STATE OF NEW YORK
PUBLIC SERVICE COMMISSION

CASE 24-E-0322 - Proceeding on Motion of the Commission as to the Rates, Charges, Rules and Regulations of Niagara Mohawk Power Corporation d/b/a National Grid for Electric Service.

CASE 24-G-0323 - Proceeding on Motion of the Commission as to the Rates, Charges, Rules and Regulations of Niagara Mohawk Power Corporation d/b/a National Grid for Gas Service.

# ORDER ADOPTING TERMS OF JOINT PROPOSAL AND ESTABLISHING RATE PLANS

Issued and Effective: August 14, 2025

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PUBLIC SERVICE COMMISSION

At a session of the Public Service Commission held in the City of Albany on August 14, 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

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# ORDER ADOPTING TERMS OF JOINT PROPOSAL AND ESTABLISHING RATE PLANS

(Issued and Effective August 14, 2025)

BY THE COMMISSION:

## INTRODUCTION

In this Order, we approve a Joint Proposal establishing three-year rate plans for electric and gas delivery service provided by Niagara Mohawk Power Corporation d/b/a National Grid (National Grid or the Company) for the period encompassing April 1, 2025, through March 31, 2028.

The Joint Proposal is signed by National Grid; trial staff of the New York State Department of Public Service (DPS

Staff); Multiple Intervenors (MI); Walmart; the Alliance for a Green Economy (AGREE); the New York Solar Energies Industry Association (NYSEIA); Independent Power Producers of New York, Inc. (IPPNY); the United States Department of Defense and all other Federal Executive Agencies (DOD); the New York Geothermal Energy Organization (NYGEO); Turning Stone Enterprises, LLC (Turning Stone); Fedrigoni Special Papers North America (Fedrigoni); Empire Natural Gas Corporation (Empire); New Yorkers for Clean Power (Clean Power); the New York Power Authority (NYPA), and the International Brotherhood of Electrical Workers Local Union No. 97 (IBEW) (collectively, the Signatory Parties).[1]

Although the New York State Office of General Services (NYSOGS) and the Environmental Defense Fund (EDF) did not sign the Joint Proposal, neither opposes it. The Public Utility Law Project of New York, Inc. (PULP), the Utility Intervention Unit of the New York State Department of State (UIU), NRG Energy, Inc. (NRG), Roger Caiazza and Constantine Kontogiannis (collectively, the Individual Intervenors) oppose various provisions in the Joint Proposal.

As is more fully discussed throughout this order, we approve and adopt the terms of the Joint Proposal, which 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

[1] Empire and Fedrigoni are parties in just the gas proceeding, and IPPNY and IBEW are parties in just the electric proceeding, so the position of each is limited to the gas or electric proceeding, respectively. NYPA supports only certain sections of the Joint Proposal and takes no position on the rest.

fully litigated proceeding; and they are consistent with the environmental, social, and economic policies of the Public Service Commission (Commission) and the State, including New York's Climate Leadership and Community Protection Act (CLCPA).[2]

## BACKGROUND

National Grid provides electric and gas utility service to approximately 2.3 million customers in upstate New York. The Company's most recent rates were established in an order issued on January 20, 2022, when the Commission approved three-year electric and gas rate plans for the period between July 1, 2021, and June 30, 2024.[3] More specifically, the Company was allowed base delivery increases of $49.4 million (Rate Year 1), $95.6 million (Rate Year 2), and $109.8 million (Rate Year 3) for its electric business and $12.5 million (Rate Year 1), $29.1 million (Rate Year 2), and 33.0 million (Rate Year 3) for its gas business.[4]

On May 28, 2024, National Grid filed amendments to its electric and gas tariff schedules proposing to increase its annual electric and gas delivery revenues effective July 31, 2025. In the filings, the Company sought to increase its electric delivery revenues by approximately $525.5 million (20% increase in base delivery revenues or an 11% increase in total revenues) and its gas delivery revenues by approximately $148.0 million (28% increase in base delivery revenues or a 15%

[2] See Chapter 106 of the Laws of 2019.

[3] Cases 20-E-0380 et al., National Grid – Electric and Gas Rates, Order Adopting Terms of Joint Proposal Establishing Rate Plans (2022 Rate Order). The 2022 Rate Order adopted the terms of a Joint Proposal that contemplated, among other things, a "stay-out" period running from July 1, 2024, until March 31, 2025 (id., pp. 19-20).

[4] Id., p. 19.

increase in total revenues). These increases were expected to result in total monthly bill increases of approximately $18.92 (15%) for the average residential electric customer and $18.34 (20%) for the average residential gas customer.

By Secretary Notice the Commission suspended the effective date of the Company's rate filings and initiated these proceedings to examine the Company's proposals.[5] The assigned Administrative Law Judges (Judges) held technical and procedural conferences on June 25, 2024, to identify interested parties and to establish a procedural schedule. Pursuant to an ensuing ruling, the Company was required to file updates and any necessary corrections to its initial filings by July 22, 2024, direct testimony and exhibits from DPS Staff and intervenors was due September 26, 2024, rebuttal testimony was due October 18, 2024, and an evidentiary hearing was scheduled for November 4, 2024.

National Grid timely filed updates and corrections, decreasing its requested electric revenue requirement to approximately $509.6 million and increasing its requested gas revenue requirement to approximately $156.5 million. On or about September 26, 2024, direct testimony was submitted by MI, AGREE, DOD, PULP, NYSOGS, NYPA, Clean Power, NRG, IPPNY, Walmart, NYSEIA, UIU, and DPS Staff. In its testimony, DPS Staff recommended an electric base rate increase of $142.0 million and a gas base rate increase of $60.7 million, with the former being approximately $367.6 million less than the Company's updated proposal and the latter about $95.8 million

[5] Notice of Suspension of the Effective Date of Major Rate Changes and Initiation of Proceedings (issued June 7, 2024). On September 10, 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 April 30, 2025.

lower. Rebuttal testimony was filed on October 18, 2024, by National Grid, DPS Staff, UIU, DOD, MI, AGREE, and EDF. In its rebuttal testimony, the Company proposed revised electric and gas revenue requirements of $511.2 million and $160.2 million, respectively.

On October 21, 2024, the Company filed a Notice of Impending Settlement Negotiations pursuant to the Commission's Settlement Rules and Guidelines.[6] Negotiations began on October 30, 2024, and continued into April 2025. Relatedly, on October 29, 2024, the Company requested postponement of the November 4, 16, 2024, evidentiary hearing and consented to an extension of the suspension period through and including June 30, 2025, subject to a "make-whole" provision that would keep the Company and its customers in the same financial position they would have been in absent the extension.[7] The Company subsequently agreed to similar extensions through and including August 31, 2025.[8] The Commission issued Orders on April 25, 2025, and July 18, 2025, extending the effective date of the tariff leaves through July 31, 2025, and further suspending such date through August 31, 2025.[9]

Settlement negotiations ultimately proved successful, resulting in the filing of the Joint Proposal on April 25, 2025. According to the Signatory Parties, the Joint Proposal provides funding for infrastructure upgrades that will enable National

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[6] Sixteen NYCRR §3.9.

[7] Request to Postpone Hearing filed October 29, 2024.

[8] Request to Continue Postponement and Extend Suspension and Further Extension of Suspension letters filed January 31, 2025, and April 29, 2025.

[9] Order on Extension of Maximum Suspension Period of Major Rate Filings, issued April 25, 2025, and Order on Extension of Maximum Suspension Period of Major Rate Filings, issued July 18, 2025.

Grid to safely and reliably satisfy its customers' energy needs, enhances access to the Company's Energy Affordability Program (EAP), establishes commitments to support electrification options for current and prospective gas customers, and includes investments and programs that further CLCPA goals.[10]

On or about May 14, 2025, statements in support of the Joint Proposal were filed by National Grid, DPS Staff, MI, AGREE, Walmart, DOD, NYGEO, IPPNY, NYSEIA, Clean Power, and IBEW. EDF filed a statement of neutrality, and statements in opposition were filed by PULP NRG, UIU, and the Individual Intervenors. On May 23, 2025, the Company, DPS Staff, and MI filed reply statements in support, and NRG and the Individual Intervenors filed reply statements in opposition.

The Judges conducted an evidentiary hearing on June 3, 2025, where a joint panel of witnesses from the Company and DPS Staff were cross examined by UIU and the Individual Intervenors, and more than 900 evidentiary exhibits were admitted into the record. On June 25, 2025, DPS Staff, National Grid, UIU, and the Individual Intervenors filed post-hearing briefs. Thereafter, post-hearing reply briefs were filed by DPS Staff, the Company, UIU, AGREE and the Individual Intervenors.

## NOTICE OF PROPOSED RULE MAKING

Notice of National Grid's tariff filings was published in newspapers throughout the Company's service area pursuant to

[10] Ex. 918, Corrected Joint Proposal, p. 2.

16 NYCRR §720-8.1 on several dates,[11] and a Notice of Proposed Rulemaking was published in the State Register pursuant to the State Administrative Procedure Act on September 4, 2024.[12]

On August 26, 2024, the Secretary issued two Notices Soliciting Comments, with one also announcing that a virtual public statement hearing would be conducted via WEBEX at 1:00 p.m. on September 25, 2024, and the other announcing that in-person public statement hearings would be held at 6:00 p.m. at the Albany Public Library on September 17, 2024, at 6:00 p.m. at the Clay Town Hall on September 18, 2024, and at 4:00 p.m. at the Buffalo Central Library on September 24, 2024. Both notices also informed the public how comments could alternatively be submitted by email, regular mail, or the Commission's toll-free opinion line, as did a Notice of Joint Proposal and Soliciting Public Comment issued by the Secretary on May 5, 2025.

Fifty-two individuals spoke at the in-person public statement hearings, and another 10 spoke at the virtual public statement hearing. Many speakers opposed the proposed rate increases, stating that bills are already unaffordable and suggesting that executive compensation and shareholder dividends be reduced prior to raising rates. Others noted that the requested rate increases outpace inflation and suggested that there should be methods for funding necessary infrastructure improvements without rate increases. Several speakers opposed

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[11] More specifically, notices were published between June 6, 2024, and June 27, 2024, in the: Albany Times Union; Recorder; Buffalo News; Cortland Standard; Daily Record; Daily Star; Press Observer; Evening Sun; Finger Lakes Times; Post Star; Hudson Register Star; Leader-Herald; Livingston County News; Palladium Times; Post-Standard; Press Republican; Rome Daily Sentinel; Daily Gazette; Observer Dispatch; Record, and the Watertown Daily Times.

[12] SAPA Nos. 24-E-0322SP1 and 24-G-0323SP1.

the expansion and replacement of additional gas infrastructure and argued in favor of a faster, shareholder-funded transition away from the gas system. Some speakers were nonetheless complimentary of National Grid, particularly the Company's economic development and infrastructure improvement programs.

Almost 9,000 written comments[13] were submitted in the two cases, with most such commentors opposed to the rate increases for reasons akin to those expressed above. Several commenters added that their bills were already outrageously high, particularly delivery costs. In addition to general criticisms premised on unaffordability or inequity, many commentors were specifically opposed to paying for smart meters that ostensibly offer little benefit to customers, and others questioned the wisdom of continued investment in gas infrastructure on environmental and justice grounds.

## REGULATORY FRAMEWORK

The Commission exercises jurisdiction over electric and gas corporations and is statutorily mandated to ensure their provision of safe, adequate, and reliable service at just and reasonable rates.[14] While just and reasonable rates must protect ratepayers from unwarranted expenses, they must also provide an opportunity for the utility to recover its justifiable costs and earn a reasonable return on its capital investments.[15] Accordingly, the Commission's goal when setting rates is to balance ratepayer and shareholder interests.

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[13] Several thousand written comments in both cases are identical (albeit submitted by different individuals).

[14] Public Service Law §§5(1); 65(1).

[15] Public Service Law §72; see Federal Power Commn. v. Hope Natural Gas Co., 320 U.S. 591, 603 (1944); Matter of Abrams v. Public Serv. Commn., 67 N.Y.2d 205, 212-215 (1986).

In evaluating a Joint Proposal, the Commission must determine if the proposal's terms, viewed as a whole, produce a result that is in the public interest.[16] Factors considered in this analysis include whether the terms: produce outcomes that may have resulted had the case been fully litigated; are consistent with the social, economic, and environmental policies of the Commission and the state; appropriately balance the interests of a utility's ratepayers, its investors and the company's long-term viability; and are supported in the record such that the Commission's decision is rational and otherwise complete.[17]

## THE JOINT PROPOSAL[18]

### A. Term

The Joint Proposal establishes a multi-year rate plan consisting of three successive individual rate years beginning on April 1, 2025, and ending on March 31, 2028. Rate Year 1 (RY1) is April 1, 2025, through March 31, 2026; Rate Year 2 (RY2) is April 1, 2026, through March 31, 2027; and Rate Year 3 (RY3) is April 1, 2027, through March 31, 2028. New rates become effective on May 1, 2025, rather than April 1, 2025, resulting in an 11-month RY1 term for the imposition of the increased rates instead of a typical 12-month rate year.

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[16] Cases 90-M-0255 et al., Procedures for Settlements and Stipulation Agreements, Opinion 92-2 (issued March 24, 1992).

[17] Id.

[18] The ensuing discussion includes subject matter that is contested or otherwise noteworthy; it is not intended to be a comprehensive recitation of every provision in the Joint Proposal.

## B. Revenue Requirements and Depreciation

### 1. Revenue Requirements

#### a. Electric

The Company requested an electric revenue requirement increase of $511.2 million for RY1,[19] while DPS Staff initially recommended a $142.0 million increase.[20] DPS Staff's recommendation was based on a proposed ROE of 9.50 percent and an 8.53 percent overall pre-tax rate of return.[21] Subsequent to the filing of testimony by DPS Staff, it identified several corrections and updates related to O&M expenses, depreciation expense, and rate base. DPS Staff's corrected and updated position would have resulted in a revenue requirement increase of $157.8 million.[22]

The Joint Proposal provides for a $288.4 million increase (unlevelized) in RY1. According to DPS Staff, the difference between its corrected revenue requirement recommendation and that reflected in the Joint Proposal ($130.6 million) results primarily from adjustments to net margin ($52.5 million), O&M expenses ($91.2 million), depreciation expense (-$7.0 million), taxes other than income taxes ($0.610 million), income taxes (-$0.007 million), ROE ($0.614 million), and rate base (-$7.3 million).

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[19] Ex. 345, National Grid Revenue Requirement Panel, Rebuttal Testimony, p. 5.

[20] Ex. 479, DPS Staff Revenue Requirement Panel, Direct Testimony, p. 11.

[21] Ex. 480, DPS Staff Revenue Requirement Panel, Exhibit__(SRRP-1), Schedule 6.

[22] DPS Staff Initial Statement, p. 22. Appendix A of DPS Staff's Statement identifies the corrections and updates DPS Staff would have made to its pre-filed position if the proceeding had followed a litigated track. See Ex. 893.

In levelized terms, the Joint Proposal recommends the adoption of electric revenue requirement increases of: $167.3 million (6.4% delivery and 3.4% total revenues) in RY1; $297.4 million (10.9% delivery and 5.6% total revenue) in RY2; and $243.4 million (8.2% delivery and 4.6% total revenue) in RY3. The following table shows the average monthly total bill impacts for a typical residential customer (with usage of 625 kWh/month) in the Company's West, Central, and East regions.[23]

West Region

| Electric | Rate Year 1 | Rate Year 2 | Rate Year 3 |
|---|---|---|---|
| Avg. Monthly Total Bill Impact ($) | $14.29 | $6.44 | $4.34 |
| Avg. Monthly Total Bill Impact (%) | 11.61% | 4.70% | 3.00% |

Central Region

| Electric | Rate Year 1 | Rate Year 2 | Rate Year 3 |
|---|---|---|---|
| Avg. Monthly Total Bill Impact ($) | $14.32 | $6.44 | $4.34 |
| Avg. Monthly Total Bill Impact (%) | 11.51% | 4.59% | 2.94% |

[23] The Company's electric service territory is within six New York Independent System Operator load zones, or regions. The Company bills customer supply rates based on the region in which a customer is located, resulting in different total bills by region due to supply price differences. The Joint Proposal provides illustrative examples of bill impacts for three of the regions.

East Region

| Electric | Rate Year 1 | Rate Year 2 | Rate Year 3 |
|---|---|---|---|
| Avg. Monthly Total Bill Impact ($) | $14.47 | $6.44 | $4.34 |
| Avg. Monthly Total Bill Impact (%) | 10.76% | 4.33% | 2.83% |

b. Gas

The Company requested a gas revenue requirement increase of $160.2 million for RY1.[24] DPS Staff originally recommended a revenue increase of $60.7 million for RY1, which was premised on its recommendation of an 9.50% ROE and an overall pre-tax overall pre-tax rate of return of 8.53%.[25] DPS Staff identified several corrections and updates after filing its testimony, which would have resulted in a revenue requirement of $60.6 million.[26]

The Joint Proposal provides for a $91.1 million increase (unlevelized) in RY1. The recommended levelized gas revenue requirements include an increase in RY1 of $57.4 million (10.8% delivery and 5.5% total revenue), a RY2 increase of $64.5 million (10.8% delivery and 5.5% total revenue), and a RY3 increase of $71.8 million (10.8% delivery and 6% total revenue). According to DPS Staff the difference between its testimonial

[24] Ex. 345, Niagara Mohawk Rebuttal Testimony of Revenue Requirement Panel, p. 5

[25] Ex. 479, DPS Staff Direct Testimony of Revenue Requirement Panel, p. 14; Ex. 480, Exhibit__(SRRP-1), Schedule 6.

[26] DPS Staff Initial Statement, p. 22. Appendix B of DPS Staff's Statement identifies the corrections and updates DPS Staff would have made to its pre-filed position if the proceeding had followed a litigated track. See Ex. 894.

recommended increase (as corrected) and the Joint Proposal's recommended increase, approximately $30.5 million, primarily results from adjustments to: net margin ($1.0 million); O&M expenses ($24.9 million); amortization of regulatory deferrals (-$0.517 million); depreciation expense ($4.4 million); taxes other than income taxes ($0.179 million); income taxes ($.010 million); ROE (8.53 percent to 8.54 percent, or $.070 million); and rate base ($0.497 million). The following table shows the average monthly total bill impacts for a typical residential customer (with usage of 78 therms/month) exclusive of the revenue adjustment mechanism (RAM).

| Gas | Rate Year 1 | Rate Year 2 | Rate Year 3 |
|---|---|---|---|
| Avg. Monthly Total Bill Impact ($) | $7.66 | $8.08 | $9.18 |
| Avg. Monthly Total Bill Impact (%) | 8.16% | 7.81% | 8.25% |

2. Rate Drivers

In RY1, the main rate drivers of the recommended increases are due to increases to operations and maintenance (O&M) expense, return on and return of (i.e., depreciation expense) capital investments, and a change in the return on equity to reflect market conditions offset by lower than previously forecast property taxes and a forecasted increase in revenue. More specifically, for the electric business, the difference between current rates and the amounts reflected in the Joint Proposal are increases to O&M expense ($330.7 million), rate base ($119.7 million), rate of return ($80.9 million), depreciation expense ($79.0 million), amortization of deferrals ($28.3 million), income taxes ($26.7 million), and miscellaneous expenses ($1.7 million). These increases are offset by a reduction in taxes other than income taxes (-$51.9 million) and net margin (-$326.8 million). Regarding the gas business, the difference between current rates and the amounts reflected in the Joint Proposal are increases to O&M expense ($53.9 million), rate base ($28.5 million), rate of return ($20.3 million), depreciation expense ($13.7 million), amortization of deferrals ($2.0 million), income taxes ($0.4 million), and miscellaneous expenses ($0.2 million). These increases are offset by a reduction in taxes other than income taxes (-$13.2 million) and net margin (-$14.7 million). In RY2 and RY3, increases for the electric and gas rates are primarily driven by O&M expense, depreciation expense, property taxes, and additions to plant-in-service.

3. Rate Mitigation

The Joint Proposal includes several provisions intended to mitigate the impact of the proposed rate increases. The Signatory Parties recommend that the proposed rate increases be implemented on a levelized percentage basis over the term of the three-year rate plan. Further, the Signatory Parties propose spreading the rate compression impacts for electric (approximately $46.5 million) across RY1 to RY2.[27] Both of these provisions will help smooth the impacts of the proposed bill increases over several years.

The Signatory Parties also note the removal of discretionary spending and non-essential programs from the Company's original proposals. The Joint Proposal also recommends deferring some capital investments and reflects more

[27] RY1 gas delivery net increases will be recovered over the period of September 1, 2025, to March 31, 2026. See Ex. 918, Corrected Joint Proposal, p. 15.

than $110 million in annual efficiency savings. The Joint Proposal includes downward-only tracking mechanisms to ensure that customers are not harmed by potential under-spending by the Company for investments in utility plant and information technology. The Joint Proposal also recommends additional resources to support the Company's energy affordability programs (EAP) and enhanced protections for financially vulnerable customers. Finally, the Joint Proposal requires accelerated amortization (4 years) of the unprotected plant balance of Excess Accumulated Deferred Income Taxes which will help mitigate the impacts of the rate increases.[28]

UIU argues that the revenue requirements in the Joint Proposal, particularly for electric, are excessive and not in the public interest. UIU faults, among other things, high returns and unsustainable levels of capital spending underlying the high revenue requirements.[29] PULP argues that the bill impacts associated with the Joint Proposal are unaffordable and inconsistent with the regulatory economic and social policies of the state. As explained below, both parties argue for specific changes intended to reduce the revenue requirement and associated bill impacts.[30]

The Company argues that the revenue requirements reflect both reasonable compromises of parties' litigation positions and parties' efforts during negotiations to find efficiencies and scale back certain capital programs the Company had proposed. The Company maintains that the proposed revenue requirements reflect one month of foregone incremental revenue at new rates resulting from the 11-month term of RY1 and

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[28] Ex. 918, Corrected Joint Proposal, p. 2.

[29] UIU Initial Statement, pp. 4-5.

[30] PULP Initial Statement, pp. 3-4.

highlights adoption of DPS Staff's proposed 9.50 percent ROE. The Company also claims that the agreed to equity ratios, O&M expense levels, and rate base represent significant compromises relative to what it originally proposed.

DPS Staff argues that the revenue requirements resulting from negotiations are significantly lower than those requested by the Company and that, overall, the increases reflect a reasonable compromise between the parties' litigation positions. DPS Staff also claims that that the multi-year rates set forth in the Joint Proposal represent a measured approach that would not be achievable through litigation.[31]

4. Make Whole

As commencement of the rate plan occurs prior to our approval of it, the Joint Proposal includes a make whole provision authorizing the Company to recover revenues as if the increases discussed below were effective on May 1, 2025.[32] In order to moderate the impact of electric rate compression on customers, the Joint Proposal proposes recovery of the RY1 base delivery net electric increases over the 19-month period between September 1, 2025, and March 31, 2027; the RY1 gas delivery net increases will be recovered during the 7-month period between September 1, 2025, and March 31, 2026.[33] These provisions are reasonable because they restore the Company to the same financial position it would have been in had new rates become effective on May 1, 2025.

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[31] DPS Staff Initial Statement, p. 5.

[32] Although RY1 begins on April 1, 2025, new rates do not become effective until May 1, 2025 (Ex. 918, Corrected Joint Proposal, p. 8).

[33] Ex. 918, Corrected Joint Proposal, p. 15.

5. Depreciation

UIU states that depreciation expense is a major contributor to the revenue requirement increases and continues to argue that the depreciation method and figures in the Joint Proposal, particularly as they relate to gas assets, require amendment.

In its filing, the Company proposed adjusting electric and gas depreciation rates including changes to average service lives, survivor curves, and net salvage factors for several accounts, and to switch to the Equal Life Group procedure starting for gas plant in Data Year 1. The Company stated that the changes were intended to recognize that current depreciation rates are too low to recover capital costs in an equitable manner and to consider the impacts related to New York's required greenhouse gas (GHG) reductions.[34] The Company calculated a theoretical reserve deficiency for electric plant of $737.778 million (22%) and for gas plant of $253.927 million (26%). Amortizing the portion of the book to theoretical reserve deficiencies exceeding the 10% difference for electric and gas plant over 10 years, as the Company proposed,[35] resulted in total amortization amounts of $444.865 million for electric and $164.611 million for gas.[36] The Company also proposed to continue amortizing costs associated with Leak Prone Pipe (LPP) to coincide with the expected completion of LPP replacement by 2032. Finally, the Company proposed to continue amortizing the remaining costs of its legacy meters by June 2027 coincident with the expected completion of the Company's AMI deployment.

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[34] Ex. 35, National Grid Direct Testimony of Ned W. Allis, pp. 5-7.

[35] Id., pp. 31-32.

[36] Ex. 435, DPS Staff Depreciation Panel, Exhibit__(SDP-6), p. 12.

UIU testified that the Company's consideration of lower customer numbers in the future is against accepted accounting practices because it considers speculative conditions and not causes of depreciation in "current operation."[37] UIU proposed different depreciation rates for several accounts based on changes to average service life and net salvage value. UIU's witness claimed that the gas system was likely to remain in use or be retired in place, so it was improper to decrease service lives at the same time as including removal costs in net salvage values. UIU also proposed different theoretical to book reserve deficiencies based on its proposed changes to average service life, net salvage, and survivor curves and recommended a twenty-year amortization for any theoretical reserve deficiency.[38]

Clean Power testified that the current depreciation methods are inequitable for electric and gas customers and proposed shifting from a straight-line method to a units of production method.[39] Clean Power testified that the latter is more equitable than the former, which is currently creating a mismatch between plant depreciation and plant utilization due to increasing electricity demand and decreasing gas demand.[40]

DPS Staff recommended several changes to the Company's depreciation rates for several electric and gas plant accounts which reduced the proposed book to theoretical reserve deficiency for electric and gas, with gas reduced to below the 10% tolerance band.[41] DPS Staff noted that reserve deficiencies

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[37] Ex. 826, UIU Direct Testimony of William W. Dunkel, pp. 8-11.

[38] Id., p. 33.

[39] Ex. 761, New Yorkers for Clean Power Direct Testimony of Anshul Gupta, pp. 2-3.

[40] Id., pp. 22-25.

[41] Ex. 431, DPS Staff Depreciation Panel, Exhibit__(SDP-2), pp. 1-2.

below 10% are not generally authorized for amortization and reserve deficiencies that are amortized are normally amortized over twenty years.[42] Therefore, DPS Staff recommended no book to theoretical deficiency amortization for gas and an electric amortization sufficient to bring the deficiency back to a 10% level over twenty years – $89.61 million to be collected over 20 years with $4.481 million collected annually.[43]

DPS Staff opposed recommendations to change the depreciation method, suggesting that such broad changes should be addressed in the Gas Planning Proceeding. DPS Staff agreed with the Company's proposal regarding depreciation expenses of LPP and legacy meters.[44]

The Joint Proposal provides for the amortization of the depreciation reserve deficiencies in the amount of $124.137 million for electric and $20.287 million for gas based on depreciation rates agreed to by the Signatory Parties.

In its initial statement, DPS Staff argues that the agreed upon deprecation figures represent a reasonable compromise and notes that they are considerably less than those originally proposed by the Company. DPS Staff further notes that the twenty-year amortization period aligns with both DPS Staff's and UIU's original testimony. DPS Staff argues that the appropriate proceeding for making wholesale changes to deprecation methods is the Gas Planning Proceeding rather than in individual rate proceedings. DPS Staff also argues that the continued accelerated amortization for LPP as well as legacy

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[42] Ex. 429, Direct Testimony of DPS Staff Depreciation Panel, p. 26.

[43] Ex. 435, DPS Staff Depreciation Panel, Exhibit__(SDP-6), p. 1.

[44] Ex. 429, Direct Testimony of DPS Staff Depreciation Panel, pp. 21-32.

meters and encoder receiver transmitters is appropriate because these assets are being removed from plant-in-service.[45]

The Company agrees that the treatment of depreciation in the Joint Proposal represents a reasonable compromise between the litigation positions presented in testimony. However, the Company continues to harbor concerns that the service lives of several accounts remain out of alignment with CLCPA timelines and will contribute to increased long-term costs.[46]

UIU offers its own depreciation figures and argues that the Commission should reject those proposed in the Joint Proposal, particularly the proposed service lives and net salvage values which it argues are speculative. UIU argues that the average service lives and net salvage values in the Joint Proposal ignore the reality that the gas distribution system will be primarily retired in place or that it will continue to be used. UIU argues that the depreciation rates in the Joint Proposal are inflated and together with the proposed levels of capital expenditure produce unsustainable rate increases.[47]

In its statement supporting the Joint Proposal, NYGEO argues that a units of production method is the correct depreciation method during a time of declining demand. NYGEO notes that depreciation expense linked to an asset’s service life rather than to the units delivered while demand declines will increase the per unit cost of delivery in proportion to the reduction in demand, which will increase the burden on future ratepayers.[48]

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[45] DPS Staff Initial Statement, pp. 24-27.

[46] National Grid Initial Statement, pp. 23-24.

[47] UIU Initial Statement, p. 8-9.

[48] NYGEO Initial Statement, p. 3.

In its reply statement, DPS Staff claims that the depreciation rates proposed in the Joint Proposal are appropriately balanced and were developed using historic data and do not incorporate future outcomes. DPS Staff continues to argue that the Gas Planning Proceeding is the most appropriate proceeding for changes to depreciation rates and policies stemming from the CLCPA.[49]

Similarly, the Company also claims that the proposed depreciation rates do not incorporate any adjustment specific to the CLCPA and argues that UIU's arguments regarding depreciation should be rejected. The Company states that the proposed depreciation rates are not significantly higher than those previously approved by the Commission and are based on the methods and procedures previously used by the Company, as well as other New York utilities. The Company argues that UIU's depreciation rates are based on unreasonably long average service lives, including a 95-year average service life for steel gas mains and a 75-year average service life for underground conductors and devices, and a previously rejected method of determining salvage values.[50]

We agree with DPS Staff and the Company that the proposed depreciation expense is reasonable and based on appropriate methods and inputs. While we note the concerns raised by the Company, we continue to believe that significant changes potentially resulting from compliance with the CLCPA are better addressed on a statewide basis in the Gas Planning Proceeding. Similarly, UIU's preferred changes are also better considered holistically in the generic proceeding. Decisions made in that proceeding are likely to frame the future of the

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[49] DPS Staff reply statement in support, pp. 11-12.

[50] National Grid reply statement in support, pp. 8-9.

gas system in New York including the resulting impacts on depreciation expense. Modifying accepted approaches to depreciation in individual rate cases risks piecemealing those policy decisions rather than providing a clear comprehensive strategy for utilities, customers, and other stakeholders.

Overall, we find the electric and gas revenue requirements proposed in the Joint Proposal to be reasonable and in the public interest. As explained in more detail throughout the order, the expenses underlying the revenue requirements are necessary to maintain safe, reliable service, to comply with State policies, and to continue to upgrade and modernize the electric system and prepare the gas system for current and future demands. They are therefore reasonable and in the public interest. Moreover, the Joint Proposal represents significant reductions from the Company's original proposals.

## C. Cost of Capital and Disposition of Earnings

The revenue requirements included in the proposed rate plans are based on a common equity ratio of 48.00%, a 9.50% ROE, and long-term debt cost rates of 4.45% in RY1, 4.59% in RY2, and 4.85% in RY3.[51] The Joint Proposal includes an earnings sharing mechanism (ESM) that is triggered if the Company's actual ROE exceeds 10.00%.[52] Earnings in excess of 10.00% up to 10.50% would be shared equally between National Grid and ratepayers; ratepayers would receive 75% of any earnings greater than 10.50% up to 11.00%; and ratepayers would receive 90% of any earnings in excess of 11.00%.[53] As more fully discussed below, earnings greater than 9.50% but less than 10.00% fall within a "dead band" and may be retained by the Company.

[51] Ex. 918, Corrected Joint Proposal, p. 11.

[52] Id., p. 37.

[53] Id., pp. 37-38.

In their respective statements in opposition, UIU urges that the 9.50% ROE be rejected because it is excessive,[54] and PULP maintains that the ESM is not in the public interest because "it does not provide equitable sharing of earnings derived from actual ROEs exceeding [the] authorized ROE."[55] More specifically, UIU would support an 8.50% or 9.00% ROE, both of which it claims are consistent with testimony offered by a UIU witness and analogous to an ROE recently approved by the Connecticut Public Utility Regulatory Authority (PURA) in an ostensibly comparable proceeding.[56] PULP requests that the Joint Proposal be modified to eliminate the dead band and begin equal sharing of any earnings that exceed the ROE we approve in this order.[57]

As the Commission has previously observed, 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."[58] Plainly, an opportunity does not equate to a guarantee, and the responsibility to manage utility operations efficiently, as well as the risks of failure to achieve profitability, rests on the utility.[59]

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[54] UIU Initial Statement, pp. 6-7.

[55] PULP Initial Statement, p. 6.

[56] UIU Initial Statement, p. 7.

[57] PULP Initial Statement, p. 7.

[58] Case 23-G-0627, National Fuel Gas Distribution Corporation – Rates, Order Adopting Terms of Joint Proposal and Establishing Gas Rate Plan with Minor Modifications (issued December 19, 2024), p. 30. It is notable that the Commission approved a 9.70% ROE in that proceeding (id., p. 34).

[59] St. Lawrence Gas, 54 A.D.2d 815 (citing Federal Power Commission v. Natural Gas Pipeline Co., 315 U.S. 575, 590 (1942).

An exhibit admitted into evidence in these proceedings, offered by PULP, is illustrative, demonstrating that National Grid's electric business underearned its authorized ROE in every rate year of the prior three rate plans, and its gas business underearned the authorized ROE in five of the eight rate years.[60] More specifically, while the Commission approved a 9.30% ROE in cases 12-E-0201 and 12-G-0202, the Company's actual ROEs were 8.56%, 6.77%, and 7.94% for electric in rate years one through three, respectively, and 9.48%, 8.15%, and 6.73% for gas.[61] In cases 17-E-0238 and 17-G-0239, the Commission approved a 9.00% ROE, with National Grid earning 8.81%, 8.08%, and 4.71% for electric in the applicable rate years and 10.19%, 8.23%, and 6.02% for gas.[62] Finally, in Cases 20-E-0380 and 20-G-0381, although a 9.00% ROE was approved, the Company earned 8.31% and 8.56% for electric in rate years one and two, respectively, and 9.58% and 7.85% for gas in the corresponding rate years.[63]

These figures amply demonstrate the asymmetrical risk borne by the Company and belie PULP's assertion that the ESM unfairly favors shareholders. Indeed, as recognized by DPS Staff, "[s]hareholders alone assume the risk of unfavorable outcomes, from inflationary cost spikes to unforeseen capital demands[, which] justifies a structure in which [the] utility company retains a modest portion of any over-earnings ... without triggering immediate sharing with customers" – e.g., those overearnings falling within the dead band.[64] This

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[60] Ex. 776, PULP Exhibit__(WDY-03) p. 10.

[61] Id.

[62] Id.

[63] Id.

[64] DPS Staff reply statement in support, p. 4.

opportunity to retain a larger share of potential efficiency savings incentivizes the Company to seek and implement efficiencies throughout the multi-year period and, when the utility next comes in for rates, such savings will be captured in full for customers' benefit.

Turning more broadly to the 9.50% ROE set forth in the Joint Proposal, such figure and the overall after-tax cost of capital represent compromises between the Signatory Parties. National Grid originally requested an overall after-tax cost of capital of 7.12% based on a 10.00% ROE, a common equity ratio of 48.00%, and a long-term debt ratio of 51.39% with a cost rate of 4.46%.[65] DPS Staff recommended an overall after-tax cost of capital of 6.87% consisting of a 9.50% ROE, a common equity ratio of 48.0%, and a long-term debt ratio of 51.39% with a cost rate of 4.43%.[66] The agreed-upon ROE is a reasonable result that reflects the market conditions at the time the Joint Proposal was signed. Finally, we note that the Connecticut proceeding cited by UIU in which PURA authorized a 9.10% ROE is not comparable to the instant proceedings. Risk reducing measures and ROE methodologies vary from state to state, as does the credit supportiveness of the regulatory environment, which make these proceedings easily distinguishable from one another.

In light of the above, we find that the Joint Proposal adopts a fair return that is expected to allow the Company to attract adequate capital to fund its anticipated investments, thereby ensuring the continued provision of safe and reliable service. Additionally, the ESM acts as a safeguard against potential overearning and ensures that ratepayers share in any

[65] Ex. 483, Duah Testimony, p. 9; Ex. 485, Exhibit___(KXD-2).

[66] Ex. 485, Exhibit___(KXD-2).

efficiency gains realized by the Company, while still providing the Company an incentive to pursue cost efficiencies.

D. Pension and Other Post-Employment Benefits (OPEB)

In their respective direct testimonies, National Grid, DPS Staff and UIU made disparate recommendations regarding the appropriate amount of pension and OPEB expenses to include in the Company's revenue requirements. More specifically, although National Grid's actuarial report forecasted the combined pension and OPEB expenses to be approximately a negative ($114) million in RY1, it proposed setting the associated rate allowance at $0.[67] In doing so, the Company argued that the negative expenses could adversely impact its cash flows because it would be unable to offset the negative expenses with cost-effective withdrawals from the OPEB and pension trusts; this, in turn, might prevent the Company from maintaining its existing credit ratings, which have been downgraded multiple times in the past six years.[68]

While DPS Staff agreed that the negative pension and OPEB expenses could impact National Grid's cash flow, it was not convinced that this would lead to a corresponding reduction in the Company's credit ratings, and it accordingly recommended adjusting the pension and OPEB expenses to reflect the actuarial forecast.[69] DPS Staff nonetheless also acknowledged an opinion from Moody's that it could downgrade the Company's credit rating

[67] Ex. 156, Direct Testimony of National Grid Revenue Requirements Panel, p. 50; Ex. 482, DPS Staff Revenue Requirements Panel EX___(SRRP-3), Attachment 1, Scenario 4, p. 374.

[68] Ex. 156, Direct Testimony of National Grid Revenue Requirements Panel, p. 52; Ex. 16, Direct Testimony of National Grid Capital Structure Panel, pp. 12, 14-15.

[69] Ex. 479, Direct Testimony of DPS Staff Revenue Requirements Panel, p. 32; Ex. 483, Direct Testimony of DPS Staff Witness Duah, pp. 94-96.

if the Company's cash flow from operations before working capital to debt fell persistently below 14%.[70]

UIU witness Dustin Madsen stated that, while he would ordinarily recommend that the full pension and OPEB expenses be reflected in the Company's revenue requirements, he appreciated National Grid's concern that the negative expense is forecast to be material and would result in a significant increase to the debit balance in the internal reserve for pension and OPEBs recorded on the Company's books.[71] In light of this concern, Madsen advocated for a similar approach to that used in the 2022 Rate Order, where the pension and OPEB expenses were set at negative amounts but the combined pension and OPEB expense would not exceed National Grid's capital funding obligations, which would result in a combined pension and OPEB rate allowance of a negative ($19.2) million.[72] Madsen added that the Company should also be directed to accrue carrying costs at its pre-tax weighted average cost of capital on the forecasted balance of pension and OPEB regulatory liabilities as of March 31, 2025, which exceeds the Company's net funding obligation and, according to him, would reduce the revenue requirement by $38.9 million.[73]

In its rebuttal testimony, National Grid reiterated the negative impact that DPS Staff's recommendation would have on its cash flow, as well as the concomitant detriment to its credit quality, and observed that, because the underlying actuarial forecasts are subject to market risk, significant rate

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[70] Ex. 483, Direct Testimony of DPS Staff Witness Duah, p. 96; Ex. 489, Duah Ex___(KXD-6), p. 2.

[71] Ex. 803, Direct Testimony of UIU Witness Madsen, pp. 42-43.

[72] Id., pp. 41-44.

[73] Id., p. 11.

volatility may occur if the negative pension and OPEB expenses projected in the current actuarial report become positive in the future.[74] The Company also argued, among other things, that DPS Staff's proposal to mitigate rates via the negative pension and OPEB expenses lacked any corresponding methodology for recovering the costs of that mitigator in the future.[75] In other words, according to National Grid, DPS Staff failed to consider that future customers might be required to pay for benefits provided to current customers.[76] The Company urged that UIU's proposals be rejected for similar reasons, adding that there was not a sound basis for requiring it to accrue additional carrying costs on its pension and OPEB regulatory liability.[77]

The provisions in the Joint Proposal related to pension and OPEB expense represent a reasonable compromise amongst the foregoing conflicting positions, reflecting negative pension and OPEB expenses for National Grid's electric and gas businesses in all three rate years, but in amounts significantly reduced from the actuarial forecast to address the inherent risks and impact on the Company's cash flow and credit metrics. More specifically, the Joint Proposal reflects negative pension and OPEB expenses in the amount of ($27.7) million in RY1, ($28.4) million in RY2, and ($20.4) million in RY3 for the Company's electric business, as well as corresponding negative pension and OPEB expenses in the amount of ($5.3) million in RY1, ($5.5) million in RY2 and ($3.9) million for RY3 for the

[74] Ex. 345, Rebuttal Testimony of National Grid Revenue Requirements Panel, pp. 21-22.

[75] Id., p. 35.

[76] Id., pp., 24, 36.

[77] Id., pp. 38, 42.

Company’s gas business.[78] As these negative amounts result in cash shortfalls of $15.0 million in RY1, 14.4 million in RY2, and $4.5 million in RY3, the Joint Proposal recognizes the need to create internal reserve debit balances related to pension and OPEB expense consistent with the Commission’s Pension & OPEB Statement of Policy.[79]

The ratemaking and accounting treatment for the internal reserve is set forth in Appendix 9 to the Joint Proposal, and Attachment A to that appendix reflects an Earnings Base/Capitalization adjustment permitting National Grid to recover the equivalent of carrying charges on the internal reserve debit balances through the end of RY3.[80] The Joint Proposal also authorizes the Company to petition the Commission at any time during the rate plan to adjust the rate allowance for pensions and OPEBs to address any known or anticipated negative impacts on its financial condition that, if ignored, could result in a downgrade of the Company’s credit ratings.[81]

While UIU now recommends that we direct the “full inclusion of all negative pension and OPEB [expenses] in rates for all rate years,”[82] we are satisfied that the foregoing provisions are reasonable and fully supported in the record.

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[78] Ex. 918, Corrected Joint Proposal, p. 62.

[79] Id., pp. 62-63; Case 91-M-0890, In the Matter of the Development of a Statement of Policy Concerning the Accounting and Ratemaking Treatment for Pensions and Postretirement Benefits Other Than Pensions, Statement of Policy and Order Concerning the Accounting and Ratemaking Treatment for Pensions and Postretirement Benefits Other Than Pensions (issued Sept. 7, 1993) (Policy Statement).

[80] Ex. 918, Corrected Joint Proposal, p. 63.

[81] Id.

[82] UIU Statement in Opposition, pp. 7-8.

Indeed, as recognized by the Company,[83] the negative expenses set forth in the Joint Proposal are greater than the negative ($19.2) million combined expense initially advocated for by UIU, and thus the revenue requirement that we approve today is lower than it would be had we adopted UIU's original proposal. Moreover, the relevant provisions appropriately contemplate the inherent risks and potential impacts on the Company's cash flows and credit metrics – concerns that warrant special treatment and are fully supported in the record[84] – and they are otherwise consistent with the Commission's Policy Statement, which requires that utilities reconcile any difference between their approved rate allowance for pension and OPEBs and the actual expenses, thus ensuring that customers pay no more than is necessary to fund the pension and OPEB plans.[85] Finally, the provisions reflect a compromise between the various parties' testimonial positions, appropriately balance those parties' competing interests, and are within the range of potential outcomes in a litigated case.

## E. Electric Revenue Allocation and Rate Design

### 1. Electric Revenue Forecast

The electric revenue forecasts reflected in the Joint Proposal are approximately $4.06 billion in RY1, $4.05 billion in RY2, and $4.01 billion in RY3.[86] These figures closely approximate the RY1 figures forecasted by DPS Staff and National

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[83] National Grid Reply Statement in Support, p. 7.

[84] Ex. 16, Direct Testimony of National Grid Capital Structure Panel, pp. 12, 14-15; Ex. 483, Direct Testimony of DPS Staff Witness Duah, p. 96; Ex. 489, Duah Ex___(KXD-6), p. 2.

[85] Case 91-M-0890, Policy Statement; DPS Staff Reply Statement in Support, p. 10.

[86] Ex. 918, Corrected Joint Proposal, Appendix 2, schedules 1.1, 1.2, and 1.3.

Grid in their respective direct and corrected testimonies,[87] and they are thus within the range of reasonable outcomes in a litigated proceeding. We accordingly adopt them.

2. TCC Auction Revenues

The electric revenue forecast used to develop National Grid's revenue requirement reflects TCC Auction Revenues of $374.5 million in all three rate years.[88] In accordance with P.S.C. No. 220 – Electric Service Tariff, the Company will continue to defer the differences between actual TCC Auction Revenues and the amount set forth in rates, exclusive of revenue taxes, and recover the differences through the TRA surcharge.[89] Consistent with the joint proposal approved in National Grid's previous rate case, the Company may continue to retain the return on equity established by the Federal Energy Regulatory Commission (FERC) for the Smart Path Connect and Energy Highway, Western New York projects.[90]

3. Electric Revenue Allocation

The recommended electric revenue allocations are set forth in Appendix 2, Schedule 3A to the Joint Proposal. They do not reflect an Embedded Cost of Service (ECOS) study sponsored by any one party to these proceedings,[91] and are instead a negotiated outcome that seeks to achieve the agreed-upon revenue requirement while gradually moving service classes closer to the

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[87] Ex. 451, Direct Testimony of DPS Staff Forecasting Panel, p. 11; Ex. 253, Deliveries Forecast by Rate Class, Exhibit__(ELF-13CU).

[88] Ex. 918, Corrected Joint Proposal, p. 16.

[89] Id.

[90] Id.; 2022 Rate Order, Joint Proposal, at §IV.3.1.1; FERC Docket Nos. 6 ERS23-973-001, ER23-974-001.

[91] Ex. 918, Corrected Joint Proposal, p. 16.

system average rate of return and thus mitigating severe impacts to any group.

UIU nonetheless urges that we "refrain from adopting the Joint Proposal's proposed methodology for revenue allocation purposes[, and that we] direct further future study into a reasonable level of classification that reflects cost causation."[92] More specifically, UIU argues that the Company's minimum system studies over-allocate certain costs to residential customers by classifying them as customer-related rather than demand-related. The Commission has previously rejected similar claims from UIU, and we do so again here.[93]

Although the practice of estimating cost causation is imprecise and may be considered a subjective exercise, the goal of a minimum system study is to establish the cost of building a system that connects all customers but does not deliver more than the "minimum" level of energy.[94] As relevant here, costs for infrastructure required to satisfy peak day demand are classified as "demand," and expenses associated with connecting customers to the distribution system that do not vary by customer usage or throughput are classified as "customer."[95] A minimum system study is used to determine the appropriate portion of costs of certain assets – like pipes, towers, and fixtures or underground conduits and conductors – that are demand- or customer-related; in other words, such "studies recognize that the diameter or size of pipes or wires are a

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[92] UIU Statement in Opposition, p. 5.

[93] See, e.g., Cases 16-E-0060 et al., Con Ed Rates, Order Approving Electric and Gas Rate Plans (issued January 25, 2017), pp. 44-47.

[94] Ex. 521, Rebuttal Testimony of DPS Staff Electric Rates Panel and DPS Staff Gas Rates Panel, p. 7.

[95] Id., pp. 2-3.

function of demand, while the length of these assets is a function of the number of customers served."[96]

Inasmuch as the National Association of Regulatory Utility Commissioners' Electric Utility Cost Allocation Manual acknowledges the validity of this premise, we decline UIU's proposal that it be rejected here.[97] We are also unpersuaded by UIU's related assertion that the cost causation methodology employed by the Company's Massachusetts affiliate, which is necessarily consistent with applicable policies of the Massachusetts Department of Public Utilities,[98] has any bearing on these proceedings.

4. Electric Rate Design

Based on the Joint Proposal, the Company's electric rates will be revised as depicted in Appendix 2, Schedule 3K for standard service classes and Schedule 3H for Service Classification (SC)-1 Voluntary Time-of-Use rates.[99] SC-7 Standby Rates will be shown on Appendix 2, Schedule 5.[100] National Grid will also update the delivery and supply incentive rates for the Residential Electric Vehicle Charge Smart Plan, as shown in Appendix 2, Schedule 6.[101] Typical bill impacts for standard service classes resulting from this rate design are set forth in Appendix 2, Schedule 4.[102]

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[96] Id., pp. 3-4. To the extent these observations include reference to gas assets, they are relevant in the gas revenue allocation section discussed below.

[97] Ex. 361, Rebuttal Testimony of National Grid Electric Rate Design Panel, pp. 19-20.

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

[99] Ex. 918, Corrected Joint Proposal, p. 17.

[100] Id.

[101] Id.

[102] Id.

The rate design reflected in the Joint Proposal includes incremental EAP discounts associated with the proposed revenue requirement increases,[103] which we find reasonable because it minimizes the likelihood that National Grid will amass a large deferral that would need to be recovered in a future rate filing. We also agree with the Signatory Parties that the Joint Proposal's rate design provisions balance the parties' various interests, limit severe impacts for any particular group of customers, and provide appropriate price signals to promote energy conservation. Finally, these provisions are supported by testimony and fall within the range of outcomes had the proceedings been litigated.

5. Excelsior Job Program Rates

The Joint Proposal updates the Excelsior Job Program (EJP) rates as shown in Appendix 2, Schedule 10 to be consistent with the revenue requirements as agreed to in the Joint Proposal.[104]

6. Earnings Adjustment Mechanism Surcharge

The Joint Proposal proposes continuing the Earnings Adjustment Mechanism (EAM) Surcharge to recover positive revenue adjustments.[105] There are five electric EAMs, including the Storage MW EAM, the Electric Demand Response EAM, the Transportation Electrification EAM, the Electric Vehicle Managed Charging Residential EAM, and the L2 and DCFC Make-Ready Share the Savings EAM.[106] The Storage and Demand Response EAM will be allocated to customer classes per the 1 Coincident Peak allocator and the Transportation Electrification and L2 and DCFC

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[103] Id.

[104] Id.

[105] Ex. 918, Corrected Joint Proposal, p. 18.

[106] Id.

Make Ready Share the Savings EAMs will be allocated to customer classes using the Tot-Dist-Rev allocator.[107] The Electric Vehicle Managed Charging Residential EAM will be allocated using the Non-Coincident Peak allocator.[108] Earned EAM revenue will be recovered on a per kWh basis for non-demand metered classes on a per kW basis from demand metered classes.[109]

7. Other Electric Tariff Changes

The Joint Proposal recommends increases to several customer charges, including an increase from $11.77 to $14.56 for customers that participate in various demand response programs. Incremental charges for SC-1, Special Provision L; SC-2, Special Provisions O and P; and SC-3, Special Provisions L and N will increase as well.[110] The Company will also modify its Incremental Energy Efficiency Surcharge to provide rate recovery for any difference between the energy efficiency costs reflected in rates and the costs authorized by the Commission in the Energy Efficiency Proceeding.[111]

The Joint Proposal recommends the addition of an "Other Delivery Surcharge" for recovery of delivery surcharges currently billed in the delivery charge line, including Dynamic Load Management, Value of Distributed Energy Resource Standard, EAM surcharge, EV Make-Ready, Arrears Management Program, Phases 1 and 2 Surcharges and the new Revenue Adjustment Mechanism (RAM), which is explained further below. The Other Delivery Surcharge will also include any other delivery surcharge

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[107] Id.

[108] Id.

[109] Id., pp. 18-19.

[110] Ex. 918, Corrected Joint Proposal, p. 19 and Appendix 2, Schedules 11.4.1 to 11.4.3.

[111] Id., p. 20.

approved in the future eliminating the need to create a corresponding additional separate line item on customer bills. The Joint Proposal requires the Company to develop a communication plan to educate customers regarding the Other Delivery Surcharge, what rate elements are included in that surcharge, and how it compares to the Delivery Charge.

The Late Payment Charge and Other Waived Fees, Net Utility Plant, and Hydrogen Energy Transfer System surcharges will be removed from the Company's tariff due to those charges expiring. The Empire Zone Rider will also be eliminated. The Joint Proposal includes updated electric RDM targets that are based upon the agreed upon rates and forecast revenue in the Joint Proposal. The updated electric RDM targets are shown in Appendix 2, Schedule 9. The Joint Proposal also contains several minor tariff adjustments and other housekeeping issues recommended by the Signatory Parties.[112]

8. Rate Adjustment Mechanism (Electric and Gas)

The Joint Proposal includes the implementation of a Rate Adjustment Mechanism (RAM) to consolidate Property Tax deferrals and Major Storm Deferred Expenses into a single surcharge/credit mechanism for recovery from or refund to customers. Costs recovered or pending recovery are subject to an audit by DPS Staff and the Company is required to make any adjustments that DPS Staff determines are needed as a result of its audit.

RAM surcharges and credits will only be instituted when the deferred amount surpasses ten basis points in a given Rate Year, and are subject to an annual cap of two percent of the Company's actual operating revenues during the previous

[112] Id., pp. 21-25.

calendar year, without compounding. Recovery of surcharges will occur from July 1 through June 30 of the respective Rate Year.

The RAM surcharge will commence on the first month following the issuance of a Commission Order adopting the Joint Proposal in these proceedings and, based on the deferral balances as of March 31, 2025, will include the deferral balances for Property Tax and Major Storm Deferred Expenditures from January 1, 2024, through March 31, 2025.[113]

## F. Gas Revenue Allocation and Rate Design

### 1. Gas Revenue Forecast

In its corrected testimony, National Grid forecasted RY1 sales of approximately 1,627,858,462 therms, resulting in total gas revenues of $789,296,780.[114] DPS Staff forecasted approximately 1,639,401,250 therms sales, resulting in RY1 revenues totaling $802,855,031.[115]

In the Joint Proposal, the forecast for RY1 sales is 1,636,921,119 therms and gas revenues of $813,786,081. The forecast sales in RY2 and RY3 are 1,650,183,548 and 1,656,290,761 therms respectively, resulting in corresponding total gas revenues of $842,498,334 and $843,295,031.[116] These figures reflect a compromise designed to minimize future revenue decoupling mechanism adjustments. The gas sales and revenues

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[113] Id., pp. 25-27. See also Appendix 2, Schedule 13 for an illustrative calculation for electric and Appendix 3, Schedule 12 for gas. Appendix 3, Schedule 12.1 contains the processes and procedures for the RAM.

[114] Ex. 271, Company Gas Load Forecasting Panel, C&U Testimony, Exhibit__(GLF-4CU); Ex. 284, Company Gas Rate Design Panel, C&U Testimony, Exhibit__(G-RDPCU-2).

[115] Ex. 454, DPS Staff Forecasting Panel, Exhibit___(SFP-3); Ex. 463, DPS Staff Gas Rates Panel, Exhibit__(SGRP-2).

[116] The total gas revenues included in the Joint Proposal are found on Appendix 3, Schedule 1.

forecasts included in the Joint Proposal are thus within the range of reasonable outcomes in a litigated proceeding, and we approve them.

2. Gas Revenue Allocation

The recommended gas revenue allocations are set forth in Appendix 3, Schedule 3A to the Joint Proposal.[117] As with the electric revenue allocations, they do not reflect an ECOS study sponsored by any one party, and they will not establish precedent for any future proceeding.

While UIU maintains that the Company's purported failure to "correct for load-carrying capacity of its gas minimum system as it has ... for electric" evinces an arbitrary classification of costs,[118] National Grid's Gas Rate Design Panel explained that a system with only 2-inch pipes – i.e., the minimum system – could not supply gas to customers due to line pressurization requirements.[119] For this reason, as well as those articulated in the electric revenue allocation section above, we find UIU's revenue allocation-related assertions unpersuasive.

3. Gas Rate Design

In direct testimony, National Grid proposed customer charge increases to all service classes and collecting the balance of the revenue requirement from the volumetric blocks.[120] To promote energy conservation, the Company recommended increasing tail block rates by a greater percentage than mid-

[117] Ex. 918, Corrected Joint Proposal, p. 27.

[118] UIU Statement in Opposition, p. 5.

[119] Ex. 372, Rebuttal Testimony of Gas Rate Design Panel, p. 15.

[120] Ex. 286, Gas Rate Design Panel Ex.__(G-RDP-4CU), Schedule 2.

block rates in service classes (SC) 1, 2,and 7.[121] Although DPS Staff generally accepted the Company's rate design methodology, it proposed lower increases to the minimum charges and a more gradual approach to block flattening.[122]

The agreed-upon gas rate design, which reflects a compromise among the parties, is shown in Appendix 3 to the Joint Proposal, schedule 3I, and typical bill impacts are depicted in schedules 4.1 through 4.4. SC-6 will have volumetric delivery rates set at a 45% discount to the applicable firm tail block rate of SC-8.[123] As with the electric rate design described above, the gas rate design includes incremental EAP discounts associated with the revenue requirement increases.

We find the Joint Proposal's gas rate design provisions reasonable, as they fall within the range of likely litigated outcomes, mitigate impacts across customer classes, and establish price signals that promote conservation.

4. Lost and Unaccounted for Gas (LAUF)

LAUF pertains to the disparity between the amount of gas metered into a distribution system and the amount of gas metered out of the system. A LAUF incentive mechanism limits

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[121] Ex. 283, Corrections and Updates Testimony, National Grid Gas Rate Design Panel, p. 7.

[122] Ex. 461, Direct Testimony of DPS Staff Gas Rates Panel, pp. 37, 44.

[123] The Company proposed lowering eligibility limits on SC-6 (interruptible) service to encourage large customers currently on firm service classifications to become interruptible customers and thus reduce demand on a peak design day (Ex. 66, Direct Testimony of National Grid Gas Rate Design Panel, p. 53). While DPS Staff favored incentivizing customers to transition to interruptible service, it disagreed with National Grid's recommendation to increase the SC-6 minimum charge (Ex. 461, Direct Testimony of DPS Staff Gas Rates Panel, p. 48).

the amount of gas expense a company can recover and thus motivates the company to control losses. Here, in direct testimony, National Grid proposed to update associated targets to reflect the five most recent annual reconciliations of gas expenses and gas cost recovery periods,[124] which allows the tariff loss factor and dead band to most accurately reflect system losses. DPS Staff agreed with this proposal,[125] and no other party took a position. Thus, the Joint Proposal reflects new LAUF targets and deadbands to become effective on September 1, 2025, subject to annual reconciliation. The targets and deadbands were determined as set forth in Appendix 3, Schedule 5 of the Joint Proposal.

5. Other Gas Provisions

The Joint Proposal eliminates the Late Payment Charge and Other Waived Fees (LPCO) and Net Utility Plant (NUP) surcharges as those surcharges have expired. The EAM surcharge will continue and be allocated to firm sales, transportation customers exclusive of Excelsior Job Program (EJP) load.[126] The Company will adopt new marginal EJP cost rates that will include an energy efficiency charge reflecting EJP customers' eligibility for the Company's energy efficiency programs. Gas EJP rates will be phased in over a five-year period. After an annual review, if the Company determines that customers paid more under the marginal EJP rates than they would have under the otherwise applicable tariff rate, it will refund the difference to the customer.

[124] Ex. 66, Direct Testimony of National Grid Gas Rate Design Panel, p. 38.

[125] Ex. 461, Direct Testimony of DPS Staff Gas Rates Panel, p. 50.

[126] Ex. 918, Corrected Joint Proposal p. 28.

G. New Reconciliations, Deferrals, and True-Ups

Pursuant to the Joint Proposal, four new electric and gas deferral accounts will be implemented.[127]

1. Leak Repairs (Gas Only)

Leak performance targets are set forth on page 71. If National Grid is able to repair increased leaks that reduce its existing leak backlog in any Rate Year, it will be permitted to defer the costs of repairing such incremental leaks for future recovery from customers.[128] This deferral is reasonable as it enables the Company to further reduce its total leak backlog, which benefits customers by improving system safety; it also benefits the environment by lowering methane emissions.

2. Uncollectible Expenses

National Grid will reconcile its actual uncollectible expense (i.e., net write-offs) in each Rate Year to the amounts reflected in electric and gas rates.[129] In addition to the delivery component of the uncollectible expense, the reconciliation will include the commodity portion of uncollectible expense recovered through the Merchant Function Charge and the amounts recovered through ESCOs through the Purchase of a Receivable Discount.[130] If actual uncollectible expenses are lower than the amounts reflected in base rates,

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[127] Appendix 5, Schedule 1 and Appendix 6, Schedule 1 set forth the electric and gas deferral accounts and other regulatory assets and liabilities balances as of December 31, 2023. But for those deferral accounts and other regulatory assets and liabilities identified therein as "Discontinued," National Grid is authorized to continue using deferral accounting and/or reconciliation mechanisms in connection with the electric and gas expenses described in Schedule 1 of both Appendices.

[128] Exhibit 918, Corrected Joint Proposal, pp. 79-80.

[129] Id., p. 80

[130] Id.

National Grid will defer 100% of the over recovery for future return to customers.[131] If the actual uncollectible expenses are greater than the amounts reflected in base rates, the Company will defer 80% of the under recovery for future recovery form customers. We agree with the Signatory Parties that this provision is reasonable, as it reflects the challenges in forecasting uncollectible expenses and offers added protection to ratepayers if the actual under-collected expenses are lower than the amounts forecasted in base rates.

3. Management and Operations Audit Expenses

The Joint Proposal includes a provision allowing deferred accounting treatment for consultant costs associated with any comprehensive management and/or operations audits that may arise during the term of the rate plan. Such a provision is appropriate as it provides the utility cost recovery for the consultant costs associated with audits initiated by the Commission that are not known at this time. We note that the Commission instituted a comprehensive management and operations audit of the Company on January 23, 2025.[132] Therefore, the Company will incur costs associated with this audit under the Company's current rate plan as well as the rate plan authorized by this Order. Pursuant to its current rate plan, the Company is authorized to defer the consultant costs associated with the ongoing audit for future recovery from customers.[133] The Joint

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[131] Id.

[132] Case 24-M-0667, In the Matter of a Comprehensive Management and Operations Audit of Niagara Mohawk Power Corporation d/b/a National Grid, The Brooklyn Union Gas Company d/b/a National Grid NY and KeySpan Gas East Corporation d/b/a National Grid.

[133] Case 20-E-0380 & 20-G-0381, Joint Proposal pg. 69, Appendix 5 & 6 Schedule 1.

Proposal continues this authority for any costs incurred under the rate plan authorized by this Order.[134]

4. Non-Pipes Alternatives (NPA) Implementation Coordinator

In order to achieve the NPA commitments described in the CLCPA section below, National Grid is permitted to utilize the services of an NPA Implementation Contractor at a cost of $0.367 million per rate year.[135] If actual costs in any rate year exceed this amount, the Company may defer the difference for future recovery from customers.[136] As this provision may enhance National Grid's efforts at reducing the risk of stranded gas infrastructure investments and emissions, it is in the public interest.

H. Capital Expenditures

In its initial testimony,[137] the Company proposed total capital expenditures for electric transmission, sub-transmission, and distribution of $1,103 million (FY25), $1,615 million (FY26), $1,827 million (FY27), and $1,906 million (FY28), cumulating in a four-year total of $6,451 million. The Company also noted that, in the same period, it planned to invest in electric capital projects, excluded from rate base (i.e., non-rate base), as previously approved by the Commission

[134] Joint Proposal pg.61, Appendix 5 & 6 Schedule 1.

[135] Id., p. 81.

[136] Id.

[137] Ex. 94, Direct Testimony of Niagara Mohawk Electric Infrastructure and Operations Panel; Ex. 99, Exhibit__(EIOP-5); Ex. 101, Exhibit__(EIOP-7), and Ex. 107, Exhibit__(EIOP-9).

as Phase 2 projects[138] representing an additional $368 million (FY25), $370 million (FY26), $569 million (FY27), and $467 million (FY28) with a four-year total of $1,774 million.[139] The Company's four-year plan for both rate base and non-rate base electric capital projects was significantly higher than the total capital reflected in the 2022 Rate Order for an analogous four-year period.[140] In its testimony, the Company noted the strong impact of cost inflation and the need to maintain the safety and reliability of an aging electric system. The Company also noted that a significant portion of the proposed capital expenditures were related to programs and projects intended to meet clean energy goals.[141]

In its testimony,[142] DPS Staff proposed total capital expenditures for electric transmission, sub-transmission, and distribution of $977 million (FY25), $1,083 million (FY26), $1,192 million (FY27), and $1,311 million (FY28) with a four-year total of $4,563 million or $1,888 million less than the amount proposed by the Company. DPS Staff made no recommendation regarding non-rate base capital expenditures, as the Commission previously approved them in the Phase Two Order. DPS Staff argued that the Company's proposed electric capital

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138 Case 20-E-0197, Proceeding to Implement Transmission Planning Pursuant to the Accelerated Renewable Energy Growth and Community Benefit Act, Order Approving Phase 2 Areas of Concern Transmission Upgrades (issued February 16, 2023) (Phase Two Order).

139 Ex. 38, Direct Testimony of DPS Staff Elec. Infrastructure and Operations Panel Testimony, pp. 18-19.

140 2022 Rate Order, Appendix 1, Schedule 5, pp. 3-18.

141 Ex. 94, Direct Testimony of Niagara Mohawk Electric Infrastructure and Operations Panel, pp. 15-18.

142 Ex. 390, Exhibit__(SEIOP-2); Ex. 391, Exhibit__(SEIOP-3), and Ex. 392, Exhibit__(SEIOP-4).

investment plan was overly ambitious and could detrimentally impact the Company's ability to efficiently complete projects, particularly considering other challenges including increasing supply chain issues, labor shortages, and siting delays. Accordingly, DPS Staff recommended electric capital expenditures reflecting an annual spending cap based on a growth rate of ten percent annually from historically approved amounts. DPS Staff's recommendations included providing the entire funding for high priority projects but rejected some of the Company's proposed capital projects as being unjustified, and designated others as best considered in other Commission proceedings. DPS Staff described the remaining projects as discretionary which the Company could prioritize based on relative importance and value.[143]

The Joint Proposal includes total capital expenditures for electric transmission, sub-transmission, and distribution, including the cost of removal, of $1,192.8 million (FY25), $1,362.9 million (FY26), $1,474.3 million (FY27), and $1,490.8 million (FY28) for a four-year total of $5,520.8 million. The Joint Proposal also provides for total common capital investments of $32.5 million (FY25), $80.1 million (FY26), $77.6 million (FY27), and $94.0 million (FY28), of which 84.16% are allocated to the electric business.[144] The capital investment levels proposed in the Joint Proposal do not include EV Charging and EV School Bus Projects proposed by the Company,[145] nor do they include capital investments related to CLCPA Phase 2 or Smart Path Connect projects, which are recovered through FERC

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[143] Ex. 388, Direct Testimony of DPS Staff Electric Infrastructure and Operations Panel, pp. 28-66.

[144] National Grid Initial Statement, p. 46 (citing Ex. 918, Corrected Joint Proposal, Appendix 1, Schedule 5).

[145] Ex. 918, Corrected Joint Proposal, p. 39.

approved rates. However, the amounts included in the Joint Proposal do include the cost of removal associated with existing plant that is being retired as part of such projects.

The Company proposed total gas investments, including the cost of removal, of $416.4 million (FY25), $343.5 million (FY26), $426.4 million (FY27), and $634.1 million (FY28) with a four-year total of $1,820.4 million.[146] The Company-proposed projects are intended to improve the safety and reliability of the gas system and include replacement of LPP, regulator and gate station improvements, heater installations, a compressed natural gas (CNG) injection facility in Moreau, residential methane detectors, and various pipeline integrity projects to meet state and federal safety requirements.[147]

DPS Staff suggested various adjustments in its initial testimony resulting in recommended gas investments, including cost of removal, of $402.4 million (FY25), $331.7 million (FY26), $374.9 million (FY27), and $301.8 million (FY28) with a four-year total of $1,410.8 million.[148]

The Joint Proposal provides for total gas investments, including the cost of removal, of $408.0 million in FY25, $338.2 million in FY26, $377.0 million in FY27 and $300.1 million in FY28 or a four-year total of $1,423.3 million.[149] Also, 15.84 percent of the common capital investments are allocated to the gas business. The Joint Proposal's recommended levels of gas

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[146] Ex. 42, Corrected and Updated Testimony, National Grid Gas Infrastructure and Operations Panel, p.5 and Exhibit GIOP-1CU (attached to testimony).

[147] Ex. 43, National Grid Gas Infrastructure and Operations Panel, Exhibit___(GIOP-1).

[148] Ex. 409, Direct Testimony of DPS Staff Net Plant and Gas Infrastructure and Operations Panel, pp. 9-10; Ex. 412, Exhibit__(SNPGIOP-3), pp. 1-3.

[149] Ex. 918, Corrected Joint Proposal, Appendix 1, Schedule 5.

capital expenditures reflect the cost of continuing various capital programs, such as LPP replacement, as well as the cost of capital projects needed for safety and reliability.

DPS Staff contends that the proposed capital expenditures strike an appropriate balance between meeting needs, workload manageability, and affordability. Further, DPS Staff asserts that the proposed electric capital expenditures are reasonable because they provide sufficient funding to maintain adequate, safe, and reliable service and to further policy initiatives while allowing the Company to concentrate on higher priority projects and moderating the overall rate impact relative to the Company's original proposal.[150]

DPS Staff contends that the gas investments reflect several continuing capital programs including LPP replacement and capital projects required for safety and reliability. Moreover, according to DPS Staff, these investments will decrease methane emissions from the gas system.[151]

National Grid asserts that investment levels proposed in the Joint Proposal are necessary to allow the continued provision of safe and reliable service, enhance system resiliency to weather events, and advance the State's clean energy goals. The Company also maintains that the proposed gas capital investment levels will allow the Company to provide safe and reliable service while investing to modernize the gas system, reduce methane emissions, and support the State's energy goals. National Grid asserts the proposed investments levels reflect a compromise of various parties' conflicting interests

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[150] DPS Staff Initial Statement, pp. 66-67.

[151] DPS Staff Initial Statement, pp. 82-83.

and moderate customer bill impacts relative to its original proposals.[152]

UIU opposes the proposed capital expenditure amounts reflected in the Joint Proposal noting that if expected CLCPA Phase 2 costs are included the capital investment figures, excluding removal costs, amount to: $1,467.9 million (FY25); $1,629.2 million (FY26); $1,912.7 million (FY27); $1,819.1 million (FY28); with a four-year total of $6,828.9 million. UIU argues that these costs will ultimately be borne by customers and asserts that such high burdens are not sustainable. UIU recommends various levels of reduced investment including approving a single year of capital spending at FY25 levels or maintaining capital spending at FY25 levels for electric and requiring a 10% reduction to the proposed gas capital expenditures. UIU also suggests that a reduction of the capital expenditure levels to those proposed by DPS Staff in testimony, although still high, would be reasonable.

UIU also notes that the revenue requirement in the Joint Proposal excludes capital costs associated with the PL-16 project ($297.74 million) and the PL-E18 project ($348.3 million) and instead proposes a surcharge mechanism to collect those costs from ratepayers if the projects are placed into service. UIU objects to these capital costs as constituting an additional, unfair burden on ratepayers.[153]

In its reply statement, DPS Staff argues that UIU's proposed capital investment levels are arbitrary because UIU does not identify any specific projects as unnecessary and claims that the Company has sufficiently justified that projects and programs included in the Joint Proposal as necessary to

[152] National Grid Initial Statement, pp. 46, 56.

[153] UIU Initial Statement, pp. 9-11.

provide safe and reliable service. DPS Staff further argues that removing the PL-16 and PL-E18 projects from rate base is a benefit to ratepayers. DPS Staff notes that if these projects are determined to be necessary to provide safe and reliable service, cost recovery must come from ratepayers either through base rates or a surcharge. According to DPS Staff, shifting these projects outside of base rates provides an opportunity for the Company to develop and implement alternative, less costly solutions and, therefore, these provisions of the Joint Proposal are reasonable.[154]

Also in reply, the Company claims that the level of electric and gas capital expenditures included in the Joint Proposal is the level required to provide safe and reliable service and serve new and expanding customers. National Grid further argues that the expenditures are also required to support the energy future envisioned under the CLCPA, and to enable a diversifying energy marketplace. The Company states that, through negotiations, it agreed to reduced capital expenditure levels that achieved consensus without eliminating essential investments, and UIU has provided no factual basis for its proposed reductions. The Company also notes that it is committed to making all reasonable efforts to avoid the need for the projects.[155]

We recognize that the levels of capital investment in the Joint Proposal are a significant driver in the overall rate increases approved here. However, the need to replace aging infrastructure to ensure safe and reliable service cannot be avoided. There is also an irrefutable need to modernize and strengthen the energy system to maintain reliability, improve

[154] DPS Staff Reply, pp. 12-13.

[155] National Grid Reply, pp. 12-13.

resiliency, and meet the State's environmental and social justice policy requirements. An expectation of increasingly sporadic and extreme weather events only adds to the urgency. Further, the proposed levels represent a reasonable compromise amongst competing interests and will moderate the rate impacts relative to the investment forecast first proposed by the Company.

1. PL-16 Pipeline Integrity Verification Project

PL-16 is a 41-mile pipeline in the Company's service territory, of which a 7.54-mile portion may need to be replaced based on the results of the Company's most recent class locations study. A new pressure-tested 24-inch pipe meeting the current class location testing requirements would replace the existing pipe. In its initial testimony, National Grid proposed the PL-16 replacement project with a forecast capital cost of $297.4 million. National Grid also filed a petition in Case 24-G-0183 requesting the Commission approve risk control activities that would avoid the need to replace the section of the pipeline at issue.[156] DPS Staff disagreed with the need for the project and recommended that the project costs be removed in these rate proceedings and considered in Case 24-G-0183.[157]

Capital expenditures related to the PL-16 replacement project are not included in the proposed revenue requirement. However, the Joint Proposal does provide for the establishment of a PRP Surcharge to recover the revenue requirement associated with up to $297.4 million of capital costs related to the

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[156] Petition of Niagara Mohawk Power Corporation d/b/a National Grid for a Waiver of the Requirements of 16 NYCRR, Section 255.611(a) and 255.611(d) to Permit the Company to Be Exempt from Certain Class Location Requirements Related to Pipeline 16 and Extend the 18-month Period Until 2026.

[157] Ex. 475, Direct Testimony of DPS Staff Pipeline Safety Panel, pp. 68-72.

project during the term of the rate plan, if such replacements are determined to be needed and placed into service. The Company also forecasts that it will incur costs for the PL-16 replacement project beyond the term of the rate plan. The Joint Proposal requires the Company to take reasonable efforts to minimize capital expenditures associated with the project. If the PL-16 replacement project is not required, the Company is authorized to include preliminary engineering and development costs for the project up to $1 million in the PRP Surcharge.[158]

2. PL-E18 Pipeline Integrity Verification Project

In testimony, the Company proposed the PL-E18 project, which involves the possible replacement of approximately ten miles of 16-inch transmission pipeline to comply with pipeline safety requirements established in 2019 by the Pipeline and Hazardous Materials Safety Administration (PHMSA). The forecasted capital expenditures associated with the PL-E18 project total approximately $348.3 million from FY25 through FY29.[159] DPS Staff recommended that the Company analyze alternatives to replacement.[160]

Like the proposed PL-16 project, capital expenditures related to the PL-E18 project are not included in the proposed revenue requirement but if the project is required by PHMSA, the Company may use the PRP surcharge to recover the revenue requirement associated with up to $348.3 million of capital costs for the project during the term of the rate plan. Project costs will also be incurred beyond the term of the rate plan.

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[158] Ex. 918, Corrected Joint Proposal, pp. 49-50.

[159] Ex. 42, Direct Testimony of National Grid Gas Infrastructure and Operations Panel, p. 53.

[160] Ex. 475, Direct Testimony of DPS Staff Pipeline Safety Panel, pp. 67-68.

In determining the need for the PL-E18 project during the term of the rate plan, the Company is required to re-evaluate all methods, other than replacement, for complying with PHMSA's Maximum Allowed Operating Pressure standard and must report the findings of the re-evaluation each year. If the PL-E18 project is needed the Company must undertake reasonable efforts to minimize related capital expenditures. If it is not needed, the Company is authorized to recover preliminary engineering and development costs of up to $5 million through the PRP surcharge.[161]

UIU objects to the capital costs associated with both pipeline projects and the creation of a surcharge mechanism to collect the costs. UIU argues that approving the Projects will shift additional cost and risk onto ratepayers.[162]

DPS Staff asserts that removal of the costs from rate base and recovery through the PRP surcharge protects customers from unnecessary investments while permitting timely recovery by the Company if the projects are deemed necessary.[163] National Grid contends that the approach to the pipeline projects represents a reasonable compromise amongst the Parties' positions that allows them to pursue alternatives to the pipelines while keeping the Company whole for necessary investments.[164]

We agree with the Signatory Parties regarding the Joint Proposal's proposed approach to the PL-16 and PL-E18 pipeline projects. UIU's argument seems to ignore that the Company is entitled to recover prudently incurred costs

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[161] Ex. 918, Corrected Joint Proposal, pp. 50-52.

[162] UIU Initial Statement, p. 11.

[163] DPS Staff Initial Statement, p. 85.

[164] National Grid Initial Statement, pp. 56-59.

associated with these projects if it is determined that either of them is needed. Moreover, the surcharge approach appropriately allows the Company to fully explore less costly alternatives and to make all reasonable efforts to minimize costs associated with the projects.

### I. Electric Infrastructure and Operations Program

#### 1. Vegetation Management

The Joint Proposal's electric revenue requirements reflect costs for distribution and transmission vegetation management of $87.387 million for RY1, $89.902 million for RY2, and $91.857 million for RY3. The Company's total vegetation management costs over the term of the rate plan remain subject to a downward-only reconciliation mechanism. An under-expenditure in any rate year will carry forward and be reconciled at the end of the three-year term. The Joint Proposal also replaces the Emerald Ash Borer mitigation program with a broader Hazard Tree Removal Program, which will allow the Company to address various emergent tree health issues impacting multiple species. The Company will report on its Vegetation Management and Hazard Tree Removal Program quarterly.[165]

#### 2. Major Storms

The definition of a Major Storm, which will be used for deferral purposes, is set forth in 16 NYCRR §97.1(c).[166] The rate allowance reflected in the revenue requirement for Major Storm is $78 million for each rate year. The Joint Proposal recommends that the difference between the rate allowance and

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[165] Ex. 918, Corrected Joint Proposal, pp. 39-40.

[166] A major storm is a period of adverse weather during which service interruptions affect at least 10 percent of the customers in an operating area and/or result in customers being without electric service for durations of at least 24 hours.

actual costs be deferred for future refund to or recovery from customers, subject to a deferral threshold of $0.750 million applied to all qualifying regions, in aggregate, within the Company's service territory for each Major Storm. The Company will be allowed to recover deferred major storm costs through the RAM if the Major Storm conditions are met.[167]

3. Minor Storms and Silver Lining Storms

The Joint Proposal reflects a minor storm rate allowance of $80.3 million in RY1, $85.7 million in RY2, and $87.6 million in RY3. It also provides that in RY1, if the Company incurs less than the allowed amount for minor storm costs, the difference will be deferred for return to customers; if actual minor storm costs are greater than the rate allowance but less than or equal to $90.3 million, no reconciliation will occur ($10 million upward deadband); and if actual minor storm costs in RY1 exceed $90.3 million, the Company will defer 90 percent of the amount exceeding $90.3 million (90/10 customer/Company sharing of costs above the deadband).

The Joint Proposal recommends a new sub-category of minor storm, referred to as Silver Lining Storms. A Silver Lining Storm is defined as a storm that, but for the Company's storm hardening and restoration initiatives, would have been classified as a major storm but did not meet the outage time threshold of a major storm due to those initiatives. The Joint Proposal provides for deferral of Silver Lining Storm costs to recognize the Company's efforts related to storm hardening and improving restoration times.

The Joint Proposal does not provide specific parameters defining a Silver Lining Storm. Specifically, the duration of interruptions, percentage of customers impacted, and

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[167] Ex. 918, Corrected Joint Proposal, p. 40.

the associated costs are currently indeterminate. To that end, prior to the start of RY1, the Company will update its accounting procedures to track and report any storm event that may be categorized as a Silver Lining Storm and within 45 days after the end of RY1, the Company and DPS Staff will work collaboratively to define a Silver Lining Storm. If the collaborative process is successful, commencing in RY2 the minor storm rate allowance will be allocated between a Silver Lining Storm Expense and an All Other Minor Storm Expense based on the data tracked during RY1. The rate allowances for Silver Lining Storm Expense and All Other Minor Storm Expense will be updated for RY3 based on actual storm expenditures incurred in RY1 and RY2 as outlined in Appendix 13 of the Joint Proposal. The Silver Lining Storm Expense will be subject to a two-way reconciliation, such that, if actual expenses are less than the rate allowance the Company will defer the difference for the benefit of customers. Conversely, if the actual expenses are more than the rate allowance the Company will defer the difference for future recovery from customers. The deferral mechanism is subject to certain parameters more fully delineated in Appendix 13 of the Joint Proposal. Only costs resulting from minor storms ultimately defined as Silver Lining Storms will be subject to deferral. The Joint Proposal provides that if the Company and DPS Staff are unable to develop and agree upon Silver Lining Storm parameters, minor storm rate allowances will remain at $85.7 million for RY2 and $87.6 million for RY3, with no deferral treatment for expenditures in excess of the rate allowance.[168]

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[168] Id., Appendix 13.

4. Pre-Staging Storm Costs

The Joint Proposal recommends that the Company be allowed to charge the major storm reserve for pre-staging and mobilization costs incurred in reasonably anticipating that a storm will affect its electric operations to the degree required for designation as a major storm, but which ultimately only has minor storm impacts. More specifically, if pre-staging costs in preparation for a storm exceed $0.250 million then all the incremental costs up to $1.5 million will be charged to the major storm reserve. For incremental costs in excess of $1.5 million the Company will be allowed to charge 85% of the incremental costs to the major storm reserve with the remainder of the costs being charged to the minor storm expense. Further, the Joint Proposal provides details for which type of pre-staging costs can be charged as major storm expenses.[169]

5. Non-Wires Alternatives

The Joint Proposal provides for continuing the ten-year amortization of all non-wire alternative (NWA) projects, as well as the existing NWA incentive and cost recovery mechanisms. The NWA incentive mechanism is fully described in Appendix 10.[170]

6. Distributed Energy Resources (DER)

The Joint Proposal recommends the adoption of two new programs intended to facilitate the interconnection of distributed energy projects with the Company's electric distribution system. The Self-Performance of Distribution Upgrades program will allow DER interconnection customers to self-perform elements of distribution upgrades required to interconnect their project, including engineering, procurement, and construction. Self-performed distribution upgrades must

[169] Id., pp. 42-43.

[170] Id., pp. 45-46 and Appendix 10.

meet or exceed the Company's technical standards, contractor requirements, and prevailing wage requirements. Any costs associated with implementing the Self-Performance of Distribution Upgrades program will be borne by participating interconnection customers. The Company will present an implementation plan for the self-performance program to the Interconnection Policy Working Group and Interconnection Technical Working Group for stakeholder discussion and DPS Staff input. Within six months of the issuance of this Order, the Company must file the implementation documents with the Secretary and the program will begin during RY1.

The Joint Proposal also provides that the Company will evaluate automatic tripping and other smart grid solutions for N-1 contingency scenarios to identify solutions eligible for use on its electric power system within six months of the issuance of this order. If such solutions can be implemented to lower substation costs related to hosting DER, the Company will notify DER interconnection customers with active queue positions that are not already in construction, who may be eligible for lower cost interconnections. The Company will conduct a new Coordinated Electric System Interconnection Review (CESIR) for developers who request and fund the new review and agree to fund the smart grid solution. The Company will adjust the amount of developers' interconnection deposit reflecting the lower cost solution. Following the six-month period, the Company will integrate eligible smart grid solutions into its consideration of upgrades when conducting CESIR studies. The Company will also update its online hosting capacity maps to indicate where such smart grid solutions may be appropriate.

7. Battery Storage

Included in the Joint Proposal's electric and common capital investment forecast are battery storage projects that will support the Company's distribution system. The Company is prohibited from selling or bidding these projects into the wholesale electric markets during the term of the rate plan. The Company must petition the Commission in the Energy Storage Proceeding[171] if it plans to bid the projects into the wholesale electric market following the rate plan term.

## J. Gas Infrastructure and Operations Programs

### 1. East Gate Reliability Assessment

The Company originally proposed an East Gate Reliability Assessment as a capital project intended to analyze demand-side management options in the East Gate supply region.[172] DPS Staff objected to the assessment as a capital project and recommended that the analysis should be conducted as part of the Company's long-term gas plan in Case 24-G-0248.[173] The Joint Proposal does not include costs related to any East Gate Reliability Assessment. However, it does permit the Company to defer up to $7.7 million of costs associated with the assessment if the Commission directs the Company to perform it in another proceeding.[174]

### 2. Energy Transfer Station Site 2 and Moreau Injection Facility Compressed Natural Gas/Renewable Natural Gas Injection

The Joint Proposal prohibits National Grid from recovering from customers any costs for the Renewable Natural Gas (RNG) injection facilities planned for the Company's Energy

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[171] Case 18-E-0130, Energy Storage Deployment Program.

[172] Ex. 41, National Grid Direct Testimony of Gas Infrastructure and Operations Panel; Ex. 45, Exhibit __ (GIOP-3) at p. 34-37.

[173] Ex. 470, Direct Testimony of DPS Staff Gas Reliability and Supply Panel at 18-21.

[174] Ex. 918, Joint Proposal, pp. 52-53.

Transfer Station (ETS) Site 2 during the term of the rate plan. The Company may assess fees from RNG suppliers wishing to inject into the Company's ETS facility. The Company will use any fees paid by RNG supplies to offset the RNG capital investment at the Moreau Injection Facility and may retain for the benefit of shareholders fees collected above the Moreau-related costs reflected in the revenue requirement. RNG injection fees, above the Moreau-related costs, will be accounted for on a "below-the-line" basis for ratemaking purposes in future rate proceedings. Any RNG interconnections shall be paid for by RNG suppliers unless otherwise directed by the Commission. The Joint Proposal also prohibits the Company from locating the ETS Site 2 within one mile of a disadvantaged community (DAC).

3. Residential Methane Detectors

The Joint Proposal provides for the Company to recover costs associated with the installation of 4,000 Residential Methane Detectors (RMDs) in RY1, 12,000 in RY2, and 24,000 in RY3. In RY1, the Company will use existing deferred negative revenue adjustment (NRA) credit balances, except for the NRA credit balance resulting from the Commission's December 20, 2024 Order in Case 24-G-0592,[175] to fund the cost of the RMD installations. The revenue requirements include costs associated with the RY2 and RY3 RMD installations.

4. Damage Prevention Costs

Similar to RMD installations, the Company will utilize existing NRA balances to offset its damage prevention costs in RY1. Damage Prevention Costs in RY2 and RY3 are included in the revenue requirements.[176]

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[175] Matter of a Natural Gas Incident at 532 W. Elm St. Oneida NY on September 9, 2023, in the Service Territory of Niagara Mohawk Power Corporation, d/b/a National Grid.

[176] Ex. 918, Corrected Joint Proposal, pp. 52-56.

## K. Gas Matters

### 1. Gas Customer Choice

The Company's Customer Choice Program provides customers the option to purchase their supplies from Marketers (also known as ESCOs). There are two service options, Daily and Monthly Balancing. Monthly Balancing customers are considered core customers in that the Company procures capacity to serve them. Daily Balancing customers are considered non-core customers and the Company does not procure any capacity on their behalf.[177] The Joint Proposal contains several provisions related to the Company's Customer Choice Program including: a new daily balanced pool alert; daily imbalance cash-out changes; changes regarding D-1 customers;[178] and changes regarding Primary Point Capacity (PPC) requirements.[179] NRG opposes the provision related to PPC. The other provisions are uncontested.

### 2. Primary Point Capacity – Daily Balanced Customers

Daily Balanced Customers are large commercial and industrial customers that receive firm, non-core transportation service from the Company and are subject to daily balancing. According to the Joint Proposal, most Daily Balanced Customers, or the Marketers supplying them, have contracted with upstream interstate natural gas pipelines for firm natural gas transportation capacity that provides PPC to the Company's city gate delivery points sufficient to serve the customer's Maximum Peak Day Quantities (MPDQ). A customer's MPDQ is the Company's

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177 Ex. 81, Direct Testimony of National Grid Gas Supply Panel, p. 34.

178 The Company provides some non-core, firm Daily Balanced Customers with the ability to make D-1 elections that require the Company to purchase gas supplies to serve a portion of the Customer's anticipated usage on certain days.

179 Ex. 918, Corrected Joint Proposal, pp. 112-121.

forecast of the maximum amount of gas that the customer will consume on a "design day," or the coldest day that Company designs its system to serve.

Some Marketers/Direct Customers[180] have not contracted for PPC to serve daily balanced firm loads and rely on secondary firm capacity which has a lower curtailment priority on the interstate pipeline system.

In its initial testimony the Company proposed to require each new firm, non-core Daily Balanced Customer to prove that it, or a Marketer acting as its supplier, has contracted enough firm PPC to meet its MPDQ and to require Marketers/Direct Customers to cure any PPC shortfalls in existing pools before serving any new firm, non-core Daily Balanced Customers.[181] NRG challenged the requirement to cure existing shortfalls, arguing it would prevent any Marketer from taking on new customers until full PPC is secured for all existing customers including customers not previously subject to a full PPC requirement under the Company's previous rate plan.[182] NRG argued the Company's concerns regarding pipeline capacity are unfounded and that the proposed restrictions contradicted Commission precedent.[183] In rebuttal testimony, the Company disagreed with NRG's assumptions

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[180] As relevant here, a Marketer is an entity that sells natural gas to National Grid's transportation customers and schedules delivery of gas to National Grid's city gates on those customers' behalf. A Direct Customer is a customer that purchases and schedules delivery of natural gas to the Company's city gate for its own consumption from one or more supplier and not for resale.

[181] Ex. 81, Direct Testimony of National Grid Gas Supply Panel Direct Testimony, pp. 7-8.

[182] Ex. 768, Direct Testimony of NRG, p. 7.

[183] Id., pp. 11-13.

and conclusions regarding possible future easing of restraints on the Company's system.

The Joint Proposal recognizes that the available quantity of PPC is less than the forecast MPDQs of the Company's existing Daily Balanced Customers and contains several provisions intended to manage this limitation. The Joint Proposal requires Marketers/Direct Customers to maintain current levels of PPC for Existing Daily Balanced Customers and to participate in the Company's annual verification of PPC. The Joint Proposal further provides that if PPC becomes available at Company's city gates (East or West) and the Company's distribution system has capacity to utilize the PPC, then annually by September 1, the Company will notify Marketers/Direct Customers lacking sufficient PPC of its availability. Then Marketers/Direct Customers may contract for such PPC to reduce their shortfall as of November 1. If that does not occur by the end of October, the Company will contract for the available PPC and release it to the deficient Marketers/Direct Customers proportionately to their existing PPC shortfall at the appropriate city gate. Capacity will be released for a one-year period each year ahead of the winter heating season at the rates paid by the Company. These procedures would commence by September 2025.

Relatedly, the Joint Proposal includes a process for Marketers/Direct Customers to provide the Company with an annual Adjusted MPDQ for customers in the Marketer's pool or for the Direct Customer. The Adjusted MPDQ will only be considered in the Company's annual PPC verification, and when a Daily Balanced Pool Alert (described below) is in effect and the customers' usage must be limited to the Adjusted MPDQ. Adjusted MPDQs will be effective for one-year and must be contractually confirmed annually with the Company by both the Marketer and the customer.

If a customer switches Marketer pools during the annual period, the Adjusted MPDQ will follow the customer in the instance of a Daily Balanced Pool Alert. The Joint Proposal provides for a penalty for unauthorized usage during a Daily Balanced Pool Alert equal to $50 per dekatherm (dth) plus the Incremental Cost of Gas for usage exceeding Adjusted MPDQ plus any authorized imbalance tolerance.[184]

For existing Non-PPC Daily Balanced Customers that transfer all or substantially all of their facilities located on the Company's distribution system to another entity that is expected to utilize gas service in the same manner, at the same delivery point, and at the same forecasted MPDQ, the acquiring entity, referred to as a Replacement Non-PPC Daily Balanced Customer, will be treated as an Existing Daily Balanced Customer and included in the Customer's Marketer's Pool Curtailment Plan.[185]

For all new Daily Balanced Customers, not considered Replacement Non-PPC Daily Balanced Customers, the Joint Proposal requires the acquisition of sufficient PPC to meet the MPDQ or the Adjusted MPDQ of the new Daily Balanced Customer. This obligation does not increase the amount of PPC required for Marketers to serve any other customers. The Joint Proposal provides that a contract for firm PPC during at least the five winter months (November – March) with a Right of First Refusal is sufficient to demonstrate the PPC requirement.

3. Daily Balanced Pool Alert

The Joint Proposal limits the issuance of Daily Balanced Pool Alerts to Daily Balanced Customers to only while a Company-issued Operational Flow Order (OFO) is in place or other

[184] Ex. 918, Corrected Joint Proposal, pp. 114-116.

[185] Id., pp. 115.

emergency conditions where the Company can demonstrate that a shortfall in deliveries by a Marketer/Direct Customer will threaten the operational reliability of the gas system. During a Balanced Pool Alert, the Company may direct curtailment according to the Marketer's Pool Curtailment Plan after confirming the Marketer/Direct Customer's nominations are inadequate to meet the relevant MPDQ or Adjusted MPDQ, but only to the extent reasonably necessary to ensure reliable operation of the gas system. The Joint Proposal provides specific Daily Balanced Pool Alert curtailment criteria to which the Company must adhere.[186] No party objects to the Daily Balanced Pool Alert provisions.

[186] Id., pp. 116-118.

4. Daily Imbalance Cash-out Changes

The Joint Proposal includes changes to the Company's Daily Imbalance cash-out. Beginning in November 2026, following implementation of the Company's new Customer Choice IT system, the East Gate cashout mechanism will include prices of gas purchased on the Tennessee pipeline system in the winter and the West Gate mechanism will include prices of gas purchased on the IGTS pipeline system in the winter. A winter and summer cashout will take place for each gate.[187] No party objects to these changes.

5. D-1 Nominations

The Company provides certain non-core, firm Daily Balanced Customers with the ability to make D-1 elections that require the Company to purchase gas supplies to serve a portion of the Customer's anticipated usage on specific days. To exercise D-1 rights the Customer with such rights or its authorized agent (Customer's Marketer) must place a pipeline nomination with the Company, not to exceed its D-1 Election, to purchase Standby Sales Service gas supplies.

Pursuant to the Joint Proposal, the Company must assess violations for Customers whose D-1 nominations exceed their usage plus five percent tolerance level. The Company will bill Marketers/Direct Customers for the D-1 nomination exceeding the tolerance level at the incremental cost of gas rate plus $5 per dth.

The Joint Proposal also provides for transfer of an Existing D-1 Customer's D-1 Election to an entity who effectively acquires all this D-1 Customer's facilities and expects to utilize them in the same manner and at the same delivery point and forecast MPDQ. Such an acquiring entity will

[187] Id., pp. 118-119.

be considered a Replacement D-1 Customer. National Grid will not grant a new D-1 election to a new customer, and Existing D-1 Customers are not allowed to transfer any of their D-1 election to other customers.[188] No party opposes the Joint Proposal's provisions relating to D-1 customers.

MI argues that Joint Proposal strikes a reasonable balance to address reliability concerns while considering the interests of customers and Marketers. MI supports the Gas Marketing provisions because, in its view, the Joint Proposal: does not modify the PPC obligations for existing customers and requires Existing Daily Balanced Customers to maintain current levels of PPC; allows facility transfers to new owners without incurring an incremental PPC obligation provided similar usage following transfer of ownership; and allows a D-1 election to be transferred with a facility to a new owner, provided that there will be no change in gas usage and certain other criteria are satisfied.[189]

NRG continues to challenge the Joint Proposal provision requiring Marketers/Direct Customers to either contract for available PPC or accept it as released from the Company to reduce the portion of their MPDQ or adjusted MPDQ lacking PPC. NRG argues that the required allocation of available PPC represents a new requirement that conflicts with established Commission policy and will lead to higher energy supply costs, undermining customers' competitive positions.[190] NRG points to the lack of any historical curtailment or interruption events and National Grid's reduced forecast of annual deliveries as evidence that existing capacity

[188] Id., pp. 120-121.

[189] MI Initial Statement, p. 19.

[190] NRG Initial Statement, pp. 3-6.

requirements including the flexibility for Marketers/Direct Customers to rely on secondary pipeline capacity do not negatively impact reliability.[191]

In its initial statement the Company recognized that the Commission has not previously required Daily Balanced Customers to maintain PPC and permitted reliance on secondary firm capacity but defended the PPC provisions in the Joint Proposal as necessary under current capacity conditions. Specifically, the Company states that the collective MPDQs of its Daily Balanced Customers load represents a significant portion of the Company's total forecast design day load requirements and a significant portion of the Company's Daily Balanced firm load is not served by PPC but rather relies on secondary firm capacity. National Grid notes that secondary firm capacity has been reliable in the past but argues that it is possible for pipeline operators to implement delivery limitations under certain conditions.

National Grid states that conditions regarding upstream capacity availability have become more constrained since the Commission originally exempted Daily Balanced Customers from PPC requirements. National Grid also notes several extreme weather events in the last 15 years as indicative that design day weather conditions are not uncommon. The Company argues that the Gas Customer Choice provisions of the Joint Proposal taken together are intended to enhance reliability while recognizing limitations concerning available PPC and providing Marketers/Direct Customers the opportunity to adjust their MPDQs and PPC requirements and to transfer their businesses even absent sufficient PPC to meet their MPDQs.[192]

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[191] Id., pp. 6-9.

[192] National Grid Initial Statement, pp. 102-109.

DPS Staff contends that Gas Customer Choice provisions provide that Daily Balanced customers without PPC will be appropriately curtailed to better safeguard gas delivery on peak days to both core gas customers and transportation customers that pay for PPC. DPS Staff further contends that these provisions provide for proper coordination between Marketers/Direct Customers' needs and the Company's gas supply planning. DPS Staff concludes that the provisions will benefit reliability and customers and should be approved.

In its reply statement, NRG continues to argue that the Company has failed to establish a reliability need justifying the imposition of additional PPC requirements on existing customers. NRG also rejects MI's contention that the JP does not modify PPC requirements for existing customers.[193]

In its reply statement, National Grid rejects NRG's arguments as self-serving and unpersuasive. National Grid argues that the PPC requirement fairly balances the interests of all its customers including the Daily Balanced Customer served by PPC. The Company also rejects NRG's arguments that a reduction in forecast deliveries equates to reduced design day requirements which it notes are projected to increase during the rate plan.[194]

In reply, DPS Staff contends that NRG's reliance on previous Commission orders is misplaced because the referenced orders address different types of customers and different PPC requirements than those at issue here. DPS Staff further notes that the risk assumed by customers relying on secondary firm capacity is shared with other customers because pressure losses on the system would impact service to core customers and other

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[193] NRG Reply.

[194] National Grid Reply, pp. 20-22.

firm customers who contracted for PPC. DPS Staff concludes that the Joint Proposal appropriately balances the needs of the gas system and its customers without putting an undue burden on Daily Balanced Customers not currently served by PPC.[195]

We note the reliability risk created by customers that are served under a firm service classification and do not have PPC, but continue to take gas from the utility when their contracted-for supplies are unavailable. As the Company points out, although the Daily Balance Pool Alert will aid in reliable operation of the gas system, curtailment is not a precise or ideal mechanism for addressing constraints. There is no mechanism to shut off customers at their location on design days or similar emergency situations, which forces the Company to rely on customer behavior to curtail usage. A firm service classification’s service should require PPC to appropriately reduce the reliability risk borne by other firm customers, and we agree with the Company and DPS Staff that the approach taken in the Joint Proposal moves in that direction, is reasonable and in the public interest.

We also recognize that this reliability risk itself is not new, and the Commission has refrained from imposing PPC requirements on Daily Balanced Customers in the past. However, the Commission previously approved full PPC requirements for new Daily Balanced Customers and directed the Company to investigate and report on the status of PPC for existing customers, to move toward correcting the problem and reducing the reliability risk in the future.[196] Given the current conditions of continuing demand growth and tight upstream capacity markets, steady movement toward reducing the reliability risk is appropriate,

[195] DPS Reply, pp. 13-17.

[196] 2022 Rate Order, pp. 121-122.

and we believe the incremental PPC requirements contained in the Joint Proposal strike a reasonable balance and move toward improving the PPC situation. Contrary to NRG’s argument, we do not see approval of these provisions as a reversal of policy but rather a continuation of our policy to remain flexible while recognizing changing conditions for various factors impacting capacity availability and system reliability.

Moreover, the approach taken in the Joint Proposal is measured and provides flexibility for existing customers. First, the requirement to contract for or accept PPC from the Company is limited to available PPC and is only in proportion to the Marketer/Direct Customer’s shortfall. Further, the requirement can be met by contracting for PPC for the five winter months (with a Right of First Refusal). The Joint Proposal also provides the flexibility for Marketers/Direct Customers to work with the Company to lower their MPDQs thereby reducing their required PPC, and Marketers are not prevented from serving new customers prior to eliminating any PPC deficiencies. Finally, the Joint Proposal allows customers to transfer their businesses under certain circumstances even if they lack sufficient PPC. Together the Gas Customer Choice provisions in the Joint Proposal result in a proper balance between market flexibility and ensuring reliable service.

## L. Gas Safety Performance Metrics

Pursuant to the Joint Proposal, the Company’s gas safety performance will be measured for each calendar year against a set of metrics described below. A total of 150 pre-tax basis points of return on common equity will be at risk per calendar year. NRAs from the Company will be deferred for future disposition by the Commission. The Gas Safety Performance Metrics will remain in effect for the term of the rate plan and will continue year-to-year, unless otherwise modified or discontinued by the Commission.[197]

1. Leak Prone Pipe (LPP)

National Grid originally proposed to decrease the LPP mileage removal targets established in the 2022 Rate Order over a new four-year rate plan. The Company proposed minimum targets of 27 miles of LPP replaced annually through 2028 and a four-year total of 128 miles by the end of 2028 and a budgeted target of 32 miles annually, or a four-year total of 128 miles by the end of 2028. The Company proposed continuation of the existing 15-basis points NRA for failing to meet the annual LPP minimum targets or the cumulative target. The Company also proposed eliminating the 10-basis point positive revenue adjustment (PRA) associated with LPP replacement.[198] DPS Staff recommended minimum LPP removal targets of 33 miles annually through 2028 or a four-year target of 152 miles by the end of 2028 and budgeted removal targets of 38 miles annually through 2028, or a cumulative target of 152 miles. Additionally, DPS Staff recommended continuing the 15-basis point NRA for each year the Company fails to meet the minimum target, and an additional 15-basis points NRA should it fail to replace a minimum cumulative total of 152 miles by 2028.[199]

The Joint Proposal includes annual minimum removal targets of 33 miles for CY 2025 and CY 2026, 31 miles in CY 2027, and a cumulative minimum target of 112 miles through 2027. Proposed budgeted annual removal targets are 38 miles for CY 2025 and CY 2026, 36 miles in CY 2027, and a cumulative target

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[197] Exhibit 918, Corrected Joint Proposal, pp. 83-86.

[198] Ex. 81, Direct Testimony of National Grid Gas Safety Panel, pp. 29-31.

[199] Ex. 475, Direct Testimony of DPS Staff Pipeline Safety Panel, pp. 18-19.

of 112 miles through 2027. The Joint Proposal recommends a 15-basis point NRA for each year the Company fails to achieve the minimum annual LPP removal target and an additional 15 basis points for failure to achieve the minimum cumulative target. The Company will continue to identify and rank segments of LPP based on risk and the use of leak data to prioritize removals.[200]

2. Leak Management

The Joint Proposal recommends reducing the total leak (Type 1, 2, 2A, and 3) backlog target by 75 leaks annually resulting in year-end targets of 375, 300, and 225 for Calendar Year (CY) 2025, CY 2026, and CY 2027, respectively. The Joint Proposal also recommends a workable leak (Type 1, 2, and 2A) end of year backlog of 25 or less for 2025 through 2027. The Company is subject to an annual NRA of 5 basis points for failing to meet the total leak backlog targets and an annual 10-basis point NRA for the workable leak backlog target. In addition, for every 50 additional leaks repaired beyond the total leaks target in a calendar year the Company will earn a positive revenue adjustment of 2 basis points, capped at 150 additional leak repairs or 6 basis points.[201] These recommendations are aligned with those made in testimony by DPS Staff[202] and the Company.[203]

3. Damage Prevention

Damage prevention refers to the Company's ability to minimize and prevent excavation damage to its gas system. National Grid originally proposed no changes to the current

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[200] Exhibit 918, Corrected Joint Proposal, pp. 83.

[201] Id.

[202] Ex. 475, Direct Testimony of DPS Staff Pipeline Safety Panel, pp. 25-27.

[203] Ex. 81, Direct Testimony of Niagara Mohawk Safety Panel, pp. 31-33.

damage prevention metric targets.[204] The Joint Proposal recommends more stringent targets than the existing ones but less stringent than those first proposed by DPS Staff. The Joint Proposal also recommends maintaining the current NRAs and PRAs.[205]

4. Emergency Response

The Joint Proposal provides for continuation of the current targets and revenue adjustments related to the Company's emergency response. Instances of 20 or more odor calls in a two-hour period resulting from a mass area odor issue not caused by the Company will continue to be excluded from the metric.[206] The targets align with those applicable to other New York utilities and the recommendations of DPS Staff[207] and the Company.[208]

5. Gas Safety Regulations Performance Metrics

National Grid proposed continuing the current targets and NRAs associated with the Gas Safety Regulations Performance metric[209] and DPS Staff recommended more rigorous NRAs.[210] The Joint Proposal represents a compromise which lowers the threshold number of high-risk violations for imposing the highest NRA of 1 basis point per violation.[211]

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[204] Id., pp. 34-35.

[205] Ex. 918, Corrected Joint Proposal, pp. 84-85.

[206] Id., pp. 85-86.

[207] Ex. 475, Direct Testimony of DPS Staff Pipeline Safety Panel, p. 30.

[208] Ex. 81, Direct Testimony of Niagara Mohawk Gas Safety Panel, p. 33-34.

[209] Id., p. 34.

[210] Ex. 475, Direct Testimony of DPS Staff Pipeline Safety Panel, Direct Testimony, p. 48; Ex. 477, Exhibit__(SPSP-2).

[211] Exhibit 918, Corrected Joint Proposal, pp. 86-89.

The recommended safety targets appropriately recognize the importance of the various aspects of maintaining a safe and reliable system and are in the public interest. The increasingly stringent targets will also drive improvements in the safety of the system. Further, the targets and revenue adjustments in the Joint Proposal consist of reasonable compromises between DPS Staff's and the Company's original proposals and are otherwise unopposed.

## M. Customer Programs

There are several beneficial customer-related provisions in the Joint Proposal, including: financial assistance programs; a shareholder funded weatherization, health and safety program; extreme weather protections; and special protection programs related to Life Support Equipment, Elderly/Blind/Disabled or Medical Equipment designations. Various requirements associated with mandatory Company outreach, education, and communications activities are also enhanced by the Joint Proposal. We highlight a number of such provisions below, as well as any opposition pertinent thereto.

### 1. Energy Affordability Program

In 2016, the Commission directed utilities to establish a statewide monthly bill discount program (EAP) for low-income customers that would assist these customers in achieving a six percent energy burden, meaning that no more than six percent of their income would be dedicated to their utility bill.[212] While National Grid provides a fixed monthly bill credit to the approximately 163,000 customers enrolled in its

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[212] Case 14-M-0565, Energy Affordability Proceeding, Order Adopting Low Income Program Modifications and Directing Utility Filings (issued May 20, 2016), p. 3.

EAP,[213] an estimated 286,000 additional low-income customers in its service territory may be eligible but are not enrolled.[214] Many such customers reside in DACs.[215]

In acknowledgement of the foregoing, the direct and rebuttal testimonies of National Grid, DPS Staff, PULP, and AGREE included various proposals for increasing enrollment in the Company's EAP, or otherwise reducing the energy burden of eligible low-income customers. In particular (among other things), AGREE recommended that National Grid create a Percentage of Income Payment Plan for select DACs, pursuant to which no participating customers would spend more than six percent of their gross income on total energy bills.[216] Alternatively, AGREE proposed that the Company establish an expanded low-income bill discount program that would provide a new bill credit to EAP participants who reside in certain DACs – e.g., those where the average energy burden has been identified as excessive.[217]

PULP suggested that the Company could identify unenrolled low-income customers by cross referencing certain census tract data with information used by the Climate Justice Working Group,[218] and it recommended an additional customer service quality metric that would track EAP self-certifications

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[213] Ex. 18, Direct Testimony of National Grid Customer Panel, p. 30.

[214] Ex. 910, AGREE Statement in Support, exhibit 16.

[215] Ex. 596, Direct Testimony of AGREE Energy Burden Panel, p. 18.

[216] Id., pp. 20-21. AGREE estimated that this program would costs about $186 million per year (id., pp. 104-105).

[217] Id., p. 21. This additional bill credit was estimated to cost approximately $97.2 million annually (id., pp. 121-122).

[218] Ex. 773, Direct Testimony of PULP witness William Yates, p. 30.

and manual enrollments.[219] It is notable that the latter recommendation was intended to provide insight and did not contemplate associated positive or negative revenue adjustments.[220]

Both DPS Staff and the Company disagreed with AGREE's proposals, arguing that broad modifications to the EAP are more appropriately considered in the Energy Affordability Proceeding or by the EAP working group.[221] Although the Company also disagreed with PULP's proposal for an EAP self-certification and manual enrollment data metric,[222] the Joint Proposal requires that such information be tracked by National Grid on a monthly basis and referenced in its monthly EAP report.[223] Relatedly, the Joint Proposal sets EAP enrollment targets for each of the next three program years, aiming to increase the average number of residential customer enrollees by 4.5% over the average number enrolled during the prior program year.[224] The Company's "Annual Energy Affordability Program Report" will indicate

[219] Id., p. 31.

[220] Id.

[221] Ex. 327, Rebuttal Testimony of National Grid Customer Panel, p. 54; Ex. 519, Rebuttal Testimony of DPS Staff Consumer Services Panel, pp. 8-9; Case 14-M-0565, Energy Affordability Proceeding.

[222] Ex. 327, Rebuttal Testimony of National Grid Customer Panel, p. 49.

[223] Ex. 918, Corrected Joint Proposal, p. 92.

[224] Id., pp. 91-92. The three program years are December 1, 2024, through November 30, 2025, December 1, 2025, through November 30, 2026, and December 1, 2026, through November 30 2027, and the "baseline" against which the first program year will be measured is the average number of residential customers enrolled between December 1, 2023, and November 30, 2024 (id.).

whether it has achieved target goals,[225] and we agree with the Signatory Parties that both this report and the self-certification metric will enable interested parties to evaluate the Company's enrollment efforts and identify successful strategies for improvement.

The Joint Proposal also requires that National Grid continue to provide broad awareness of its EAP and other financial assistance programs to all customers in its service territory, as well as to actively seek more opportunities to conduct direct outreach and in-person promotional events regarding EAP, the Home Energy Affordability Program (HEAP), Emergency HEAP, Home & Warmth Energy Fund, Hearts Fighting Hunger, and Care & Share.[226] With respect to 20 specific DACs identified by the Climate Justice Working Group as having average home energy burdens higher than 80% of New York State's census tracts – and also identified by AGREE as having EAP enrollment rates of less than 25% of potentially eligible customers - the Company commits to conducting in-person outreach events in each DAC at least once per year of the rate plan, so that each DAC receives at least three in-person outreach events.[227] Similarly, for those 106 DACs referenced in Appendix 17 to the Joint Proposal, National Grid will perform incremental direct outreach to customers whose utility service has been terminated for non-payment but not sent to collections, and to

[225] Id., p. 92.

[226] Id., p. 90.

[227] Id. Where appropriate, the Company will obtain authorization from Native American or indigenous communities before hosting an event in such communities.

customers who are eligible for field action.[228] To the maximum extent possible, the Company will also conduct incremental direct outreach to customers in these DACs who have unresolved arrears or whose account histories reflect difficulty paying their utility bills.[229]

While PULP commends the Signatory Parties "for shedding increased light on the current under[-]enrollment of the EAP and attempting to address it" with the enhanced outreach activities described above, it nonetheless maintains that more ambitious annual EAP targets and "consequences" for failing to achieve such targets are warranted. We disagree and concur with the Signatory Parties that the Joint Proposal's enhanced outreach measures and increased annual EAP enrollment goals reflect thoughtful, targeted efforts for improving the Company's EAP. Moreover, these provisions are supported by and consistent with evidence in the record, and they accordingly fall within the range of possible litigated outcomes. We accordingly adopt them.

2. Education and Outreach to Commercial and Industrial Customers

The Joint Proposal requires that National Grid develop outreach and training materials for its Strategic Account Managers (SAMs) so they can educate industrial and commercial customers about incentives and benefits available through the

[228] Id., p. 91. These DACs were likewise identified by the Climate Justice Working Group as having an average energy burden greater than 80% of New York State's census tracts, but by AGREE as having estimated EAP enrollment rates of less than 50% of potentially eligible customers. Field action involves an in-person visit to a customer who has received a final shut-off notice and may result in payment, a deferred payment agreement to avert a shutoff, or an actual shutoff.

[229] Id.

Company's energy efficiency, electric vehicles, demand response and non-pipe alternative (NPA) programs, including information related to potential tax credits for which the customers may be eligible and different energy options for the customers' premises.[230] This provision was proposed by AGREE, which argues that SAMs are in the best position to identify which of the Company's customers would benefit from industrial electrification and whether there are any specific barriers to implementation of industrial-scale heat pumps.[231] We find it reasonable to provide commercial and industrial customers with energy efficiency-related information and adopt the provision.

3. Extreme Weather Protections

The Joint Proposal requires the Company to implement several cold weather protections during the "Cold Weather Period," which is the period between November 1 and April 15.[232] More specifically, National Grid will accept all HEAP payments and suspend field collections for customers that receive a HEAP payment regardless of the amount due or the customers' payment status.[233] The Company will also offer deferred payment agreements (DPAs) to customers where a HEAP payment is received regardless of whether the customer has previously defaulted on a DPA.[234] Further, the Company will not terminate residential gas customers on days when the forecast predicts temperatures below 32 degrees Fahrenheit or when the forecast high, with the wind chill, is lower than 32 degrees Fahrenheit for two or more

[230] Id., p. 92.

[231] Ex. 658, AGREE Direct Testimony of Jessica Azulay, pp. 124-125.

[232] Ex. 918, Corrected Joint Proposal, p. 93.

[233] Id.

[234] Id.

consecutive days.[235] Nor will the Company terminate service to residential accounts identified as elderly, blind, or disabled during the cold weather period.[236]

In addition to these cold weather protections, National Grid will suspend residential electric service terminations for nonpayment when the National Weather Service declares a "heat advisory" in any given region of the Company's service territory, 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 for one or more days. This provision is subject to any related action in Case 24-M-0586,[237] which the Commission instituted to establish uniform standards and procedures for extreme heat events.[238] While PULP urges that we modify the Joint Proposal by decreasing the extreme heat threshold to 90 degrees, we agree with the Signatory Parties that any modifications to this threshold are more appropriately made in the statewide Extreme Heat Proceeding.

4. Promotion of Special Protections

PULP recommended that National Grid increase the promotion and marketing of its special protection programs, such as Life Support Equipment, Elderly/Blind/Disabled, or Medical Equipment designations,[239] and the Joint Proposal requires that information about these programs be made more available at in-

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[235] Id.

[236] Id.

[237] Id.

[238] 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 Proceeding), pp. 1-2.

[239] Ex. 773, Direct Testimony of PULP witness William Yates, p. 54.

person events and more visible on the Company's website.[240] National Grid will also enhance the training of call center representatives who can provide relevant information to customers who may be eligible for special protections.[241] This provision of the Joint Proposal is in the public interest.

5. Energy Efficiency Program Costs

The Joint Proposal recommends that National Grid's electric and gas efficiency program costs will be recovered in base rates.[242] In RY1, the energy efficiency costs reflected in the Company's revenue requirements are $112.95 million for electric and $23.67 million for gas.[243] In RY2 and RY3, the revenue requirements assume costs of $82.57 million for electric and $16.47 million for gas, which are the amounts included in the provisional annual budgets set forth in the Commission's Order Directing Energy Efficiency and Building Electrification Proposals.[244]

National Grid will establish a separate incremental energy efficiency (IEE) surcharge mechanism to facilitate the recovery of any difference between the amount of energy efficiency costs reflected in rates and any incremental energy efficiency costs approved by the Commission for the established rate years.[245] The Company will also implement a downward-only energy efficiency cost reconciliation mechanism to reconcile the energy efficiency costs recovered through either base rates or

[240] Ex. 918, Corrected Joint Proposal, p. 94.

[241] Id.

[242] Ex. 918, Corrected Joint Proposal, p. 94.

[243] Id.

[244] Id.; Case 18-M-0084, A Comprehensive Energy Efficiency Initiative, Order Directing Energy Efficiency and Building Electrification Proposals (issued July 20, 2023).

[245] Ex. 918, Corrected Joint Proposal, p. 95.

the IEE surcharge and their actual energy efficiency expenditures.[246] At the conclusion of RY3, National Grid will defer any cumulative unspent energy efficiency funds for the benefit of customers.[247] The Joint Proposal's revenue requirements also provide funding for four energy efficiency-related full-time equivalent (FTE) positions in RY1.[248]

The recommendation to collect energy efficiency and building electrification program costs through rates was consistent with Commission directives at the time the Joint Proposal was filed.[249] However, in May 2025 the Commission directed all the utilities to begin recovering these program costs through a surcharge mechanism beginning January 1, 2026.[250] Therefore, the Company is directed to collect energy efficiency and building electrification program costs in accordance with the May 15, 2025 Order in Case 18-M-0084. Otherwise, the Joint Proposal includes a downward-only reconciliation mechanism, reflects budget amounts approved by the Commission, and acknowledges the Commission's ongoing authority over these matters. We approve the Joint Proposal's FTE funding in RY1, which will better equip the Company to satisfy increasing energy efficiency workforce demands.

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[246] Id.

[247] Id.

[248] Id., pp. 95-96.

[249] See Case 18-M-0084, supra, Order Authorizing Utility Energy Efficiency and Building Electrification Portfolios through 2025 (issued January 16, 2020) and Order Adopting Accelerated Energy Efficiency Targets (issued December 13, 2018).

[250] Cases 18-M-0084, supra, Order Authorizing Non-Low- to Moderate-Income Energy Efficiency and Building Electrification Portfolios for 2026-2030 (issued May 15, 2025).

6. Economic Development Discount Program

The Joint Proposal continues the Company's existing electric and gas economic discount programs and requires that all new recipients of the Excelsior Jobs Program explore energy efficiency opportunities available through National Grid, the New York State Energy Research and Development Authority or other entities.[251] The amounts reflected in rates for economic development discounts are $0.96 million (RY1), $1.56 million (RY2), and $4.80 million (RY3) for the Company's electric business and $0.53 million (RY1), $0.59 million (RY2), and $0.77 million (RY3) for the Company's gas business.[252] Any rate discounts provided are subject to full reconciliation.[253]

These provisions are reasonable because they continue the Company's economic development offerings and create local jobs, while ensuring that worthwhile programs have adequate funding.

7. Economic Development Grant Programs

The Company will continue its electric and gas economic development grant programs, which will be funded at $11.0 million and $1.0 million per year, respectively, and subject to downward-only reconciliations over the term of the rate plan.[254] If there is any difference between the respective rate allowance and actual program costs in a particular rate year, the difference will be carried forward and reconciled at the end of RY3.[255] Any under-expenditure will be deferred for future use in funding the Company's economic development

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[251] Ex. 918, Corrected Joint Proposal, p. 96.

[252] Id., p. 64.

[253] Id., p. 96.

[254] Id., p. 65.

[255] Id.

programs, or the Company may petition the Commission to use any deferred balances to fund emergency economic assistance or other economic development programs.[256] If the Company anticipates an over-expenditure, it may petition the Commission for deferral treatment but will not have any obligation to make additional expenditures unless and until the Commission authorizes deferral of amounts in excess of the three-year aggregate rate allowance.[257] The gas economic development grant program will be funded by amortizing up to $1 million of the existing economic development programs gas deferral balance in each rate year.[258]

Specific electric development grant programs provided by National Grid during the term of the rate plans are: capital investment incentive; three phase power incentive; cooperative business recruitment; strategic economic development; energy efficiency in Empire zones; agribusiness productivity; power quality enhancement; electric manufacturing productivity; renewable energy and economic development; brownfield redevelopment assistance; building ready update; industrial building redevelopment; shovel ready incentive; clean tech incubation; urban center/commercial district revitalization; Mainstreet revitalization; targeted financial assistance, and 25-cycle investment incentive.[259] The gas economic development programs are: natural gas manufacturing productivity; economic development and future of heat; sustainable gas and economic development.[260] As proposed by the Company and agreed to by DPS Staff, several of these programs will be modified through

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[256] Id.

[257] Id.

[258] Id.

[259] Id., pp. 96-97.

[260] Id., p. 97.

additional funding for eligible projects located in DACs or the prioritization of projects that involve the expansion, retention, and attraction of customers in clean energy sectors and their associated supply chains.[261]

These provisions of the Joint Proposal are reasonable because they better align the economic development grant program offerings with the CLCPA and emphasize economic growth in disadvantaged communities and/or the clean energy sector. Additionally, amortizing the existing gas economic development deferral to fund the gas economic development grant programs during the rate plan will ensure that any funds previously collected in rates are used for their intended purpose.

8. Economic Development Reporting

National Grid is required to file an annual report by April 1 of each year that reviews economic development program activity for the previous calendar year, as well as the Company's associated plans for the current calendar year.[262] Although the Company did not propose any changes to this reporting requirement,[263] DPS Staff recommended that the annual report include information regarding greenhouse gas emissions stemming from projects that received grant funding from the Economic Development and the Future of Heat and the Sustainable Gas and Economic Development programs.[264]

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[261] Ex. 18, Direct Testimony of National Grid Customer Panel, pp. 125-126; Ex. 423, Direct Testimony of DPS Staff Consumer Services Panel, pp. 101-102.

[262] Ex. 18, Direct Testimony of National Grid Customer Panel, p. 129.

[263] Id., p. 130.

[264] Ex. 423, Direct Testimony of DPS Staff Consumer Services Panel, pp. 112-113.

The Joint Proposal adopts DPS Staff's recommendation, requiring the Company to include in its annual report greenhouse gas emissions impacts associated with applicable completed projects and the total anticipated dekatherms or MMBtu savings associated with the approval of relevant grants.[265] This modification to the reporting requirement will provide DPS Staff with critical information for future analysis of pertinent projects, as well as data that can be used to evaluate the success of these programs in reducing greenhouse gas emissions. It is accordingly in the public interest.

9. Distributed Energy Resource Flexibility Market

The Joint Proposal requires National Grid to implement a DER Flexibility Market digital platform that will enable DER operators and aggregators to more clearly understand the locations where the Company seeks grid services, the value of providing such services at those locations, and the required terms for providing that flexibility during the term of the rate plan.[266] The proposal was advanced by National Grid in its direct testimony,[267] and it is not opposed by any party. We find that this provision is beneficial to ratepayers, as DER programs are used to manage grid congestion and reduce system costs by adjusting energy consumption.

10. Building To Grid Pilot Program

The "Building to Grid Pilot Program" expands upon a demonstration project that National Grid successfully implemented with a single customer; the program will encourage owners and developers of all-electric multifamily and commercial

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265 Ex. 918, Corrected joint Proposal, p. 98.

266 Id., p. 99.

267 Ex. 18, Direct Testimony of National Grid Customer Panel, p. 98.

new construction to provide localized hosting capacity and peak demand constraint through the Company's existing DER dispatch mechanisms.[268] More specifically, signals would be sent prior to peak load periods to curtail load and increase export to the grid.[269] Alternatively, during periods when feeder- and substation-level electric usage is low, and intermittent generation is high, signals may be sent to increase on-site load to minimize the need to curtail renewable generation.[270] In connection with the program, the Company would provide financial incentives to customers in exchange for operating their integrated load and generation assets in ways that address both locational hosting capacity and peak load constraints.[271]

No party other than the Company took a position on this proposed program, which has an O&M budget of $0.500 million over four years.[272] We approve the program, which is reasonable and will support increased focus on the electric system needs as the state moves forward with building electrification.

11. Residential Service Termination and Uncollectable Expense Incentive Mechanism

Previously, the Company was subject to a termination and uncollectible incentive mechanism that provided a PRA if the Company reduced residential service terminations and/or uncollectibles below certain targets and imposed an NRA if terminations or uncollectibles rose above limits. The mechanism was paused during the Covid-19 pandemic and the Company proposed to continue the pause due to expectations that terminations and

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268 Id., p. 100.

269 Id.

270 Id.

271 Id.

272 Id.

uncollectibles would remain high relative to historic levels. DPS Staff agreed with the Company's recommendation.

The Joint Proposal recommends that this mechanism remain paused during the rate plans and requires the Company to convene a stakeholder meeting prior to October 1, 2027, to discuss potential metrics and targets for this mechanism for potential inclusion in the Company's next rate filing.[273]

12. Weatherization Health and Safety Program

In direct testimony, AGREE proposed that the Company develop a weatherization, health and safety program similar to the program adopted in its downstate service territory.[274] According to AGREE, implementation of the program would "help address prerequisite home conditions to enable customers to access weatherization services more equitably because weatherization often involves significant home construction projects."[275] AGREE added that the program might also provide valuable data with which the Commission, Company, and other interested entities could determine whether retrofits and pre-weatherization offer significant, verifiable energy and cost savings to residential households.[276]

The Joint Proposal adopts AGREE's recommendation, requiring that National Grid provide a 100% shareholder-funded weatherization, health and safety program (WH&S) capped at $1.0

[273] Ex. 918, Corrected Joint Proposal, p. 99.

[274] Ex. 658, AGREE Direct Testimony of Jessica Azulay, p. 52; Cases 23-G-0225 et al., The Brooklyn Union Gas Company d/b/a National Grid NY and KeySpan Gas East Corporation d/b/a National Grid - Rates, Order Approving Terms of Joint Proposal and Establishing Rate Plans, with Minor Modifications and Corrections (issued August 15, 2024), pp. 137-138.

[275] Ex. 658, AGREE Direct Testimony of Jessica Azulay, p. 53.

[276] Id.

million annually.[277] This program will allow the Company to provide non-energy related services to address barriers to energy efficiency in DACs and low-to-moderate income (LMI) households; services include remediation of carbon monoxide hazards, mold, pests, insufficient airing or ventilation, plumbing problems, blocked access to spaces in the home, and unsafe appliances.[278] National Grid will design the program in consultation with NYSERDA and Regional Clean Energy Hubs in the Company's service territory, and it will allow participating customers to self-attest to their income for purposes of program qualification.[279] Any unspent funding in a given rate year will be allocated to the following year and, at the close of the term of the Rate Plan, the Company will perform a reconciliation of program expenditures.[280]

Within 60 days of the start of each rate year, the Company must file an annual implementation plan setting forth, among other things: the process by which customers are enrolled in the program; the process by which eligible customers are prioritized for participation in the program; measure and customer cost caps; collaboration and coordination efforts with other energy efficiency or building electrification program administrators; spending by category; the number of customers served; the number of projects in DACs compared to the number of projects outside of DACs; the total number of LMI customers in the Company's service territory, and lessons learned.[281]

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[277] Ex. 918, Corrected Joint Proposal, p. 99

[278] Id., p. 100.

[279] Id.

[280] Id.

[281] Id., pp. 100-101. In RY1, the Company's implementation plan will be due within 60 days from the date of this Order.

We approve this program because it will be implemented using shareholder funds, benefitting LMI customers and customers in DACs without burdening rate payers. Moreover, the detailed planning and reporting requirements will provide DPS Staff, the Commission, and stakeholders with useful information for consideration of the remediation of health and safety barriers to energy efficiency on a statewide basis.

N. Advanced Metering Infrastructure (AMI)

The Commission authorized National Grid's adoption of AMI in 2020, noting that it would contribute to the modernization of the Company's electric system and gas distribution system.[282] At the time, National Grid was directed to pursue solutions for improving the resiliency of its AMI system, including consideration of extended batteries that can last days without power.[283] In the 2022 Rate Order, the Company was authorized to recover $119.17 million of AMI-related operations costs, subject to a downward only reconciliation at the end of the six-year deployment period, which encompasses the period between the start of Fiscal Year 2022 and the end of Fiscal Year 2027.[284]

The Joint Proposal continues this downward-only tracker and approves $7.75 million in incremental AMI-related capital expenditures for storm hardening battery packs that will enhance resiliency of the AMI system.[285] Both provisions are reasonable, and we approve them.

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[282] Cases 17-E-0238 et al., Niagara Mohawk Power Corporation d/b/a National Grid - Electric and Gas Rates, Order Authorizing Implementation of AMI (issued November 20, 2020), p. 26.

[283] Id., p. 32.

[284] 2022 Rate Order, p. 70.

[285] Ex. 918, Corrected Joint Proposal, pp. 56-57.

## O. Information Technology and Digital (IT&D)

### 1. IT&D Capital Investment

IT&D capital investments are owned by National Grid USA Service Company and allocated to the Company as service company rent expense, which includes the return on, and the amortization or depreciation of, current investments and those forecast for the rate years.[286] As National Grid and DPS Staff proposed different amounts for these expenses,[287] the service company rent levels set forth in the Joint Proposal strike an equitable balance between the level of investment proposed by the Company and that recommended by DPS Staff.[288] These investment levels are within the range of a potential litigated outcome, and they will facilitate National Grid's continued provision of safe and reliable service. We accordingly approve them.

### 2. IT&D Capital Reporting

In accordance with the Joint Proposal, National Grid's IT&D Capital Report will be consistent with requirements set forth in the "Information Technology and Digital Reporting Format" report filed with the Commission on March 28, 2025, in Cases 23-G-0225 and 23-G-0226.[289] We agree that this provision is reasonable and that conformity of reporting requirements across National Grid's New York operations will benefit both the Company and its customers.

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[286] Ex. 135, Direct Testimony of National Grid Information technology and Digital Panel, pp. 17-18.

[287] Ex. 404, Direct Testimony of DPS Staff Information Technology Panel, pp. 15, 38.

[288] Appendix 1, Schedule 7 sets forth the IT&D capital investment plan by program.

[289] Ex. 918, Corrected Joint Proposal, p. 58.

P. Electric and Gas Service Quality Assurance Programs

The Company's Service Quality Assurance Program, described in Appendix 14 to the Joint Proposal, is comprised of Customer Service Performance Indicators (CSPI) and Electric Reliability performance metrics. These measures are designed to maintain and promote service quality and electric reliability via targets that, if unsatisfied, subject National Grid to NRAs.

In particular, the Joint Proposal establishes CSPI metrics for the following categories: Complaint Rate; Residential Customer Satisfaction Survey; Small/Medium Commercial and Industrial Customer Satisfaction Survey, and Percentage of Calls Answered by a Representative within 30 seconds. Although these metrics and targets are consistent with those set forth in the 2022 Rate Order, the maximum potential NRAs progressively increase during each year of the rate plan.

The Joint Proposal also retains the four electric reliability measures adopted in the prior rate order: System Average Interruption Frequency Index (SAIFI); Customer Average Interruption Duration Index (CAIDI); Estimating, and Inspection and Maintenance Program, and similarly increases potential NRA levels for both the SAIFI and CAIDI metrics.

The foregoing Joint Proposal provisions incentivize National Grid to maintain high levels of customer service and to meet or exceed reliability standards. They are also consistent with related criteria imposed upon other major utilities across New York State and are thus in the public interest.

Q. Climate Leadership and Community Protection Act (CLCPA)

As alluded to throughout this Order, a prerequisite to our determination that the Joint Proposal is in the public interest is a finding that it is consistent with the social, economic, and environmental policies of the Commission and the state, including the CLCPA. The Individual Intervenors nevertheless urge us to reject the Joint Proposal precisely because of such consistency; indeed, according to them, the Joint Proposal "will have a detrimental impact on [] ratepayers, and cannot be supported or reconciled to any extent by the unsubstantiated and dangerous expectations of the CLCPA," which are ostensibly "in direct contradiction to the statutory and regulatory obligations of the Company and the Commission."[290]

We accordingly offer the following CLCPA background, as well as information related to Commission action emanating therefrom, as context for our discussion of these misguided assertions.[291] Notably, in connection with all such action referenced below, the Commission has regularly reiterated that its core mission is to ensure the continued provision of safe, reliable and adequate utility service at just and reasonable rates.

The CLCPA was signed into law in July 2019. As relevant here, it requires that: (1) New York's greenhouse gas (GHG) emissions be 40% below 1990 levels by 2030 and 85% below

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[290] Individual Intervenors post-hearing brief, p. 10, statement in opposition, p. 4.

[291] While we will address the Individual Intervenors' arguments to the extent necessary, we note that they did not seek party status in these proceedings until April 28, 2025 – three days after the Joint Proposal was submitted for our consideration – they did not pre-file testimony, evidence, or exhibits, and they did not participate in any of the more than 30 settlement discussions conducted amongst the other active parties (Ruling on Objection, issued May 29, 2025). Moreover, the Individual Intervenors raise several matters of statewide concern that are beyond the scope of this Order (e.g., nuclear generation, EV school buses, or an electric system that is purportedly "overly weather-reliant") or founded upon unsubstantiated opinion. Finally, by the Individual Intervenors' own admission, multiple proposals and/or hypotheticals set forth in their statement in opposition are "presently unlawful" in New York (pp. 14, 25).

such levels by 2050; (2) the Commission consider the impact of its decisions and approvals on the state's ability to achieve these emission goals; and (3) final Commission determinations do not disproportionately burden DACs, i.e., those communities with high concentrations of low- and moderate-income households that already suffer from negative public health effects, environmental pollution and the consequences of climate change.[292]

Approximately nine months later (March 2020), the Commission initiated a generic gas planning proceeding to ensure that gas utilities implement improved planning and operational practices to meet customer needs, minimize infrastructure investments that may have long-term GHG emissions or ratepayer implications, and conduct such practices consistent with the CLCPA (Gas Planning Proceeding).[293] Among other things, the Gas Planning Proceeding Order requires utilities to file long-term plans that include demand forecasts incorporating energy efficiency, electrification, demand response and non-pipe alternatives (NPAs), as well as report GHG emissions for all proposed solutions to satisfying gas supply and demand; the order established a flexible and transparent gas system planning process that includes significant stakeholder participation to ensure that gas utilities continue to provide safe and reliable gas service while reducing gas infrastructure and GHG emissions in a manner consistent with the CLCPA.[294]

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[292] Environmental Conservation Law (ECL) §§75-0101(5), 75-0107(1); Chapter 106 of the Laws of 2019 §7(2), (3).

[293] See Case 20-G-0131, Proceeding on Motion of the Commission in Regard to Gas Planning Procedures, Order Instituting Proceeding (issued March 19, 2020), pp. 4-10.

[294] Gas Planning Proceeding Order, pp. 29, 35-37.

In May 2022, the Commission established a proceeding to monitor progress toward meeting the CLCPA's decarbonization targets, review existing Commission practices, and develop new policies to further CLCPA goals.[295] The Commission directed the State's major electric and gas utilities to work with DPS Staff to develop proposals for a GHG Emissions Inventory report that includes an inventory of total gas system-wide emissions and an assessment of direct and indirect GHG emissions, and a GHG Emissions Reduction Pathways Study that analyzes the scale, timing, costs, risks, uncertainties, and customer bill impacts of achieving significant and quantifiable reductions in GHG emissions from the use of gas delivered by the utilities. The Commission also directed utilities to assess "the GHG emissions impacts of each specific investment, capital expenditure, program, and initiative included in their rate filings."[296]

In December 2022, the New York State Climate Action Council[297] released a Final Scoping Plan (Scoping Plan) containing recommendations for attainment of the statewide GHG emissions set forth above. According to the Scoping Plan, achievement of the CLCPA's emission limits will entail a substantial reduction of natural gas usage with a corresponding downsizing and decarbonization of the natural gas infrastructure system. The Scoping Plan notes that this will require

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[295] Case 22-M-0149, In the Matter of Assessing Implementation of and Compliance with the Requirements and Targets of the Climate Leadership and Protection Act, Order on Implementation of the Climate Leadership and Protection Act (issued May 12, 2022) (CLCPA Implementation Order).

[296] CLCPA Implementation Order, p. 16; Ex. 3, Direct Testimony of National Grid CLCPA Panel, pp. 9, 16, 26-27; Ex. 5, National Grid CLCPA Panel Exhibit ___ (CLCPA-2), Estimated GHG Emissions Impacts from Gas and Electric Operations; Ex. 418, Direct Testimony of DPS Staff CLCPA Panel, pp. 13-21.

[297] See ECL §75-0103(13).

coordination among multiple sectors, including the buildout of local electric transmission and distribution systems to meet anticipated increases in demand for electricity, increases to demand reduction measures for fossil natural gas, and the identification of strategic opportunities to retire existing pipelines as demand declines.[298]

To complement the foregoing and to further particularize achievement of CLCPA goals, the Commission has commenced various other statewide proceedings.[299] For example, in September 2022, the Commission initiated a proceeding to fulfill the objectives of the Utility Thermal Energy Network and Jobs Act, which was enacted into law on July 5, 2022.[300] In doing so, the Commission recognized the need to transition from natural gas use in New York's building stock to reduce or eliminate GHG emissions from combustion of fuels in buildings in a manner that ensures the continuation of safe and reliable utility service. The Commission has also funded programs to support the electrification of both heating load in buildings and the transportation industry, supported large scale and distributed clean energy project development, funded programs to reduce natural gas and electricity usage across the State, and instituted a coordinated planning process to evaluate local

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298 Scoping Plan, pp. 350-351.

299 We note that several of these proceedings were established pursuant to PSL §66-p, which otherwise has no bearing on the instant rate cases.

300 Case 22-M-0429, Proceeding on Motion of the Commission to Implement the Requirements of the Utility Thermal Energy Network and Jobs Act, Order on Developing Thermal Energy Networks (issued September 15, 2022).

transmission and distribution system needs to support the State's transition to renewable energy generation.[301]

Finally, in May 2025, the Commission reaffirmed that energy efficiency is a stalwart of New York's clean energy agenda; more specifically, "[b]y reducing the amount of energy needed to heat and cool a home, and run appliances, weatherization and energy efficiency can lower total system costs for all ratepayers and serve as important resources to the electric grid and natural gas system."[302] The Commission added that reducing demand promotes grid reliability and can

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[301] See, e.g., 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); Order Adopting a Ratemaking and Utility Revenue Model Policy Framework (issued May 19, 2016); Case 15-M-0252, In the Matter of Utility Energy Efficiency Programs, Order Authorizing Utility-Administered Gas Energy Efficiency Portfolios for Implementation Beginning January 1, 2016 (issued June 19, 2015); Case 15-E-0302, Proceeding on Motion of the Commission to Implement a Large-Scale Renewable Program and Clean Energy Standard, Order Adopting Modifications to the Clean Energy Standard (issued October 15, 2020); Case 18-M-0084, supra, Order Authorizing Utility Energy Efficiency and Building Electrification Portfolios Through 2025 (issued January 16, 2020)(2020 NENY Order); Case 20-E-0197, Proceeding on Motion of the Commission to Implement Transmission Planning Pursuant to the Accelerated Renewable Energy Growth and Community Benefit Act, Order on Phase 1 Local Transmission and Distribution Project Proposals (issued February 11, 2021); Case 20-E-0197, Proceeding on Motion of the Commission to Implement Transmission Planning Pursuant to the Accelerated Renewable Energy Growth and Community Benefit Act, Order on Local Transmission and Distribution Planning Process and Phase 2 Project Proposals (issued September 9, 2021).

[302] Case 25-M-0248, In the Matter of the 2026-2030 Non-Low- to Moderate-Income Energy Efficiency and Building Electrification Portfolios, Order Authorizing Non-Low- to Moderate-Income Energy Efficiency and Building Electrification Portfolios for 2026-2030, p. 22. Portfolios for 2026-2030, p. 22 (issued May 15, 2025).

contribute to a reduction in costs associated with utility operations.[303]

It is against this backdrop that the Signatory Parties collaborated on the following CLCPA-related provisions, all of which advance New York's policy goals, particularly when considered in conjunction with complementary provisions that we have already discussed such as the Company's enhanced EAP and the weatherization health and safety program.

1. Non-Pipe Alternatives (NPAs)

NPAs are intended to reduce GHG emissions while avoiding unnecessary construction or upgrades to the natural gas system, which can be accomplished through installation of all-electric equipment or connections to other low-carbon infrastructure. While explicitly ensuring that any such measures should not jeopardize the safety and reliability of the gas system, the Joint Proposal requires that National Grid consider NPAs in lieu of LPP replacements, system reinforcements, main extensions, new service line installations and service line replacements, and forecast load growth areas.[304]

More specifically, the Company will seek opportunities to avoid LPP replacement projects through deployment of thermal energy networks or individual ground or air-source heat pumps.[305] In this effort, the Company will prioritize NPA opportunities that have the highest level of customer interest and/or reflect the lowest level of LPP risk, and it will inform its implementation strategy with lessons learned from similar programs previously undertaken by other utilities, particularly

[303] Id.

[304] Ex. 918, Corrected Joint Proposal, p. 102.

[305] Id.

in connection with billing, operational, or customer service obstacles.[306]

With respect to system reinforcements, National Grid will pursue NPAs designed to reduce firm demand and obviate the need for future reinforcements, including targeted incentives for electrification, demand response and energy efficiency.[307] The Company will prioritize such efforts on the most constrained portions of its service areas, and issue RFPs for applicable programs or projects,[308] which will help mitigate potential pressure issues on the gas system. To ensure adequate time for customer participation, National Grid's related outreach will focus specifically on NPAs that might replace traditional reinforcement projects scheduled for implementation at least three years in the future.[309]

For gas service requests involving a main extension of more than 100 feet, the Company will conduct an analysis to determine whether the prospective customers' needs can be satisfied with an NPA.[310] If such a project proves feasible, is financially beneficial to customers and will result in lower GHG emissions, National Grid will present those customers with alternative electrification measures.[311] If a project is deemed infeasible, the Company will explain why in its annual NPA report.[312]

[306] Id., pp. 102-103.

[307] Id., p. 103.

[308] Id., p. 104.

[309] Id.

[310] Id.

[311] Id.

[312] Id.

The Joint Proposal also requires that National Grid develop an NPA proposal focused on new gas service line installations and existing service line replacements under the NPA framework in place when the project will be implemented, which will include a method for educating customers regarding the benefits of non-fossil alternatives.[313] Within six months of issuance of this Order, the Company will convene a stakeholder engagement meeting to discuss its progress on this proposal, including a description of strategies that have been successful, those that have been unsuccessful, and any Company plans to improve the program.[314]

National Grid must also monitor areas on its system where load growth trends suggest that future infrastructure investments will be necessary and proactively develop load reduction strategies to mitigate or avoid the need for such investment.[315] This commitment will facilitate NPA consideration early in the Company's investment planning process and allow for timely customer outreach, thus enhancing the likelihood of successful NPAs.

In addition to the foregoing, and to address concerns expressed by various parties that customer participation has been a significant obstacle to NPA adoption throughout National Grid's service territory, the Joint Proposal includes an NPA Heat Pump Monthly Credit intended to incentivize residential and small commercial customers to install a heat pump as part of an NPA.[316] The credit is available to qualifying customers for five years and will offset costs associated with converting from gas

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[313] Id., p. 105.

[314] Id.

[315] Id.

[316] Id., p. 110.

to electric heating.[317] To alert customers to the availability of the credit, as well as to otherwise promote NPA opportunities, National Grid must provide relevant, timely information on its website and in promotional materials, make direct contact with NPA-eligible customers through in-person engagement (knocking on doors), email, telephone calls, bill inserts, or at public events, and develop an outreach methodology for both building and non-building owners.[318] All such efforts must be tracked and evaluated by National Grid, which will provide an analysis of customer outreach efforts and customer feedback in its annual NPA report.[319]

Finally, in connection with a recommendation by AGREE that National Grid adopt a Heating Electrification Make-Ready Program, the Joint Proposal allows NPAs to include costs associated with behind-the-meter upgrades (e.g., to wiring or electric panels), as well as health and safety measures that may be necessary to facilitate NPA participation.[320] A related provision requires that the Company "consider and quantify the impacts of an NPA on bill affordability [and] identify the number of [anticipated] EAP participants," so it can develop a strategy for mitigating energy burden increases associated with NPA-related electrification.[321]

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[317] Id. Participation in the Heat Pump Monthly Credit program has no bearing on a customer's eligibility for the Company's EAP.

[318] Id., p. 108

[319] Id., pp. 108-109.

[320] Id., p. 107; Ex. 658, AGREE Direct Testimony of Jessica Azulay, p. 45.

[321] Ex. 918, Corrected Joint Proposal, p. 109.

2. Integrated Energy Planning Pilot to Support LPP NPAs

National Grid will implement an Integrated Energy Planning (IEP) pilot to support targeted customer electrification for NPAs, particularly with respect to nine LPP segments that the Company has identified in the East Gate region that require minimal electric system upgrades to electrify.[322] These segments provide service to 150 customers and are located within three towns in the Capital District, two of which include DACs.[323] As part of the pilot, the Company will consider offering costumers various incentives for their participation, including a free home energy assessment before they decide to participate, coverage of all costs stemming from the replacement of gas equipment with electric alternatives, providing the NPA Heat Pump Monthly Credit discussed above to offset increases in electricity bills, and coverage of 100% of weatherization costs necessary to ensure effective sizing and efficiency of electric heating equipment.[324]

The pilot will focus on four primary objectives: (1) defining and testing joint gas and electric IEP processes and engineering methodologies to support NPAs; (2) developing and testing a joint gas and electric cost recovery framework for NPAs that contemporaneously accounts for customer equipment replacements, gas system retirements, and electric system upgrades; (3) evaluating joint gas and electric approaches to customer engagement to identify methods for increasing customer participation in coordinated gas to electric conversions; and (4) identifying and mitigating barriers to customer adoption.[325]

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[322] Id., p. 106.

[323] Id.

[324] Id.

[325] Id.

National Grid will commence community outreach for the pilot within three months of the issuance date of this Order and, in RY2, will make an IEP Pilot Deployment filing to pursue cost recovery associated with electric upgrades, customer incentives, and gas system retirements where customers have opted to move forward with equipment conversions.[326] Upon approval of the filing, the Company will plan to implement necessary building and system replacements in RY3, at which time it will also submit a pilot evaluation report outlining pilot results, lessons learned, and recommendations for future electrification efforts and NPA commitments.[327] Program costs will be allocated to and recovered from only those rate classes participating in the pilot.[328]

We agree with the Signatory Parties that the IEP pilot will enhance the Company's ability to implement NPAs; it reflects a systematic and holistic approach to electrification that considers not only customer needs, but the needs of the electric and gas systems. Indeed, the pilot will provide invaluable lessons for integrated energy planning that can serve as a model across New York State.

3. CLCPA Disadvantaged Communities Report and Analysis

The Joint Proposal requires that National Grid provide an annual report that details its CLCPA activities and investments in disadvantaged communities, including specific information regarding energy efficiency programs, demand response programs, main replacement and leak repair, customer operations data, and clean energy jobs.[329] The Company must also

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[326] Id., p. 107.

[327] Id.

[328] Id.

[329] Ex. 918, Corrected Joint Proposal, p. 122; Appendix 11.

convene a stakeholder meeting within 60 days after it files the report, enabling interested entities to discuss the report and provide feedback on the information provided therein.[330]

4. Utility Thermal Energy Network Proceeding

During the term of the rate plans, National Grid will remain a participant in Case 22-M-0429 and will implement natural geothermal energy systems as authorized by the Commission.[331]

5. Gas Marketing Cessation

National Grid will cease gas marketing efforts for new gas connections and conversions and encourage applicants seeking new or expanded gas service to consider electrification options.[332] Additionally, none of the Company's direct energy efficiency marketing will refer to gas as clean or suggest that it has environmental benefits.[333]

In light of all of the above, we find that our adoption of the Joint Proposal is consistent with the CLCPA and will not interfere with the attainment of the State-wide greenhouse gas emission limits established in Article 75 of the ECL. Indeed, the foregoing amply demonstrates that the Joint Proposal appropriately promotes the CLCPA's electrification and greenhouse gas emission reduction goals. Moreover, the rate plans that we approve today do not result in a disproportionate burden on disadvantaged communities; on the contrary, the record supports a finding that the Joint Proposal will have an overall positive impact on such communities.

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[330] Id.

[331] Ex. 918, Corrected Joint Proposal, p. 123.

[332] Ex. 918, Corrected Joint Proposal, p. 111.

[333] Id.

## R. Management and Operations Audits

Combination gas and electric corporations, such as National Grid, must undergo Commission-directed management and operations audits at least once every five years.[334] These audits assess the efficiency and effectiveness of utility operations and result in recommendations for improvement opportunities. Upon release of a final audit report, the subject utility must submit a plan to the Commission outlining its strategy for implementing the recommendations contained therein.[335] Pursuant to PSL §66(19)(c), the Commission must review a corporation's compliance with the most recent audit whenever the corporation applies for a major change in rates.

As relevant here, the Commission instituted a proceeding for an independent third-party consultant to conduct a comprehensive management and operations audit of National Grid along with National Grid USA's two gas utilities (collectively, the Companies) in 2018.[336] After DPS Staff terminated the contract with the third-party consultant, DPS Staff completed a final audit report, released to the public in November 2020, that included 24 recommendations for improving the Companies' performance.[337] The Companies filed an Implementation Plan in December 2020, that plan was approved by the Commission in May 2021,[338] and the Companies thereafter filed written implementation plan updates. By letter issued in March 2023,

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[334] PSL §66(19)(a).

[335] PSL §66(19)(b).

[336] Case 18-M-0195, National Grid USA's New York Electric and Gas Utilities – Management Audit.

[337] Case 18-M-0195, supra, Order Releasing Audit Report (issued November 19, 2020).

[338] Case 18-M-0195, supra, Order Approving Implementation Plan (issued May 13, 2021).

DPS Staff acknowledged that the Companies implemented all audit recommendations.[339]

Accordingly, pursuant to PSL §66(19), we find that National Grid is currently in compliance with the directions and recommendations associated with the most recently completed management and operations audit

## CONCLUSION

Based upon the record, and in consideration of the parties' respective arguments in support of or opposition to the Joint Proposal, we find that it is in the public interest. Indeed, while reflecting a considerable reduction from National Grid's original request, the Joint Proposal nonetheless provides sufficient funding for the Company to maintain safe, adequate and reliable utility service at just and reasonable rates; thus, the Joint Proposal appropriately balances the interests of ratepayers, the Company, and its investors. We are also satisfied that the Joint Proposal's terms are consistent with the social, economic and environmental policies of the Commission and the State, including the CLCPA. Accordingly, consistent with our discussion throughout this Order, the rate plans adopted herein are approved.

The Commission orders:

1. The rates, terms, conditions, and provisions of the Joint Proposal dated April 25, 2025, filed in these proceedings, and attached hereto as Attachment A, are adopted and incorporated herein to the extent consistent with the discussion herein as part of this Order.

[339] Case 18-M-0195, Audit Close Out Letter (issued March 20, 2023).

2. Niagara Mohawk Power Corporation d/b/a National Grid is directed to file cancellation supplements, effective on not less than one day’s notice, on or before August 20, 2025, cancelling the tariff amendments and supplements listed in Attachment B to this Order.

3. Niagara Mohawk Power Corporation d/b/a National Grid is directed to file, on not less than four days’ notice, to take effect on a temporary basis on September, 1, 2025, such further tariff changes as are necessary to effectuate the terms of this Order for Rate Year 1, the twelve-month period ending March 31, 2026, and to incorporate any tariff amendments that were previously approved by the Commission since the tariff amendments listed in Attachment B were ordered.

4. Niagara Mohawk Power Corporation d/b/a National Grid is directed to file, on not less than 30 days’ notice, to take effect on a temporary basis on April 1, 2026, such further tariff changes as are necessary to effectuate the terms of this Order for Rate Year 2, the twelve-month period ending March 31, 2027.

5. Niagara Mohawk Power Corporation d/b/a National Grid is directed to file, on not less than 30 days’ notice, to take effect on a temporary basis on April 1, 2027, such further tariff changes as are necessary to effectuate the terms of this Order for Rate Year 3, the twelve-month period ending March 31, 2028.

6. Niagara Mohawk Power Corporation d/b/a National Grid shall serve copies of the tariff filings directed in Ordering Clauses 3, 4, and 5 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 Commission and serving its comments upon all active parties within 14 days of service of the proposed

amendments. The tariff amendments specified in Ordering Clauses 3, 4, and 5 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 §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 Niagara Mohawk Power Corporation d/b/a National Grid shall file with the Secretary of the Commission, no later than six weeks following the effective date of the amendments, proof that notice to the public of the changes set forth in the amendments has been published once a week for consecutive weeks in one or more newspapers having general circulation in the service territory and areas affected by the amendments. The requirements of Public Service Law §66(12)(b) and Title 16 of the New York Codes, Rules and Regulations §720-8.1 are not waived for tariff changes necessary to implement the rate plans in Rate Years 2 and 3, or with respect to tariff filings in compliance with this Order made in subsequent years.

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