff notes that the maximum also includes 15 basis points for the separate EV Make-Ready EAM. See Staff Statement in Support, pp. 80-81.

[191] Joint Proposal, Appendix 16, pp. 2-3.

[192] Compare Joint Proposal, Appendix 16, pp. 4, 5, 7, 9, 12, 14, with Hearing Exhibit 199 (Staff Exhibit SEAMP-5), p. 3, Hearing Exhibit 200 (Staff Exhibit SEAMP-6) and Hearing Exhibit 202 (Staff Exhibit SEAMP-8); See also Hearing Exhibit 194 (Staff EAM Panel Initial Testimony), pp. 68-71, 83; Hearing Exhibit 138 (Company EAM Panel Rebuttal Testimony), p. 31.

embedded in the cost-of-service ratemaking model.[193] Staff argues that the EAMs set forth in the Joint Proposal are in the public interest, emphasizing that the EV adoption metric supports an accelerated transition away from combustion vehicles; the DER utilization metrics prevent the Company from earning a return on – or a return of – its investments through the traditional utility business model because the Joint Proposal excludes utility-owned assets from target achievement; the demand response metric incentivizes both customer participation and participant performance during program events; and the financial incentives for both managed charging metrics are closely aligned with those approved in the 2023 Con Edison Rate Order.[194] No parties oppose the EAMs set forth in the Joint Proposal.

The EAMs in the Joint Proposal are the product of negotiation, within the range of outcomes in pre-filed testimony, and aligned with the State's energy goals. In addition to encouraging deployment of EVs to reduce emissions in the Company's territory, the proposed EAMs will promote grid reliability by providing appropriate financial incentives for the Company to encourage greater development of solar energy generation and BESS, optimizing participant performance in demand response programs, and decreasing peak coincident electrical vehicle charging demand. The proposed EAMs appropriately balance and better align the interests of the

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[193] Case 14-M-0101, supra, Order Adopting a Ratemaking and Utility Revenue Model Policy Framework (issued May 19, 2016), p. 59.

[194] Staff Statement in Support, pp. 81-83; Cases 22-E-0064 et al., Con Edison – Electric and Gas Rates, Order Adopting Terms of Joint Proposal and Establishing Electric and Gas Rate Plans with Additional Requirements (issued July 20, 2023), pp. 146-147.

ratepayers and the Company's shareholders, as well as support the public policy of the State. Thus, the EAM provisions are reasonable and support our conclusion that the Joint Proposal is in the public interest.

K. CLCPA

The Joint Proposal contains projects and programs directly related to managing emissions and supporting CLCPA requirements that are buttressed, according to the Signatory Parties, by several other provisions that align the Company's rates and tariffs with the State's climate goals. More specifically, the Joint Proposal includes: the clean energy EAMs discussed above; the 6 MWh-expansion of the existing Pomona BESS; and a main and service replacement program that prioritizes high-risk gas pipe for replacement to support safe and reliable service as well as reduce methane gas emissions.[195]

These programs in the Joint Proposal are estimated to result in an emissions savings of over 428,757 metric tons (MT) of carbon dioxide equivalent (CO2e) over the course of the three-year electric and gas rate plans.[196] This savings reduces the Company's expected emissions for the three-year rate plan to a net of 4,297,581 MT of CO2e.

Disadvantaged Communities Report

The Joint Proposal requires the Company to file a report by May 31 following each Rate Year that describes the

[195] These programs are in addition to various clean energy investments and programs that have been authorized outside the context of this rate case, including heating electrification efforts through the New Efficiency New York, Energy Efficiency and Clean Heat program, as well as various EV programs, including the SmartCharge NY and PowerReady programs.

[196] The savings is 424,715 MT of CO2e for the electric side and 4,042.69 MT of CO2e for the gas side.

Company's activities related to DACs within its service territory. The report will include detailed quantitative information covering nine major topic areas: (1) energy efficiency and building electrification programs; (2) the EV Make-Ready program; (3) Demand Response programs; (4) DER projects; (5) strategic electric capital investments, including projects related to system expansion, risk reduction, environmental improvements, and safety and security; (6) customer outages; (7) the Gas Main Replacement Program; (8) gas leak repairs; and (9) customer operations data, including EAP activities, deferred payment agreements, service disconnections, and average customer usage. The report will also include a narrative discussion of the reported data, explaining, among other things, how the Company tracked and collected the data, assumptions used in the report and, for energy efficiency, an explanation of the Company's efforts to reach customers located in disadvantaged communities.[197] The Joint Proposal also requires the Company to convene a meeting for interested stakeholders within 60 days of filing the report.[198]

Staff and the Company support the DAC reporting requirements and claim that such reports will provide stakeholders with important information regarding CLCPA implementation and compliance efforts.[199] Staff notes that, inasmuch as these reporting requirements were not raised in pre-filed testimony, they represent a beneficial outcome of settlement that would not have resulted from a fully litigated

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[197] Joint Proposal, pp. 66-73.

[198] Id., p. 66.

[199] Staff Statement in Support, pp. 83-84; Company Statement in Support, pp. 44-45.

case and that the reporting requirements are analogous to requirements recently approved by the Commission.[200]

The reporting requirements in the Joint Proposal will provide for an appropriate assessment of the Company's activities and investments in DAC, thereby allowing us to determine whether these activities and investments are sufficiently aligned with the CLCPA requirement to prioritize the reduction of GHG and co-pollutant emissions in DACs and to ensure that those communities receive a minimum threshold of the benefits of clean energy and energy efficiency investments. These reporting requirements are reasonable and in the public interest.

Based upon the foregoing, we find that the Joint Proposal will not interfere with the attainment of the statewide GHG emission limits established in Article 75 of the ECL and, therefore, complies with Section 7(2) of the CLCPA. The projects and programs funded by this Joint Proposal and discussed throughout this Order will support heating electrification, support energy efficiency efforts, promote electric vehicle use, and reduce GHG emissions, while still enabling the Company to provide safe and reliable service to its customers.

In addition, the record supports a finding that the rate plan complies with Section 7(3) of the CLCPA inasmuch as it does not disproportionately burden DACs. Indeed, the Joint Proposal contains many provisions that are intended to support and provide benefits to such communities, such as the expansion of the Pomona BESS project, which will support the distribution system in an identified DAC, provisions to address affordability, and expanded protections regarding disconnections

[200] Staff Statement in Support, p. 83.

during periods of extreme heat and cold. In addition, as discussed above, the Company has agreed to provide a detailed annual report outlining the Company's investments and activities related to DACs.

L. Management Audit

Staff and the Company each provided testimony concerning PSL §66(19)(c).[201] The completed 2014 Management Audit was a comprehensive management and operations audit of the Company (and its affiliate, Con Edison) performed by NorthStar Consulting Group (NorthStar) that was open at the time of the 2022 Rate Order.[202] On May 20, 2016, the Commission authorized the release of NorthStar's final audit report and approved the Company's (and Con Edison's) implementation plan on October 13, 2016.[203] The Company fully complied with the active audit and subsequent implementation order and, on January 13, 2023, Staff filed a letter acknowledging that the Company had satisfactorily implemented all recommendations.[204] We find that this determination by Staff eliminates any need to address or incorporate those recommendations into this Order. The ongoing COR Audit is addressed above and is more fully described in the 2022 Rate Order.[205]

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[201] Hearing Exhibit 250 (Staff Management Audit Panel Testimony), pp. 8-12; Hearing Exhibit 1 (Company Accounting Panel Testimony), pp. 69-70.

[202] Hearing Exhibit 250, supra, pp. 8-9, citing Case 14-M-0001, Comprehensive Management and Operations Audit of Consolidated Edison Company of New York, Inc. and Orange and Rockland Utilities, Inc.

[203] Id., p. 10.

[204] Id.; Case 14-M-0001, supra, DMM Item No. 46.

[205] 2022 Rate Plan, pp. 135-136.

The ongoing 2021 Management Audit is a comprehensive management and operations audit of the Company (and Con Edison), with a specific focus on construction program planning processes and operational efficiency.[206] It includes a review of certain issues from the previous management audit, information systems planning and implementation, elements of customer operations, gas safety, and improvements to electric load forecasting processes to support grid modernization goals.[207] The 2021 Management Audit also reviews how the Company and Con Edison incorporate various legal mandates and other regulatory objectives into their performance management and construction program planning processes.[208] On September 9, 2021, the Commission selected NorthStar to conduct the audit.[209]

The Commission issued its Order Releasing Audit Report on February 16, 2023, authorizing the issuance of NorthStar's final audit report that contains 42 recommendations for improvement at the Company and Con Edison.[210] On August 29, 2023, the Company and Con Edison filed a revised implementation plan, which the Commission approved in October 2023.[211] The Company and Con Edison filed their most recent implementation update on December 31, 2024.[212]

Based on the foregoing, we determine that the Company has demonstrated satisfactory compliance with the 2014

[206] Hearing Exhibit 250, supra, pp. 9, 11, citing Case 21-M-0193, Comprehensive Management and Operations Audit of Consolidated Edison Company of New York, Inc. and Orange and Rockland Utilities, Inc.

[207] Hearing Exhibit 250, supra, p. 11.

[208] Id.

[209] Id.

[210] Id., pp. 11-12.

[211] Id., p. 12; Case 21-M-0193, supra, DMM Item No. 20.

[212] Case 21-M-0193, supra, DMM Item No. 33.

Management Audit, and the Company remains subject to the COR Audit and the 2021 Management Audit, which are ongoing.

M. Make-Whole Provision

Because this Order is being issued after January 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 agreement to extend the suspension period to accommodate settlement negotiations in these proceedings. The revenue differences will be recovered or credited, with interest, over the remaining months of 2025, as detailed in Appendices 17 and 18 to the Joint Proposal.

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 the plan is in the public interest as a whole.

The Commission orders:

1. The rates, terms, conditions, and provisions of the Joint Proposal dated November 8, 2024, 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. Orange and Rockland Utilities, Inc. is directed to file cancellation supplements, effective on not less than one day's notice, on or before March 27, 2025, cancelling the tariff amendments and supplements listed in Attachment B to this Order.

3. Orange and Rockland Utilities, Inc. is directed to file, on not less than five days' notice, to take effect on April 1, 2025, on a temporary basis, such tariff amendments as are necessary to effectuate the terms of this Order for Rate Year 1, the twelve-month period ending December 31, 2025, and to incorporate any tariff amendments that were previously approved by the Commission since the tariff amendments listed on Attachment B were filed.

4. Orange and Rockland Utilities, Inc. shall serve copies of its filings on all active parties to these proceedings. 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.

5. Orange and Rockland Utilities, Inc. is directed to file, on not less than 30 days' notice, to take effect January 1, 2026, on a temporary basis, such tariff changes as are necessary to effectuate the rates for Rate Year 2, the twelve-month period ending December 31, 2026, 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. Orange and Rockland Utilities, Inc. is directed to file, on not less than 30 days' notice, to take effect January 1, 2027, on a temporary basis, such tariff changes as are necessary to effectuate the rates for Rate Year 3, the twelve-month period ending December 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.

7. The requirements of Public Service Law §66(12)(b) and Title 16 of the New York Codes, Rules and Regulations (16 NYCRR) §720-8.1 that newspaper publication be completed prior to the effective date of the amendments for Rate Year 1 are waived; provided however, that Orange and Rockland Utilities, Inc. shall file with the Secretary to 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 four successive 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 16 NYCRR §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.

8. 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.

9. These proceedings are continued.

By the Commission,

(SIGNED)

MICHELLE L. PHILLIPS
Secretary

STATE OF NEW YORK
PUBLIC SERVICE COMMISSION

CASE 24-E-0060 –	Proceeding on Motion of the Commission as to the Rates, Charges, Rules and Regulations of Orange and Rockland Utilities, Inc. for Electric Service.
CASE 24-G-0061 –	Proceeding on Motion of the Commission as to the Rates, Charges, Rules and Regulations of Orange and Rockland Utilities, Inc. for Gas Service.

JOINT PROPOSAL

November 8, 2024

TABLE OF CONTENTS

Page

Introduction 1

Procedural Setting 3

A. Term 5

B. Rates and Revenue Levels 5

1. Electric 5

a. Market Supply Charge/Energy Cost Adjustment 7

b. Revenue Decoupling Mechanism 7

c. Other Charges 8

2. Gas 8

a. Gas Supply Charge/Monthly Gas Adjustment 10

b. Revenue Decoupling Mechanism 11

c. Base Rate Imputations 11

d. Lost and Unaccounted for Gas 12

C. Computation and Disposition of Earnings 14

1. Earnings Sharing Threshold 14

2. Earnings Calculation Method 15

3. Disposition of Shared Earnings 17

D. Reconciliations & Deferrals 17

1. Electric 17

a. Net Plant Reconciliation 17

b. Capital Expenditure Reporting 18

c. Non-Wires Alternative (“NWA”) Adjustment Mechanism 19

d. Federal Infrastructure Funding 20

2. Gas 21

a. Net Plant Reconciliation 21

b. Capital Expenditure Reporting 22

c. Non-Pipeline Alternative (“NPA”) Adjustment Mechanism 22

3. Non-Plant Reconciliations/Deferrals 23

a. Property Taxes (Electric and Gas) 23

b. Pensions/OPEBs (Electric and Gas) 24

c. Environmental Remediation (Electric and Gas) 26

d. Non-Officer Management Variable Pay (Electric and Gas)..................26

e. Adjustments for Competitive Services (Electric and Gas) 27

f. Low Income Assistance/Energy Affordability Program (Electric and Gas) 27

g. Research and Development Expense (Electric and Gas).......................27

h. Energy Efficiency & Building Electrification Program (Electric and Gas) 27

i. Major Storm Cost Reserve (Electric)..28

j. Asbestos Workers Compensation Reserve (Electric) 30

k. Tree Trimming (Electric)...31

l. REV Demonstration Project Costs (Electric) 31

m. Platform Service Revenue (Electric) 31

n. Combined Uncollectible Expense and Late Payment Charge Reconciliation (Electric and Gas) 32

o. State Tax Law Change (Electric and Gas)...33

p. Federal Income Tax- Gas Repairs 34

q. Transmission Service Agreement (Electric)..35

r. Customer Analytics Reporting & Engagement Program (Electric and Gas) 35

s. Additional Reconciliation/Deferral Provisions......................................35

t. Discontinued Reconciliations 36

E. Additional Accounting Provisions 37

1. Productivity...37

2. Depreciation Rates and Reserves...37

3. Interest on Deferred Costs 37

4. Property Tax Refunds and Credits..38

5. Income Taxes and Cost of Removal Audit 39

6. Allocation of Common Expenses/Plant...39

7. Legislative Lobbying 40

F. Revenue Allocation/Rate Design and Other Tariff Changes...................................40

1. Electric 40

a. Embedded Cost of Service (“ECOS”) Study..40

b. Tariff Changes 41

2. Gas 43
a. ECOS Study 43
b. Marginal Cost Study 43
c. Interruptible Transportation Rates 43
d. Tariff Changes 44
G. Performance Metrics 45
H. Additional Electric Programs 46
1. REV Demonstration Project Costs 46
2. Pomona Battery Expansion 46
3. Little Tor Substation 47
4. West Point Project 47
5. Storm Material Warehouse and the Emergency Response Control Facility 48
6. Vegetation Management Reporting 48
7. Pole Replacement Reporting 48
I. Additional Gas Programs 49
1. AMI-Enabled Natural Gas Detectors ("NGDs") 49
2. Non-Pipes Alternatives 49
a. Continuing NPA Activities 50
b. New NPA Activities 51
c. NPA Reporting 52
3. Fusion Re-Dig Program 53
4. Certified Gas 53
J. Customer Service 57
1. Outreach and Education 57
2. Same-Day Electric Service Reconnections 57
a. Weekday Same-Day Reconnections 57
b. Reporting 58
3. Voluntary Protections During Periods of Extreme Cold and Heat 58
a. Cold Weather Protections 58
b. Excessive Heat Protections 59
4. Digital Customer Experience ("DCX") 59
5. Customer Analytics Reporting & Engagement Program ("CARE") 59

6. Data Analytics Program....60
7. Customer and Project Management Platform (NUCON) Replacement....60
8. New Business Services (NBS) Training Platform....61
9. Retail Access System Replacement....61
10. Customer Service System ("CSS") Enhancements....61
11. Residential Termination/Uncollectible Metric....61
12. Reconnection Fee Waiver (Electric)....62
K. Electric and Gas Low Income Assistance/Energy Affordability Programs....62
1. Monthly Bill Credit....62
2. Reconnection Fee Waiver....63
3. Reporting Requirements....63
L. Earnings Adjustment Mechanisms ("EAMs")....64
M. Disadvantaged Communities Report....65
1. Annual Report....65
2. Contents of the Report....65
3. Definition of Disadvantaged Communities....66
4. Stakeholder meeting....66
5. Data Covered in the Report....66
a. Clean Energy Spending....67
b. Electric Vehicle Make Ready Program....68
c. Demand Response....68
d. Distributed Energy Resources....68
e. Strategic Electric Capital Investments....69
f. Customer Outages....69
g. Main Replacement Program....70
h. Leak Repairs....71
i. Customer Operations Data....71
6. Effect of Subsequent Commission Order....73
N. Miscellaneous Provisions....73
1. Continuation of Provisions; Rate Changes; Reservation of Authority....73
2. Legislative, Regulatory and Related Actions....75
3. Financial Protections....76
4. Trade Secret Protection....77

5. Provisions Not Separable ... 77
6. Provisions Not Precedent ... 78
7. Submission of Proposal ... 79
8. Procedures in the Event of a Disagreement ... 79
9. Effect of Commission Adoption of Terms of this Proposal ... 79
10. Further Assurances ... 80
11. Scope of Provisions ... 80
12. Execution ... 80

Appendices

Appendix 1 – Electric Revenue Requirement

Appendix 2 – Gas Revenue Requirement

Appendix 3 – Amortization of Regulatory Deferrals (Electric & Gas)

Appendix 4 – Electric Sales & Revenue Forecast

Appendix 5 – Gas Sales & Revenue Forecast

Appendix 6 – Electric Reconciliation Targets

Appendix 7 – Gas Reconciliation Targets

Appendix 8 – Net Plant Reconciliation Targets (Electric & Gas)

Appendix 9 – Capital Expenditures (Electric & Gas)

Appendix 10 – Gas Lost and Unaccounted For ("LAUF")

Appendix 11 – Book Depreciation Rates (Electric & Gas)

Appendix 12 – Earnings Sharing Partial Year (Electric & Gas)

Appendix 13 – Electric Reliability Performance Mechanism

Appendix 14 – Gas Safety Performance Mechanism

Appendix 15 – Customer Service Performance Mechanism (Electric & Gas)

Appendix 16 – Earnings Adjustment Mechanisms (Electric & Gas)

Appendix 17 – Electric Revenue Allocation and Rate Design

Appendix 18 – Gas Revenue Allocation and Rate Design

Appendix 19 – Electric, Gas, Common Capital Expenditure Reporting Requirements

Appendix 20 – Revenue Decoupling Mechanism (Electric & Gas)

Appendix 21 – Energy Efficiency and Building Electrification Labor

STATE OF NEW YORK
PUBLIC SERVICE COMMISSION

CASE 24-E-0060 – Proceeding on Motion of the Commission as to the Rates, Charges, Rules and Regulations of Orange and Rockland Utilities, Inc. for Electric Service.

CASE 24-G-0061 – Proceeding on Motion of the Commission as to the Rates, Charges, Rules and Regulations of Orange and Rockland Utilities, Inc. for Gas Service.

JOINT PROPOSAL

THIS JOINT PROPOSAL ("Proposal") is made as of the 8th day of November 2024, by and among Orange and Rockland Utilities, Inc. ("Orange and Rockland" or the "Company"), New York State Department of Public Service Staff ("Staff"), Utility Intervention Unit of the New York State Department of State, and other parties whose signature pages are or will be attached to this Proposal (collectively referred to herein as the "Signatory Parties").

Introduction

This Proposal sets forth the terms of an electric rate plan for the period January 1, 2025 through December 31, 2027 ("Electric Rate Plan") and a gas rate plan for the period January 1, 2025 through December 31, 2027 ("Gas Rate Plan").[1] The Rate Plans prescribe agreed-upon rate levels and address operational and accounting matters, as well

[1] Collectively, the Electric Rate Plan and the Gas Rate Plan are referred to as the "Rate Plans."

as various other rate design and revenue allocation issues. The Rate Plans are designed to support the continued reliability, safety, and security of the Company's electric and gas systems at just and reasonable rates.

Among other things, the Electric Rate Plan reflects a revenue requirement based on the adoption of the electric sales and revenue forecast agreed to by the Signatory Parties, the continuation of a revenue decoupling mechanism ("RDM") and various other reconciliations, including a property tax reconciliation, reconciliation of net plant balances in the event that actual average net plant is lower than that reflected in rates, continuation of electric performance metrics and the New York Public Service Commission's ("Commission") low income customer assistance/energy affordability program. The Electric Rate Plan is supportive of and consistent with the goals of the Climate Leadership and Community Protection Act ("CLCPA").

Among other things, the Gas Rate Plan reflects a revenue requirement based on the adoption of the gas sales and revenue forecast agreed to by the Signatory Parties, the continuation of the interruptible sales benefit imputation, the continuation of an RDM and various other reconciliations, including a property tax reconciliation, reconciliation of net plant balances in the event that actual average net plant is lower than that reflected in rates, provision of additional resources to various gas safety initiatives, continuation and/or enhancement of gas performance metrics, and the Commission's low income customer assistance/energy affordability program. The Gas Rate Plan is supportive of and consistent with the goals of CLCPA and provides for the continued exploration of potential Non-Pipe Alternatives ("NPA").

Procedural Setting

Orange and Rockland is currently operating under an electric and gas rate order that established electric and gas rates effective January 1, 2022.[2] The 2022 Rate Order established electric and gas base rates for the three years ending December 31, 2024.

On January 26, 2024, Orange and Rockland filed new tariff leaves and supporting testimony for new rates and charges for electric and gas service effective on January 1, 2025, for the 12-month period ending December 31, 2025. In the filings, the Company also included financial information for the two succeeding 12-month periods, in order to facilitate development of multi-year rate plans through settlement discussions in the event parties elected to do so.

Three administrative law judges ("ALJs"), Erika Bergen, Dakin Lecakes and Nicholas Planty, were appointed to preside over the rate proceedings. Parties engaged in discovery, with the Company responding to over 800 formal discovery requests on the filings. A procedural conference was held virtually on February 14, 2024.

On January 31, 2024, ALJs Bergen and Lecakes issued a Ruling Adopting Protective Order. On February 22, 2024, ALJs Bergen, Lecakes and Planty issued a Ruling on Schedule, providing dates for certain activities in these cases, including an update of the Company's filing, Staff and intervenor testimony, rebuttal testimony of the Company's filings, and evidentiary hearings.

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2 Cases 21-E-0074, Proceeding on Motion of the Commission as to the Rates, Charges, Rules and Regulations of Orange and Rockland Utilities, Inc. for Electric Service; Case 21-G-0073, Proceeding on Motion of the Commission as to the Rates, Charges, Rules and Regulations of Orange and Rockland Utilities, Inc. for Gas Service, Order Adopting Terms of Joint Proposal and Establishing Electric and Gas Rate Plans (issued April 14, 2022) ("2022 Rate Order").

On April 5, 2024, the Company provided the parties with its revenue requirement updates and updated testimony.

On May 24, 2024, three parties filed testimony in response to the Company's filings. On June 10, 2024, the Company filed rebuttal testimony. Staff also filed rebuttal testimony.

By notice dated June 10, 2024, Orange and Rockland notified all parties of the commencement of settlement negotiations on June 20, 2024.[3] Settlement negotiations began on June 20, 2024, and continued on June 28,[4] July 12, July 25, August 5, August 6, August 15, August 27, September 12, September 17, September 20, September 25 and September 27. In addition, the parties engaged in several "breakout" meetings on specific topics. All settlement negotiations were held virtually and were subject to the Commission's Settlement Rules, 16 NYCRR §3.9, including the provision of appropriate notices for negotiating sessions.

The parties' negotiations have been successful and have resulted in this Proposal, which is presented to the Commission for its consideration.

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3 This notice was filed with the Secretary to the Commission ("Secretary").

4 On June 10, 2024, the Company filed a letter with the Secretary agreeing to a 60-day extension of the statutory suspension period in these proceedings subject to a "make-whole" provision that would keep the Company and its customers in the same position they would have been absent the extension. On August 16, 2024, the Company agreed to an additional 45-day extension of the statutory suspension period, also subject to a "make whole."

A. Term

The Signatory Parties recommend that the Commission adopt a three-year Electric Rate Plan and Gas Rate Plan for Orange and Rockland as set forth herein, effective as of January 1, 2025 and continuing through December 31, 2027.

For the purposes of this Proposal, Rate Year means the 12-month period starting January 1 and ending December 31; Rate Year 1 ("RY1") means the 12-month period starting January 1, 2025 and ending December 31, 2025; Rate Year 2 ("RY2") means the 12-month period starting January 1, 2026 and ending December 31, 2026; and Rate Year 3 ("RY3") means the 12-month period starting January 1, 2027 and ending December 31, 2027.

B. Rates and Revenue Levels

1. Electric

This Proposal recommends changes to the Company's electric delivery service rates and charges designed to produce a reduction of $13.060 million in revenues on an annual basis starting in RY1, an additional $24.786 million increase in revenues on an annual basis starting in RY2, and an additional $44.061 million increase in revenues on an annual basis starting in RY3. The electric revenue requirement calculations underlying the Proposal are set forth in Appendix 1.

The Signatory Parties recommend that the Commission adopt the option to phase in these three base rate changes to provide rate stability over the Electric Rate Plan. The revenue changes would be an $0 million increase in RY1, an additional $17.677 million increase in RY2, and an additional $17.677 million increase in RY3.[5] The revenue changes to each service class associated with the proposed additional revenues, including interest, are shown in Appendix 17. The incremental electric revenue decreases/increases and associated impacts are shown below:[6]

		Unlevelized ($000)	**Shaped ($000)**
RY1[7]	Revenue Increase/(Decrease)	($13,060)	$0
	Impact on Delivery	-3.3%	0.0%
	Impact on Total Bill	-1.7%	0.0%
RY2	Revenue Increase/(Decrease)	$24,786	$17,677
	Impact on Delivery	6.5%	4.5%
	Impact on Total Bill	3.3%	2.3%
RY3	Revenue Increase/(Decrease)	$44,061	$17,677
	Impact on Delivery	10.9%	4.2%
	Impact on Total Bill	5.7%	2.3%

The proposed "shaped" revenue changes for each of RY1, RY2 and RY3 will be effective on the first day of each Rate Year.[8]

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[5] The shaped rate changes are inclusive of interest on the deferred rate change calculated at the current Other Customer-Provided Capital Rate of 5.95%. The Company will calculate the change in interest for any change in the Other Customer-Provided Capital Rate in future years and defer the difference for surcharge or credit to customers, as applicable.

[6] The cumulative shaped revenue increase of $53.0 million, including interest, and cumulative unlevelized revenue increase of $54.5 million over the three years of the Rate Plan is detailed in Appendix 1.

[7] The delivery and total bill impacts shown for RY1 exclude the impact of the expiration of the electric temporary credit from Case Nos. 21-E-0074 and 21-G-0073. The delivery bill impacts including the expiration of the temporary credit are -0.9% and 2.5% for the unlevelized and shaped revenue changes, respectively. The total bill impacts including the expiration of the temporary credit are -0.5% and 1.3% for the unlevelized and shaped revenue changes, respectively.

[8] If, based on the make whole extension letters referred to in footnote 3, the Commission does not issue an order on this Proposal until after January 1, 2025, the Company will recover shortfalls and refund over-collections that result from the extension of the suspension period in this proceeding through a "make-whole" provision, as detailed in the make whole extension letters. The revenue differences will be recovered or credited, with interest, over the remaining months of 2025 as detailed in Appendices 17 and 18.

The Signatory Parties recognize that shaping the revenue increases over the three years of the Electric Rate Plan to moderate customer bill impacts will result in lower base delivery rate revenues for the Company at the end of RY3 than would result if the revenue increases were not shaped. To address this circumstance, $38.110 million of the RY3 rate increase will be included in base rates and $20.433 million of the RY3 rate increase will be refunded via a temporary credit through the Energy Cost Adjustment ("ECA").

The major components of the electric revenue requirements underlying this Proposal are set forth in Appendix 1. These revenue requirements are net of the amortizations of various customer credits and debits on the Company's books of account that have previously been or are projected to be deferred by the Company. The list of deferred customer credits and debits to be applied during the Electric Rate Plan is attached as Appendix 3.

The electric sales and delivery revenue forecasts for each of RY1, RY2, and RY3 are set forth in Appendix 4.

a. Market Supply Charge/Energy Cost Adjustment

The Company will continue to recover all prudently incurred supply and supply-related costs, including, but not limited to, power purchase costs, through the Market Supply Charge ("MSC") and ECA ("Energy Cost Adjustment") mechanisms.

b. Revenue Decoupling Mechanism

For the term of the Electric Rate Plan, the Company will continue to implement an RDM, as set forth in the Company's electric tariff, amended to reflect the modifications recommended in this Proposal as outlined in Appendix 20. The RDM, as modified, will continue thereafter until changed by the Commission, except for restating the RDM targets for the Rate Year commencing January 1, 2028, to reflect the expiration of the temporary credit discussed in paragraph B.1 above, if the Company does not file for new base delivery rates to be effective within 15 days after the expiration of RY3.

c. Other Charges

The Signatory Parties agree that, whenever the Company is or will be subject to governmental or regional transmission organization ("RTO") transmission and/or generation-related charges, costs or credits (*e.g.*, FERC, NYISO, PJM, EPA)[9] not already listed in or otherwise covered by the then-effective MSC or ECA tariff language, the Company may make a tariff filing with the Commission providing for recovery of such charges/costs, or application of these credits, through the MSC mechanism, ECA mechanism, and/or comparable adjustment mechanism. The proposed tariff amendment is subject to review and approval by the Commission and may include charges/costs/credits applicable to the period prior to the effective date of the tariff amendment.

2. Gas

This Proposal recommends changes to the Company's retail gas sales and gas transportation service rates and charges, designed to produce a $3.568 million increase in revenues on an annual basis starting in RY1, an additional $18.038 million increase in

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9 Federal Energy Regulatory Commission ("FERC"), New York Independent System Operator ("NYISO"), PJM Interconnection, L.L.C. ("PJM"), and Environmental Protection Agency ("EPA").

revenues on an annual basis starting in RY2, and an additional $16.498 million increase in revenues on an annual basis starting in RY3.[10]

The Signatory Parties recommend that the Commission adopt the option to phase in these three base rate changes on a levelized basis to provide rate stability over the term of the Gas Rate Plan. The annual revenue changes would be a $10.448 million increase in RY1, RY2 and RY3.[11] The revenue changes to each service class associated with the proposed additional revenues, including interest, are shown in Appendix 18.

The incremental gas revenue increases and associated impacts are shown below:

[12]

		Unlevelized ($000)	Levelized ($000)
RY1[13]	Revenue Increase/(Decrease)	$3,568	$10,448
	Impact on Delivery	2.0%	6.0%
	Impact on Total Bill	1.2%	3.4%
RY2	Revenue Increase/(Decrease)	$18,038	$10,448
	Impact on Delivery	10.0%	5.6%
	Impact on Total Bill	5.8%	3.3%
RY3	Revenue Increase/(Decrease)	$16,498	$10,448
	Impact on Delivery	8.4%	5.4%
	Impact on Total Bill	5.0%	3.1%

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[10] Unless specifically stated otherwise in this Proposal, the terms "customers" and "base rate" with respect to gas apply to the Company's firm gas customers who are served under SC Nos. 1, 2, and 6.

[11] The levelized rate changes are inclusive of interest on the deferred rate increase calculated at the current Other Customer-Provided Capital Rate of 5.95%. The Company will calculate the change in interest for any change in the Other Customer-Provided Capital Rate in future years and defer the difference for surcharge or credit to customers, as applicable.

[12] The cumulative levelized revenue increase of $62.7 million, including interest, and cumulative unlevelized revenue increase of $63.3 million over the three years of the Rate Plan is detailed in Appendix 2.

[13] The delivery and total bill impacts shown for RY1 exclude the impact of the expiration of the gas temporary credit from Case Nos. 21-E-0074 and 21-G-0073. The delivery bill impacts

The proposed levelized revenue changes for each of RY1, RY2 and RY3, will be effective on the first day of each Rate Year.[14]

The Signatory Parties recognize that levelizing the revenue increases over the three years of the Gas Rate Plan to moderate customer bill impacts will result in lower base delivery rate revenues for the Company at the end of RY3 than would result if the revenue increases were not levelized. To address this circumstance, $17.207 million will be included in base rates in RY3 and $6.759 million will be refunded via a temporary credit through the Monthly Gas Adjustment ("MGA").

The major components of the gas revenue requirements underlying this Proposal are set forth in Appendix 2. These revenue requirements are net of the amortizations of various customer credits and debits on the Company's books of account that have previously been or are projected to be deferred by the Company. The list of deferred customer credits and debits to be applied during the Gas Rate Plan is attached as Appendix 3.

The gas sales and delivery revenue forecasts for each of RY1, RY2 and RY3 are set forth in Appendix 5.

a. Gas Supply Charge/Monthly Gas Adjustment

The Company will continue to recover all prudently incurred supply and supply-related costs through the Gas Supply Charge ("GSC") and MGA. Costs associated with

including the expiration of the temporary credit are 4.7% and 8.7% for the unlevelized and levelized revenue changes, respectively. The total bill impacts including the expiration of the temporary credit are 2.7% and 5.0% for the unlevelized and levelized revenue changes, respectively.

[14] *See* footnote 6.

balancing assets will continue to be recovered from all Service Classification ("SC") Nos. 1, 2, and 6 customers through a common cents per Ccf component in the MGA.[15]

b. Revenue Decoupling Mechanism

For the term of the Gas Rate Plan, the Company will continue to implement an RDM, amended to reflect the modifications recommended in this Proposal as outlined in Appendix 20. The RDM will continue unless and until changed by the Commission, except for restating the RDM targets for the Rate Year commencing January 1, 2028, to reflect the expiration of the temporary credit discussed in paragraph B.2 above, if the Company does not file for new base delivery rates to be effective within 15 days after the expiration of RY3.

c. Base Rate Imputations

The base rate imputation shall be set at $4.48 million in all three Rate Years. These revenue imputations reflect (i) imputations for interruptible benefits[16] of $4.48 million ("Interruptible Benefits Imputation"); and (ii) an imputation of $0 for net benefits associated with the delivery of gas to electric generating facilities previously owned by the Company ("Power Generation Imputation") in each Rate Year. Any variances, either positive or negative, between the actual revenue margin and the Interruptible Benefits Imputation, during each Rate Year the Gas Rate Plan is effective, will be shared on an

[15] The Company recovers various costs and charges, and provides certain credits, through the GSC, MGA and Weighted Average Cost of Transportation ("WACOT"). For costs, charges, and credits covered by the language of these adjustment mechanisms, the Company will continue to recover such costs and charges, and provide such credits, as incurred, by reflecting these charges, costs and/or credits in monthly statements filed pursuant to these adjustment mechanisms.

[16] Interruptible benefits shall be defined as total interruptible (SC No. 8) and firm withdrawable (SC No. 9) revenues minus any associated gas costs and revenue tax surcharge revenues.

80% customer/20% Company basis and the 80% customer over-/under-recovery will be credited to/recovered from customers as applicable through the MGA. One hundred percent of any variances, either positive or negative, between the actual revenue margin and the Power Generation Imputation, during each Rate Year the Gas Rate Plan is effective, will be credited to/recovered from customers as applicable through the MGA.

d. Lost and Unaccounted for Gas

The Factor of Adjustment ("FOA"), reflecting lost and unaccounted for ("LAUF") gas, will be reset every November 1 based on the average of the actual FOAs for the previous five 12-month periods ended August 31.

Actual LAUF will be calculated annually as follows:

1. Losses = Total Pipeline Receipts less metered deliveries to customers (Retail Sales and Transportation Deliveries + Deliveries to Generators + Gas Used for Company Purposes[17]).
2. Adjusted Line Loss = Losses minus the contribution to the system line loss from generators.
3. Line Loss Factor ("LLF") = Adjusted Line Loss divided by Citygate receipts adjusted for generators.

Wholesale generators served under SC No. 14 that have a capacity that is at least 50 MW are to provide 1% of their consumption to cover losses unless the system average is lower. Wholesale generators that are not on a dedicated line but are on a high-pressure

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[17] Metered gas for inactive accounts is included in "Gas Used for Company Purposes" and reflected as such in the gas revenue requirement and LAUF calculation. The estimate for Gas Used for Company Purposes used to establish the gas revenue requirement includes an estimated amount for metered gas for inactive accounts based on the Company's gas service termination procedures.

transmission line can negotiate a specific LLF, subject to a minimum of 1% of their consumption unless the system average is lower. Wholesale generators that are not served by dedicated lines, and that do not negotiate an LLF, will have the system average LLF applied. The volumes associated with wholesale generators served by dedicated lines shall be excluded from the LLF calculation by deducting the metered amount from the total send out.

In order to determine if the Company receives an incentive or pays a penalty for the annual LLF achieved commencing with the 12-month period ending August 31, 2025, the Company will compare the LLF level for such period to a targeted dead band based on the FOA in effect at the time of the filing of the annual gas cost rate reconciliation (*i.e.*, based on the average of the five-year LLFs through August 31, 2024) ("Target Dead Band"). The Target Dead Band will be reset annually based on the average of the prior five-year LLFs.[18] The Target Dead Band limits are set at minus two standard deviations ("lower limit") and plus two standard deviations ("upper limit") of the FOA in effect. In the event that two standard deviations below the FOA is below 0%, the lower limit will be 0%, and the upper limit will be 0% plus four standard deviations. If the LLF is within the Target Dead Band, no incentive or penalty will arise. If the LLF is greater than the upper limit of the Target Dead Band, a penalty will be assessed according to the tariff. If the LLF is less than the lower limit of the Target Dead Band, an incentive will be provided to the Company according to the tariff. The Company will not earn an incentive on any portion of an LLF below 0.0%.

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[18] The Target Dead Band will also be reset annually for the System Performance Adjustment ("SPA") Mechanism.

Appendix 10 provides sample calculations of the determination of the potential benefit or cost to the Company. Appendix 10 also details the calculation of the continuing SPA Mechanism.

If an unforeseeable and uncontrollable event(s) occurs that significantly increases actual line losses, then the Company reserves the right to file a petition with the Commission to modify the annual reconciliation of the GSC in order to reflect such increased line losses. The Company will have the burden of demonstrating the increase in actual line losses and that such increase was not due to the Company's negligent actions or omissions, in the event it makes such a filing.

C. Computation and Disposition of Earnings

Following each electric and gas Rate Year covered by the Rate Plans, the Company will compute, separately, the earned rate of return on common equity ("ROE") for its electric and gas businesses for the preceding Rate Year. The Company will submit these computations of earnings to the Secretary under Cases 24-E-0060 and 24-G-0061 by no later than March 31 (*i.e.*, within three months after the end of each Rate Year).

1. Earnings Sharing Threshold

The ROE reflected in the revenue requirements for electric for RY1, RY2 and RY3, and for gas for RY1, RY2 and RY3 are set forth in Appendices 1 and 2 (*i.e.*, 9.75 percent). Following each of RY1, RY2 and RY3, the Company will compute, separately, the earned rate of return on common equity for its electric and gas businesses for the preceding Rate Year. If the level of the earned electric or gas ROE for any Rate Year exceeds 10.25 percent ("Earnings Sharing Threshold"), calculated as set forth below, then the amount in excess of the Earnings Sharing Threshold shall be deemed shared earnings ("Shared Earnings") for the purposes of the Rate Plans.

During the terms of the Rate Plans, one-half of the revenue requirement equivalent of any electric or gas Shared Earnings above 10.25 percent but less than 10.75 percent will be deferred for the benefit of customers and the remaining one-half of any Shared Earnings will be retained by the Company; 75 percent of the revenue requirement equivalent of any electric or gas Shared Earnings equal to or in excess of 10.75 percent but less than 11.25 percent will be deferred for the benefit of customers and the remaining 25 percent of any Shared Earnings will be retained by the Company; and 90 percent of the revenue requirement equivalent of any electric or gas Shared Earnings equal to or in excess of 11.25 percent will be deferred for the benefit of customers and the remaining 10 percent of any Shared Earnings will be retained by the Company.

2. Earnings Calculation Method

For each Rate Year, for purposes of determining the actual earned ROE:

a. The calculation of the actual ROE on common equity capital allocated to New York jurisdictional electric and gas utility operations shall be on a "per books" basis, that is, computed from the Company's books of account for each Rate Year, excluding the effects of: (i) Company incentives and performance-based revenue adjustments (both positive and negative), including incentives for Non-Wires Alternatives ("NWAs") and NPAs, under Earnings Adjustment Mechanisms set forth in Appendix 16, and the performance metrics set forth in Appendices 13, 14 and 15; (ii) the Company's share of property tax refunds earned during the applicable Rate Year; and

(iii) any other Commission-approved ratemaking incentives and revenue adjustments in effect during the applicable Rate Year.

b. Such earnings computations will reflect the lesser of: (i) an equity ratio equal to 50 percent, or (ii) the Company's actual average common equity ratio to the extent that it is less than 50 percent of its ratemaking capital structure. The Company's actual common equity ratio will exclude all components related to "other comprehensive income" that may be required by generally accepted accounting principles ("GAAP"); such charges are recognized for financial accounting reporting purposes but are not recognized or realized for ratemaking purposes.

c. If the Company does not file for new base delivery rates to take effect within 30 days after the expiration of RY3, the Earnings Sharing Threshold and the other earnings sharing thresholds will continue until base delivery rates are reset by the Commission. Such calculation will be performed on an annual basis in the same manner as set forth above.[19]

d. The actual average rate base for any stay-out period less than 12 months will be adjusted by an operating income ratio factor. This adjustment to rate base is intended to align operating income to the level of rate base that generated that income. This factor will be calculated as the ratio of operating income during the same partial year period in the previous Rate Year to the total operating income for that Rate Year. This methodology is illustrated in Appendix 12.

[19] For purposes of the earnings threshold calculation after RY3, revenue targets and trued-up expenses contained in Appendices 6 and 7 will be based on RY3 levels for electric and gas.

3. Disposition of Shared Earnings

For electric and/or gas Shared Earnings in any Rate Year, the Company will apply 50 percent of its share and the full amount of the customers' share of electric and/or gas Shared Earnings that would otherwise be deferred for the benefit of customers under this Proposal, to reduce respective deferred under-collections of Site Investigation and Remediation ("SIR") costs.

In the event the amount of Shared Earnings for electric and/or gas available to reduce respective deferred under-collections of SIR costs exceeds the amount of such deferred under-collections, the Company will apply the amount of the excess to reduce other deferred costs (for electric, the Company will apply the excess to under-collections of storm costs first). The Company's annual earnings report will include the amount, if any, of deferred under-collections of SIR costs, storm costs, or other costs written down with the Company's and the customers' respective shares of Shared Earnings.

D. <u>Reconciliations & Deferrals</u>

1. Electric

a. Net Plant Reconciliation

The electric revenue requirements for RY1, RY2 and RY3 reflect the average net plant balances set forth in Appendix 8 ("Electric Net Plant In Service Target Balances").

The Electric Net Plant In Service Target Balances reflect a level of capital expenditures supported by various capital programs and projects. The Company, however, has the flexibility over the term of the Electric Rate Plan to modify the list, priority, nature and scope of its capital programs and projects.

The Company will defer for the benefit of customers the revenue requirement impact (*i.e.*, carrying costs, including depreciation, as identified in Appendix 8) of the amount by which the Company's actual expenditures for electric capital programs and projects result in actual average net plant that is less than the amount included in the Electric Net Plant In Service Target Balances, as set forth in Appendix 8, for RY1, RY2 and RY3 ("target levels"), on a cumulative basis;[20] that is, the carrying charges resulting from the difference (whether representing underspending or overspending) in actual Electric Net Plant In Service Balances and the target levels will carry forward for each of the Rate Years and will be summed at the end of RY3.[21] If at the end of RY3 the cumulative carrying charges represent underspending, the Company will book a regulatory liability for the cumulative underspent carrying charges. If at the end of RY3 the cumulative carrying charges represent overspending, no deferrals will be made. Examples of how this reconciliation will work are set forth in Appendix 8.

b. Capital Expenditure Reporting

The Company's planned electric capital funding is set forth in Appendix 9. The Company has the flexibility over the term of the Rate Plan to modify the list, priority, nature and scope of its capital programs and projects. The Company will submit quarterly and annual reports regarding its capital expenditures in the manner set forth in Appendix 19.[22]

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[20] The revenue requirement impact will be calculated by applying an annual carrying charge factor (*see* Appendix 8) to the amount by which the actual net plant was below the amount included in the Average Electric Plant In Service Target Balances.

[21] Subject to the provisions in Section D.1.c and D.1.d, which addresses situations where the Average Electric Plant In Service Target Balances will be adjusted.

[22] Appendix 19 also includes O&M reporting requirements.

c. Non-Wires Alternative ("NWA") Adjustment Mechanism

The costs incurred by the Company for implementation of new NWAs (ones that are not included in base rates or for which the Company has not filed a Benefit Cost Analysis) during the Electric Rate Plan, including the overall pre-tax rate of return on such costs, will be deferred and recovered over ten years. Recovery of these NWA costs during the Electric Rate Plan will be through the Energy Cost Adjustment ("ECA"). Unamortized NWA costs, including the return, will be incorporated into the Company's base rates when electric base delivery rates are reset.

To the extent such new NWAs result in the Company displacing a capital project reflected in the Average Electric Plant In Service Balances, the balance(s) will be reduced to exclude the forecasted net plant associated with the displaced project. The carrying charge on the reduction of the Average Electric Plant In Service Balances that would otherwise be deferred for customer benefit will instead be applied as a credit against the recovery of the NWA in the ECA. In the event the carrying charge on the net plant of any displaced project is higher than the NWA recovery, the difference will be deferred for the benefit of customers.

The Company will earn incentives for successfully implementing Non-Wire Alternative projects consistent with the Operating Procedure for Calculation of Financial Incentives for Non-Wire Alternatives filed on December 18, 2017 in Case 17-M-0178 in compliance with the November 16, 2017 Order Granting Petition In Part in the same proceeding.

d. Federal Infrastructure Funding

The Company has applied for federal funding under the Infrastructure Investment and Jobs Act. The Company will notify Staff and interested parties via email of the funding determination within 30 days of receiving the notification from the Department of Energy.

If the Company receives any federal funding under the Infrastructure Investment and Jobs Act, customers will receive the revenue requirement impact associated with the decrease in program or project costs. To the extent such federal funding results in the Company displacing a capital project in whole or part reflected in the Average Electric Plant In Service Balances, the balance(s) will be reduced to exclude the forecasted net plant associated with the displaced funds. The Company will sur-credit the carrying costs including depreciation associated with any federal funding received through the ECA. The sur-credit will begin as soon as practicable after the underlying project goes in-service and the Company is in receipt of the federal funding. No later than 30 days prior to the implementation of the sur-credit, the Company shall report sur-credit amounts with supporting documentation for Staff's review. Subsequent to Staff's review, if any adjustments and/or corrections need to be made to the sur-credit amounts, the adjustments and/or corrections will be made before implementation of the sur-credit, or as soon as practicable if the sur-credit has already been implemented.

In the event the Company receives a grant for a program/project that requires Company co-funding that is not included in rates, the Company may file an expedited petition for surcharge recovery of such co-funding requirement until base rates are reset.

2. Gas

a. Net Plant Reconciliation

The gas revenue requirements for RY1, RY2 and RY3 reflect the average net plant balances set forth in Appendix 8 ("Gas Net Plant In Service Target Balances").

The Gas Net Plant In Service Target Balances reflect a level of capital expenditures supported by various capital programs and projects. The Company, however, has the flexibility over the term of the Gas Rate Plan to modify the list, priority, nature and scope of its gas capital programs and projects.

The Company will defer for the benefit of customers the revenue requirement impact (*i.e.*, carrying costs, including depreciation, as identified in Appendix 8) of the amount by which the Company's actual expenditures for gas capital programs and projects result in average net plant that is less than the amount included in the Gas Net Plant In Service Target Balances as set forth in Appendix 8, for RY1, RY2 and RY3 ("target levels"), on a cumulative basis;[23] that is, the revenue requirement impact resulting from the difference (whether representing underspending or overspending) in actual Gas Net Plant In Service Balances and the target levels will carry forward each of the Rate Years and will be summed at the end of RY3.[24] If at the end of RY3 the cumulative carrying charges represent underspending, the Company will book a regulatory liability for the cumulative underspent carrying charges. If at the end of RY3

[23] The revenue requirement impact will be calculated by applying an annual carrying charge factor for the applicable average net plant in service category (*see* Appendix 8) to the amount by which actual net plant was below the amount included in the Average Gas Plant In Service Target Balances.

[24] Subject to the provisions in Section D.2.c, which addresses situations where the Average Gas Plant In Service Target Balances will be adjusted.

the cumulative carrying charges represent overspending, no deferrals will be made. Examples of how this reconciliation will work are set forth in Appendix 8.

b. Capital Expenditure Reporting

The Company's planned gas capital funding is set forth in Appendix 9. The Company has the flexibility over the term of the Rate Plan to modify the list, priority, nature and scope of its capital programs and projects. The Company will provide quarterly and annual reports relating to capital expenditures in the manner set forth in Appendix 19.

c. Non-Pipeline Alternative ("NPA") Adjustment Mechanism

The costs incurred by the Company for implementation of new NPAs (*i.e.*, those that are not included in base rates) during the Gas Rate Plan, including the overall pre-tax rate of return on such costs, will be deferred and recovered over twenty years. Recovery of these NPA costs during the Gas Rate Plan will be through the NPA Adjustment Mechanism, a component of the MGA. Amortized NPA program costs will be collected on a common cents per Ccf basis from customers served under SC Nos. 1, 2, and 6. Unamortized NPA costs, including the return, will be incorporated into the Company's base rates when gas base delivery rates are reset.

To the extent such new NPAs result in the Company displacing a capital project reflected in the Average Gas Plant In Service Balances, the balance(s) will be reduced to exclude the forecasted net plant associated with the displaced project. The carrying charge on the reduction of the Average Gas Plant In Service Balances that would otherwise be deferred for customer benefit will instead be applied as a credit against the recovery of the NPA in the MGA. In the event the carrying charge on the net plant of any displaced project is higher than the NPA recovery, the difference will be deferred for the benefit of customers.

3. Non-Plant Reconciliations/Deferrals

The Company will reconcile the following costs and revenues to the levels provided in rates, as set forth in Appendices 6 and 7. Variations subject to recovery from or to be credited to customers will be deferred on the Company's books of account over the term of the Rate Plans, and the revenue requirement effects of such deferred debits and credits, as the case may be, will be addressed in future rate proceedings.

a. Property Taxes (Electric and Gas)

If the level of actual electric or gas expense for property taxes, excluding the effect of property tax refunds (as defined in Section E.4 of this Proposal), varies in any Rate Year from the projected level provided in rates for that service, which levels are set forth in Appendices 6 and 7, 90 percent of the variation will be deferred on the Company's books of account and either recovered from or credited to customers, subject to the following cap: the Company's 10 percent share of property tax expenses above or below the level in rates is capped at an annual amount equal to 10 basis points on common equity in RY1, 7.5 basis points on common equity in RY2, and 5 basis points on common equity in RY3.[25] The Company will defer on its books of account, for recovery from or credit to customers, 100 percent of the variation above or below the level at which the cap takes effect.

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[25] For electric, such amounts are estimated to be $862,220 in RY1, $696,703 in RY2 and $544,468 in RY3. For gas, such amounts are estimated to be $481,000 in RY1, $396,479 in RY2 and $285,948 in RY3.

The Company will not be precluded from applying for a greater share of lower than forecasted property tax expenses (including the period beyond RY3) if its extraordinary efforts result in fundamental taxation changes and produce substantial net benefits to customers. The Signatory Parties reserve the right to support or oppose any such filing.

b. Pensions/OPEBs (Electric and Gas)

Pursuant to the Commission's Pension Policy Statement,[26] the Company will reconcile its actual pensions and Other Post-Employment Benefits ("OPEBs") expenses to the levels provided in rates as set forth in Appendices 6 and 7. The Company will recover the variance via surcharge/sur-credit, subject to a separate annual surcharge/sur-credit cap for electric and gas through the ECA and the MGA, respectively, that produces no more than a 0.5% total bill impact per commodity.[27] Any amounts in excess of the annual surcharge/sur-credit cap in a specific year will be rolled forward for recovery or refund and will count towards the following year's surcharge/sur-credit cap. Any residual amounts at the end of 2027 above the annual cap will be deferred for collection/refund in the Company's next base rate case or as otherwise authorized by the Commission.

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[26] Case 91-M-0890, In the Matter of the Development of a Statement of Policy Concerning the Accounting and Ratemaking Treatment for Pensions and Post-Retirement Benefits Other Than Pensions, Statement of Policy and Order Concerning the Accounting and Ratemaking Treatment for Pensions and Post-Retirement Benefits Other Than Pensions (issued September 7, 1993) ("Pension Policy Statement").

[27] A half percent total bill impact is currently equivalent to \$3.1 million, \$3.2 million and \$3.2 million for Rate Year 1, 2, and 3, respectively for electric operations and \$1.5 million, \$1.5 million and \$1.7 million for Rate Years 1, 2, and 3, respectively, for gas operations.

Prior to implementing the surcharge/sur-credit, and by March 31 of each year, the Company will provide the surcharge/sur-credit amounts and supporting workpapers to Staff for its review and verification. The Company may begin to implement recoveries/credits 60 days after the notification to Staff. Subsequent to Staff's review, if any adjustments and/or corrections need to be made to the surcharge/sur-credit amounts and the surcharge/sur-credit has already been implemented, such adjustments and/or corrections will be implemented as soon as practicable.

The Pension Policy Statement provides that companies may seek prospective interest accruals or rate base treatment for amounts funded above the cost recoveries included in rates.[28] During the term of the Rate Plans, the Company may be required to fund its pension plan at a level above the rate allowance pursuant to the annual minimum pension funding requirements contained within the Pension Protection Act of 2006. The Company, its actuary and the Signatory Parties are unable to predict with certainty if the minimum funding threshold will exceed rate recoveries during the term of the Rate Plans. In lieu of a provision in this Proposal addressing the Company's additional financing requirements should it be required to fund its pension plan above the level provided in rates during the term of these Rate Plans, the Proposal does not preclude the Company from petitioning the Commission to defer the financing costs associated with funding the pension plan at levels above the current rate allowance should funding above the rate allowance be required; the Company's right to obtain authority to defer such financing costs on its books of account will not be subject to requirements respecting materiality.

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[28] *See* Pension Policy Statement, Appendix A, page 16, footnote 3.

c. Environmental Remediation (Electric and Gas)

If the level of actual Site Investigation and Remediation ("SIR") expenditures,[29] including expenditures associated with former manufactured gas plant ("MGP") sites, Superfund sites, and other sites allocated to electric and gas operations, varies in any Rate Year from the levels provided in rates, which are set forth in Appendices 6 and 7, such variation shall be deferred and recovered from or credited to customers. Deferred SIR cost balances varying from the level reflected in rate base during each Rate Year, as set forth in Appendices 6 and 7, will accrue a carrying cost at the pre-tax rate of return. The deferred cost balances will be reduced by accruals, insurance and third party recoveries, associated reserves and deferred taxes, and other offsets, if any, obtained by the Company.

d. Non-Officer Management Variable Pay (Electric and Gas)

The electric and gas revenue requirements reflect estimated expense for the Company's Non-Officer Management Variable Pay Program. The Company will defer for future credit to customers, the amount by which the actual expense by service in any Rate Year is less than the amount shown on Appendices 6 and 7 for that service for that Rate Year.

[29] SIR expenditures are the costs Orange and Rockland incurs to investigate, remediate or pay damages (including natural resource damages) with respect to industrial and hazardous waste or contamination, spills, discharges and emissions for which the Company is deemed responsible. These costs are net of insurance reimbursements (if any); nothing herein will require the Company to initiate or pursue litigation for purposes of obtaining insurance reimbursement, nor preclude or limit the Commission's authority to review the reasonableness of the Company's conduct in such matters.

e. Adjustments for Competitive Services (Electric and Gas)

The Company will continue to reconcile competitive service charges in accordance with current tariff provisions. Competitive service charges consist of the supply-related and credit and collections-related components of the Merchant Function Charge ("MFC"), the credit and collections component of the Purchase of Receivables ("POR") discount rate, and the Billing and Payment Processing Charge.

f. Low Income Assistance/Energy Affordability Program (Electric and Gas)

The Company will reconcile actual payments (monthly bill credits) to low-income customers to the levels provided in electric and gas rate designs, as set forth in Appendices 6 and 7.

g. Research and Development Expense (Electric and Gas)

The Company will reconcile its actual Research and Development ("R&D") expenses to the levels provided in electric and gas rates, as set forth in Appendices 6 and 7. The Company shall have the flexibility over the term of the Rate Plans to modify the list, priority, nature and scope of the R&D projects to be undertaken.

h. Energy Efficiency & Building Electrification Program (Electric and Gas)

The Company's base rates reflect energy efficiency program costs[30] forecasted to be incurred during the term of the Rate Plan as regulatory assets, amortized over fifteen years. The Company will reconcile the revenue requirement effect of the actual level of

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[30] As detailed in Appendix 21, labor costs to support energy efficiency and building electrification are included in base rates. These labor costs are not included in the program costs in the energy efficiency program reconciliation targets.

costs incurred for the energy efficiency program to the three-year cumulative (electric and gas separately) reconciliation targets, as set forth in Appendices 6 and 7, and defer any cumulative over-collection or under-collection over the term of the Rate Plans for future credit to customers.

If the Commission authorizes different RY1, RY2 and RY3 energy efficiency budgets for the Company in Case 18-M-0084, or in another proceeding, than what is included in rates, the Company will defer the impact of any variance between the level in rates and the authorized budgets for collection/refund in the next base rate case or as otherwise authorized by the Commission.

RY1 (*i.e.*, 2025) costs are subject to the cap in the Commission's Order Authorizing Utility Energy Efficiency and Building Electrification Portfolios Through 2025 ("NENY Order"). In accordance with the NENY Order, 2019-2025 costs will be reconciled up to the cumulative authorized NENY cap in existing rate plan and the Company has the ability to transfer costs across programs and commodities.

i. Major Storm Cost Reserve (Electric)

i. **Major Storm Reserve Funding**

The Company's annual electric revenue requirements provide funding for the major storm reserve of $12.6 million in RY1, $12.9 million in RY2, and $13.2 million in RY3,[31] as shown in Appendix 6.[32] Except as provided herein, all incremental major

[31] See Appendix 1, Page 5, "Storm Allowance."

[32] A "major storm" is defined in 16 NYCRR Part 97 as a period of adverse weather during which service interruptions affect at least ten percent of the Company's customers within an operating area and/or results in customers being without electric service for durations of at least 24 hours.

storm costs above $200,000 per event will be charged to the major storm reserve. To the extent that the Company incurs incremental major storm costs in excess of the annual amounts stated above in a Rate Year, the Company will defer on its books of account expenses in excess of the annual amounts stated above for future recovery from customers. To the extent that the Company incurs major storm costs less than the annual amounts stated above, the Company will defer any variation less than those amounts for the benefit of customers. All major storm costs are subject to Staff review.

The Company's annual electric revenue requirements provide for $19.1 million in each Rate Year, reflecting a three year amortization of previously incurred incremental major storm costs (net of insurance and other recoveries) due to major storms in excess of collections for major storm reserve funding.

ii. **Costs Chargeable to the Major Storm Reserve**

The Company will be allowed to charge to the major storm reserve for costs incurred to obtain the assistance of contractors and/or utility companies providing mutual assistance, incremental employee labor, transportation, meals, lodging, and travel time (collectively, "Pre-Staging and Mobilization Costs") it incurs in reasonable anticipation that a storm will affect its electric operations to the degree meeting the criteria of a major storm as defined in 16 NYCRR Part 97, but which ultimately does not do so. Pre-Staging and Mobilization Costs up to $100,000 per event will not be chargeable to the major storm reserve. The Company will be allowed to charge to the major storm reserve Pre-Staging and Mobilization Costs in excess of $100,000 per event, up to a total of $1.9 million. For Pre-Staging and Mobilization Costs in excess of $1.9 million, per event, the Company will be allowed to charge 85% of such costs to the major storm reserve, and the

Company will expense 15% of such costs in the year incurred. The Company may file a petition to defer the 15% of Pre-Staging and Mobilization Costs in excess of $1.9 million, per event. Each such petition will be subject to the Commission's three-part test traditionally applied to petitions requesting deferral accounting treatment.

The Company will not charge employee overtime to the major storm reserve for overtime work occurring more than 60 days following the date on which the Company is able to restore service to all customers. In addition, the Company will not charge stores handling, engineering, and other overheads costs to the major storm reserve.

iii. Revenue Adjustment Mechanism

If the Company's actual major storm costs vary from the rate allowance by more than $2 million in a rate year, the Company will recover the variance, up to a cap of 2.5% of delivery revenues each year as a component of the ECA.[33] Costs chargeable to the reserve in excess of the 2.5% cap will remain a deferral for recovery from customers in the next electric base rate case.

j. Asbestos Workers Compensation Reserve (Electric)

The Company's electric revenue requirements do not reflect asbestos claim payments to the Company's former employees. If the Company incurs any such payments during the term of the Electric Rate Plan, the Company will defer these payments on its books of account for future recovery from customers.

[33] A 2.5% percent delivery bill impact is currently equivalent to $9.7 million, $10.2 million and $10.8 million for Rate Year 1, 2, and 3, respectively for electric operations.

k. Tree Trimming (Electric)

The Company will defer for the benefit of customers any cumulative shortfall over the term of the Electric Rate Plan between actual expenditures for the Company's transmission and distribution vegetation management programs, including the Hazard Tree Removal Programs and the Three-Phase Clearance Program, and the levels provided in rates, as set forth in Appendix 6. This reconciliation will continue after RY3 on an annual basis or on a pro-rated basis (by month) for any period less than 12 months.

l. REV Demonstration Project Costs (Electric)

The Company's electric revenue requirements include estimated REV Demonstration project costs, deferred as regulatory assets, and amortized over ten years. The Company will reconcile its actual costs for this item with the levels provided in rates, as set forth in Appendix 6. The demonstration project budget cap, regardless of cost recovery mechanism, is the revenue requirement associated with $10 million in capital expenditures, as described in the Track One Order.[34] In the event that demonstration projects would result in the Company exceeding the demonstration project budget cap, the Company may file a petition with the Commission to increase the budget cap.

m. Platform Service Revenue (Electric)

Revenue generated from the sale of products and services on the Company's MY ORU Store online marketplace, as well as advertising and other program income, will be treated as a platform service revenue ("PSR"). Consistent with the REV Track 2 Order,

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[34] Case 14-M-0101, Order Adopting Policy Framework and Implementation Plan (issued February 26, 2015).

80 percent of the PSR will be deferred for customer benefit until base rates are reset and 20 percent will be retained by the Company.

n. Combined Uncollectible Expense and Late Payment Charge Reconciliation (Electric and Gas)

The Company's electric and gas revenue requirements reflect forecasted uncollectible expenses and forecasted revenues from late payment charges. Once the annual threshold is met, the Company is to defer for recovery/refund the difference between (i) its actual uncollectible expenses and late payment charges and (ii) the levels of uncollectible expenses and late payment charges provided in rates, as set forth in Appendices 6 and 7, that is above the threshold. The variance, in an annual amount, will be calculated and applied separately for electric and gas. The annual threshold is $900k for electric and $500k for gas. The threshold will apply on a Rate Year basis. The deferral amount will be excluded from rate base and will accrue interest at the Other Customer Provided Capital Rate.

Recovery from, or refund to, customers of the variance will be via surcharge/sur-credit through the ECA and MGA. Surcharge recovery is subject to separate annual caps for electric and gas that produce no more than 0.5% total bill impact for electric or gas. Any amounts in excess of the annual surcharge cap in a specific year will be rolled forward for recovery and will count toward the following year's surcharge cap. Any residual amounts at the end of 2027 above the annual cap will be deferred for collection in the next base rate case or as otherwise authorized by the Commission.

The Company will calculate the variance after each Rate Year. The Company may begin collecting/refunding the variance above the threshold 30 days after notification to Staff that the threshold has been met. In its notification, the Company will provide to Staff the surcharge/sur-credit amounts and supporting workpapers. Subsequent to Staff's review, if any adjustments and/or corrections need to be made to the surcharge/sur-credit amounts and the surcharge/surcredit has already been implemented, such adjustments and/or corrections will be implemented as soon as practicable. The Company will provide Staff annual reports on any variance by March 31 of the following year.

The Company will continue to defer the change in its uncollectible expense reserve through the end of the Rate Plan. For under-collections, the Company shall not be in an over-earnings position after the costs at issue are deferred. If the deferral of costs put the Company in an over-earnings position,[35] the Company will instead expense the costs above the Company's authorized Return on Equity. This reconciliation will be discontinued at the end of RY3 (*i.e.*, December 31, 2027).

o. State Tax Law Change (Electric and Gas)

In May 2023, New York State passed a law that increased the corporate franchise tax rate on business income from 6.5 percent to 7.25 percent for companies that meet certain thresholds for the tax years 2024 to 2026. Based on the Company's forecasts, the electric and gas revenue requirements include a 7.25 percent New York State corporate income tax rate for Rate Year 1 and Rate Year 2 and a 6.5 percent corporate tax rate for Rate Year 3, as set forth in Appendices 6 and 7. If the actual New York State income tax rate in Rate Year 3 is not as reflected in the revenue requirements, the Company will

[35] To be calculated in accordance with Section C.2.a of this Proposal.

defer for customer benefit or Company recovery the income tax effect of the difference between the actual income tax rate and the 6.5% tax rate reflected in Appendices 6 and 7 in Rate Year 3. No state income tax differences resulting from variations in the Company's taxable income in Rate Year 3 and subsequent Rate Years shall be reconciled.

p. Federal Income Tax- Gas Repairs

In April 2023, the Internal Revenue Service ("IRS") issued Revenue Procedure 2023-15, which provides a safe harbor method of accounting utilities may use to determine whether to expense or capitalize expenditures related to the repair, maintenance, replacement, or improvement of natural gas transmission and distribution property. The Company is following the rules in Revenue Procedure 2023-15 for linear gas property, taking advantage of the safe harbor provision by implementing the above gas repair deduction tax accounting change in tax year 2023. Further, the Company's plant related tax depreciation and deferred income taxes for Rate Years 1, 2, and 3 reflect estimated annual gas repair deduction amounts as reflected in Appendices 6 and 7. The Company will reconcile the income tax impact of the actual annual gas repair deduction amounts net of related changes in tax depreciation with the levels provided in rates. The Company will also reconcile the income tax impact of any tax attributes (i.e., net operating losses ("NOL") on a standalone basis and corporate alternative minimum tax ("CAMT") credit carryforward allocated) during the term of the rate plan.[36] If the

[36] On August 16, 2022, the Inflation Reduction Act ("IRA") was signed into law and implemented a CAMT that imposes a 15 percent tax on modified GAAP net income. Pursuant to the IRA, corporations are entitled to a tax credit (minimum tax credit) to the extent the CAMT liability exceeds the regular tax liability. If during the term of the rate plan the Company is subject to the CAMT, the reconciliation calculation will include CAMT; if the Company is not subject to the CAMT, the CAMT will be excluded from the actual reconciliation calculation.

Company utilizes a portion of the NOL carryover (net of any increase in CAMT credit carryforward) in any tax year (*i.e.*, Rate Years 1, 2 and 3) during the term of the rate plan, the Company will accrue a carrying charge on the cash savings benefit(s) of the NOL used in each tax year to make ratepayers whole. The accrued carrying charge will be calculated using the Other Customer Provided Capital Rate.

q. Transmission Service Agreement (Electric)

The Company's revenue requirements include forecasted costs associated with its Transmission Service Agreement with its New Jersey subsidiary, Rockland Electric Company, which is currently being renegotiated. The Company will reconcile and defer for future recovery or refund the variance between its actual costs and the amount provided in rates.

r. Customer Analytics Reporting & Engagement Program (Electric and Gas)

The Company's revenue requirements include estimated O&M costs for the Customer Analytics Reporting & Engagement Program (as further discussed in Section J.5 of this Proposal). The Company will defer for the benefit of customers any cumulative shortfall over the term of the Rate Plans between actual expenditures for the program and the levels provided in rates, as set forth in Appendices 6 and 7.

s. Additional Reconciliation/Deferral Provisions

In addition to the foregoing reconciliation provisions, along with all other provisions of this Proposal embodying the use of a reconciliation and/or deferral accounting mechanism, all other applicable existing reconciliations and/or deferral accounting mechanisms will continue in effect through the term of these Rate Plans and thereafter until modified or discontinued by the Commission, except for those expressly identified in this Proposal for termination. Continuing reconciliation and/or deferral accounting mechanisms include, but are not limited to those for: MTA taxes; New York Public Service Law §18-a regulatory assessment; Renewable Portfolio Standard charges; vacation pay accrual pursuant to ASC 980 Regulated Operations; carrying charges for storage gas; the GSC; MGA; MSC; ECA; and System Benefits Charge ("SBC") mechanisms. The Company will defer any differences between the Company's actual revenues and authorized revenues, as determined by the Company's RDMs. In addition, the Company will defer any carrying costs for projects approved or required by the Commission that are incremental to the Company's capital additions, such as participation in regulated backstop solutions or generation as the provider of last resort.

Appendix 3 sets forth the annual amortization of deferred regulatory assets and liabilities included in the annual revenue requirements.

t. Discontinued Reconciliations

i. Pomona NWA (Electric)

Effective December 31, 2024, the Company will terminate its reconciliation for the energy efficiency portion of the Pomona NWA. The Company has completed this initiative.

ii. Pipeline Emergency Responders Initiative (Gas)

Effective December 31, 2024, the Company will terminate its reconciliation for the Pipeline Emergency Responders Initiative. The Company has completed this initiative.

E. <u>Additional Accounting Provisions</u>

1. Productivity

The electric and gas revenue requirements reflected in the Rate Plans contain a one percent productivity adjustment to the cost of direct labor, fringe benefits (*i.e*., pension, post-employment benefits and employee welfare expenses) for Rate Year 1, a 1.25 percent productivity adjustment in Rate Year 2, and a 1.5 percent productivity adjustment in Rate Year 3.

2. Depreciation Rates and Reserves

The average services lives, net salvage factors and life tables used in calculating the depreciation reserve and establishing the revenue requirements for electric and gas service are set forth in Appendix 11.

Existing pipe to be replaced under the Company's pipe replacement program (mainly cast iron, bare steel and Aldyl-A plastic pipe) is to be fully amortized by 2029.

The average service lives, net salvage factors, and life tables have been agreed to for the purposes of this Proposal, but such agreement does not necessarily imply endorsement of any methodology for determining any of them by any Signatory Party.

3. Interest on Deferred Costs

The Company is required to record on its books of account various credits and debits that are to be charged or refunded to customers. Unless otherwise specified in this Proposal or by Commission order, the Company will accrue interest on these book amounts, net of federal and state income taxes, at the Other Customer-Provided Capital Rate published annually by the Commission. MTA tax deferrals are either offset by other balance sheet items or reflected in the Company's rate base and will not be subject to interest.

4. Property Tax Refunds and Credits

Property tax refunds allocated to electric and/or gas that are not reflected in the respective Rate Plans and that result from the Company's efforts, including credits against tax payments or similar forms of tax reductions (intended to return or offset past overcharges or payments determined to have been in excess of the property tax liability appropriate for Orange and Rockland), will be deferred for future disposition, except for an amount equal to 14 percent of the net refund or credit, which will be retained by the Company. Incremental expenses incurred by the Company to achieve the property tax refunds, credits or reductions in future property tax assessments will be offset against the refund or credit before any allocation of the proceeds is calculated. The 14 percent retention will apply to all such property tax refunds and/or credits against future tax payments actually achieved by Orange and Rockland during the term of the Rate Plans.[37] The deferral and retention of property tax refunds and credits will be subject to an annual showing in a report to the Secretary by the Company of its ongoing efforts to reduce its property tax burden, in March of each Rate Year. The report will be filed in the latest Consolidated Edison Company of New York, Inc. ("Con Edison") electric base rate case docket (currently, Case 22-E-0064). In addition, the Company is not relieved of the requirements of 16 NYCRR §89.3 with respect to any refunds it receives.

[37] This includes 14 percent of any property tax refunds, finalized during the term of the Rate Plans, but actually received after the end of the term of the Rate Plans (*i.e.*, after December 31, 2027).

5. Income Taxes and Cost of Removal Audit

On January 11, 2018, the Commission issued an order commencing a focused operations audit to investigate the income tax accounting of Orange and Rockland and other New York State utilities in Case 18-M-0013 ("COR Audit").[38] Specifically, the COR Audit focuses on determining whether an error in income tax accounting occurred with respect to cost of removal ("COR") as alleged and whether Orange and Rockland ratepayers received the benefit of the lower income tax expenses in rates as a result of the claimed errors. The COR Audit is currently being performed by Staff. The Signatory Parties agree that the final, non-appealable Commission-ordered findings in the COR Audit are binding on the instant proceedings (*i.e.*, any Commission-ordered adjustment to the amounts related to the alleged COR error embedded in the Company's cost of service forecast (income tax expense and excess deferred federal income tax liability balances) in the instant rate filings will be reconciled (*i.e.*, refunded to or collected from customers) to any Commission-ordered findings in Case 18-M-0013). The Signatory Parties reserve all of their administrative and judicial rights to take and pursue their respective positions with respect to all issues, rulings and decisions in Case 18-M-0013.

6. Allocation of Common Expenses/Plant

During the term of the Rate Plans and thereafter until revised by the Commission, common expenses and common plant, other than intangible common plant (software), will be allocated according to the following percentages: 66.93% electric operations and

[38] Case 18-M-0013, *In the Matter of a Focused Operations Audit to Investigate the Income Tax Accounting of Certain New York State Utilities*, Order Approving and Issuing the Request for Proposals Seeking a Third-Party Consultant to Perform Audits to Investigate the Income Tax Accounting of Certain New York State Utilities (issued January 11, 2018).

33.07% gas operations.[39] Should the Commission approve different common allocation percentages for electric and/or gas service prior to the next base rate case for the electric and/or gas businesses, the resulting annual revenue requirement impacts will be deferred for future recovery from or credit to customers.

7. Legislative Lobbying

The electric and gas revenue requirements underlying this Proposal do not include membership fees for any organization that engages in legislative lobbying.

F. Revenue Allocation/Rate Design and Other Tariff Changes

The Signatory Parties have agreed on a reasonable allocation of the revenue requirement to the individual customer classes. The agreement does not imply endorsement of the Company's Embedded Cost of Service ("ECOS") results, or any methodology used in developing the revenue allocation, by any Signatory Party.

1. Electric

The revenue allocation and rate design changes being made as part of this Proposal are set forth in Appendix 17.

a. ECOS Study

Following its next electric rate filing, the Company will conduct, for interested parties, a post-filing walk-through of the ECOS study and rate design underlying the proposed electric base delivery rates. Additionally, the Company will provide and review at the walk-through, an explanation of the differences in the ECOS studies filed pursuant

[39] Intangible common plant (software) is allocated 72.37% to electric service and 27.63% to gas service.

to this Proposal, a more detailed explanation of the purpose of each file and cross-references of the underlying data sources, a table of acronyms used, a table of contents, and an index of files.

In its next electric rate case, the Company will provide, for illustrative purposes, an alternative ECOS study that excludes T&D components from customer-related costs (*i.e.*, the ECOS study does not make use of the minimum system methodology and poles (FERC Account 364), conductors (FERC Accounts 365, 366, 367) and transformers (FERC Account 368) are classified as entirely demand-related.

b. Tariff Changes

Changes will be made to the Company's electric tariff for each Rate Year as summarized below. The specific language of the changes will be set forth in the tariff leaves to be filed with the Commission.

<u>Rate Year One Compliance Filing Changes – To Be Filed on Date Set Forth in Commission Order</u>

- Update RY1 delivery rates for SC Nos. 1, 2, 3, 4, 5, 6, 9, 15, 16, 19, 20, 21, and 22.
- Update the Billing and Payment Processing Charge to $2.10.
- Update the targets for the Merchant Function Charge fixed components for all three Rate Years.
- Update the targets for the Credit and Collections Lost Revenue Associated with Retail Access Component of the POR Discount for all three Rate Years.
- Remove expired language in the Transition Adjustment for Competitive Services related to the reconciliation of the Credit and Collections Lost Revenue Associated with Retail Access since it has been included for reconciliation in the POR Discount effective January 1, 2023.
- Update the POR Discount Percentage for Rate Year 1.
- Update the Reactive Power Demand Charge to $1.05.
- Update the customer bill credit applicable to energy delivered under the Recharge New York allocation for all three Rate Years. Such credit shall be set at $0.00083 per kWh, $0.00108 per kWh, and $0.00133 per kWh in Rate Year 1, Rate Year 2, and Rate Year 3, respectively.

- State the RDM targets by customer group for all three Rate Years.
- Change the threshold associated with when an interim RDM Adjustment filing may be made for all three Rate Years.
- Revise language on how the RDM will be implemented if the Company does not file for new base delivery rates to be effective after December 31, 2027
- Revise the ECA mechanism to: (1) eliminate the Base ECA and move to a monthly reconciliation of certain ECA components; (2) revise the Temporary Credit amounts that will be effective in Rate Year 3; (3) change the case number for the allocators used for EAM cost recovery to the current case number; and (4) add the new reconciliation components to the ECA related to Federal Infrastructure Funding and Pension and OPEBs.
- Extend the applicability of Rider H – Economic Development Rider for an additional 5 years.
- If the Commission approves new rates to become effective January 1, 2025, deletion of the language in the tariff related to the existing Delivery Revenue Surcharge (*i.e.*, the surcharges effective for Make Whole purposes) will be filed. If the effective date for new rates occurs after January 1, 2025, the language of the existing Delivery Revenue Surcharge will be amended specific to the provisions of this case.
- Eliminate Rider J – Smart Home Rate since this Rider is no longer available to customers.

<u>Rate Year Two Compliance Filing – To Be Filed on Date Set Forth in Commission Order</u>

- Update Rate Year 2 delivery rates for SC Nos. 1, 2, 3, 4, 5, 6, 9, 15, 16, 19, 20, 21, and 22.
- Update the POR Discount Percentage for Rate Year 2.

<u>Rate Year Three Compliance Filing – To Be Filed on Date Set Forth in Commission Order</u>

- Update Rate Year 3 delivery rates for SC Nos. 1, 2, 3, 4, 5, 6, 9, 15, 16, 19, 20, 21, and 22.
- Update the POR Discount Percentage for Rate Year 3.

2. Gas

The revenue allocation and rate design changes being made as part of this Proposal are set forth in Appendix 18.

a. ECOS Study

Following its next gas rate filing, the Company will conduct, for interested parties, a walk-through of the ECOS study and rate design underlying the proposed gas base delivery rates. Additionally, the Company will provide and review at the walk-through, an explanation of the differences in the ECOS studies filed pursuant to this Proposal, a more detailed explanation of the purpose of each file and cross-references of the underlying data sources, a table of acronyms used, a table of contents, and an index of files.

In its next gas rate case, the Company will provide, for illustrative purposes, an alternative ECOS study that excludes T&D components from customer-related costs (*i.e.*, the ECOS study classifies mains (FERC Account 376) as entirely demand-related).

b. Marginal Cost Study

The marginal cost study, originally submitted by the Company, forms the basis for the Excelsior Jobs Program ("EJP") discounts shown below, which will be applicable to customers commencing service on the EJP on or after January 1, 2025:

SC Nos. 2 and 6 – RS IB and II	- 9.4 %

c. Interruptible Transportation Rates

SC No. 8 rates will continue to consist of a block rate design and a minimum monthly charge. The minimum monthly charge for 100 Ccf will be set at $157 in RY1, $160 in RY2, and $164 in RY3. The monthly minimum charge will then remain at $164 until base rates are reset. A Base Charge will continue to be used to determine the block rates for usage greater than 100 Ccf. The Base Charge will be determined each month and shall not exceed 29.8 cents per Ccf during RY1, 32.1 cents per Ccf during RY2, and 34.9 cents per Ccf during RY3 and thereafter until such time as the Commission resets the Company's gas base rates.

d. Tariff Changes

Changes will be made to the Company's gas tariff in each Rate Year as summarized below. The specific language of the changes will be shown on tariff leaves to be filed with the Commission.

Rate Year One Compliance Filing Changes – To Be Filed on Date Set Forth in Commission Order

- Update RY1 delivery rates for SC Nos. 1, 2, and 6, and Riders B and C.
- Update the Base Charge Cap and Minimum Charge for SC No. 8 for all three Rate Years.
- Update the Billing and Payment Processing Charge to $2.10.
- Update the targets for the Merchant Function Charge fixed components for all three Rate Years.
- Update the targets for the Credit and Collections Lost Revenue Associated with Retail Access Component of the POR Discount for all three Rate Years.
- Remove expired language in the Transition Adjustment for Competitive Services related to the reconciliation of the Credit and Collections Lost Revenue Associated with Retail Access since it has been included for reconciliation in the POR Discount effective January 1, 2023.
- Update the POR Discount Percentage for Rate Year 1.
- State the RDM targets by customer group for all three Rate Years.
- Change the threshold associated with when an interim RDM Adjustment filing may be made for all three Rate Years.
- Revise language on how the RDM will be implemented if the Company does not file for new base delivery rates to be effective after December 31, 2027.
- Revise the MGA mechanism to add the new reconciliation component to the MGA related to Pension and OPEBs.

- If the Commission approves new rates to become effective January 1, 2025, deletion of the language in the tariff related to the existing Delivery Revenue Surcharge (*i.e.*, the surcharges effective for Make Whole purposes) will be filed. If the effective date for new rates occurs after January 1, 2025, the language of the existing Delivery Revenue Surcharge will be amended specific to the provisions of this case.
- Update the definition of the weather normalization adjustment normal heating degree days to be reset to be 4,836 heating degree days, the average for the 10 calendar years ended December 31, 2023.
- Update the EJP discount for customers commencing EJP service on or after January 1, 2025 to 9.4%.
- Add that new building connection applications received after December 30, 2025 for new gas service for buildings that are seven stories or less would be denied, subject to a number of exceptions, in compliance with Energy Law §11-104 and Executive Law § 378 (as amended by L 2023, ch. 56, Part RR).
- Add that any application for gas service where action has failed to advance a pending application that is more than six months old shall be deemed abandoned and a new application for service will be required whereby any eligibility criteria or requirements at the time the new application is submitted will be applicable.

Rate Year Two Compliance Filing – To Be Filed on Date Set Forth in Commission Order

- Update Rate Year 2 delivery rates for SC Nos. 1, 2, and 6.
- Update the POR Discount Percentage for Rate Year 2.

Rate Year Three Compliance Filing – To Be Filed on Date Set Forth in Commission Order

- Update Rate Year 3 delivery rates for SC Nos. 1, 2, and 6.
- Update the POR Discount Percentage for Rate Year 3.

G. Performance Metrics

Performance metrics designed to measure various activities that are applicable to the Company's Electric, Gas and Customer Service Operations, and assess negative and/or positive revenue adjustments where performance targets are not met or are exceeded, are set forth in Appendices 13, 14, and 15. Any negative or positive revenue adjustments incurred by the Company during the Rate Plans relating to the performance metrics will be recovered from or credited to customers through the ECA/MGA over a 12-month period commencing June 1. Any negative or positive revenue adjustments are subject to Staff audit and full reconciliation, even after monies have been recovered from or credited to customers through the ECA/MGA. Any such surcharge or credit will be applicable to customers who are subject to the ECA and MGA on a common cents per kWh or cents per Ccf basis, respectively. The Company will perform an annual reconciliation of these revenue adjustments.

H. Additional Electric Programs

1. REV Demonstration Project Costs

The Company will continue to manage REV Demonstration Projects during the Rate Plans. Costs are to be reconciled in accordance with Section D.3.l. of this Proposal. The Company acknowledges that the inclusion of a proposed individual demonstration project under this mechanism does not imply endorsement by Staff, nor whether Staff will approve this project under the established REV Demonstration Proposal process.

2. Pomona Battery Expansion

The Company plans to expand the existing Battery Energy Storage System from 3MW/12MWh to 3MW/18MWh. The addition of the 6MWh is a valuable component of the overall Pomona NWA Program which aids in providing customers reliable service during peak load days and system events. Funding for $7.2 million in capital expenditures in RY2 is included in the electric rate plan for the expansion. The revenue requirement includes six existing full-time equivalents (“FTEs”) and three incremental FTEs beginning in RY1 to support battery energy storage matters.

3. Little Tor Substation

Due to the ongoing litigation, at the time of the filing of this Proposal, the schedule to build Little Tor Substation has not been confirmed and so funding to develop the project is $0.125 million in each of RY1, RY2 and RY3. Notwithstanding the Commission's adoption of this settlement, the Company may file a petition with the Commission seeking recovery of Little Tor Substation costs via surcharge during the term of the Electric Rate Plan.

4. West Point Project

Because the United States Military Academy ("USMA") is a contract customer, there is currently a cost sharing agreement for the engineering and design portion of the current project scope for the West Point Project. Shared construction costs were based on the allocation of an overall system allocation 71%/29% split. The cost-share agreement between West Point and the Company is based on the actual demand ratio based on load that occurred in 2021; this cost sharing ratio was agreed to by both parties. The development of any future new load by either the Company or USMA could result in reoccurring updates to the cost-sharing ratio. The Company's 29% split is reflected in this Proposal's allowance of $19.9 million, $13.1 million, $6.0 million for RY1, RY2, and RY3, respectively for the West Point Project, with an estimated in-service date of June 2027.

5. Storm Material Warehouse and the Emergency Response Control Facility

The Company plans to begin construction of a Storm Material Warehouse[40] and an Emergency Response and Control Facility during this rate plan. These two projects are not reflected in the Company's revenue requirement because the expected in-service date is 2028.

6. Vegetation Management Reporting

The Company will track spending and progress for the Vegetation Management Program and submit quarterly and annual reports. The reports will include three categories: Distribution Vegetation Management Program (*i.e.*, Distribution Line Clearance), Other Distribution Vegetation Management Program (including, but not limited to, Customer Assist Work, Municipal Work, Contractor Supervision Work) and Hazard Tree Removal Program. The Company will file with the Secretary quarterly reports by May 15, August 15, and November 15 of each year. Orange and Rockland will file with the Secretary an annual report by February 28 after the end of each Rate Year.

7. Pole Replacement Reporting

The Company will track spending and quantity of poles replaced on an annual basis and submit an annual report. The annual report will contain the latest inspection date and finding for each replaced pole in the prior Rate Year, reason each pole was replaced (*e.g.*, capital improvement, new business request, non-restorable pole), average

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[40] The Storm Material Warehouse is a part of the Storm Material Management Program, which also includes the purchasing of storm material stock. The Company will be increasing its storm material stock by an incremental 15 days (to 20 days' worth of emergency equipment), starting in RY3.

age of the replaced poles in the prior Rate Year, and average cost for pole replacements in the prior Rate Year. The reason each pole was replaced must also include the specific programs (*e.g.*, Broadband Make Ready, Inspections, Storms). The Company will submit the annual report to the Commission no later than March 31 after the end of RY1, RY2 and RY3.

I. <u>Additional Gas Programs</u>

1. AMI-Enabled Natural Gas Detectors ("NGDs")

The Company agrees to install approximately 30,000 AMI-enabled NGDs over the term of the Gas Rate Plan. Orange and Rockland will file with the Secretary an annual report no later than 90 days following the close of each Rate Year. The annual report shall include, at a minimum:

(1) number of AMI NGDs installed in the subject Rate Year;

(2) total number of AMI NGDs installed to date;

(3) costs for installations in the subject Rate Year;

(4) costs for installations to date;

(5) alarms received by the control center in the subject Rate Year and two prior years; and

(6) actions taken by Orange and Rockland in response to each of the alarms received (including identifying any leaks found).

2. Non-Pipes Alternatives

The Signatory Parties acknowledge that Orange and Rockland applied screening and suitability criteria to all traditional gas infrastructure projects planned for the term of the Gas Rate Plan to determine the feasibility of NPAs. The Company included the results of these assessments in the exhibits (white papers) supporting the Company's Gas Infrastructure and Operations Panel. The Signatory Parties further acknowledge that the Company recently has initiated NPA programs under Case 21-G-0073.[41] Going forward, the Company will report on all NPA activities (regardless of case number) as explained below.

a. Continuing NPA Activities

The Company will continue applying the screening and suitability criteria to all new gas infrastructure projects and exploring NPAs to defer or eliminate the need for these projects, including leak prone pipe ("LPP") removal/replacement, farm taps and others. The Signatory Parties anticipate that the Commission likely will issue an order during the term of the Gas Rate Plan that establishes a standard, comprehensive NPA Framework in Case 20-G-0131, the Gas Planning Proceeding. The Company will implement any necessary future modifications that may be required because of Commission action in the Gas Planning Proceeding.

Prior to Commission approval of a standard, comprehensive NPA Framework in Case 20-G-0131, the Company will address any new NPAs implemented during the term of the Gas Rate Plan as follows:

1.) The Company will apply the screening and suitability criteria it proposed in its August 2022 filing in Case 20-G-0131. The Company will then apply societal cost test ("SCT") to assess cost effectiveness of new NPA projects.

[41] Case 21-G-0073, Proceeding on Motion of the Commission as to the Rates, Charges, Rules and Regulations of Orange and Rockland Utilities, Inc. for Gas Service, Orange and Rockland Utilities, Inc. Non-Pipeline Alternatives Implementation Plan (filed April 23, 2024).

2.) The Company will apply an NPA Adjustment Mechanism, as discussed in Section D.2.c of this Proposal, to new NPA projects that arise during the Gas Rate Plan to the extent that implementation of such project(s) has begun prior to the date of a Commission Order that establishes an NPA Framework in Case 20-G-0131.

3.) In the event the carrying charge on the net plant of any displaced project is higher than the NPA recovery, the difference will be deferred for the benefit of customers. In the event an NPA portfolio is not viable, the Company, subject to Staff's review, will treat prudently incurred spending associated with the project up to the Company's determination of non-viability as a regulatory asset.

4.) Consistent with the shareholder incentive mechanism filed by the Joint Utilities in August 2022 in Case 20-G-0131, an incentive of 30% of initial net benefits as determined by a societal cost test ("SCT") will apply to NPAs. Any earned incentives will be recovered through the MGA.

b. New NPA Activities

In order to promote the further expansion of the Company's NPA programs, the Company will convene a Technical Conference within one year of the Commission's order approving this Proposal to update the parties to these proceedings on the status of ongoing and planned NPA projects, provide insights on the Company's future NPA program direction (including potential future service line NPAs), and give parties the opportunity to provide feedback on the Company's efforts. For the Technical Conference, the Company plans to explore and discuss the following topics:

i. System Reinforcements NPAs: Potential NPAs to reduce gas system firm demand and avoid future gas system reinforcements, including through targeted incentives for energy efficiency, demand response, and electrification;

ii. Main Extensions NPAs: Potential NPAs to meet the needs of the prospective customers with more than 100 feet main extension;

iii. Service Line NPAs: Potential NPAs for new gas service line installation and replacements or relocations; and

iv. NPA Customer Outreach: Potential methods to increase the Company efforts to inform customers of NPA project opportunities and increase customer education and outreach.

c. NPA Reporting

Beginning in Rate Year One and for every rate year thereafter, the Company will file three quarterly reports (by April 30, July 31, and October 31) covering the status of ongoing and planned NPA projects for the previous quarter. In lieu of a fourth quarterly report, the Company will file an annual report no later than January 31 covering the previous calendar year (*i.e.*, January 31, 2026 annual report would cover all activities of CY2025), detailing the overall NPA activities, program changes, and lessons learned in the previous year.

3. Fusion Re-Dig Program

Orange and Rockland will continue to comply with the Commission's order in Case 14-G-0212[42] to inspect a representative sample of its plastic pipe fusion joints on underground gas facilities and remediate or replace any defective fusion. For any plastic fusion found to be defective that requires removal and replacement, the Company will continue to have the contractor who performed a defective plastic fusion pay for replacement, including the remediation and restoration of the site.

4. Certified Gas

Certified Gas is natural gas that has been evaluated and verified by an independent third-party to have been produced with reduced greenhouse gas ("GHG") emissions and environmental impacts, beyond current environmental regulations. The Company will implement a pilot program during the Rate Plan designed to allow for the procurement of Certified Gas, limited to an annual cost above traditional supplies of $100,000 per year. Procured Certified Gas will be recovered similarly to other natural gas purchases through the Company's Gas Supply Charge. The Company agrees to limit purchases to those certified as: (1) MiQ Grade A rating; and (2) Oil and Gas Methane Partnership ("OGMP") 2.0, Level 5 rating; or (3) Project Canary Trustwell Platinum rating. Further, the Company agrees to the following process for the procurement of Certified Gas:

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[42] Case 14-G-0212, Proceeding on Motion of the Commission to Investigate the Practices of Qualifying Persons to Perform Plastic Fusions on Natural Gas Facilities, Order Requiring Local Distribution Companies to Follow and Complete Remediation Plans as Modified by this Order and to Implement New Inspection Protocols (issued May 15, 2015).

1. The Company will send a Request for Proposals ("RFP") to pre-approved natural gas producers and natural gas marketers seeking arrangements for Certified Gas supply. The RFP will specify bid offers are limited to purchases of Certified Gas supply with the certification ratings listed above;
2. The Company will award volumes to suppliers based on a set of factors including purchase location, quantity of supplies offered, certification to be provided, and price;
3. Upon completion of the contracting process with the awarded suppliers, the Company will send a formal survey to the counterparties awarded Certified Gas volumes. The Company will share the proposed survey with Staff in writing before the survey is deployed and Staff may provide feedback. To facilitate survey completeness, the survey may include an option for survey respondents to indicate "unknown" or "decline to respond" for each question. The survey will request, at a minimum, the following information: Work Practice Standards: (1) Leak detection & repair (LDAR): The frequency of instrument-based monitoring for leaks and abnormal emissions at well production facilities, compressor stations, gathering and boosting facilities and transportation pipelines, including at smaller sites; the type of instrument used to detect/monitor leaks; and approximate time for repair of leaks; (2) Pneumatic devices: The number of non-zero-emitting pneumatic devices utilized by the potential provider in its supply chain and a timeline for transition to zero-emitting pneumatic devices; (3) Venting and flaring: The annual amount of gas lost to routine venting and flaring in the potential provider's supply chain; (4) Tank emissions: The control/capture

requirements for tank emissions in the potential provider's supply chain; (5) Completions: Measures taken by the potential provider to minimize emissions during well completions; (6) Liquids unloading: Measures taken by the potential provider to minimize emissions from liquids unloading; and (7) Compressors: Emission standards for reciprocating and centrifugal compressors.

i. Greenhouse Gas Emissions: Description of supplier efforts to incorporate empirical measurement data into their reporting and efforts to achieve compliance with reporting standards outlined in the Oil and Gas Methane Partnership (OGMP) 2.0 Level 5 standard (available at https://www.ccacoalition.org/en/resources/oil-and-gas-methanepartnership-ogmp-20-framework).

ii. Methane Intensity Information: Numeric methane intensity of the RSG, calculated (consistent with the calculation methods set forth by the Oil and Gas Climate Initiative) as a percentage representing the volume of methane emissions from the certified gas (mcf) divided by the total certified production from the facility (mcf); the share the certified production represents of the total production portfolio; and the estimated methane intensity of the total portfolio, calculated as a percentage representing the volume of methane emissions divided by the total marketed gas across the potential provider's entire portfolio.

iii. Upstream and midstream methane emissions associated with the supplier's delivery to the title transfer point for the Company's RSG purchase.

4. The Company will share the proposed survey with the Signatory Parties in writing before the survey is deployed and parties may provide feedback. To facilitate survey completeness, the survey may include an option for survey respondents to indicate "unknown" or "decline to respond" for each question.

- In May of each year, the Company will file an annual report (covering the previous calendar year) containing the following minimum information:
    - copies of each transaction confirmation that includes all commercial business terms associated with Certified Gas purchased,
    - volume of Certified Gas purchased,
    - additional cost to customers for Certified Gas purchased,
    - the number of suppliers used and the names of all certifiers,
    - the methane emissions intensity of the Certified Gas purchased,
    - calculation of $/CO2e by dividing the incremental cost of the Certified Gas, as compared to the average cost of gas, by the GHG emissions savings of the Certified Gas, as compared to non-Certified Gas, in CO2e,
    - cost savings to customers (if GHG emissions penalties would have been assessed),
    - reliability issues as a result of added equipment/processes by the producers, and
    - recommended changes/lessons learned to be considered in the future.
- Maximum annual additional commodity cost to customers may not exceed $100,000 for Orange and Rockland's share of the joint portfolio with its affiliate Con Edison.
- Following the filing of the annual report, the Company will meet with Staff each June to discuss its plan to either continue or terminate the pilot program, based on the data, and make a filing with the Commission if seeking any modifications to the pilot.

J. Customer Service

1. Outreach and Education

Orange and Rockland will continue to develop and implement outreach and education activities, programs and materials that will aid its customers in understanding their rights and responsibilities as utility customers, as well as provide important safety information. Annually, on April 1 of each calendar year, the Company will file in Case 17-M-0475 an outreach and education plan with the Secretary, along with a summary and assessment of its customer education efforts in the previous year. The annual plan shall include: the goals of the outreach and education program, detailed budgets, the specific outreach campaign messages to be disseminated, the communication vehicles to be used to disseminate them, and the criteria for measuring the program's achievement. The Company shall use the outreach and education plan template provided by Staff to all New York utilities in March 2024.

2. Same-Day Electric Service Reconnections

a. Weekday Same-Day Reconnections

The Company shall exercise reasonable efforts, within the Company's existing staffing levels and budgets, in attempting 100% same-day electric service reconnection for residential electric customers whose service was disconnected for non-payment at the meter and who become eligible for reconnection (*e.g.*, by making payment) by 5:00 p.m. Monday-Friday, excluding Company holidays. This process does not include customers whose meter was removed or service was cut in the street.

b. Reporting

The Company shall file a report on residential same-day reconnections for each calendar quarter (the “reporting period”). Each report will be filed with the Secretary, with copies provided by email to interested parties, within 30 days after the end of each reporting period. The report will indicate the number of residential electric customer reconnection work orders issued by 5:00 p.m. Monday-Friday, the number of same-day reconnections attempts made to such customers, and the number of completed same-day reconnections.

3. Voluntary Protections During Periods of Extreme Cold and Heat

The Company shall implement the following excessive cold weather protections and excessive heat protections.[43]

a. Cold Weather Protections

The Company commits to the following additional protections for residential customers during the period of November 1 through April 15 (“Cold Weather Period”).

i. The Company shall accept all regular and/or emergency Home Energy Assistance Program (“HEAP”) payments and restore service when necessary upon receipt or guarantee of such a payment. This excludes "Heat Included" benefits for households that pay for heat as a portion of their rental cost as explained in the New York State Office of Temporary and Disability Assistance HEAP Program information outline.

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[43] Weather information that will trigger these protections will be based on the National Weather Service website. Weather information for Orange and Rockland’s Eastern Division will be based on conditions in Spring Valley, N.Y. Weather information for Orange and Rockland’s Central Division will be based on conditions in Monroe, N.Y. Weather information for Orange and Rockland’s Western Division will be based on conditions in Middletown, N.Y.

ii. The Company shall consider a Regular and Emergency HEAP payment as entitling the applicant to a fair and reasonable payment agreement regardless of any previous payment agreement defaults.

iii. The Company shall refrain from scheduling residential service terminations for non-payment on days when high temperatures, factoring in wind chill, are forecasted to be 32 degrees Fahrenheit or lower.

iv. The Company shall establish a voluntary moratorium on winter terminations for customers who are elderly, blind or disabled.

b. Excessive Heat Protections

The Company shall suspend residential service terminations for non-payment:

i. On days where the heat index is forecasted to reach 93 degrees Fahrenheit or higher; and

ii. One calendar day before days where the heat index is forecasted to reach 93 degrees Fahrenheit or higher.

4. Digital Customer Experience ("DCX")

The Company shall file jointly with its affiliate Con Edison quarterly reports by February 28, May 31, August 31, and November 30 of each Rate Year on the DCX program. The reports will detail progress on the re-design of existing digital content and services, and implementation of new digital services/functionality.

5. Customer Analytics Reporting & Engagement Program ("CARE")

The Company shall implement a Customer Analytics Reporting and Engagement ("CARE") Program. The tools provided through the CARE Program are intended to improve customers' digital experience, facilitate decision-making, and encourage participation in energy efficiency initiatives and clean energy programs. In RY1, the Company will file a midyear report, as described below, by August 31. Starting in RY2, the Company will file quarterly reports by February 28 (which would include data listed below pertaining to the fourth quarter of the prior rate year), May 31, August 31, and November 30 of each Rate Year. The reports will provide the annual budget, budget spent in the time period covered by the report, budget spent year to date, work planned and performed, outreach and education efforts, implementation milestones and progress toward them, and metrics demonstrating customer use of tools, when applicable. As detailed in Section D.3.r of this Proposal, the program is subject to a cumulative, downward-only reconciliation.

6. Data Analytics Program

The Company shall file annual reports by January 31 following the end of each Rate Year on its Data Analytics Program. Such reports shall include descriptions of the use cases developed; information on how the use cases will result in an improved customer experience and/or cost avoidance; and information on the Company's actual capital costs compared to budgeted costs, broken down by use case or other components.

7. Customer and Project Management Platform (NUCON) Replacement

The Company plans to replace its legacy NUCON system with a new system that is used to manage customer construction projects that connect new services or upgrade existing services. The new technology will provide better support and enhance communication, collaboration and execution among the Company and stakeholders across project lifecycle.

8. New Business Services (NBS) Training Platform

The Company plans to implement a modernized NBS Training Platform designed to accelerate employee effectiveness and proficiency, improve knowledge transfer, reduce training costs and enable the Company's NBS group to improve knowledge and skills essential to supporting customer construction projects.

9. Retail Access System Replacement

The Company plans to replace its legacy retail access system in conjunction with its affiliate Con Edison. The system replacement will allow the Companies and energy service providers ("ESCOs") to better manage and exchange information involving electric and gas retail commodity customers.

10. Customer Service System ("CSS") Enhancements

The Company plans, in conjunction with its affiliate Con Edison, continue to enhance its new customer service system with hardware and software upgrades to accommodate new regulatory requirements and customer expectations.

11. Residential Termination/Uncollectible Metric

The Company's termination and uncollectible metric, previously authorized in the 2019 Rate Order,[44] shall continue to be suspended for the term of the Rate Plans. The parties will reconsider the pause on the Residential Termination/Uncollectible metric in the Company's next rate proceedings.

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[44] Cases 18-E-0067 and 18-G-0068, Proceeding on Motion of the Commission as to the Rates, Charges, Rules and Regulations of Orange and Rockland Utilities, Inc. for Electric and Gas Service, Order Adopting Terms of Joint Proposal and Establishing Electric and Gas Rate Plans (issued March 14, 2019).

12. Reconnection Fee Waiver (Electric)

The Company shall waive the reconnection charge for electric customers with remote connect/disconnect capable meters whose service was shut off for non-payment or tampering-related reasons where the Company is able to complete the reconnection of electric service remotely.

K. Electric and Gas Low Income Assistance/Energy Affordability Programs

1. Monthly Bill Credit

Orange and Rockland's Energy Affordability Program ("EAP") will provide bill discounts to eligible customers consistent with the Commission's August 2021 EAP Order.[45] The bill discount credits are set forth in the electric and gas tariffs.[46] The level of funding provided for the bill discount credits, subject to symmetrical deferral, is projected to be $14,461,671 and $7,248,720 in each Rate Year for electric and gas credits, respectively, based on the current number of customers in each tier (and set forth in Appendices 6 and 7). The RY1 bill discounts are projected to be:

Income Level	Electric Heating	Electric Non-Heat	Gas Heating	Gas Non-Heat
Tier 1	$59.29	$59.29	$15.30	$3.00
Tier 2	$69.79	$69.79	$42.67	$3.00
Tier 3	$88.25	$88.25	$63.33	$3.00
Tier 4	$82.73	$82.73	$57.15	$3.00

[45] Case 14-M-0565, *Proceeding on Motion of the Commission to Examine Programs to Address Energy Affordability for Low Income Utility Customers*, Order Adopting Energy Affordability Policy Modifications and Directing Utility Filings (issued August 12, 2021) ("August 2021 EAP Order")

[46] Bill discount credits may change based on the annual Low Income Plan the Company is required to file with analysis of customer bills.

As directed in the Commission's August 2021 EAP Order, the Company will update its EAP discounts following a rate order in Cases 24-E-0060 and 24-G-0061, and file new discount amounts via tariff statements as part of its Rate Year 1 compliance filing. Discounts will be further adjusted via tariff statements filed by November 1 of each Rate Year in Case 14-M-0565 to be effective December 1 of each Rate Year, as required by the August 2021 EAP Order.

2. Reconnection Fee Waiver

During the term of the Rate Plans, the Company shall continue its policy of waiving its reconnection fee for any Orange and Rockland electric and/or gas customer who is enrolled in the Company's Low Income/Energy Affordability Program, according to the terms set forth in the Company's electric and gas tariffs.

3. Reporting Requirements

As directed in the August 2021 EAP Order, on January 30 of each Rate Year the Company will file with the Secretary an Annual Energy Affordability Program Report in Cases 24-E-0060, 24-G-0061, 14-M-0565, and 20-M-0266. This report will contain information consistent with the requirements of the Low Income Orders.

The Company will file a report on the Electric and Gas Energy Affordability Program for each calendar month as directed in the June 2022 Order Authorizing Phase I Arrears Reduction Program in Cases 14-M-0565, 20-M-0266, and 20-M-0479. The monthly report will be filed with the Secretary in Cases 24-E-0060, 24-G-0061, 14-M-0565, and 20-M-0266.

L. Earnings Adjustment Mechanisms ("EAMs")

Incentives associated with Electric EAMs will continue to be recovered through the EAM Surcharge component of the Company's ECA Mechanism.

Recovery will be over a 12-month period commencing July 1. Recovery will be on a kWh basis for non-demand customers and on a kW basis for demand customers (on a kW of contract demand basis for standby customers), with rates determined for the following service classification groups:

Group 1: SC Nos. 1 and 19;

Group 2: SC No. 2 Secondary Non-Demand Billed;

Group 3: SC Nos. 2 Secondary and 20;

Group 4: SC Nos. 2 Primary, 3, and 21;

Group 5: SC Nos. 9 and 22; and

Group 6: SC Nos. 4, 5, 6, and 16.

Such collection will be based on the aggregate results of the following allocation methodologies divided by either forecast kWh or kW over the respective recovery period:

- Demand Response Metric will be allocated using the transmission demand allocator (D01);
- EV Adoption and Metric and Managed Charging Metrics (Commercial and Residential) will be allocated to each service classification or rate class in proportion to each class's delivery revenues; and

- DER Utilization Metrics (Solar PV and Energy Storage) will be allocated using the following three allocators that will be equally weighted: coincident peak (D01), non-coincident peak (D02), and energy allocator (E01).

These rates will be applied to the energy (kWh) or demand (kW) deliveries, as applicable, on the bills of all customers served under the above-mentioned SC groups.

Recoveries (eleven months actual, one month forecast) will be reconciled to allocable costs for each 12-month recovery period ending June 30, with any over- or under-recoveries included in the development of the succeeding EAM Surcharge component of the ECA. Reconciliation amounts related to the one-month forecast will be included in the next subsequent rates determination.

Orange and Rockland will adopt electric EAMs as of January 1, 2025. Achievement of EAMs will be measured on December 31, 2025 and thereafter on a Rate Year basis over the term of the Rate Plans for all metrics. There are six EAM metrics for electric. All EAM targets and incentives are set forth in Appendix 16.

M. <u>Disadvantaged Communities Report</u>

1. Annual Report

The Company will file a report with the Secretary under Cases 24-E-0060 and 24-G-0061 on the data enumerated in Subsection (5) of this Proposal, by May 31 of the year following each Rate Year.

2. Contents of the Report

Each report will include a narrative discussion of the data reported on, including how the Company tracked and collected the data, any assumptions relied on in the report and, for energy efficiency and building electrification programs marketed by the

Company, descriptions of the Company's efforts to reach disadvantaged communities and low income customers, including specific program implementation and outreach strategies targeted towards such populations; samples of communication materials directed towards customers in disadvantaged communities; and descriptions of Company engagement and partnerships with community-based organizations that serve disadvantaged communities.

3. Definition of Disadvantaged Communities

The Company will use the Department of Environmental Conservation disadvantaged community maps in effect for the Rate Year that is the subject of the report. For reporting related to the Electric Vehicle Make-Ready Program,[47] the Company will apply the disadvantaged communities' criteria required by the Commission for the program at the time of reporting and will not include a one-mile buffer zone around disadvantaged communities qualified census tracts.

4. Stakeholder meeting

Within 60 days of filing the report, the Company will convene a meeting for interested stakeholders to discuss and provide feedback on the report and the Company's activities as discussed therein.

5. Data Covered in the Report

The report will include the data set forth in this subsection.

[47] The Company will use the definition of disadvantaged communities reporting requirements under the July 2020 Make Ready Order in Case 18-E-0138 until such a time as there is a consistent disadvantaged communities definition between that Order and the CLCPA definition.

a. Clean Energy Spending

For each of its energy efficiency and building electrification programs, including new programs instituted during the period covered by this Proposal, the Company will report the:

i. Total number of incentive dollars spent;

ii. Total number of incentive dollars spent in disadvantaged communities;

iii. Total energy savings achieved;

iv. Total energy savings achieved in disadvantaged communities;

v. Total number participants;

vi. Total number of participants in disadvantaged communities;

vii. Average savings and incentives by participant;

viii. Average savings and incentives by participant in disadvantaged communities;

ix. Total installations by measure category (*i.e.*, System Energy Efficiency Plan ("SEEP") and Clean Heat Annual Report categories); and

x. Total installations by measure category in disadvantaged communities.

If the Company launches a new energy efficiency or building electrification program that is not available to customers in disadvantaged communities, the Company will explain in the report covering the year during which the program was launched the reasons the program is not available to customers in disadvantaged communities.

b. Electric Vehicle Make Ready Program

For light-duty and medium and heavy duty vehicles, the Company will report the:

i. Total amount of Make-Ready incentive funding spent;

ii. Total amount of Make-Ready incentive funding spent in disadvantaged communities;

iii. Total number of charging plugs installed under the Make-Ready program; and

iv. Total number of charging plugs under the Make-Ready program installed in disadvantaged communities.

c. Demand Response

For each Company demand response program, the Company will report:

i. Total program participants;

ii. Total program participants in disadvantaged communities;

iii. Total MW committed and delivered; and

iv. Total MW committed and delivered by participants in disadvantaged communities and low-income customers participating in the Company's energy affordability program.

d. Distributed Energy Resources

For all distribution-interconnected projects, including community distributed generation, remote crediting, and net metered projects, the Company will report:

i. Total number of projects;

ii. Total number of projects in disadvantaged communities;

iii. Total MW installed; and

iv. Total MW installed in disadvantaged communities.

For all community distributed generation and remote crediting projects, the Company will report:

i. Total number of subscribers;

ii. Total number of subscribers in disadvantaged communities; and

iii. Total number of subscribers who are low-income customers participating in the Company's energy affordability program.

For all net metering projects, the Company will report:

i. Total number of projects;

ii. Total number of projects installed for low-income customers;

iii. Total number of projects in disadvantaged communities;

iv. Total MW installed;

v. Total MW installed for low-income customers; and

vi. Total MW installed in disadvantaged communities.

e. Strategic Electric Capital Investments

The Company will report its discretionary capital investments in the following capital categories:

i. System Expansion;

ii. Risk Reduction;

iii. Environmental; and

iv. Safety and Security.

f. Customer Outages

The Company will report all outages as follows:

i. Excludable and Non-Excludable outages system-wide; and

ii. Excludable and Non-Excludable outages by customers in disadvantaged communities and by customers in non-disadvantaged communities.

"Excludable outages" are outages excluded from the Company's SAIFI and CAIDI metrics. "Non-excludable outages" are outages that count against the Company's SAIFI and CAIDI metrics.

g. Main Replacement Program

The Company will report:

i. Total footage of leak prone pipe retired system-wide, on a county basis;

ii. Total footage of leak prone pipe retired in disadvantaged communities, on a county basis;

iii. Total footage of leak prone pipe replaced system-wide, on a county basis;

iv. Total footage of leak prone pipe replaced in disadvantaged communities, on a county basis;

v. Total emissions reductions system-wide due to leak prone pipe replacement and retirement (calculated using the EPA Methane Challenge methodology); and

vi. Total emissions reductions in disadvantaged communities due to leak prone pipe replacement and retirement (calculated using the EPA Methane Challenge methodology).

For items (i) and (ii) replacement and retirement will be tracked separately.

h. Leak Repairs

The Company will report:

i. Total leaks repaired system-wide, on a county basis; and

ii. Total leaks repaired in disadvantaged communities, on a county basis.

i. Customer Operations Data

The Company will report:

i. Promotion, education and outreach of the EAP program in disadvantaged communities and non-disadvantaged communities;

ii. Total amount of residential electric and gas usage in disadvantaged communities and non-disadvantaged communities;

iii. Average electric and gas usage per residential customer in disadvantaged communities and non-disadvantaged communities;

iv. Number of unpaid residential accounts that are 60 to 90 days overdue in disadvantaged communities and non-disadvantaged communities;

v. Dollar value of unpaid residential accounts 60 to 90 days overdue in disadvantaged communities and non-disadvantaged communities;

vi. Number of unpaid residential accounts that are 90 or more days overdue in disadvantaged communities and non-disadvantaged communities;

vii. Dollar value of unpaid residential accounts that are 90 or more days overdue in disadvantaged communities and non-disadvantaged communities;

viii. Number of residential service disconnections for non-payment in disadvantaged communities and non-disadvantaged communities;

ix. Number of residential service restorations due to payment in disadvantaged communities and non-disadvantaged communities;

x. Number of residential customers with DPAs in in disadvantaged communities and non-disadvantaged communities;

xi. Dollar value of residential DPAs in disadvantaged communities and non-disadvantaged communities;

xii. Number of customers enrolled in the EAP in disadvantaged communities and non-disadvantaged communities;

xiii. Amount expended for electric and gas EAP discounts in disadvantaged communities and non-disadvantaged communities; and

xiv. Total number of residential customers in disadvantage communities and non-disadvantaged communities.

For items that are cumulative in nature, *i.e.*, nos. (i)-(iii), (viii), (ix) and (xiii), the report will reflect data for the Rate Year. For items that are expressed as a point in time, *i.e*., nos. (iv)-(vii), (x)-(xii), and (xiv), the report will reflect data as of a point in time in December of the just-concluded Rate Year. The Company will begin collecting data for the above dataset in August 2025. Data for RY1 will therefore include August –

December data only. For RY2 and RY3, the Company's reports will cover the entire year. Reporting on item (i) will include a narrative description of outreach activities to promote the EAP, sample materials, and campaign statistics (*e.g.*, number of customers touched in disadvantaged communities). For items (ii)-(xiv), the Company will apply disadvantaged community criteria to customer account data.

6. Effect of Subsequent Commission Order

If in a different proceeding the Commission orders Orange and Rockland to report on data covered in this Section, the form and content of the reporting required by the Commission in that proceeding will supersede the reporting requirement in this Proposal.

N. Miscellaneous Provisions

1. Continuation of Provisions; Rate Changes; Reservation of Authority

Unless otherwise expressly provided herein, the provisions of this Proposal will continue after RY3 for electric and for gas, unless and until electric or gas base delivery service rates, respectively, are reset by Commission order. For any provision subject to RY1, RY2 and RY3 targets, the RY3 target shall be applicable to any additional Rate Year(s).

Nothing herein precludes Orange and Rockland from filing a new general electric rate case or a new general gas rate case prior to January 1, 2028, for rates to be effective on or after January 1, 2028.

Changes to the Company's base delivery service rates during the term of the Electric or Gas Rate Plan will not be permitted, except for (a) changes provided for in this Proposal; and (b) subject to Commission approval, changes as a result of the following circumstances:

a. A minor change in any individual base delivery service rate or rates whose revenue effect is *de minimis*, or essentially offset by associated changes within the same class or for other classes. It is understood that, over time, such minor changes are routinely made and that they may continue to be sought during the term of the Electric and Gas Rate Plans, provided they will not result in a change (other than a *de minimis* change) in the revenues that Orange and Rockland's base delivery service rates are designed to produce overall before such changes.

b. If a circumstance occurs which, in the judgment of the Commission, so threatens Orange and Rockland's economic viability or ability to maintain safe, reliable and adequate service as to warrant an exception to this undertaking, Orange and Rockland will be permitted to file for an increase in base delivery service rates at any time under such circumstances.

c. The Signatory Parties recognize that the Commission reserves the authority to act on the level of Orange and Rockland's electric and/or gas rates in the event of unforeseen circumstances that, in the Commission's opinion, have such a substantial impact on the range of earnings levels or equity costs envisioned by these Rate Plans as to render Orange and Rockland's electric and/or gas rates unreasonable or insufficient for the provision of safe and adequate service at just and reasonable rates.

d. Nothing herein will preclude any Signatory Party from petitioning the Commission for approval of new services, the implementation of new service classifications and/or cancellation of existing service classifications, or rate design or revenue allocation changes within or among service classes, which are not contrary to the agreed upon terms and conditions set forth herein. All changes will be implemented on a revenue neutral and earnings neutral basis.

e. The Signatory Parties reserve the right to support or oppose any filings made under this Section.

2. Legislative, Regulatory and Related Actions

a. If at any time the federal government, State of New York and/or other local governments make changes in their tax laws (other than local property taxes, which will be reconciled in accordance with Section D.3.a of this Proposal), that result in a change in the Company's costs[48] in an annual amount, calculated and applied separately for electric and gas, equating to ten basis points of return on common equity or more,[49] and if the Commission does not address the treatment (*e.g.*, through a surcharge or credit) of any such tax law changes, including any new, additional, repealed or reduced federal, State, local government taxes, fees or levies, Orange and Rockland will defer on its books of account the full change in expense and reflect such deferral as credits or debits to customers in the next base rate change subject to any final Commission determination in a generic proceeding prescribing utility implementation of a specific tax enactment, including a Commission determination of any Company-specific compliance filing made in connection therewith.[50]

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[48] Costs in this context include current and deferred tax impacts.

[49] For electric, such amounts are estimated to be $862,220 in RY1, $928,940 in RY2 and $1,088,940 in RY3. For gas, such amounts are estimated to be $481,000 in RY1, $528,640 in RY2 and $571,900 in RY3. During the Electric and Gas Rate Plans, basis points will be calculated on actual average rate base at the end of each Rate Year.

[50] All Signatory Parties reserve all of their administrative and judicial rights in connection with such generic proceeding(s).

b. If at any time any other law, rule, regulation, order, or other requirement or interpretation (or any repeal or amendment of an existing rule, regulation, order or other requirement) of the federal, State, or local government or courts, results in a change in Orange and Rockland's annual electric or gas revenues, costs or expenses not anticipated in the forecasts and assumptions on which the rates in this Proposal are based in an annual amount, calculated and applied separately for electric and gas, equating to ten basis points of return on common equity or more,[51] Orange and Rockland will defer on its books of account the full change in revenue or expense. Any deferrals associated with a change in expense shall be reflected in the Company's next base rate proceeding or in a manner to be determined by the Commission. Any deferrals associated with a change in revenue shall be recovered or refunded over an 18-month period. Surcharge/surcredit of such revenues may begin 90 days after a filing with the Secretary, subject to adjustment by the Commission.

c. The Company will retain the right to petition the Commission for authorization to defer on its books of account extraordinary expenditures not otherwise addressed by this Proposal.

3. Financial Protections

Annually, the Company will provide Staff with the five-year earnings forecast for Consolidated Edison Inc. ("CEI") and each direct subsidiary of CEI (*e.g.*, Con Edison,

[51] For purposes of this Proposal, the ten basis points return on common equity will be applied on a case-by-case basis and not to the aggregate impact of changes of two or more laws, rules, etc.; provided, however, that this threshold will be applied on a Rate Year basis to the incremental aggregate impact of all contemporaneous changes (*e.g.*, changes made as a package even if they occur or are implemented over a period of months) affecting a particular subject area and not to the individual provisions of the new law, rule, etc.

Orange and Rockland, and Con Edison Transmission, Inc.). The forecast will include the income statement, balance sheet and cash flow statements for CEI and each above-listed direct subsidiary of CEI. The Company will submit the forecast to Staff no later than thirty (30) calendar days after it is reviewed by the Finance Committee of CEI's Board of Directors. The Company will update Staff when there are material changes to the five-year forecast.

After the completion of the Company's annual audit by its external auditors, Orange and Rockland will provide Staff with actual financial statements (*i.e.,* income statement, balance sheet, cash flow statement and consolidating adjustments) for CEI and each direct subsidiary for the previous year. The Company will submit those statements to Staff no later than thirty (30) calendar days after the completion of the annual audit by its external auditors.

The five-year earnings forecast and actual financial statements will be provided to Staff by filing with the Records Access Officer pursuant to the Commission's trade secret process.

4. Trade Secret Protection

Nothing in this Proposal prevents Orange and Rockland from seeking trade secret protection under 16 NYCRR Part 6 for all or any part(s) of any document or report filed (or submitted to Staff) in accordance with the Rate Plans or prohibits or restricts any other Signatory Party from challenging any such request.

5. Provisions Not Separable

The Signatory Parties intend this Proposal to be a complete resolution of all the issues in Cases 24-E-0060 and 24-G-0061. It is understood that each provision of this

Proposal is in consideration and support of all the other provisions, and expressly conditioned upon acceptance by the Commission. Except as set forth herein, none of the Signatory Parties is deemed to have approved, agreed to or consented to any principle, methodology or interpretation of law underlying or supposed to underlie any provision herein. Consistent with the Commission's Settlement Guidelines,[52] if the Commission fails to adopt this Proposal according to its terms, then the Signatory Parties to this Proposal will be free to pursue their respective positions in this proceeding without prejudice.

6. Provisions Not Precedent

The terms and provisions of this Proposal apply solely to, and are binding only in, the context of the purposes and results of this Proposal. None of the terms or provisions of this Proposal and none of the positions taken herein by any Signatory Party may be referred to, cited, or relied upon by any other Signatory 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 Proposal.

Concessions made by Signatory Parties on various electric and gas issues do not preclude those Signatory Parties from addressing such issues in future rate proceedings or in other proceedings.

[52] Opinion 92-2, Settlement Guidelines, Section F(2) (issued March 24, 1992).

7. Submission of Proposal

The Signatory Parties agree to submit this Proposal to the Commission and to individually support and request its adoption by the Commission as set forth herein. The Signatory Parties hereto believe that the Proposal will satisfy the requirements of Public Service Law §65(1) that Orange and Rockland provide safe and adequate service at just and reasonable rates.

8. Procedures in the Event of a Disagreement

In the event of any disagreement over the interpretation of this Proposal or the implementation of any of the provisions of this Proposal, which cannot be resolved informally among the Signatory Parties, such disagreement will be resolved as follows: the Signatory Parties promptly will confer and in good faith will attempt to resolve such disagreement. If any such disagreement cannot be resolved by the Signatory Parties within 15 business days from notification invoking this process, or a longer period if agreed to by the Signatory Parties, any Signatory Party may petition the Commission for a determination on the disputed matter.

9. Effect of Commission Adoption of Terms of this Proposal

No provision of this Proposal or the Commission's adoption of the terms of this Proposal shall in any way abrogate or limit the Commission's statutory authority under the Public Service Law. The Parties recognize that any Commission adoption of the terms of this 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.

10. Further Assurances

The Signatory Parties recognize that certain provisions of this Proposal require that actions be taken in the future to fully effectuate this Proposal. Accordingly, the Signatory Parties agree to cooperate with each other in good faith in taking such actions.

11. Scope of Provisions

No term or provision of this Proposal that relates specifically to one but not both electric and gas service, limits any rights of the Company or any Signatory Party to petition the Commission for any purpose with respect to the service not specified in such term or provision.

12. Execution

This Proposal is being executed in counterpart originals and shall be binding on each Signatory Party when the counterparts have been executed.

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

ORANGE AND ROCKLAND
UTILITIES, INC.

Dated: November 8, 2024

By: Grace Su

Grace Su
Associate General Counsel

NEW YORK STATE DEPARTMENT OF PUBLIC SERVICE

Dated: 11/8/2024

By: ______________________
Steven Kramer
Staff Counsel

IN WITNESS WHEREOF, The Utility Intervention Unit of the New York State Department of State's Division of Consumer Protection has this day signed this Joint Proposal as it relates to the above-referenced electric and gas proceedings.

UTILITY INTERVENTION UNIT,
DIVISION OF CONSUMER PROTECTION,
NEW YORK STATE DEPARTMENT OF STATE

Dated: 11/8/2024

By: John Haff
John Haff
Director, Utility Intervention Unit

Orange and Rockland Utilites, Inc.
Case 24-E-0060
Electric Revenue Requirement
For The Twelve Months Ending December 31, 2025
$ 000's

	Rate Year 1 Forecast	Rate Change	Rate Year 1 With Rate Change
Operating revenues			
Sales & deliveries to public	$ 589,983	$ (13,060)	$ 576,923
Sales for resale	23,810		23,810
Other operating revenues	15,644	(88)	15,556
Total operating revenues	629,437	(13,148)	616,289
Operating expenses			
Purchased power	173,699		173,699
Operations & maintenance expenses	192,868	(88)	192,781
Depreciation	77,105		77,105
Regulatory amortizations	4,478		4,478
Taxes other than income taxes	60,274	(229)	60,045
Total operating expenses	508,425	(316)	508,109
Operating income before income taxes	121,012	(12,832)	108,180
New York State income taxes	5,632	(930)	4,702
Federal income taxes	12,225	(2,499)	9,726
Utility operating income	$ 103,155	$ (9,402)	$ 93,753
Rate Base	$ 1,293,147		$ 1,293,147
Rate of Return	7.98%		7.25%

Orange and Rockland Utilites, Inc.
Case 24-E-0060
Electric Revenue Requirement
For The Twelve Months Ending December 31, 2025 and December 31, 2026
$ 000's

	Rate Year 1 With Rate Change	Rate Year 2 Revenue/Expense Rate Base Changes	Rate Change	Rate Year 2 With Rate Change
Operating revenues				
Sales & deliveries to public	$ 576,923	$ (2,283)	$ 24,786	$ 599,425
Sales for resale	23,810	1,075	-	24,885
Other operating revenues	15,556	94	166	15,816
Total operating revenues	616,289	(1,115)	24,952	640,126
Operating expenses				
Purchased power	173,699	4,122		177,821
Operations & maintenance expenses	192,781	7,138	166	200,085
Depreciation	77,105	931		78,036
Regulatory amortizations	4,478	943		5,421
Taxes other than income taxes	60,045	1,771	434	62,250
Total operating expenses	508,109	14,905	600	523,614
Operating income before income taxes	108,180	(16,020)	24,352	116,512
New York State income taxes	4,702	(2,017)	1,766	4,450
Federal income taxes	9,726	(3,832)	4,743	10,636
Utility operating income	$ 93,753	$ (10,171)	$ 17,843	$ 101,426
Rate Base	$ 1,293,147	100,064		$ 1,393,211
Rate of Return	7.25%			7.28%

Orange and Rockland Utilites, Inc.
Case 24-E-0060
Electric Revenue Requirement
For The Twelve Months Ending December 31, 2026 and December 31, 2027
$ 000's

Operating revenues	Rate Year 2 With Rate Change	Rate Year 3 Revenue/Expense Rate Base Changes	Rate Change	Rate Year 3 With Rate Change
Sales & deliveries to public	$ 599,425	$ (7,660)	$ 44,061	$ 635,826
Sales for resale	24,885	1,869	-	26,754
Other operating revenues	15,816	62	295	16,173
Total operating revenues	640,126	(5,729)	44,356	678,753
Operating expenses				
Purchased power	177,821	(8,496)		169,325
Operations & maintenance expenses	200,085	5,329	295	205,709
Depreciation	78,036	14,336		92,372
Regulatory Amortizations	5,421	941	-	6,362
Taxes other than income taxes	62,250	1,257	771	64,278
Total operating expenses	523,614	13,367	1,066	538,047
Operating income before income taxes	116,512	(19,096)	43,290	140,707
New York State income taxes	4,450	(1,439)	2,814	5,825
Federal income taxes	10,636	(4,603)	8,500	14,534
Utility operating income	$ 101,426	$ (13,054)	$ 31,976	$ 120,348
Rate Base	$ 1,393,211	$ 253,124		$ 1,646,336
Rate of Return	7.28%			7.31%

ORANGE AND ROCKLAND UTILITIES, INC.
Case 24-E-0060
Electric Other Operating Revenues
For The Twelve Months Ending December 31, 2025, December 31, 2026, and December 31, 2027
$ 000's

	Rate Year 1	Rate Year 2 Changes	Rate Year 2	Rate Year 3 Changes	Rate Year 3
Miscellaneous Service & Other Revenues					
AMI/AMR Meter Reading/Change Out Fees	$ 155	$ -	$ 155		$ 155
Customer Reconnect Fees	6		6		6
Late Payment Charges	3,860	151	4,011	244	4,254
POR Discount	649		649		649
Shared Meter Assessment	(2)		(2)		(2)
Agency Checks Dishonored	3		3		3
Platform Service Revenues	27		27		27
Bad Check Charge	75		75		75
Collection Charges	84		84		84
Solar Application Fee	57		57		57
Total Miscellaneous Service & Other Revenues	4,915	151	5,065	244	5,309
Rents					
Joint Operating Rents	6,353		6,353		6,353
Pole Attachment and Parity Billings	3,626	109	3,735	113	3,848
Other Rents	663		663		663
Total Rents	10,642	109	10,751	113	10,864
Total Other Operating Revenue	$ 15,556	$ 260	$ 15,816	$ 357	$ 16,173

ORANGE AND ROCKLAND UTILITIES, INC.
Case 24-E-0060
Electric Operations & Maintenance Expenses
For The Twelve Months Ending December 31, 2025, December 31, 2026, and December 31, 2027
$ 000's

	Rate Year 1	Rate Year 2 Changes	Rate Year 2	Rate Year 3 Changes	Rate Year 3
Fuel and Purchased Power	$ 173,699	$ 4,122	$ 177,821	$ (8,496)	$ 169,325
A & G Health Insurance and Capital Overhead	(1,332)	(24)	(1,356)	(21)	(1,376)
Bond Administration & Bank Fees	184	4	188	4	192
Company Labor	70,984	2,693	73,676	2,068	75,744
Customer Billing Postage	1,246	27	1,273	28	1,301
Employee Welfare Expense	7,849	173	8,022	176	8,198
Facilities	1,994	44	2,038	45	2,082
Information Technology	11,645	1,353	12,998	2,484	15,482
Informational Advertising	159	4	163	4	166
Injuries & Damages/ Workers Compensation	97	2	99	2	101
Institutional Dues & Subscription	30	1	30	1	31
Insurance Premium	915	38	953	19	972
Intercompany Shared Services	15,053	257	15,310	246	15,556
Legal and Other Professional Services	366	8	374	8	383
Load Dispatching	454	10	464	10	474
MGP/Superfund	472	2,609	3,081	(658)	2,423
Ops - Corporate & Shared Services	2,269	96	2,365	208	2,573
Ops - Customer Operations	6,098	(293)	5,805	(163)	5,642
Ops - Electric Operations	28,145	1,199	29,344	646	29,989
Ops - Engineering	3,230	730	3,960	2,008	5,969
Ops - Substation Operations	1,992	44	2,036	45	2,081
Other Compensation	653	19	672	1	673
Pension and OPEB Costs	(15,195)	6,603	(8,592)	2,927	(5,665)
Regulatory Commission Expense - General and R&D	2,852	63	2,915	64	2,979
Renewable Portfolio Charges	4,799	(1,497)	3,302	(867)	2,435
Rent	2,413	107	2,520	29	2,549
Research & Development	721	16	737	16	753
Storm Allowance	12,610	277	12,887	284	13,171
System Benefit Charge	24,720	(7,710)	17,010	(4,464)	12,546
Uncollectible Reserve - Customer	3,865	151	4,016	244	4,260
Uncollectible Reserve - Sundry	464	-	464	-	464
Worker's Comp NYS Assessment	68	1	69	2	71
Bargaining Unit Contract Cost	88	-	88	-	88
Environmental Affairs	361	8	369	8	377
External Audit Services	622	14	636	14	650
Finance & Accounting Operations	10	0	10	0	10
Other O&M	1,239	27	1,266	28	1,294
Company Labor - Fringe Benefit Adjustment	643	251	894	178	1,072
Total O&M Expenses	$ 366,480	$ 11,426	$ 377,906	$ (2,872)	$ 375,034

ORANGE AND ROCKLAND UTILITIES, INC.
Case 24-E-0060
Electric Taxes Other Than Income Taxes
For The Twelve Months Ending December 31, 2025, December 31, 2026, and December 31, 2027
$ 000's

	Rate Year 1	Rate Year 2 Changes	Rate Year 2	Rate Year 3 Changes	Rate Year 3
Property Taxes					
State, County & Town	$ 14,111	$ 574	$ 14,685	$ 218	$ 14,903
Village	2,065	31	2,096	31	2,126
School	28,149	825	28,974	828	29,802
Total Property Taxes	44,325	1,430	45,755	1,077	46,832
Payroll Taxes	5,454	279	5,733	214	5,947
Revenue Taxes	10,067	496	10,563	737	11,300
Other Taxes					
Sale & Use Tax	-	-		-	
Other Taxes	200	-	200	-	200
Total Other Taxes	200	-	200	-	200
				-	
Total Taxes Other Than Income Taxes	$ 60,045	$ 2,205	$ 62,250	$ 2,028	$ 64,278

ORANGE AND ROCKLAND UTILITIES, INC.
Case 24-E-0060
Electric New York State Income Taxes
For The Twelve Months Ending December 31, 2025, December 31, 2026, and December 31, 2027
$ 000's

	Rate Year 1	Rate Year 2 Changes	Rate Year 2	Rate Year 3 Changes	Rate Year 3
Operating Income Before Income Taxes	$ 108,180	$ 8,332	$ 116,512	$ 24,194	$ 140,707
Interest Expense	(38,031)	(6,881)	(44,913)	(6,635)	(51,548)
Book Income Before State Income Taxes	70,149	1,451	71,600	17,559	89,159
Tax Computation					
Current State Income Taxes	1,052	(3,310)	(2,258)	2,102	(156)
Deferred State Income Taxes	3,648	3,059	6,707	(727)	5,980
NYS Income Tax Expense	$ 4,701	$ (251)	$ 4,449	$ 1,375	$ 5,824

ORANGE AND ROCKLAND UTILITIES, INC.
Case 24-E-0060
Electric Federal Income Taxes
For The Twelve Months Ending December 31, 2025, December 31, 2026, and December 31, 2027
$ 000's

	Rate Year 1	Rate Year 2 Changes	Rate Year 2	Rate Year 3 Changes	Rate Year 3
Operating Income Before Income Taxes	$ 108,180	$ 8,332	$ 116,512	$ 24,194	$ 140,707
Interest Expense	(38,031)	(6,881)	(44,913)	(6,635)	(51,548)
Book Income Before Income Taxes	70,149	1,451	71,600	17,559	89,159
Tax Computation					
Current Federal Income Taxes	5,928	(9,064)	(3,136)	5,423	2,287
Deferred Federal Income Taxes	8,411	9,974	18,386	(1,526)	16,860
Excess Deferred Federal Income Tax - Property	(4,210)	0	(4,210)	(0)	(4,210)
Excess Deferred Federal Income Tax - Non-Property	98	-	98	-	98
R&D Tax Credit	(502)	-	(502)	-	(502)
Federal Income Tax Expense	$ 9,726	$ 911	$ 10,636	$ 3,897	$ 14,534

Orange and Rockland Utilities, Inc.
Rate Case 24-E-0060
Average Electric Rate Base
For Twelve Months Ending December 31, 2025 and December 31, 2026
($000's)

	Rate Year 1	Rate Year 2 Changes	Rate Year 2
Utility Plant			
Electric Plant In Service	$1,899,693	$ 112,115	$ 2,011,808
Electric Plant Held For Future Use	8,102	0	8,102
Common Utility Plant (Electric Allocation)	245,868	22,393	268,261
Total	2,153,663	134,508	2,288,171
Utility Plant Reserves:			
Accumulated Reserve for Depreciation - Plant in Service	(662,492)	(44,117)	(706,609)
Accumulated Reserve for Depreciation - Common Plant (Electric Allocation)	(93,533)	(17,268)	(110,801)
Total	(756,025)	(61,384)	(817,409)
Net Plant	1,397,638	73,124	1,470,762
Non-Interest Bearing CWIP	100,056	28,951	129,008
Working Capital - Materials/Supplies, Prepayment and Cash Working Capital	76,029	2,605	78,634
Unamortized Premium & Discount	6,072	523	6,595
Customer Advance Construction	(27,745)	0	(27,745)
Net Deferrals / Credits from Reconciliation Mechanisms	41,970	6,844	48,813
Accumulated Deferred Income Taxes			
Accumulated Deferred Federal Income Taxes	(208,652)	(7,439)	(216,091)
Accumulated Deferred State Income Taxes	(47,433)	(4,593)	(52,026)
Total	(256,085)	(12,032)	(268,117)
Average Rate Base	1,337,935	100,015	1,437,950
Earnings Base Capitalization Adjustment to Rate Base	(43,253)	-	(43,253)
Isaias Storm Settlement Forecast Earning	(1,535)	50	(1,485)
Total Average Rate Base	$ 1,293,147	$ 100,065	$ 1,393,211

Orange and Rockland Utilities, Inc.
Rate Case 24-E-0060
Average Electric Rate Base
For Twelve Months Ending December 31, 2026 and December 31, 2027
($000's)

	Rate Year 2	Rate Year 3 Changes	Rate Year 3
Utility Plant			
Electric Plant In Service	$ 2,011,808	$ 269,209	2,281,017
Electric Plant Held For Future Use	8,102	(0)	8,102
Common Utility Plant (Electric Allocation)	268,261	68,811	337,072
Total	2,288,171	338,020	2,626,191
Utility Plant Reserves:			
Accumulated Reserve for Depreciation - Plant in Service	(706,609)	(49,287)	(755,896)
Accumulated Reserve for Depreciation - Common Plant (Electric Allocation)	(110,801)	(22,002)	(132,803)
Total	(817,409)	(71,290)	(888,699)
Net Plant	1,470,762	266,730	1,737,492
Non-Interest Bearing CWIP	129,008	(1,085)	127,923
Working Capital - Materials/Supplies, Prepayment and Cash Working Capital	78,634	830	79,464
Unamortized Premium & Discount	6,595	418	7,013
Customer Advance Construction	(27,745)	(0)	(27,745)
Net Deferrals / Credits from Reconciliation Mechanisms	48,813	6,438	55,252
Accumulated Deferred Income Taxes			
Accumulated Deferred Federal Income Taxes	(216,091)	(13,794)	(229,886)
Accumulated Deferred State Income Taxes	(52,026)	(6,461)	(58,487)
Total	(268,117)	(20,256)	(288,373)
Average Rate Base	1,437,950	253,076	1,691,025
Earnings Base Capitalization Adjustment to Rate Base	(43,253)	-	(43,253)
Isaias Storm Settlement Forecast Earning	(1,485)	49	(1,436)
Total Average Rate Base	$ 1,393,211	$ 253,125	1,646,336

Orange and Rockland Utilities, Inc.
Case 24-E-0060
Average Capital Structure & Cost of Money
For the Twelve Months Ending December 31, 2025, December 31, 2026 and December 31, 2027

RY 1

	Capital Structure %	Cost Rate %	Cost of Capital %	Pre Tax Cost %
Long term debt	51.32%	4.95%	2.54%	2.54%
Customer deposits	0.68%	4.20%	0.03%	0.03%
Subtotal	52.00%		2.57%	2.57%
Common Equity	48.00%	9.75%	4.68%	6.39%
Total	100.00%		7.25%	8.96%

RY 2

	Capital Structure %	Cost Rate %	Cost of Capital %	Pre Tax Cost %
Long term debt	51.40%	5.01%	2.57%	2.57%
Customer deposits	0.60%	4.20%	0.03%	0.03%
Subtotal	52.00%		2.60%	2.60%
Common Equity	48.00%	9.75%	4.68%	6.39%
Total	100.00%		7.28%	8.99%

RY 3

	Capital Structure %	Cost Rate %	Cost of Capital %	Pre Tax Cost %
Long term debt	51.45%	5.08%	2.61%	2.61%
Customer deposits	0.55%	4.20%	0.02%	0.02%
Subtotal	52.00%		2.63%	2.63%
Common Equity	48.00%	9.75%	4.68%	6.33%
Total	100.00%		7.31%	8.96%

Orange and Rockland Utilities, Inc.
Case 24-E-0060
Calculation of Phased Rate Increase
For the Twelve Months Ending December 31, 2025, December 31, 2026 and December 31, 2027
$ 000's

Rate Increase	Twelve Months Ending December 31, 2025	2026	2027	Cumulative Total
RY - 1	$ (13,060)	$ (13,060)	$ (13,060)	$ (39,180)
RY - 2		24,786	24,786	49,571
RY - 3			44,061	44,061
Total	$ (13,060)	$ 11,726	$ 55,787	$ 54,453

Phased rate increase without interest				
RY - 1	$ -	$ -	$ -	$ -
RY - 2		18,151	18,151	36,302
RY - 3			18,151	18,151
Total	$ -	$ 18,151	$ 36,302	$ 54,453
Variation	**$ (13,060)**	**$ (6,425)**	**$ 19,485**	**$ -**
Interest at 5.95%	$ (285)	$ (709)	$ (428)	$ (1,422)

Phased rate increase with interest				
RY - 1	$ -	$ -	$ -	$ -
RY - 2		17,677	17,677	35,354
RY - 3			17,677	17,677
Total	$ -	$ 17,677	$ 35,354	$ 53,030

Orange and Rockland Utilites, Inc.
Case 24-G-0061
Gas Revenue Requirement
For The Twelve Months Ending December 31, 2025
$ 000's

Operating revenues	Rate Year 1 Forecast	Rate Change	Rate Year 1 With Rate Change
Sales revenues	$ 284,125	$ 3,568	$ 287,693
Other operating revenues	2,398	12	2,410
Total operating revenues	286,524	3,579	290,103
Operating expenses			
Purchased gas costs	101,296	-	101,296
Operations & maintenance expenses	62,665	24	62,689
Depreciation	38,728	-	38,728
Regulatory amortizations	(8,358)	-	(8,358)
Taxes other than income taxes	33,181	60	33,241
Total operating expenses	227,512	84	227,596
Operating income before income taxes	59,012	3,495	62,507
New York State income taxes	2,744	254	2,998
Federal income taxes	6,659	681	7,340
Utility operating income	$ 49,609	$ 2,561	$ 52,170
Rate Base	$ 719,600		$ 719,600
Rate of Return	6.89%		7.25%

Orange and Rockland Utilites, Inc.
Case 24-G-0061
Gas Revenue Requirement
For The Twelve Months Ending December 31, 2025 and December 31, 2026
$ 000's

Operating revenues	Rate Year 1 With Rate Change	Rate Year 2 Revenue/Expense Rate Base Changes	Rate Change	Rate Year 2 With Rate Change
Sales revenues	$ 287,693	$ 3,522	$ 18,038	$ 309,253
Other operating revenues	2,410	12	63	2,486
Total operating revenues	290,103	3,534	18,101	311,739
Operating expenses				
Purchased gas costs	101,296	4,270		105,566
Operations & maintenance expenses	62,689	7,335	121	70,145
Depreciation	38,728	2,225		40,953
Regulatory amortizations	(8,358)	166		(8,192)
Taxes other than income taxes	33,241	601	301	34,143
Total operating expenses	227,596	14,598	422	242,616
Operating income before income taxes	62,507	(11,063)	17,679	69,123
New York State income taxes	2,998	(998)	1,282	3,281
Federal income taxes	7,340	(2,518)	3,443	8,265
Utility operating income	$ 52,170	$ (7,548)	$ 12,954	$ 57,576
Rate Base	$ 719,600	$ 71,266		$ 790,866
Rate of Return	7.25%			7.28%

Orange and Rockland Utilites, Inc.
Case 24-G-0061
Gas Revenue Requirement
For The Twelve Months Ending December 31, 2026 and December 31, 2027
$ 000's

	Rate Year 2 With Rate Change	Rate Year 3 Revenue/Expense Rate Base Changes	Rate Change	Rate Year 3 With Rate Change
Operating revenues				
Sales revenues	$ 309,253	$ 3,583	$ 16,498	$ 329,334
Other operating revenues	2,486	13	58	2,556
Total operating revenues	311,739	3,596	16,556	331,890
Operating expenses				
Purchased gas costs	105,566	3,671		109,237
Operations & maintenance expenses	70,145	3,702	111	73,958
Depreciation	40,953	4,891		45,844
Regulatory Amortizations	(8,192)	167		(8,025)
Taxes other than income taxes	34,143	569	276	34,987
Total operating expenses	242,616	13,000	387	256,002
Operating income before income taxes	69,123	(9,404)	16,169	75,889
New York State income taxes	3,281	(928)	1,051	3,405
Federal income taxes	8,265	(2,013)	3,175	9,428
Utility operating income	$ 57,576	$ (6,463)	$ 11,943	$ 63,056
Rate Base	$ 790,866	$ 71,745		$ 862,611
Rate of Return	7.28%			7.31%

ORANGE AND ROCKLAND UTILITIES, INC.
Case 24-G-0061
Gas Other Operating Revenues
For The Twelve Months Ending December 31, 2025, December 31, 2026, and December 31, 2027
$ 000's

	Rate Year 1	Rate Year 2 Changes	Rate Year 2	Rate Year 3 Changes	Rate Year 3
Miscellaneous Service & Other Revenues					
Customer Reconnect Fees	$ 4	$ -	$4	$ -	$4
Late Payment Charge Revenues	1,009	75	1,085	71	1,155
POR Discount	747	-	747	-	747
Shared Meter Assessment	71	-	71	-	71
Access Fines	16	-	16	-	16
R&D Ventures	7	-	7	-	7
Total Miscellaneous Service & Other Revenues	1,854	75	$1,929	71	1,999
Joint Operating Rents	557	-	557	-	557
Total Other Operating Revenues	$ 2,410	$ 75	$ 2,486	$ 71	$ 2,556

ORANGE AND ROCKLAND UTILITIES, INC.
Case 24-G-0061
Gas Operations & Maintenance Expenses
For The Twelve Months Ending December 31, 2025, December 31, 2026, and December 31, 2027
$ 000's

	Rate Year 1	Rate Year 2 Changes	Rate Year 2	Rate Year 3 Changes	Rate Year 3
Fuel & Purchased Gas Costs	$101,296	$ 4,270	$ 105,566	$ 3,671	$ 109,237
A&G Health Insurance and Capital Overhead	(658)	(11)	(669)	(10)	(679)
Bond Administration & Bank Fees	63	2	65	1	66
Company Labor - Corporate & Shared Services	4,795	167	4,962	92	5,054
Company Labor - Customer Operations	5,467	122	5,589	105	5,694
Company Labor - Gas Ops	20,084	986	21,070	574	21,644
Company Labor - Engineering	2,301	97	2,398	230	2,628
Customer Billing Postage	615	14	629	14	643
Employee Welfare Expense	3,877	85	3,962	88	4,050
Facilities	986	21	1,007	23	1,030
Information Technology	5,598	654	6,252	1,213	7,465
Informational Advertising	196	5	201	4	205
Injuries & Damages/ Workers Compensation	47	2	49	1	50
Institutional Dues & Subscription	1	-	1	-	1
Insurance Premium	453	19	472	9	481
Intercompany Shared Services	7,428	127	7,555	122	7,677
Legal and Other Professional Services	191	4	195	5	200
Ops - Corporate & Shared Services	1,361	30	1,391	31	1,422
Ops - Customer Operations	2,778	(150)	2,628	(86)	2,542
Ops - Gas Operations	8,141	312	8,453	186	8,639
Ops - Engineering	949	72	1,021	(182)	839
Ops - Substation Operations	4	-	4	-	4
Other Compensation	323	9	332	-	332
Pensions and OPEBs	(7,510)	3,263	(4,247)	1,447	(2,800)
Site Investigation & Remediation	233	1,289	1,522	(325)	1,197
Regulatory Commission Expenses - General & R&D	1,360	30	1,390	31	1,421
Rent	206	7	213	(5)	208
Uncollectible Reserve - Customer	1,928	144	2,072	135	2,207
Uncollectible Reserve - Sundry	230	-	230	-	230
Worker's Comp NYS Assessment	34	1	35	-	35
Bargaining Unit Contract Costs	44	(0)	44	(0)	44
Environmental Affairs	136	3	139	3	142
External Audit Services	307	7	314	6	321
Finance & Accounting Operations	4	0	4	(1)	4
All Other	459	10	469	11	480
Company Labor - Fringe Benefit Adjustment	256	137	393	91	484
Total O&M Expenses	$ 163,985	$ 11,728	$ 175,712	$ 7,484	$ 183,196

ORANGE AND ROCKLAND UTILITIES, INC.
Case 24-G-0061
Gas Taxes Other Than Income Taxes
For The Twelve Months Ending December 31, 2025, December 31, 2026, and December 31, 2027
$ 000's

	Rate Year 1	Rate Year 2 Changes	Rate Year 2	Rate Year 3 Changes	Rate Year 3
Property Taxes:					
State, County & Town	$ 8,133	$ 120	$ 8,253	$ 122	$ 8,375
Village	1,468	22	1,490	22	1,512
School	16,147	239	16,386	243	16,629
Total Property Taxes	25,748	381	26,129	387	26,516
Payroll Taxes	2,662	142	2,804	104	2,908
Revenue Taxes	4,797	379	5,176	354	5,529
Other Taxes					
Sale & Use Tax	-	-	-	-	-
Other Taxes	34	-	34	-	34
Total Other Taxes	34	-	34	-	34
Total Taxes Other Than Income Taxes	$ 33,241	$ 902	$ 34,143	$ 844	$ 34,987

ORANGE AND ROCKLAND UTILITIES, INC.
Case 24-G-0061
Gas New York State Income Taxes
For The Twelve Months Ending December 31, 2025, December 31, 2026, and December 31, 2027
$ 000's

	Rate Year 1	Rate Year 2 Changes	Rate Year 2	Rate Year 3 Changes	Rate Year 3
Operating Income Before Income Taxes	$ 62,507	$ 6,615	$ 69,123	$ 6,766	$ 75,889
Interest Expense	(18,986)	(2,469)	(21,455)	(2,191)	(23,646)
Book Income Before Income Taxes	43,521	4,146	47,668	4,575	52,243
Tax Computation					
Current State Income Taxes	1,546	148	1,693	3	1,696
Deferred State Income Taxes	1,452	136	1,588	120	1,709
NYS Income Tax Expense	$ 2,998	$ 284	$ 3,282	$ 123	$ 3,405

ORANGE AND ROCKLAND UTILITIES, INC.
Case 24-G-0061
Gas Federal Income Taxes
For The Twelve Months Ending December 31, 2025, December 31, 2026, and December 31, 2027
$ 000's

	Rate Year 1	Rate Year 2 Changes	Rate Year 2	Rate Year 3 Changes	Rate Year 3
Operating Income Before Income Taxes	$ 62,507	$ 6,615	$ 69,123	$ 6,766	$ 75,889
Interest Expense	(18,986)	(2,469)	(21,455)	(2,191)	(23,646)
Book Income Before Income Taxes	43,521	4,146	47,668	4,575	52,243
Tax Computation					
Current Federal Income Taxes	5,792	270	6,062	562	6,625
Deferred Federal Income Taxes	3,457	655	4,112	600	4,712
Excess Deferred Federal Income Tax - Property	(1,466)	(0)	(1,466)	0	(1,466)
Excess Deferred Federal Income Tax - Non-Property	(195)	-	(195)	-	(195)
R&D Tax Credit	(248)	-	(248)	-	(248)
Federal Income Tax Expense	$ 7,340	$ 925	$ 8,265	$ 1,162	$ 9,428

Orange and Rockland Utilities, Inc.
Case 24-G-0061
Average Gas Rate Base
For Twelve Months Ending December 31, 2025 and December 31, 2026
($000's)

	Rate Year 1	Rate Year 2 Changes	Rate Year 2
Utility Plant			
Gas Plant In Service	$ 1,187,620	$ 85,540	$ 1,273,160
Gas Plant Held For Future Use	-	-	-
Common Utility Plant (Gas Allocation)	110,156	10,583	120,739
Total	1,297,776	96,123	1,393,899
Utility Plant Reserves:			
Accumulated Reserve for Depreciation - Plant in Service	(378,251)	(31,950)	(410,201)
Accumulated Reserve for Depreciation - Common Plant (Gas Allocation)	(42,212)	(7,290)	(49,503)
Total	(420,463)	(39,241)	(459,704)
Net Plant	877,312	56,882	934,195
Non-Interest Bearing CWIP	21,697	8,277	29,974
Working Capital - Materials/Supplies, Prepayment and Cash Working Capital	28,150	873	29,023
Unamortized Premium & Discount	3,000	259	3,259
Customer Advance Construction	(3,562)	-	(3,562)
Net Deferrals / Credits from Reconciliation Mechanisms	24,156	8,484	32,640
Accumulated Deferred Income Taxes			
Accumulated Deferred Federal Income Taxes	(168,979)	(2,024)	(171,003)
Accumulated Deferred State Income Taxes	(34,573)	(1,484)	(36,057)
Total	(203,552)	(3,508)	(207,060)
Average Rate Base	747,202	71,266	818,469
Earnings Base Capitalization Adjustment to Rate Base	(27,603)	-	(27,603)
Total Average Rate Base	$ 719,600	$ 71,266	$ 790,866

Orange and Rockland Utilities, Inc.
Case 24-G-0061
Average Gas Rate Base
For Twelve Months Ending December 31, 2026 and December 31, 2027
($000's)

	Rate Year 2	Rate Year 3 Changes	Rate Year 3
Utility Plant			
Gas Plant In Service	$ 1,273,160	$ 88,044	1,361,204
Gas Plant Held For Future Use	-	-	-
Common Utility Plant (Gas Allocation)	120,739	29,329	150,067
Total	1,393,899	117,372	1,511,271
Utility Plant Reserves:			
Accumulated Reserve for Depreciation - Plant in Service	(410,201)	(32,775)	(442,976)
Accumulated Reserve for Depreciation - Common Plant (Gas Allocation)	(49,503)	(9,251)	(58,754)
Total	(459,704)	(42,026)	(501,730)
Net Plant	934,195	75,347	1,009,541
Non-Interest Bearing CWIP	29,974	(7,999)	21,976
Working Capital - Materials/Supplies, Prepayment and Cash Working Capital	29,023	653	29,676
Unamortized Premium & Discount	3,259	206	3,465
Customer Advance Construction	(3,562)	(0)	(3,562)
Net Deferrals / Credits from Reconciliation Mechanisms	32,640	7,809	40,449
Accumulated Deferred Income Taxes			
Accumulated Deferred Federal Income Taxes	(171,003)	(2,656)	(173,658)
Accumulated Deferred State Income Taxes	(36,057)	(1,615)	(37,673)
Total	(207,060)	(4,271)	(211,331)
Average Rate Base	818,469	71,745	890,213
Earnings Base Capitalization Adjustment to Rate Base	(27,603)	-	(27,603)
Total Average Rate Base	$ 790,866	$ 71,745	862,611

Orange and Rockland Utilities, Inc.
Case 24-G-0061
Average Capital Structure & Cost of Money
For the Twelve Months Ending December 31, 2025, December 31, 2026 and December 31, 2027

RY 1

	Capital Structure %	Cost Rate %	Cost of Capital %	Pre Tax Cost %
Long term debt	51.32%	4.95%	2.54%	2.54%
Customer deposits	0.68%	4.20%	0.03%	0.03%
Subtotal	52.00%		2.57%	2.57%
Common Equity	48.00%	9.75%	4.68%	6.39%
Total	100.00%		7.25%	8.96%

RY 2

	Capital Structure %	Cost Rate %	Cost of Capital %	Pre Tax Cost %
Long term debt	51.40%	5.01%	2.57%	2.57%
Customer deposits	0.60%	4.20%	0.03%	0.03%
Subtotal	52.00%		2.60%	2.60%
Common Equity	48.00%	9.75%	4.68%	6.39%
Total	100.00%		7.28%	8.99%

RY 3

	Capital Structure %	Cost Rate %	Cost of Capital %	Pre Tax Cost %
Long term debt	51.45%	5.08%	2.61%	2.61%
Customer deposits	0.55%	4.20%	0.02%	0.02%
Subtotal	52.00%		2.63%	2.63%
Common Equity	48.00%	9.75%	4.68%	6.34%
Total	100.00%		7.31%	8.97%

Orange and Rockland Utilities, Inc.
Case 24-G-0061
Calculation of Phased Rate Increase/(Decrease)
For the Twelve Months Ending December 31, 2025, December 31, 2026 and December 31, 2027
$ 000's

Rate Increase/(Decrease)	Twelve Months Ending December 31, 2025	2026	2027	Cumulative Total
RY - 1	$ 3,568	$ 3,568	$ 3,568	$ 10,703
RY - 2		18,038	18,038	36,076
RY - 3			16,498	16,498
Total	$ 3,568	$ 21,605	$ 38,103	$ 63,276

Phased rate increase/(decrease) without interest	2025	2026	2027	Cumulative Total
RY - 1	$ 10,546	$ 10,546	$ 10,546	$ 31,638
RY - 2		10,546	10,546	21,092
RY - 3			10,546	10,546
Total	$ 10,546	$ 21,092	$ 31,638	$ 63,276
Variation	**$ (6,979)**	**$ 513**	**$ 6,465**	**$ -**
Interest at Pre-Tax ROR	$ (152)	$ (293)	$ (142)	$ (587)

Phased rate increase/(decrease) with interest	2025	2026	2027	Cumulative Total
RY - 1	$ 10,448	$ 10,448	$ 10,448	$ 31,345
RY - 2		10,448	10,448	20,896
RY - 3			10,448	10,448
Total	$ 10,448	$ 20,896	$ 31,344	$ 62,690
Add. Surcharge			(6,759)	
Base Rate Increase	10,448	10,448	10,448	

Orange and Rockland Utilities, Inc.
Case 24-E-0060
Amortization of Electric Regulatory Deferrals (Credits & Debits)
$ 000's

Electric	Amortization Period	Twelve Months Ending December 31, 2025	2026	2027	Total
Regulatory Assets (Debits)					
Storm Deferral	3	$19,102	$19,102	$19,102	$57,306
Energy Efficiency Programs	15	3,132	4,068	5,009	12,209
Legacy meters	9	1,584	1,584	1,584	4,752
Low Income	3	1,547	1,547	1,547	4,641
Rate Case Costs	3	629	629	629	1,887
Interest on Storm Reserve	3	516	516	516	1,548
Rev Demo Projects	10	192	199	199	590
Plant Reconciliation	3	126	126	126	378
NYS Tax Law Change Deferral	3	114	114	114	342
Other Environmental Sites	3	50	50	50	150
Credit Card Fees	3	18	18	18	54
Retention Tax Credit	3	1	1	1	3
Total Regulatory Assets (a)		$ 27,011	$ 27,954	$ 28,895	$ 83,860
Regulatory Liabilities (Credits)					
Pension	3	$10,594	$10,594	$10,594	$31,782
OPEB	3	3,452	3,452	3,452	10,356
MGP Sites	3	1,897	1,897	1,897	5,691
Property Taxes	3	1,463	1,463	1,463	4,389
Tree Trimming Deferral	3	1,174	1,174	1,174	3,522
Pomona DER	3	1,115	1,115	1,115	3,345
Monsey NWA Program	3	963	963	963	2,889
Energy Efficiency Program Carrying Charges	3	376	376	376	1,128
Sales and Use Tax Refund	3	351	351	351	1,053
Sale of Property - Springhill Valley Easement	3	234	234	234	702
Environmental Carrying Charge	3	197	197	197	591
Tropical Storm Isaias Insurance Reimbursement	3	196	196	196	588
Interest on Levelized Revenues	3	182	182	182	546
Non Officer Management Variable Pay	3	140	140	140	420
R&D	3	65	65	65	195
Sale of Property - Sugarloaf Easement	3	58	58	58	174
Late Payment Charges 2020	3	40	40	40	120
Sale of Property - Mountainview Ave Easement	3	20	20	20	60
Carbon Reduction 18' Case Cost Reconciliation	3	10	10	10	30
Property Tax Refunds	3	6	6	6	18
Total Regulatory Liabilities (b)		$ 22,533	$ 22,533	$ 22,533	$ 67,599
Net Debits (a - b)		$ 4,478	$ 5,421	$ 6,362	$ 16,261

Orange and Rockland Utilities, Inc.
Case 24-G-0061
Amortization of Gas Regulatory Deferrals (Credits & Debits)
$ 000's

Gas	Amortization Period	Twelve Months Ending December 31, 2025	2026	2027	Total
Regulatory Assets (Debits)					
Low Income	3	$1,111	$1,111	$1,111	$3,333
Energy Efficiency Programs	15	615	781	948	2,344
Rate Case Costs	3	223	223	223	669
NYS Tax Law Change Deferral	3	140	140	140	420
Gas Safety Incentive 2018 14-G-0494	3	90	90	90	270
Other Environmental Sites	3	25	25	25	75
Credit Card Fees	3	10	10	10	30
Total Regulatory Assets (a)		$ 2,214	$ 2,380	$ 2,547	$ 7,141
Regulatory Liabilities (Credits)					
Pension	3	$5,232	$5,232	$5,232	$15,696
OPEB	3	1,707	1,707	1,707	5,121
Customer Portfolio Shared Earnings	3	1,465	1,465	1,465	4,395
MGP Sites	3	938	938	938	2,814
Property Taxes	3	411	411	411	1,233
Environmental Carrying Charge	3	353	353	353	1,059
Sales and Use Tax Refund	3	173	173	173	519
Plant Reconciliation	3	107	107	107	321
Interest on Levelized Revenues	3	92	92	92	276
Pipeline Emergency Responders Initiative	3	29	29	29	87
Energy Efficiency Program Carrying Charges	3	25	25	25	75
R&D	3	21	21	21	63
Late Payment Charges 2020	3	20	20	20	60
Total Regulatory Liabilities (b)		$ 10,573	$ 10,573	$ 10,573	$ 31,719
Net Credits (a - b)		$ (8,359)	$ (8,193)	$ (8,026)	$ (24,578)

Orange and Rockland Utilities, Inc.
Case 24-E-0060
Forecast of Sales Volume (MWh)
Rate Year 1

	SC 01	SC 19	SC 02 s	SC 20	SC 02 p	SC 03	SC 09	SC 21	SC 22	SC 25	SC 04	SC 05	SC 06	SC 16	PA	Total O&R
Jan-25	147,575	5,611	75,915	7,746	5,065	22,430	48,793	2,628	19,674	226	1,057	179	351	1,303	8,624	347,178
Feb-25	137,765	5,404	75,077	6,964	6,141	22,275	38,230	2,452	19,512	265	893	180	299	1,126	7,726	324,308
Mar-25	119,784	4,846	70,246	6,748	5,161	21,414	35,881	2,295	20,162	3	876	178	291	1,037	7,098	296,019
Apr-25	110,069	4,556	68,141	6,831	3,495	21,005	35,797	2,294	22,844	935	748	179	250	958	7,353	285,455
May-25	103,500	4,438	65,828	7,121	3,093	21,104	38,440	2,314	19,333	828	686	180	238	884	7,282	275,269
Jun-25	139,233	4,479	75,605	7,269	9,008	26,742	47,310	2,956	26,378	172	622	182	208	842	9,184	350,190
Jul-25	182,367	9,175	83,278	7,775	6,029	25,453	36,756	1,867	23,261	255	658	179	218	837	9,565	387,673
Aug-25	200,395	8,270	86,090	8,632	4,768	26,618	50,070	2,235	22,954	36	428	204	276	960	10,756	422,692
Sep-25	170,025	7,583	81,208	9,142	6,408	24,627	41,100	3,530	21,356	39	787	180	272	963	9,940	377,160
Oct-25	129,062	5,511	68,664	8,234	6,090	19,621	36,317	1,970	18,385	101	934	184	320	1,098	8,163	304,654
Nov-25	107,845	4,652	63,375	7,244	5,187	18,347	34,459	2,053	17,793	1,325	975	181	337	1,146	6,871	271,790
Dec-25	132,621	5,809	71,093	7,808	5,372	24,680	42,623	2,531	21,588	4	1,033	179	357	1,234	7,973	324,904
Total Billed	1,680,241	70,334	884,520	91,513	65,817	274,316	485,776	29,125	253,239	4,189	9,697	2,185	3,417	12,388	100,535	3,967,292
Net Unbilled	(712)	(177)	(580)	(180)	(317)	(82)	(652)	-	(110)							(2,810)
RY 1 Total	1,679,529	70,157	883,940	91,333	65,500	274,234	485,124	29,125	253,129	4,189	9,697	2,185	3,417	12,388	100,535	3,964,482

Orange and Rockland Utilities, Inc.
Case 24-E-0060
Forecast of Sales Volume (MWh)
Rate Year 2

	SC 01	SC 19	SC 02 s	SC 20	SC 02 p	SC 03	SC 09	SC 21	SC 22	SC 25	SC 04	SC 05	SC 06	SC 16	PA	Total O&R
Jan-26	149,137	5,671	75,448	7,698	5,040	21,108	47,705	2,472	18,516	226	1,045	177	347	1,288	8,511	344,389
Feb-26	139,147	5,459	74,736	6,933	6,110	20,968	37,374	2,308	18,369	265	883	178	295	1,113	7,625	321,762
Mar-26	126,711	5,127	73,315	7,043	5,387	21,923	37,926	2,350	20,642	3	866	176	288	1,025	7,506	310,288
Apr-26	114,069	4,720	69,274	6,944	3,539	18,903	33,730	2,064	20,557	926	739	177	247	948	7,048	283,885
May-26	103,287	4,429	64,546	6,982	3,012	22,218	41,922	2,436	20,353	811	679	178	235	874	7,969	279,931
Jun-26	138,315	4,450	73,959	7,111	8,849	22,888	41,903	2,530	22,576	171	614	180	205	833	8,279	332,863
Jul-26	185,082	9,311	83,309	7,776	6,037	26,482	39,374	1,943	24,200	255	651	177	216	827	10,117	395,758
Aug-26	204,877	8,454	86,803	8,703	4,823	24,999	48,150	2,099	21,555	36	423	201	273	950	10,322	422,669
Sep-26	173,234	7,726	81,507	9,176	6,424	23,155	39,649	3,320	20,079	38	778	178	269	953	9,528	376,013
Oct-26	128,291	5,478	67,017	8,036	5,949	19,169	36,597	1,924	17,962	99	924	182	316	1,087	8,079	301,110
Nov-26	109,832	4,737	62,900	7,189	5,152	19,491	37,578	2,181	18,903	1,303	964	179	333	1,134	7,269	279,145
Dec-26	136,190	5,965	71,234	7,823	5,384	22,766	40,342	2,334	19,913	3	1,021	177	353	1,221	7,396	322,122
Total Billed	1,708,172	71,527	884,048	91,414	65,706	264,070	482,250	27,961	243,624	4,136	9,587	2,160	3,377	12,253	99,649	3,969,934
Net Unbilled	5,415	1,342	1,762	546	962	310	2,478	-	418							13,233
RY 2 Total	1,713,587	72,869	885,810	91,960	66,668	264,380	484,728	27,961	244,042	4,136	9,587	2,160	3,377	12,253	99,649	3,983,167

Orange and Rockland Utilities, Inc.
Case 24-E-0060
Forecast of Sales Volume (MWh)
Rate Year 3

	SC 01	SC 19	SC 02 s	SC 20	SC 02 p	SC 03	SC 09	SC 21	SC 22	SC 25	SC 04	SC 05	SC 06	SC 16	PA	Total O&R
Jan-27	148,526	5,648	73,308	7,480	4,897	20,156	46,762	2,361	17,682	226	1,040	177	346	1,280	8,259	338,148
Feb-27	139,450	5,470	73,221	6,793	5,983	20,727	37,908	2,281	18,158	265	879	177	294	1,107	7,623	320,336
Mar-27	130,351	5,273	73,840	7,093	5,425	21,679	38,460	2,323	20,413	3	862	176	287	1,020	7,504	314,710
Apr-27	117,156	4,849	70,104	7,027	3,577	21,100	38,456	2,304	22,946	924	736	176	246	943	7,767	298,310
May-27	104,745	4,490	64,508	6,978	3,003	18,941	36,793	2,077	17,352	806	676	177	234	870	6,963	268,613
Jun-27	138,102	4,442	72,971	7,015	8,750	23,645	44,132	2,613	23,322	171	612	179	204	829	8,544	335,531
Jul-27	189,073	9,512	83,765	7,819	6,074	26,248	40,002	1,926	23,989	255	647	177	215	823	10,141	400,666
Aug-27	206,482	8,521	86,129	8,636	4,795	24,785	48,656	2,081	21,372	36	421	200	272	946	10,347	423,679
Sep-27	185,077	8,254	85,723	9,651	6,755	23,882	41,735	3,424	20,711	38	775	178	268	948	9,881	397,300
Oct-27	133,762	5,711	68,619	8,228	6,092	20,498	40,054	2,059	19,207	98	920	181	315	1,082	8,603	315,429
Nov-27	113,712	4,905	63,529	7,261	5,204	17,928	35,578	2,006	17,386	1,288	960	178	332	1,129	6,774	278,170
Dec-27	139,466	6,109	71,251	7,825	5,382	22,624	41,029	2,320	19,788	3	1,017	176	352	1,215	7,369	325,925
Total Billed	1,745,902	73,184	886,968	91,806	65,937	262,213	489,565	27,775	242,326	4,113	9,545	2,152	3,365	12,192	99,775	4,016,818
Net Unbilled	5,295	1,310	1,618	502	883	184	1,467	-	247							11,506
RY 3 Total	1,751,197	74,494	888,586	92,308	66,820	262,397	491,032	27,775	242,573	4,113	9,545	2,152	3,365	12,192	99,775	4,028,324

Orange and Rockland Utilities, Inc.
Case 24-E-0060
Sales Revenues*
$ 000's

	RY 1	RY 2	RY 3
Delivery**	$ 376,840	$ 397,078	$ 439,959
Competitive Services	8,744	8,954	9,379
Reactive Power	373	373	373
Subtotal	$ 385,957	$ 406,405	$ 449,711
MSC	163,482	167,234	159,106
SBC	29,519	20,312	14,982
Other ***	738	767	(19,346)
Tax Recovery Revenue	10,291	10,658	10,941
Total Sales Revenues	$ 589,987	$ 605,376	$ 615,393
Sales for Resale ****	$ 23,789	$ 24,876	$ 26,755
Grand Total Revenues	$ 613,776	$ 630,252	$ 642,148

** Includes Low Income Discount
*** Includes MFC accrual, uncollectibles and other purchased power
**** Includes PSA Fixed Charges, Intercompany Fuel & PSA Bill and Temporary Energy Cost Adjustment (RY3)

Orange and Rockland Utilities, Inc.
Gas Case 24-G-0061
Sales Revenues*
$ 000's

	Twelve Months Ending December 31,		
Firm and Interruptible Revenues	2025	2026	2027
Delivery Revenues			
- Non Competitive	192,315	201,516	211,506
- Competitive	3,850	3,969	4,123
Low Income	(7,249)	(7,249)	(7,249)
Monthly Gas Adjustments	19,370	19,622	19,625
Gas Supply Charge	81,475	85,493	89,148
Revenue Taxes	4,813	5,193	5,422
Subtotal	294,574	308,544	322,575
Other Revenues			
System Benefit Charge	-	-	-
Revenue Taxes	-	-	-
Subtotal	-	-	-
Grand Total	$ 294,574	$ 308,544	$ 322,575
Volumes (MCF)			
Total Firm Billed/Unbilled	21,017,399	20,921,806	20,623,228
Total Interruptible	3,203,600	3,203,600	3,203,600
Total Volume - Billed/Unbilled/Interruptible	24,220,999	24,125,406	23,826,828

*At levelized rates

Orange and Rockland Utilities, Inc.
Case 24-E-0060
True-Up Targets
$ 000's

Expense Items	Twelve Months Ending December 31, 2025	2026	2027
Property Taxes - State, County & Town	14,111	14,685	14,903
Property Taxes - Village	2,065	2,096	2,126
Property Taxes - School	28,149	28,974	29,802
Total Property Taxes	44,325	45,755	46,832
Pension Costs - Qualified Plan	(8,418)	(2,841)	752
- Non Qualified Plan	587	861	1,108
OPEB Costs	(7,364)	(6,612)	(7,525)
Total	(15,195)	(8,592)	(5,665)
Non-Officer Management Variable Pay	2,148	2,187	2,220
Site Investigation & Remediation (True-up target)	472	3,081	2,423
Uncollectible Expenses	3,865	4,016	4,260
Customer Analytics Reporting & Engagement Program	567	438	381
Major Storm Cost Reserve	12,610	12,887	13,171
Contractor Tree Trimming (shortfall true-up only) (a)	10,897	11,137	11,382
Research and Development	721	737	753
Revenue Item			
Low Income Program (b)	14,462	14,462	14,462
Late Payment Charges	3,860	4,011	4,254
Transmission Service Agreement	14,869	15,601	17,773
Rate Base True-Ups			
Site Investigation & Remediation	(3,385)	(2,032)	(684)
Energy Efficiency	28,167	35,782	43,116
Rev Demo Project Costs	1,144	1,220	1,109

(a) Annual over / under expenditures may be netted, true up is cumulative.

(b) This item is handled through rate design (versus base rates)

Orange and Rockland Utilities, Inc.
Case 24-G-0061
True-Up Targets
($000's)

	Twelve Months Ending December 31,		
Expense Items	2025	2026	2027
Property Taxes - State, County & Town	8,133	8,253	8,375
Property Taxes - Village	1,468	1,490	1,512
Property Taxes - School	16,147	16,386	16,629
Total Property Taxes	25,748	26,129	26,516
Pension Costs - Qualified Plan	(4,161)	(1,405)	372
- Non Qualified Plan	290	426	548
OPEB Costs	(3,640)	(3,268)	(3,719)
Total	(7,510)	(4,247)	(2,800)
Non-Officer Management Variable Pay	1,061	1,079	1,096
Site Investigation & Remediation (True-up target)	233	1,522	1,197
Uncollectible Expenses	1,928	2,072	2,207
Customer Analytics Reporting & Engagement Program	280	216	188
Revenue Item			
Low Income Program (a)	7,249	7,249	7,249
Late Payment Charges	1,009	1,085	1,155
Rate Base True-Ups			
Site Investigation & Remediation	(1,672)	(1,003)	(337)
Energy Efficiency	5,029	6,937	8,197
Acc Deferred Income Taxes - Gas Repairs	(29,008)	(29,463)	(30,176)

(a) This item is handled through rate design (versus base rates)

Orange and Rockland Utilities, Inc.
Case 24-E-0060
Electric Net Plant In Service Target Balances - Included in Rate Base
Effective Janaury 1, 2025 - December 31, 2027
$ 000's

MONTH ENDED	Rate Year 1 Elec. Plant In Service Target	Rate Year 1 Reserve For Depreciation Target*	Rate Year 1 Net Plant Target
December 31, 2024 @ 50%	$ 1,060,771	$ (362,724)	$ 698,047
January	2,125,410	(730,620)	1,394,790
February	2,129,537	(735,742)	1,393,795
March	2,133,167	(740,852)	1,392,314
April	2,137,472	(745,876)	1,391,595
May	2,142,908	(750,951)	1,391,957
June	2,150,722	(756,022)	1,394,701
July	2,159,000	(761,035)	1,397,965
August	2,164,007	(766,163)	1,397,843
September	2,170,123	(771,241)	1,398,882
October	2,175,765	(776,303)	1,399,462
November	2,180,744	(781,478)	1,399,267
December 31, 2025 @ 50%	1,114,331	(393,295)	721,037
Total	$ 25,843,957	$ (9,072,302)	$ 16,771,655
13 Point Average	$ 2,153,663	$ (756,024)	$ 1,397,638

MONTH ENDED	Rate Year 2 Elec. Plant In Service Target	Rate Year 2 Reserve For Depreciation Target*	Rate Year 2 Net Plant Target
December 31, 2025 @ 50%	$ 1,114,331	$ (393,295)	$ 721,037
January	2,233,628	(791,713)	1,441,916
February	2,238,379	(796,905)	1,441,474
March	2,242,628	(802,066)	1,440,562
April	2,247,241	(807,184)	1,440,057
May	2,252,394	(812,175)	1,440,220
June	2,289,303	(817,281)	1,472,022
July	2,296,151	(822,506)	1,473,645
August	2,303,351	(827,592)	1,475,758
September	2,311,143	(832,817)	1,478,326
October	2,319,015	(837,905)	1,481,110
November	2,325,767	(843,202)	1,482,564
December 31, 2026 @ 50%	1,284,721	(424,263)	860,458
Total	$ 27,458,052	$ (9,808,904)	$ 17,649,148
13 Point Average	$ 2,288,171	$ (817,409)	$ 1,470,762

MONTH ENDED	Rate Year 3 Elec. Plant In Service Target	Rate Year 3 Reserve For Depreciation Target*	Rate Year 3 Net Plant Target
December 31, 2026 @ 50%	$ 1,284,721	$ (424,263)	$ 860,458
January	2,574,507	(855,222)	1,719,285
February	2,579,829	(861,955)	1,717,875
March	2,584,750	(868,666)	1,716,084
April	2,590,038	(875,382)	1,714,656
May	2,595,062	(882,089)	1,712,973
June	2,631,716	(888,743)	1,742,973
July	2,637,690	(895,473)	1,742,218
August	2,643,879	(902,008)	1,741,871
September	2,650,924	(908,702)	1,742,222
October	2,656,885	(915,438)	1,741,447
November	2,663,390	(922,033)	1,741,356
December 31, 2027 @ 50%	1,420,899	(464,409)	956,490
Total	$ 31,514,289	$ (10,664,381)	$ 20,849,907
13 Point Average	$ 2,626,191	$ (888,699)	$ 1,737,492

* includes Vehicle Depreciation

Orange and Rockland Utilities, Inc.
Case 24-E-0060
Capital True-up Rate - Electric Net Plant Reconciliation
For Twelve Months Ending December 31, 2025, and December 31, 2026, and December 31,2027

Rate Year 1	
Electric Carrying Charge - Net Plant	
- Before Tax ROR*	8.96%
- Composite Depreciation Rate	3.82%
	12.78%
Rate Year 2	
Electric Carrying Charge - Net Plant	
- Before Tax ROR*	8.99%
- Composite Depreciation Rate	3.72%
	12.71%
Rate Year 3	
Electric Carrying Charge - Net Plant	
- Before Tax ROR*	8.97%
- Composite Depreciation Rate	3.82%
	12.79%

* See Appendix 1 page 11 Capital Structure

Orange and Rockland Utilities, Inc.
Case 24-G-0061
Gas Net Plant In Service Target Balances - Included in Rate Base
Effective January 1, 2025 - December 31, 2027
$ 000's

	Rate Year 1		
MONTH ENDED	Gas Plant In Service Target	Reserve For Depreciation Target*	Net Plant Target
December 31, 2024 @ 50%	$ 627,138	$ (200,812)	$ 426,326
January	1,260,825	(404,736)	856,089
February	1,267,327	(407,802)	859,525
March	1,274,233	(410,942)	863,291
April	1,281,357	(414,038)	867,319
May	1,288,729	(417,206)	871,523
June	1,296,223	(420,329)	875,895
July	1,305,084	(423,530)	881,554
August	1,312,859	(426,708)	886,151
September	1,320,550	(429,964)	890,586
October	1,328,746	(433,158)	895,589
November	1,336,491	(436,453)	900,038
December 31, 2025 @ 50%	673,749	(219,884)	453,865
Total	$ 15,573,310	$ (5,045,561)	$ 10,527,749
13 Point Average	$ 1,297,776	$ (420,463)	$ 877,312

	Rate Year 2		
MONTH ENDED	Gas Plant In Service Target	Reserve For Depreciation Target*	Net Plant Target
December 31, 2025 @ 50%	$ 673,749	$ (219,884)	$ 453,865
January	1,354,467	(443,075)	911,392
February	1,361,380	(446,327)	915,053
March	1,368,732	(449,650)	919,081
April	1,376,280	(452,923)	923,357
May	1,384,084	(456,273)	927,812
June	1,391,990	(459,581)	932,409
July	1,400,320	(462,967)	937,353
August	1,408,539	(466,314)	942,225
September	1,416,702	(469,744)	946,958
October	1,425,457	(473,104)	952,353
November	1,433,525	(476,575)	956,950
December 31, 2026 @ 50%	731,561	(240,033)	491,528
Total	$ 16,726,785	$ (5,516,451)	$ 11,210,334
13 Point Average	$ 1,393,899	$ (459,704)	$ 934,195

	Rate Year 3		
MONTH ENDED	Gas Plant In Service Target	Reserve For Depreciation Target*	Net Plant Target
December 31, 2026 @ 50%	$ 731,561	$ (240,033)	$ 491,528
January	1,470,008	(483,659)	986,349
February	1,476,844	(487,208)	989,636
March	1,484,033	(490,829)	993,204
April	1,491,394	(494,403)	996,991
May	1,498,974	(498,052)	1,000,922
June	1,513,348	(501,657)	1,011,691
July	1,521,203	(505,348)	1,015,855
August	1,528,944	(508,975)	1,019,969
September	1,536,752	(512,627)	1,024,125
October	1,544,619	(516,235)	1,028,384
November	1,552,086	(519,921)	1,032,165
December 31, 2027 @ 50%	785,485	(261,812)	523,673
Total	$ 18,135,251	$ (6,020,758)	$ 12,114,492
13 Point Average	$ 1,511,271	$ (501,730)	$ 1,009,541

* includes Vehicle Depreciation

Orange and Rockland Utilities, Inc.
Case 24-G-0061
Capital True-up Rate - Gas Net Plant Reconciliation
For Twelve Months Ending December 31, 2025, December 31, 2026 and December 31, 2027

Rate Year 1

Gas Carrying Charge - Net Plant	
- Before Tax ROR*	8.96%
- Composite Depreciation Rate	3.25%
	12.21%

Rate Year 2

Gas Carrying Charge - Net Plant	
- Before Tax ROR*	8.99%
- Composite Depreciation Rate	3.22%
	12.21%

Rate Year 3

Gas Carrying Charge - Net Plant	
- Before Tax ROR*	8.97%
- Composite Depreciation Rate	3.33%
	12.30%

* See Appendix 2 page 11 Capital Structure

Orange and Rockland Utilities, Inc.
Case 24-E-0060 and 24-G-0061
Calculation of Composite Depreciation Rate for Carrying Charges on Net Plant
($000's)

	Electric		Gas	
Rate Year 1				
Depreciation Expense 1/25-12/25:				
-Depreciation Expense	$	62,567.1	$	32,810.2
-Allocated portion of Common		18,534.7		7,894.7
Total	$	81,101.8	$	40,704.9
Plant Balance @ 12/31/24:				
-Plant Balance	$	1,883,170.2	$	1,147,642.9
-Allocated portion of Common		238,372.7		106,632.7
Total	$	2,121,542.9	$	1,254,275.6
Composite Rate		3.82%		3.25%
Rate Year 2				
Depreciation Expense 1/26-12/26:				
-Depreciation Expense	$	63,596.2	$	35,042.6
-Allocated portion of Common		19,200.3		8,280.8
Total	$	82,796.6	$	43,323.4
Plant Balance @ 12/31/25:				
-Plant Balance	$	1,971,830.9	$	1,232,168.0
-Allocated portion of Common		256,831.4		115,329.2
Total	$	2,228,662.3	$	1,347,497.2
Composite Rate		3.72%		3.22%
Rate Year 3				
Depreciation Expense 1/27-12/27:				
-Depreciation Expense	$	70,110.5	$	36,900.7
-Allocated portion of Common		27,918.2		11,772.1
Total	$	98,028.7	$	48,672.8
Plant Balance @ 12/31/26:				
-Plant Balance	$	2,248,394.9	$	1,320,818.8
-Allocated portion of Common		321,047.0		142,303.4
Total	$	2,569,441.9	$	1,463,122.1
Composite Rate		3.82%		3.33%

Orange and Rockland Utilities, Inc.
Electric Rate Case 24-E-0060
Calculation of Interest on Electric Net Plant
Effective January 1, 2025 - December 31, 2027
($000's)

EXAMPLE 1 - Carrying Charge in December 2027 - end of RY3

As of the end of RY3, the cumulative interest is positive at $374k indicating the actual plant balances are above the target, therefore no interest is accrued to the customer as of the end of the multi-year plan.

	Net Plant						
	Actual (sample)	**PSC Target**	**Variation**	Interest Computed **12.78%**	Interest Computed Cumulative	**Current Month Interest recorded**	**Cumulative Interest Accrued to Customer**
Dec-21	$ 697,000	$ 698,047	$ (1,047)	$ (11)			
Jan-22	1,393,000	$ 1,394,790	(1,790)	(19)	$ (30)	$ (30)	$ (30)
Feb-22	1,393,000	$ 1,393,795	(795)	(8)	(38)	(8)	(38)
Mar-22	1,392,000	$ 1,392,314	(314)	(3)	(41)	(3)	(41)
Apr-22	1,392,000	$ 1,391,595	405	4	(37)	4	(37)
May-22	1,392,000	$ 1,391,957	43	-	(37)	-	(37)
Jun-22	1,397,000	$ 1,394,701	2,299	24	(13)	24	(13)
Jul-22	1,397,000	$ 1,397,965	(965)	(10)	(23)	(10)	(23)
Aug-22	1,397,000	$ 1,397,843	(843)	(9)	(32)	(9)	(32)
Sep-22	1,397,000	$ 1,398,882	(1,882)	(20)	(52)	(20)	(52)
Oct-22	1,397,000	$ 1,399,462	(2,462)	(26)	(78)	(26)	(78)
Nov-22	1,397,000	$ 1,399,267	(2,267)	(24)	(102)	(24)	(102)
Dec-22	720,000	$ 721,037	(1,037)	(11)	(113)	(11)	(113)
Average	$ 1,396,750	$ 1,397,638	$ (888)				

	Net Plant						
	Actual (sample)	**PSC Target**	**Variation**	**12.71%**			
Dec-22	$ 720,000	$ 721,037	$ (1,037)	$ (11)	$ (124)	$ (11)	$ (124)
Jan-23	1,440,000	$ 1,441,916	(1,916)	(20)	(144)	(20)	(144)
Feb-23	1,440,000	$ 1,441,474	(1,474)	(16)	(160)	(16)	(160)
Mar-23	1,440,000	$ 1,440,562	(562)	(6)	(166)	(6)	(166)
Apr-23	1,440,000	$ 1,440,057	(57)	(1)	(167)	(1)	(167)
May-23	1,440,000	$ 1,440,220	(220)	(2)	(169)	(2)	(169)
Jun-23	1,475,000	$ 1,472,022	2,978	32	(137)	32	(137)
Jul-23	1,475,000	$ 1,473,645	1,355	14	(123)	14	(123)
Aug-23	1,475,000	$ 1,475,758	(758)	(8)	(131)	(8)	(131)
Sep-23	1,475,000	$ 1,478,326	(3,326)	(35)	(166)	(35)	(166)
Oct-23	1,479,000	$ 1,481,110	(2,110)	(22)	(188)	(22)	(188)
Nov-23	1,479,000	$ 1,482,564	(3,564)	(38)	(226)	(38)	(226)
Dec-23	856,000	$ 860,458	(4,458)	(47)	(273)	(47)	(273)
Average	$ 1,469,500	$ 1,470,762	$ (1,262)				

	Net Plant						
	Actual (sample)	**PSC Target**	**Variation**	**12.79%**			
Dec-23	$ 856,000	$ 860,458	$ (4,458)	$ (47)	$ (320)	$ (47)	$ (320)
Jan-24	1,721,000	$ 1,719,285	1,715	18	(29)	291	(29)
Feb-24	1,721,000	$ 1,717,875	3,125	33	4	29	-
Mar-24	1,721,000	$ 1,716,084	4,916	52	56	-	-
Apr-24	1,721,000	$ 1,714,656	6,344	68	124	-	-
May-24	1,721,000	$ 1,712,973	8,027	86	210	-	-
Jun-24	1,744,000	$ 1,742,973	1,027	11	221	-	-
Jul-24	1,744,000	$ 1,742,218	1,782	19	240	-	-
Aug-24	1,744,000	$ 1,741,871	2,129	23	263	-	-
Sep-24	1,744,000	$ 1,742,222	1,778	19	282	-	-
Oct-24	1,744,000	$ 1,741,447	2,553	27	309	-	-
Nov-24	1,744,000	$ 1,741,356	2,644	28	337	-	-
Dec-24	960,000	$ 956,490	3,510	37	374	-	-
Average	$ 1,740,417	$ 1,737,492	$ 2,924				

Orange and Rockland Utilities, Inc.
Gas Rate Case 24-G-0061
Calculation of Interest on Gas Net Plant
Effective January 1, 2025 - December 31, 2027
($000's)

EXAMPLE 2 - Carrying Charge in December 2027 - end of RY3

As of the end of RY3, cumulative interest is negative for $77k, indicating the actual plant balances are below the target, therefore the cumulative interest of $77k is accrued to the customer as of the end of the multi-year rate plan.

	Net Plant						
	Actual (sample)	**PSC Target**	**Variation**	Interest Computed **12.21%**	Interest Computed Cumulative	**Current Month Interest recorded**	**Cumulative Interest Accrued to Customer**
Dec-21	$ 427,000	$ 426,326	$ 674	$ 7			
Jan-22	857,000	856,089	911	9	$ 16	-	-
Feb-22	860,000	859,525	475	5	21	-	-
Mar-22	864,000	863,291	709	7	28	-	-
Apr-22	868,000	867,319	681	7	35	-	-
May-22	872,000	871,523	477	5	40	-	-
Jun-22	876,000	875,895	105	1	41	-	-
Jul-22	881,000	881,554	(554)	(6)	35	-	-
Aug-22	881,000	886,151	(5,151)	(52)	(17)	(17)	(17)
Sep-22	891,000	890,586	414	4	(13)	4	(13)
Oct-22	896,000	895,589	411	4	(9)	4	(9)
Nov-22	901,000	900,038	962	10	1	9	-
Dec-22	454,000	453,865	135	1	2		-
Average	$ 877,333	$ 877,312	$ 21				

	Net Plant						
	Actual (sample)	**PSC Target**	**Variation**	**12.21%**			
Dec-22	$ 454,000	$ 453,865	$ 135	$ 1	$ 3		
Jan-23	912,000	911,392	608	6	9	-	-
Feb-23	916,000	915,053	947	10	19	-	-
Mar-23	921,000	919,081	1,919	20	39	-	-
Apr-23	920,000	923,357	(3,357)	(34)	5	-	-
May-23	921,000	927,812	(6,812)	(69)	(64)	(64)	(64)
Jun-23	930,000	932,409	(2,409)	(25)	(89)	(25)	(89)
Jul-23	936,000	937,353	(1,353)	(14)	(103)	(14)	(103)
Aug-23	948,000	942,225	5,775	59	(44)	59	(44)
Sep-23	949,000	946,958	2,042	21	(23)	21	(23)
Oct-23	955,000	952,353	2,647	27	4	23	-
Nov-23	957,000	956,950	50	1	5	-	-
Dec-23	491,000	491,528	(528)	(5)	-	-	-
Average	$ 934,167	$ 934,195	$ (28)				

	Net Plant						
	Actual (sample)	**PSC Target**	**Variation**	**12.30%**			
Dec-23	$ 491,000	$ 491,528	$ (528)	$ (5)	$ (5)	$ (5)	$ (5)
Jan-24	990,000	986,349	3,651	37	32	$ 5	-
Feb-24	990,000	989,636	364	4	36	-	-
Mar-24	995,000	993,204	1,796	18	54	-	-
Apr-24	995,000	996,991	(1,991)	(20)	34	-	-
May-24	1,000,000	1,000,922	(922)	(9)	25	-	-
Jun-24	1,010,000	1,011,691	(1,691)	(17)	8	-	-
Jul-24	1,015,000	1,015,855	(855)	(9)	(1)	(1)	(1)
Aug-24	1,018,000	1,019,969	(1,969)	(20)	(21)	(20)	(21)
Sep-24	1,023,000	1,024,125	(1,125)	(12)	(33)	(12)	(33)
Oct-24	1,025,000	1,028,384	(3,384)	(35)	(68)	(35)	(68)
Nov-24	1,032,000	1,032,165	(165)	(2)	(70)	(2)	(70)
Dec-24	523,000	523,673	(673)	(7)	(77)	(7)	(77)
Average	$ 1,008,917	$ 1,009,541	$ (624)				

ORANGE AND ROCKLAND UTILITIES, INC.
Electric Case 24-E-0060
Electric Capital Expenditures Exhibit
($000)

Project Name	RY1	RY2	RY3
AX090 - Computers			
10002996 - LV1-E-T239AE-O&R-2011 EMS EQUI	$ 1,189.2	$ 588.4	$ 589.5
10003009 - LV1-E-T305AE-O&R-2011 JUMP PRO	882.8	982.8	982.8
AX101 - Distribution			
10002542 - LV1-E-D387BX-O&R-LITTLE TOR SU	125.0	125.0	125.0
10106251 - Transformers - NY OH	2,187.5	2,187.5	2,187.5
10106252 - Transformers - NY UG	1,887.5	1,887.5	1,887.5
10106257 - E Dist Bkt - New Business NY	8,833.4	10,744.8	10,620.4
10106260 - E Dist Bkt - Interference NY	395.2	390.1	408.3
10106263 - E Dist Bkt -Sys Reliability NY	6,506.4	6,705.6	6,600.1
10106283 - U/G Rebuild Blanket (NY)	1,747.8	1,786.2	1,825.5
10106285 - U/G Rehab Blanket (NY)	619.4	619.4	619.4
10106289 - Electric Meter Purchases - NY	600.0	600.0	600.0
10106292 - Electric Meter 1st Install Bkt	800.0	800.0	800.0
10106303 - Paving & Drainage Blanket - NY	99.6	99.6	99.6
10106339 - NY Incremental Reliab Def Pole	900.0	900.0	900.0
20946006 - L1.Tamar Property ROW Acquisit	50.0	50.0	50.0
21335352 - L1.Bullville Substation Upgrad	749.9	4,999.5	11,000.7
21442603 - E Dist Bkt - Replacement NY	4,640.2	4,652.0	4,831.6
22589789-Chester - Pine Hill Black Meadow to Kings Highway Conversion	550.4	-	-
22589824-Middletown - Gas Plant 4kV Circuit Removal	42.7	-	-
22589844 - 2020 Middletown - 17K Scotchtown Collabar To Union School Rd Conv	-	-	600.5
22589879-Circleville - Goshen Turnpike - Shawangunk Road Conversion to 17K Step	625.6	-	-
22590359- Chester - Glenmere Ave - Werner Ave. to 17A	-	600.5	-
22590368 - 2021 Middletown - Kirbytown Rd Mt. Orange To Pocatello	-	-	750.9
22594287 - Pascack Rd UG Ckt 19-13-13	500.1	699.7	-
22594290 - Old Nyack Turnpike UG Ckt 21-16-13	500.0	700.0	-
23187638 - L1_New Goshen UG Circuit Exits	250.0	2,499.6	2,249.8
23189843 - New Goshen Transmission Tap	124.1	312.6	2,046.4
23190661 - West Haverstraw - Rt 202 to Rt 9w - 6400ft	2,500.1	2,700.0	-
23200046 - L1_New Goshen Station (LegoLan	500.1	3,400.1	15,000.2
23259115 - Bullville UG Circuit Exits	-	199.5	2,148.1
23259224 - Bullville Transmission Tap	100.0	299.9	1,099.6
23291893-Piermont - Rt 9w (Ash P# 61355/38112)	800.9	-	-
23291950-Suffern Hilltop Rd 4kv conversion 3900 ft	-	650.6	-
23292062-Blooming Grove - Tuthill Rd - Mainline - Pt 2	-	541.0	-
23292126-Goshen-Clowes / W Maon / Grand/Canal 4kv	-	501.0	-
23292620-Spring Glen - Mountaindale Rd - reconductor	-	550.4	-
23292643-Howells-Pine Grove-Timothy Collard-Maple	-	575.4	-
23841642 - New Woodbury Substation UG Exits	11,000.1	7,500.0	10,000.0
23844838 - Shoemaker 50MVA Banks on 138kV Bus	-	204.5	1,999.9
23844976 - Shoemaker UG Exits	-	204.4	2,500.2
23844985 - Little Tor Sub - Rt 45 (S Mtn to Rt 202) - 3,800 ft - Urd Dip	-	200.7	2,200.0
23861900 - ADMS Phase 2-DERMS	3,500.0	4,000.0	3,500.0
23900364 - L1 Tallman - Cherry Lane - Hendrix 56565/39982 & 56461/40366 - 4100ft	650.1	-	-
23900377 - L1_Goshen - Pulaski Highway (Part 1)	-	700.1	-
23955987 - Goshen - Pulaski Highway (Part 2)	-	-	700.1
24545310 - Burns 3rd Bank Addition	8,500.0	3,500.1	-
24545333 - New Mobile Substation	-	-	4,000.0
24545577 - Tuxedo Park - Urd dip (front gate - 5,100 ft 4/0 triplex)	200.0	1,800.2	-
24545586 - Wurtsboro Sub upgrade 34kv	299.9	-	-
24545599 - Snake Hill - Urd Dip (Snake Hill to Nyack) 13,200 ft	205.0	4,109.0	4,279.4
24545604 - Burns UG Circuits	1,000.0	4,000.0	3,000.0
24545747 - Rio Two 69-13.2kV Banks	-	500.1	3,000.0
24545748 - Rio UG exit upgrades	-	-	250.4
24792125 - L1_U/G Storm Hardening - Gilchrest Rd, Congers	10.3	100.0	1,900.1
24792135 - L1_U/G Storm Hardening - Blue Lake Ckt Exit	2,400.1	1,400.0	-
25364086 - L1_Tuxedo - Nursery Rd - Conversion	-	-	140.1
25364097 - L1_Sparkhill-Ferdon-Rockland Rd. Hendrix New tie 50-2	1,500.7	-	-
25364100 - L1_Spring Valley-S Pascack Rd -3,000 ft Hendrix	800.4	-	-
25373727 - L1_Bloomingburg SH UG 109-4-34 Winterton Rd	199.5	1,843.0	1,040.3
25373812 - L1_Harriman UG SH Ckt exits 71-1,2,& 8-13	204.6	1,034.4	200.2
25386805 - L1_Middletown - Route 211 Goshen Tpke to Camp Orange	-	400.0	-
25386806 - Goshen - Old Chester Rd. Heritage Estates to Goshen Training Center	-	-	1,201.0
25386808 - L1_Monroe - Lakes Rd - Cedar Cliff to Laroe Recon. & Conv.	-	-	600.5
25386812 - Grandview - Rt 9w (old Mountain P# 61313/39092 & 61307/38583- 4900ft-	-	950.3	-
25449452 - L1_Otisville-13.2kV Conversion Main St Highland & Seabolt	-	800.1	-
26178065 - L1_Stony Point - Beach Road & E Main Street - 2300 ft	-	-	367.6
26178066 - L1_Piermont - Ash Street - Storm Hardening -1000ft Hendrix	-	-	350.7
26178068 - L1_Mongaup - Mill Road (Station to Cty Rt 43) 9,000ft - 2-1-13	1,500.7	-	-
26178069 - L1_Central valley - Smith (P 55983/48645 56247/48818)-3200ft Hendrix	-	-	500.2
26178075 - L1_Spring Valley - Buena Vista & Karnel - new ckt tie - 1700ft	-	511.1	-
26178076 - L1_Blooming Grove - Mtn Lodge Rd & Perry Creek 4000Ft – Hendrix	801.0	-	-
26178077 - L1_Monsey - Ralph to Jill La to Rita to Susanne to Howard - 5200 ft	-	-	1,201.0
26178107 - L1_Blooming Grove - Helms Hill Rd & Mtn Lodge Rd - 6500ft Hendrix	1,500.7	-	-
26218933 - L1_New Wisner Sub UG Exits	3,500.1	2,500.0	0.1
26218935 - L1_East Wallkill SH UG Circuit Exit 15-1-13	-	-	799.9
26218939 - L1_Sparkill Circuit Exits	1,499.9	1,500.1	-
26242099 - L1_Mongaup 69-13kV Banks	-	-	1,000.0
26287429-L1_Monsey 240 MVA Banks	4,500.7	4,500.5	-
26287430-L1_NY UG Storm Hardening Program	6,000.0	5,999.9	6,000.0
26341014 - L1_Otisville - 13.2kV Conversion Mountain Rd. Seybolt	-	-	600.5
26341015 - L1_Otisville - 13.2kV Conversion Mountain Rd. Homestead Lane	-	-	675.7
26351218 - L1_Tuxedo Park - UG dip - Front Gate	-	-	100.2
26351219 - L1_Upper Nyack - Broadway (Castle Heights to Larchdale)	-	-	966.8

ORANGE AND ROCKLAND UTILITIES, INC.
Electric Case 24-E-0060
Electric Capital Expenditures Exhibit
($000)

Project Name		RY1		RY2		RY3
27119694 - L1_Westtown UG Circuit Exits		3,000.5		9,000.3		-
27122196 - L1_Monsey Bank/Bus Breakers 3-3000A		250.1		-		-
27122211 - L1_Forest Ave Mobile		500.1		-		-
27141313 - L1_Mongaup - Plank Road		-		350.9		-
27141315 - L1_Port Jervis - King Street (SE)		500.2		-		-
27141318 - L1_Spring Valley - Viola Road (by-pass)		-		-		350.9
27141319 - L1_Pomona - Camp Hill Rd - (SH)		-		-		980.1
xxxxxx05 - Summitville Flood Mitigation		136.5		-		-
xxxxxx06 - Hillburn Flood Mitigation		500.5		-		-
xxxxxx11 - Storm Material Management (Distribution)		-		-		682.0
xxxxxx15 - Pomona Extension (3MW/ 12 MWh) - Total		-		7,200.0		-
xxxxxx17 - 2025-2027 Rate Period (Goshen | 5MW/ 25MWh) - Total		-		150.0		150.0
xxxxxx18 - 2025-2027 Rate Period (Bulville | 5MW/ 25MWh) - Total		-		-		150.0
xxxxxx19 - 2025-2027 Rate Period (Otisville| 6MW/ 24MWh) - Total		-		-		150.0
10106281 - O/H Capital Tools Blanket (NY)		188.8		188.8		188.8
10106287 - U/G Capital Tools Blanket (NY)		72.2		72.2		72.2
10106528 - CMO Miscellane Equip Bkt - NY		100.0		100.0		100.0
24545614 - GRID Mod 4G-5G		506.0		862.0		862.0
xxxxxx09 - ORU Emergency Response Ops & Control		1,250.3		5,461.0		7,836.0
xxxxxx10 - Storm Material Management Facility		750.0		7,779.8		10,500.0
xxxxxx13 - Micronet Weather Stations		163.0		-		-
10075237 - Disttri-Auto/Smart Grid Exp NY		8,354.7		8,538.5		8,726.4
10106318 - Smart Grid Equipment Blanket		74.5		74.6		74.9
23250081-L1_OMS Enhancements		2,000.0		2,000.0		2,000.0
27122194 - L1_Operational Technology Infrastructure		1,809.2		1,181.2		542.5
27172707 - L1_O&R EEDM Forecasting		-		2,000.9		-
10002963 - LV1-E-T114ME-O&R-2011 SUB COMM		7.0		7.2		7.3
10002990 - LV1-E-T174BX-O&R-LINE 31 RECON		2,200.0		-		-
10075397 - LV1-PR.T278BE - Shoreline Pro		-		250.4		1,500.1
10106306 - Transmission Relay Upgd Bkt NY		500.0		500.0		500.0
10106346 - Substation Depart Bkt - NY		204.3		204.3		204.3
20140137 - Lines 11 / 14 Pole 68		6,153.1		-		-
20467629 - Subst Security Equip? Transmission		199.7		199.7		199.7
20758218-NY Incremental Reliability TL Enforcement Blankets		50.0		50.0		50.0
21487901 - L1.RTU Upgrades		400.1		400.1		400.0
22594274 - L1_New line 705 Underground		20,598.5		18,000.0		-
22594275 - L1_Burns Terminal		482.7		2,261.6		-
22594281 - L1_West Nyack 2nd Autobank		5,080.7		7,016.1		-
22983736 - L1_2018 HILBURN BANK 317		-		1,000.0		5,999.9
23841450-L1_New Shoemaker 34.5kV, 69 and 138 Yards		6,000.0		10,000.0		16,999.9
23841454 - Transmission reconfiguration for Shoemaker 69/138kV yards		1,500.0		2,000.7		3,000.9
23841460 - New Woodbury Substation		23,000.1		13,000.0		-
23841631 - Transition Station in Monroe area		488.3		2,161.7		-
23843947 - West Nyack Breaker Replacements		700.3		-		-
23844069-L1_CSX West Shorelines Structure 190, 197, 211		3,300.4		-		-
24132406-L1_Upgrade of Trans. Line 841, 851, 853 to 69kV		13,914.2		9,225.7		4,213.7
24132449-L1_Dean Substation Upgrade Design and Construction		993.5		565.4		301.3
24132457 - L1_Wilson Gate Joi_PrjID:06125		4,969.3		3,259.1		1,504.8
24545751 - Upgrade Transmission Lines 12 & 13/131		999.8		4,000.9		7,999.5
24802248 - L1_Line 96 Double Circuit Rebuild		4,000.1		9,999.8		22,055.9
25351764 - L1_Upgrade Line 18 to 69kV		1,250.1		1,499.3		14,999.6
26218936 - L1_New Wisner Substation		16,300.1		15,300.1		-
26218938 - L1_Sparkill Substation Expansion		399.6		-		-
26219465 - L1_Blooming Grove Decommissioning		301.2		-		-
26219659 - L1_CSX West Shore Line Structures 67 & 68		799.7		800.6		-
26219661 - L1_Lines 531/541 Structures 86 & 87		500.1		-		-
26219663 - L1_Lines 24/25 Structure 24 Replacement		199.7		-		-
26242098 - L1_Transmission to New Wisner Sub		1,400.0		1,599.8		-
26242102 - L1_CLCPA-Upgrade Line 100 Decker Switch to Bullville		-		-		500.0
27050952 - L1_Lines 551/702 and 562 Shield Wire Pole Replacements, NYS ThruwayCr		7,500.6		-		-
27119690 - L1_Corporate Drive 56MVA Banks		-		-		1,000.3
27119691 - L1_Burns Breaker Replacement		-		1,000.5		-
27119692 - L1_34.5kV Breaker Replacement		1,296.7		-		-
27119693 - L1_Westtown Bank Replacement		-		-		4,000.1
27119695 - L1_Westtown 2nd 35MVA Bank and New Circuits		1,999.9		5,500.0		-
27119696 - L1_Bloomingburg Sub Upgrade		-		-		499.9
27119698 - L1_Otisville Property		-		299.7		-
27119699 - L1_Otisville Substation		-		-		1,000.0
27119703 - L1_Line 18 Terminal at Rio		-		-		249.9
27122197 - L1_Otisville Transmission Tap		-		-		100.0
27122198 - L1_Bloomingburg Transmission Tap		-		-		49.8
27122199 - L1_Washington Heights Second 69kV Transmission Terminal		100.0		300.0		1,100.1
27122201 - L1_Substation_Secondary Oil Containment Program-NY		1,125.0		1,124.4		1,124.8
27122210 - L1_Line 96 2nd Circuit Terminal at Monroe		-		499.9		1,000.2
27122213 - L1_OH 69 kV TL from Washington Heights to Bullville		499.9		6,500.1		14,999.9
xxxxxx01 - OH Structure Replacement		1,444.0		2,284.0		3,172.4
xxxxxx03 - Shoreline Erosion Protection		1,000.0		1,030.0		1,060.9
xxxxxx07 - Lovett Flood Mitigation		2,548.0		5,248.9		5,406.3
xxxxxx12 - Storm Material Management (Transmission)		-		-		379.0
27153679 - L1_Viola Property		1,000.8		-		-
Total Electric Capex	**$**	**244,045.8**	**$**	**272,657.4**	**$**	**270,044.6**
Total Removals		7,449.9		6,031.8		6,178.9
Total Electric Capex excluding removals	**$**	**251,495.7**	**$**	**278,689.2**	**$**	**276,223.5**

Note: The Company has the flexibility over the term of the Rate Plan to modify the list, priority, nature and scope of its capital programs and projects.

ORANGE AND ROCKLAND UTILITIES, INC.
Gas Case 24-G-0061
Gas Capital Expenditures Exhibit
($000)

Project Name	RY1	RY2	RY3
AX101 - Distribution			
10003169 - LV1-G-G015EX-O&R-G-G015EX-O&R	$ 550.0	$ 550.0	$ 550.0
10003177 - LV1-G-G022EX-O&R-G-G022EX-O&R	250.0	250.0	250.0
10003179 - LV1-G-G024EX-O&R-G-G024EX-O&R	175.0	175.0	175.0
10003183 - LV1-G-G032EX-O&R-GAS MAINS BLA	27,799.2	28,806.3	29,418.7
10003185 - LV1-G-G033EX-O&R-GAS SERVICES	14,610.4	14,610.4	14,640.7
10003187 - LV1-G-G034EX-O&R-GAS REGULATOR	327.0	327.0	327.9
10003189 - LV1-G-G035EX-O&R-GAS METER BAR	220.6	220.6	221.1
10003200 - LV1-G-G052EX-O&R-GAS MAINS BLA	4,679.2	4,724.9	4,953.9
10003202 - LV1-G-G053EX-O&R-Aldyl Repl Bl	5,728.6	5,728.6	4,975.5
10003204 - LV1-G-G054EX-O&R-GAS REGULATOR	249.6	249.6	249.9
10003206 - LV1-G-G055EX-O&R-GAS METER BAR	2,730.7	2,730.7	2,773.3
10003295 - LV1-G-G686EE-O&R-Valve Replace	100.8	100.8	100.8
10006285 - L1-Mains-Municipal Blanket	5,478.2	6,897.7	5,536.1
10006297 - Services Municipal	500.0	600.0	600.0
10006321 - Meter Bars Municipal	146.7	149.0	149.5
10006333 - Regulator Materials	133.3	135.5	138.1
10006343-LV 2 - G-G017EX-O&R - CATHODIC PROTECTION BLANKET FOR TEST STATION:	290.0	290.0	290.0
10006345-LV 2 - G-G018EX-O&R - CATHODIC PROTECTION BLANKET FOR - PROTECTION	1,005.0	1,005.0	1,005.0
10006347-LV 2 - G-G019EX-O&R - CATHODIC PROTECTION BLANKET FOR SERVICES	119.1	119.1	119.1
10075310 - Upgrade Denton Hill Regulator Station	254.5	-	-
10106238 - Mains - New Busi	1,996.7	2,170.2	2,012.4
10106240 - Services - New Busi	5,599.8	6,006.7	5,679.9
10106244 - Meter Bars - New Busi	505.2	-	519.4
10106327 - Metretek Remote Read Eq Bkt	191.5	191.5	191.5
20472706 - Transmission-Distribution	650.0	650.0	650.0
20498974 - Gate Station Generators	48.9	48.9	48.9
20947981 - Chester Reg Upgrade and/or New (King's Hwy)	164.3	-	-
22206731 - L1_2016-MR-BS ORANGEBURG UPGRA	752.6	73.0	76.6
22825721 - Pipeline Integrity Gate Station Upgrades	1,500.0	1,500.0	1,000.0
24653043 - L1-Vayoel Moshe Gardens- Phase 1	157.9	166.3	190.6
24795145 - L1_Gas OMS	600.0	-	-
24795773 - L1_Elimination of Farm Taps	300.0	249.9	249.9
24801786 - L1_AMI Natural Gas Detector Program	5,636.5	5,724.1	5,812.5
24801788 - L1_Gas Control SCADA Upgrade and Display Upgrade	544.5	461.9	995.0
24802456 - Locus View	49.4	49.4	49.4
25320248 - L1_2022 Vayoel Moshe Gardens Nininger Rd Phase 2 Gas	864.9	880.0	866.3
27180015 - L1_Monsey Reliability Contigency	-	-	199.6
27182126 - L1_KJ Reliability Contingency	2,000.0	3,000.0	2,500.0
xxxxxx23 - Ultrasonic Meter & Supermonitor Program	500.0	500.0	500.0
xxxxxx26 - Main Replacement - Bridges	345.0	345.0	345.0
AX220 - General Equipment			
10003171 - LV1-G-G016EX-O&R-G-G016EX-O&R	359.7	364.4	364.4
10006349 - L1-Industrial Reg & Metering	172.8	175.0	172.7
10106242 - Reg Install - New Busi	298.3	323.1	388.2
AX331 - Office Buildings			
23187177 - L1_Goshen Training Center Impr	-	-	100.0
AX450 - Software			
10075325 - LV1-PR.G185EX - GCC Facility	1,350.0	225.0	-
10075326 - LV1-PR.G186EX - GCC Network U	100.0	100.0	100.0
22113354 - GCC Improvements Project	125.0	125.0	125.0
xxxxxx24 - Data Governance & Innovation	616.0	717.0	717.0
AX511 - Transmission			
10003211 - LV1-G-G107EE-O&R-2011 REMOTE O	250.0	250.0	250.0
Total Gas Capex	**$ 91,026.8**	**$ 91,966.6**	**$ 90,579.0**
Total Removals	299.9	303.8	299.5
Total Gas Capex excluding removals	**$ 91,326.7**	**$ 92,270.4**	**$ 90,878.5**

Note: The Company has the flexibility over the term of the Rate Plan to modify the list, priority, nature and scope of its capital programs and projects.

ORANGE AND ROCKLAND UTILITIES, INC.
Electric Case 24-E-0060 & Gas Case 24-G-0061
Common Capital Expenditures Exhibit
($000)

Project Name	RY1	RY2	RY3
AX020 - AMI-Capitalized Software			
24645886 - L1_AMI ORU/CECONY Synch work	$ 837.3	$ 410.1	$ -
AX030 - AMI-Communications Equipment			
24645908 - L1_CM&TO Blanket for AMI Communications	100.0	100.0	100.0
24645914 - L1_CM&TO Blanket for AMI Extended Batteries	50.0	50.0	50.0
AX090 - Computers			
10106357 - Corporate P/C Purchase Blanket	553.4	423.9	400.0
AX220 - General Equipment			
10001909 - LV1-C-P122ME-O&R-2011 Microwav	206.8	258.6	216.0
10001918 - LV1-C-P138ME-O&R-2011 Radio Bl	493.0	71.2	77.6
10001929 - LV1-C-P140ME-O&R-2011 WAN Blan	173.0	213.8	231.5
10001943 - LV1-C-P174ME-O&R-2011 LAN EQUI	203.2	290.5	190.6
10002031 - LV1-C-P302ME-O&R-2011 Repl't o	552.8	601.9	517.0
10002061 - LV1-C-P425ME-O&R-2011 TELECOMM	230.9	225.6	113.2
10002121 - LV1-C-P506ME-O&R-BATTERY/ POWE	61.2	213.9	70.6
10075344 - LV1-PR.P241ME - SCADA Diversi	50.0	50.0	50.0
10079800 - LV1-C-P242ME-O&R-2012 Video Co	38.4	38.4	40.0
10106354 - Safety Blanket	12.4	12.4	12.4
10106383 - Facilities Small Tools & Eq Bk	25.0	25.0	25.0
10106384 - Company Furniture Blanket	34.9	34.9	34.9
10106385 - Modular Furniture Repl Bkt-NY	75.0	75.0	75.0
10106387 - Security Sys Cam Mont Bkt-NY0	1,250.0	1,250.0	1,250.0
10106390 - Stores Blanket - T&D Store Rooms	50.0	50.0	50.0
10106394 - Misc. Equip Replace-Transp Bkt	300.0	300.0	300.0
10106527 - A-V / Graphics Blanket	37.4	37.4	37.4
20944674 - L1.Call Center Telephone System Blanket	150.0	150.0	150.0
22469689 - L1_IT Infrastructure - Share	834.0	1,977.4	996.2
22469842 - L1_IT Infrastructure -Share	82.4	222.8	154.0
23974002-L1_Mainframe & Infrastructure Upgrades	1,391.0	2,455.0	300.0
24879860 - L1_Grid Modernization Infrastructure - NY.	783.8	800.0	750.0
26351209 - L1_Corporate Security NVR and DVR replacements (ORU)	105.0	105.0	105.0
26736495 - ORU EV Charging Infrastructure	440.6	462.7	529.4
27147611 - L1_Perimeter Protection Program	1,234.0	1,234.0	1,234.0
27173011 - L1_ORU EV Charging Infrastructure NJ	2,067.0	2,465.0	3,185.1
27184231 - L1_Facilities Upgrades (SV and BG)	289.3	2,420.0	1,642.1
AX331 - Office Buildings			
10001963 - LV1-C-P228ME-O&R-2011 CABLE IN	48.0	35.5	30.0
10106381 - Building Improvements Blanket	750.0	750.0	750.0
10106382 - Lighting Replacement Prog Bkt	45.0	46.0	47.0
20934943 - L1.Conference Ctr/Forestry Bla	49.8	49.8	49.8
21485565 - L1.Blooming Grove Auditorium Building Improvements	300.0	450.0	-
22078076 - L1_SVOC Building Roof Program	-	225.0	1,650.0
22078078 - L1_Blooming Grove Paving	-	-	604.2
22078079 - L1_Middletown Paving	-	-	800.0
22078084-L1_HVAC Replacement Program	45.8	45.8	45.8
22642262-L1_BUILDING ROOF PROGRAM	305.0	311.7	318.5
24661514 - L1_SVOC Auditorium	-	-	350.0
27171220 - L1_Clean Energy Buildings	1,500.0	1,500.0	1,500.0
27171221 - L1_Relocate Super Tech to Eastern Division	-	-	25.0
27171222 - L1_SVOC Addition	6,000.0	12,000.1	2,000.0
AX450 - Software			
20947579 - L1.Budget System Software Enha	112.9	112.9	112.9
22525008 - L1_UPGRADE METRIX IDR	10.4	31.5	-
22675349-L1_BUSINESS SYSTEM SUSTAINABILITY	2,065.5	1,565.0	1,565.0
23195681 - L1_O&R_Project Management Soft	140.0	140.0	-
23272852 - L1_L&I Digital Learning Transformation Or	43.4	105.0	105.0
24650684 - Corporate Website Upgrade (DCX) Blanket	840.0	840.0	840.0
24795161 - L1_WMS Replacement Project	14,400.0	13,100.0	12,400.0
24802392 - L1_CC&B Enhancements	566.0	566.0	471.0
24802394 - L1_Oracle Analytical Systems Platform	2,050.0	2,000.0	2,000.0
25379404 - L1_Data Integration Modernization ORU	199.5	133.0	-
26351203 - L1_NYISO revenue metering daily reports (ORU)	-	12.7	-
26351206 - L1_Fraud Data Analytics Platform (ORU)	119.0	119.0	119.0
26351207 - L1_Enterprise Architecture Modernization (ORU)	21.0	-	-
26854496-L1_Data Governance Program ORU	163.3	154.0	-
27034693 - L1_IT System Testing COE ORU	181.0	181.0	181.0
27034695 - L1_End User Computing ORU	430.5	525.0	325.5
27141640 - L1_Customer Data Sharing ORU	175.0	175.0	-
27155561 - L1_Bill Pay Expansion ORU	70.0	70.0	-
27168431 - L1_Nucon Replacement	4,000.0	2,000.0	-
27168507 - L1_O&R Retail Access System Replacement from CECONY	1,573.3	558.3	-
27172708 - L1_O&R AMI Analytics	1,990.0	2,070.6	2,128.0
27309188-L1_Cyber Security Infrastructure Shared Services	225.0	225.0	225.0
27309493 - L1_Geographic Information System (Maping)	16,059.0	21,431.0	-
27311932-L1_Telephone System Migration	3,500.0	-	-
27311933-L1_New Business Training Program	550.0	-	-
27314923 - Customer Analytics Reporting and Engagement Program CARE	3,054.0	3,029.0	2,929.0
xxxxx14 - Mainframe Data Retention and Archival	1,077.0	1,008.0	-
AX530 - Vehicles			
10106391 - Passenger Car Replace Bkt	505.0	990.9	3,306.9
10106392 - Truck Replacement Blanket	12,737.1	21,025.6	9,815.1
10106393 - Transportation Equip Repl Bkt	300.0	300.0	300.0
Total Common Capex	**$ 88,913.3**	**$ 104,906.9**	**$ 57,880.7**
Total Removals	(95.4)	(70.4)	193.4
Total Common Capex excluding removals	**$ 88,817.9**	**$ 104,836.5**	**$ 58,074.1**

Note: The Company has the flexibility over the term of the Rate Plan to modify the list, priority, nature and scope of its capital programs and projects.

ORANGE AND ROCKLAND UTILITIES, INC.

Case 24-G-0061

Illustrative Calculation of Lost and Unaccounted for Gas ("LAUF") and Dead Band Target

		12 ME Aug-24	12 ME Aug-23	12 ME Aug-22	12 ME Aug-21	12 ME Aug-20	12 ME Aug-19
	Citygate Receipts						
1	**Total Pipeline Receipts**	24,219,000	24,268,323	26,457,277	27,534,802	26,308,861	26,534,355
	Deliveries to Customers						
2	Retail Sales and Transportation Deliveries	23,000,000	23,430,023	24,663,175	24,593,553	24,516,851	25,648,853
3	Gas Used for Company Purposes (Including Inactive Gas Metered Usage)	40,000	43,160	56,796	46,676	42,826	54,867
4	Deliveries to Generation	270,000	534,546	1,315,243	2,288,544	1,513,414	316,922
5	**Total Deliveries (Line 2 - Line 4)**	23,310,000	24,007,730	26,035,215	26,928,774	26,073,091	26,020,642
6	**Losses (Line 1 - Line 5)**	909,000	260,593	422,062	606,028	235,770	513,714
7	**Contribution to system line loss from Generation at 1.0% (Line 4 * 0.01)**	2,700	5,345	13,152	22,885	15,134	3,169
8	**Adjusted Line Loss (Line 6 - Line 7)**	906,300	255,248	408,910	583,143	220,636	510,544
9	**Citygate Receipts adjusted for Generation (Line 1 - Line 7)**	23,946,300	23,728,432	25,128,882	25,223,373	24,780,313	26,214,264
10	***Annual Line Loss Factor (Line 8 / Line 9)***	3.785%	1.076%	1.627%	2.312%	0.890%	1.948%

	DETERMINE LAUF% TARGET & DEAD BAND	
	Basis: Target & Dead Band are calculated from 5 years of historical data	
	Dead Band is equal to +/- 2 standard deviations	
	No Incentive to Be Earned for LAUF % Target < 0	
	Revised Line Loss Factor (5 Year Average 12 ME Aug 20 - 12 ME Aug 24)	1.938%
	5-Year Statistics (12 ME Aug 19 - 12 ME Aug 23)	
11	**Mean LAUF% (Average of Line 10)**	1.571%
12	**Std Deviation (Std Deviation of Line 10)**	0.592%
13	**2 Std Deviation (Line 12 * 2)**	1.184%
	Target & Dead Band	
14	**LAUF% Target**	1.571%
15	**Upper Band (Mean + 2 SD)**	2.755%
16	**Lower Band (Mean - 2 SD)**	0.386%

The Fixed FOA will be reset every November 1 based on the average of the actual FOAs for the previous five twelve-month periods ended August 31.

Numbers shown for 12 ME Aug-24 are illustrative.

ORANGE AND ROCKLAND UTILITIES, INC.

Case 24-G-0061
Gas Lost and Unaccounted For

Illustrative Calculation of Line Loss Incentive / Penalty

1	Total Distribution Sendout		23,949,000	Mcf
2	Customer Metered Volumes		23,042,700	Mcf
3	Actual Line Loss -- [(Line 1 - Line 2) / Line 1]		3.784%	
4	Actual Factor of Adjustment -- [1 / (1 - 0.0378)]		1.0393	
5	If Line 4 is ≥ Lower Dead band and ≤ Upper Dead band, equal to line 4 If Line 4 is < Lower Dead band, equal to line 12 If Line 4 is > Upper Dead band, equal to line 11		1.0283	
	Calculation of Benefit / (Shortfall):			
6	Total Cost of Gas 12 months Ended August XX		$52,000,000	
7	(Line 5 Above) -------------------------------- Actual Factor of Adjustment (Line 4 above)	1.0283 ---------- 1.0393	0.989416	
8	Net Adjusted Commodity Cost of Gas (Line 6 x Line 7)		$51,449,632	
9	Company Benefit / (Penalty) due to Line Losses (Line 8 - Line 6)		($550,368)	

'** The Fixed FOA for purposes of calculating incentives / penalties based on 1.571% losses equals:

10 $$\frac{100.0}{(100.0 - 1.571)} = \frac{100.0}{98.429} = 1.0160$$

** The maximum FOA Before Adjustment based on 2.755% losses equals:

11 $$\frac{100.0}{(100.0 - 2.755)} = \frac{100.0}{97.245} = 1.0283$$

** The miniimum FOA Before Adjustment based on 0.386% losses equals:

12 $$\frac{100.0}{(100.0 - 0.386)} = \frac{100.0}{99.614} = 1.0039$$

Note: The Fixed FOA will be reset every November 1 based on the average of the actual FOAs for the previous five twelve-month periods ended August 31.

ORANGE AND ROCKLAND UTILITIES, INC.

Case 24-G-0061
Gas Lost and Unaccounted For

Illustrative Calculation of
System Performance Adjustment ("SPA") Mechanism

1	Total Distribution Sendout		23,949,000	Mcf
2	Customer Metered Volumes		23,042,700	Mcf
3	Actual Line Loss -- [(Line 1 - Line 2) / Line 1]		3.784%	
4	Actual Factor of Adjustment -- [1 / (1 - 0.0378)]		1.0393	
5	If Line 4 is ≥ Lower Dead band and ≤ Upper Dead band, equal to line 4 If Line 4 is < Lower Dead band, equal to line 14 If Line 4 is > Upper Dead band, equal to line 13		1.0283	
	Calculation of Benefit / (Shortfall):			
6	Total Cost of Gas 12 months Ended August XX		$52,000,000	
7	(Line 5 above) --------------------------------- Fixed Factor of Adjustment (Line 13 Below)	1.0283 ---------- 1.0160	1.012106	
8	Net Adjusted Commodity Cost of Gas (Line 6 x Line 7)		$52,629,512	
9	SPA Dollars to (Credit) / Charge Customers through MGA (Line 8 - Line 6)		$629,512	
10	Forecasted Firm Sales (SC Nos. 1, 2, and 6) (Ccf) for 12 ME Dec 20XX		230,000,000	Ccf
11	SPA Mechanism Rate ($/Ccf) in Monthly Gas Adjustment		$0.00274	

'** The Fixed FOA for purposes of calculating incentives / penalties based on 1.571% losses equals:

12 $$\frac{100.0}{(100.0 - 1.571)} = \frac{100.0}{98.429} = 1.0160$$

** The maximum FOA Before Adjustment based on 2.755% losses equals:

13 $$\frac{100.0}{(100.0 - 2.755)} = \frac{100.0}{97.245} = 1.0283$$

** The miniimum FOA Before Adjustment based on 0.386% losses equals:

14 $$\frac{100.0}{(100.0 - 0.386)} = \frac{100.0}{99.614} = 1.0039$$

Note: The Fixed FOA will be reset every November 1 based on the average of the actual FOAs for the previous five twelve-month periods ended August 31.

ORANGE & ROCKLAND UTILITIES
AVERAGE SERVICE LIVES, NET SALVAGE
ANNUAL DEPRECIATION RATES AND LIFE TABLES
(EFFECTIVE 1/1/2025)

PSC ACCT NUMBER	ACCOUNT DESCRIPTION	LIFE TABLE	AVERAGE SERVICE LIFE (Years)	NET SALVAGE %	ANNUAL RATE %	
ELECTRIC PLANT						
INTANGIBLE PLANT						
303880	ECC/ACC	SQ	5	-	20.00	(B)
303080	ELECTRIC SOFTWARE 15Y CLOUD	SQ	15	-	6.67	(B)
303270	ELECTRIC SOFTWARE 10Y CLOUD	SQ	10	-	10.00	(B)
303930	ADMS	SQ	5	-	20.00	(B)
303940	SOFTWARE 5 YEARS	SQ	5	-	20.00	(B)
303945	SOFTWARE 5 YEARS CLOUD	SQ	5	-	20.00	(B)
TRANSMISSION PLANT						
350000	LAND-EASEMENTS	R3	70	-	1.43	
350100	LAND AND LAND RIGHTS	-	-	-	-	
351000	ENERGY STORAGE EQUIPMENT TRANS	S2.5	15	-	6.67	
352000	STRUCTURES AND IMPROVEMENTS	R1.5	65	(10)	1.69	
353000	STATION EQUIPMENT	S0	45	(20)	2.67	
354000	TOWERS AND FIXTURES	R3	70	(30)	1.86	
355000	POLES AND FIXTURES-WOOD	R3	60	(45)	2.42	
355100	POLES AND FIXTURES-STEEL	R3	60	(45)	2.42	
356000	OVERHEAD CONDUCTORS & DEVICES	R2	65	(20)	1.85	
356100	OVERHEAD COND & DEVICES-CLEARING	R2	65	0	1.54	
357000	UNDERGROUND CONDUIT	R3	45	-	2.22	
358000	UNDERGROUND COND AND DEVICES	S3	35	(5)	3.00	
359000	ROADS AND TRAILS	R4	70	-	1.43	
DISTRIBUTION PLANT						
360000	LAND-EASEMENTS	S3	70	-	1.43	
360100	LAND AND LAND RIGHTS-FEE	-	-	-	-	
361000	STRUCTURES AND IMPROVEMENTS	R2.5	60	(20)	2.00	
362000	STATION EQUIPMENT	S0.5	50	(15)	2.30	
363000	ENERGY STORAGE EQUIPMENT DIST	S2.5	15	-	6.67	
364000	POLES,TOWERS, AND FIXTURES	R1	60	(105)	3.42	
365000	OVERHEAD CONDUCTOR AND DEVICES	R1	70	(90)	2.71	
365100	O/H COND AND DEVICES-CAPACITORS	R1	30	(35)	4.50	
366000	UNDERGROUND CONDUIT	R3	75	(45)	1.93	
367000	UNDERGROUND CONDUCTOR & DEVICES	R4	60	(50)	2.50	
367100	U.G. COND. & DEVICES - CABLE CURE	(A)	-	-	-	
368100	LINE TRANSFORMERS-OVERHEAD	R0.5	50	(20)	2.40	
368200	LINE TRANSFORMERS-O/H INSTALLS	R0.5	50	(20)	2.40	
368300	LINE TRANSFORMERS-UNDERGROUND	R0.5	50	(20)	2.40	
368400	LINE TRANSFORMERS-U/G INSTALLS	R0.5	50	(20)	2.40	
369100	SERVICES-OVERHEAD	R3	65	(110)	3.23	
369200	SERVICES-UNDERGROUND	R3	65	(110)	3.23	
370100	METERS - ELECTRO-MECHANICAL	L0	25	-	4.00	
370110	METERS - SOLID-STATE	S2.5	20	-	5.00	
370120	METERS - AMI METERS	S2	20	-	5.00	
370150	METERS - UNRECOVERED EM PURCHASES					(D)
370160	METERS - UNRECOVERED SS PURCHASES					(D)
370200	METER INSTALLATIONS - ELECTRO-MECHANICAL	L0	25	-	4.00	
370210	METER INSTALLATIONS - SOLID-STATE	S2.5	20	-	5.00	
370220	METER INSTALLATIONS - AMI	S2	20	-	5.00	
370250	METERS - UNRECOVERED EM INSTALL					(D)
370260	METERS - UNRECOVERED SS INSTALL					(D)
371000	INSTALLATION ON CUSTOMER PREMISES	R1	45	-	2.22	
371100	PALISADES MALL METERING		-	-	-	(A)
373100	STREET LIGHTS-OVERHEAD	R0.5	40	(45)	3.63	
373200	STREET LIGHTS-UNDERGROUND	R0.5	40	(45)	3.63	

ORANGE & ROCKLAND UTILITIES
AVERAGE SERVICE LIVES, NET SALVAGE
ANNUAL DEPRECIATION RATES AND LIFE TABLES

PSC ACCT NUMBER	ACCOUNT DESCRIPTION	LIFE TABLE	AVERAGE SERVICE LIFE (Years)	NET SALVAGE %	ANNUAL RATE %	
ELECTRIC PLANT						
GENERAL PLANT						
389100	LAND AND RIGHTS - FEE	-	-	-	-	
390000	STRUCTURES AND IMPROVEMENTS	S0	50	(30)	2.60	
391100	OFFICE FURN/EQUIP-FURNITURE	SQ	20	-	5.00	(B)
391200	OFFICE FURN/EQUIP-OFFICE MACHINES	SQ	15	-	6.67	(B)
391700	OFFICE FURN/EQUIP-P/C EQUIPMENT	SQ	8	-	12.50	(B)
391800	OFFICE FURN/EQUIP-E.C.C.	SQ	13	-	7.69	(B)
392100	TRANSP EQUIP-PASSENGER CARS	S2.5	12	10	7.50	
392200	TRANSP EQUIP-LIGHT TRUCKS	S1	10	10	9.00	
392300	TRANSP EQUIP-HEAVY TRUCKS	L3	14	5	6.79	
392400	TRANSP EQUIP-TRAILERS/TRAILER MTD EQ.	L3	14	5	6.79	
393000	STORES EQUIPMENT	SQ	20	-	5.00	(B)
394000	TOOLS, SHOP AND WORK EQUIPMENT	SQ	20	-	5.00	(B)
395000	LABORATORY EQUIPMENT	SQ	20	-	5.00	(B)
396000	POWER OPERATED EQUIPMENT	R3	18	15	4.72	
396100	POWER OPERATED EQ - NON FLEET	R3	18	15	4.72	
397000	COMMUNICATION EQUIPMENT	SQ	15	-	6.67	(B)
397100	COMMUNICATION EQUIPT-TELE SYSTEM COMPUTER	SQ	15	-	6.67	(B)
398000	MISCELLANEOUS EQUIPMENT	SQ	20	-	5.00	(B)
PLANT HELD FOR FUTURE USE - TRANSMISSION						
350009	LAND AND LAND RIGHTS-EASEMENTS		0	-	-	
PLANT HELD FOR FUTURE USE - DISTRIBUTION						
360009	LAND AND LAND RIGHTS-EASEMENTS		0	-	-	
360109	LAND AND LAND RIGHTS-EASEMENTS	-	-	-	-	

ORANGE & ROCKLAND UTILITIES
AVERAGE SERVICE LIVES, NET SALVAGE
ANNUAL DEPRECIATION RATES AND LIFE TABLES

PSC ACCT NUMBER	ACCOUNT DESCRIPTION	LIFE TABLE	AVERAGE SERVICE LIFE (Years)	NET SALVAGE %	ANNUAL RATE %	
COMMON PLANT						
INTANGIBLE PLANT						
301000	ORGANIZING	-	-	-	-	
303270	COMMON SOFTWARE 10 YR - CLOUD	SQ	10	-	10.00	(B)
303080	COMMON SOFTWARE 15 YEARS CLOUD	SQ	15	-	6.67	(B)
303330	PROJECT ONE- GL	SQ	15	-	6.67	(B)
303450	ORACLE STRATEGIC AGREEMENT	SQ	15		6.67	(B)
303510	POWERPLAN SOFTWARE	SQ	15	-	6.67	(B)
303840	FIELD ORDER ROUTE DESIGN SYSTEM	SQ	5	-	20.00	(A)
303940	COMMON SOFTWARE 5 YEARS	SQ	5	-	20.00	(B)
303945	COMMON SOFTWARE 5 YEARS CLOUD	SQ	5	-	20.00	(B)
303941	COMMON SOFTWARE 15 YEARS	SQ	15		6.67	(B)
303991	AMI SOFTWARE	SQ	20	-	5.00	(B)
303998	AMI SOFTWARE CLOUD	SQ	20	-	5.00	(B)
GENERAL PLANT EQUIPMENT						
389000	LAND-EASEMENTS	R3	50	-	2.00	
389100	LAND AND LAND RIGHTS -FEES	-	-	-	-	
390000	STRUCTURES AND IMPROVEMENTS	S0	45	(30)	2.89	
390100	LEASEHOLD IMPROVEMENTS-BLUE HILL		-	-	-	(C)
391100	OFFICE FURN/EQUIP-FURNITURE	SQ	20	-	5.00	(B)
391200	OFFICE FURN/EQUIP-OFFICE MACHINES	SQ	15	-	6.67	(B)
391300	OFFICE FURN/EQUIP-CASH EQUIPMENT	SQ	8	-	12.50	(B)
391700	OFFICE FURN/EQUIP-P/C EQUIPMENT	SQ	8	-	12.50	(B)
391710	OFFICE FURN/EQUIP-NON P/C EQUIPMENT	SQ	8	-	12.50	(B)
392100	TRANSP EQUIP-PASSENGER CARS	S2.5	12	10	7.50	
392200	TRANSP EQUIP-LIGHT TRUCKS	S1	10	10	9.00	
392300	TRANSP EQUIP-HEAVY TRUCKS	L3	14	5	6.79	
392400	TRANSP EQUIP-TRAILERS/TRAILER MTD EQ.	L3	14	5	6.79	
393000	STORES EQUIPMENT	SQ	20	-	5.00	(B)
394000	TOOLS, SHOP AND WORK EQUIPMENT	SQ	20	-	5.00	(B)
394200	GARAGE EQUIPMENT	SQ	20	-	5.00	(B)
395000	LABORATORY EQUIPMENT	SQ	20	-	5.00	(B)
396000	POWER OPERATED EQUIPMENT	R3	18	15	4.72	
396100	POWER OPERATED EQ. - NON FLEET	R3	18	15	4.72	
397000	COMMUNICATION EQUIPMENT	SQ	15	-	6.67	(B)
397100	COMMUNICATION EQ.-TELE SYS COMPUTER	SQ	15	-	6.67	(B)
397200	COMMUNICATION EQ.-TELE SYS EQPT	SQ	15	-	6.67	(B)
398000	MISCELLANEOUS EQUIPMENT	SQ	20	-	5.00	(B)

ORANGE & ROCKLAND UTILITIES
AVERAGE SERVICE LIVES, NET SALVAGE
ANNUAL DEPRECIATION RATES AND LIFE TABLES

PSC ACCT NUMBER	ACCOUNT DESCRIPTION	LIFE TABLE	AVERAGE SERVICE LIFE (Years)	NET SALVAGE %	ANNUAL RATE %	
GAS PLANT						
TRANSMISSION PLANT						
367002	GAS MAINS STEEL	S1.5	70	(35)	1.93	
367003	GAS MAINS PLASTIC	S1.5	70	(35)	1.93	
367005	MAINS LPP	SQUARE	Dec 2029	(35)		(E)
367322	MAINS - STEEL - STONY POINT		-	-	-	
367502	MAINS - LEDERLE		-	-	-	(A)
DISTRIBUTION PLANT						
374000	LAND & LAND RIGHTS - EASEMENTS	R4	75	-	1.33	
374100	LAND & LAND RIGHTS - FEE	-	-	-	-	
374200	LAND - FEE - CLEVEPAK		-	-	-	(A)
375000	STRUCTURES & IMPROVEMENTS	R2.5	65	(30)	2.00	
375100	ST. & IMPROV. - STONY POINT MAIN		-	-	-	(A)
376000	GAS MAINS PLASTIC	S1.5	70	(35)	1.93	
376005	MAINS PLASTIC LPP	SQUARE	Dec 2029	(35)		(E)
376100	GAS MAINS CAST IRON	SQUARE	Dec 2029	(35)		(E)
376200	MAINS - CLEVEPAK		-	-	-	(A)
376300	GAS MAINS STEEL	S1.5	70	(35)	1.93	
376305	MAINS-STEEL LPP	SQUARE	Dec 2029	(35)		(E)
376330	MAINS - TRANSCO		-	-	-	(A)
378000	MEASURING AND REGULATING EQ.	S0	35	(20)	3.43	
378100	MEAS. & REG. EQ. - STONY POINT		-	-	-	(A)
378330	MEAS. & REG. EQ. - TRANSCO		-	-	-	(A)
378340	MEAS. & REG. EQ. - TRANSCO ORDER 63		-	-	-	(A)
380000	SERVICES	R3	65	(95)	3.00	
380005	SERVICES PLASTIC LPP	SQUARE	Dec 2029	(90)		(E)
380006	SERVICES STEEL	R3	65	(95)	3.00	
380007	SERVICES STEEL LPP	SQUARE	Dec 2029	(90)		(E)
381000	METERS	R2.5	40	-	2.50	
381200	METERS - AMI PURCHASE	S2	20	-	5.00	
382000	METER INSTALLATIONS	R3	55	(10)	2.00	
382200	METER INST. - AMI	S2	20	(15)	5.75	
382400	METER BAR INSTALLATIONS	R3	55	(10)	2.00	
383000	HOUSE REGULATORS	R2.5	40	-	2.50	
384000	HOUSE REGULATOR INSTALLATIONS	R3	55	(10)	2.00	
385000	INDUSTRIAL MEAS. & REG. EQ.	R5	40	(5)	2.63	
385500	IND. MEAS. & REG. EQ. - LEDERLE		-	-	-	(A)
386300	OTHER PROP. ON CUSTS.' PREM.	S3	20	-	5.00	
GENERAL PLANT EQUIPMENT						
389100	LAND - FEE	-	-	-	-	
390000	STRUCTURES AND IMPROVEMENTS	S0	50	(30)	2.60	
391100	OFFICE FURNITURE & EQ. - FURNITURE	SQ	20	-	5.00	(B)
391200	OFFICE FURNITURE & EQ. - MACHINES	SQ	15	-	6.67	(B)
391700	OFFICE FURNITURE & EQ. - EDP EQ.	SQ	8	-	12.50	(B)
392100	TRANSPORTATION EQ. - PASS. CARS	S2.5	12	10	7.50	
392200	TRANS. EQ. - LIGHT TRUCKS	S1	10	10	9.00	
392300	TRANS. EQ. - HEAVY TRUCKS	L3	14	5	6.79	
392400	TRANS. - TRAILERS	L3	14	5	6.79	
393000	STORES EQUIPMENT	SQ	20	-	5.00	(B)
394000	TOOLS & WORK EQUIPMENT	SQ	20	-	5.00	(B)
395000	LABORATORY EQUIPMENT	SQ	20	-	5.00	(B)
396000	POWER OPERATED EQUIPMENT	R3	18	15	4.72	
396100	POWER OPERATED EQUIPMENT - NON FLEET	R3	18	15	4.72	
397000	COMMUNICATION EQUIPMENT	SQ	15	-	6.67	(B)
397500	COMM EQ NG DETECTOR	SQ	5	-	20.00	
398000	MISCELLANEOUS EQUIPMENT	SQ	20	-	5.00	(B)

ORANGE & ROCKLAND UTILITIES
AVERAGE SERVICE LIVES, NET SALVAGE
ANNUAL DEPRECIATION RATES AND LIFE TABLES

PSC ACCT NUMBER	ACCOUNT DESCRIPTION	LIFE TABLE	AVERAGE SERVICE LIFE (Years)	NET SALVAGE %	ANNUAL RATE %	
INTANGIBLE PLANT						
302100	FRANCHISES AND CONSENTS					
302200	FRANCHISES & CONSENTS - AMORT.	SQ	5	-	20.00	(A)
303080	GAS SOFTWARE 15Y CLOUD	SQ	15		6.67	(B)
303110	GAS AMI SW CLOUD	SQ	20		5.00	(B)
303270	GAS SOFTWARE 15Y CLOUD	SQ	15		6.67	(B)
303940	GAS SOFTWARE 5 YEARS	SQ	5	-	20.00	(B)
303945	GAS SW CLOUD	SQ	5	-	20.00	(B)
NONUTILITY PROPERTY						
304100	LAND & LAND RIGHTS - FEE					
304200	LAND & LAND RIGHTS - EASEMENTSTRUCTURES AND					(A)
304300	STRUCTURES AND IMPROVEMENTS					(A)

NOTES:

(A) **Account is fully recovered**

(B) **Amortizable Accounts**

(C) **Account is amortizable over the remaining life of the assets.**

(D) **Additional accounts are opened to record unrecovered meters. The annual amortization expenses are:**

OR - E- 370150 - UNRECOVERED EM PURCHASE	**$437,667**
OR - E- 370160 - UNRECOVERED SS PURCHASE	**$447,133**
OR - E- 370250 - UNRECOVERED EM INSTALL	**$166,133**
OR - E- 370260 - UNRECOVERED SS INSTALL	**$519,533**
	$1,570,466

(E) **Fixed amortization starting at January 1, 2024 for 10 years.** **The annual amortization expenses are:**

OR-G- 367005 - MAINS LPP	**$29,748**
OR-G- 376005 - MAINS PLASTIC LPP	**$318,811**
OR-G- 376100 - GAS MAINS CAST IRON	**$6,921**
OR-G- 376305 - MAINS STEEL LPP	**$86,947**
OR-G-380005 - SERVICES PLASTIC LPP	**$288,796**
OR-G-380007 - SERVICES STEEL LPP	**$20,487**
	$751,710

Orange and Rockland
Cases 24-E-0060 and 24-G-0061
Earnings Sharing Partial Year
Stub Period Starting January 1, 2028
(000's)

Assumption: O&R Files for New Gas Rates Effective January 2028,
but Delays Filing for New Electric Rates for Six Months

Month / Year	Electric Operating Income (1)	
January-28	$ 2,400	
February-28	1,500	
March-28	300	
April-28	1,800	
May-28	2,800	
June-28	10,500	
Total		$ 19,300

	Electric Rate Base (1)	
Projected Rate Base at December 31, 2027	$ 1,000,000	
Projected Rate Base at June 30, 2028	1,020,000	
Total	2,020,000	
Divided by Two	2	
Average Rate Base During Stub Period	$ 1,010,000	
x Ratio of operating income for the six months ended June 2027 to operating income for the 12 months ended December 2027	25.3%	
Rate Base Subject to Earnings Test		$ 255,000
Overall Rate of Return ($ 19,300 / $ 255,000)		7.57%
Return on Equity (Page 2)	10.28%	
Earnings Sharing Threshold	10.25%	
Earnings Above / (Under) Threshold	0.03%	
Equity Earnings Base ($ 255,000 x 48.00%)	$ 122,400	
Equity Earnings Above / (Under) Threshold Subject to Sharing ($ 122,400 x 0.03%)	$ 30	

Note: the approach illustrated above would also apply to a delay in filing a gas case.

(1) All the amounts contained in this appendix are hypothetical.

Orange and Rockland
Cases 24-E-0060 and 24-G-0061
Capital Structure & Cost of Money
Stub Period Starting January 1, 2028

	Capital Structure %	Cost Rate %	Cost of Capital %
Long Term Debt	51.45%	5.08%	2.61%
Customer Deposits	0.55%	4.20%	0.02%
Total Debt	52.00%		2.64%
Common Equity	48.00%	10.28%	4.93%
Total	100.00%		7.57%

Orange and Rockland Utilities, Inc.
Cases 24-E-0060 and 24-G-0061

Electric Reliability Performance Mechanism

Operation of Mechanism:

The Reliability Performance Mechanism ("RPM") is currently in effect for Orange and Rockland and the modifications recommended in this Joint Proposal will remain in effect until reset by the Commission. The RPM includes targets for the frequency and duration of electric service interruption, as defined below.

1. Customer Average Interruption Duration Index ("CAIDI") – the average interruption duration time (hours) for those customers that experience an interruption during the year.
2. System Average Interruption Frequency Index ("SAIFI") – the average number of times that a customer is interrupted during a year.

The SAIFI and CAIDI performance targets for Orange and Rockland are 1.20 and 1.85, respectively, with negative revenue adjustments of 30 basis points for each failure to achieve a performance target on a calendar year basis.

Exclusions:

The following exclusions will be applicable under the RPM.

1. Any outages resulting from a major storm, as defined in 16 NYCRR Part 97.
2. Any incident resulting from a strike or a catastrophic event beyond the control of the Company, including but not limited to a plane crash, water main break, or natural disasters (*e.g.*, hurricanes, floods, earthquakes).
3. Any incident where issue(s) beyond the Company's control involving generation or the

bulk transmission system is the key factor in the outage, including, but not limited to, NYISO mandated load shedding. This criterion is not intended to exclude incidents that occur as a result of unsatisfactory performance by the Company.

The Company shall use the following process for potential exclusions, other than major storms:

1. The Company will provide preliminary notice and supporting documentation for potential annual report exclusions to the Director of the Office of Resilience and Emergency Preparedness for review within 45 days of the event. The Company will continue to submit supporting documentation for all exclusions in its annual reliability report.
2. The Company may petition the Commission for exemption from the requirements and/or revenue adjustment associated with the RPM metrics, on a case-by-case basis.

<u>Reporting:</u>

The RPM will be measured on a calendar year basis. Accordingly, the results of the performance measurements, as measured during the calendar year 2025, 2026, and 2027, respectively, will be applied to Rate Years 1, 2, and 3, respectively.

The Company will prepare an annual report(s) on its performance under this RPM. The annual report(s) will be filed by March 31st following each Rate Year with the Secretary to the Commission (*e.g.*, the annual report for 2025 shall be due by March 31, 2026).

The annual reports will provide:

1. The Company's annual system-wide performance under the RPM and identify

whether a revenue adjustment is applicable and, if so, the amount of the revenue adjustment; and

2. Whether any exclusions should apply, the basis for requesting each exclusion, and adequate support for all requested exclusions.

Orange and Rockland Utilities, Inc.
Cases 24-G-0061

Gas Safety Performance Metrics

The gas safety performance measures described herein will be in effect for the term of the Gas Rate Plan. All gas safety measures and targets (and associated revenue adjustments)[1] for calendar year 2027 remain in effect thereafter unless and until changed by the Commission.[2]

Negative Revenue Adjustments

1. **Leak Management/Emergency Response/Damages**

a. Leak Management – Repairable Leaks

If the repairable leak backlog (types 1, 2 and 2A) exceeds the targets set forth below in calendar year 2025, 2026 and 2027, the following negative rate adjustment will apply for each calendar year that the performance measures noted below are not attained.[3]

2025	
Less than or equal to 12	No adjustment
Greater than 12	10 basis points[4]

2026	
Less than or equal to 10	No adjustment
Greater than 10	10 basis points

[1] Negative revenue adjustments relating to the Gas Safety Performance metrics in this section shall not exceed 150 basis points in RY1, RY2 or RY3.

[2] The 66-mile replacement target established below, for the three-year period 2025 to 2027, does not remain in effect beyond 2027. However, the 20 miles of main removal per year will remain in effect beyond 2027, unless and until changed by the Commission.

[3] Only "successful elimination" of a leak will be considered a valid leak repair.

[4] The basis point negative rate adjustment associated with each measure is stated on a pre-tax basis. The revenue requirement equivalents of ten basis points on common equity capital per the gas revenue requirements under this Proposal are estimated to be approximately $481,000 in RY1, $528,640 in RY2 and $571,900 in RY3.

2027

Less than or equal to 10	No adjustment
Greater than 10	10 basis points

Orange and Rockland will be recognized as having met the leak backlog targets if they are achieved between December 21 and December 31 in RY1, RY2 and RY3.

b. Leak Management - Year-End Total Backlog

If the year-end total leak backlog (types 1, 2, 2A and 3) exceeds the targets set forth below in calendar year 2025, 2026 and 2027, the following negative rate adjustment will apply for each calendar year that the performance measures noted below are not attained.[5]

2025

Less than or equal to 30	No adjustment
Greater than 30	5 basis points

2026

Less than or equal to 25	No adjustment
Greater than 25	5 basis points

2027

Less than or equal to 25	No adjustment
Greater than 25	5 basis points

Orange and Rockland will be recognized as having met the leak backlog targets if they are achieved between December 21 and December 31 in RY1, RY2 and RY3.

[5] Only "successful elimination" of a leak will be considered a valid leak repair. In addition, the Company will recheck Type 3 leaks.

c. Emergency Response - 30 Minute Response Time

If Orange and Rockland does not respond to gas leak or odor calls within 30 minutes for at least 75 percent of the calls for calendar years 2025, 2026 and 2027, a negative rate adjustment of twelve basis points will apply for each calendar year that the performance measures are not attained.

The Company may seek the following exclusion to operating performance under this measure:

> Gas leak and odor calls resulting from such events as mass area odor complaints involving ten or more odor calls received within a two-hour period resulting from major weather-related occurrences or major equipment failure not caused by the Company.

Orange and Rockland shall provide an informational filing in the respective case number for the event that the Company is seeking an exclusion for within two weeks or ten business days from the conclusion of such event. Such exclusion filings should include details as described in testimony filed by the Staff Pipeline Safety Panel in case 24-G-0061. Staff will respond whether it consents or does not consent to the requested exclusion.[6] The Company may proceed with filing its request for an exclusion if it has not received a response from Staff within 90 days.

d. Emergency Response - 45 Minute Response Time

If Orange and Rockland does not respond to gas leak or odor calls within 45 minutes for at least 90 percent of the calls for calendar years 2025, 2026 and 2027, a negative rate adjustment of eight basis points will apply for each calendar year that the performance measures are not attained.

[6] This exclusion, as well as the right to petition the Commission pursuant to the General Provisions section below, also applies to the 45-Minute Response Time and 60-Minute Response Time measures.

e. Emergency Response - 60 Minute Response Time

If Orange and Rockland does not respond to gas leak or odor calls within 60 minutes for at least 95 percent of the calls for calendar years 2025, 2026 and 2027, a negative rate adjustment of five basis points will apply for each calendar year that the performance measures are not attained.

f. Damage Prevention

All damages will be tracked, measured and counted following the guidelines for the data reported for the Annual Gas Safety Performance Measures report. Hand damages where notification has been provided to the one call notification center will be included in this measure. Human or animal related damages without a valid one-call ticket are not included.

If the number of total damages to Company gas facilities made by any party exceeds the targets set forth below per 1,000 one-call tickets in calendar year 2025, 2026 and 2027, the negative rate adjustment associated with such target will apply for each calendar year that the performance measure noted below is not attained.[7]

<u>2025</u>

Greater than 1.35 but less than 1.95	No adjustment
greater than or equal to 1.95 but less than 2.35	5 basis points
greater than or equal to 2.35 but less than 2.40	10 basis points
greater than or equal to 2.40	20 basis points

<u>2026</u>

Greater than 1.35 but less than 1.95	No adjustment
greater than or equal to 1.95 but less than 2.35	5 basis points
greater than or equal to 2.35 but less than 2.40	10 basis points
greater than or equal to 2.40	20 basis points

<u>2027</u>

Greater than 1.35 but less than 1.95	No adjustment

[7] Orange and Rockland will have the option to average the current year and prior year total damage number to calculate the total damages number used to establish the Company's performance for 2025, 2026 and 2027. (*e.g.*, if this option is exercised, the total damage performance for Orange and Rockland in 2025 would be the average of the Company's total damage performance for 2024 and 2025).

greater than or equal to 1.95 but less than 2.35	5 basis points
greater than or equal to 2.35 but less than 2.40	10 basis points
greater than or equal to 2.40	20 basis points

2. **Gas Main Replacement**

The Company will remove from service a minimum of 66 miles of leak-prone gas main[8] during the three calendar year period 2025 to 2027. The Gas Rate Plan establishes minimum replacement targets of 20 miles in 2025, 20 miles in 2026 and 20 miles in 2027. Following the term of the Gas Rate Plan, a minimum of 20 miles of leak-prone gas main will be replaced each year.

If the Company does not meet the annual 20-mile minimum for removal of leak-prone gas main in 2025, 2026 or 2027, the Company will be subject to a negative revenue adjustment equivalent to: fifteen basis points for failing to meet the minimum in 2025 and/or 2026; and seven and one-half basis points for failing to meet the minimum in 2027. If the Company does not remove from service a total of 66 miles of leak-prone pipe over the three-year period, the Company will be subject to a negative rate adjustment equivalent to seven and one-half basis points.

Ineffectively coated steel will be counted if it is in the top 5% riskiest for that year. In addition, on a case-by-case basis, Orange & Rockland may request that other ineffectively coated steel not in the top 5% riskiest for that year, and vintage plastic piping that meets the Company's DIMP criteria for elevated risk similar to the top 5% riskiest ineffectively coated steel piping, be included as long as proper justification is provided to Staff and Staff consents with the request. Requests shall be submitted to safety@dps.ny.gov.

3. **Gas Regulations Performance Measure**

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[8] Bare steel and aldyl plastic will be considered for this measure. The Company may count ineffectively coated steel that is in the top 5% riskiest pipe for that year. Also, on a case-by-case basis, Orange and Rockland may request for inclusion of other ineffectively coated steel not in the top 5% riskiest for that year, and vintage plastic piping that meets the Company's Distribution Integrity Management Plan (DIMP) criteria for elevated risk similar to the top 5% riskiest ineffectively coated steel piping (e.g., piping found with high leakage rates). Staff to respond whether it consents or does not consent with the request.

This metric applies to instances of non-compliance (violations) with the gas safety regulations set forth below that are identified during Staff field and records audits. The categorization of violations hereunder as “High” or “Other” Risk is for administrative purposes of this metric only and do not constitute an admission by the Company as to the level of risk associated with any such regulation or violation thereunder or that there is any risk associated with a violation.

Only violations identified and included in Staff field and record audit letters may be counted for purposes of this metric. The audit letters cite violations as, for example, “1 violation, ten occurrences,” which means one code section has been violated ten times. For the Gas Regulations Performance Measure, this example constitutes ten violations (the number of occurrences is the number of violations).

At the conclusion of each audit, Staff and the Company will have a compliance meeting at which Staff will present its findings to the Company, including which violation(s), if any, that Staff recommends be subject to this metric. The Company will have five business days from the date of the compliance meeting to cure any identified document deficiency. Only official Company records, as defined in the Company’s Operating and Maintenance plan, will be considered by Staff as a cure to a document deficiency. In addition, if the Company is found to be in violation of its work procedure, but the work procedure exceeds Code 255 or 261, and the Company is not in violation of the Code requirement, the violation will not be subject to a negative revenue adjustment under this this Safety Violation metric.

Negative revenue adjustments, if any, would be applied as set forth in the following charts:

High Risk **Records** Audit	Other Risk **Records** Audit
Threshold - 0-5 (0 BP) for RY1, RY2, and RY3 RY1 – 6-10 (1/2 BP); ≥11 (1 BP) RY2 – 6-10 (1/2 BP); ≥11 (1 BP) RY3 – 6-10 (1/2 BP); ≥11 (1 BP)	Threshold - 0-10 (0 BP) for RY1, RY2, and RY3 RY1 – ≥11 (1/4 BP) RY2 – ≥11 (1/4 BP) RY3 – ≥11 (1/4 BP)

High Risk **Field** Audit	Other Risk **Field** Audit
RY1 – 1-5 (1/2 BP); ≥6 (1 BP) RY2 – 1-5 (1/2 BP); ≥6 (1 BP) RY3 – 1-5 (1/2 BP); ≥6 (1 BP)	RY1 – All Violations (1/4 BP) RY2 – All Violations (1/4 BP) RY3 – All Violations (1/4 BP)

Any negative revenue adjustments assessed under this metric shall not exceed 75 basis points for 2025, 2026 and 2027 and subsequent calendar years, until changed by the Commission. For any code section, the number of violations will be capped at ten for the negative revenue adjustment determination, for record audits on a service territory wide basis, with the requirement that violations in excess of ten be addressed by a corrective action plan formally submitted to Staff by the Company to achieve compliance going forward. If the Company does not file a corrective action plan with the Secretary to the Commission within 90 days from the date of the record audit letter, or if the Company does not adhere to its corrective action plan, the number of violations of a given code section in excess of ten will be included and the negative revenue adjustment associated with the violations will be applied. The corrective action plan will be provided in the Company's response to the audit letter.

This metric will be effective as of January 1, 2025 and will be measured on a calendar year basis. For **Field Audits**, only actions performed or required to be performed in the year that the Field Audit is conducted and witnessed by Staff may constitute an occurrence under this metric (*e.g.*, violations arising from 2025 Field Audit findings would count towards any applicable Rate Year 1 (2025) Negative Revenue Adjustments). For **Record Audits**, only documentation required to be performed during the calendar year prior to the year in which the Record Audit is conducted may constitute an occurrence under this metric (*e.g.*, violations arising from 2026 Record Audit findings for activities performed or not performed in 2025 would count towards any applicable Rate Year 2 (2026) Negative Revenue Adjustments).

Staff will submit its final audit reports to the Secretary under Case 24-G-0061. If the Company disputes any of Staff's final audit results, or elects to seek exclusions based on extenuating circumstances, the Company may appeal Staff's finding to the Commission. The Company will include in any such petition a remediation plan addressing such violations. If the Company elects to dispute any of Staff's findings, the Company will not incur a negative revenue adjustment on those Staff findings until such time as the Commission has issued a final decision on the Company's appeal. Upon Company request, the Commission may in its discretion, provide the Company with an evidentiary hearing prior to any final determination. The Company does not waive its right to seek judicial appeal of any Commission determination regarding a violation or penalty under applicable law.

Positive Rate Adjustments

1. Emergency Response/Damage Prevention

a. Emergency Response - 30 Minute Response Time

If Orange and Rockland responds to gas leak or odor calls within 30 minutes for at least 91 percent of the calls for calendar year 2025, the Company shall receive a positive revenue adjustment for calendar year 2025 of 2 basis points for each percentage increase of 2 percent, capped at a maximum of 6 basis points.

If Orange and Rockland responds to gas leak or odor calls within 30 minutes for at least 92 percent of the calls for calendar years 2026 and 2027, the Company shall receive a positive revenue adjustment for the applicable year(s) of 2 basis points for each percentage increase of 2 percent, capped at a maximum of 6 basis points.

The Table below shows the basis points available for different response time performance for Rate Year 2022, Rate Year 2023 and Rate Year 2024.

Rate Year 2025:		
Basis Points Incentive if Emergency Response – 30 Minute Percentage Is:		
2 BP	4 BP	6 BP
≥91% to <93%	≥93% to <95%	≥ 95%

Rate Year 2026 and Rate Year 2027:		
Basis Points Incentive if Emergency Response – 30 Minute Percentage Is:		
2 BP	4 BP	6 BP
≥92% to <94%	≥94% to <96%	≥ 96%

b. Damage Prevention

If the Company successfully reduces the number of total damages to Company gas facilities made by any party by the targets set forth below per 1,000 one-call tickets in calendar year 2025, 2026 and/or 2027, the Company shall receive a positive revenue adjustment for the applicable year(s). The Table below shows the basis points available for damage prevention performance for Rate Year 2025, Rate Year 2026 and Rate Year 2027.

Rate Year	Basis Points Incentive if Total Damages per 1000 one-call Tickets Is:		
2025	5 BP	10 BP	15 BP
	1.15 to <1.35	1.05 to <1.15	<1.05
2026	5 BP	10 BP	15 BP
	1.15 to <1.35	1.05 to <1.15	<1.05
2027	5 BP	10 BP	15 BP
	1.15 to <1.35	1.05 to <1.15	<1.05

General Provisions

The Company will report its annual performance in each of the areas set forth in this Appendix to the Secretary no later than 60 days following the end of each calendar year. If a performance metric is not met, the associated negative revenue adjustment will be excused when the Company can demonstrate to the Commission extenuating circumstances that prevented the Company from meeting such performance metric. The determination of whether such circumstances exist will be made on a case-by-case basis by the Commission. The Company does not waive its right to seek judicial appeal of any Commission determination regarding a violation or penalty under applicable law.

With respect to leak-prone pipe replacement, the report shall include material type, mileage, project location, and a summary noting the totals of aldyl plastic, bare steel and ineffectively coated steel that were replaced and what percentage of pipe replaced, in that year, was in the top 5% of riskiest pipe at the start of the calendar year, as established by the Company.

The Company will provide, to safety@dps.ny.gov, a list of the top 5% riskiest pipe yet to be replaced at the start of each calendar year. For any pipe on the list for the calendar year that the Company does not plan to replace in that calendar year, the Company will provide a brief explanation. Along with the list, the Company will identify any riskiest pipe on the preceding calendar year's list that was not replaced as planned.

2025-2027 Case 24-G-0061 - O&R - Pipeline Safety Measures

Pipeline Safety Measures	Criteria	Unit	NRA (BPs)	PRA (BPs)	CY 2025 Target	NRA (BPs)	PRA (BPs)	CY 2026 Target	NRA (BPs)	PRA (BPs)	CY 2027 Target	NRA (BPs)	PRA (BPs)	Beyond 2027 Target
Leak Backlog or Management [1-2]	Total: Type 1, 2A, 2, and 3	Leaks	5	-	> 30	5	-	> 25	5	-	> 25	5	-	> 25
	Repairable: Type 1, 2A, and 2	Leaks	10	-	> 12	10	-	> 10	10	-	> 10	10	-	> 10
	(1) O&R will be recognized as having met the leak backlog targets if they are achieved between December 21, and December 31. (2) Only "successful elimination" of a leak will be considered a valid leak repair and rechecks are required for Type 3 leaks.													
Leak Prone Pipe (LPP) [3-4-5]	Removal Target [3]	Miles	15	-	< 20	15	-	< 20	7.5	-	< 20	15	-	< 20
	(3) All leak prone services are to be removed in conjunction with this LPP program. LPP removals resulting from non-pipeline alternative projects may be included in the calendar year total mileage.													
	(4) Annual reporting on the progress of LPP removal is to be submitted by O&R. Inspections should be commensurate with that of the level of leak prone pipe removal. Bare steel, and aldyl-a plastic will be considered for this measure. Ineffectively coated steel allowed if in top 5% riskiest for that year. On a case-by-case basis, O&R may request the inclusion of other ineffectively coated steel and vintage plastic piping that meets the DIMP criteria for elevated risk similar to the top 5% riskiest ineffectively coated steel piping. Staff to respond whether it consents or does not consent with the request.													
	(5) 3-year cumulative target of 66 miles. If not met, an NRA of 7.5 BPs would be applied.													
Emergency Response [6]	Respond within 30 minutes	%	12	-	75	12	-	75	12	-	75	12	-	75
	Respond within 45 minutes	%	8	-	90	8	-	90	8	-	90	8	-	90
	Respond within 60 minutes	%	5	-	95	5	-	95	5	-	95	5	-	95
	Respond within 30 minutes	%	-	2	≥ 91 - < 93	-	2	≥ 92 - < 94		2	≥ 92 - < 94		2	≥ 92 - < 94
	Respond within 30 minutes	%	-	4	≥ 93 - < 95	-	4	≥ 94 - < 96		4	≥ 94 - < 96		4	≥ 94 - < 96
	Respond within 30 minutes	%	-	6	≥ 95	-	6	≥ 96		6	≥ 96		6	≥ 96
	(6) Any reports resulting from mass area complaints involving 10 or more odor calls, received within a two-hour period resulting from major weather-related occurrences, or major equipment failure not caused by the Company, may be excluded from this measure provided an informational filing is made within the respective case number. Exclusions are considered on a case-by-case basis, must be made via email or in writing, and shall be requested within 2 weeks or 10 business days from the conclusion of such event. Such exclusion filings should include details as described in testimony filed by the Staff Pipeline Safety Panel in case 24-G-0061. Staff will respond whether it consents or does not consent to the exclusion request. O&R may proceed with the exclusion request if it has not received a response from Staff within 90 days.													
Violations or Non-Compliances [7]	Record Audits: **High** Risk	Per	1	-	≥ 11	1	-	≥ 11	1	-	≥ 11	1	-	≥ 11
	Record Audits: **High** Risk	Per	1/2	-	6 to 10	1/2	-	6 to 10	1/2	-	6 to 10	1/2	-	6 to 10
	Record Audits: **High** Risk	Per	-	-	0 to 5	-	-	0 to 5	-	-	0 to 5	-	-	0 to 5
	Record Audits: Other Risk	Per	1/4	-	≥ 11	1/4	-	≥ 11	1/4	-	≥ 11	1/4	-	≥ 11
	Record Audits: Other Risk	Per	-	-	0 to 10	-	-	0 to 10	-	-	0 to 10	-	-	0 to 10
	Field Audits: **High** Risk	Per	1	-	≥ 6	1	-	≥ 6	1	-	≥ 6	1	-	≥ 6
	Field Audits: **High** Risk	Per	1/2	-	1 to 5	1/2	-	1 to 5	1/2	-	1 to 5	1/2	-	1 to 5
	Field Audits: Other Risk	Per	1/4	-	All violations	1/4	-	All violations	1/4	-	All violations	1/4	-	All violations
	(7) Cap of 10 for **record** audit violations of a single regulation annually on a service territory wide basis. Remediation plans to be filed and adhered to for instances where there are 10 or more violations for a single regulation. If a remediation plan is not adhered to, or not filed with the Secretary to the Commission within 90 days from the date of the record audit letter, the number of violations of a given code section in excess of 10 will be included with the remainder of the violations being considered for this measure.													
Damage Prevention (per 1,000 one-call tickets) [8]	Total: No Calls, Excavator Error, Company and Company Contractor Error, and Mismarks	Rate	20	-	≥ 2.40	20	-	≥ 2.40	20	-	≥ 2.40	20	-	≥ 2.40
		Rate	10	-	2.35 to < 2.40	10	-	2.35 to < 2.40	10	-	2.35 to < 2.40	10	-	2.35 to < 2.40
		Rate	5	-	1.95 to < 2.35	5	-	1.95 to < 2.35	5	-	1.95 to < 2.35	5	-	1.95 to < 2.35
		Rate	-	-	1.35 to < 1.95	-	-	1.35 to < 1.95	-	-	1.35 to < 1.95	-	-	1.35 to < 1.95
		Rate	-	5	1.15 to < 1.35	-	5	1.15 to < 1.35	-	5	1.15 to < 1.35	-	5	1.15 to < 1.35
		Rate	-	10	1.05 to < 1.15	-	10	1.05 to < 1.15	-	10	1.05 to < 1.15	-	10	1.05 to < 1.15
		Rate	-	15	< 1.05	-	15	< 1.05	-	15	< 1.05	-	15	< 1.05
	(8) Reporting of damage data shall be in compliance with December 11, 2015, guidance. Hand damages where notification has been provided to the one call notification center will be included in this measure. (9) Human or animal related damages without a valid one-call ticket are not included.													
Total Exposure			150	21		150	21		150	21		150	21	

List of Regulations for Violations Metric

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
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

List of Regulations for Violations Metric

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
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
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

List of Regulations for Violations Metric

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
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
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

Orange and Rockland Utilities, Inc.
Cases 24-E-0060 & 24-G-0061

Customer Service Performance Incentive Mechanism

The Customer Service Performance Incentive Mechanism ("CSPIM") described herein will be in effect for the terms of the Rate Plans and thereafter unless and until changed by the Commission.

a) Audited Historic Performance: For the period 2021 through 2023.

Staff conducted an audit of the Company's 2021, 2022 and 2023 electric and gas CSPIM data provided in the Company's reports and confirmed that the Company did not incur any customer service NRAs for 2021, 2022, or 2023.

b) Operation of Mechanism

The CSPIM establishes threshold performance levels for designated aspects of customer service. For all measures, the threshold performance levels are detailed on page 4 of this Appendix. Failure by the Company to achieve these specified targets will result in a revenue adjustment of up to 27 combined basis points of return on common equity in RY1, 30 combined basis points of return on common equity in RY2, and 45 combined basis points of return on common equity in RY3.[1] All revenue adjustments related to the CSPIM will be deferred for the benefit of customers.

The CSPIM will be measured on a calendar year basis. Accordingly, the results of the performance measurements, as measured during calendar years 2025, 2026 and 2027, respectively, will be applied to Rate Years 1, 2 and 3, respectively.

[1] For purposes of the CSPIM, 1 combined basis point will equal the value of 1 basis point return on common equity for electric plus the value of 1 basis point return on common equity for gas. This combined amount would then be allocated using the common allocator of 66.93% electric and 33.07% gas.

c) Exclusions

For measurement purposes, results from months having abnormal operating conditions will not be considered. Abnormal operating conditions are deemed to occur during any period of emergency, catastrophe, strike, natural disaster, major storm, or other unusual event not in the Company's control affecting more than 10 percent of the customers in an operating area during any month. A "major storm" will have the same definition as set forth in 16 NYCRR Part 97.

d) Reporting

The Company will prepare an annual report on its performance that will be filed with the Secretary by March 1 following each Rate Year (*e.g.*, the annual report for 2025 shall be due by March 1, 2026). Each report will state: (1) the Company's actual performance for the calendar year on each measure; (2) whether a revenue adjustment is applicable and, if so, the amount of the revenue adjustment; and (3) whether any exclusions should apply, the basis for requesting each exclusion, and adequate support for all requested exclusions.

e) Threshold Standards

The Company's threshold performance will be measured based on the Company's cumulative monthly performance for each Rate Year for the following three activities, except as otherwise noted.

i. Commission Complaints

The annual Complaint Rate will be calculated in the manner approved by the Commission in its Order Approving Complaint Rate Targets issued August 26, 2005.[2] In calculating the annual Complaint Rate, (i) duplicative rate consultant complaints, (ii) high

[2] Case 02-G-1553, *Proceeding on Motion of the Commission as to the Rates, Charges, Rules, and Regulations of Orange and Rockland Utilities, Inc. for Gas Service*, and Case 03-E-0797, *In the Matter of Orange and Rockland Utilities, Inc.'s Proposal for an Extension of an Existing Rate Plan, filed in Case 96-E-0900*, Order Approving Complaint Rate Target (issued August 26, 2005).

commodity prices complaints, and (iii) complaints relating to natural disasters, major storms, or other unusual events not in the Company's control, will be excluded. During the Rate Plans, the complaint rate not to exceed targets and associated revenue adjustment levels are set forth in Table 1, below. The annual average monthly Complaint Rate is calculated using the below formula:

$$\left(\frac{(12\ Month\ Escalated\ Complaint\ Total\ \div 12)}{Customer\ Total}\right) \times 100{,}000$$

ii. Customer Satisfaction

The Company contracts with a third-party vendor to conduct a monthly Customer Contact Satisfaction Survey. The vendor surveys customers utilizing a 10-point scale to rank customer satisfaction with Company performance based upon a series of questions and one overall customer satisfaction index question:

> *"Using a scale from 1 to 10 where 1 means you were very dissatisfied and 10 means you were very satisfied, how satisfied were you the way the Orange and Rockland's Customer Service Representative handled your recent issue/request?"*

The Company reports the percentage of customers surveyed that responded with a score of 7–10 to the overall customer satisfaction index question.

iii. Call Answer Rate

"Call Answer Rate" is the percentage of calls answered by a Company representative within 30 seconds of the customer's request to speak to a representative between the hours of 8:00 AM and 4:30 PM Monday through Friday (excluding holidays). The performance rate is the sum of the number of calls answered by a representative within 30 seconds divided by the number of calls in which a customer requests to speak with a representative, excluding those calls abandoned by the customer within 30 seconds, such that the Company did not have the full 30 seconds in which to answer. The Company reports the performance rate monthly in its Performance Indicator Report. The calculation of the performance rate is based on the metric manual that was developed after the Overland Audit in 2014.[3] The monthly Call Answer Rate is calculated using the below formula:[4]

$$\frac{Number\ of\ Calls\ Answered\ Within\ 30\ Seconds}{Number\ of\ Total\ Calls\ Requesting\ a\ Rep. - All\ Calls\ Abandoned\ within\ 30\ seconds}\ X\ 100$$

[3] Case 13-M-0314, *Issue a Request for a Proposal for an Independent Third-Party Consultant to Conduct a Review of the Accuracy and Effectiveness of Certain Reliability and Customer Service Systems at all Gas and Combination Gas and Electric Utilities in New York State that Provide Statistics to the Commission on the Services They provide Customers,* Order Releasing Report and Providing Guidance on Response (issued April 20, 2016).

[4] Annual performance for this metric is calculated as the average of the 12 monthly Call Answer Rates during the calendar year.

Table 1 - Customer Service Performance Incentive Mechanism Targets

2025-2027	CSPI Performance					
Indices	**RY1**	**RY2**	**RY3**	**RY1 (NRA) BPs**	**RY2 (NRA) BPs**	**RY3 (NRA) BPs**
Call Answer Rate						
Target	>61.0	>62.0	>63.0	None	None	None
Minimum	≤61.0	≤62.0	≤63.0	(3)	(3)	(5)
Middle	≤59.0	≤60.0	≤60.0	(6)	(7)	(10)
Max	≤57.0	≤58.0	≤58.0	(9)	(10)	(15)
PSC Complaint Rate						
Target	≤1.0	≤1.0	≤1.0	None	None	None
Minimum	>1.0	>1.0	>1.0	(3)	(3)	(5)
Middle	≥1.1	≥1.1	≥1.1	(6)	(7)	(10)
Max	≥1.2	≥1.2	≥1.2	(9)	(10)	(15)
Transactional Survey						
Target	>92.6	>92.6	>92.6	None	None	None
Minimum	≤92.6	≤92.6	≤92.6	(3)	(3)	(5)
Middle	≤91.8	≤91.8	≤91.8	(6)	(7)	(10)
Max	≤91.0	≤91.0	≤91.0	(9)	(10)	(15)

Appendix 16
Orange and Rockland
Case 24-E-0060
Earnings Adjustment Mechanisms

Orange and Rockland ("O&R" or the "Company") will implement Earnings Adjustment Mechanisms ("EAM") as of January 1, 2025, for the term of this Joint Proposal including Rate Year ("RY")1, RY2, and RY3. The Company will measure and report on the achievement of EAMs annually on a calendar year basis for RY1, RY2 and RY3.

1.0 Incentives

The Company will earn pre-tax earnings adjustments based on its performance relative to established performance targets. Each EAM metric will have minimum, mid-point and maximum performance targets. The Company will earn pre-tax earnings adjustments on a prorated basis for performance between the minimum and mid-point performance levels, as well as for performance between the mid-point and maximum performance levels. EAM incentives will be earned based upon absolute dollars.

Tables 1 and 2, and 3 (below) list the incentive opportunities for each EAM in absolute dollars and basis points for reference for each Rate Year, respectively. Table 3 provides the dollar value of a basis point for each Rate Year.

Table 1: Electric EAM Incentive (Absolute $)[1]

Metric	Level	RY1	RY2	RY3
DER Utilization (Solar PV)	Minimum	$258,666	$278,682	$326,682
	Mid-Point	$431,110	$464,470	$544,470
	Maximum	$862,220	$928,940	$1,088,940
DER Utilization (Energy Storage)	Minimum	$172,444	$185,788	$217,788
	Mid-Point	$344,888	$371,576	$435,576
	Maximum	$862,220	$928,940	$1,088,940
Electric Vehicle (EV) Adoption	Minimum	$215,555	$232,235	$272,235
	Mid-Point	$431,110	$464,470	$544,470
	Maximum	$862,220	$928,940	$1,088,940
Demand Response (DR)	Minimum	$172,444	$185,788	$217,788
	Mid-Point	$344,888	$371,576	$435,576
	Maximum	$862,220	$928,940	$1,088,940
Residential Managed Charging	Minimum	$172,444	$232,235	$326,682
	Mid-Point	$258,666	$325,129	$435,576
	Maximum	$431,110	$557,364	$816,705
Commercial Managed Charging	Minimum	N/A	$185,788	$272,235
	Mid-Point		$278,682	$381,129
	Maximum		$464,470	$653,364

[1] The Electric EAM Incentive in Absolute dollars was calculated based upon Basis Point Values as of 09/26/2024.

Table 2: Electric EAM Incentive (Basis Points)

Metric	Level	RY1	RY2	RY3
DER Utilization - Solar PV	Minimum	3.0	3.0	3.0
	Mid-Point	5.0	5.0	5.0
	Maximum	10.0	10.0	10.0
DER Utilization - Energy Storage	Minimum	2.0	2.0	2.0
	Mid-Point	4.0	4.0	4.0
	Maximum	10.0	10.0	10.0
Electric Vehicle (EV) Adoption	Minimum	2.5	2.5	2.5
	Mid-Point	5.0	5.0	5.0
	Maximum	10.0	10.0	10.0
Demand Response (DR)	Minimum	2.0	2.0	2.0
	Mid-Point	4.0	4.0	4.0
	Maximum	10.0	10.0	10.0
Residential Managed Charging	Minimum	2.0	2.5	3.0
	Mid-Point	3.0	3.5	4.0
	Maximum	5.0	6.0	7.5
Commercial Managed Charging	Minimum	N/A	2.0	2.5
	Mid-Point		3.0	3.5
	Maximum		5.0	6.0

Table 3: Value of a Basis Point

Value of an EAM basis point	RY1	RY2	RY3
[RY_x $ BP Electric]	$86,222	$92,894	$108,894

2.0 Metrics

The EAMs, targets, incentives (earnings adjustments) and measurements are described in the sections that follow.

2.1 DER Utilization Solar PV Metric

Description

The Distributed Energy Resources ("DER") Utilization - Solar Photovoltaic ("PV") metric is an outcome-based metric that incentivizes O&R to work with third parties to expand the use of solar PV in the O&R service territory. This metric will measure the sum of the incremental megawatts ("MW") interconnected in each Rate Year from all installations of 5 MW or less (including residential, commercial and industrial solar PV installations and Community Distributed Generation ("CDG") installations) in the O&R service territory.

Metric

The DER Utilization Solar PV metric will be calculated as follows:

Incremental DER Utilization Solar PV (MW) RY_x = sum of all 5MW or less solar PV MW interconnected in RY_x

Measurement

Solar PV interconnected MWs will be quantified using reporting from the Company's interconnection application portal, Power Clerk.

Targets

Table 4: DER Solar PV Utilization Targets (MW) Targets

DER Utilization Solar PV Targets (MW)	RY1	RY2	RY3
Minimum	33.0	34.65	35.97
Mid-Point	38.16	39.23	40.08
Maximum	45.79	47.08	48.09

Achievement

The Company will earn an EAM incentive if the Incremental DER Utilization Solar (MW) RY_x achievement is greater or equal to the RY_x MW $Target_{min}$ in a given Rate Year. The incentive will be calculated based on a prorated basis for performance between the minimum and mid-point performance levels, as well as for performance between the mid-point and maximum performance levels.

2.2 DER Utilization Energy Storage Metric

Description
The DER Utilization - Energy Storage metric is an outcome-based metric that incentivizes O&R to work with third parties to expand the use of electric energy storage resources in the O&R service territory. This metric will measure the sum of the incremental MW interconnected of all storage systems that are 5MW or less in each Rate Year (including residential and commercial storage installations and CDG installations) in the O&R service territory. This metric excludes energy storage related to Non-Wires Alternatives ("NWA") and Company owned energy storage.

Metric
The DER Utilization Energy Storage metric will be calculated as follows:

Incremental DER Utilization Energy Storage (MW) RY_x = sum of all Energy Storage MW interconnected that is 5MW or less in RY_x (excluding NWA and Company owned energy storage).

Measurement
Energy Storage interconnected MWs will be quantified using reporting from the Company's interconnection application portal, Power Clerk.

Targets
Table 5: DER Utilization Energy Storage Targets (MW) Targets

DER Utilization Energy Storage Targets (MW)	RY1	RY2	RY3
Minimum	11.34	11.34	11.34
Mid-Point	12.89	12.89	12.89
Maximum	15.46	15.46	15.46

Achievement
The Company will earn an EAM incentive if the Incremental DER Utilization Energy Storage (MW) RY_x achievement is greater or equal to the RY_x MW $Target_{min}$ in a given Rate Year. The incentive will be calculated based on a prorated basis for performance between the minimum and mid-point performance levels, as well as for performance between the mid-point and maximum performance levels.

2.3 EV Adoption Metric

Description

The EV Adoption metric will measure the lifetime short tons of avoided carbon dioxide (“CO_2”) in US Tons from the incremental deployment of electric vehicles (“EVs”) in the O&R service territory in a given Rate Year. Eligible EVs consist of battery EVs (“BEVs”) and plug-in hybrid electric vehicles (“PHEVs”).

Metric

Incremental lifetime tons of CO_2 will be calculated from the number of incremental EV registrations (calculated as the difference in the number of original registrations at the end of the prior year to the number of original registrations in the measured year) in each year multiplied by per-unit assumptions of avoided CO_2 multiplied by the average electric vehicle lifetime as set forth below.

BEV: incremental number of BEV registrations × Emissions Reduction per BEV Vehicle × Average Electric Vehicle Lifetime

PHEV: incremental number PHEV registrations × Emissions Reduction per PHEV Vehicle × Average Electric Vehicle Lifetime

> *Where:*
> Emissions Reduction per BEV Vehicle = 4.91 US Tons per year[2]
> Emissions Reduction per PHEV Vehicle = 2.65 US Tons per year[3]
> Average Electric Vehicle Lifetime = 10 years

Measurement

Incremental registrations of eligible BEVs and PHEVs in the O&R service territory will be calculated using original vehicle registration data as published on the Atlas Public Policy EValuateNY website, a NYSERDA-funded tool, or other equivalent source.

[2] Emissions Reduction US Ton per year is for EAM purposes only.
[3] ibid

Targets

Table 6: EV Adoption Targets

EV Adoption Targets (Incremental Lifetime Tons of CO_2)	RY1	RY2	RY3
Minimum	180,753	224,614	273,530
Mid-Point	255,171	339,498	574,175
Maximum	330,287	454,334	873,810

Achievement

The Company will earn an EAM incentive if the incremental lifetime tons of CO_2 RY_x achievement is greater or equal to the RY_x $Target_{min}$ in a given Rate Year. The incentive will be calculated based on a prorated basis for performance between minimum and mid-point performance levels, as well as for performance between the mid-point and maximum performance levels.

2.4 Demand Response Metric

Description

The Demand Response ("DR") metric encourages the Company to achieve greater growth in DR programs by increasing the total MW of operationally available DR resources participating in the programs. This EAM promotes grid flexibility by developing a larger and more reliable DR resource that can be called to reduce peak demand and during system contingencies. This metric will measure the growth of DR programs on a MW basis, including the Company's Commercial System Relief Program ("CSRP"), Distribution Load Relief Program ("DLRP"), Term-and Auto-Dynamic Load Management ("DLM") programs, Direct Load Control ("DLC") program, and the NYISO Special Case Resource ("SCR") program within the Company's service territory.[4]

Metric

The DR metric is the total incremental MW of operationally available DR from the Company's DR programs and the portion of the NYISO's SCR program within the Company's service territory in any given Rate Year compared to the prior Rate Year calculated as:

$$\mathrm{RY_x\ Incremental\ MW\ Reduction = RY_x\ MW\ Reduction - RY_{x-1} MW\ Reduction}$$

Where:

X	1, 2 and 3 for RY1, RY2, or RY3, respectively.
RY_x Incremental MW Reduction	The total incremental MW load reduction in RY_x from the Company's DR programs and the portion of NYISO's SCR program within the Company's service territory.

[4] To the extent that new Company DR programs are launched during the rate period or modifications are made to existing programs, MWs participating in these programs will also count toward metric achievement.

RY_x MW Reduction	The total MW load reduction in RY_x from the Company's DR programs, plus the total MW load reduction in RY_x from the portion NYISO's SCR program within the Company's service territory. Each program will have their incremental MW calculated on a per event basis. At the end of a Capability Period occurring during the RYx, these per event calculations will be averaged over the number of total events (which include test events).
RY_{x-1} MW Reduction	The total MW load reduction from the Company's DR programs in RY_{x-1} plus the total MW load reduction in RY_{x-1} from the portion of NYISO's SCR program within the Company's service territory.

And where:

The total MW load reduction from the Company's DR programs will be the same as reported in the Company's DR Annual report filed in Case 14-E-0423.

The total MW load reduction from the NYISO's SCR program is calculated for O&R customers that participate in the NYISO's Programs by using the same methodology used to calculate MW load reduction for the Company's CSRP and DLRP programs.

Measurement

The Company will use data calculated using the methodology that the Company has employed in the Company's Annual DR Program report to measure incremental "operationally available" load relief (MW) from the Company's DR programs. Specifically, for CSRP and DLRP, "operationally available" load relief (MW) is calculated in accordance with the Company's Customer Baseline (CBL) methodology. The Company will then calculate Performance Factor for CSRP and DLRP by dividing the operationally available load relief by the enrolled load relief amount. Should the performance factor exceed 100% for CSRP or DLRP, the operationally available load relief will be capped at the enrolled program amount. The Company will use the NYISO provided list of customers in O&R territory participating in the NYISO's SCR program and will then apply the same methodology used to calculate operationally available load relief for CSRP and DLRP.

Targets

The annual minimum, midpoint and maximum targets will be set as follows:

$$\text{RY}_\text{x}\ \text{Incremental MW Reduction Target}_{minimum}$$
$$= \text{Total MW load reduction from the Company's DR programs in RY}_{\text{x}-1}\ \text{X Company Program Growth Rate}_{minimum}$$
$$+ \text{Total MW load reduction from the NYISO's SCR program in RY}_{\text{x}-1}\text{X theNYISO's SCR Program Growth Rate}_{minimum}$$

$$\mathrm{RY_x}\ \text{Incremental MW Reduction Target}_{midpoint} = \text{Total MW load reduction from the Company's DR programs in } \mathrm{RY_{x-1}} \text{ X Company Program Growth Rate}_{midpoint} + \text{Total MW load reduction from the NYISO's SCR program in } \mathrm{RY_{x-1}} \text{X theNYISO's SCR Program Growth Rate}_{midpoint}$$

$$\mathrm{RY_x}\ \text{Incremental MW Reduction Target}_{maximum} = \text{Total MW load reduction from the Company's DR programs in } \mathrm{RY_{x-1}} \text{ X the Company's Program Growth Rate}_{maximum} + \text{Total MW load reduction from the NYISO's SCR program in } \mathrm{RY_{x-1}} \text{X theNYISO's SCR Program Growth Rate}_{maximum}$$

where growth rates are set as follows:

	Level	**Company DR Program Growth Rate (%)**	**NYISO SCR Growth Rate (%)**
Growth Rates to calculate Annual Target	Minimum	7.00	0.0
	Mid-point	11.75	11.75
	Maximum	23.50	23.50

	Level	**2025**	**2026**	**2027**
DR (Incremental MW)	Minimum	Determined formulaically based on prior years actual performance		
	Mid-point			
	Maximum			

Achievement
The Company will earn a financial reward if the RY_x Incremental MW Reduction achievement is greater or equal to the RY_x Incremental MW Reduction $Target_{min}$ in a given Rate Year. The financial reward will be calculated based on a prorated basis for performance between the minimum and mid-point performance levels, as well as for performance between the mid-point and maximum performance levels.

2.5 Residential Managed Charging Metric

Description
The Residential Managed Charging metric incentivizes the Company to increase enrollment in the Company's SmartCharge NY managed charging program which encourages avoidance of charging during peak hours and decrease peak coincident EV charging demand, relative to baseline performance.

Metric

The Residential Managed Charging EAM measures the avoided peak charging in kilowatts (kW) during the summer period between June and September of all participants enrolled in SmartCharge NY, and then scales Pactual to the full year to align the timing of the variables.

The metric will be calculated as follows:

For RYx, Avoided Peak Charging per EV (kW)

$$= \frac{RY_x Pmax_{YE} - RY_x Pactual_{YE}}{RY_x EVs\ on\ the\ Road_{YE}}$$

Where:

x	Is equal to 1, 2 and 3 for RY_1, RY_2, and RY_3, respectively.
$Pmax_{YE}$	$Pmax_{YE}$ is the sum of the maximum possible demand of participants in SmartCharge NY at the end of the year, based on the SCNY Enrollment at Year End multiplied by 7.2 kW (the agreed upon average nameplate for residential chargers in O&R's service territory), calculated as follows: $$Pmax_{YE} = SCNY\ Enrollment_{YE} \times 7.2\ kW$$
$Pactual_{YE}$	$Pactual_{YE}$ is $Pactual_{SE}$ scaled to a year-end value so that appropriate time alignment between summer performance and year-end enrollment occurs. The scaling uses a ratio of SCNY Enrollment at Year End to SCNY Enrollment at Summer End ("SE"), calculated as follows: $$Pactual_{YE} = Pactual_{SE} \times \frac{SCNY\ Enrollment_{YE}}{SCNY\ Enrollment_{SE}}$$
$Pactual_{SE}$	The highest aggregate observed 15-minute coincident charging demand (kW) of participants in the program during the system peak period (2:00 pm - 6:00 pm) between June and September.
$EVs\ on\ the\ Road_{YE}$	Total number of light-duty EVs in the Company's

service territory at the end of year.

Measurement

SCNY Enrollment will be calculated at Summer End (*i.e.,* September 30) and year end based on using the ev.energy enrollment dashboard. Observed 15-minute demand of participants in the program will be calculated using the monthly charging data provided by ev.energy EVs on the Road YE in the O&R service territory will be calculated using vehicle registration data as published on the Atlas Public Policy EValuateNY website, a NYSERDA-funded tool, or other equivalent source.

Targets

The Rate Year minimum, midpoint, and maximum targets for Residential Managed Charging Metric will be based on the following: Baseline reflects the maximum possible peak charging demand of participants in the SmartCharge NY program less the adjusted actual peak charging demand compared to the number of light-duty EV on the road in the O&R service territory, each from the prior calendar year.

The baseline is calculated as follows:

Baseline Avoided Peak Charging per EV (kW)

$$= \frac{\mathrm{RY_x Baseline\ Pmax_{YE-1}} - \mathrm{RY_x Baseline\ Pactual_{YE-1}}}{\mathrm{RY_x Baseline\ EVs\ on\ the\ Road_{YE-1}}}$$

Where:

x	Is equal to 1, 2 and 3 for RY_1, RY_2, and RY_3, respectively.
$Pmax_{YE-1}$	$Pmax_{YE-1}$ is the sum of the maximum possible demand of participants in SmartCharge NY at the end of the prior year, based on the SCNY Enrollment at Prior Year End multiplied by 7.2 kW, calculated as follows: $$\mathrm{Pmax_{YE-1}} = \mathrm{SCNY\ Enrollment_{YE-1}} \times 7.2\ \mathrm{kW}$$
$Pactual_{YE-1}$	$Pactual_{YE-1}$ is $\mathrm{Pactual_{SE}}$ scaled to a prior year-end value so that appropriate time alignment between

summer performance and year-end enrollment occurs. The scaling uses a ratio of, SCNY Enrollment at prior Year End to SCNY Enrollment at prior year Summer End ("SE"), calculated as follows:

$$\text{Pactual}_{\text{YE}-1} = \text{Pactual}_{\text{SE}-1} \times \frac{\text{SCNY Enrollment}_{\text{YE}-1}}{\text{SCNY Enrollment}_{\text{SE}-1}}$$

$\text{Pactual}_{\text{SE}-1}$	The highest aggregate observed 15-minute coincident charging demand (kW) of participants in the program during the system peak period (2:00 pm - 6:00 pm) between June and September of the prior calendar year.
$\text{EVs on the Road}_{\text{YE}-1}$	Total number of light-duty EVs in the O&R service territory at the end of the prior year.

The minimum, mid-point, and maximum targets will be set at 5.0 percent, 10.0 percent, and 17.0 percent above baseline, respectively.

Achievement
The Company will calculate the earned reward in a given Rate Year corresponding to its RYx Percent Improvement in Total Charging kW Avoided (%). The financial reward will be calculated based on a prorated basis for performance between the minimum and mid-point performance levels, as well as for performance between the mid-point and maximum performance levels.

2.6 Commercial Managed Charging Metric

Description
The Commercial Managed Charging ("CMC") metric incentivizes the Company to increase enrollment in the Company's CMC program which encourages avoidance of charging during peak hours to decrease peak coincident EV charging demand, relative to baseline performance.

Metric
The CMC EAM measures enrollment and the charging station demand coincident with the site's substation peak during the summer period when grid value is typically highest.
The metric is calculated as follows:

RY_x Percent Total Charging kW Avoided On Peak

$$= \frac{RY_xPmax - RY_xPactual}{RY_xTotal\ Charging\ kW}$$

Where:

x	Is equal to 2 and 3 for RY_2, and RY_3, respectively. This metric will be measured in RY_2 and RY_3.
Pmax	Pmax is the sum of the maximum possible demand of chargers enrolled in the CMC program in kW at the end of the summer period, September 30, of RY_x.
Pactual	The sum of each substation's window peak[5] observed maximum 15-minute coincident charging demand (kW) of the chargers enrolled in the program, during the summer period of June 1 through September 30 of RY_x.
Total Charging kW	Total installed commercial charging capacity (kW) across the O&R service territory at the end of the summer period, September 30, of RY_x.

Measurement

This metric will be calculated using data from various sources including O&R's program management application, Clean Power Research's PowerClerk, other O&R internal electric systems and meter data and data provided by Company's Managed Charging vendor(s).

Targets

The Rate Year minimum, mid-point, and maximum targets for the CMC Charging metric will be based on the following: Baseline will be calculated as the maximum potential charging capacity for chargers enrolled in the program less the actual charging demand of chargers enrolled in the program compared to the maximum capacity of commercial chargers in the O&R service territory, each at the end of the summer period.

5 Based upon the substation window peak in effect at the beginning of the summer period for that RY, as set forth in the Consolidated Edison Company of New York, Inc. and Orange and Rockland Utilities, Inc. Immediate Solutions Implementation Plan, and approved in Case 22-E-0236, Order Establishing Framework for Alternatives to Traditional Demand-Based Rate Structures.

Baseline Avoided Peak Total Charging (%)

$$= \frac{RY_x \text{Baseline Pmax} - RY_x \text{Baseline Pactual}}{RY_x \text{Total Charging kW}}$$

Where:

x	Is equal to 2 and 3 for RY_2 and RY_3, respectively.
Baseline Pmax	Baseline Pmax is the sum of the maximum possible demand of chargers enrolled in the CMC program in kW at the end of the prior summer period, September 30, of RYx-1.
Baseline Pactual	The sum of each substation's window peak observed maximum 15-minute coincident charging demand (kW) of the chargers enrolled in the program, during the summer period of June 1 through September 30 of RY_{x-1}.
Total Charging kW	Total installed commercial charging capacity (kW) across the O&R service territory at the end of the summer period, September 30, of the prior year, of RY_{x-1}.

The minimum, mid-point, and maximum targets will be set at 5.0 percent, 10.0 percent, and 17.0 percent above baseline, respectively.

Achievement

The Company will calculate the earned reward in a given Rate Year corresponding to its RYx Percent Improvement in Total Charging kW Avoided (%). The financial reward will be calculated based on a prorated basis for performance between the minimum and mid-point performance levels, as well as for performance between the mid-point and maximum performance levels.

3.0 EAM Reporting Requirements

The Company will file an annual EAM report on a calendar year basis. On June 30, 2026, 2027, and 2028, the Company will file with the Secretary of the Commission this annual EAM report on its previous Rate Year's performance in relation to the targets and include a discussion of its earned EAMs, if applicable.

Orange and Rockland Utilities, Inc.
Cases 24-E-0060 & 24-G-0061

ELECTRIC REVENUE ALLOCATION AND RATE DESIGN

1. Revenue Allocation

Two adjustments were made to the incremental revenue requirement before allocating it among customer classes. The first adjustment to the incremental revenue requirement for each Rate Year ("RY")[1] is the subtraction of amounts included for New York State Gross Receipts and Franchise Tax surcharge revenues, Municipal Tax surcharge revenues and Metropolitan Transportation Authority Business Tax surcharge revenues. The second adjustment was made to adjust the revenue requirement to offset the incremental credits that are projected to be paid to low income residential customers in RY1.[2]

For each RY, before the adjusted incremental revenue requirement was applied to each customer class, the RY delivery revenues for each class were realigned in a revenue neutral manner to reduce interclass deficiencies and surpluses. In each RY, deficiency and surplus indications have been reduced by one-third. The RY delivery revenue change was then allocated among the Service Classifications ("SC") in proportion to the relative contribution made by each SC's realigned RY delivery revenue to the total realigned RY delivery revenue. The delivery revenue changes by SC for each RY were mitigated in a manner such that each SC received a percentage change in delivery revenue that was no more than 1.25 times and no less than 0.5 times the overall RY percentage change in delivery revenue.

[1] RY1 is defined as the 12 months ending December 31, 2025, RY2 is defined as the 12 months ending December 31, 2026, and RY3 is defined as the 12 months ending December 31, 2027.
[2] This adjustment was an increase of $3,742,847 in RY1. There were no incremental increases in RY2 or RY3.

2. Rate Design (Excluding Standby Service and Buyback Service)

The rate design process for each RY for all classes consists of the following six steps:

- Determine revised customer charges and a revised Reactive Power Demand Charge ("RPDC") and associated delivery revenue changes.
- Determine revised competitive service charges and associated delivery revenue changes.
- Adjust class-specific delivery revenue changes to determine non-competitive delivery revenue changes excluding customer charges and the RPDC ("adjusted non-competitive delivery revenue changes").
- Calculate class-specific adjusted non-competitive delivery revenue changes for a historical period.
- Implement intraclass rate structure changes for certain SCs.
- Apply adjusted non-competitive delivery revenue changes within each SC.

a. Revised Customer Charges and RPDC and Associated Delivery Revenue Changes

(i) The following summarizes the customer charges in each RY for classes were there is a change in the customer charge.

SC	RY1	RY2	RY3
SC No. 1 – Standard Rates	$22.00	$22.50	$23.00
SC No. 19 – Standard Rates	30.00	29.00	28.00
SC No. 2 Sec NDB Mtd – Standard Rates	21.00	21.00	21.00
SC No. 2 Pri - Standard Rates	32.00	32.00	32.00
SC No. 20 - Standard Rates	30.00	30.00	30.00
SC No. 3 - Standard Rates	45.00	45.00	45.00
SC No. 21 - Standard Rates	45.00	45.00	45.00

For all other SCs (except for Standby Service and Buyback Service), the customer charges will remain at their current levels.

(ii) The RPDC will be increased to $1.05/kVAr of billable reactive power demand.

b. Revised Competitive Service Charges and Associated Delivery Revenue Changes

The competitive delivery components include: the billing and payment processing ("BPP") charge; the merchant function charge ("MFC") fixed components, that is the MFC procurement and credit and collections ("C&C") components; and the purchase of receivables ("POR") C&C component. The revised competitive service charge revenue levels for each RY were compared with competitive service charge revenues determined based on competitive service charges for the previous RY to determine the change in competitive service revenues.

(i) Based on ECOS study indications, the BPP charge has been increased in RY1 from $1.50 to $2.10. The incremental revenue associated with the change in the BPP charge was based on the number of forecasted bills times the incremental BPP charge.

(ii) The revised revenue levels for the MFC fixed components and the POR C&C component were based on percentages of delivery revenue as determined in the ECOS study.

c. Determination of Class-Specific Adjusted Non-competitive Delivery Revenues

For each RY, the revenue changes associated with the competitive service charges, customer charges, and RPDC were used to adjust the class-specific delivery revenue changes to determine class-specific adjusted non-competitive delivery revenue changes.

d. Determination of Class-Specific Adjusted Non-Competitive Delivery Revenue Changes for a Historical Period

Class-specific revenue ratios were developed for each RY by dividing (a) adjusted non-competitive delivery revenues for each class based on billing data for the historical period (*i.e.*, the twelve months ended December 31, 2022) and rates for the previous RY by (b) adjusted non-competitive delivery revenues for each class based on RY billing data and rates for the previous RY. These revenue ratios for each class were applied to each RY's adjusted non-competitive delivery revenue change to determine each class's historical period adjusted non-competitive delivery revenue change.

e. Intraclass Rate Structure Changes

The following rate structure changes were made in a revenue neutral manner before applying the historical period adjusted non-competitive delivery revenue changes within each of the affected SCs.

SC No. 2 – Secondary Demand Billed

For SC No. 2 Secondary Demand Billed service, in RY1, the existing two block kWh usage rate structure will be changed to a one block usage rate structure with rates that differ by season. Additionally, in each RY, 5% of kWh usage related delivery revenue was shifted from usage charges to demand charges on a seasonal basis. The historical period adjusted non-competitive delivery revenue change was then applied to the class's usage rates in RY1, and to demand rates in RY2 and RY3.[3]

SC Nos. 20 and 21

For SC Nos. 20 and 21, in each RY, the Company applied adjustments to the summer and winter revenue differentials of each class to adjust the seasonal delivery revenue ratio to begin to gradually approach the seasonal delivery cost ratio. The class-specific

[3] SC No. 2 – Secondary Demand Billed received a decrease in adjusted non-competitive delivery revenue in RY1 and received increases in adjusted non-competitive delivery revenues in RY2 and RY3.

historical period adjusted non-competitive delivery revenue change was then applied to each class's respective demand rates.

f. Application of Historical Period Adjusted Non-Competitive Delivery Revenue Change Within Each SC

For all remaining demand billed classes, the Company applied historical period adjusted non-competitive delivery revenue increases to each class's respective demand rates and historical period adjusted non-competitive delivery revenue decreases to each class's respective usage rates.

For all other SCs, each class-specific historical period adjusted non-competitive delivery revenue change, determined as set forth above, was divided by the total of the historical period kWh usage related revenue or luminaire related revenue at the previous RY's rate levels, to establish an average class-specific percentage by which non-competitive delivery rates, excluding the customer charges, were changed.

3. Unbundled Charges

a. Merchant Function Charge

For the term of the Electric Rate Plan, the Company will continue to implement the MFC, as set forth in the Company's electric tariff**.** The MFC fixed component monthly targets for each RY are set forth in Schedule 4 of this Appendix.

b. Transition Adjustment for Competitive Services

For the term of the Electric Rate Plan, the Company will continue to implement the Transition Adjustment for Competitive Services ("TACS"), as set forth in the Company's electric tariff.

c. POR Discount

For the term of the Electric Rate Plan, the Company will continue to implement the POR discount, as set forth in the Company's electric tariff. The POR C&C component monthly targets for each RY are set forth in Schedule 4 of this Appendix.

d. BPP Charge

The Company's BPP charge will increase from $1.50 per bill to $2.10 per bill.

4. Rate Design – Standby Service and Buyback Service

a. Standby Service Rate Design

Standby Service Rates were developed consistent with the guidelines set forth in the Commission's October 13, 2023 Order in Case No. 15-E-0751, *In the Matter of the Value of Distributed Energy Resources* (The "October 2023 Standby Order"). The guidelines in the October 2023 Standby Order state, "The Commission required that Standby rates be designed to be revenue neutral to the Otherwise Applicable Service Class ("OASC") – that is, the rates designed under the updated Standby Service charges are to collect the same amount of revenue from all members of their OASC under Standby Service Rates as they do under the default rates for the OASC." (October 2023 Standby Order, p. 4). Consistent with these guidelines, and as a starting point for the Standby Service Rate design, the Company used the delivery revenue requirement for each SC based on the proposed rates. Standby Service Rates for each class developed using the Commission's allocated cost of service ("ACOS") methodology were thus designed to be revenue neutral to the OASC.

The Company set the Standby Service Rate customer charge for each class based on the proposed customer charge of the OASC. The customer charge revenue for each SC was then subtracted from the delivery revenue requirement. The Company also subtracted for each SC the customer-related costs not included in the customer charge from the delivery revenue requirement. This amount was determined by multiplying the number of bills by the difference between the otherwise applicable customer charge and the ACOS customer costs. The resulting adjusted delivery revenue requirement was allocated among transmission costs, substation costs, primary costs, and secondary costs based on the ACOS study. The allocated revenue requirement was then used to determine the contract demand charges and as-used daily demand charges. The class delivery revenue requirements to be recovered through contract demand charges were developed by applying the applicable percentages as provided in Exhibit ___ (DAC-4), Schedule 2 ("ACOS Matrix") of the DAC Panel's initial filing exhibits to the portions of the adjusted delivery revenue requirement applicable to transmission costs, substation costs, primary costs, and secondary costs. The Company then added in the revenues attributable to the customer-related costs not included in the customer charges to arrive at the contract demand revenue requirements. These contract demand revenue requirements were then divided by the applicable estimated Standby Service contract demand billing determinants. The estimated standby contract demand billing determinants were developed by applying a ratio reflecting the relationship between estimated contract demand and monthly billing demand to the applicable billing demands in each class. The ratio for each rate class was developed from load research or billing data and was calculated by dividing (1) twelve times the maximum billing demand for customers in the class by (2) the sum of the twelve monthly billing demands for customers in the class. The class delivery revenue requirements to be recovered through as-used daily demand charges were developed based upon the allocations shown in the ACOS Matrix. To determine the amount of revenue to be included in each component of the as-used daily demand charges, the Company applied the following rules:

- The Summer Super-Peak rate was set to recover a certain percentage of the class-specific transmission revenue. For the residential classes and for the non-residential secondary classes, 50 percent of such transmission revenue was placed in the Summer Super-Peak rate. For other classes, 25 percent of such transmission revenue was placed in the Summer Super-Peak rate.
- The Summer On-Peak rate was set equal to the Winter On-Peak rate.
- The Off-Peak rates were set to zero.

The as-used daily demand charge revenue requirements determined for each period using the above rules were divided by the applicable estimated daily demand billing determinants for each period to develop the as-used daily demand charges. The estimated daily demands were developed using relationships between non-coincident peak demand and average daily demand developed from load research for the entire class. These relationships were applied to the applicable billing demands in each class. To determine bills for customers who were billed under Standby Service Rates prior to March 16, 2022, and opted to be billed under a phase-in to ACOS-based Standby Service Rates, the Company calculates the customer's monthly bill under the ACOS-based rates and under Standby Service Rates determined using the pre-ACOS methodology, and then applies a phase-in percentage for the applicable year to the difference, and either credits or charges the customer for such difference. Since there is one customer who was billed under Standby Service Rates prior to March 16, 2022, the

Company determined this additional set of pre-ACOS Standby Service Rates only for SC No. 22 – Transmission.

The MFC, BPP, and RPDC for Standby Service rates are equal to that of the OASC.

(b) Buyback Service Rate Design

The Company set the Buyback Service customer charge for each class based on the proposed customer charge of the otherwise applicable Standard Rate. Contract demand charges for Buyback Service were developed in a manner similar to contract demand charges for the ACOS-based Standby Service Rates. The class revenue requirements to be recovered through Buyback Service contract demand charges were developed by applying the applicable percentages in the ACOS matrix to the portions of the revenue requirement applicable to transmission costs, substation costs, primary costs, and secondary costs. Unlike the determination of contract demand charges for Standby Service Rates, revenues attributable to the customer-related costs not included in customer charges were not included in the Buyback Service contract demand revenue requirements. The resulting contract demand revenue requirements were then divided by the applicable Standby Service contract demand billing determinants to arrive at the Buyback Service contract demand charges.

5. Energy Cost Adjustment

The Energy Cost Adjustment ("ECA") will be amended to: (1) eliminate the Base ECA and move to a monthly reconciliation of certain ECA components; (2) revise the Temporary Credit amounts to those that will be effective in RY3 of the Electric Rate Plan in Case 24-E-0060; (3) change the case number for the allocators used for EAM cost recovery to Case 24-

E-0060; and (4) add the new reconciliation components to the ECA related to Federal Infrastructure Funding and Pension and OPEBs.

6. Make Whole Provisions

If the Commission makes rates effective for RY1 after January 1, 2025, the Company will implement a make whole provision. Differences in non-competitive delivery service revenues that result from the extension of the Case 24-E-0060 suspension period plus interest at the Commission's Other Customer Capital Rate will be collected via the implementation of a Delivery Revenue Surcharge ("DRS").[4] The DRS will be in effect on the date rates become effective in this case through the remainder of RY1. The unit amount to be collected from customers will be shown by SC on the Statement of Delivery Revenue Surcharge.[5] Any difference between amounts required to be collected and actual amounts collected will be charged or credited to customers in a subsequent DRS Statement that will become effective March 1, 2026.

7. Tariff Filing Dates

By January 1, 2025, 2026 and 2027 the Company will file tariff revisions implementing the rate changes for RY1, RY2, and RY3, respectively,[6] unless the Commission makes rates effective for RY1 after January 1, 2025 in this proceeding, at which time the Company will place RY1 rates into effect on another date subject to the make whole provisions described above.

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[4] Competitive services' revenue differences associated with the extension of the Case 24-E-0060 suspension period will be reconciled and surcharged or recovered through the TACS.
[5] Standby Service customers will be charged on a per-kW of contract demand basis while all other customers will be charged on a per-kWh basis.
[6] The tariff filings for RY2 and RY3 will be made at least 30 days prior to the effective date of new rates unless the Commission orders another filing date for the RY2 and RY3 compliance filings.

ORANGE AND ROCKLAND UTILITIES, INC.

Case 24-E-0060

Appendix 17 - Electric Revenue Allocation and Rate Design

Index of Schedules

Schedule 1	Page 1	Impact of RY1 Rate Change on Total Revenue
	Page 2	Calculation of RY1 Incremental Revenue Requirement
	Page 3	Allocation of RY1 Incremental Revenue Requirement
	Page 4	Determination of RY1 Non-Competitive Increase
Schedule 2	Page 1	Impact of RY2 Rate Change on Total Revenue
	Page 2	Calculation of RY2 Incremental Revenue Requirement
	Page 3	Allocation of RY2 Incremental Revenue Requirement
	Page 4	Determination of RY2 Non-Competitive Increase
Schedule 3	Page 1	Impact of RY3 Rate Change on Total Revenue
	Page 2	Calculation of RY3 Incremental Revenue Requirement
	Page 3	Allocation of RY3 Incremental Revenue Requirement
	Page 4	Determination of RY3 Non-Competitive Increase
	Page 5	Summary of RY3 ECA Temporary Surcharge
Schedule 4		Summary of MFC Targets by Month
Schedule 5		Rates in Brief - RY1
Schedule 6		Rates in Brief - RY2
Schedule 7		Rates in Brief - RY3

ORANGE AND ROCKLAND UTILITIES, INC.

Case 24-E-0060

Impact of Proposed Rate Change on Total Revenue
For the Rate Year Twelve Months Ending December 31, 2025 (1)
(Based on Billed Sales and Revenues)

Based on Levelized Revenue Requirement

Service Classification	Rate Year Billed Sales (MWH)	Customers	Revenue At Current Rates ($000s)	Revenue At Proposed Rates ($000s)	Change ($000s)	Percent Change
SC1	1,680,241	208,759	392,282	397,409	5,127	1.3%
SC19	70,334	3,323	15,304	15,591	287	1.9%
Total Res	1,750,575	212,082	407,586	413,000	5,414	1.3%
SC2 Sec	855,452	25,525	165,384	167,849	2,465	1.5%
SC2 Sec Heat	13,288	231	2,209	2,237	27	1.2%
SC2 Sec ND & UM	15,780	4,465	3,849	3,915	65	1.7%
SC20	91,513	470	14,260	14,448	188	1.3%
Total Secondary	976,033	30,690	185,702	188,449	2,746	1.5%
SC2 Pri	65,817	240	9,998	10,099	102	1.0%
SC3	274,316	249	40,675	41,104	430	1.1%
SC21	29,125	24	4,249	4,297	48	1.1%
Total Primary	369,258	513	54,922	55,501	579	1.1%
Total Sec & Pri	1,345,291	31,203	240,624	243,950	3,325	1.4%
SC9 (Commercial)	485,776	48	59,768	60,203	436	0.7%
SC22 (Industrial)	257,428	32	32,331	32,627	296	0.9%
Total SC9 & SC22	743,204	80	92,099	92,830	732	0.8%
SC4	9,697	65	3,307	3,383	76	2.3%
SC5	2,185	536	446	454	8	1.8%
SC6	3,417	0	581	589	8	1.4%
SC 16 -dusk-to-dawn	9,679	2,239	4,037	4,137	100	2.5%
SC 16 - energy only	2,709	418	624	636	12	2.0%
SC16 - Total	12,388	2,657	4,661	4,773	112	2.4%
Total Lighting	27,687	3,258	8,995	9,199	205	2.3%
Total	3,866,757	246,623	749,304	758,979	9,675	1.3%

Notes:
1. For comparison purposes, an estimated electric supply charge for retail access customers has been included in total revenues. This is equivalent, on a per unit basis, to the cost of electric supply included in full service customer revenues.

ORANGE AND ROCKLAND UTILITIES, INC.

Case 24-E-0060

Calculation of Incremental Revenue Requirement for Rate Year 1

Based on Levelized Revenue Requirement

a.	Incremental Revenue Requirement for Rate Year Including Gross Receipts/MTA Taxes (1)	$0
b.	Gross Receipts/MTA Tax Included in Incremental Revenue Requirement (2)	0
c.	Incremental Revenue Requirement for Rate Year Excluding Gross Receipts/MTA Taxes (a - b)	$0
d.	Low Income Incremental Funding	$3,742,847
e.	Total Revenue Reqirement + Low Income Incremental Funding	$3,742,847
f.	Rate Year Bundled Delivery Revenues	$394,278,500
g.	Rate Year Percentage Increase in Delivery Revenues (e / f)	0.94929%
h.	Rate Year Overall Percentage Increase in Delivery Revenues Less Low Income Incremental Funding (c/f)	0.00000%

Note:
1. Twelve months ending December 31, 2025
2. GRT/MTA Gross Up Included in Rev Req =   1.75%

ORANGE AND ROCKLAND UTILITIES, INC.

Case 24-E-0060

Allocation of Incremental Revenue Requirement Among Customer Classes for Rate Year 1

Based on Levelized Revenue Requirement

Class	Bundled Rate Yr. Delivery Rev ($)	Adjusted Net (Surplus)/ Deficiency ($)	Adj. Rate Yr. Delivery Revenue ($)	Proposed Rate Yr. Incr. @ 0.94929% ($)	Rate Yr. Bundled Delivery Rev. at 'Proposed Rate Level ($)	Proposed RY Increase Incl. (Sur)/Def ($)	Mitigation Adjustment ($)	Adjusted Rate Yr. Increase Including Mitigation Adj ($)	Rate Yr. Bundled %
SC1	243,628,700	3,157,549	246,786,249	2,342,717	249,128,966	5,500,266	(2,633,557)	2,866,709	1.2%
SC19	8,577,000	0	8,577,000	81,421	8,658,421	81,421	(842)	80,579	0.9%
Total Res	252,205,700	3,157,549	255,363,249	2,424,138	257,787,387	5,581,687	(2,634,399)	2,947,288	1.2%
SC2 Sec	84,601,964	(3,199,237)	81,402,727	772,748	82,175,475	(2,426,489)	2,828,052	401,563	0.5%
SC2 Sec Heating	960,634	85,185	1,045,819	9,928	1,055,747	95,113	(83,817)	11,296	1.2%
SC2 Sec ND	2,337,302	(149,107)	2,188,195	20,772	2,208,967	(128,335)	139,429	11,094	0.5%
SC20	5,636,600	0	5,636,600	53,508	5,690,108	53,508	(553)	52,955	0.9%
Total Sec	93,536,500	(3,263,158)	90,273,342	856,956	91,130,298	(2,406,202)	2,883,111	476,909	0.5%
SC2 Pri	3,742,800	(29,337)	3,713,463	35,252	3,748,715	5,915	11,850	17,765	0.5%
SC3	14,769,500	(65,017)	14,704,483	139,588	14,844,071	74,571	0	74,571	0.5%
SC21	1,508,600	(114,617)	1,393,983	13,233	1,407,216	(101,384)	108,544	7,160	0.5%
Total Pri	20,020,900	(208,970)	19,811,930	188,073	20,000,003	(20,897)	120,394	99,497	0.5%
Total Sec & Pri	113,557,400	(3,472,128)	110,085,272	1,045,029	111,130,301	(2,427,099)	3,003,505	576,406	0.5%
Total SC9 (Com)	14,138,000	(65,453)	14,072,547	133,589	14,206,136	68,136	0	68,136	0.5%
Total SC22 (Mfg)	8,017,000	368,173	8,385,173	79,600	8,464,773	447,773	(353,466)	94,307	1.2%
Total SC 9 & SC 22	22,155,000	302,720	22,457,720	213,189	22,670,909	515,909	(353,466)	162,443	0.7%
SC4	2,379,000	(3,197)	2,375,803	22,553	2,398,356	19,356	(233)	19,123	0.8%
SC5	242,000	10,663	252,663	2,399	255,062	13,062	(10,216)	2,846	1.2%
SC6	256,000	(20,557)	235,443	2,235	237,678	(18,322)	19,537	1,215	0.5%
SC 16 -dusk-to-dawn	3,146,000	0	3,146,000	29,865	3,175,865	29,865	(309)	29,556	0.9%
SC 16 - energy only	337,400	24,948	362,348	3,440	365,788	28,388	(24,421)	3,967	1.2%
SC16 - Total	3,483,400	24,948	3,508,348	33,305	3,541,653	58,253	(24,730)	33,523	1.0%
Total Lights	6,360,400	11,858	6,372,258	60,492	6,432,750	72,350	(15,642)	56,708	0.9%
Total	394,278,500	0	394,278,500	3,742,848	398,021,348	3,742,848	0	3,742,846	0.9%

ORANGE AND ROCKLAND UTILITIES, INC.

Case 24-E-0060

Determination of Non-Competitive Delivery Revenue Increases for Rate Year 1

Based on Levelized Revenue Requirement

Incremental Competitive Service, Customer Charge, and RPDC Revenues

Class	Adj. Rate Yr. Incr. Incl. (Sur)/Def Incl. Mitigation Adj./Incr A ($)	MFC Supply Related Rev B ($)	MFC PP WC Related Rev C ($)	MFC Credit & Collections Related Rev D ($)	POR Credit & Collections Related Rev E ($)	Customer Charge Rev F ($)	Reactive Power Demand Charge Rev G ($)	BPP Charge Rev H ($)	Total Rate Yr. Incremental Comp. Services Rev I = ∑ (A to H) ($)	Non-Competitive Rate Yr. Delivery Revenue Incr J = A - I ($)
SC1	2,866,709	318,329	642,013	203,894	(3,033)	0	0	885,452	2,046,656	820,054
SC19	80,579	15,954	32,178	10,219	(1,568)	(79,720)	0	11,596	(11,341)	91,920
Total Res	2,947,288	334,283	674,191	214,113	(4,601)	(79,720)	0	897,048	2,035,315	911,974
SC2 Sec Dmd	401,563	132,138	195,129	58,431	15,928	0	956	99,487	502,069	(100,506)
SC2 Sec Heating	11,296	945	1,396	418	429	0	0	0	3,188	8,108
SC2 Sec ND	11,094	1,476	2,179	653	745	(74,448)	0	17,401	(51,994)	63,089
SC20	52,955	5,697	8,412	2,519	627	(56,400)	235	634	(38,277)	91,232
Total Sec	476,909	140,256	207,116	62,021	17,729	(130,848)	1,191	117,522	414,987	61,922
SC2 Pri	17,765	24,263	15,863	6,764	(346)	(25,832)	353	0	21,065	(3,299)
SC3	74,571	42,710	27,924	11,907	3,680	(44,905)	15,365	457	57,138	17,434
SC21	7,160	1,252	818	349	185	(8,640)	1,600	86	(4,349)	11,509
Total Pri	99,497	68,225	44,605	19,020	3,519	(79,377)	17,318	544	73,853	25,644
Total Sec & Pri	576,406	208,481	251,721	81,041	21,248	(210,225)	18,509	118,066	488,840	87,566
Total SC9 (Com)	68,136	20,962	13,705	5,845	2,950	0	19,176	40	62,678	5,458
Total SC22 (Mfg)	94,307	48,535	31,732	13,530	202	0	33,271	140	127,410	(33,103)
Total SC 9 & SC 22	162,443	69,497	45,437	19,375	3,152	0	52,447	180	190,088	(27,645)
SC4	19,123	3,621	5,347	1,601	(454)	0	0	0	10,115	9,008
SC5	2,846	41	60	18	164	0	0	360	643	2,203
SC6	1,215	510	753	225	141	576	0	166	2,371	(1,156)
SC 16 -dusk-to-dawn	29,556	2,763	4,080	1,222	(183)	0	0	81	7,963	21,593
SC 16 - energy only	3,967	774	1,142	343	(57)	96	0	1,157	3,455	512
SC16 - Total	33,523	3,537	5,222	1,565	(240)	96	0	1,238	11,418	22,105
Total Lights	56,708	7,709	11,382	3,409	(389)	672	0	1,598	24,547	32,161
Total	3,742,846	619,970	982,732	317,938	19,410	(289,273)	70,956	1,016,892	2,738,790	1,004,056

ORANGE AND ROCKLAND UTILITIES, INC.

Case 24-E-0060

Impact of Proposed Rate Change on Total Revenue
For the Rate Year Twelve Months Ending December 31, 2026 (1)
(Based on Billed Sales and Revenues)

Based on Levelized Revenue Requirement

Service Classification	Rate Year Billed Sales (MWH)	Customers	Revenue At Current Rates ($000s)	Revenue At Proposed Rates ($000s)	Change ($000s)	Percent Change
SC1	1,708,172	210,625	403,215	416,451	13,237	3.3%
SC19	71,527	3,299	15,806	16,173	367	2.3%
Total Res	1,779,699	213,924	419,020	432,624	13,604	3.3%
SC2 Sec	854,889	25,842	167,650	169,525	1,875	1.1%
SC2 Sec Heat	13,338	219	2,239	2,291	52	2.3%
SC2 Sec ND & UM	15,821	4,453	3,909	3,960	51	1.3%
SC20	91,414	471	14,142	14,368	226	1.6%
Total Secondary	975,462	30,984	187,939	190,144	2,205	1.2%
SC2 Pri	65,706	252	10,046	10,169	123	1.2%
SC3	264,070	246	39,545	40,075	530	1.3%
SC21	27,961	24	4,142	4,175	33	0.8%
Total Primary	357,737	522	53,733	54,419	686	1.3%
Total Sec & Pri	1,333,199	31,506	241,672	244,563	2,891	1.2%
SC9 (Commercial)	482,250	48	59,364	59,873	509	0.9%
SC22 (Industrial)	247,760	32	31,292	31,699	407	1.3%
Total SC9 & SC22	730,010	80	90,657	91,573	916	1.0%
SC4	9,587	65	3,344	3,439	96	2.9%
SC5	2,160	536	450	463	13	2.9%
SC6	3,377	0	580	586	6	1.1%
SC 16 -dusk-to-dawn	9,570	2,235	4,088	4,221	133	3.3%
SC 16 - energy only	2,683	417	636	653	17	2.7%
SC16 - Total	12,253	2,652	4,724	4,875	151	3.2%
Total Lighting	27,377	3,253	9,097	9,363	266	2.9%
Total	3,870,285	248,763	760,447	778,123	17,676	2.3%

Notes:
1. For comparison purposes, an estimated electric supply charge for retail access customers has been included in total revenues. This is equivalent, on a per unit basis, to the cost of electric supply included in full service customer revenues.

ORANGE AND ROCKLAND UTILITIES, INC.

Case 24-E-0060

Calculation of Incremental Revenue Requirement for Rate Year 2

Based on Levelized Revenue Requirement

a.	Incremental Revenue Requirement for Rate Year Including Gross Receipts/MTA Taxes (1)	$17,677,000
b.	Gross Receipts/MTA Tax Included in Incremental Revenue Requirement (2)	309,000
c.	Incremental Revenue Requirement for Rate Year Excluding Gross Receipts/MTA Taxes (a - b)	$17,368,000
d.	Low Income Incremental Funding	$0
e.	Total Revenue Reqirement + Low Income Incremental Funding	$17,368,000
f.	Rate Year Bundled Delivery Revenues	$399,869,608
g.	Rate Year Percentage Increase in Delivery Revenues (e / f)	4.34342%
h.	Rate Year Overall Percentage Increase in Delivery Revenues Less Low Income Incremental Funding (c/f)	4.34342%

Note:
1. Twelve months ending December 31, 2026
2. GRT/MTA Gross Up Included in Rev Req = 1.75%

ORANGE AND ROCKLAND UTILITIES, INC.

Case 24-E-0060

Allocation of Incremental Revenue Requirement Among Customer Classes for Rate Year 2

Based on Levelized Revenue Requirement

Class	Bundled Rate Yr. Delivery Rev ($)	Adjusted Net (Surplus)/ Deficiency ($)	Adj. Rate Yr. Delivery Revenue ($)	Proposed Rate Yr. Incr. @ 4.34342% ($)	Rate Yr. Bundled Delivery Rev. at 'Proposed Rate Level ($)	Proposed RY Increase Incl. (Sur)/Def ($)	Mitigation Adjustment	Adjusted Rate Yr. Increase Including Mitigation Adj	Rate Yr. Bundled %
SC1	250,068,900	3,157,549	253,226,449	10,998,688	264,225,137	14,156,237	(1,153,880)	13,002,357	5.2%
SC19	8,776,600	0	8,776,600	381,205	9,157,805	381,205	(19,915)	361,290	4.1%
Total Res	258,845,500	3,157,549	262,003,049	11,379,893	273,382,942	14,537,442	(1,173,795)	13,363,647	5.2%
SC2 Sec	84,944,213	(3,199,237)	81,744,976	3,550,528	85,295,504	351,291	1,493,451	1,844,742	2.2%
SC2 Sec Heating	973,283	85,185	1,058,469	45,974	1,104,443	131,159	(80,719)	50,440	5.2%
SC2 Sec ND	2,328,311	(149,107)	2,179,205	94,652	2,273,857	(54,455)	105,019	50,564	2.2%
SC20	5,403,200	0	5,403,200	234,684	5,637,884	234,684	(12,260)	222,424	4.1%
Total Sec	93,649,008	(3,263,158)	90,385,850	3,925,838	94,311,688	662,680	1,505,491	2,168,171	2.3%
SC2 Pri	3,699,600	(29,337)	3,670,263	159,415	3,829,678	130,078	(8,328)	121,750	3.3%
SC3	14,266,900	(65,017)	14,201,883	616,847	14,818,730	551,830	(32,225)	519,605	3.6%
SC21	1,474,200	(114,617)	1,359,583	59,052	1,418,635	(55,565)	87,580	32,015	2.2%
Total Pri	19,440,700	(208,970)	19,231,730	835,314	20,067,044	626,344	47,027	673,371	3.5%
Total Sec & Pri	113,089,708	(3,472,128)	109,617,580	4,761,152	114,378,732	1,289,024	1,552,518	2,841,542	2.5%
Total SC9 (Com)	13,853,000	(65,453)	13,787,547	598,851	14,386,398	533,398	(31,285)	502,113	3.6%
Total SC22 (Mfg)	7,728,000	368,173	8,096,173	351,651	8,447,824	719,824	(318,621)	401,203	5.2%
Total SC 9 & SC 22	21,581,000	302,720	21,883,720	950,502	22,834,222	1,253,222	(349,906)	903,316	4.2%
SC4	2,370,000	(3,197)	2,366,803	102,800	2,469,603	99,603	(5,370)	94,233	4.0%
SC5	242,000	10,663	252,663	10,974	263,637	21,637	(9,071)	12,566	5.2%
SC6	252,000	(20,557)	231,443	10,053	241,496	(10,504)	15,976	5,472	2.2%
SC 16 -dusk-to-dawn	3,153,000	0	3,153,000	136,948	3,289,948	136,948	(7,154)	129,794	4.1%
SC 16 - energy only	336,400	24,948	361,348	15,695	377,043	40,643	(23,199)	17,444	5.2%
SC16 - Total	3,489,400	24,948	3,514,348	152,643	3,666,991	177,591	(30,353)	147,238	4.2%
Total Lights	6,353,400	11,858	6,365,258	276,470	6,641,728	288,328	(28,818)	259,510	4.1%
Total	399,869,608	0	399,869,608	17,368,017	417,237,625	17,368,017	0	17,368,016	4.3%

ORANGE AND ROCKLAND UTILITIES, INC.

Case 24-E-0060

Determination of Non-Competitive Delivery Revenue Increases for Rate Year 2

Based on Levelized Revenue Requirement

Class	Adj. Rate Yr. Incr. Incl. (Sur)/Def Incl. Mitigation Adj./Incr A ($)	Incremental Competitive Service, Customer Charge, and RPDC Revenues: MFC Supply Related Rev B ($)	MFC PP WC Related Rev C ($)	MFC Credit & Collections Related Rev D ($)	POR Credit & Collections Related Rev E ($)	Customer Charge Rev F ($)	Reactive Power Demand Charge Rev G ($)	BPP Charge Rev H ($)	Total Rate Yr. Incremental Comp. Services Rev I = ∑ (A to H) ($)	Non-Competitive Rate Yr. Delivery Revenue Incr J = A - I ($)
SC1	13,002,357	87,450	17,662	22,791	16,458	1,263,805	0	0	1,408,166	11,594,192
SC19	361,290	4,431	895	1,155	529	(39,548)	0	0	(32,538)	393,828
Total Res	13,363,647	91,881	18,557	23,946	16,987	1,224,257	0	0	1,375,627	11,988,020
SC2 Sec Dmd	1,844,742	22,603	5,271	6,801	8,262	0	0	0	42,937	1,801,805
SC2 Sec Heating	50,440	162	38	49	122	0	0	0	370	50,070
SC2 Sec ND	50,564	253	59	76	206	0	0	0	594	49,970
SC20	222,424	985	229	297	342	360	0	0	2,213	220,211
Total Sec	2,168,171	24,003	5,597	7,223	8,932	360	0	0	46,114	2,122,057
SC2 Pri	121,750	2,432	434	272	341	(24)	0	0	3,455	118,296
SC3	519,605	4,127	735	462	1,403	75	0	0	6,803	512,803
SC21	32,015	121	22	14	56	(240)	0	0	(27)	32,043
Total Pri	673,371	6,680	1,191	748	1,800	(189)	0	0	10,230	663,141
Total Sec & Pri	2,841,542	30,683	6,787	7,971	10,732	171	0	0	56,344	2,785,198
Total SC9 (Com)	502,113	2,026	360	227	905	0	0	0	3,518	498,595
Total SC22 (Mfg)	401,203	4,696	837	525	829	0	0	0	6,887	394,317
Total SC 9 & SC 22	903,316	6,721	1,197	752	1,734	0	0	0	10,405	892,911
SC4	94,233	620	145	187	47	0	0	0	999	93,235
SC5	12,566	7	1	2	35	0	0	0	45	12,521
SC6	5,472	87	20	26	47	576	0	0	757	4,716
SC 16 -dusk-to-dawn	129,794	473	110	143	69	0	0	0	795	128,999
SC 16 - energy only	17,444	133	31	40	18	(192)	0	0	29	17,415
SC16 - Total	147,238	606	141	183	87	(192)	0	0	825	146,414
Total Lights	259,510	1,319	308	398	216	384	0	0	2,625	256,885
Total	17,368,016	130,604	26,849	33,067	29,669	1,224,812	0	0	1,445,001	15,923,015

ORANGE AND ROCKLAND UTILITIES, INC.

Case 24-E-0060

Impact of Proposed Rate Change on Total Revenue
For the Rate Year Twelve Months Ending December 31, 2027 (1) (2)
(Based on Billed Sales and Revenues)

Based on Levelized Revenue Requirement

Service Classification	Rate Year Billed Sales (MWH)	Customers	Revenue At Current Rates ($000s)	Revenue At Proposed Rates ($000s)	Change ($000s)	Percent Change
SC1	1,745,902	212,509	413,896	428,724	14,828	3.6%
SC19	73,184	3,275	16,046	16,440	394	2.5%
Total Res	1,819,086	215,784	429,942	445,164	15,222	3.5%
SC2 Sec	857,606	26,164	164,893	165,033	140	0.1%
SC2 Sec Heat	13,440	207	2,221	2,286	65	2.9%
SC2 Sec ND & UM	15,922	4,441	3,872	3,865	(7)	-0.2%
SC20	91,806	472	13,941	14,183	241	1.7%
Total Secondary	978,774	31,283	184,927	185,367	440	0.2%
SC2 Pri	65,937	264	9,787	9,915	128	1.3%
SC3	262,213	243	38,236	38,790	554	1.5%
SC21	27,775	24	3,966	3,960	(5)	-0.1%
Total Primary	355,925	531	51,988	52,665	677	1.3%
Total Sec & Pri	1,334,699	31,814	236,916	238,032	1,116	0.5%
SC9 (Commercial)	489,565	48	57,686	58,228	541	0.9%
SC22 (Industrial)	246,439	32	30,018	30,542	524	1.8%
Total SC9 & SC22	736,004	80	87,704	88,770	1,066	1.2%
SC4	9,545	65	3,362	3,463	101	3.0%
SC5	2,152	536	448	464	16	3.6%
SC6	3,365	0	559	558	(1)	-0.2%
SC 16 -dusk-to-dawn	9,525	2,232	4,139	4,279	139	3.4%
SC 16 - energy only	2,667	416	632	655	22	3.5%
SC16 - Total	12,192	2,648	4,771	4,933	162	3.4%
Total Lighting	27,254	3,249	9,140	9,418	278	3.0%
Total	3,917,043	250,927	763,701	781,384	17,682	2.3%

Notes:

1. For comparison purposes, an estimated electric supply charge for retail access customers has been included in total revenues. This is equivalent, on a per unit basis, to the cost of electric supply included in full service customer revenues.

2. Revenue at proposed rates includes the RY3 temporary credit.

ORANGE AND ROCKLAND UTILITIES, INC.

Case 24-E-0060

Calculation of Incremental Revenue Requirement for Rate Year 3

Based on Levelized Revenue Requirement

a.	Incremental Revenue Requirement for Rate Year Including Gross Receipts/MTA Taxes (1)	$38,110,000
b.	Gross Receipts/MTA Tax Included in Incremental Revenue Requirement (2)	667,000
c.	Incremental Revenue Requirement for Rate Year Excluding Gross Receipts/MTA Taxes (a - b)	$37,443,000
d.	Low Income Incremental Funding	$0
e.	Total Revenue Reqirement + Low Income Incremental Funding	$37,443,000
f.	Rate Year Bundled Delivery Revenues	$422,835,900
g.	Rate Year Percentage Increase in Delivery Revenues (e / f)	8.85521%
h.	Rate Year Overall Percentage Increase in Delivery Revenues Less Low Income Incremental Funding (c/f)	8.85521%

Note:
1. Twelve months ending December 31, 2027
2. GRT/MTA Gross Up Included in Rev Req = 1.75%

ORANGE AND ROCKLAND UTILITIES, INC.

Case 24-E-0060

Allocation of Incremental Revenue Requirement Among Customer Classes for Rate Year 3

Based on Levelized Revenue Requirement

Class	Bundled Rate Yr. Delivery Rev ($)	Adjusted Net (Surplus)/ Deficiency ($)	Adj. Rate Yr. Delivery Revenue ($)	Proposed Rate Yr. Incr. @ 4.34342% ($)	Rate Yr. Bundled Delivery Rev. at 'Proposed Rate Level ($)	Proposed RY Increase Incl. (Sur)/Def ($)	Mitigation Adjustment	Adjusted Rate Yr. Increase Including Mitigation Adj	Rate Yr. Bundled %
SC1	267,828,300	3,157,549	270,985,849	23,996,366	294,982,215	27,153,915	124,390	27,278,305	10.2%
SC19	9,306,700	0	9,306,700	824,128	10,130,828	824,128	4,272	828,400	8.9%
Total Res	277,135,000	3,157,549	280,292,549	24,820,494	305,113,043	27,978,043	128,662	28,106,705	10.1%
SC2 Sec	87,268,445	(3,199,237)	84,069,208	7,444,505	91,513,713	4,245,268	38,590	4,283,858	4.9%
SC2 Sec Heating	1,028,840	85,185	1,114,026	98,649	1,212,675	183,834	(69,952)	113,882	11.1%
SC2 Sec ND	2,382,015	(149,107)	2,232,908	197,729	2,430,637	48,622	57,869	106,491	4.5%
SC20	5,731,400	0	5,731,400	507,528	6,238,928	507,528	2,631	510,159	8.9%
Total Sec	96,410,700	(3,263,158)	93,147,542	8,248,411	101,395,953	4,985,253	29,138	5,014,391	5.2%
SC2 Pri	3,828,200	(29,337)	3,798,863	336,397	4,135,260	307,060	1,744	308,804	8.1%
SC3	14,762,400	(65,017)	14,697,383	1,301,484	15,998,867	1,236,467	6,746	1,243,213	8.4%
SC21	1,487,200	(114,617)	1,372,583	121,545	1,494,128	6,928	59,549	66,477	4.5%
Total Pri	20,077,800	(208,970)	19,868,830	1,759,426	21,628,256	1,550,456	68,039	1,618,495	8.1%
Total Sec & Pri	116,488,500	(3,472,128)	113,016,372	10,007,837	123,024,209	6,535,709	97,177	6,632,886	5.7%
Total SC9 (Com)	14,523,000	(65,453)	14,457,547	1,280,246	15,737,793	1,214,793	6,636	1,221,429	8.4%
Total SC22 (Mfg)	8,117,000	368,173	8,485,173	751,380	9,236,553	1,119,553	(221,082)	898,471	11.1%
Total SC 9 & SC 22	22,640,000	302,720	22,942,720	2,031,626	24,974,346	2,334,346	(214,446)	2,119,900	9.4%
SC4	2,451,000	(3,197)	2,447,803	216,758	2,664,561	213,561	1,124	214,685	8.8%
SC5	254,000	10,663	264,663	23,436	288,099	34,099	(5,984)	28,115	11.1%
SC6	252,000	(20,557)	231,443	20,495	251,938	(62)	11,325	11,263	4.5%
SC 16 -dusk-to-dawn	3,263,000	0	3,263,000	288,946	3,551,946	288,946	1,498	290,444	8.9%
SC 16 - energy only	352,400	24,948	377,348	33,415	410,763	58,363	(19,356)	39,007	11.1%
SC16 - Total	3,615,400	24,948	3,640,348	322,361	3,962,709	347,309	(17,858)	329,451	9.1%
Total Lights	6,572,400	11,858	6,584,258	583,050	7,167,308	594,908	(11,393)	583,515	8.9%
Total	422,835,900	0	422,835,900	37,443,007	460,278,907	37,443,007	0	37,443,007	8.9%

ORANGE AND ROCKLAND UTILITIES, INC.

Case 24-E-0060

Determination of Non-Competitive Delivery Revenue Increase for Rate Year 3

Based on Levelized Revenue Requirement

		Incremental Competitive Service, Customer Charge, and RPDC Revenues								
Class	Adj. Rate Yr. Incr. Incl. (Sur)/Def Incl. Mitigation Adj./Incr A ($)	MFC Supply Related Rev B ($)	MFC PP WC Related Rev C ($)	MFC Credit & Collections Related Rev D ($)	POR Credit & Collections Related Rev E ($)	Customer Charge Rev F ($)	Reactive Power Demand Charge Rev G ($)	BPP Charge Rev H ($)	Total Rate Yr. Incremental Comp. Services Rev I = ∑ (A to H) ($)	Non-Competitive Rate Yr. Delivery Revenue Incr J = A - I ($)
SC1	27,278,305	215,708	10,138	62,463	36,761	1,275,207	0	0	1,600,277	25,678,028
SC19	828,400	11,058	520	3,202	1,055	(39,300)	0	0	(23,465)	851,865
Total Res	28,106,705	226,767	10,658	65,665	37,816	1,235,907	0	0	1,576,812	26,529,893
SC2 Sec Dmd	4,283,858	45,780	2,966	11,343	19,117	0	0	0	79,206	4,204,652
SC2 Sec Heating	113,882	328	21	81	297	0	0	0	727	113,155
SC2 Sec ND	106,491	512	33	127	503	0	0	0	1,175	105,316
SC20	510,159	2,022	131	501	785	(480)	0	0	2,959	507,200
Total Sec	5,014,391	48,642	3,151	12,052	20,702	(480)	0	0	84,067	4,930,324
SC2 Pri	308,804	3,520	247	655	716	(16)	0	0	5,121	303,683
SC3	1,243,213	5,912	414	1,101	3,250	(45)	0	0	10,632	1,232,581
SC21	66,477	172	12	33	131	(240)	0	0	108	66,369
Total Pri	1,618,495	9,604	673	1,789	4,097	(301)	0	0	15,862	1,602,633
Total Sec & Pri	6,632,886	58,246	3,824	13,841	24,799	(781)	0	0	99,929	6,532,957
Total SC9 (Com)	1,221,429	2,890	202	538	2,133	0	0	0	5,763	1,215,665
Total SC22 (Mfg)	898,471	6,738	472	1,254	1,794	0	0	0	10,258	888,213
Total SC 9 & SC 22	2,119,900	9,628	675	1,792	3,927	0	0	0	16,022	2,103,878
SC4	214,685	1,261	82	312	71	0	0	0	1,725	212,960
SC5	28,115	14	1	3	84	0	0	0	102	28,013
SC6	11,263	177	12	44	111	576	0	0	920	10,344
SC 16 -dusk-to-dawn	290,444	962	62	239	135	0	0	0	1,399	289,045
SC 16 - energy only	39,007	270	17	67	34	(480)	0	0	(92)	39,099
SC16 - Total	329,451	1,232	80	306	169	(480)	0	0	1,307	328,145
Total Lights	583,515	2,684	174	665	435	96	0	0	4,054	579,461
Total	37,443,007	297,325	15,330	81,963	66,977	1,235,222	0	0	1,696,817	35,746,190

ORANGE AND ROCKLAND UTILITIES, INC.

Case 24-E-0060

**Temporary Credit to be Refunded through
Energy Cost Adjustment in Rate Year 3**

Class	Bundled Rate Yr. 3 Delivery Rev. (1) ($)	Rate Yr. 3 Incr. -4.74780% ($)	Rate Yr. 3 Sales (MWh)	Temporary ECA Credit ($/kWh)
SC1	267,828,300	(12,715,952)	1,745,902	(0.00728)
SC19	9,306,700	(441,864)	73,184	(0.00604)
Total Res	277,135,000	(13,157,816)	1,819,086	
SC2 Sec	87,268,445	(4,143,331)	857,606	(0.00483)
SC2 Sec Heating	1,028,840	(48,847)	13,440	(0.00363)
SC2 Sec ND & UM	2,382,015	(113,093)	15,922	(0.00710)
SC20	5,731,400	(272,115)	91,806	(0.00296)
Total Sec	96,410,700	(4,577,386)	978,774	
SC2 Pri	3,828,200	(181,755)	65,937	(0.00276)
SC3	14,762,400	(700,889)	262,213	(0.00267)
SC21	1,487,200	(70,609)	27,775	(0.00254)
Total Pri	20,077,800	(953,253)	355,925	
Total Sec & Pri	116,488,500	(5,530,639)	1,334,699	
Total SC9 (Com)	14,523,000	(689,523)	489,565	(0.00141)
Total SC22 (Mfg)	8,117,000	(385,379)	246,439	(0.00156)
Total SC 9 & SC 22	22,640,000	(1,074,902)	736,004	
SC4	2,451,000	(116,369)	9,545	(0.01219)
SC5	254,000	(12,059)	2,152	(0.00560)
SC6	252,000	(11,964)	3,365	(0.00356)
SC 16 -dusk-to-dawn	3,263,000	(154,921)	9,525	(0.01626)
SC 16 - energy only	352,400	(16,731)	2,667	(0.00627)
SC16 - Total	3,615,400	(171,652)	12,192	0.00000
Total Lights	6,572,400	(300,080)	27,254	0.00000
Total	422,835,900	(20,063,437)	3,917,043	

Notes:

RY 3 ECA Increase	($20,433,000)
Revenue Taxes	(357,578)
Increase Less Revenue Taxes	(20,075,423)
RY 3 Delivery Revenues	422,835,900
% Decrease	-4.74780%

ORANGE AND ROCKLAND UTILITIES, INC.

Case 24-E-0060

Summary of MFC Monthly Targets
For Rates Effective January 1, 2025, January 1, 2026 and January 1, 2027

Based on Levelized Revenue Requirement

For Rates Effective January 1, 2025	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Total
Supply Related Component*	$390,862	$368,627	$326,821	$306,081	$289,947	$375,311	$469,495	$503,373	$439,902	$343,209	$296,896	$355,375	$4,465,899
Credit and Collections Related Component	76,588	72,034	63,507	59,098	55,882	72,690	93,060	100,236	86,861	67,144	57,411	69,289	873,799
POR Discount Related Component	43,126	41,429	37,480	35,834	34,155	43,462	50,430	55,114	48,702	38,871	34,247	41,049	503,898
Total	$510,576	$482,091	$427,808	$401,013	$379,983	$491,463	$612,985	$658,722	$575,464	$449,224	$388,553	$465,714	$5,843,596

For Rates Effective January 1, 2026	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Total
Supply Related Component*	$401,675	$378,755	$352,233	$320,625	$296,462	$377,215	$487,207	$523,485	$455,813	$347,861	$308,813	$369,569	$4,619,714
Credit and Collections Related Component	79,235	74,504	68,856	62,493	57,349	73,730	96,957	104,889	90,586	68,425	59,992	72,654	909,672
POR Discount Related Component	45,428	43,636	41,506	38,197	36,049	44,435	54,044	58,764	51,743	40,502	36,702	43,533	534,540
Total	$526,338	$496,894	$462,595	$421,315	$389,860	$495,381	$638,208	$687,139	$598,142	$456,789	$405,507	$485,757	$6,063,925

For Rates Effective January 1, 2027	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Total
Supply Related Component*	$417,124	$396,448	$377,791	$346,266	$310,906	$395,262	$520,189	$551,914	$508,637	$379,731	$331,399	$394,743	$4,930,411
Credit and Collections Related Component	84,441	79,987	75,819	69,059	61,996	79,112	106,125	113,300	103,656	76,531	66,256	79,632	995,912
POR Discount Related Component	49,315	47,814	46,518	43,518	39,134	48,982	60,489	65,009	60,500	46,452	40,928	48,620	597,281
Total	$550,880	$524,249	$500,129	$458,843	$412,036	$523,357	$686,803	$730,223	$672,792	$502,715	$438,583	$522,995	$6,523,604

* MFC Supply Related Component Includes purchased power working capital.

Orange and Rockland Utilities, Inc.
Case 24-E-0060

Rates in Brief - Rate Year 1

Service Classification No. 1

		Present Summer	Present Winter	Proposed Summer	Proposed Winter
Customer Charge:	per month	$22.00	$22.00	$22.00	$22.00
Delivery Charges:					
First 250 kWh	¢ per kWh	10.363	10.363	10.409	10.409
Over 250 kWh	¢ per kWh	12.960	10.363	13.018	10.409
Minimum Charge:					
Monthly*	monthly	$22.00		$22.00	
Per Contract	per contract	132.00		132.00	
Standby Rates					
Customer Charge:	per month	$22.00	$22.00	$22.00	$22.00
Delivery Charges:					
Contract Demand Charge	per kW	$3.30	$3.30	$2.74	$2.74
As Used Daily Demand Charge					
Period I	per kW	$1.2692	N/A	$1.4234	N/A
Period II	per kW	$0.8511	N/A	$0.9826	N/A
Period III	per kW	N/A	$0.8511	N/A	$0.9826
Charges Applicable to Both Standard and Standby Service Rates					
Merchant Function Charge		See Page 22 of 22		See Page 22 of 22	
Billing & Payment Processing Chg		See Page 22 of 22		See Page 22 of 22	
Other Delivery and Supply Charges		As Described in Tariff		As Described in Tariff	

* Plus any applicable billing and payment processing charges.

Orange and Rockland Utilities, Inc.
Case 24-E-0060

Rates in Brief - Rate Year 1

Service Classification No. 2 Secondary - Non-Demand Billed Customers

		Present		Proposed	
		Summer	Winter	Summer	Winter
Customer Charge:					
Metered Service	per month	$24.00	$24.00	$21.00	$21.00
Unmetered Service	per month	20.00	20.00	20.00	20.00
Delivery Charge:					
Usage Charge					
All kWh	¢ per kWh	8.683	6.416	9.158	6.767
Space Heating:					
Delivery	¢ per kWh	14.943	3.734	15.071	3.766
Minimum Charge		Customer Charge*		Customer Charge*	
Standby Rates					
Customer Charge:	per month	$26.00	$26.00	$26.00	$26.00
Delivery Charges:					
Contract Demand Charge	per kW	$3.25	$3.25	$2.63	$2.63
As Used Daily Demand Charge					
Period I	per kW	$1.1421	N/A	$1.1955	N/A
Period II	per kW	$0.7225	N/A	$0.7814	N/A
Period III	per kW	N/A	$0.7225	N/A	$0.7814
Charges Applicable to Both Standard and Standby Service Rates					
Merchant Function Charge		See Page 22 of 22		See Page 22 of 22	
Billing & Payment Processing Chg		See Page 22 of 22		See Page 22 of 22	
Other Delivery and Supply Charges		As Described in Tariff		As Described in Tariff	

* Plus any applicable billing and payment processing charges.

Orange and Rockland Utilities, Inc.
Case 24-E-0060

Rates in Brief - Rate Year 1

Service Classification No. 2 Secondary Demand Billed

		Present Summer	Present Winter	Proposed Summer	Proposed Winter
Standard Rates					
Customer Charge:					
Metered Service	per month	$27.00	$27.00	$27.00	$27.00
Delivery Charge:					
Demand Charge					
First 5 kW	per kW	$4.00	$2.36	$4.79	$2.80
Over 5 kW	per kW	26.30	15.29	25.97	15.08
Usage Charge					
First 1,250 kWh	¢ per kWh	4.758	3.673	3.428	3.141
Over 1,250 kWh	¢ per kWh	3.084	2.970	3.428	3.141
Minimum Charge		Customer Charge plus the demand charges*		Customer Charge plus the demand charges*	
Standby Rates					
Customer Charge:	per month	$26.00	$26.00	$26.00	$26.00
Delivery Charges:					
Contract Demand Charge	per kW	$3.25	$3.25	$2.63	$2.63
As Used Daily Demand Charge					
Period I	per kW	$1.1421	N/A	$1.1955	N/A
Period II	per kW	$0.7225	N/A	$0.7814	N/A
Period III	per kW	N/A	$0.7225	N/A	$0.7814
Charges Applicable to Both Standard and Standby Service Rates					
Merchant Function Charge		See Page 22 of 22		See Page 22 of 22	
Billing & Payment Processing Chg		See Page 22 of 22		See Page 22 of 22	
Reactive Power Demand Charge		See Page 22 of 22		See Page 22 of 22	
Other Delivery and Supply Charges		As Described in Tariff		As Described in Tariff	

* Plus any applicable billing and payment processing charges.

Orange and Rockland Utilities, Inc.
Case 24-E-0060

Rates in Brief - Rate Year 1

Service Classification No. 2 Primary

		Present Summer	Present Winter	Proposed Summer	Proposed Winter
Standard Rates					
Customer Charge:	per month	$41.00	$41.00	$32.00	$32.00
Delivery Charge:					
Demand Charge	per kW	$20.94	$11.62	$20.94	$11.62
Usage Charge	¢ per kWh	0.786	0.786	0.781	0.781
Minimum Charge		Customer Charge plus the demand charges*		Customer Charge plus the demand charges*	
Standby Rates					
Customer Charge:	per month	$41.00	$41.00	$32.00	$32.00
Delivery Charges:					
Contract Demand Charge	per kW	$2.38	$2.38	$2.47	$2.47
As Used Daily Demand Charge					
Period I	per kW	$0.8160	N/A	$0.7993	N/A
Period II	per kW	$0.6117	N/A	$0.6011	N/A
Period III	per kW	N/A	$0.6117	N/A	$0.6011
Charges Applicable to Both Standard and Standby Service Rates					
Merchant Function Charge		See Page 22 of 22		See Page 22 of 22	
Billing & Payment Processing Chg		See Page 22 of 22		See Page 22 of 22	
Reactive Power Demand Charge		See Page 22 of 22		See Page 22 of 22	
Other Delivery and Supply Charges		As Described in Tariff		As Described in Tariff	

* Plus any applicable metering and/or billing and payment processing charges.

Orange and Rockland Utilities, Inc.
Case 24-E-0060

Rates in Brief - Rate Year 1

Service Classification No. 3

		Present		Proposed	
		Summer	Winter	Summer	Winter
Standard Rates					
Customer Charge:	per month	$60.00	$60.00	$45.00	$45.00
Delivery Charge:					
Demand Charge	per kW	$24.60	$13.92	$24.63	$13.94
Usage Charge	¢ per kWh	0.696	0.696	0.696	0.696
Minimum Charge:		$60.00	plus the demand charges*	$45.00	plus the demand charges*
Standby Rates					
Customer Charge:	per month	$61.00	$61.00	$45.00	$45.00
Delivery Charges:					
Contract Demand Charge	per kW	$3.01	$3.01	$2.84	$2.84
As Used Daily Demand Charge					
Period I	per kW	$0.8989	N/A	$0.8880	N/A
Period II	per kW	$0.6726	N/A	$0.6816	N/A
Period III	per kW	N/A	$0.6726	N/A	$0.6816
Charges Applicable to Both Standard and Standby Service Rates					
Merchant Function Charge		See Page 22 of 22		See Page 22 of 22	
Billing & Payment Processing Chg		See Page 22 of 22		See Page 22 of 22	
Reactive Power Demand Charge		See Page 22 of 22		See Page 22 of 22	
Other Delivery and Supply Charges		As Described in Tariff		As Described in Tariff	

* Plus any applicable metering and/or billing and payment processing charges.

Orange and Rockland Utilities, Inc.
Case 24-E-0060

Rates in Brief - Rate Year 1

Service Classification No. 4

Luminaire Charge, per month

Nominal Lumens	Luminaire Type	Watts	Total Wattage	Present Delivery Charge	Proposed Delivery Charge
Street Lighting Luminaires					
5,800	Sodium Vapor	70	108	$12.98	$13.03
9,500	Sodium Vapor	100	142	14.16	14.21
16,000	Sodium Vapor	150	199	16.82	16.88
27,500	Sodium Vapor	250	311	22.49	22.58
46,000	Sodium Vapor	400	488	31.49	31.61
Off-Roadway Luminaires					
27,500	Sodium Vapor	250	311	$29.15	$29.26
46,500	Sodium Vapor	400	488	36.04	36.18
LED Street Lighting Luminaires					
3,000	LED	15-29	23	$11.55	$11.59
3,900	LED	30-39	35	11.68	11.72
5,000	LED	40-59	50	11.80	11.84
7,250	LED	60-89	68	13.04	13.09
12,000	LED	90-129	103	13.73	13.78
16,000	LED	130-169	140	15.08	15.14
22,000	LED	170-220	200	20.56	20.64

The following luminaires will no longer be installed. Charges are for existing luminaires only.

Nominal Lumens	Luminaire Type	Watts	Total Wattage	Present Delivery Charge	Proposed Delivery Charge
600	Open Bottom Inc	52	52	$6.41	$6.43
1,000	Open Bottom Inc	92	92	8.74	8.77
4,000	Mercury Vapor PB	100	127	10.30	10.34
4,000	Mercury Vapor	100	127	11.65	11.69
7,900	Mercury Vapor PB	175	215	12.63	12.68
7,900	Mercury Vapor	175	211	14.13	14.18
12,000	Mercury Vapor	250	296	18.51	18.58
22,500	Mercury Vapor	400	459	23.64	23.73
59,000	Mercury Vapor	1,000	1,105	46.44	46.62
130,000	Sodium Vapor	1,000	1,120	66.29	66.54

Orange and Rockland Utilities, Inc.
Case 24-E-0060

Rates in Brief - Rate Year 1

Service Classification No. 4 (Continued)

The following luminaires will no longer be installed. Charges are for existing luminaires only.

Luminaire Charge, per month

Nominal Lumens	Luminaire Type	Watts	Total Wattage	Present Delivery Charge	Proposed Delivery Charge
5,890	LED	70	74	$14.19	$14.24
9,365	LED	100	101	16.09	16.15
3,400	Induction	40	45	14.15	14.20
12,750	Induction	150	160	19.30	19.37

		Present	Proposed
Additional Charge:			
UG Svc- Customer owned and maintained duct	per month	$5.00	$5.02
15 Foot Brackets	$ per month	0.47	0.47
Merchant Function Charge		See Page 22 of 22	See Page 22 of 22
Billing & Payment Processing Chg		See Page 22 of 22	See Page 22 of 22
Other Delivery and Supply Charges		As Described in Tariff	As Described in Tariff

Orange and Rockland Utilities, Inc.
Case 24-E-0060

Rates in Brief - Rate Year 1

Service Classification No. 5

		Present Year-round	Proposed Year-round
Delivery Charge:	¢ per kWh	10.985	11.085
Merchant Function Charge		See Page 22 of 22	See Page 22 of 22
Billing & Payment Processing Chg		See Page 22 of 22	See Page 22 of 22
Other Delivery and Supply Charges		As Described in Tariff	As Described in Tariff

Orange and Rockland Utilities, Inc.
Case 24-E-0060

Rates in Brief - Rate Year 1

Service Classification No. 6

		Present Year-round	Proposed Year-round
Delivery Charges for Service Types A & B:	¢ per kWh	8.415	8.377
Delivery Charges for Service Type C:			
Customer Charge		$24.00	$24.00
Delivery Charge	¢ per kWh	7.814	7.779
Merchant Function Charge		See Page 22 of 22	See Page 22 of 22
Billing & Payment Processing Chg		See Page 22 of 22	See Page 22 of 22
Other Delivery and Supply Charges		As Described in Tariff	As Described in Tariff

Orange and Rockland Utilities, Inc.
Case 24-E-0060

Rates in Brief - Rate Year 1

Service Classification No. 9

				Present Year-round	Proposed Year-round
Standard Rates					
Customer Charge:			per month	$500.00	$500.00
Delivery Charges:					
Primary:					
Demand Charge					
	Period A	All kW @	per kW	$25.91	$25.92
	Period B	All kW @	per kW	12.16	12.17
	Period C	All kW @	per kW	No Charge	No Charge
Usage Charge					
	Period A	All kWh @	¢ per kWh	0.441	0.441
	Period B	All kWh @	¢ per kWh	0.441	0.441
	Period C	All kWh @	¢ per kWh	0.164	0.164
Substation:					
Demand Charge					
	Period A	All kW @	per kW	$18.73	$18.74
	Period B	All kW @	per kW	8.47	8.47
	Period C	All kW @	per kW	No Charge	No Charge
Usage Charge					
	Period A	All kWh @	¢ per kWh	0.244	0.244
	Period B	All kWh @	¢ per kWh	0.244	0.244
	Period C	All kWh @	¢ per kWh	0.150	0.150
Transmission:					
Demand Charge					
	Period A	All kW @	per kW	$9.24	$9.24
	Period B	All kW @	per kW	6.29	6.29
	Period C	All kW @	per kW	No Charge	No Charge
Usage Charge					
	Period A	All kWh @	¢ per kWh	0.139	0.139
	Period B	All kWh @	¢ per kWh	0.139	0.139
	Period C	All kWh @	¢ per kWh	0.131	0.131

Orange and Rockland Utilities, Inc.
Case 24-E-0060

Rates in Brief - Rate Year 1

Service Classification No. 9 (Continued)

		Present	Proposed
Standby Rates			
Customer Charge:	per month	$500.00	$500.00
Delivery Charges:			
Primary:			
Contract Demand Charge	per kW	$2.43	$2.50
As Used Daily Demand Charge			
Period I	per kW	$0.7984	$0.8008
Period II	per kW	$0.6022	$0.6114
Period III	per kW	$0.6022	$0.6114
Substation:			
Contract Demand Charge	per kW	$1.36	$0.97
As Used Daily Demand Charge			
Period I	per kW	$0.6691	$0.8574
Period II	per kW	$0.3840	$0.5065
Period III	per kW	$0.3840	$0.5065
Transmission:			
Contract Demand Charge	per kW	$2.93	$2.25
As Used Daily Demand Charge			
Period I	per kW	$0.3183	$0.5165
Period II	per kW	$0.1262	$0.2158
Period III	per kW	$0.1262	$0.2158
Minimum Charge		Sum of the Customer Charge, Min. Monthly Demand Charge, contract demand charge, the reactive power demand charge, and any applicable BPP charges.	Sum of the Customer Charge, Min. Monthly Demand Charge, contract demand charge, the reactive power demand charge, and any applicable BPP charges.
Min. Monthly Demand Charge		$50.56	$51.74
Contract Demand Charge - Pri	per kW of CD	$3.68	$3.77
Contract Demand Charge - Sec	per kW of CD	$6.04	$6.18

Orange and Rockland Utilities, Inc.
Case 24-E-0060

Rates in Brief - Rate Year 1

Service Classification No. 9 (Continued)

Charges Applicable to Both Standard and Standby Service Rates

	Present	Proposed
Merchant Function Charge	See Page 22 of 22	See Page 22 of 22
Billing & Payment Processing Chg	See Page 22 of 22	See Page 22 of 22
Reactive Power Demand Charge	See Page 22 of 22	See Page 22 of 22
Other Delivery and Supply Charges	As Described in Tariff	As Described in Tariff

Definition of Rating Periods (Standard Rates):

Period A -	8:00 a.m. to 11:00 p.m. prevailing time, Monday through Friday, except holidays, June through September.
Period B -	8:00 a.m. to 11:00 p.m. prevailing time, Monday through Friday, except holidays, October through May.
Period C -	11:00 p.m. to 8:00 a.m. prevailing time, Monday through Friday, all hours on Saturday, Sunday and holidays, all months.

Orange and Rockland Utilities, Inc.
Case 24-E-0060

Rates in Brief - Rate Year 1

Service Classification No. 15

		Present Year-round	Proposed Year-round
Customer Charge*:			
SC Nos. 1 and 19	per month	$22.00	$22.00
SC Nos. 2 Secondary and 20	per month	26.00	26.00
SC No. 2 Primary	per month	41.00	32.00
SC Nos. 3 and 21	per month	61.00	45.00
SC No. 9	per month	500.00	500.00
SC No. 22	per month	500.00	500.00
Contract Demand Charge*			
SC Nos. 1 and 19	per kW	$0.03	$0.01
SC Nos. 2 Secondary and 20	per kW	0.16	0.18
SC No. 2 Primary	per kW	0.17	0.35
SC Nos. 3 and 21	per kW	0.49	0.66
SC No. 9 - Primary	per kW	0.34	0.38
SC No. 9 - Substation	per kW	0.54	0.42
SC No. 9 - Transmission	per kW	1.60	1.04
SC No. 22 - Primary	per kW	0.02	0.49
SC No. 22 - Substation	per kW	1.29	1.30
SC No. 22 - Transmission	per kW	0.87	0.43
Reactive Power Demand Charge		See Page 22 of 22	See Page 22 of 22

* Based on the customer's otherwise applicable service classification.

		Plus: Increase in Rates and Charges	Plus: Increase in Rates and Charges

Orange and Rockland Utilities, Inc.
Case 24-E-0060

Rates in Brief - Rate Year 1

Service Classification No. 16

Luminaire Charge, per month

Nominal Lumens	Luminaire Type	Watts	Total Wattage	Present Delivery Charge	Proposed Delivery Charge
Power Bracket Luminaires					
5,800	Sodium Vapor	70	108	$24.03	$24.20
9,500	Sodium Vapor	100	142	25.69	25.87
16,000	Sodium Vapor	150	199	30.20	30.41
Street Lighting Luminaires					
5,800	Sodium Vapor	70	108	$26.30	$26.48
9,500	Sodium Vapor	100	142	28.05	28.24
16,000	Sodium Vapor	150	199	32.46	32.69
27,500	Sodium Vapor	250	311	41.37	41.66
46,000	Sodium Vapor	400	488	56.79	57.18
Flood Lighting Luminaires					
27,500	Sodium Vapor	250	311	$41.37	$41.66
46,000	Sodium Vapor	400	488	56.79	57.18
LED Street Lighting Luminaires					
3,000	LED	15-29	23	$10.88	$10.96
3,900	LED	30-39	35	11.00	11.08
5,000	LED	40-59	50	11.12	11.20
7,250	LED	60-89	68	12.28	12.37
12,000	LED	90-129	103	12.93	13.02
16,000	LED	130-169	140	14.21	14.31
22,000	LED	170-220	200	19.37	19.50
LED Flood Lighting Luminaires					
15,000	LED	100-159	125	$13.91	$14.01
27,000	LED	160-249	205	16.40	16.51
37,500	LED	230-320	290	18.91	19.04
LED Power Bracket Luminaires					
3,950	LED	25-39	35	$9.23	$9.29
5,550	LED	44-55	50	9.30	9.36
7,350	LED	56-70	65	9.39	9.46

The following luminaires will no longer be installed. Charges are for existing luminaires only.

Nominal Lumens	Luminaire Type	Watts	Total Wattage	Present Delivery Charge	Proposed Delivery Charge
Power Bracket Luminaires					
4,000	Mercury Vapor	100	127	$22.06	$22.21
7,900	Mercury Vapor	175	215	25.54	25.72
22,500	Mercury Vapor	400	462	36.69	36.94
Street Lighting Luminaires					
21,250	Mercury Vapor	250	263	$49.30	$49.64
4,000	Mercury Vapor	100	127	24.18	24.35
7,900	Mercury Vapor	175	211	27.99	28.18
12,000	Mercury Vapor	250	296	35.25	35.49
22,500	Mercury Vapor	400	459	43.42	43.72
40,000	Mercury Vapor	700	786	64.25	64.70
59,000	Mercury Vapor	1,000	1,105	80.17	80.73
1,000	Incandescent	92	92	19.22	19.35
5,890	LED	70	74	35.01	35.25
9,365	LED	100	101	37.84	38.10

Rates in Brief - Rate Year 1

Service Classification No. 16 (Continued)

Nominal Lumens	Luminaire Type	Watts	Total Wattage	Present Delivery Charge	Proposed Delivery Charge
The following luminaires will no longer be installed. Charges are for existing luminaires only.					
Flood Lighting Luminaires					
12,000	Mercury Vapor	250	296	$35.25	$35.49
22,500	Mercury Vapor	400	459	43.42	43.72
40,000	Mercury Vapor	700	786	64.25	64.70
59,000	Mercury Vapor	1,000	1,105	80.17	80.73
15 Foot Brackets			$ per month	0.81	0.82
Delivery Charges for Service Type C:					
Customer Charge (Metered)			per month	$24.00	$24.00
Customer Charge (Unmetered)			per month	20.00	20.00
Delivery Charge			¢ per kWh	8.541	8.561
Merchant Function Charge				See Page 22 of 22	See Page 22 of 22
Billing & Payment Processing Chg				See Page 22 of 22	See Page 22 of 22
Other Delivery and Supply Charges				As Described in Tariff	As Described in Tariff

Orange and Rockland Utilities, Inc.
Case 24-E-0060

Rates in Brief - Rate Year 1

Service Classification No. 19

				Present Year-round	Proposed Year-round
Customer Charge:			per month	$32.00	$30.00
Delivery Charges:					
	Period I	All kWh @	¢ per kWh	41.846	42.384
	Period II	All kWh @	¢ per kWh	14.973	15.165
	Period III	All kWh @	¢ per kWh	14.973	15.165
	Period IV	All kWh @	¢ per kWh	2.695	2.730
Minimum Charge:		per contract (not less than) plus applicable billing and payment processing charges		$384.00	$360.00
Standby Rates					
Customer Charge:		per month		$22.00	$22.00
Delivery Charges:					
Contract Demand Charge		per kW		$3.30	$2.74
As Used Daily Demand Charge					
	Period I	per kW		$1.2692	$1.4234
	Period II	per kW		$0.8511	$0.9826
	Period III	per kW		$0.8511	$0.9826
Charges Applicable to Both Standard and Standby Service Rates					
Merchant Function Charge				See Page 22 of 22	See Page 22 of 22
Billing & Payment Processing Chg				See Page 22 of 22	See Page 22 of 22
Other Delivery and Supply Charges				As Described in Tariff	As Described in Tariff

Definition of Rating Periods (Standard Rates):

Period I -	12:00 p.m. to 7:00 p.m. prevailing time, Monday through Friday, except holidays, June through September.
Period II -	10:00 a.m. to 12:00 p.m. and 7:00 p.m. to 9:00 p.m. prevailing time, Monday through Friday, except holidays, June through September.
Period III -	10:00 a.m. to 9:00 p.m. prevailing time, Monday through Friday, except holidays, October through May.
Period IV -	9:00 p.m. to 10:00 a.m. prevailing time, Monday through Friday, all hours on Saturday, Sunday and holidays, all months

Orange and Rockland Utilities, Inc.
Case 24-E-0060

Rates in Brief - Rate Year 1

Service Classification No. 20

			Present Year-round	Proposed Year-round
Standard Rates				
Customer Charge:		per month	$40.00	$30.00
Delivery Charges:				
Demand Charge				
Period I	All kW @	per kW	$35.72	$33.92
Period II	All kW @	per kW	15.29	16.94
Period III	All kW @	per kW	0.73	0.76
Usage Charge				
Period I	All kWh @	¢ per kWh	3.592	3.349
Period II	All kWh @	¢ per kWh	0.863	0.939
Period III	All kWh @	¢ per kWh	0.048	0.049
Minimum Charge:			Sum of the Customer Charge and $120.00 plus any applicable billing and payment processing charges.	Sum of the Customer Charge and $90.00 plus any applicable billing and payment processing charges.
Standby Rates				
Customer Charge:		per month	$26.00	$26.00
Delivery Charges:				
Contract Demand Charge		per kW	$3.25	$2.63
As Used Daily Demand Charge				
Period I		per kW	$1.1421	$1.1955
Period II		per kW	$0.7225	$0.7814
Period III		per kW	$0.7225	$0.7814
Charges Applicable to Both Standard and Standby Service Rates				
Merchant Function Charge			See Page 22 of 22	See Page 22 of 22
Billing & Payment Processing Chg			See Page 22 of 22	See Page 22 of 22
Reactive Power Demand Charge			See Page 22 of 22	See Page 22 of 22
Other Delivery and Supply Charges			As Described in Tariff	As Described in Tariff

Definition of Rating Periods (Standard Rates):

Period I -	1:00 p.m. to 7:00 p.m. prevailing time, Monday through Friday, except holidays, June through September.
Period II -	10:00 a.m. to 9:00 p.m. prevailing time, Monday through Friday, except holidays, October through May.
Period III -	7:00 p.m. to 1:00 p.m. prevailing time, Monday through Friday, June through September; 9:00 p.m. to 10:00 a.m. prevailing time, Monday through Friday, October through May; all hours on Saturday, Sunday and holidays, all months.

Orange and Rockland Utilities, Inc.
Case 24-E-0060

Rates in Brief - Rate Year 1

Service Classification No. 21

				Present Year-round	Proposed Year-round
Customer Charge:			per month	$73.00	$45.00
Delivery Charges:					
Demand Charge					
	Period I	All kW @	per kW	$35.56	$31.33
	Period II	All kW @	per kW	12.53	14.97
	Period III	All kW @	per kW	No Charge	No Charge
Usage Charge					
	Period I	All kWh @	¢ per kWh	1.553	1.356
	Period II	All kWh @	¢ per kWh	1.553	1.839
	Period III	All kWh @	¢ per kWh	0.136	0.144
Minimum Charge:				Sum of the Customer Charge and any applicable billing and payment processing charges.	Sum of the Customer Charge and any applicable billing and payment processing charges.

Standby Rates

		Present	Proposed
Customer Charge:	per month	$61.00	$45.00
Delivery Charges:			
Contract Demand Charge	per kW	$3.01	$2.84
As Used Daily Demand Charge			
Period I	per kW	$0.8989	$0.8880
Period II	per kW	$0.6726	$0.6816
Period III	per kW	$0.6726	$0.6816

Charges Applicable to Both Standard and Standby Service Rates

	Present	Proposed
Merchant Function Charge	See Page 22 of 22	See Page 22 of 22
Billing & Payment Processing Chg	See Page 22 of 22	See Page 22 of 22
Reactive Power Demand Charge	See Page 22 of 22	See Page 22 of 22
Other Delivery and Supply Charges	As Described in Tariff	As Described in Tariff

Definition of Rating Periods (Standard Rates):

Period I -	1:00 p.m. to 7:00 p.m. prevailing time, Monday through Friday, except holidays, June through September.
Period II -	10:00 a.m. to 9:00 p.m. prevailing time, Monday through Friday, except holidays, October through May.
Period III -	7:00 p.m. to 1:00 p.m. prevailing time, Monday through Friday, June through September; 9:00 p.m. to 10:00 a.m. prevailing time, Monday through Friday, October through May; all hours on Saturday, Sunday and holidays, all months.

Orange and Rockland Utilities, Inc.
Case 24-E-0060

Rates in Brief - Rate Year 1

Service Classification No. 22

				Present Year-round	Proposed Year-round
Standard Rates					
Customer Charge:			per month	$500.00	$500.00
Delivery Charges:					
Primary:					
Demand Charge					
	Period A	All kW @	per kW	$19.65	$19.65
	Period B	All kW @	per kW	11.21	11.21
	Period C	All kW @	per kW	No Charge	No Charge
Usage Charge					
	Period A	All kWh @	¢ per kWh	0.710	0.684
	Period B	All kWh @	¢ per kWh	0.710	0.684
	Period C	All kWh @	¢ per kWh	0.126	0.121
Substation:					
Demand Charge					
	Period A	All kW @	per kW	$12.62	$12.62
	Period B	All kW @	per kW	6.96	6.96
	Period C	All kW @	per kW	No Charge	No Charge
Usage Charge					
	Period A	All kWh @	¢ per kWh	0.298	0.287
	Period B	All kWh @	¢ per kWh	0.298	0.287
	Period C	All kWh @	¢ per kWh	0.126	0.121
Transmission:					
Demand Charge					
	Period A	All kW @	per kW	$7.25	$7.37
	Period B	All kW @	per kW	6.34	6.45
	Period C	All kW @	per kW	No Charge	No Charge
Usage Charge					
	Period A	All kWh @	¢ per kWh	0.126	0.121
	Period B	All kWh @	¢ per kWh	0.126	0.121
	Period C	All kWh @	¢ per kWh	0.126	0.121
Minimum Charge				Sum of the Customer Charge, Min. Monthly Demand Charge, contract demand charge, the reactive power demand charge, and any applicable billing and payment processing charges.	Sum of the Customer Charge, Min. Monthly Demand Charge, contract demand charge, the reactive power demand charge, and any applicable billing and payment processing charges.
Min. Monthly Demand Charge				$50.56	$51.74
Contract Demand Charge - Pri			per kW of CD	$3.68	$3.77
Contract Demand Charge - Sec			per kW of CD	$6.04	$6.18

Orange and Rockland Utilities, Inc.
Case 24-E-0060

Rates in Brief - Rate Year 1

Service Classification No. 22 (Continued)

		Present	Proposed
Standby Rates			
Customer Charge:	per month	$500.00	$500.00
Delivery Charges:			
Primary:			
Contract Demand Charge	per kW	$1.80	$2.48
As Used Daily Demand Charge			
Period I	per kW	$0.7041	$0.6436
Period II	per kW	$0.5303	$0.4916
Period III	per kW	$0.5303	$0.4916
Substation:			
Contract Demand Charge	per kW	$1.49	$1.50
As Used Daily Demand Charge			
Period I	per kW	$0.5629	$0.5363
Period II	per kW	$0.2821	$0.2891
Period III	per kW	$0.2821	$0.2891
Transmission:			
Contract Demand Charge	per kW	$1.14	$0.67
As Used Daily Demand Charge			
Period I	per kW	$0.3965	$0.5600
Period II	per kW	$0.1975	$0.2377
Period III	per kW	$0.1975	$0.2377

Orange and Rockland Utilities, Inc.
Case 24-E-0060

Rates in Brief - Rate Year 1

Service Classification No. 22 (Continued)

		Present Year-round	Proposed Year-round
Standby Service Rates – Existing Standby Service Customer on Phase- In			
Customer Charge:	per month	$500.00	$500.00
Transmission:			
Contract Demand Charge	per kW	$1.44	$1.38
As Used Daily Demand Charge (S)	per kW	$0.3447	$0.3720
As Used Daily Demand Charge (W)	per kW	$0.3127	$0.3395
Charges Applicable to Both Standard and Standby Service Rates			
Merchant Function Charge		See Page 22 of 22	See Page 22 of 22
Billing & Payment Processing Chg		See Page 22 of 22	See Page 22 of 22
Reactive Power Demand Charge		See Page 22 of 22	See Page 22 of 22
Other Delivery and Supply Charges		As Described in Tariff	As Described in Tariff

Definition of Rating Periods (Standard Rates):

Period A - 8:00 a.m. to 11:00 p.m. prevailing time, Monday through Friday, except holidays, June through September.

Period B - 8:00 a.m. to 11:00 p.m. prevailing time, Monday through Friday, except holidays, October through May.

Period C - 11:00 p.m. to 8:00 a.m. prevailing time, Monday through Friday, all hours on Saturday, Sunday and holidays, all months.

Orange and Rockland Utilities, Inc.
Case 24-E-0060

Rates in Brief - Rate Year 1

Other Charges

		Present	Proposed
Merchant Function Charge			
Service Classification Nos. 1 & 19			
Supply Related	¢ per kWh	0.190	0.179
Purch Pwr Wrking Cap	¢ per kWh	0.053	0.097
Credit & Collections	¢ per kWh	0.052	0.059
Uncollectibles	¢ per kWh	Variable	Variable
Service Classification Nos. 2 Secondary, 20, 4, 5, 6 & 16			
Supply Related	¢ per kWh	0.099	0.098
Purch Pwr Wrking Cap	¢ per kWh	0.053	0.097
Credit & Collections	¢ per kWh	0.023	0.029
Uncollectibles	¢ per kWh	Variable	Variable
Service Classification Nos. 2 Primary, 3, 9, 21 & 22			
Supply Related	¢ per kWh	0.050	0.096
Purch Pwr Wrking Cap	¢ per kWh	0.053	0.097
Credit & Collections	¢ per kWh	0.008	0.021
Uncollectibles	¢ per kWh	Variable	Variable
Billing & Payment Processing Chg	per month	$1.50	$2.10
Reactive Power Demand Charge	per KVAr	$0.85	$1.05

Orange and Rockland Utilities, Inc.
Case 24-E-0060

Rates in Brief - Rate Year 2

Service Classification No. 1

		Present Summer	Present Winter	Proposed Summer	Proposed Winter
Customer Charge:	per month	$22.00	$22.00	$22.50	$22.50
Delivery Charges:					
First 250 kWh	¢ per kWh	10.409	10.409	11.052	11.052
Over 250 kWh	¢ per kWh	13.018	10.409	13.822	11.052
Minimum Charge:					
Monthly*	monthly	$22.00		$22.50	
Per Contract	per contract	132.00		135.00	
Standby Rates					
Customer Charge:	per month	$22.00	$22.00	$23.00	$23.00
Delivery Charges:					
Contract Demand Charge	per kW	$2.74	$2.74	$2.59	$2.59
As Used Daily Demand Charge					
Period I	per kW	$1.4234	N/A	$1.5428	N/A
Period II	per kW	$0.9826	N/A	$1.0650	N/A
Period III	per kW	N/A	$0.9826	N/A	$1.0650
Charges Applicable to Both Standard and Standby Service Rates					
Merchant Function Charge		See Page 22 of 22		See Page 22 of 22	
Billing & Payment Processing Chg		See Page 22 of 22		See Page 22 of 22	
Other Delivery and Supply Charges		As Described in Tariff		As Described in Tariff	

* Plus any applicable billing and payment processing charges.

Orange and Rockland Utilities, Inc.
Case 24-E-0060

Rates in Brief - Rate Year 2

Service Classification No. 2 Secondary - Non-Demand Billed Customers

		Present Summer	Present Winter	Proposed Summer	Proposed Winter
Customer Charge:					
Metered Service	per month	$21.00	$21.00	$21.00	$21.00
Unmetered Service	per month	20.00	20.00	20.00	20.00
Delivery Charge:					
Usage Charge					
All kWh	¢ per kWh	9.158	6.767	9.535	7.045
Space Heating:					
Delivery	¢ per kWh	15.071	3.766	15.860	3.963
Minimum Charge		Customer Charge*		Customer Charge*	
Standby Rates					
Customer Charge:	per month	$26.00	$26.00	$26.00	$26.00
Delivery Charges:					
Contract Demand Charge	per kW	$2.63	$2.63	$2.66	$2.66
As Used Daily Demand Charge					
Period I	per kW	$1.1955	N/A	$1.2294	N/A
Period II	per kW	$0.7814	N/A	$0.8035	N/A
Period III	per kW	N/A	$0.7814	N/A	$0.8035
Charges Applicable to Both Standard and Standby Service Rates					
Merchant Function Charge		See Page 22 of 22		See Page 22 of 22	
Billing & Payment Processing Chg		See Page 22 of 22		See Page 22 of 22	
Other Delivery and Supply Charges		As Described in Tariff		As Described in Tariff	

* Plus any applicable billing and payment processing charges.

Orange and Rockland Utilities, Inc.
Case 24-E-0060

Rates in Brief - Rate Year 2

Service Classification No. 2 Secondary Demand Billed

		Present Summer	Present Winter	Proposed Summer	Proposed Winter
Standard Rates					
Customer Charge:					
Metered Service	per month	$27.00	$27.00	$27.00	$27.00
Delivery Charge:					
Demand Charge					
First 5 kW	per kW	$4.79	$2.80	$5.75	$3.34
Over 5 kW	per kW	25.97	15.08	26.63	15.44
Usage Charge					
First 1,250 kWh	¢ per kWh	3.428	3.141	3.428	3.141
Over 1,250 kWh	¢ per kWh	3.428	3.141	3.428	3.141
Minimum Charge		Customer Charge plus the demand charges*		Customer Charge plus the demand charges*	
Standby Rates					
Customer Charge:	per month	$26.00	$26.00	$26.00	$26.00
Delivery Charges:					
Contract Demand Charge	per kW	$2.63	$2.63	$2.66	$2.66
As Used Daily Demand Charge					
Period I	per kW	$1.1955	N/A	$1.2294	N/A
Period II	per kW	$0.7814	N/A	$0.8035	N/A
Period III	per kW	N/A	$0.7814	N/A	$0.8035
Charges Applicable to Both Standard and Standby Service Rates					
Merchant Function Charge		See Page 22 of 22		See Page 22 of 22	
Billing & Payment Processing Chg		See Page 22 of 22		See Page 22 of 22	
Reactive Power Demand Charge		See Page 22 of 22		See Page 22 of 22	
Other Delivery and Supply Charges		As Described in Tariff		As Described in Tariff	

* Plus any applicable billing and payment processing charges.

Orange and Rockland Utilities, Inc.
Case 24-E-0060

Rates in Brief - Rate Year 2

Service Classification No. 2 Primary

		Present		Proposed	
		Summer	Winter	Summer	Winter
Standard Rates					
Customer Charge:	per month	$32.00	$32.00	$32.00	$32.00
Delivery Charge:					
Demand Charge	per kW	$20.94	$11.62	$21.76	$12.07
Usage Charge	¢ per kWh	0.781	0.781	0.781	0.781
Minimum Charge		Customer Charge plus the demand charges*		Customer Charge plus the demand charges*	
Standby Rates					
Customer Charge:	per month	$32.00	$32.00	$32.00	$32.00
Delivery Charges:					
Contract Demand Charge	per kW	$2.47	$2.47	$2.58	$2.58
As Used Daily Demand Charge					
Period I	per kW	$0.7993	N/A	$0.8227	N/A
Period II	per kW	$0.6011	N/A	$0.6187	N/A
Period III	per kW	N/A	$0.6011	N/A	$0.6187
Charges Applicable to Both Standard and Standby Service Rates					
Merchant Function Charge		See Page 22 of 22		See Page 22 of 22	
Billing & Payment Processing Chg		See Page 22 of 22		See Page 22 of 22	
Reactive Power Demand Charge		See Page 22 of 22		See Page 22 of 22	
Other Delivery and Supply Charges		As Described in Tariff		As Described in Tariff	

* Plus any applicable metering and/or billing and payment processing charges.

Orange and Rockland Utilities, Inc.
Case 24-E-0060

Rates in Brief - Rate Year 2

Service Classification No. 3

		Present Summer	Present Winter	Proposed Summer	Proposed Winter
Standard Rates					
Customer Charge:	per month	$45.00	$45.00	$45.00	$45.00
Delivery Charge:					
Demand Charge	per kW	$24.63	$13.94	$25.66	$14.53
Usage Charge	¢ per kWh	0.696	0.696	0.696	0.696
Minimum Charge:		$45.00	plus the demand charges*	$45.00	plus the demand charges*
Standby Rates					
Customer Charge:	per month	$45.00	$45.00	$45.00	$45.00
Delivery Charges:					
Contract Demand Charge	per kW	$2.84	$2.84	$2.84	$2.84
As Used Daily Demand Charge					
Period I	per kW	$0.8880	N/A	$0.9257	N/A
Period II	per kW	$0.6816	N/A	$0.7106	N/A
Period III	per kW	N/A	$0.6816	N/A	$0.7106

Charges Applicable to Both Standard and Standby Service Rates

	Present	Proposed
Merchant Function Charge	See Page 22 of 22	See Page 22 of 22
Billing & Payment Processing Chg	See Page 22 of 22	See Page 22 of 22
Reactive Power Demand Charge	See Page 22 of 22	See Page 22 of 22
Other Delivery and Supply Charges	As Described in Tariff	As Described in Tariff

* Plus any applicable metering and/or billing and payment processing charges.

Orange and Rockland Utilities, Inc.
Case 24-E-0060

Rates in Brief - Rate Year 2

Service Classification No. 4

Luminaire Charge, per month

Nominal Lumens	Luminaire Type	Watts	Total Wattage	Present Delivery Charge	Proposed Delivery Charge
Street Lighting Luminaires					
5,800	Sodium Vapor	70	108	$13.03	$13.54
9,500	Sodium Vapor	100	142	14.21	14.77
16,000	Sodium Vapor	150	199	16.88	17.55
27,500	Sodium Vapor	250	311	22.58	23.47
46,000	Sodium Vapor	400	488	31.61	32.86
Off-Roadway Luminaires					
27,500	Sodium Vapor	250	311	$29.26	$30.42
46,500	Sodium Vapor	400	488	36.18	37.61
LED Street Lighting Luminaires					
3,000	LED	15-29	23	$11.59	$12.05
3,900	LED	30-39	35	11.72	12.18
5,000	LED	40-59	50	11.84	12.31
7,250	LED	60-89	68	13.09	13.61
12,000	LED	90-129	103	13.78	14.32
16,000	LED	130-169	140	15.14	15.74
22,000	LED	170-220	200	20.64	21.46

The following luminaires will no longer be installed. Charges are for existing luminaires only.

Nominal Lumens	Luminaire Type	Watts	Total Wattage	Present Delivery Charge	Proposed Delivery Charge
600	Open Bottom Inc	52	52	$6.43	$6.68
1,000	Open Bottom Inc	92	92	8.77	9.12
4,000	Mercury Vapor PB	100	127	10.34	10.75
4,000	Mercury Vapor	100	127	11.69	12.15
7,900	Mercury Vapor PB	175	215	12.68	13.18
7,900	Mercury Vapor	175	211	14.18	14.74
12,000	Mercury Vapor	250	296	18.58	19.31
22,500	Mercury Vapor	400	459	23.73	24.67
59,000	Mercury Vapor	1,000	1,105	46.62	48.46
130,000	Sodium Vapor	1,000	1,120	66.54	69.17

Rates in Brief - Rate Year 2

Service Classification No. 4 (Continued)

The following luminaires will no longer be installed. Charges are for existing luminaires only.

Luminaire Charge, per month

Nominal Lumens	Luminaire Type	Watts	Total Wattage	Present Delivery Charge	Proposed Delivery Charge
5,890	LED	70	74	$14.24	$14.80
9,365	LED	100	101	16.15	16.79
3,400	Induction	40	45	14.20	14.76
12,750	Induction	150	160	19.37	20.14

		Present	Proposed
Additional Charge:			
UG Svc- Customer owned and maintained duct	per month	$5.02	$5.22
15 Foot Brackets	$ per month	0.47	0.49
Merchant Function Charge		See Page 22 of 22	See Page 22 of 22
Billing & Payment Processing Chg		See Page 22 of 22	See Page 22 of 22
Other Delivery and Supply Charges		As Described in Tariff	As Described in Tariff

Orange and Rockland Utilities, Inc.
Case 24-E-0060

Rates in Brief - Rate Year 2

Service Classification No. 5

		Present	Proposed
		Year-round	Year-round
Delivery Charge:	¢ per kWh	11.085	11.659
Merchant Function Charge		See Page 22 of 22	See Page 22 of 22
Billing & Payment Processing Chg		See Page 22 of 22	See Page 22 of 22
Other Delivery and Supply Charges		As Described in Tariff	As Described in Tariff

Orange and Rockland Utilities, Inc.
Case 24-E-0060

Rates in Brief - Rate Year 2

Service Classification No. 6

		Present Year-round	Proposed Year-round
Delivery Charges for Service Types A & B:	¢ per kWh	8.377	8.534
Delivery Charges for Service Type C:			
Customer Charge		$24.00	$24.00
Delivery Charge	¢ per kWh	8.561	8.721
Merchant Function Charge		See Page 22 of 22	See Page 22 of 22
Billing & Payment Processing Chg		See Page 22 of 22	See Page 22 of 22
Other Delivery and Supply Charges		As Described in Tariff	As Described in Tariff

Orange and Rockland Utilities, Inc.
Case 24-E-0060

Rates in Brief - Rate Year 2

Service Classification No. 9

				Present Year-round	Proposed Year-round
Standard Rates					
Customer Charge:			per month	$500.00	$500.00
Delivery Charges:					
Primary:					
Demand Charge					
	Period A	All kW @	per kW	$25.92	$26.97
	Period B	All kW @	per kW	12.17	12.66
	Period C	All kW @	per kW	No Charge	No Charge
Usage Charge					
	Period A	All kWh @	¢ per kWh	0.441	0.441
	Period B	All kWh @	¢ per kWh	0.441	0.441
	Period C	All kWh @	¢ per kWh	0.164	0.164
Substation:					
Demand Charge					
	Period A	All kW @	per kW	$18.74	$19.50
	Period B	All kW @	per kW	8.47	8.81
	Period C	All kW @	per kW	No Charge	No Charge
Usage Charge					
	Period A	All kWh @	¢ per kWh	0.244	0.244
	Period B	All kWh @	¢ per kWh	0.244	0.244
	Period C	All kWh @	¢ per kWh	0.150	0.150
Transmission:					
Demand Charge					
	Period A	All kW @	per kW	$9.24	$9.62
	Period B	All kW @	per kW	6.29	6.55
	Period C	All kW @	per kW	No Charge	No Charge
Usage Charge					
	Period A	All kWh @	¢ per kWh	0.139	0.139
	Period B	All kWh @	¢ per kWh	0.139	0.139
	Period C	All kWh @	¢ per kWh	0.131	0.131

Orange and Rockland Utilities, Inc.
Case 24-E-0060

Rates in Brief - Rate Year 2

Service Classification No. 9 (Continued)

		Present	Proposed
Standby Rates			
Customer Charge:	per month	$500.00	$500.00
Delivery Charges:			
Primary:			
Contract Demand Charge	per kW	$2.50	$2.52
As Used Daily Demand Charge			
Period I	per kW	$0.8008	$0.8357
Period II	per kW	$0.6114	$0.6381
Period III	per kW	$0.6114	$0.6381
Substation:			
Contract Demand Charge	per kW	$0.97	$0.98
As Used Daily Demand Charge			
Period I	per kW	$0.8574	$0.8905
Period II	per kW	$0.5065	$0.5260
Period III	per kW	$0.5065	$0.5260
Transmission:			
Contract Demand Charge	per kW	$2.25	$2.29
As Used Daily Demand Charge			
Period I	per kW	$0.5165	$0.5396
Period II	per kW	$0.2158	$0.2254
Period III	per kW	$0.2158	$0.2254
Minimum Charge		Sum of the Customer Charge, Min. Monthly Demand Charge, contract demand charge, the reactive power demand charge, and any applicable BPP charges.	Sum of the Customer Charge, Min. Monthly Demand Charge, contract demand charge, the reactive power demand charge, and any applicable BPP charges.
Min. Monthly Demand Charge		$51.74	$54.74
Contract Demand Charge - Pri	per kW of CD	$3.77	$3.99
Contract Demand Charge - Sec	per kW of CD	$6.18	$6.54

Orange and Rockland Utilities, Inc.
Case 24-E-0060

Rates in Brief - Rate Year 2

Service Classification No. 9 (Continued)

Charges Applicable to Both Standard and Standby Service Rates

	Present	Proposed
Merchant Function Charge	See Page 22 of 22	See Page 22 of 22
Billing & Payment Processing Chg	See Page 22 of 22	See Page 22 of 22
Reactive Power Demand Charge	See Page 22 of 22	See Page 22 of 22
Other Delivery and Supply Charges	As Described in Tariff	As Described in Tariff

Definition of Rating Periods (Standard Rates):

Period A -	8:00 a.m. to 11:00 p.m. prevailing time, Monday through Friday, except holidays, June through September.
Period B -	8:00 a.m. to 11:00 p.m. prevailing time, Monday through Friday, except holidays, October through May.
Period C -	11:00 p.m. to 8:00 a.m. prevailing time, Monday through Friday, all hours on Saturday, Sunday and holidays, all months.

Orange and Rockland Utilities, Inc.
Case 24-E-0060

Rates in Brief - Rate Year 2

Service Classification No. 15

		Present	Proposed
		Year-round	Year-round
Customer Charge*:			
SC Nos. 1 and 19	per month	$22.00	$23.00
SC Nos. 2 Secondary and 20	per month	26.00	26.00
SC No. 2 Primary	per month	32.00	32.00
SC Nos. 3 and 21	per month	45.00	45.00
SC No. 9	per month	500.00	500.00
SC No. 22	per month	500.00	500.00
Contract Demand Charge*			
SC Nos. 1 and 19	per kW	$0.01	$0.01
SC Nos. 2 Secondary and 20	per kW	0.18	0.19
SC No. 2 Primary	per kW	0.35	0.36
SC Nos. 3 and 21	per kW	0.66	0.69
SC No. 9 - Primary	per kW	0.38	0.40
SC No. 9 - Substation	per kW	0.42	0.43
SC No. 9 - Transmission	per kW	1.04	1.08
SC No. 22 - Primary	per kW	0.49	0.52
SC No. 22 - Substation	per kW	1.30	1.38
SC No. 22 - Transmission	per kW	0.43	0.46
Reactive Power Demand Charge		See Page 22 of 22	See Page 22 of 22

* Based on the customer's otherwise applicable service classification.

		Present	Proposed
		Plus: Increase in Rates and Charges	Plus: Increase in Rates and Charges

Orange and Rockland Utilities, Inc.
Case 24-E-0060

Rates in Brief - Rate Year 2

Service Classification No. 16

Luminaire Charge, per month

Nominal Lumens	Luminaire Type	Watts	Total Wattage	Present Delivery Charge	Proposed Delivery Charge
Power Bracket Luminaires					
5,800	Sodium Vapor	70	108	$24.20	$25.21
9,500	Sodium Vapor	100	142	25.87	26.95
16,000	Sodium Vapor	150	199	30.41	31.68
Street Lighting Luminaires					
5,800	Sodium Vapor	70	108	$26.48	$27.58
9,500	Sodium Vapor	100	142	28.24	29.42
16,000	Sodium Vapor	150	199	32.69	34.05
27,500	Sodium Vapor	250	311	41.66	43.39
46,000	Sodium Vapor	400	488	57.18	59.56
Flood Lighting Luminaires					
27,500	Sodium Vapor	250	311	$41.66	$43.39
46,000	Sodium Vapor	400	488	57.18	59.56
LED Street Lighting Luminaires					
3,000	LED	15-29	23	$10.96	$11.42
3,900	LED	30-39	35	11.08	11.54
5,000	LED	40-59	50	11.20	11.67
7,250	LED	60-89	68	12.37	12.88
12,000	LED	90-129	103	13.02	13.56
16,000	LED	130-169	140	14.31	14.91
22,000	LED	170-220	200	19.50	20.31
LED Flood Lighting Luminaires					
15,000	LED	100-159	125	$14.01	$14.59
27,000	LED	160-249	205	16.51	17.20
37,500	LED	230-320	290	19.04	19.83
LED Power Bracket Luminaires					
3,950	LED	25-39	35	$9.29	$9.68
5,550	LED	44-55	50	9.36	9.75
7,350	LED	56-70	65	9.46	9.85

The following luminaires will no longer be installed. Charges are for existing luminaires only.

Nominal Lumens	Luminaire Type	Watts	Total Wattage	Present Delivery Charge	Proposed Delivery Charge
Power Bracket Luminaires					
4,000	Mercury Vapor	100	127	$22.21	$23.13
7,900	Mercury Vapor	175	215	25.72	26.79
22,500	Mercury Vapor	400	462	36.94	38.48
Street Lighting Luminaires					
21,250	Mercury Vapor	250	263	$49.64	$51.71
4,000	Mercury Vapor	100	127	24.35	25.36
7,900	Mercury Vapor	175	211	28.18	29.35
12,000	Mercury Vapor	250	296	35.49	36.97
22,500	Mercury Vapor	400	459	43.72	45.54
40,000	Mercury Vapor	700	786	64.70	67.39
59,000	Mercury Vapor	1,000	1,105	80.73	84.09
1,000	Incandescent	92	92	19.35	20.16
5,890	LED	70	74	35.25	36.72
9,365	LED	100	101	38.10	39.69

Orange and Rockland Utilities, Inc.
Case 24-E-0060

Rates in Brief - Rate Year 2

Service Classification No. 16 (Continued)

Nominal Lumens	Luminaire Type	Watts	Total Wattage	Present Delivery Charge	Proposed Delivery Charge
The following luminaires will no longer be installed. Charges are for existing luminaires only.					
Flood Lighting Luminaires					
12,000	Mercury Vapor	250	296	$35.49	$36.97
22,500	Mercury Vapor	400	459	43.72	45.54
40,000	Mercury Vapor	700	786	64.70	67.39
59,000	Mercury Vapor	1,000	1,105	80.73	84.09
15 Foot Brackets			$ per month	0.82	0.85
Delivery Charges for Service Type C:					
Customer Charge (Metered)			per month	$24.00	$24.00
Customer Charge (Unmetered)			per month	20.00	20.00
Delivery Charge			¢ per kWh	8.561	9.251

	Present	Proposed
Merchant Function Charge	See Page 22 of 22	See Page 22 of 22
Billing & Payment Processing Chg	See Page 22 of 22	See Page 22 of 22
Other Delivery and Supply Charges	As Described in Tariff	As Described in Tariff

Orange and Rockland Utilities, Inc.
Case 24-E-0060

Rates in Brief - Rate Year 2

Service Classification No. 19

				Present Year-round	Proposed Year-round
Customer Charge:			per month	$30.00	$29.00
Delivery Charges:					
	Period I	All kWh @	¢ per kWh	42.384	44.651
	Period II	All kWh @	¢ per kWh	15.165	15.976
	Period III	All kWh @	¢ per kWh	15.165	15.976
	Period IV	All kWh @	¢ per kWh	2.730	2.876
Minimum Charge:		per contract (not less than) plus applicable billing and payment processing charges		$360.00	$348.00
Standby Rates					
Customer Charge:		per month		$22.00	$23.00
Delivery Charges:					
Contract Demand Charge		per kW		$2.74	$2.59
As Used Daily Demand Charge					
	Period I	per kW		$1.4234	$1.5428
	Period II	per kW		$0.9826	$1.0650
	Period III	per kW		$0.9826	$1.0650
Charges Applicable to Both Standard and Standby Service Rates					
Merchant Function Charge				See Page 22 of 22	See Page 22 of 22
Billing & Payment Processing Chg				See Page 22 of 22	See Page 22 of 22
Other Delivery and Supply Charges				As Described in Tariff	As Described in Tariff

Definition of Rating Periods (Standard Rates):

Period I -	12:00 p.m. to 7:00 p.m. prevailing time, Monday through Friday, except holidays, June through September.
Period II -	10:00 a.m. to 12:00 p.m. and 7:00 p.m. to 9:00 p.m. prevailing time, Monday through Friday, except holidays, June through September.
Period III -	10:00 a.m. to 9:00 p.m. prevailing time, Monday through Friday, except holidays, October through May.
Period IV -	9:00 p.m. to 10:00 a.m. prevailing time, Monday through Friday, all hours on Saturday, Sunday and holidays, all months

Orange and Rockland Utilities, Inc.
Case 24-E-0060

Rates in Brief - Rate Year 2

Service Classification No. 20

			Present Year-round	Proposed Year-round
Standard Rates				
Customer Charge:		per month	$30.00	$30.00
Delivery Charges:				
Demand Charge				
Period I	All kW @	per kW	$33.92	$34.95
Period II	All kW @	per kW	16.94	18.02
Period III	All kW @	per kW	0.76	0.80
Usage Charge				
Period I	All kWh @	¢ per kWh	3.349	3.299
Period II	All kWh @	¢ per kWh	0.939	0.955
Period III	All kWh @	¢ per kWh	0.049	0.049
Minimum Charge:			Sum of the Customer Charge and $90.00 plus any applicable billing and payment processing charges.	Sum of the Customer Charge and $90.00 plus any applicable billing and payment processing charges.
Standby Rates				
Customer Charge:		per month	$26.00	$26.00
Delivery Charges:				
Contract Demand Charge		per kW	$2.63	$2.66
As Used Daily Demand Charge				
Period I		per kW	$1.1955	$1.2294
Period II		per kW	$0.7814	$0.8035
Period III		per kW	$0.7814	$0.8035
Charges Applicable to Both Standard and Standby Service Rates				
Merchant Function Charge			See Page 22 of 22	See Page 22 of 22
Billing & Payment Processing Chg			See Page 22 of 22	See Page 22 of 22
Reactive Power Demand Charge			See Page 22 of 22	See Page 22 of 22
Other Delivery and Supply Charges			As Described in Tariff	As Described in Tariff

Definition of Rating Periods (Standard Rates):

Period I -	1:00 p.m. to 7:00 p.m. prevailing time, Monday through Friday, except holidays, June through September.
Period II -	10:00 a.m. to 9:00 p.m. prevailing time, Monday through Friday, except holidays, October through May.
Period III -	7:00 p.m. to 1:00 p.m. prevailing time, Monday through Friday, June through September; 9:00 p.m. to 10:00 a.m. prevailing time, Monday through Friday, October through May; all hours on Saturday, Sunday and holidays, all months.

Orange and Rockland Utilities, Inc.
Case 24-E-0060

Rates in Brief - Rate Year 2

Service Classification No. 21

				Present Year-round	Proposed Year-round
Customer Charge:			per month	$45.00	$45.00
Delivery Charges:					
Demand Charge					
	Period I	All kW @	per kW	$31.33	$31.56
	Period II	All kW @	per kW	14.97	15.64
	Period III	All kW @	per kW	No Charge	No Charge
Usage Charge					
	Period I	All kWh @	¢ per kWh	1.356	1.332
	Period II	All kWh @	¢ per kWh	1.839	1.874
	Period III	All kWh @	¢ per kWh	0.144	0.145
Minimum Charge:				Sum of the Customer Charge and any applicable billing and payment processing charges.	Sum of the Customer Charge and any applicable billing and payment processing charges.
Standby Rates					
Customer Charge:			per month	$45.00	$45.00
Delivery Charges:					
Contract Demand Charge			per kW	$2.84	$2.84
As Used Daily Demand Charge					
	Period I		per kW	$0.8880	$0.9257
	Period II		per kW	$0.6816	$0.7106
	Period III		per kW	$0.6816	$0.7106
Charges Applicable to Both Standard and Standby Service Rates					
Merchant Function Charge				See Page 22 of 22	See Page 22 of 22
Billing & Payment Processing Chg				See Page 22 of 22	See Page 22 of 22
Reactive Power Demand Charge				See Page 22 of 22	See Page 22 of 22
Other Delivery and Supply Charges				As Described in Tariff	As Described in Tariff

Definition of Rating Periods (Standard Rates):

- Period I - 1:00 p.m. to 7:00 p.m. prevailing time, Monday through Friday, except holidays, June through September.
- Period II - 10:00 a.m. to 9:00 p.m. prevailing time, Monday through Friday, except holidays, October through May.
- Period III - 7:00 p.m. to 1:00 p.m. prevailing time, Monday through Friday, June through September; 9:00 p.m. to 10:00 a.m. prevailing time, Monday through Friday, October through May; all hours on Saturday, Sunday and holidays, all months.

Orange and Rockland Utilities, Inc.
Case 24-E-0060

Rates in Brief - Rate Year 2

Service Classification No. 22

				Present Year-round	Proposed Year-round
Standard Rates					
Customer Charge:			per month	$500.00	$500.00
Delivery Charges:					
Primary:					
Demand Charge					
	Period A	All kW @	per kW	$19.65	$20.85
	Period B	All kW @	per kW	11.21	11.89
	Period C	All kW @	per kW	No Charge	No Charge
Usage Charge					
	Period A	All kWh @	¢ per kWh	0.684	0.684
	Period B	All kWh @	¢ per kWh	0.684	0.684
	Period C	All kWh @	¢ per kWh	0.121	0.121
Substation:					
Demand Charge					
	Period A	All kW @	per kW	$12.62	$13.39
	Period B	All kW @	per kW	6.96	7.38
	Period C	All kW @	per kW	No Charge	No Charge
Usage Charge					
	Period A	All kWh @	¢ per kWh	0.287	0.287
	Period B	All kWh @	¢ per kWh	0.287	0.287
	Period C	All kWh @	¢ per kWh	0.121	0.121
Transmission:					
Demand Charge					
	Period A	All kW @	per kW	$7.37	$7.81
	Period B	All kW @	per kW	6.45	6.83
	Period C	All kW @	per kW	No Charge	No Charge
Usage Charge					
	Period A	All kWh @	¢ per kWh	0.121	0.121
	Period B	All kWh @	¢ per kWh	0.121	0.121
	Period C	All kWh @	¢ per kWh	0.121	0.121
Minimum Charge				Sum of the Customer Charge, Min. Monthly Demand Charge, contract demand charge, the reactive power demand charge, and any applicable billing and payment processing charges.	Sum of the Customer Charge, Min. Monthly Demand Charge, contract demand charge, the reactive power demand charge, and any applicable billing and payment processing charges.
Min. Monthly Demand Charge				$51.74	$54.74
Contract Demand Charge - Pri			per kW of CD	$3.77	$3.99
Contract Demand Charge - Sec			per kW of CD	$6.18	$6.54

Orange and Rockland Utilities, Inc.
Case 24-E-0060

Rates in Brief - Rate Year 2

Service Classification No. 22 (Continued)

		Present	Proposed
Standby Rates			
Customer Charge:	per month	$500.00	$500.00
Delivery Charges:			
Primary:			
Contract Demand Charge	per kW	$2.48	$2.51
As Used Daily Demand Charge			
Period I	per kW	$0.6436	$0.6840
Period II	per kW	$0.4916	$0.5225
Period III	per kW	$0.4916	$0.5225
Substation:			
Contract Demand Charge	per kW	$1.50	$1.58
As Used Daily Demand Charge			
Period I	per kW	$0.5363	$0.5672
Period II	per kW	$0.2891	$0.3057
Period III	per kW	$0.2891	$0.3057
Transmission:			
Contract Demand Charge	per kW	$0.67	$0.70
As Used Daily Demand Charge			
Period I	per kW	$0.5600	$0.6033
Period II	per kW	$0.2377	$0.2561
Period III	per kW	$0.2377	$0.2561

Orange and Rockland Utilities, Inc.
Case 24-E-0060

Rates in Brief - Rate Year 2

Service Classification No. 22 (Continued)

		Present Year-round	Proposed Year-round
Standby Service Rates – Existing Standby Service Customer on Phase- In			
Customer Charge:	per month	$500.00	$500.00
Transmission:			
Contract Demand Charge	per kW	$1.38	$1.46
As Used Daily Demand Charge (S)	per kW	$0.3720	$0.3929
As Used Daily Demand Charge (W)	per kW	$0.3395	$0.3582
Charges Applicable to Both Standard and Standby Service Rates			
Merchant Function Charge		See Page 22 of 22	See Page 22 of 22
Billing & Payment Processing Chg		See Page 22 of 22	See Page 22 of 22
Reactive Power Demand Charge		See Page 22 of 22	See Page 22 of 22
Other Delivery and Supply Charges		As Described in Tariff	As Described in Tariff

Definition of Rating Periods (Standard Rates):

Period A -	8:00 a.m. to 11:00 p.m. prevailing time, Monday through Friday, except holidays, June through September.
Period B -	8:00 a.m. to 11:00 p.m. prevailing time, Monday through Friday, except holidays, October through May.
Period C -	11:00 p.m. to 8:00 a.m. prevailing time, Monday through Friday, all hours on Saturday, Sunday and holidays, all months.

Orange and Rockland Utilities, Inc.
Case 24-E-0060

Rates in Brief - Rate Year 2

Other Charges

		Present	Proposed
Merchant Function Charge			
Service Classification Nos. 1 & 19			
Supply Related	¢ per kWh	0.179	0.186
Purch Pwr Wrking Cap	¢ per kWh	0.097	0.099
Credit & Collections	¢ per kWh	0.059	0.061
Uncollectibles	¢ per kWh	Variable	Variable
Service Classification Nos. 2 Secondary, 20, 4, 5, 6 & 16			
Supply Related	¢ per kWh	0.098	0.104
Purch Pwr Wrking Cap	¢ per kWh	0.097	0.099
Credit & Collections	¢ per kWh	0.029	0.031
Uncollectibles	¢ per kWh	Variable	Variable
Service Classification Nos. 2 Primary, 3, 9, 21 & 22			
Supply Related	¢ per kWh	0.096	0.104
Purch Pwr Wrking Cap	¢ per kWh	0.097	0.099
Credit & Collections	¢ per kWh	0.021	0.022
Uncollectibles	¢ per kWh	Variable	Variable
Billing & Payment Processing Chg	per month	$2.10	$2.10
Reactive Power Demand Charge	per KVAr	$1.05	$1.05

Orange and Rockland Utilities, Inc.
Case 24-E-0060

Rates in Brief - Rate Year 3

Service Classification No. 1

		Present Summer	Present Winter	Proposed Summer	Proposed Winter
Customer Charge:	per month	$22.50	$22.50	$23.00	$23.00
Delivery Charges:					
First 250 kWh	¢ per kWh	11.052	11.052	12.446	12.446
Over 250 kWh	¢ per kWh	13.822	11.052	15.566	12.446
Minimum Charge:					
Monthly*	monthly	$22.50		$23.00	
Per Contract	per contract	135.00		138.00	
Standby Rates					
Customer Charge:	per month	$23.00	$23.00	$23.00	$23.00
Delivery Charges:					
Contract Demand Charge	per kW	$2.59	$2.59	$2.61	$2.61
As Used Daily Demand Charge					
Period I	per kW	$1.5428	N/A	$1.7921	N/A
Period II	per kW	$1.0650	N/A	$1.2371	N/A
Period III	per kW	N/A	$1.0650	N/A	$1.2371
Charges Applicable to Both Standard and Standby Service Rates					
Merchant Function Charge		See Page 22 of 22		See Page 22 of 22	
Billing & Payment Processing Chg		See Page 22 of 22		See Page 22 of 22	
Other Delivery and Supply Charges		As Described in Tariff		As Described in Tariff	

* Plus any applicable billing and payment processing charges.

Orange and Rockland Utilities, Inc.
Case 24-E-0060

Rates in Brief - Rate Year 3

Service Classification No. 2 Secondary - Non-Demand Billed Customers

		Present		Proposed	
		Summer	Winter	Summer	Winter
Customer Charge:					
Metered Service	per month	$21.00	$21.00	$21.00	$21.00
Unmetered Service	per month	20.00	20.00	20.00	20.00
Delivery Charge:					
Usage Charge					
All kWh	¢ per kWh	9.535	7.045	10.325	7.629
Space Heating:					
Delivery	¢ per kWh	15.860	3.963	17.635	4.407
Minimum Charge		Customer Charge*		Customer Charge*	
Standby Rates					
Customer Charge:	per month	$26.00	$26.00	$26.00	$26.00
Delivery Charges:					
Contract Demand Charge	per kW	$2.66	$2.66	$2.69	$2.69
As Used Daily Demand Charge					
Period I	per kW	$1.2294	N/A	$1.3103	N/A
Period II	per kW	$0.8035	N/A	$0.8564	N/A
Period III	per kW	N/A	$0.8035	N/A	$0.8564
Charges Applicable to Both Standard and Standby Service Rates					
Merchant Function Charge		See Page 22 of 22		See Page 22 of 22	
Billing & Payment Processing Chg		See Page 22 of 22		See Page 22 of 22	
Other Delivery and Supply Charges		As Described in Tariff		As Described in Tariff	

* Plus any applicable billing and payment processing charges.

Orange and Rockland Utilities, Inc.
Case 24-E-0060

Rates in Brief - Rate Year 3

Service Classification No. 2 Secondary Demand Billed

		Present Summer	Present Winter	Proposed Summer	Proposed Winter
Standard Rates					
Customer Charge:					
Metered Service	per month	$27.00	$27.00	$27.00	$27.00
Delivery Charge:					
Demand Charge					
First 5 kW	per kW	$5.75	$3.34	$7.04	$4.07
Over 5 kW	per kW	26.63	15.44	28.55	16.53
Usage Charge					
First 1,250 kWh	¢ per kWh	3.428	3.141	3.428	3.141
Over 1,250 kWh	¢ per kWh	3.428	3.141	3.428	3.141
Minimum Charge		Customer Charge plus the demand charges*		Customer Charge plus the demand charges*	
Standby Rates					
Customer Charge:	per month	$26.00	$26.00	$26.00	$26.00
Delivery Charges:					
Contract Demand Charge	per kW	$2.66	$2.66	$2.69	$2.69
As Used Daily Demand Charge					
Period I	per kW	$1.2294	N/A	$1.3103	N/A
Period II	per kW	$0.8035	N/A	$0.8564	N/A
Period III	per kW	N/A	$0.8035	N/A	$0.8564
Charges Applicable to Both Standard and Standby Service Rates					
Merchant Function Charge		See Page 22 of 22		See Page 22 of 22	
Billing & Payment Processing Chg		See Page 22 of 22		See Page 22 of 22	
Reactive Power Demand Charge		See Page 22 of 22		See Page 22 of 22	
Other Delivery and Supply Charges		As Described in Tariff		As Described in Tariff	

* Plus any applicable billing and payment processing charges.

Orange and Rockland Utilities, Inc.
Case 24-E-0060

Rates in Brief - Rate Year 3

Service Classification No. 2 Primary

		Present Summer	Present Winter	Proposed Summer	Proposed Winter
Standard Rates					
Customer Charge:	per month	$32.00	$32.00	$32.00	$32.00
Delivery Charge:					
Demand Charge	per kW	$21.76	$12.07	$23.86	$13.23
Usage Charge	¢ per kWh	0.781	0.781	0.781	0.781
Minimum Charge		Customer Charge plus the demand charges*		Customer Charge plus the demand charges*	
Standby Rates					
Customer Charge:	per month	$32.00	$32.00	$32.00	$32.00
Delivery Charges:					
Contract Demand Charge	per kW	$2.58	$2.58	$2.72	$2.72
As Used Daily Demand Charge					
Period I	per kW	$0.8227	N/A	$0.8960	N/A
Period II	per kW	$0.6187	N/A	$0.6738	N/A
Period III	per kW	N/A	$0.6187	N/A	$0.6738
Charges Applicable to Both Standard and Standby Service Rates					
Merchant Function Charge		See Page 22 of 22		See Page 22 of 22	
Billing & Payment Processing Chg		See Page 22 of 22		See Page 22 of 22	
Reactive Power Demand Charge		See Page 22 of 22		See Page 22 of 22	
Other Delivery and Supply Charges		As Described in Tariff		As Described in Tariff	

* Plus any applicable metering and/or billing and payment processing charges.

Orange and Rockland Utilities, Inc.
Case 24-E-0060

Rates in Brief - Rate Year 3

Service Classification No. 3

		Present Summer	Present Winter	Proposed Summer	Proposed Winter
Standard Rates					
Customer Charge:	per month	$45.00	$45.00	$45.00	$45.00
Delivery Charge:					
Demand Charge	per kW	$25.66	$14.53	$28.15	$15.94
Usage Charge	¢ per kWh	0.696	0.696	0.696	0.696
Minimum Charge:		$45.00	plus the demand charges*	$45.00	plus the demand charges*
Standby Rates					
Customer Charge:	per month	$45.00	$45.00	$45.00	$45.00
Delivery Charges:					
Contract Demand Charge	per kW	$2.84	$2.84	$2.89	$2.89
As Used Daily Demand Charge					
Period I	per kW	$0.9257	N/A	$1.0134	N/A
Period II	per kW	$0.7106	N/A	$0.7779	N/A
Period III	per kW	N/A	$0.7106	N/A	$0.7779
Charges Applicable to Both Standard and Standby Service Rates					
Merchant Function Charge		See Page 22 of 22		See Page 22 of 22	
Billing & Payment Processing Chg		See Page 22 of 22		See Page 22 of 22	
Reactive Power Demand Charge		See Page 22 of 22		See Page 22 of 22	
Other Delivery and Supply Charges		As Described in Tariff		As Described in Tariff	

* Plus any applicable metering and/or billing and payment processing charges.

Orange and Rockland Utilities, Inc.
Case 24-E-0060

Rates in Brief - Rate Year 3

Service Classification No. 4

Luminaire Charge, per month

Nominal Lumens	Luminaire Type	Watts	Total Wattage	Present Delivery Charge	Proposed Delivery Charge
Street Lighting Luminaires					
5,800	Sodium Vapor	70	108	$13.54	$14.72
9,500	Sodium Vapor	100	142	14.77	16.06
16,000	Sodium Vapor	150	199	17.55	19.08
27,500	Sodium Vapor	250	311	23.47	25.52
46,000	Sodium Vapor	400	488	32.86	35.73
Off-Roadway Luminaires					
27,500	Sodium Vapor	250	311	$30.42	$33.08
46,500	Sodium Vapor	400	488	37.61	40.89
LED Street Lighting Luminaires					
3,000	LED	15-29	23	$12.05	$13.10
3,900	LED	30-39	35	12.18	13.24
5,000	LED	40-59	50	12.31	13.38
7,250	LED	60-89	68	13.61	14.80
12,000	LED	90-129	103	14.32	15.57
16,000	LED	130-169	140	15.74	17.11
22,000	LED	170-220	200	21.46	23.33

The following luminaires will no longer be installed. Charges are for existing luminaires only.

Nominal Lumens	Luminaire Type	Watts	Total Wattage	Present Delivery Charge	Proposed Delivery Charge
600	Open Bottom Inc	52	52	$6.68	$7.26
1,000	Open Bottom Inc	92	92	9.12	9.92
4,000	Mercury Vapor PB	100	127	10.75	11.69
4,000	Mercury Vapor	100	127	12.15	13.21
7,900	Mercury Vapor PB	175	215	13.18	14.33
7,900	Mercury Vapor	175	211	14.74	16.03
12,000	Mercury Vapor	250	296	19.31	21.00
22,500	Mercury Vapor	400	459	24.67	26.82
59,000	Mercury Vapor	1,000	1,105	48.46	52.69
130,000	Sodium Vapor	1,000	1,120	69.17	75.21

Rates in Brief - Rate Year 3

Service Classification No. 4 (Continued)

The following luminaires will no longer be installed. Charges are for existing luminaires only.

Luminaire Charge, per month

Nominal Lumens	Luminaire Type	Watts	Total Wattage	Present Delivery Charge	Proposed Delivery Charge
5,890	LED	70	74	$14.80	$16.09
9,365	LED	100	101	16.79	18.26
3,400	Induction	40	45	14.76	16.05
12,750	Induction	150	160	20.14	21.90

Additional Charge:		Present	Proposed
UG Svc- Customer owned and maintained duct	per month	$5.22	$5.68
15 Foot Brackets	$ per month	0.49	0.53

	Present	Proposed
Merchant Function Charge	See Page 22 of 22	See Page 22 of 22
Billing & Payment Processing Chg	See Page 22 of 22	See Page 22 of 22
Other Delivery and Supply Charges	As Described in Tariff	As Described in Tariff

Orange and Rockland Utilities, Inc.
Case 24-E-0060

Rates in Brief - Rate Year 3

Service Classification No. 5

		Present Year-round	Proposed Year-round
Delivery Charge:	¢ per kWh	11.659	12.945
Merchant Function Charge		See Page 22 of 22	See Page 22 of 22
Billing & Payment Processing Chg		See Page 22 of 22	See Page 22 of 22
Other Delivery and Supply Charges		As Described in Tariff	As Described in Tariff

Orange and Rockland Utilities, Inc.
Case 24-E-0060

Rates in Brief - Rate Year 3

Service Classification No. 6

		Present Year-round	Proposed Year-round
Delivery Charges for Service Types A & B:	¢ per kWh	8.534	8.884
Delivery Charges for Service Type C:			
Customer Charge		$24.00	$24.00
Delivery Charge	¢ per kWh	9.251	9.631
Merchant Function Charge		See Page 22 of 22	See Page 22 of 22
Billing & Payment Processing Chg		See Page 22 of 22	See Page 22 of 22
Other Delivery and Supply Charges		As Described in Tariff	As Described in Tariff

Orange and Rockland Utilities, Inc.
Case 24-E-0060

Rates in Brief - Rate Year 3

Service Classification No. 9

				Present Year-round	Proposed Year-round
Standard Rates					
Customer Charge:			per month	$500.00	$500.00
Delivery Charges:					
Primary:					
Demand Charge					
	Period A	All kW @	per kW	$26.97	$29.51
	Period B	All kW @	per kW	12.66	13.85
	Period C	All kW @	per kW	No Charge	No Charge
Usage Charge					
	Period A	All kWh @	¢ per kWh	0.441	0.441
	Period B	All kWh @	¢ per kWh	0.441	0.441
	Period C	All kWh @	¢ per kWh	0.164	0.164
Substation:					
Demand Charge					
	Period A	All kW @	per kW	$19.50	$21.34
	Period B	All kW @	per kW	8.81	9.64
	Period C	All kW @	per kW	No Charge	No Charge
Usage Charge					
	Period A	All kWh @	¢ per kWh	0.244	0.244
	Period B	All kWh @	¢ per kWh	0.244	0.244
	Period C	All kWh @	¢ per kWh	0.150	0.150
Transmission:					
Demand Charge					
	Period A	All kW @	per kW	$9.62	$10.53
	Period B	All kW @	per kW	6.55	7.17
	Period C	All kW @	per kW	No Charge	No Charge
Usage Charge					
	Period A	All kWh @	¢ per kWh	0.139	0.139
	Period B	All kWh @	¢ per kWh	0.139	0.139
	Period C	All kWh @	¢ per kWh	0.131	0.131

Orange and Rockland Utilities, Inc.
Case 24-E-0060

Rates in Brief - Rate Year 3

Service Classification No. 9 (Continued)

		Present	Proposed
Standby Rates			
Customer Charge:	per month	$500.00	$500.00
Delivery Charges:			
Primary:			
Contract Demand Charge	per kW	$2.52	$2.56
As Used Daily Demand Charge			
Period I	per kW	$0.8357	$0.9205
Period II	per kW	$0.6381	$0.7028
Period III	per kW	$0.6381	$0.7028
Substation:			
Contract Demand Charge	per kW	$0.98	$1.02
As Used Daily Demand Charge			
Period I	per kW	$0.8905	$0.9707
Period II	per kW	$0.5260	$0.5734
Period III	per kW	$0.5260	$0.5734
Transmission:			
Contract Demand Charge	per kW	$2.29	$2.40
As Used Daily Demand Charge			
Period I	per kW	$0.5396	$0.5948
Period II	per kW	$0.2254	$0.2485
Period III	per kW	$0.2254	$0.2485
Minimum Charge		Sum of the Customer Charge, Min. Monthly Demand Charge, contract demand charge, the reactive power demand charge, and any applicable BPP charges.	Sum of the Customer Charge, Min. Monthly Demand Charge, contract demand charge, the reactive power demand charge, and any applicable BPP charges.
Min. Monthly Demand Charge		$54.74	$60.38
Contract Demand Charge - Pri	per kW of CD	$3.99	$4.40
Contract Demand Charge - Sec	per kW of CD	$6.54	$7.21

Orange and Rockland Utilities, Inc.
Case 24-E-0060

Rates in Brief - Rate Year 3

Service Classification No. 9 (Continued)

Charges Applicable to Both Standard and Standby Service Rates

	Present	Proposed
Merchant Function Charge	See Page 22 of 22	See Page 22 of 22
Billing & Payment Processing Chg	See Page 22 of 22	See Page 22 of 22
Reactive Power Demand Charge	See Page 22 of 22	See Page 22 of 22
Other Delivery and Supply Charges	As Described in Tariff	As Described in Tariff

Definition of Rating Periods (Standard Rates):

Period A -	8:00 a.m. to 11:00 p.m. prevailing time, Monday through Friday, except holidays, June through September.
Period B -	8:00 a.m. to 11:00 p.m. prevailing time, Monday through Friday, except holidays, October through May.
Period C -	11:00 p.m. to 8:00 a.m. prevailing time, Monday through Friday, all hours on Saturday, Sunday and holidays, all months.

Orange and Rockland Utilities, Inc.
Case 24-E-0060

Rates in Brief - Rate Year 3

Service Classification No. 15

		Present	Proposed
		Year-round	Year-round
Customer Charge*:			
SC Nos. 1 and 19	per month	$23.00	$23.00
SC Nos. 2 Secondary and 20	per month	26.00	26.00
SC No. 2 Primary	per month	32.00	32.00
SC Nos. 3 and 21	per month	45.00	45.00
SC No. 9	per month	500.00	500.00
SC No. 22	per month	500.00	500.00
Contract Demand Charge*			
SC Nos. 1 and 19	per kW	$0.01	$0.01
SC Nos. 2 Secondary and 20	per kW	0.19	0.20
SC No. 2 Primary	per kW	0.36	0.40
SC Nos. 3 and 21	per kW	0.69	0.76
SC No. 9 - Primary	per kW	0.40	0.44
SC No. 9 - Substation	per kW	0.43	0.47
SC No. 9 - Transmission	per kW	1.08	1.19
SC No. 22 - Primary	per kW	0.52	0.59
SC No. 22 - Substation	per kW	1.38	1.55
SC No. 22 - Transmission	per kW	0.46	0.52
Reactive Power Demand Charge		See Page 22 of 22	See Page 22 of 22

* Based on the customer's otherwise applicable service classification.

	Present	Proposed
	Plus: Increase in Rates and Charges	Plus: Increase in Rates and Charges

Orange and Rockland Utilities, Inc.
Case 24-E-0060

Rates in Brief - Rate Year 3

Service Classification No. 16

Luminaire Charge, per month

Nominal Lumens	Luminaire Type	Watts	Total Wattage	Present Delivery Charge	Proposed Delivery Charge
Power Bracket Luminaires					
5,800	Sodium Vapor	70	108	$25.21	$27.48
9,500	Sodium Vapor	100	142	26.95	29.37
16,000	Sodium Vapor	150	199	31.68	34.53
Street Lighting Luminaires					
5,800	Sodium Vapor	70	108	$27.58	$30.06
9,500	Sodium Vapor	100	142	29.42	32.07
16,000	Sodium Vapor	150	199	34.05	37.11
27,500	Sodium Vapor	250	311	43.39	47.29
46,000	Sodium Vapor	400	488	59.56	64.92
Flood Lighting Luminaires					
27,500	Sodium Vapor	250	311	$43.39	$47.29
46,000	Sodium Vapor	400	488	59.56	64.92
LED Street Lighting Luminaires					
3,000	LED	15-29	23	$11.42	$12.45
3,900	LED	30-39	35	11.54	12.58
5,000	LED	40-59	50	11.67	12.72
7,250	LED	60-89	68	12.88	14.04
12,000	LED	90-129	103	13.56	14.78
16,000	LED	130-169	140	14.91	16.25
22,000	LED	170-220	200	20.31	22.14
LED Flood Lighting Luminaires					
15,000	LED	100-159	125	$14.59	$15.90
27,000	LED	160-249	205	17.20	18.75
37,500	LED	230-320	290	19.83	21.61
LED Power Bracket Luminaires					
3,950	LED	25-39	35	$9.68	$10.55
5,550	LED	44-55	50	9.75	10.63
7,350	LED	56-70	65	9.85	10.74
The following luminaires will no longer be installed. Charges are for existing luminaires only.					
Power Bracket Luminaires					
4,000	Mercury Vapor	100	127	$23.13	$25.21
7,900	Mercury Vapor	175	215	26.79	29.20
22,500	Mercury Vapor	400	462	38.48	41.94
Street Lighting Luminaires					
21,250	Mercury Vapor	250	263	$51.71	$56.36
4,000	Mercury Vapor	100	127	25.36	27.64
7,900	Mercury Vapor	175	211	29.35	31.99
12,000	Mercury Vapor	250	296	36.97	40.30
22,500	Mercury Vapor	400	459	45.54	49.64
40,000	Mercury Vapor	700	786	67.39	73.45
59,000	Mercury Vapor	1,000	1,105	84.09	91.65
1,000	Incandescent	92	92	20.16	21.97
5,890	LED	70	74	36.72	40.02
9,365	LED	100	101	39.69	43.26

Orange and Rockland Utilities, Inc.
Case 24-E-0060

Rates in Brief - Rate Year 3

Service Classification No. 16 (Continued)

Nominal Lumens	Luminaire Type	Watts	Total Wattage	Present Delivery Charge	Proposed Delivery Charge
The following luminaires will no longer be installed. Charges are for existing luminaires only.					
Flood Lighting Luminaires					
12,000	Mercury Vapor	250	296	$36.97	$40.30
22,500	Mercury Vapor	400	459	45.54	49.64
40,000	Mercury Vapor	700	786	67.39	73.45
59,000	Mercury Vapor	1,000	1,105	84.09	91.65
15 Foot Brackets			$ per month	0.85	0.93
Delivery Charges for Service Type C:					
Customer Charge (Metered)			per month	$24.00	$24.00
Customer Charge (Unmetered)			per month	20.00	20.00
Delivery Charge			¢ per kWh	9.251	10.810
Merchant Function Charge				See Page 22 of 22	See Page 22 of 22
Billing & Payment Processing Chg				See Page 22 of 22	See Page 22 of 22
Other Delivery and Supply Charges				As Described in Tariff	As Described in Tariff

Orange and Rockland Utilities, Inc.
Case 24-E-0060

Rates in Brief - Rate Year 3

Service Classification No. 19

				Present Year-round	Proposed Year-round
Customer Charge:			per month	$29.00	$28.00
Delivery Charges:					
	Period I	All kWh @	¢ per kWh	44.651	49.444
	Period II	All kWh @	¢ per kWh	15.976	17.691
	Period III	All kWh @	¢ per kWh	15.976	17.691
	Period IV	All kWh @	¢ per kWh	2.876	3.185
Minimum Charge:		per contract (not less than) plus applicable billing and payment processing charges		$348.00	$336.00
Standby Rates					
Customer Charge:		per month		$23.00	$23.00
Delivery Charges:					
Contract Demand Charge		per kW		$2.59	$2.61
As Used Daily Demand Charge					
	Period I	per kW		$1.5428	$1.7921
	Period II	per kW		$1.0650	$1.2371
	Period III	per kW		$1.0650	$1.2371
Charges Applicable to Both Standard and Standby Service Rates					
Merchant Function Charge				See Page 22 of 22	See Page 22 of 22
Billing & Payment Processing Chg				See Page 22 of 22	See Page 22 of 22
Other Delivery and Supply Charges				As Described in Tariff	As Described in Tariff

Definition of Rating Periods (Standard Rates):

Period I -	12:00 p.m. to 7:00 p.m. prevailing time, Monday through Friday, except holidays, June through September.
Period II -	10:00 a.m. to 12:00 p.m. and 7:00 p.m. to 9:00 p.m. prevailing time, Monday through Friday, except holidays, June through September.
Period III -	10:00 a.m. to 9:00 p.m. prevailing time, Monday through Friday, except holidays, October through May.
Period IV -	9:00 p.m. to 10:00 a.m. prevailing time, Monday through Friday, all hours on Saturday, Sunday and holidays, all months

Orange and Rockland Utilities, Inc.
Case 24-E-0060

Rates in Brief - Rate Year 3

Service Classification No. 20

			Present Year-round	Proposed Year-round
Standard Rates				
Customer Charge:		per month	$30.00	$30.00
Delivery Charges:				
Demand Charge				
Period I	All kW @	per kW	$34.95	$37.94
Period II	All kW @	per kW	18.02	20.09
Period III	All kW @	per kW	0.80	0.88
Usage Charge				
Period I	All kWh @	¢ per kWh	3.299	3.256
Period II	All kWh @	¢ per kWh	0.955	0.968
Period III	All kWh @	¢ per kWh	0.049	0.049
Minimum Charge:			Sum of the Customer Charge and $90.00 plus any applicable billing and payment processing charges.	Sum of the Customer Charge and $90.00 plus any applicable billing and payment processing charges.
Standby Rates				
Customer Charge:		per month	$26.00	$26.00
Delivery Charges:				
Contract Demand Charge		per kW	$2.66	$2.69
As Used Daily Demand Charge				
Period I		per kW	$1.2294	$1.3103
Period II		per kW	$0.8035	$0.8564
Period III		per kW	$0.8035	$0.8564
Charges Applicable to Both Standard and Standby Service Rates				
Merchant Function Charge			See Page 22 of 22	See Page 22 of 22
Billing & Payment Processing Chg			See Page 22 of 22	See Page 22 of 22
Reactive Power Demand Charge			See Page 22 of 22	See Page 22 of 22
Other Delivery and Supply Charges			As Described in Tariff	As Described in Tariff

Definition of Rating Periods (Standard Rates):

Period I -	1:00 p.m. to 7:00 p.m. prevailing time, Monday through Friday, except holidays, June through September.
Period II -	10:00 a.m. to 9:00 p.m. prevailing time, Monday through Friday, except holidays, October through May.
Period III -	7:00 p.m. to 1:00 p.m. prevailing time, Monday through Friday, June through September; 9:00 p.m. to 10:00 a.m. prevailing time, Monday through Friday, October through May; all hours on Saturday, Sunday and holidays, all months.

Orange and Rockland Utilities, Inc.
Case 24-E-0060

Rates in Brief - Rate Year 3

Service Classification No. 21

				Present Year-round	Proposed Year-round
Customer Charge:			per month	$45.00	$45.00
Delivery Charges:					
Demand Charge					
	Period I	All kW @	per kW	$31.56	$32.63
	Period II	All kW @	per kW	15.64	16.75
	Period III	All kW @	per kW	No Charge	No Charge
Usage Charge					
	Period I	All kWh @	¢ per kWh	1.332	1.309
	Period II	All kWh @	¢ per kWh	1.874	1.907
	Period III	All kWh @	¢ per kWh	0.145	0.145
Minimum Charge:				Sum of the Customer Charge and any applicable billing and payment processing charges.	Sum of the Customer Charge and any applicable billing and payment processing charges.

Standby Rates

		Present Year-round	Proposed Year-round
Customer Charge:	per month	$45.00	$45.00
Delivery Charges:			
Contract Demand Charge	per kW	$2.84	$2.89
As Used Daily Demand Charge			
Period I	per kW	$0.9257	$1.0134
Period II	per kW	$0.7106	$0.7779
Period III	per kW	$0.7106	$0.7779

Charges Applicable to Both Standard and Standby Service Rates

	Present	Proposed
Merchant Function Charge	See Page 22 of 22	See Page 22 of 22
Billing & Payment Processing Chg	See Page 22 of 22	See Page 22 of 22
Reactive Power Demand Charge	See Page 22 of 22	See Page 22 of 22
Other Delivery and Supply Charges	As Described in Tariff	As Described in Tariff

Definition of Rating Periods (Standard Rates):

Period I - 1:00 p.m. to 7:00 p.m. prevailing time, Monday through Friday, except holidays, June through September.

Period II - 10:00 a.m. to 9:00 p.m. prevailing time, Monday through Friday, except holidays, October through May.

Period III - 7:00 p.m. to 1:00 p.m. prevailing time, Monday through Friday, June through September; 9:00 p.m. to 10:00 a.m. prevailing time, Monday through Friday, October through May; all hours on Saturday, Sunday and holidays, all months.

Orange and Rockland Utilities, Inc.
Case 24-E-0060

Rates in Brief - Rate Year 3

Service Classification No. 22

				Present Year-round	Proposed Year-round
Standard Rates					
Customer Charge:			per month	$500.00	$500.00
Delivery Charges:					
Primary:					
Demand Charge					
	Period A	All kW @	per kW	$20.85	$23.56
	Period B	All kW @	per kW	11.89	13.43
	Period C	All kW @	per kW	No Charge	No Charge
Usage Charge					
	Period A	All kWh @	¢ per kWh	0.684	0.684
	Period B	All kWh @	¢ per kWh	0.684	0.684
	Period C	All kWh @	¢ per kWh	0.121	0.121
Substation:					
Demand Charge					
	Period A	All kW @	per kW	$13.39	$15.13
	Period B	All kW @	per kW	7.38	8.34
	Period C	All kW @	per kW	No Charge	No Charge
Usage Charge					
	Period A	All kWh @	¢ per kWh	0.287	0.287
	Period B	All kWh @	¢ per kWh	0.287	0.287
	Period C	All kWh @	¢ per kWh	0.121	0.121
Transmission:					
Demand Charge					
	Period A	All kW @	per kW	$7.81	$8.82
	Period B	All kW @	per kW	6.83	7.72
	Period C	All kW @	per kW	No Charge	No Charge
Usage Charge					
	Period A	All kWh @	¢ per kWh	0.121	0.121
	Period B	All kWh @	¢ per kWh	0.121	0.121
	Period C	All kWh @	¢ per kWh	0.121	0.121
Minimum Charge				Sum of the Customer Charge, Min. Monthly Demand Charge, contract demand charge, the reactive power demand charge, and any applicable billing and payment processing charges.	Sum of the Customer Charge, Min. Monthly Demand Charge, contract demand charge, the reactive power demand charge, and any applicable billing and payment processing charges.
Min. Monthly Demand Charge				$54.74	$60.38
Contract Demand Charge - Pri			per kW of CD	$3.99	$4.40
Contract Demand Charge - Sec			per kW of CD	$6.54	$7.21

Orange and Rockland Utilities, Inc.
Case 24-E-0060

Rates in Brief - Rate Year 3

Service Classification No. 22 (Continued)

		Present	Proposed
Standby Rates			
Customer Charge:	per month	$500.00	$500.00
Delivery Charges:			
Primary:			
Contract Demand Charge	per kW	$2.51	$2.58
As Used Daily Demand Charge			
Period I	per kW	$0.6840	$0.7755
Period II	per kW	$0.5225	$0.5924
Period III	per kW	$0.5225	$0.5924
Substation:			
Contract Demand Charge	per kW	$1.58	$1.75
As Used Daily Demand Charge			
Period I	per kW	$0.5672	$0.6375
Period II	per kW	$0.3057	$0.3436
Period III	per kW	$0.3057	$0.3436
Transmission:			
Contract Demand Charge	per kW	$0.70	$0.76
As Used Daily Demand Charge			
Period I	per kW	$0.6033	$0.6795
Period II	per kW	$0.2561	$0.2884
Period III	per kW	$0.2561	$0.2884

Orange and Rockland Utilities, Inc.
Case 24-E-0060

Rates in Brief - Rate Year 3

Service Classification No. 22 (Continued)

		Present	Proposed
		Year-round	Year-round
Standby Service Rates – Existing Standby Service Customer on Phase- In			
Customer Charge:	per month	$500.00	$500.00
Transmission:			
Contract Demand Charge	per kW	$1.46	$1.63
As Used Daily Demand Charge (S)	per kW	$0.3929	$0.4402
As Used Daily Demand Charge (W)	per kW	$0.3582	$0.4011
Charges Applicable to Both Standard and Standby Service Rates			
Merchant Function Charge		See Page 22 of 22	See Page 22 of 22
Billing & Payment Processing Chg		See Page 22 of 22	See Page 22 of 22
Reactive Power Demand Charge		See Page 22 of 22	See Page 22 of 22
Other Delivery and Supply Charges		As Described in Tariff	As Described in Tariff

Definition of Rating Periods (Standard Rates):

Period A -	8:00 a.m. to 11:00 p.m. prevailing time, Monday through Friday, except holidays, June through September.
Period B -	8:00 a.m. to 11:00 p.m. prevailing time, Monday through Friday, except holidays, October through May.
Period C -	11:00 p.m. to 8:00 a.m. prevailing time, Monday through Friday, all hours on Saturday, Sunday and holidays, all months.

Orange and Rockland Utilities, Inc.
Case 24-E-0060

Rates in Brief - Rate Year 3

Other Charges

		Present	Proposed
Merchant Function Charge			
Service Classification Nos. 1 & 19			
Supply Related	¢ per kWh	0.186	0.203
Purch Pwr Wrking Cap	¢ per kWh	0.099	0.099
Credit & Collections	¢ per kWh	0.061	0.066
Uncollectibles	¢ per kWh	Variable	Variable
Service Classification Nos. 2 Secondary, 20, 4, 5, 6 & 16			
Supply Related	¢ per kWh	0.104	0.116
Purch Pwr Wrking Cap	¢ per kWh	0.099	0.099
Credit & Collections	¢ per kWh	0.031	0.034
Uncollectibles	¢ per kWh	Variable	Variable
Service Classification Nos. 2 Primary, 3, 9, 21 & 22			
Supply Related	¢ per kWh	0.104	0.115
Purch Pwr Wrking Cap	¢ per kWh	0.099	0.099
Credit & Collections	¢ per kWh	0.022	0.024
Uncollectibles	¢ per kWh	Variable	Variable
Billing & Payment Processing Chg	per month	$2.10	$2.10
Reactive Power Demand Charge	per KVAr	$1.05	$1.05

Orange and Rockland Utilities, Inc.
Cases 24-E-0060 & 24-G-0061

GAS REVENUE ALLOCATION AND RATE DESIGN

1. Revenue Allocation

Two adjustments were made to the incremental revenue requirement before allocating it among customer classes. The first adjustment to the incremental revenue requirement for each Rate Year ("RY")[1] is the subtraction of amounts included for New York State Gross Receipts and Franchise Tax surcharge revenues, Municipal Tax surcharge revenues and Metropolitan Transportation Authority Business Tax surcharge revenues. The second adjustment was made to offset the incremental credits that are projected to be paid to low income residential customers in RY1.[2]

For each RY, before the adjusted incremental revenue requirement was applied to each customer class, the RY delivery revenues for each class were realigned in a revenue neutral manner to reduce interclass deficiencies and surpluses. In each RY, deficiency and surplus indications have been reduced by one-third. The RY delivery revenue increase was then allocated among the Service Classifications ("SC") in proportion to the relative contribution made by each SC's realigned RY delivery revenue to the total realigned RY delivery revenue. The delivery revenue changes by SC for each RY were mitigated in a manner such that each SC received a percentage change in delivery revenue that was no more than 1.25 times and no less than 0.75 times the overall RY percentage change in delivery revenue.

[1] RY1 is defined as the 12 months ending December 31, 2025, RY2 is defined as the 12 months ending December 31, 2026, and RY3 is defined as the 12 months ending December 31, 2027.
[2] This adjustment was $1,980,093 in RY1 with no incremental increases in RY2 and RY3.

2. Rate Design

The rate design process for each RY for firm rates consists of the following five steps:

- Determine revised competitive service charges and associated delivery revenue changes.
- Adjust class-specific delivery revenue increases to determine non-competitive delivery revenue increases.
- Determine first block charges and associated changes in delivery revenue.
- Implement intraclass rate structure changes.
- Adjust class-specific non-competitive delivery revenue increases for revenue changes associated with increases in first block charges; and apply non-competitive delivery revenue increases, adjusted for revenue changes associated with increases in first block charges, on a common percentage basis to the per-Ccf charges within each SC.

a. Revised Competitive Service Charges and Associated Delivery Revenue Changes

(i) The competitive delivery components include the billing and payment processing ("BPP") charge; the Merchant Function Charge ("MFC") fixed components, that is the MFC procurement and credit and collections components; and the purchase of receivables ("POR") credit and collections ("C&C") component. For each RY, revised revenue levels for the MFC fixed components and the POR C&C component were based on percentages of delivery revenue as determined in the ECOS study. Based on ECOS study indications, the BPP charge has been increased in RY1 from $1.50 to $2.10. The incremental revenue associated with the change in the BPP charge was based on the number of forecasted bills times the incremental BPP charge.

The revised competitive service charge revenue levels for each RY were compared with competitive service charge revenues determined based on competitive service charges for the previous RY to determine the change in competitive service revenues.

b. <u>Determination of Class-Specific Non-Competitive Delivery Revenue Increases</u>

For each RY, the revenue changes associated with the competitive service charges were used to adjust the class-specific delivery revenue increases to determine class-specific non-competitive delivery revenue increases.

c. <u>Revenue Neutral Intraclass Rate Structure Changes</u>

For SC No. 2 and SC No. 6 Rate Schedule IB, the Company combined the second and third blocks of the existing four-block structure into a single flat rate. In RY1, one-third of the differential between the newly combined second and third block rate and the tail block rate was eliminated. In RY2 and RY3, the remaining two-thirds of the differential was eliminated, and the result is a flat rate structure for any usage over 3 Ccf for the SC No. 2 and SC No. 6 Rate Schedule IB classes. This revenue neutral change impacted the SC No. 6 Rate Schedule II tail block rate, which is set equal to the tail block rate of SC No. 2 and SC No. 6 Rate Schedule IB.

d. <u>Revised First Block Charges and Associated Delivery Revenue Changes</u>

The following summarizes the first block charges in each RY.

SC	RY1	RY2	RY3
SC1 / SC6 1A	$22.00	$22.50	$23.00
SC2 / SC6 1B	34.00	35.00	36.00

e. Application of Delivery Revenue Increase Adjusted for Revenue Associated with First Block Charges Within Each Service Classification

For RY1, the remaining incremental revenue requirement in each class, after subtracting any revenue associated with changes in the first block charges as described above, was applied to all rate block charges, except the first block charges, on an equal percentage basis. The revenue impacts of the rate design changes on firm customers are summarized in Schedule 1 of this Appendix.

3. Unbundled Charges

a. Merchant Function Charge

For the term of the Gas Rate Plan, the Company will continue to implement the MFC, as set forth in the Company's gas tariff**.** The MFC fixed component monthly targets (commodity procurement and credit and collections) for RY1, RY2 and RY3 are set forth in Schedule 4 of this Appendix.

b. Transition Adjustment for Competitive Services

For the term of the Gas Rate Plan, the Company will continue to implement the Transition Adjustment for Competitive Services ("TACS"), as set forth in the Company's gas tariff.

c. POR Discount

For the term of the Gas Rate Plan, the Company will continue to implement the POR discount, as set forth in the Company's gas tariff. The POR C&C component monthly targets for each RY are set forth in Schedule 4 of this Appendix.

d. BPP Charge

The Company's BPP charge will increase from $1.50 per bill to $2.10 per bill.

4. Distributed Generation Rates

The rates for service under Rider B (non-residential DG rate) and Rider C (residential DG rate) have been increased at the percentage increases in per Ccf delivery service revenues for the otherwise applicable service classification (i.e., SC No. 2 for Rider B and SC No. 1 for Rider C).

5. Additional Items for Collection through the Monthly Gas Adjustment

As set forth in Appendix 9, the Monthly Gas Adjustment ("MGA") will be amended to include the reconciliation component of Pension and OPEBs.

6. Make Whole Provisions

If the Commission makes rates effective for RY1 after January 1, 2025, the Company will implement a make whole provision. Differences in non-competitive delivery service revenues that result from the extension of the Case 24-G-0061 suspension period plus interest at the Commission's Other Customer Capital Rate will be collected via the implementation of a Delivery Revenue Surcharge ("DRS").[3] The DRS will be in effect on the date rates become effective in this case through the remainder of RY1. The unit amount to be collected from customers will be shown by SC on the Statement of Delivery Revenue Surcharge. Any difference between amounts required to be collected and actual amounts collected will be charged or credited to customers in a subsequent DRS Statement that will become effective March 1, 2026.

[3] Competitive services' revenue differences associated with the extension of the Case 24-G-0061 suspension period will be reconciled and surcharged or recovered through the TACS.

6. Tariff Filing Dates

By January 1, 2025, 2026 and 2027, the Company will file tariff revisions implementing the rate changes for RY1, RY2, and RY3, respectively,[4] unless the Commission makes rates effective for RY1 after January 1, 2025, in this proceeding, at which time the Company will place RY1 rates into effect on another date subject to the make whole provisions described above.

[4] The tariff filings for RY2 and RY3 will be made at least 30 days prior to the effective date of new rates unless the Commission orders another filing date for the RY2 and RY3 compliance filings.

ORANGE AND ROCKLAND UTILITIES, INC.

Case 24-G-0061

Appendix 18 - Gas Revenue Allocation and Rate Design

Index of Schedules

Schedule 1	Page 1	Impact of RY1 Rate Change on Total Revenue
	Page 2	Calculation of RY1 Incremental Revenue Requirement
	Page 3	Allocation of RY1 Incremental Revenue Requirement
	Page 4	Determination of RY1 Non-Competitive Increase
Schedule 2	Page 1	Impact of RY2 Rate Change on Total Revenue
	Page 2	Calculation of RY2 Incremental Revenue Requirement
	Page 3	Allocation of RY2 Incremental Revenue Requirement
	Page 4	Determination of RY2 Non-Competitive Increase
Schedule 3	Page 1	Impact of RY3 Rate Change on Total Revenue
	Page 2	Calculation of RY3 Incremental Revenue Requirement
	Page 3	Allocation of RY3 Incremental Revenue Requirement
	Page 4	Determination of RY3 Non-Competitive Increase
	Page 5	Summary of RY3 MGA Temporary Surcharge
Schedule 4		Summary of MFC Targets by Month
Schedule 5		Rates in Brief - RY1
Schedule 6		Rates in Brief - RY2
Schedule 7		Rates in Brief - RY3

ORANGE AND ROCKLAND UTILITIES, INC.

Case 24-G-0061

Impact of Proposed Rate Change on Total Firm Revenue - Company Impact
For the Rate Year Twelve Months Ending December 31, 2025 (1) (2)
(Based on Billed Sales and Revenues)

Based on Levelized Revenue Requirement

Service Classification	Type of Service	Rate Year Billed Sales (Mcf)	Customers	Revenue At Present Rates ($000s)	Revenue At Proposed Rates ($000s)	Change ($000's)	Percent Change
1 / 6 IA	Residential	14,473,618	131,559	$224,446	$235,896	$11,450	5.1%
1 / 6 IA	Non Residential	1,064,118	6,320	16,056	17,046	991	6.2%
2 / 6 IB	Commercial	4,249,624	5,783	46,364	48,235	1,871	4.0%
6 II	Large Commercial	1,184,731	92	12,247	12,888	641	5.2%
	Total Firm	20,972,092	143,754	$299,112	$314,065	$14,953	5.0%

Notes:

1. For comparison purposes, an estimated cost of gas supply has been included in the SC No. 6 revenue. This is equivalent on a per unit basis, to the cost of gas supply included in SC No. 1 and 2 revenues.
2. Revenue at proposed rates reflects the expiration of the RY3 temporary credit from Case No. 21-G-0073.

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ORANGE AND ROCKLAND UTILITIES, INC.

Case 24-G-0061

Calculation of Incremental Revenue Requirement for Rate Year 1

Based on Levelized Revenue Requirement

a.	Incremental Revenue Requirement for the Rate Year Including Gross Receipts/MTA Taxes	$10,448,000
b.	Less Gross Receipts/MTA Tax Included in Incremental Revenue Requirement (2)	173,000
c.	Incremental Revenue Requirement for the Rate Year Excluding Gross Receipts/MTA Taxes (a - b)	$10,275,000
d.	Low Income Credits	$1,980,093
e.	Total Revenue Requirement + Low Income Credits (c + d)	$12,255,093
f.	Rate Year Bundled Delivery Revenues for the Rate Year for Firm Service Classification Nos. 1, 2, and 6	$178,198,586
g.	Rate Year Overall Percentage Increase in Delivery Revenues (e / f)	6.87721%
h.	Rate Year Overall Percentage Increase in Delivery Revenues less Low Income Credits (c / f)	5.76604%

Note:

1. Twelve months ending December 31, 2025
2. GRT/MTA Gross Up Included in Rev Req = 1.66%

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ORANGE AND ROCKLAND UTILITIES, INC.

Case 24-G-0061

Allocation of Incremental Revenue Requirement Among Customer Classes for Rate Year 1

Based on Levelized Revenue Requirement

	(1)	(2)	(3)=(1)+(2)	(4)	(5)=(3)+(4)	(6)=(2)+(4)	(7)	(8)	(9)	(10)=(6)+(8)+(9)	(11)=(1)+(10)	(12)=(10)/(1)
Class	Rate Year Bundled Delivery Rev. ($)	Adjusted Net (Surplus)/ Deficiency ($)	Adjusted Rate Year Del Revenue ($)	Rate Increase 6.877% ($)	Adj Delivery Rev incl Rate Incr at Rate Yr Rate Level ($)	Rate Year Increase Incl. (Surplus)/Deficiency ($)	Rate Year % Increase	Mitigation Adjustment (b) ($)	Mitigation Increase ($)	Adj. Rate Year Incl. (Surplus)/Deficiency Incl. Mitigation Adj./Dec. ($)	Adj Rate Year Bundled Delivery Revenue At Rate Year Level ($)	Adjusted Rate Year % Increase
SC Nos. 1 & 6 RS IA	152,552,980	1,858,964	154,411,944	10,619,234	165,031,178	12,478,198	8.18%	0	(1,545,884)	10,932,314	163,485,294	7.166%
SC Nos. 2 & 6 RS 1B & II	25,645,606	(1,858,964)	23,786,642	1,635,857	25,422,499	(223,107)	-0.87%	1,545,884	0	1,322,777	26,968,383	5.158%
Total	178,198,586	0	178,198,586	12,255,091	190,453,677	12,255,091		1,545,884	(1,545,884)	12,255,091	190,453,677	6.877%

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ORANGE AND ROCKLAND UTILITIES, INC.

Case 24-G-0061

Determination of Non-Competitive Delivery Revenue Increases for Rate Year 1

Based on Levelized Revenue Requirement

	(1)	(2)	(3)	(4)	(5)=(1)-(2)-(3)-(4)
		Incremental Competitve Svc Revenues			
Service Class	Adj Rate Year Incr. Incl (Surplus)/Deficiency Incl Mitigation Adj. Delivery Rev. (a)	MFC Fixed Component Related Revenue (b)	BPP Component Related Revenue (c)	POR Credit & Collections Related Revenue (d)	Non-Competitive Rate Year Delivery Revenue Increase
	($)	($)	($)	($)	($)
SC Nos. 1 & 6 RS IA	$10,932,314	($68,972)	$439,567	($105,812)	$10,667,531
SC Nos. 2 & 6 RS IB & II	1,322,777	10,229	15,343	(61,011)	1,358,216
Total	$12,255,091	($58,743)	$454,910	($166,823)	$12,025,747

ORANGE AND ROCKLAND UTILITIES, INC.

Case 24-G-0061

Impact of Proposed Rate Change on Total Firm Revenue - Company Impact
For the Rate Year Twelve Months Ending December 31, 2026 (1)
(Based on Billed Sales and Revenues)

Based on Levelized Revenue Requirement

Service Classification	Type of Service	Rate Year Billed Sales (Mcf)	Customers	Revenue At Present Rates ($000s)	Revenue At Proposed Rates ($000s)	Change ($000's)	Percent Change
1 / 6 IA	Residential	14,540,102	132,088	$240,239	$248,948	$8,709	3.6%
1 / 6 IA	Non Residential	1,068,341	6,356	17,365	17,994	629	3.6%
2 / 6 IB	Commercial	4,281,355	5,767	49,663	50,383	720	1.4%
6 II	Large Commercial	1,190,052	92	13,301	13,692	391	2.9%
	Total Firm	21,079,849	144,303	$320,568	$331,016	$10,449	3.3%

Notes:

1. For comparison purposes, an estimated cost of gas supply has been included in the SC No. 6 revenue. This is equivalent on a per unit basis, to the cost of gas supply included in SC No. 1 and 2 revenues.

ORANGE AND ROCKLAND UTILITIES, INC.

Case 24-G-0061

Calculation of Incremental Revenue Requirement for Rate Year 2

Based on Levelized Revenue Requirement

a.	Incremental Revenue Requirement for the Rate Year Including Gross Receipts/MTA Taxes	$10,448,000
b.	Less Gross Receipts/MTA Tax Included in Incremental Revenue Requirement (2)	173,000
c.	Incremental Revenue Requirement for the Rate Year Excluding Gross Receipts/MTA Taxes (a - b)	$10,275,000
d.	Low Income Credits	$0
e.	Total Revenue Requirement + Low Income Credits (c + d)	$10,275,000
f.	Rate Year Bundled Delivery Revenues for the Rate Year for Firm Service Classification Nos. 1, 2, and 6	$191,505,996
g.	Rate Year Overall Percentage Increase in Delivery Revenues (e / f)	5.36537%
h.	Rate Year Overall Percentage Increase in Delivery Revenues less Low Income Credits (c / f)	5.36537%

Note:

1. Twelve months ending December 31, 2026
2. GRT/MTA Gross Up Included in Rev Req = 1.66%

ORANGE AND ROCKLAND UTILITIES, INC.

Case 24-G-0061

Allocation of Incremental Revenue Requirement Among Customer Classes for Rate Year 2

Based on Levelized Revenue Requirement

	(1)	(2)	(3)=(1)+(2)	(4)	(5)=(3)+(4)	(6)=(2)+(4)	(7)	(8)	(9)	(10)=(6)+(8)+(9)	(11)=(1)+(10)	(12)=(10)/(1)
	Rate Year Bundled Delivery Rev.	Adjusted Net (Surplus)/ Deficiency	Adjusted Rate Year Del Revenue	Rate Increase 5.365%	Adj Delivery Rev incl Rate Incr at Rate Yr Rate Level	Rate Year Increase Incl. (Surplus)/Deficiency	Rate Year % Increase	Mitigation Adjustment (b)	Mitigation Increase	Adj. Rate Year Incl. (Surplus)/Deficiency Incl. Mitigation Adj./Dec.	Adj Rate Year Bundled Delivery Revenue At Rate Year Level	Adjusted Rate Year % Increase
Class	($)	($)	($)	($)	($)	($)		($)	($)	($)	($)	
SC Nos. 1 & 6 RS IA	164,360,081	1,858,964	166,219,045	8,918,267	175,137,312	10,777,231	6.56%	0	(1,594,586)	9,182,645	173,542,726	5.59%
SC Nos. 2 & 6 RS 1B & II	27,145,915	(1,858,964)	25,286,951	1,356,738	26,643,689	(502,226)	-1.85%	1,594,586	0	1,092,360	28,238,275	4.02%
Total	191,505,996	0	191,505,996	10,275,005	201,781,001	10,275,005		1,594,586	(1,594,586)	10,275,005	201,781,001	5.365%

ORANGE AND ROCKLAND UTILITIES, INC.

Case 24-G-0061

Determination of Non-Competitive Delivery Revenue Increases for Rate Year 2

Based on Levelized Revenue Requirement

	(1)	(2)	(3)	(4)	(5)=(1)-(2)-(3)-(4)
		Incremental Competitve Svc Revenues			
Service Class	Adj Rate Year Incr. Incl (Surplus)/Deficiency Incl Mitigation Adj. Delivery Rev. (a)	MFC Fixed Component Related Revenue (b)	BPP Component Related Revenue (c)	POR Credit & Collections Related Revenue (d)	Non-Competitive Rate Year Delivery Revenue Increase
	($)	($)	($)	($)	($)
SC Nos. 1 & 6 RS IA	$9,182,645	$67,671	$0	$21,518	$9,093,455
SC Nos. 2 & 6 RS IB & II	1,092,360	4,455	0	4,138	1,083,767
Total	$10,275,005	$72,126	$0	$25,656	$10,177,223

ORANGE AND ROCKLAND UTILITIES, INC.

Case 24-G-0061

Impact of Proposed Rate Change on Total Firm Revenue - Company Impact
For the Rate Year Twelve Months Ending December 31, 2027 (1) (2)
(Based on Billed Sales and Revenues)

Based on Levelized Revenue Requirement

Service Classification	Type of Service	Rate Year Billed Sales (Mcf)	Customers	Revenue At Present Rates ($000s)	Revenue At Proposed Rates ($000s)	Change ($000's)	Percent Change
1 / 6 IA	Residential	14,343,768	132,216	$251,486	$261,177	$9,691	3.9%
1 / 6 IA	Non Residential	1,054,580	6,377	18,190	18,899	708	3.9%
2 / 6 IB	Commercial	4,239,900	5,738	51,530	51,495	(34)	-0.1%
6 II	Large Commercial	1,177,238	92	14,005	14,087	82	0.6%
	Total Firm	20,815,485	144,423	$335,212	$345,658	$10,447	3.1%

Notes:
1. For comparison purposes, an estimated cost of gas supply has been included in the SC No. 6 revenue. This is equivalent on a per unit basis, to the cost of gas supply included in SC No. 1 and 2 revenues.
2. Revenue at proposed rates reflects the RY3 temporary credit.

ORANGE AND ROCKLAND UTILITIES, INC.

Case 24-G-0061

Calculation of Incremental Revenue Requirement for Rate Year 3

Based on Levelized Revenue Requirement

a.	Incremental Revenue Requirement for the Rate Year Including Gross Receipts/MTA Taxes	$17,207,000
b.	Less Gross Receipts/MTA Tax Included in Incremental Revenue Requirement (2)	286,000
c.	Incremental Revenue Requirement for the Rate Year Excluding Gross Receipts/MTA Taxes (a - b)	$16,921,000
d.	Low Income Credits	$0
e.	Total Revenue Requirement + Low Income Credits (c + d)	$16,921,000
f.	Rate Year Bundled Delivery Revenues for the Rate Year for Firm Service Classification Nos. 1, 2, and 6	$199,732,939
g.	Rate Year Overall Percentage Increase in Delivery Revenues (e / f)	8.47181%
h.	Rate Year Overall Percentage Increase in Delivery Revenues less Low Income Credits (c / f)	8.47181%

Note:

1. Twelve months ending December 31, 2027
2. GRT/MTA Gross Up Included in Rev Req = 1.66%

ORANGE AND ROCKLAND UTILITIES, INC.

Case 24-G-0061

Allocation of Incremental Revenue Requirement Among Customer Classes for Rate Year 2

Based on Levelized Revenue Requirement

	(1)	(2)	(3)=(1)+(2)	(4)	(5)=(3)+(4)	(6)=(2)+(4)	(7)	(8)	(9)	(10)=(6)+(8)+(9)	(11)=(1)+(10)	(12)=(10)/(1)
	Rate Year Bundled Delivery Rev.	Adjusted Net (Surplus)/ Deficiency	Adjusted Rate Year Del Revenue	Rate Increase 8.472%	Adj Delivery Rev incl Rate Incr at Rate Yr Rate Level	Rate Year Increase Incl. (Surplus)/Deficiency	Rate Year % Increase	Mitigation Adjustment (b)	Mitigation Increase	Adj. Rate Year Incl. (Surplus)/Deficiency Incl. Mitigation Adj./Dec.	Adj Rate Year Bundled Delivery Revenue At Rate Year Level	Adjusted Rate Year % Increase
Class	($)	($)	($)	($)	($)	($)		($)	($)	($)	($)	
SC Nos. 1 & 6 RS IA	171,767,018	1,858,964	173,625,983	14,709,263	188,335,246	16,568,227	9.65%	0	(1,424,148)	15,144,080	186,911,098	8.82%
SC Nos. 2 & 6 RS 1B & II	27,965,921	(1,858,964)	26,106,956	2,211,732	28,318,688	352,768	1.26%	1,424,148	0	1,776,915	29,742,836	6.35%
Total	199,732,939	0	199,732,939	16,920,995	216,653,934	16,920,995		1,424,148	(1,424,148)	16,920,995	216,653,934	8.472%

ORANGE AND ROCKLAND UTILITIES, INC.

Case 24-G-0061

Determination of Non-Competitive Delivery Revenue Increases for Rate Year 3

Based on Levelized Revenue Requirement

	(1)	(2)	(3)	(4)	(5)=(1)-(2)-(3)-(4)
		Incremental Competitve Svc Revenues			
Service Class	Adj Rate Year Incr. Incl (Surplus)/Deficiency Incl Mitigation Adj. Delivery Rev. (a) ($)	MFC Fixed Component Related Revenue (b) ($)	BPP Component Related Revenue (c) ($)	POR Credit & Collections Related Revenue (d) ($)	Non-Competitive Rate Year Delivery Revenue Increase ($)
SC Nos. 1 & 6 RS IA	$15,144,080	$90,707	$0	$28,604	$15,024,769
SC Nos. 2 & 6 RS IB & II	1,776,915	4,227	0	5,031	1,767,658
Total	$16,920,995	$94,934	$0	$33,635	$16,792,427

ORANGE AND ROCKLAND UTILITIES, INC.

Case 24-G-0061

Temporary Credit to be Refunded through Monthly Gas Adjustment in Rate Year 3

Temp Surcharge/(Credit)	($6,759,000)	
Less GRT/MTA Tax	(112,199)	
Net	($6,646,801)	
Rate Year Sales (CCF)	208,154,847	
MGA Surcharge	($0.03193)	per CCF

ORANGE & ROCKLAND UTILITIES, INC.

Case 24-G-0061

Summary of MFC Monthly Targets
For Rates Effective January 1, 2025, January 1, 2026 and January 1, 2027

Based on Levelized Revenue Requirement

For Rates Effective January 1, 2025	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Total
Supply Related Component	$209,491	$222,191	$177,548	$129,837	$70,086	$43,657	$33,620	$27,406	$30,202	$37,570	$77,524	$150,200	$1,209,332
Credit and Collections Related Component	59,081	62,659	50,076	36,620	19,758	12,301	9,459	7,715	8,494	10,584	21,868	42,247	340,864
POR Discount Related Component	16,236	16,589	13,787	10,296	6,541	3,984	2,887	2,458	2,517	3,380	6,198	10,602	95,475
Total	$284,809	$301,439	$241,411	$176,754	$96,385	$59,942	$45,966	$37,580	$41,212	$51,533	$105,591	$203,049	$1,645,671

For Rates Effective January 1, 2026	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Total
Supply Related Component	$221,981	$235,430	$188,079	$137,568	$74,191	$46,222	$35,626	$29,033	$32,006	$39,781	$82,166	$159,173	$1,281,258
Credit and Collections Related Component	62,561	66,347	53,012	38,775	20,900	13,015	10,017	8,167	8,995	11,198	23,161	44,739	360,887
POR Discount Related Component	17,233	17,605	14,623	10,922	6,979	4,251	3,076	2,622	2,681	3,601	6,575	11,235	101,402
Total	$301,775	$319,382	$255,714	$187,265	$102,070	$63,488	$48,719	$39,823	$43,681	$54,580	$111,902	$215,147	$1,743,547

For Rates Effective January 1, 2027	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Total
Supply Related Component	$238,742	$253,211	$202,180	$147,791	$79,596	$49,444	$38,028	$30,926	$34,131	$42,483	$88,127	$171,038	$1,375,696
Credit and Collections Related Component	67,277	71,351	56,982	41,653	22,421	13,920	10,691	8,698	9,590	11,958	24,839	48,070	387,452
POR Discount Related Component	18,541	18,937	15,715	11,733	7,478	4,554	3,293	2,805	2,867	3,859	7,055	12,076	108,913
Total	$324,560	$343,499	$274,877	$201,177	$109,494	$67,918	$52,011	$42,430	$46,588	$58,300	$120,021	$231,184	$1,872,061

ORANGE AND ROCKLAND UTILITIES, INC.

Case 24-G-0061

Present and Proposed Rates in Brief - RY1

Present S.C. No. 1 (Monthly)
(Residential and Space Heating)

Delivery Charges:

Delivery:

First	3	Ccf or less	$22.00	
All over	3	Ccf	75.079	¢/Ccf

Proposed S.C. No. 1 (Monthly)
(Residential and Space Heating)

Delivery Charges:

Delivery:

First	3	Ccf or less	$22.00	
All over	3	Ccf	82.163	¢/Ccf

Present S.C. No. 2 (Monthly)
(General Service)

Delivery Charges:

Delivery:

First	3	Ccf or less	$33.00	
Next	47	Ccf	45.014	¢/Ccf
Next	4,950	Ccf	43.757	¢/Ccf
All over	5,000	Ccf	39.314	¢/Ccf

Proposed S.C. No. 2 (Monthly)
(General Service)

Delivery Charges:

Delivery:

First	3	Ccf or less	$34.00	
Next	47	Ccf	45.816	¢/Ccf
Next	4,950	Ccf	45.816	¢/Ccf
All over	5,000	Ccf	42.615	¢/Ccf

Other Charges Applicable to Service Classification Nos. 1 and 2

Merchant Function Charge	See Page 5 of 5	Merchant Function Charge	See Page 5 of 5
Billing & Payment Processing Charge	See Page 5 of 5	Billing & Payment Processing Charge	See Page 5 of 5
Other Delivery and Supply Charges	As Described in Tariff	Other Delivery and Supply Charges	As Described in Tariff

ORANGE AND ROCKLAND UTILITIES, INC.

Case 24-G-0061

Present and Proposed Rates in Brief - RY1

Present S.C. No. 6 (Monthly) (Firm Transportation Service)					**Proposed S.C. No. 6 (Monthly) (Firm Transportation Service)**				
Rate Schedule IA - Residential:					**Rate Schedule IA - Residential:**				
Delivery Charges:					**Delivery Charges:**				
					Delivery:				
First	3	Ccf or less	$22.00		First	3	Ccf or less	$22.00	
All over	3	Ccf	75.079	¢/Ccf	All over	3	Ccf	82.163	¢/Ccf
Rate Schedule IB - Non-Residential:					**Rate Schedule IB - Non-Residential:**				
Delivery Charges:					**Delivery Charges:**				
					Delivery:				
First	3	Ccf or less	$33.00		First	3	Ccf or less	$34.00	
Next	47	Ccf	45.014	¢/Ccf	Next	47	Ccf	45.816	¢/Ccf
Next	4,950	Ccf	43.757	¢/Ccf	Next	4,950	Ccf	45.816	¢/Ccf
All over	5,000	Ccf	39.314	¢/Ccf	All over	5,000	Ccf	42.615	¢/Ccf
Rate Schedule II:					**Rate Schedule II:**				
Delivery Charges:					**Delivery Charges:**				
					Delivery:				
First	100	Ccf or less	$255.18		First	100	Ccf or less	$255.18	
Over	100	Ccf	39.314	¢/Ccf	Over	100	Ccf	42.615	¢/Ccf

Other Charges Applicable to Service Classification No. 6 Rate Schedules 1A, 1B, and II

Billing & Payment Processing Charge*	See Page 5 of 5	Billing & Payment Processing Charge*	See Page 5 of 5
Other Delivery and Supply Charges	See Page 5 of 5	Other Delivery and Supply Charges	See Page 5 of 5

* Assessed on customers receiving a utility single bill

ORANGE AND ROCKLAND UTILITIES, INC.

Case 24-G-0061

Present and Proposed Rates in Brief - RY1

Present Rider B - Rate Schedule I Rate IA

Delivery Charges (Summer):

First	3 Ccf or less	$158.86
All over	3 Ccf	24.299 ¢/Ccf

Delivery Charges (Winter):

First	3 Ccf or less	$158.86
All over	3 Ccf	30.163 ¢/Ccf

Minimum Charge - $158.86 per month

Other Charges:

Rates and other provisions of the customer’s otherwise applicable service classification*

Present Rider B - Rate Schedule I Rate IB

Delivery Charges (Summer):

First	3 Ccf or less	$269.75
All over	3 Ccf	24.212 ¢/Ccf

Delivery Charges (Winter):

First	3 Ccf or less	$269.75
All over	3 Ccf	30.163 ¢/Ccf

Minimum Charge - $269.75 per month

Other Charges:

Rates and other provisions of the customer’s otherwise applicable service classification*

Present Rider B - Rate Schedule I Rate IC

Delivery Charges (Summer):

First	3 Ccf or less	$410.62
All over	3 Ccf	24.299 ¢/Ccf

Delivery Charges (Winter):

First	3 Ccf or less	$410.62
All over	3 Ccf	30.163 ¢/Ccf

Minimum Charge - $410.62 per month

Other Charges:

Rates and other provisions of the customer’s otherwise applicable service classification*

* Excluding the RDM Adjustment

Proposed Rider B - Rate Schedule I Rate IA

Delivery Charges (Summer):

First	3 Ccf or less	$167.05
All over	3 Ccf	25.666 ¢/Ccf

Delivery Charges (Winter):

First	3 Ccf or less	$167.05
All over	3 Ccf	31.860 ¢/Ccf

Minimum Charge - $167.05 per month

Other Charges:

Rates and other provisions of the customer’s otherwise applicable service classification*

Proposed Rider B - Rate Schedule I Rate IB

Delivery Charges (Summer):

First	3 Ccf or less	$283.66
All over	3 Ccf	25.574 ¢/Ccf

Delivery Charges (Winter):

First	3 Ccf or less	$283.66
All over	3 Ccf	31.860 ¢/Ccf

Minimum Charge - $283.66 per month

Other Charges:

Rates and other provisions of the customer’s otherwise applicable service classification*

Proposed Rider B - Rate Schedule I Rate IC

Delivery Charges (Summer):

First	3 Ccf or less	$431.80
All over	3 Ccf	25.666 ¢/Ccf

Delivery Charges (Winter):

First	3 Ccf or less	$431.80
All over	3 Ccf	31.860 ¢/Ccf

Minimum Charge - $431.80 per month

Other Charges:

Rates and other provisions of the customer’s otherwise applicable service classification*

* Excluding the RDM Adjustment

ORANGE AND ROCKLAND UTILITIES, INC.

Case 24-G-0061

Present and Proposed Rates in Brief - RY1

Present Rider B - Rate Schedule I Rate ID

Delivery Charges (Summer):

First	3 Ccf or less	$521.52	
All over	3 Ccf	24.299	¢/Ccf

Delivery Charges (Winter):

First	3 Ccf or less	$521.52	
All over	3 Ccf	30.163	¢/Ccf

Minimum Charge - $521.52 per month

Other Charges:

Rates and other provisions of the customer's otherwise applicable service classification*

Proposed Rider B - Rate Schedule I Rate ID

Delivery Charges (Summer):

First	3 Ccf or less	$548.42	
All over	3 Ccf	25.666	¢/Ccf

Delivery Charges (Winter):

First	3 Ccf or less	$548.42	
All over	3 Ccf	31.860	¢/Ccf

Minimum Charge - $548.42 per month

Other Charges:

Rates and other provisions of the customer's otherwise applicable service classification*

Present Rider B - Rate Schedule II

Delivery Charges (Summer):

First	3 Ccf or less	$59.95	
All over	3 Ccf	4.859	¢/Ccf

Delivery Charges (Winter):

First	3 Ccf or less	$59.95	
All over	3 Ccf	6.034	¢/Ccf

Contract Demand - $42.97 per Ccf of Contract Demand

Minimum Charge - First 3 Ccf charge plus Contract Demand charge

Other Charges:

Rates and other provisions of the customer's otherwise applicable service classification*

Proposed Rider B - Rate Schedule II

Delivery Charges (Summer):

First	3 Ccf or less	$63.04	
All over	3 Ccf	5.132	¢/Ccf

Delivery Charges (Winter):

First	3 Ccf or less	$63.04	
All over	3 Ccf	6.373	¢/Ccf

Contract Demand - $45.39 per Ccf of Contract Demand

Minimum Charge - First 3 Ccf charge plus Contract Demand charge

Other Charges:

Rates and other provisions of the customer's otherwise applicable service classification*

Present Rider C

Delivery Charges:

First	3 Ccf or less	$42.07	
All over	3 Ccf	27.160	¢/Ccf

Other Charges:

Rates and other provisions of the customer's otherwise applicable service classification*

* Excluding the RDM Adjustment

Proposed Rider C

Delivery Charges:

First	3 Ccf or less	$45.08	
All over	3 Ccf	29.723	¢/Ccf

Other Charges:

Rates and other provisions of the customer's otherwise applicable service classification*

* Excluding the RDM Adjustment

ORANGE AND ROCKLAND UTILITIES, INC.

Case 24-G-0061

Present and Proposed Rates in Brief - RY1

		Present	Proposed
Merchant Function Charge			
SC No. 1			
Fixed Procurement	¢ per Ccf	0.991	0.845
Credit and Collections	¢ per Ccf	0.304	0.240
Storage WC (supply related)	¢ per Ccf	0.164	0.164
Uncollectibles	¢ per Ccf	Variable	Variable
SC No. 2			
Fixed Procurement	¢ per Ccf	0.435	0.396
Credit and Collections	¢ per Ccf	0.114	0.098
Storage WC (supply related)	¢ per Ccf	0.164	0.164
Uncollectibles	¢ per Ccf	Variable	Variable
Billing & Payment Processing Chg	per month	$1.50	$2.10

ORANGE AND ROCKLAND UTILITIES, INC.

Case 24-G-0061

Present and Proposed Rates in Brief - RY2

Present S.C. No. 1 (Monthly) (Residential and Space Heating)				**Proposed S.C. No. 1 (Monthly) (Residential and Space Heating)**			
Delivery Charges:				**Delivery Charges:**			
Delivery:				Delivery:			
First	3	Ccf or less	$22.00	First	3	Ccf or less	$22.50
All over	3	Ccf	82.163 ¢/Ccf	All over	3	Ccf	87.628 ¢/Ccf

Present S.C. No. 2 (Monthly) (General Service)				**Proposed S.C. No. 2 (Monthly) (General Service)**			
Delivery Charges:				**Delivery Charges:**			
Delivery:				Delivery:			
First	3	Ccf or less	$34.00	First	3	Ccf or less	$35.00
Next	47	Ccf	45.816 ¢/Ccf	Next	47	Ccf	47.008 ¢/Ccf
Next	4,950	Ccf	45.816 ¢/Ccf	Next	4,950	Ccf	47.008 ¢/Ccf
All over	5,000	Ccf	42.615 ¢/Ccf	All over	5,000	Ccf	45.875 ¢/Ccf

Other Charges Applicable to Service Classification Nos. 1 and 2

Merchant Function Charge	See Page 5 of 5	Merchant Function Charge	See Page 5 of 5
Billing & Payment Processing Charge	See Page 5 of 5	Billing & Payment Processing Charge	See Page 5 of 5
Other Delivery and Supply Charges	As Described in Tariff	Other Delivery and Supply Charges	As Described in Tariff

ORANGE AND ROCKLAND UTILITIES, INC.

Case 24-G-0061

Present and Proposed Rates in Brief - RY2

Present S.C. No. 6 (Monthly) (Firm Transportation Service)					**Proposed S.C. No. 6 (Monthly) (Firm Transportation Service)**				
Rate Schedule IA - Residential:					**Rate Schedule IA - Residential:**				
Delivery Charges:					**Delivery Charges:**				
					Delivery:				
First	3	Ccf or less	$22.00		First	3	Ccf or less	$22.50	
All over	3	Ccf	82.163	¢/Ccf	All over	3	Ccf	87.628	¢/Ccf
Rate Schedule IB - Non-Residential:					**Rate Schedule IB - Non-Residential:**				
Delivery Charges:					**Delivery Charges:**				
					Delivery:				
First	3	Ccf or less	$34.00		First	3	Ccf or less	$35.00	
Next	47	Ccf	45.816	¢/Ccf	Next	47	Ccf	47.008	¢/Ccf
Next	4,950	Ccf	45.816	¢/Ccf	Next	4,950	Ccf	47.008	¢/Ccf
All over	5,000	Ccf	42.615	¢/Ccf	All over	5,000	Ccf	45.875	¢/Ccf
Rate Schedule II:					**Rate Schedule II:**				
Delivery Charges:					**Delivery Charges:**				
					Delivery:				
First	100	Ccf or less	$255.18		First	100	Ccf or less	$255.18	
Over	100	Ccf	42.615	¢/Ccf	Over	100	Ccf	45.875	¢/Ccf

Other Charges Applicable to Service Classification No. 6 Rate Schedules 1A, 1B, and II

Billing & Payment Processing Ch	See Page 5 of 5	Billing & Payment Processing Ch	See Page 5 of 5
Other Delivery and Supply Charg	See Page 5 of 5	Other Delivery and Supply Charg	See Page 5 of 5

* Assessed on customers receiving a utility single bill

ORANGE AND ROCKLAND UTILITIES, INC.

Case 24-G-0061

Present and Proposed Rates in Brief - RY2

Present Rider B - Rate Schedule I Rate IA

Delivery Charges (Summer):

First	3 Ccf or less	$167.05	
All over	3 Ccf	25.666	¢/Ccf

Delivery Charges (Winter):

First	3 Ccf or less	$167.05	
All over	3 Ccf	31.860	¢/Ccf

Minimum Charge - $167.05 per month

Other Charges:

Rates and other provisions of the customer's otherwise applicable service classification*

Present Rider B - Rate Schedule I Rate IB

Delivery Charges (Summer):

First	3 Ccf or less	$283.66	
All over	3 Ccf	25.574	¢/Ccf

Delivery Charges (Winter):

First	3 Ccf or less	$283.66	
All over	3 Ccf	31.860	¢/Ccf

Minimum Charge - $283.66 per month

Other Charges:

Rates and other provisions of the customer's otherwise applicable service classification*

Present Rider B - Rate Schedule I Rate IC

Delivery Charges (Summer):

First	3 Ccf or less	$431.80	
All over	3 Ccf	25.666	¢/Ccf

Delivery Charges (Winter):

First	3 Ccf or less	$431.80	
All over	3 Ccf	31.860	¢/Ccf

Minimum Charge - $431.80 per month

Other Charges:

Rates and other provisions of the customer's otherwise applicable service classification*

* Excluding the RDM Adjustment

Proposed Rider B - Rate Schedule I Rate IA

Delivery Charges (Summer):

First	3 Ccf or less	$173.77	
All over	3 Ccf	26.736	¢/Ccf

Delivery Charges (Winter):

First	3 Ccf or less	$173.77	
All over	3 Ccf	33.188	¢/Ccf

Minimum Charge - $173.77 per month

Other Charges:

Rates and other provisions of the customer's otherwise applicable service classification*

Proposed Rider B - Rate Schedule I Rate IB

Delivery Charges (Summer):

First	3 Ccf or less	$295.07	
All over	3 Ccf	26.640	¢/Ccf

Delivery Charges (Winter):

First	3 Ccf or less	$295.07	
All over	3 Ccf	33.188	¢/Ccf

Minimum Charge - $295.07 per month

Other Charges:

Rates and other provisions of the customer's otherwise applicable service classification*

Proposed Rider B - Rate Schedule I Rate IC

Delivery Charges (Summer):

First	3 Ccf or less	$449.18	
All over	3 Ccf	26.736	¢/Ccf

Delivery Charges (Winter):

First	3 Ccf or less	$449.18	
All over	3 Ccf	33.188	¢/Ccf

Minimum Charge - $449.18 per month

Other Charges:

Rates and other provisions of the customer's otherwise applicable service classification*

* Excluding the RDM Adjustment

ORANGE AND ROCKLAND UTILITIES, INC.

Case 24-G-0061

Present and Proposed Rates in Brief - RY2

Present Rider B - Rate Schedule I Rate ID

Delivery Charges (Summer):

First	3 Ccf or less	$548.42	
All over	3 Ccf	25.666	¢/Ccf

Delivery Charges (Winter):

First	3 Ccf or less	$548.42	
All over	3 Ccf	31.860	¢/Ccf

Minimum Charge - $548.42 per month

Other Charges:

Rates and other provisions of the customer’s otherwise applicable service classification*

Proposed Rider B - Rate Schedule I Rate ID

Delivery Charges (Summer):

First	3 Ccf or less	$570.49	
All over	3 Ccf	26.736	¢/Ccf

Delivery Charges (Winter):

First	3 Ccf or less	$570.49	
All over	3 Ccf	33.188	¢/Ccf

Minimum Charge - $570.49 per month

Other Charges:

Rates and other provisions of the customer’s otherwise applicable service classification*

Present Rider B - Rate Schedule II

Delivery Charges (Summer):

First	3 Ccf or less	$63.04	
All over	3 Ccf	5.132	¢/Ccf

Delivery Charges (Winter):

First	3 Ccf or less	$63.04	
All over	3 Ccf	6.373	¢/Ccf

Contract Demand - $45.39 per Ccf of Contract Demand

Minimum Charge - First 3 Ccf charge plus Contract Demand charge

Other Charges:

Rates and other provisions of the customer’s otherwise applicable service classification*

Proposed Rider B - Rate Schedule II

Delivery Charges (Summer):

First	3 Ccf or less	$65.58	
All over	3 Ccf	5.346	¢/Ccf

Delivery Charges (Winter):

First	3 Ccf or less	$65.58	
All over	3 Ccf	6.639	¢/Ccf

Contract Demand - $47.28 per Ccf of Contract Demand

Minimum Charge - First 3 Ccf charge plus Contract Demand charge

Other Charges:

Rates and other provisions of the customer’s otherwise applicable service classification*

Present Rider C

Delivery Charges:

First	3 Ccf or less	$45.08	
All over	3 Ccf	29.723	¢/Ccf

Other Charges:

Rates and other provisions of the customer’s otherwise applicable service classification*

* Excluding the RDM Adjustment

Proposed Rider C

Delivery Charges:

First	3 Ccf or less	$47.60	
All over	3 Ccf	31.700	¢/Ccf

Other Charges:

Rates and other provisions of the customer’s otherwise applicable service classification*

* Excluding the RDM Adjustment

ORANGE AND ROCKLAND UTILITIES, INC.

Case 24-G-0061

Present and Proposed Rates in Brief - RY2

		Present	Proposed
Merchant Function Charge			
SC No. 1			
Fixed Procurement	¢ per Ccf	0.845	0.892
Credit and Collections	¢ per Ccf	0.240	0.253
Storage WC (supply related)	¢ per Ccf	0.164	0.164
Uncollectibles	¢ per Ccf	Variable	Variable
SC No. 2			
Fixed Procurement	¢ per Ccf	0.396	0.417
Credit and Collections	¢ per Ccf	0.098	0.103
Storage WC (supply related)	¢ per Ccf	0.164	0.164
Uncollectibles	¢ per Ccf	Variable	Variable
Billing & Payment Processing Chg	per month	$2.10	$2.10

ORANGE AND ROCKLAND UTILITIES, INC.

Case 24-G-0061

Present and Proposed Rates in Brief - RY3

Present S.C. No. 1 (Monthly) (Residential and Space Heating)				**Proposed S.C. No. 1 (Monthly) (Residential and Space Heating)**			
Delivery Charges:				**Delivery Charges:**			
Delivery:				Delivery:			
First	3	Ccf or less	$22.50	First	3	Ccf or less	$23.00
All over	3	Ccf	87.628 ¢/Ccf	All over	3	Ccf	97.145 ¢/Ccf

Present S.C. No. 2 (Monthly) (General Service)				**Proposed S.C. No. 2 (Monthly) (General Service)**			
Delivery Charges:				**Delivery Charges:**			
Delivery:				Delivery:			
First	3	Ccf or less	$35.00	First	3	Ccf or less	$36.00
Next	47	Ccf	47.008 ¢/Ccf	Next	47	Ccf	49.786 ¢/Ccf
Next	4,950	Ccf	47.008 ¢/Ccf	Next	4,950	Ccf	49.786 ¢/Ccf
All over	5,000	Ccf	45.875 ¢/Ccf	All over	5,000	Ccf	49.786 ¢/Ccf

Other Charges Applicable to Service Classification Nos. 1 and 2

Merchant Function Charge	See Page 5 of 5	Merchant Function Charge	See Page 5 of 5
Billing & Payment Processing Charge	See Page 5 of 5	Billing & Payment Processing Charge	See Page 5 of 5
Other Delivery and Supply Charges	As Described in Tariff	Other Delivery and Supply Charges	As Described in Tariff

ORANGE AND ROCKLAND UTILITIES, INC.

Case 24-G-0061

Present and Proposed Rates in Brief - RY3

Present S.C. No. 6 (Monthly) (Firm Transportation Service)					Proposed S.C. No. 6 (Monthly) (Firm Transportation Service)				
Rate Schedule IA - Residential:					**Rate Schedule IA - Residential:**				
Delivery Charges:					**Delivery Charges:**				
					Delivery:				
First	3	Ccf or less	$22.50		First	3	Ccf or less	$23.00	
All over	3	Ccf	87.628	¢/Ccf	All over	3	Ccf	97.145	¢/Ccf
Rate Schedule IB - Non-Residential:					**Rate Schedule IB - Non-Residential:**				
Delivery Charges:					**Delivery Charges:**				
					Delivery:				
First	3	Ccf or less	$35.00		First	3	Ccf or less	$36.00	
Next	47	Ccf	47.008	¢/Ccf	Next	47	Ccf	49.786	¢/Ccf
Next	4,950	Ccf	47.008	¢/Ccf	Next	4,950	Ccf	49.786	¢/Ccf
All over	5,000	Ccf	45.875	¢/Ccf	All over	5,000	Ccf	49.786	¢/Ccf
Rate Schedule II:					**Rate Schedule II:**				
Delivery Charges:					**Delivery Charges:**				
					Delivery:				
First	100	Ccf or less	$255.18		First	100	Ccf or less	$255.18	
Over	100	Ccf	45.875	¢/Ccf	Over	100	Ccf	49.786	¢/Ccf

Other Charges Applicable to Service Classification No. 6 Rate Schedules 1A, 1B, and II

Billing & Payment Processing Charge*	See Page 5 of 5	Billing & Payment Processing Charge*	See Page 5 of 5
Other Delivery and Supply Charges	See Page 5 of 5	Other Delivery and Supply Charges	See Page 5 of 5

* Assessed on customers receiving a utility single bill

ORANGE AND ROCKLAND UTILITIES, INC.

Case 24-G-0061

Present and Proposed Rates in Brief - RY3

Present Rider B - Rate Schedule I Rate IA

Delivery Charges (Summer):

First	3 Ccf or less	$173.77
All over	3 Ccf	26.736 ¢/Ccf

Delivery Charges (Winter):

First	3 Ccf or less	$173.77
All over	3 Ccf	33.188 ¢/Ccf

Minimum Charge - $173.77 per month

Other Charges:

Rates and other provisions of the customer's otherwise applicable service classification*

Present Rider B - Rate Schedule I Rate IB

Delivery Charges (Summer):

First	3 Ccf or less	$295.07
All over	3 Ccf	26.640 ¢/Ccf

Delivery Charges (Winter):

First	3 Ccf or less	$295.07
All over	3 Ccf	33.188 ¢/Ccf

Minimum Charge - $295.07 per month

Other Charges:

Rates and other provisions of the customer's otherwise applicable service classification*

Present Rider B - Rate Schedule I Rate IC

Delivery Charges (Summer):

First	3 Ccf or less	$449.18
All over	3 Ccf	26.736 ¢/Ccf

Delivery Charges (Winter):

First	3 Ccf or less	$449.18
All over	3 Ccf	33.188 ¢/Ccf

Minimum Charge - $449.18 per month

Other Charges:

Rates and other provisions of the customer's otherwise applicable service classification*

* Excluding the RDM Adjustment

Proposed Rider B - Rate Schedule I Rate IA

Delivery Charges (Summer):

First	3 Ccf or less	$184.81
All over	3 Ccf	28.546 ¢/Ccf

Delivery Charges (Winter):

First	3 Ccf or less	$184.81
All over	3 Ccf	35.435 ¢/Ccf

Minimum Charge - $184.81 per month

Other Charges:

Rates and other provisions of the customer's otherwise applicable service classification*

Proposed Rider B - Rate Schedule I Rate IB

Delivery Charges (Summer):

First	3 Ccf or less	$313.82
All over	3 Ccf	28.444 ¢/Ccf

Delivery Charges (Winter):

First	3 Ccf or less	$313.82
All over	3 Ccf	35.435 ¢/Ccf

Minimum Charge - $313.82 per month

Other Charges:

Rates and other provisions of the customer's otherwise applicable service classification*

Proposed Rider B - Rate Schedule I Rate IC

Delivery Charges (Summer):

First	3 Ccf or less	$477.72
All over	3 Ccf	28.546 ¢/Ccf

Delivery Charges (Winter):

First	3 Ccf or less	$477.72
All over	3 Ccf	35.435 ¢/Ccf

Minimum Charge - $477.72 per month

Other Charges:

Rates and other provisions of the customer's otherwise applicable service classification*

* Excluding the RDM Adjustment

ORANGE AND ROCKLAND UTILITIES, INC.

Case 24-G-0061

Present and Proposed Rates in Brief - RY3

Present Rider B - Rate Schedule I Rate ID

Delivery Charges (Summer):

First	3 Ccf or less	$570.49	
All over	3 Ccf	26.736	¢/Ccf

Delivery Charges (Winter):

First	3 Ccf or less	$570.49	
All over	3 Ccf	33.188	¢/Ccf

Minimum Charge - $570.49 per month

Other Charges:

Rates and other provisions of the customer’s otherwise applicable service classification*

Proposed Rider B - Rate Schedule I Rate ID

Delivery Charges (Summer):

First	3 Ccf or less	$606.74	
All over	3 Ccf	28.546	¢/Ccf

Delivery Charges (Winter):

First	3 Ccf or less	$606.74	
All over	3 Ccf	35.435	¢/Ccf

Minimum Charge - $606.74 per month

Other Charges:

Rates and other provisions of the customer’s otherwise applicable service classification*

Present Rider B - Rate Schedule II

Delivery Charges (Summer):

First	3 Ccf or less	$65.58	
All over	3 Ccf	5.346	¢/Ccf

Delivery Charges (Winter):

First	3 Ccf or less	$65.58	
All over	3 Ccf	6.639	¢/Ccf

Contract Demand - 47.28 per Ccf of Contract Demand

Minimum Charge - First 3 Ccf charge plus Contract Demand charge

Other Charges:

Rates and other provisions of the customer’s otherwise applicable service classification*

Proposed Rider B - Rate Schedule II

Delivery Charges (Summer):

First	3 Ccf or less	$69.75	
All over	3 Ccf	5.708	¢/Ccf

Delivery Charges (Winter):

First	3 Ccf or less	$69.75	
All over	3 Ccf	7.089	¢/Ccf

Contract Demand - 50.48 per Ccf of Contract Demand

Minimum Charge - First 3 Ccf charge plus Contract Demand charge

Other Charges:

Rates and other provisions of the customer’s otherwise applicable service classification*

Present Rider C

Delivery Charges:

First	3 Ccf or less	$47.60
All over	3 Ccf	31.700 ¢/Ccf

Other Charges:

Rates and other provisions of the customer’s otherwise applicable service classification*

* Excluding the RDM Adjustment

Proposed Rider C

Delivery Charges:

First	3 Ccf or less	$51.80
All over	3 Ccf	35.142 ¢/Ccf

Other Charges:

Rates and other provisions of the customer’s otherwise applicable service classification*

* Excluding the RDM Adjustment

ORANGE AND ROCKLAND UTILITIES, INC.

Case 24-G-0061

Present and Proposed Rates in Brief - RY3

		Present	Proposed
Merchant Function Charge			
SC No. 1			
Fixed Procurement	¢ per Ccf	0.892	0.971
Credit and Collections	¢ per Ccf	0.253	0.275
Storage WC (supply related)	¢ per Ccf	0.164	0.164
Uncollectibles	¢ per Ccf	Variable	Variable
SC No. 2			
Fixed Procurement	¢ per Ccf	0.417	0.451
Credit and Collections	¢ per Ccf	0.103	0.112
Storage WC (supply related)	¢ per Ccf	0.164	0.164
Uncollectibles	¢ per Ccf	Variable	Variable
Billing & Payment Processing Chg	per month	$2.10	$2.10

Orange and Rockland Utilities, Inc.
Cases 24-E-0060 & 24-G-0061

A. Electric, Gas, Common Capital Program Expenditure Reporting Requirements

The Company will file a quarterly report by May 15, August 15, and November 15 of each Rate Year. The annual report will be due by February 28 after the end of each Rate Year.

The quarterly and annual reports will list all the capital projects as set forth below and will reflect cumulative expenditures and plant additions during the Rate Year. The quarterly and annual reports will include the following information separated by Electric, Gas, and Common:

- Summary of Capital Expenditures by Asset Class (*e.g.*, Transmission, Distribution, General Equipment, Software, Office Buildings)
- Summary of Plant Additions by Asset Class (*e.g.*, Transmission, Distribution, General Equipment, Software, Office Buildings)
- List of Capital Projects, including projects under blankets, over $1.0 million (Electric); over $0.5 million (Gas and Common) and include the following information:
    - Project Start date
    - Rate Case – in-service date
    - Projected in-service date
    - Breakdown of expenditures (*e.g.*, payroll, accounts payable, and materials and supplies categories)
    - Comparison of Rate Year budgeted vs. Rate Year actual to date
- For capital non-blanket programs that include multiple projects, a list of projects that are covered under a program (including, but not limited to, the selective undergrounding program, overhead enhancement (Hendrix) program, smart grid distribution automation program, transmission overhead structure replacement program). The Company has the flexibility over the term of the Rate Plan to modify the list, priority, nature, and scope of its capital programs and projects.
    - The reports will explain any significant changes in project timelines or changes in cost estimates exceeding 15%, as well as an explanation of any new capital projects budgeted over $1.0 million for Electric, and over $0.5 million for Gas and Common.
    - The Company will highlight all new capital projects in the quarterly and annual capital expenditure reports and provide white papers, schedules and any additional information as per requests from Staff.
- Gas R&D Expenditure Reports

- Annual Five-year capital budget for the projects and programs in the categories noted above (Annual Report only)

In addition, by February 28 after the end of each Rate Year, the Company will provide to Gas Safety Staff:

- The Annual Leak Prone Pipe Program Report that includes the location (specific location of each section of leak prone pipe removed or abandoned), risk priority score of section(s) replaced, length and type of leak prone pipe replaced, length and type of material replaced/installed, and number of leak prone services replaced. The Annual Leak Prone Pipe Program Report will be in the following format:

Company Name ______________
Date ______________

Location	Risk Priority	Length Installed		Length Removed per Material (ft)						Number of Services Replaced	Category
		Plastic	Steel	Plastic	Prot. Steel	Bare Steel	Cast Iron	Wrought Iron	Universal		
Smith St, NY	2	3510	1020	1408	3378	1335	2135	0	0	256	LPP Replacement
	Total Footage (ft)	45100	119,830	14,186	24,681	59,435	28,437	9,610	2,083	256	
	Miles	8.5	22.7	2.7	4.7	11.3	5.4	1.8	0.4		

B. O&M Reporting Requirements

The Company will file on a quarterly basis by May 15, August 15, and November 15 of each year. The annual report will be due by February 28 after the end of each Rate Year. The O&M reports will include:

- Summary of O&M expenses by organization and
    - A further breakdown will be provided for Electric Engineering, Electric Operations, Gas Operations, Gas Engineering, Corporate Shared Services, and the Non-Deferred Storm Expenses.
        - Breakdowns will include, but are not limited to, details around the following programs:
            - Maintenance – DA Battery Replacement, Aerial Inspections and Infrared Inspections (Electric Ops)
            - Enhanced Overhead (Electric Ops)
            - Shoreline Erosion (Electric Engineering)
            - Grid Mod 4G – 5G (Electric Engineering)
            - Micronet Weather Stations (Corporate Shared Services)
    - Highlighting any new programs in O&M under the organizations.
        - Narrative on program description, need, and its affect to existing programs.
        - Program documentation for any new O&M programs.

- Where the Company's actual O&M expenditures vary by more than fifteen (15) percent from the previous calendar year’s estimates by major category; the report will also provide an explanation for any such variations.

REVENUE DECOUPLING MECHANISM

I. Electric Revenue Decoupling Mechanism

The Electric Revenue Decoupling Mechanism ("RDM") will continue to be based on a total delivery revenue methodology for customer groups that are included in the RDM, as set forth in the Company's electric tariff, modified commencing with the effective date of the Electric Rate Plan as follows:

- If the Company does not file for new base delivery rates to take effect within 15 days upon the expiration of RY3, the RDM will remain in effect and the delivery revenue targets effective January 1, 2028 will continue, but will be restated to reflect the expiration of the temporary credit that is being collected through the Energy Cost Adjustment in RY3.

The Electric RDM targets for each Rate Year are detailed in Schedule 1 to this Appendix.

II. Gas Revenue Decoupling Mechanism

The Gas Revenue Decoupling Mechanism ("RDM") will continue to be based on a total delivery revenue methodology for customer groups that are included in the RDM, as set forth in the Company's gas tariff, modified commencing with the effective date of the Gas Rate Plan as follows:

- If the Company does not file for new base delivery rates to take effect within 15 days upon the expiration of RY3, the RDM will remain in effect and the delivery revenue targets effective January 1, 2028 will continue, but will be restated to reflect the expiration of the temporary credit that is being collected through the Monthly Gas Adjustment in RY3.

The Gas RDM targets for each Rate Year are detailed in Schedule 2 to this Appendix.

III. Provisions Applicable to Both Electric and Gas

a. Filing of Statements

RDM Statements will be filed three calendar days before the effective date of a change in the RDM Adjustments, both for an annual filing and for an interim filing.

b. Adjustments to RDM Targets

During the course of the Electric and Gas Rate Plans, the Company through a tariff filing, or any Signatory Party by petition to the Commission, may propose an adjustment to the currently-effective RDM targets if the Company or such Signatory Party, as applicable, believes that circumstances are resulting in anomalous results unduly impacting certain customers. Any proposed changes to RDM targets are to be revenue neutral to the Company.

c. Make Whole Provisions

If new rates do not become effective January 1, 2025, for the Company's annual RDM reconciliation for RY1 for both electric and gas, the revenue targets to which actual revenues are compared for the period January 1, 2025 until the date rates become effective as a result of the extension of the Case Nos. 24-E-0060 and 24-G-0061 suspensions will be equal to the monthly targets under the existing

Case Nos. 21-E-0074 and 21-G-0073 rate plans, less the temporary credit included in those targets. The targets for the remainder of RY1 will be the monthly targets as contained in Schedules 1 and 2 to this Appendix.

Orange and Rockland Utilities Inc.

Case No. 24-E-0060

Summary of Monthly Electric RDM Targets - RY 1
Revenue Targets for Rate Year Ending December 31, 2025 - (Thousand $)

	Residential SC 1/19	Secondary SC 2/20	SC 2p/3/21	Primary SC 9	SC 22	Lighting	TOTAL Billed	Unbilled	O&R
Jan-25	$20,311	$6,447	$1,139	$691	$417	$223	$29,228	$1,638	$30,866
Feb-25	$19,323	$6,501	$1,308	$628	$435	$236	$28,431	$2,518	$30,949
Mar-25	$17,479	$6,351	$1,255	$549	$458	$233	$26,325	($1,423)	$24,902
Apr-25	$16,477	$6,367	$1,269	$572	$600	$230	$25,515	($171)	$25,344
May-25	$15,804	$6,349	$1,407	$617	$517	$225	$24,919	($488)	$24,431
Jun-25	$20,511	$8,204	$2,127	$1,289	$726	$220	$33,077	$3,933	$37,010
Jul-25	$27,694	$10,669	$2,336	$1,635	$895	$224	$43,453	($367)	$43,086
Aug-25	$29,614	$10,624	$2,403	$1,745	$950	$147	$45,483	($1,476)	$44,007
Sep-25	$26,050	$10,285	$2,399	$1,553	$852	$233	$41,372	$685	$42,057
Oct-25	$19,947	$8,026	$1,747	$1,220	$638	$231	$31,809	($2,410)	$29,399
Nov-25	$16,279	$6,236	$1,164	$561	$480	$225	$24,945	($2,644)	$22,301
Dec-25	$18,870	$6,426	$1,380	$726	$551	$212	$28,165	$48	$28,213
RY ending Dec 2025	$248,359	$92,485	$19,934	$11,786	$7,519	$2,639	$382,722	($157)	$382,565

Orange and Rockland Utilities Inc.

Case No. 24-E-0060

Summary of Monthly Electric RDM Targets - RY 2
Revenue Targets for Rate Year Ending December 31, 2026 - (Thousand $)

	Residential SC 1/19	Secondary SC 2/20	SC 2p/3/21	Primary SC 9	SC 22	Lighting	TOTAL Billed	Unbilled	O&R
Jan-26	$21,584	$6,565	$1,135	$716	$454	$229	$30,683	$1,476	$32,159
Feb-26	$20,517	$6,624	$1,301	$667	$447	$241	$29,797	$2,324	$32,121
Mar-26	$19,171	$6,638	$1,332	$652	$514	$239	$28,546	($421)	$28,125
Apr-26	$17,788	$6,558	$1,225	$602	$583	$236	$26,992	$721	$27,713
May-26	$16,608	$6,411	$1,512	$727	$570	$231	$26,059	($1,336)	$24,723
Jun-26	$21,564	$8,300	$2,055	$1,310	$692	$225	$34,146	$2,191	$36,337
Jul-26	$29,595	$10,911	$2,350	$1,717	$888	$230	$45,691	$799	$46,490
Aug-26	$31,853	$10,932	$2,379	$1,825	$941	$152	$48,082	($1,017)	$47,065
Sep-26	$27,915	$10,572	$2,382	$1,627	$875	$239	$43,610	$1,488	$45,098
Oct-26	$20,886	$8,016	$1,726	$1,252	$638	$237	$32,755	($2,703)	$30,052
Nov-26	$17,355	$6,343	$1,286	$675	$558	$229	$26,446	($2,598)	$23,848
Dec-26	$20,276	$6,564	$1,323	$690	$542	$217	$29,612	$101	$29,713
RY ending Dec 2026	$265,112	$94,434	$20,006	$12,460	$7,702	$2,705	$402,419	$1,023	$403,442

Orange and Rockland Utilities Inc.

Case No. 24-E-0060

Summary of Monthly Electric RDM Targets - RY 3
Revenue Targets for Rate Year Ending December 31, 2027 - (Thousand $)

	Residential SC 1/19	Secondary SC 2/20	SC 2p/3/21	Primary SC 9	SC 22	Lighting	TOTAL Billed	Unbilled	O&R
Jan-27	$22,645	$6,395	$1,109	$702	$478	$232	$31,561	$1,145	$32,706
Feb-27	$21,622	$6,502	$1,306	$681	$478	$247	$30,836	$1,833	$32,669
Mar-27	$20,586	$6,614	$1,340	$638	$535	$245	$29,958	($495)	$29,463
Apr-27	$19,063	$6,582	$1,381	$675	$696	$244	$28,641	$591	$29,232
May-27	$17,623	$6,426	$1,385	$645	$529	$239	$26,847	($753)	$26,094
Jun-27	$22,646	$8,187	$2,108	$1,359	$771	$236	$35,307	$2,644	$37,951
Jul-27	$31,980	$11,205	$2,482	$1,850	$1,010	$239	$48,766	($287)	$48,479
Aug-27	$34,054	$11,063	$2,498	$1,936	$1,081	$156	$50,788	($1,298)	$49,490
Sep-27	$31,261	$11,267	$2,600	$1,819	$1,016	$248	$48,211	$2,781	$50,992
Oct-27	$22,741	$8,244	$1,848	$1,348	$715	$243	$35,139	($2,563)	$32,576
Nov-27	$18,696	$6,397	$1,228	$646	$544	$233	$27,744	($1,981)	$25,763
Dec-27	$21,709	$6,519	$1,346	$707	$578	$220	$31,079	($343)	$30,736
RY ending Dec 2027	$284,626	$95,401	$20,631	$13,006	$8,431	$2,782	$424,877	$1,276	$426,153

O&R Gas RDM Targets - RY 1

(in $000s)

	Billed SC1	SC2 (w/o Rider B)	Total Billed	UnBilled	TOTAL
Jan-25	25,012.95	4,057.75	29,070.71	2,527.65	31,598.35
Feb-25	26,318.48	4,049.40	30,367.88	(3,696.92)	26,670.96
Mar-25	21,551.06	3,486.79	25,037.85	(1,823.10)	23,214.76
Apr-25	16,496.90	2,681.28	19,178.18	(5,021.03)	14,157.15
May-25	10,114.27	1,949.05	12,063.32	(1,751.10)	10,312.22
Jun-25	7,280.84	1,404.72	8,685.56	(2,726.81)	5,958.75
Jul-25	6,186.73	1,062.08	7,248.81	318.85	7,567.66
Aug-25	5,545.04	958.88	6,503.92	340.84	6,844.77
Sep-25	5,799.60	970.82	6,770.43	607.14	7,377.57
Oct-25	6,606.89	1,182.60	7,789.49	4,080.20	11,869.69
Nov-25	10,898.66	1,745.19	12,643.85	5,510.22	18,154.07
Dec-25	18,134.41	3,226.10	21,360.51	2,683.04	24,043.55
TOTAL	159,945.84	26,774.66	186,720.50	1,049.00	187,769.50

O&R Gas RDM Targets - RY2

(in $000s)

	Billed SC1	SC2 (w/o Rider B)	Total Billed	UnBilled	TOTAL
Jan-26	26,663.10	4,252.47	30,915.57	3,272.75	34,188.32
Feb-26	28,061.58	4,235.06	32,296.64	(5,419.80)	26,876.84
Mar-26	22,954.35	3,640.35	26,594.70	(2,511.10)	24,083.61
Apr-26	17,540.06	2,798.52	20,338.58	(5,280.99)	15,057.59
May-26	10,702.64	2,044.18	12,746.82	(1,609.69)	11,137.13
Jun-26	7,667.35	1,474.88	9,142.23	(2,880.56)	6,261.67
Jul-26	6,495.29	1,111.77	7,607.06	284.94	7,892.00
Aug-26	5,807.83	1,002.86	6,810.69	372.19	7,182.88
Sep-26	6,080.43	1,013.89	7,094.32	605.09	7,699.41
Oct-26	6,945.10	1,234.63	8,179.73	4,292.52	12,472.25
Nov-26	11,542.39	1,819.00	13,361.39	5,846.00	19,207.39
Dec-26	19,293.54	3,356.84	22,650.38	2,257.85	24,908.23
TOTAL	169,753.66	27,984.45	197,738.11	(770.80)	196,967.31

O&R Gas RDM Targets - RY3

(in $000s)

	Billed SC1	SC2 (w/o Rider B)	Total Billed	UnBilled	TOTAL
Jan-27	28,120.28	4,223.03	32,343.30	4,974.25	37,317.55
Feb-27	29,604.13	4,199.72	33,803.84	(5,541.48)	28,262.36
Mar-27	24,184.51	3,602.33	27,786.84	(2,874.78)	24,912.06
Apr-27	18,439.30	2,769.75	21,209.05	(5,605.43)	15,603.62
May-27	11,184.06	2,029.34	13,213.41	(1,645.30)	11,568.10
Jun-27	7,963.49	1,468.24	9,431.72	(2,784.77)	6,646.95
Jul-27	6,720.02	1,107.55	7,827.57	488.22	8,315.79
Aug-27	5,990.54	999.47	6,990.01	373.89	7,363.90
Sep-27	6,279.65	1,009.61	7,289.26	559.43	7,848.69
Oct-27	7,196.07	1,226.35	8,422.42	4,398.08	12,820.49
Nov-27	12,074.55	1,800.65	13,875.20	6,124.64	19,999.84
Dec-27	20,299.18	3,318.09	23,617.27	2,683.27	26,300.54
TOTAL	178,055.78	27,754.11	205,809.89	1,150.00	206,959.89

Appendix 21
Energy Efficiency and Building Electrification Labor

	PROPOSED EE/BE LABOR BUDGET & FTE COUNT FOR 2025-2027			
	Labor $s[1]			
	2024	**2025**	**2026**	**2027**
Electric	$1,767,183	$1,959,098	$2,000,248	$2,035,944
Gas	$311,856	$345,613	$352,838	$359,100
Total Combined E&G Labor	**$2,079,039**	**$2,304,712**	**$2,353,086**	**$2,395,044**
	Labor FTEs			
	2024	**2025**	**2026**	**2027**
Electric	9.1	9.9	9.9	9.9
Gas	1.5	1.7	1.7	1.7
Total Combined E&G Labor	**10.6**	**11.6**	**11.6**	**11.6**

Notes:

(1) Labor figures represent fully loaded labor costs (e.g., salary, employee benefits, payroll taxes, etc.) reflected in base rates for all EE/BE FTEs.

SUBJECT: Filings by ORANGE AND ROCKLAND UTILITIES, INC.

Amendments to Schedule P.S.C. No. 3 – Electricity

First Revised Leaves Nos. 221.27, 321.1, 356.2, 356.3
Second Revised Leaves Nos. 220.2, 221.1, 221.3, 221.4, 221.11, 221.12, 221.13, 331.1
Third Revised Leaves Nos. 221.2, 221.2.1, 221.5, 221.6
Fifth Revised Leaves Nos. 108, 162
Sixth Revised Leaves Nos. 90, 148.1, 166, 270.1, 276.1, 283.1, 356.1
Seventh Revised Leaves Nos. 167, 343
Eighth Revised Leaf No. 169
Tenth Revised Leaf No. 5
Twelfth Revised Leaf No. 266
Fourteenth Revised Leaves Nos. 168, 346, 351
Fifteenth Revised Leaves Nos. 4, 264, 270, 312, 331, 332, 336, 359
Sixteenth Revised Leaves Nos. 274, 284, 341
Seventeenth Revised Leaves Nos. 283, 321
Nineteenth Revised Leaves Nos. 269, 276, 295, 309, 345
Twentieth Revised Leaves Nos. 285, 290, 333, 350
Twenty-First Revised Leaf No. 89

Suspension Supplement Nos. 54, 58, 66

Amendments to Schedule P.S.C. No. 4 – Gas

Original Leaf No. 12.2
Second Revised Leaf No. 12.1
Third Revised Leaf No. 24
Fourth Revised Leaf No. 87
Fifth Revised Leaves Nos. 88, 89
Seventh Revised Leaf No. 94.25
Twelfth Revised Leaves Nos. 79.1, 80.3.1
Thirteenth Revised Leaf No. 80.4
Fifteenth Revised Leaf No. 81.1
Seventeenth Revised Leaves Nos. 4, 34, 137.2
Twenty-First Revised Leaves Nos. 94.9, 94.10
Twenty-Fourth Revised Leaf No. 94.16
Twenty-Eighth Revised Leaf No. 33.3
Thirty-First Revised Leaf No. 133

Thirty-Fourth Revised Leaves Nos. 114, 130
Thirty-Seventh Revised Leaf No. 116

Suspension Supplement Nos. 82, 84, 87