STATE OF NEW YORK
PUBLIC SERVICE COMMISSION

CASE 20-E-0380

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 20-G-0381

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

CASE 19-M-0133

IN THE MATTER OF NIAGARA MOHAWK POWER CORPORATION'S NOTICE OF PENSION SETTLEMENT LOSS AND REQUEST FOR WAIVER OF 60-DAY FILING REQUIREMENT

JOINT PROPOSAL

By and Among:

Niagara Mohawk Power Corporation d/b/a National Grid
Department of Public Service Staff
Multiple Intervenors
New York Power Authority
Direct Energy Services LLC
Marathon Power LLC
New York State Office of General Services
Walmart, Inc.
International Brotherhood of Electrical Workers, Local Union 97

Dated: September 27, 2021

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STATE OF NEW YORK
PUBLIC SERVICE COMMISSION

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JOINT PROPOSAL

This Joint Proposal ("Joint Proposal") is made this 24th day of September 2021, by and among Niagara Mohawk Power Corporation d/b/a National Grid ("Niagara Mohawk" or "Company"), New York State Department of Public Service Staff ("Staff"), Multiple Intervenors, New York Power Authority ("NYPA"), Direct Energy Services LLC, Marathon Power LLC, New York State Office of General Services ("OGS"),[1] the International Brotherhood of Electrical Workers, Local Union 97, and Walmart, Inc. (collectively, the "Signatory Parties").[2] This Joint Proposal establishes a three-year rate plan for Niagara Mohawk's electric and gas businesses, contains provisions that apply in a Stayout Period in the event the Company does not file to

[1] OGS signs this Joint Proposal in support of Section IV.15.4 only and takes no position with respect to any of the other provisions in the Joint Proposal.

[2] In addition, Family Energy, ChargePoint, the Environmental Defense Fund, Utility Intervention Unit of the New York State Department of State Division of Consumer Protection, Alliance for a Green Economy, Natural Resources Defense Council, Sierra Club, New York Geothermal Energy Organization, Public Utility Law Project of New York, AARP NY, while not supporting this Joint Proposal, have stated that they will not oppose it.

establish new delivery rates for the period immediately following the rate plan, and either resolves or establishes a framework for resolving all issues raised in Cases 20-E-0380 and 20-G-0381 ("Rate Cases"). In addition, this Joint Proposal resolves all issues in Case 19-M-0133; a proceeding in which the Company sought authority to defer certain actuarial expense losses associated with lump sum pension payments under its pension plan.

I. Procedural Background

1. Rate Cases

On July 31, 2020, Niagara Mohawk filed tariff leaves and supporting testimony and exhibits for new rates and charges for electric and gas service to be effective September 1, 2020.[3] The new tariffs were designed to increase electric and gas delivery revenues by approximately $100.4 million and $41.8 million, respectively, for the twelve months ending June 30, 2022.

Administrative law judges ("ALJs") were appointed to conduct the proceedings and to review Niagara Mohawk's rate filings. On September 1, 2020, the ALJs held a virtual procedural conference that was immediately followed by a technical presentation by the Company discussing various aspects of the rate filings.

On September 3, 2020, the ALJs issued a *Procedural Ruling* that provided dates for certain activities in the cases, including the filing of parties' initial and rebuttal testimony and hearings. The active parties engaged in extensive discovery throughout the proceedings, with the Company responding to approximately 2,000 information requests.

Niagara Mohawk filed corrections and updates testimony and exhibits on October 14, 2020, increasing the electric revenue requirement to approximately $103.3 million and decreasing

[3] On August 20, 2020, the Secretary issued a Notice suspending the effective date of the Company's new rates until December 29, 2020.

the gas revenue requirement to approximately $37.1 million. On November 25, 2020, eighteen parties, including Staff, filed direct testimony and exhibits addressing the Company's filing. Niagara Mohawk, Staff and eight other parties each filed rebuttal testimony and exhibits on December 16, 2020.

2. Case 19-M-0133

By a Petition dated February 28, 2019, Niagara Mohawk sought authorization from the Commission to defer the early accounting recognition of normally occurring actuarial expense losses associated with lump sum pension payments to the Company's employees upon their retirement. The lump sum payments were due to normal retirements and not the result of any pension plan change or early retirement. In the petition, the Company proposed to defer an estimated $8.1 million of actuarial expense losses incurred during its Fiscal Year ending March 31, 2019.

3. The Settlement Process

On December 9, 2020, Niagara Mohawk notified the active parties of the commencement of settlement negotiations in Cases 20-E-0380 and 20-G-0381 pursuant to the Commission's settlement procedures set forth in 16 NYCRR § 3.9 and filed a formal notice of impending settlement negotiations with the Secretary.[4]

Settlement negotiations were held on January 5, March 2, April 13, and 20, May 14, June 3, July 13 and 23, August 4, and September 17 and 22, 2021. Additional, numerous settlement breakout sessions were held to discuss discrete issues. All settlement conferences were duly

4 A notice of settlement negotiations in Case 19-M-0133 was filed on July 9, 2021.

noticed to the active parties and held virtually via video conference, which included the option to participate via telephone.

To facilitate settlement discussions and allow time to finalize this Joint Proposal, on December 22, 2020 and February 22, May 5, July 21 and August 13, 2021, Niagara Mohawk filed requests to extend the suspension period (most recently through March 1, 2022), subject to a make whole provision that would restore the Company and customers to the same financial position they would have been in had there been no extension and new rates went into effect on July 1, 2021.

This Joint Proposal is the product of the active parties' settlement negotiations and was developed pursuant to, and in accordance with, the Commission's settlement procedures. The Signatory Parties believe that this Joint Proposal represents a fair and reasonable resolution of the issues presented in these proceedings and satisfies the requirements of Public Service Law § 65(1) that Niagara Mohawk provide safe and adequate service at just and reasonable rates.

II. Overall Framework

The Signatory Parties have developed a comprehensive set of terms and conditions for a three-year rate plan for Niagara Mohawk's electric and gas businesses. The terms and conditions of this rate plan are set forth below and in the attached Appendices. Specifically, this Joint Proposal addresses the following topics:

1. Effective Date and Term;
2. Electric and Gas Revenue Requirements;
3. Electric Revenue Allocation and Rate Design;
4. Gas Revenue Allocation and Rate Design;
5. Computation and Disposition of Excess Earnings;

6. Electric Capital and Common Investment Levels and Infrastructure and Operations Programs;
7. Gas Capital Investment Levels and Infrastructure and Operations Programs;
8. Advanced Metering Infrastructure;
9. Electric Vehicles;
10. Information Technology;
11. Street Lighting;
12. Electric and Gas Reconciliations, Deferrals and True-Ups;
13. Electric and Gas Service Quality Assurance Programs and Other Performance Metrics;
14. Gas Safety Performance Metrics;
15. Customer Programs;
16. Earnings Adjustment Mechanisms;
17. Non-Pipe Alternatives ("NPAs"), Energy Efficiency, Renewable Natural Gas, Economic Development and Related Matters;
18. Gas Matters;
19. Filing for New Rates; and
20. Other Provisions.

The rate plan reflects provisions that recognize and address conditions created by the COVID-19 pandemic and the goals of the Climate Leadership and Community Protection Act ("CLCPA"). With regard to addressing the goals of the CLCPA, Section IV of this Joint Proposal includes the following sections:

6.2 Gilmantown Energy Storage;

6.6 Non-Wires Alternatives;

7.2 Withdrawal of Application for the Albany Loop Project;

7.10 Enhanced High Emitter Methane Detection Program;

9 Electric Vehicles;

11.7 Street Light Program Initiatives;

14.1 Leak Prone Pipe Removal;

14.2 Leak Management

16 Earnings Adjustment Mechanisms;

17.1 Non-Pipe Alternatives;

17.2 Gas Demand Response Program;

17.4 Multi-Use Hydrogen / Energy Transfer Station Facility;

17.5 Online Fuel Switching Calculator;

17.7 Energy Efficiency Programs;

18.1 Reducing Billed Gas Usage / Non-Pipe Alternatives;

18.1.1 Termination of Gas Expansion Programs and Marketing;

18.1.2 Alternate Heating Options;

18.1.2.1 Heat Pump Conversion Program;

18.1.3 CLCPA Study;

18.1.4 Depreciation Study;

18.1.5 Heat Pump Non-Pipe Alternatives: Leak-Prone Pipe Alternatives and Customer Connections Pilots; and

18.1.6 Climate Assessment of Investments and Initiatives.

III. Definitions

1. “Effective Date” means July 1, 2021, or such other date as the Commission may determine.
2. “Rate Year One” means July 1, 2021 through June 30, 2022.
3. “Rate Year Two” means July 1, 2022 through June 30, 2023.
4. “Rate Year Three” means July 1, 2023 through June 30, 2024.
5. “Case 17-E-0238 Joint Proposal” means the Joint Proposal, dated January 19, 2018, in Cases 17-E-0238, *et al.*, the terms of which were adopted by the Commission in those proceedings, pursuant to the Commission’s “Order Adopting Terms of Joint Proposal and Establishing Electric and Gas Rate Plans” (issued March 15, 2018) (“2018 Rate Order”).
6. “Stayout Period” means the period beginning July 1, 2024, and ending on the earlier of either the effective date of revised base rates for Niagara Mohawk or March 31, 2025.
7. “Fiscal Year” means the twelve-month period ending March 31 of a given year. When a specific year is stated, it is the year in which the Fiscal Year ends; *e.g.*, Fiscal Year 2022 is the twelve months ending March 31, 2022.
8. The three Rate Years are collectively referred to herein as “Rate Years” and individually as a “Rate Year.”

IV. Rate Plan

1. Effective Date and Term

The term of Niagara Mohawk’s electric and gas rate plan is three years, beginning July 1, 2021 and continuing through June 30, 2024. If Niagara Mohawk does not file for new rates to be effective on July 1, 2024, the term of the electric and gas rate plan also includes the Stayout Period, unless otherwise specified. For administrative reasons, certain targets and mechanisms are on different 12-month schedules (*e.g.*, calendar year periods), as set forth herein. In addition, unless specifically noted in this Joint Proposal, all terms of this Joint Proposal will continue in effect until changed by the Commission.

2. <u>Electric and Gas Revenue Requirements</u>

2.1. Rate Plan Revenue Requirements

This Joint Proposal provides for Rate Year One, Rate Year Two, and Rate Year Three electric and gas revenue requirement increases as follows:[5]

Electric w/GRT ($M)			
	Revenue Requirement Increase	Delivery Revenue Percent Increase	Total Revenue Percent Increase
RY1	$49.379	2.4%	1.6%
RY2	$95.582	4.5%	3.0%
RY3	$109.816	4.9%	3.2%

Gas w/GRT ($M)			
	Revenue Requirement Increase	Delivery Revenue Percent Increase	Total Revenue Percent Increase
RY1	$12.523	2.9%	1.5%
RY2	$29.078	6.4%	3.6%
RY3	$32.992	6.7%	3.9%

The revenue requirements will be adjusted for rate compression, the amortization of certain deferred credits and reductions in Gross Receipts Tax (GRT) such that the resulting total revenue increases and percentage increases are as follows:

[5] The percent increases this and the following table are based on total system revenues and include an estimated level of Energy Service Company (ESCO) commodity revenues.

Electric ($M)									
	Revenue Requirement Increase	Rate Compression	Delivery Revenue Percent Increase	Total Revenue Percent Increase	Amortization of Deferred Credits	GRT on the Amortization of Deferred Credits	Revenue Increase After Use of Credits	Delivery Revenue Percent Increase w/Credits	Total Revenue Percent Increase w/Credits
RY1	$49.379	$0.000	4.8%	3.2%	-$26.483	-$0.350	$22.546	2.2%	1.4%
RY2	$95.582	-$22.516	4.5%	3.0%	-$10.256	-$0.487	$62.323	2.9%	1.9%
RY3	$109.816	$0.000	4.9%	3.2%	-$45.946	-$0.609	$63.262	2.8%	1.9%

Gas ($M)									
	Revenue Requirement Increase	Rate Compression	Delivery Revenue Percent Increase	Total Revenue Percent Increase	Amortization of Deferred Credits	GRT on the Amortization of Deferred Credits	Revenue Increase After Use of Credits	Delivery Revenue Percent Increase w/Credits	Total Revenue Percent Increase w/Credits
RY1	$12.523		5.0%	2.5%	-$3.519	-$0.050	$8.954	3.6%	1.8%
RY2	$29.078	-$6.46	6.4%	3.6%	-$6.808	-$0.156	$15.656	3.4%	1.9%
RY3	$32.992		6.7%	3.9%	-$16.400	-$0.255	$16.337	3.3%	1.9%

The components of the electric and gas revenue requirements are set forth in Appendix 1, Schedules 1 and 2. The revenue requirements are based on the following parameters:

a. a return on equity ("ROE") of 9.0 percent[6] for the term of the rate plan;

b. a capital structure and overall cost of capital consisting of the following components and cost rates:

Rate Year One

	% of Capital	Annual Cost	Weighted Cost Percent	Weighted Cost Pre-Tax
Long-Term Debt	51.25%	3.41%	1.75%	1.75%
Customer Deposits	0.38%	0.05%	0.00%	0.00%
Preferred Stock	0.36%	3.66%	0.01%	0.01%

6 One pre-tax basis point is equivalent to approximately: (i) $0.425 million and $0.102 million in electric and gas revenues, respectively, in Rate Year One; (ii) $0.453 million and $0.112 million in electric and gas revenues, respectively, in Rate Year Two; and (iii) $0.489 million and $0.123 million in electric and gas revenues, respectively, in Rate Year Three. These basis point values will be used for purposes of calculating negative or positive revenue adjustments incurred during these periods. For the Stayout Period, and until the Company's rates are next reset, basis point value used for calculating negative or positive revenue adjustments will remain at the Rate Year Three level.

Common Equity	48.00%	9.00%	4.32%	5.90%
Total Capital	**100.00%**		6.08%	7.66%

Rate Year Two

	% of Capital	**Annual Cost**	**Weighted Cost Percent**	**Weighted Cost Pre-Tax**
Long-Term Debt	51.26%	3.39%	1.74%	1.74%
Customer Deposits	0.38%	0.05%	0.00%	0.00%
Preferred Stock	0.36%	3.66%	0.01%	0.01%
Common Equity	48.00%	9.00%	4.32%	5.90%
Total Capital	**100.00%**		6.07%	7.65%

Rate Year Three

	% of Capital	**Annual Cost**	**Weighted Cost Percent**	**Weighted Cost Pre-Tax**
Long-Term Debt	51.28%	3.41%	1.75%	1.75%
Customer Deposits	0.37%	0.05%	0.00%	0.00%
Preferred Stock	0.35%	3.66%	0.01%	0.01%
Common Equity	48.00%	9.00%	4.32%	5.90%
Total Capital	**100.00%**		6.08%	7.66%

c. In recognition of the COVID-19 pandemic, no funding for increases in management wages for senior managers for the period July 1, 2020 through June 30, 2022.

d. A Rate Year One electric rate base of $6.481 billion and a gas rate base of $1.560 billion, a Rate Year Two electric rate base of $6.913 billion and a gas rate base of $1.704 billion, and a Rate Year Three electric rate base of $7.463 billion and a gas rate base of $1.882 billion.

e. Niagara Mohawk’s gas transmission and distribution plant depreciation rates have been updated and are set forth in Appendix 1, Schedule 4. The Company’s revised gas depreciation rates reflect the annual amortization of $1.95 million of costs associated with Electronic Remote Transmitters and the annual amortization of $8.27 million (approximately $6.96 million incremental to approved mains and services depreciation rates) of costs associated with leak prone pipe ("LPP") in Rate Years One, Two and Three. In recognition of the need to ameliorate bill impacts in these proceedings, $3 million of the $8.27 million of annual amortization of LPP will be deferred for future recovery during the term of the rate plan. The current gas general plant depreciation rates, previously adopted by the Commission in Case 08-G-0609,[7] will also continue without change and are also included for reference in Appendix 1, Schedule 4. The Company's electric transmission, distribution, and common plant depreciation rates, previously adopted by the Commission in the 2018 Rate Order, will continue as adjusted only for the annual amortization of $10 million of retired Automatic Meter Reading devices and are included in Appendix 1, Schedule 3.

f. The annual amortization of Niagara Mohawk's allocated share of the remaining costs of the 2018 Management Audit of National Grid USA,[8] of $0.45 million, over a three-year period. This amount is allocated on an 83 percent/17 percent basis between the Company's electric and gas operations.

g. An increase in the New York State corporate income tax rate from 6.5 percent to 7.25 percent.

2.1.1. Amortization of Excess Deferred Taxes

The Company's revenue requirement for its electric operations reflects the amortization of $50.9 million of excess accumulated deferred income taxes ("ADIT")[9] in Rate Year One, $37.8 million in Rate Year Two, and $32.7 million in Rate Year Three. The Company's revenue

7 Case 08-G-0609, *Niagara Mohawk – Gas Rates*, Order Adopting the Terms of a Joint Proposal and Implementing a State Assessment Surcharge (issued May 15, 2009).

8 Case 18-M-0195, *Proceeding on Motion of the Commission to Conduct a Comprehensive Management and Operations Audit of National Grid USA's New York Electric and Gas Utilities*.

9 The amounts being amortized reflect both protected and unprotected excess ADIT as well as the flow through effect of other historical plant-related timing differences such as depreciation and cost of removal.

requirement for its gas operations reflects the amortization of excess ADIT of $24.9 million in Rate Year One, $14.4 million in Rate Year Two, and $8.6 million in Rate Year Three.

If, during the term of this Joint Proposal, the Company determines that the amortization of excess ADIT related to protected plant would be in violation of the tax normalization provisions of the Internal Revenue Code such that the Company would be precluded from the full use of accelerated depreciation, then the Company shall have the right to modify its accounting for ADIT and the amortization of excess ADIT related to protected plant , as, and to the extent necessary to maintain consistency with applicable tax normalization principles and remain eligible to use accelerated depreciation without interruption. To the extent the Company determines that it is necessary to modify its accounting for ADIT and/or its amortization of excess ADIT related to protected plant to avoid a normalization violation, the Company shall file a notice of such action with the Secretary to the Commission. Such notice shall provide an explanation of the change in the tax normalization provision and/or the Internal Revenue Service's interpretation of the tax normalization provision of the Internal Revenue Code that results in a need for the Company to modify its accounting for ADIT and/or its amortization of excess ADIT related to protected plant. Further, the notice shall include the Company's proposed modification to avoid a tax normalization violation, the materiality of the proposed modification, and the Company's proposed rate treatment of the impact of the proposed modification. Any issues raised by the Company's notice shall be resolved in its next base rate case proceeding.

2.2. Shaping of Rate Increases

In recognition of the financial impacts of the COVID-19 pandemic on the Company's customers and other considerations, the Signatory Parties propose that the base rate changes be implemented in a manner designed to achieve revenue increases of 1.4 percent for the Company's electric operations and 1.8 percent for the Company's gas operations in Rate Year One and 1.9% for both electric and gas operations in Rate Year Two and Rate Year Three on a total bill basis. The annual revenue changes are set forth in Appendix 1, Schedule 6, pages 1 and 3 for the Company's electric and gas operations, respectively.

To achieve these outcomes, the Company will credit electric customers with a portion of the forecast electric deferral balance in the amount of $145.907 million and credit gas customers with a portion of the forecast gas deferral balance in the amount of $53.502 million (inclusive of $12.928 million to be used in the Stayout Period). The credits will allow for a gradual transition to full cost-of-service rates (*i.e.*, step increases from Rate Year One to Rate Year Two, from Rate Year Two to Rate Year Three, and from Rate Year Three to the Stayout Period for gas only), as reflected in Appendix 2, Schedules 2.6, 2.8, and 2.10 for electric, and in Appendix 3, Schedules 3.2, 3.3, 3.4 and 3.5 for gas.

The deferral credits will be calculated by using specific projected deferred credit balances, as illustrated in Appendix 1, Schedule 6, page 2 for electric and page 4 for gas.

2.3. Make Whole Provision

The Signatory Parties recognize that Commission approval of this Joint Proposal can occur only after July 1, 2021. Accordingly, the Signatory Parties propose that the Company will recover the revenue shortfall resulting from the extension of the suspension period through a make whole provision. The make whole provision is designed to ensure the Company is restored to the same position it would have been in had new rates gone into effect on July 1, 2021.

The Company will calculate any revenue adjustments as the difference between revenues the Company would have received during the extension of the suspension period and the actual revenues received. The revenue adjustments will include all applicable surcharges and carrying charges and be subject to reconciliation in accordance with all reconciliation mechanisms, where applicable. The electric reconciliation mechanisms to be updated to reflect new targets are the Revenue Decoupling Mechanism (“RDM”), Transmission Revenue Adjustment (“TRA”), and the reconcilable components of the Merchant Function Charge (“MFC”). The gas reconciliation mechanisms to be updated to reflect new targets are the RDM, Net Revenue Sharing (“NRS”), Gas Safety and Reliability Surcharge (“GSRS”) and the reconcilable components of MFC. The change in rates related to the non-reconcilable components of the MFCs (uncollectible expense, working capital, and return on storage (gas only)) will be calculated and included in the make whole provision. An illustrative example of this calculation is included in Appendix 2, Schedule 13 for electric and Appendix 3, Schedule 13 for gas.[10] Financial true-up targets established in this Joint Proposal, as well as depreciation and amortization expense, will be applied to the extension of the suspension period. All accounting/ratemaking will be in accordance with this Joint Proposal and be effective as of July 1, 2021.

3. <u>Electric Revenue Allocation and Rate Design</u>

3.1. Electric Revenue Forecast

The retail delivery electric revenue forecast used to develop the Company’s revenue requirement increases for the Rate Years is set forth in Appendix 2, Schedule 1. Appendix 2, Schedule 1.1 depicts the Rate Year One revenue using the current delivery rates. Appendix 2, Schedule 1.2, depicts the Rate Year Two revenue using the Rate Year One delivery rates, and Appendix 2, Schedule 1.3 depicts the Rate Year Three revenue using the Rate Year Two rates.

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[10] If a Commission order adopting the terms of this Joint Proposal is not issued prior to January 1, 2022, and thus new rates are not effective on January 1, 2022, the Make Whole provision and any other calculation in the Joint Proposal that is based on new rates becoming effective on January 1, 2022, will need to be addressed to reflect the actual date new rates go into effect.

3.1.1. FERC Order 1000-type Transmission Projects

The Company will be permitted to retain the return on equity established by the Federal Energy Regulatory Commission ("FERC") for any New York Power Authority Priority Transmission projects, any Western New York Transmission projects, and any similar FERC-regulated transmission projects.[11]

3.2. Electric Revenue Allocation

The Signatory Parties agree that no embedded cost of service ("ECOS") methodology or set of assumptions sponsored by any party in these proceedings for allocating either the Advanced Metering Infrastructure ("AMI") related costs or the overall revenue requirements should establish precedent for revenue allocation in any future proceeding. The revenue allocation recommended in this Joint Proposal does not endorse any one ECOS methodology or set of assumptions and will not establish precedent for any future proceeding.

Rate Year One revenue increases will be allocated to service classes as shown on Appendix 2, Schedule 2. Revenue increases in Rate Year Two and Rate Year Three will be allocated to all classes, as shown on Appendix 2, Schedule 2. As shown on Appendix 2, Schedules 2.7 and 2.9, there is a separate allocation of the incremental costs associated with AMI. The Company is also providing a summary of allocator values in Appendix 2, Schedule 2.4 and the summary results of the Allocated Cost of Service studies in Appendix 2, Schedules 2.5 and 2.6.

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[11] "Western New York Transmission Projects" means transmission projects related to the Western New York Public Policy Transmission Needs identified by the Commission in July 2015 and the subsequent Western New York Public Policy Transmission Project as approved through the New York Independent System Operator's Public Policy Planning Process; Final Report issued October 17, 2017. The only other FERC-regulated project expected to be placed in service during the term of the rate plan are the NYPA Smart Path Connect project, which was referred to NYPA for development pursuant to the Commission's "Order on Priority Transmission Projects" issued on October 15, 2020 in Case 20-E-0197, and Segment A of the Public Policy Transmission Need identified by the Commission in its December 17, 2015 order in Case 12-T-0502.

3.3. Electric Rate Design

Niagara Mohawk's electric rates will be revised as shown in Appendix 2, Schedule 3 for standard service classes and SC-1 Voluntary Time-of-Use rates, and as shown on Appendix 2, Schedule 5 for SC-7 Standby Rates. Typical bill impacts for standard service classes resulting from this rate design are set forth in Appendix 2, Schedule 4.

3.3.1. Empire Zone Rates and Excelsior Job Program Rates

The Empire Zone Rates ("EZR") and Excelsior Job Program ("EJP") rates will be revised and reflect a five-year phase-in of rate increases as shown in Appendix 2, Schedule 10 and includes an Efficiency Transition Implementation Plan ("ETIP") adder for the EJP rates. The ETIP adder rates are derived in Appendix 2, Schedules 3.9, 3.11 and 3.12.

3.4. Modifications to Tariff, Fees and Provisions – Electric

Unless otherwise specified, the tariff modifications set forth in this section will be made in the first tariff compliance filing directed by a Commission order adopting the terms of this Joint Proposal.

3.4.1. Earnings Adjustment Mechanism Surcharge

The Company will continue to recover earned electric Earnings Adjustment Mechanism ("EAM") positive revenue adjustments through the existing EAM surcharge. EAM revenues will be allocated as follows:

(i) Electric Peak Reduction metric – Coincident peak demand allocator;

(ii) LSRV Load Factor metric – Non-coincident peak at primary voltage allocator;

(iii) Electric Energy Efficiency Share the Savings, and Electric LMI EE Customer Savings – the same proportion of Coincident peak demand, Non-coincident peak at primary voltage, Energy, and Total Distribution Revenue allocators as is used to recover electric energy efficiency costs in base rates as discussed in Section IV.17.2.2;

(iv) Distributed Energy Resource Utilization metrics – equal share of Coincident peak demand, Non-coincident peak at primary voltage and Energy allocators; and

(v) Building Electrification, Transportation Electrification and Make Ready Share the Savings – Total Distribution Revenue allocator.

The Company will amend Rule 49 of the tariff to specify that annual adjustments to its EAM surcharge will be filed and served on the parties 15 days in advance of the effective date. The Company will also modify Rule 49 of the tariff to update the surcharge allocation factors consistent with this Joint Proposal.

3.4.2. Demand Response Program Charges

The Company's monthly program charges related to advanced metering requirements for customers that participate in (i) the Energy Demand Response Program, (ii) the Day Ahead Demand Response Program, (iii) the Commercial System Relief Program and (iv) the Distribution Load Relief Program will be revised from $12.42 to $11.77 as shown in Appendix 2, Schedule 11.4. The Company will amend its tariff to clarify that this charge will no longer apply to customers once the Company installs AMI meters for such customers.

3.4.3. Incremental Charges for SC-1, Special Provision L and SC-2, Special Provision O

The Company will revise the incremental monthly charge assessed to SC-1, Special Provision L and SC-2, Special Provision O customers from $3.36 to $3.11 as shown in Appendix 2, Schedule 11.5.

3.4.4. Incremental Charges for SC-2, Special Provision P and SC-3, Special Provisions L and N

The Company will revise the incremental monthly charges assessed to SC-2, Special Provision P and SC-3, Special Provisions L and N customers from $43.46 to $24.71 as shown in Appendix 2, Schedule 11.6.

3.4.5. Competitive Metering Program

The Company will amend its tariff to eliminate language related to its Competitive Metering Program that has been terminated.

3.4.6. Non-Wires Alternatives Surcharge

The Company will update its Non-Wires Alternatives ("NWA") Surcharge language in Rule 45 of the tariff to clarify that the costs of NWAs will be amortized over ten years and that any NWA costs recovered in base rates will not be recovered through the NWA Surcharge. The Company will modify Rule 45 of the tariff to update the surcharge allocation factors consistent with this Joint Proposal.

3.4.7. SC-2, Special Provisions A and B – Unmetered Service

The Company will revise SC-2, Special Provision A to clarify that unmetered service will be offered when metered service presents safety or environmental risks or is not appropriate for the specific application as determined by the Company in its discretion. The Company will also add a Special Provision B that will permit the Company to bill unmetered service of licensed attachments for use of the Company's electric distribution system in accordance with the terms of a separate, mutually executed attachment agreement between the Company and the customer.

3.4.8. SC-7, Special Provision G

The Company will remove language from SC-7, Special Provision G that provides for split billing but retain the provision that provides an exemption for customers with generation nameplates that are less than 15 percent of customer's total usage.

3.4.9. Rule 57.2 Tariff Provision – Revenue Decoupling

The Company will modify Rule 57.2 of its tariff to clarify that interim Revenue Decoupling Mechanism ("RDM") adjustments are applicable for the remainder of the Rate Year and that the Company will have flexibility to determine when to implement interim adjustments to its RDM balances. The Company will modify the tariff language of the RDM to clarify that an RDM adjustment will be recovered over a 12-month period, *i.e.*, the under or over collection from the prior rate year (12 months ending June 30) will be collected or refunded during the 12-month period beginning July 1 of the upcoming Rate Year.

3.4.10. Energy Efficiency Requirements for Excelsior Jobs Program Customers

The Company will modify its tariff to include a requirement that newly certified EJP customers explore energy efficiency opportunities through programs offered by the Company, NYSERDA or other entities offering such programs.

3.4.11. Net Metering and Value of Distributed Energy Resource Credits

The Company will modify its tariff to move certain language concerning the applicability of net metering and credits related to the Value Stack Tariff from SC-4 and SC-12 to Rules 29, 36, 37 and 40 of its electric tariff.

3.4.12. Energy Affordability Program

The Company will file revised tariff leaves eliminating references to Tier 5 of the Energy Affordability Program ("EAP").

3.4.13. Service Class Deferral Credits

The Company will modify Rule 58 of its tariff to reflect updated deferral surcredits as provided in Appendix 2, Schedule 3.

3.4.14. Rule 59 Deletion

The Company will delete Rule 59 from its tariff because the Electric Vehicle Direct Current Fast Charge program expired December 31, 2020. This program has been replaced by the Direct Current Fast Charging component of the Make Ready Program discussed in Section IV.9.

3.4.15. SC-4 Deletions

The Company will revise SC-4 to delete references to rates that are no longer effective.

3.4.16. Energy Storage Surcharge

The Company will revise Rule 56 of the tariff to clarify that the costs of energy storage projects that will be recovered in base rates will be excluded from the Energy Storage surcharge.

3.4.17. Tariff Revisions Related to the Definition of the Rate Year Under This Joint Proposal

The Company will modify its tariff where necessary to revise the definition of the term "Rate Year" consistent with this Joint Proposal.

3.4.18. Dynamic Load Management Surcharge

The Company will modify Rule 64 of the tariff to update the surcharge allocation factors consistent with this Joint Proposal.

3.4.19. Residential Automatic Meter Reading Opt-Out Fees

The Company will modify Rule 25.6 of the tariff to update automatic meter reading ("AMR") Opt-Out fees. The initial fee, and re-installation fee, for removal of existing AMR meter and installation of non-AMR meter will be updated to $44.63 for an electric only meter and to $89.03 for an electric and gas meter replacement. The monthly meter reading fee for an electric-only meter will be updated to $11.64 and for a gas and electric-meter the fee will be $17.71. The updated fees are further provided in Appendix 2, Schedule 11.7. In addition, Rule 25.6 in the tariff will be modified to include the same fees for AMI opt-outs once AMI meters are installed.

3.4.20. Transmission Revenue Adjustment Targets

Pursuant to PSC 220 Rule 43, the Company will continue to reconcile the actual transmission revenue realized, exclusive of revenue taxes, to the updated forecast transmission revenue credit assumed in rates of $216,182,439 for Rate Year 1, $216,620,592 in Rate Year Two, and $220,179,098 in Rate Year Three. The Company will modify Rule 43 of the tariff to update the surcharge allocation factors consistent with this Joint Proposal.

3.4.21. Exemption from Reconnection Fees

The Company will modify Rule 9.1.2 to provide an exemption from reconnection fees for EAP recipients.

3.4.22. Temporary Rates for Customers Switching to Submetering

The Company will add a provision to tariff Rule 8 to provide optional, temporary volumetric rates for customers that have submitted a submetering application, in accordance with Section 15.6 of this Joint Proposal.

3.4.23. Clarification of Letter of Credit Provision for Extensions to Non-Residing Applicants

The Company will modify Rule 16.6.1 of the tariff to clarify that letters of credit will be reviewed annually and will be reduced annually at the end of the review period on a *pro rata* basis as each new customer is connected for service from the Company during the period reviewed.

3.4.24. Hydrogen Energy Transfer System Non-Labor Operations and Maintenance Surcharge

The Company will add a provision to the tariff to implement a non-labor operations and maintenance ("O&M") surcharge related to the costs associated with operating the Hydrogen Energy Transfer System ("ETS") facility as further described in Section IV.12.2.9. An illustration of this surcharge is provided in Appendix 2, Schedule 9.

3.4.25. Net Utility Plant and Depreciation Expense Reconciliation Mechanism Surcharge

The Company will add a new rule to the tariff to implement a surcharge during the Stayout Period to recover costs related to the new Net Utility Plant and Depreciation Expense Reconciliation Mechanism as further specified and conditioned in Section IV.19.2 (i) and (iii) of this Joint Proposal. The surcharge will be based on the cap of the forecasted net utility plant and depreciation levels for the nine months ending March 31, 2025, which are set forth in Appendix 1, Schedule 8 and subject to a two-way reconciliation. An illustration of this surcharge is provided in Appendix 2, Schedule 12.

3.4.26. Incremental New Efficiency: New York Costs Surcharge

The Company will add a new rule to the tariff to implement a surcharge to recover costs related to any Commission-approved New Efficiency: New York ("NE:NY") budget (or other approved energy efficiency programs) not otherwise recovered in rates needed to achieve energy efficiency targets in the nine months ending March 31, 2025, as further specified and conditioned in Section IV.19.2 (ii) and (iii) of this Joint Proposal. The surcharge will recover the difference of such Commission-approved NE:NY budgets (or other approved energy efficiency programs) less the forecast of Commission-approved NE:NY energy efficiency budgets in the nine months ending March 31, 2025, which are set forth in Appendix 1, Schedule 8 as well as in Appendix 5, Schedule 12. This surcharge will be subject to a downward-only reconciliation. An illustration of this surcharge is provided in Appendix 2, Schedule 12.

3.5. Paperless Billing Credit

The Paperless Billing Credit will continue at its present amount. The calculation showing that no change is necessary for the Paperless Billing Credit is provided in Appendix 2, Schedule 11.2.

3.6. Updated Billing Charges and Billing Back-out Credit

During the term of the rate plan, the Company's billing charges to an ESCO that supplies electricity to an electric only customer will be $0.82 per bill. The billing charge to an ESCO that supplies electric to a dual gas and electric customer will be $0.41 per bill. The backout billing credit to a dual gas and electric customer that is supplied electric by an ESCO and receives a consolidated bill from either the Company or the ESCO will be $0.41 per bill. The backout billing credit to an electric only customer that is supplied by an ESCO and receives a consolidated bill from the Company or an ESCO will be $0.82 per bill. The Company will modify Rule 39.11 of the tariff to update the applicable Billing Charges and Billing Back-out Credits as further specified in Appendix 2, Schedule 11.3.

3.7. Re-Establishment Charges and Disconnection Fees

During the term of the rate plan, the Company will assess electric re-establishment meter fees of $54 during normal business hours and $68 after normal business hours. The Company will also assess electric pole disconnect fees of $214 during normal business hours and $375 after normal business hours. Rule 9 of the tariff will be modified to update the applicable fees, as further provided in Appendix 2, Schedule 11.1.

3.8. Revenue Decoupling Mechanism

The RDM targets will be updated consistent with the final revenue requirement and rate design. The RDM targets for each service class for each year of the rate plan are as shown in Appendix 2, Schedule 6.

3.9. Merchant Function Charge

The Merchant Function Charge will be modified to reflect updated revenue targets and uncollectible percentages consistent with this Joint Proposal as shown in Appendix 2, Schedule 7.

3.10. Efficiency Transition Implementation Plan Exemption

The ETIP Exemption credits, applicable to customers exempt from the Systems Benefits Charge, as specified in Rule 41.7 of the tariff, will be updated in the tariff consistent with the final rate design as shown in Appendix 2, Schedule 3.

3.11. Next Base Rate Case

In its next base rate filing, Niagara Mohawk will submit an historical Embedded Cost of Service Study as part of its responses to the pre-filing information requests to the active parties in that proceeding. Niagara Mohawk will not be required to use the results of that study for any purpose.

4. Gas Revenue Allocation and Rate Design

4.1. Gas Revenue Forecast

The gas delivery revenue forecast used to develop the Company's revenue requirement for the Rate Years is set forth in Appendix 3, Schedule 1. For Rate Year One, the revenue forecasts were developed for SC-1 (Residential), SC-2 (Small Commercial), SC-5 (Firm Gas Sales and Transportation), SC-6 (Large Volume Interruptible Transportation), SC-7 (Small Volume Firm Gas Sales and Transportation), SC-8 (Gas Sales and Transportation Service with Standby Sales), SC-10 (Natural Gas Vehicles), SC-12 (Distributed Generation Service – Non-Residential), SC-13 (Distributed Generation) and New York State Electric and Gas Corporation ("NYSEG") by using the forecast number of customers and deliveries multiplied by current tariff rates. For Rate Year Two, the revenue forecasts for SC-1, SC-2, SC-5, SC-6, SC-7, SC-8, SC-10, SC-12, SC-13 and NYSEG were developed by using the forecast number of customers and deliveries multiplied by Rate Year One base delivery rates. For Rate Year Three, the revenue forecast for SC-1, SC-2, SC-5, SC-6, SC-7, SC-8, SC-10, SC-12, SC-13 and NYSEG was developed by using the forecast number of customers and deliveries multiplied by Rate Year Two base delivery rates.

The revenue forecast for SC-9 (Negotiated Transportation Services/Special Contracts) was based on the customers' current contract terms for all Rate Years. The revenue forecast for SC-14 (Dual Fuel Electric Generators) was developed based on either a customer's negotiated contract terms or the applicable standard current tariff rates for all Rate Years because the base delivery rates were not changed in this Rate Case.

4.2. Gas Revenue Allocation

The Signatory Parties agree that no ECOS methodology or set of assumptions sponsored by any party in these proceedings for allocating either the AMI-related costs or the overall revenue requirements should establish precedent for revenue allocation in any future proceeding. The revenue allocation recommended in this Joint Proposal does not endorse any one ECOS methodology or set of assumptions and will not establish precedent for any future proceeding.

The Rate Year One revenue increase will be allocated to service classes as set forth in Appendix 3, Schedule 2.2. Revenue increases in Rate Years Two and Three will be allocated as set forth in Appendix 3, Schedules 3.3 and 3.4. As shown on Appendix 3, Schedule 3.6, there is a separate allocation of the incremental costs associated with AMI. A summary of allocator values is set forth in Appendix 3, Schedule 2.4, and the summary results of the Allocated Cost of Service studies is set forth in Appendix 3, Schedules 2.5 and 2.6.

4.3. Gas Rate Design

Niagara Mohawk's gas rates will be revised as shown in Appendix 3, Schedules 3.1-3.5. Bill impacts resulting from this rate design are set forth in Appendix 3, Schedules 4.1 – 4.4. SC-6 will have volumetric delivery rates set at a 40-percent discount of the applicable firm tail block rate of SC-8.

4.4. Gas Safety and Reliability Surcharge

The current Gas Safety and Reliability Surcharge ("GSRS") will continue to allow the Company to recover incremental LPP investment costs which consist of a return on investment and depreciation expense (capped at 102 percent of the Company's average LPP replacement costs) associated with incremental replacement of LPP above the level funded in base rates. The surcharge will be calculated by first allocating the revenue requirement associated with the incremental LPP investment costs to each firm service classification on the basis of the forecast delivery revenues established in this Joint Proposal and then developing a rate for each service classification. The GSRS will be reconciled annually and included in the Delivery Rate

Adjustment recovered from firm sales and firm transportation customers beginning November 1 of the following Rate Year. An illustrative example of the GSRS calculation is set forth on Appendix 6, Schedule 15.

4.5. Gas Tariff Modifications

Unless otherwise specified, the tariff modifications set forth in this section will be made in the first tariff compliance filing directed by a Commission order adopting the terms of this Joint Proposal.

4.5.1. Modifications to SC-2, SC-5, SC-6, SC-7, and SC-8 and Elimination of SC-3

The Company will eliminate SC-3 and include a sales option to SC-5, SC-7, and SC-8 to ensure that similarly situated customers pay the same delivery rate regardless of whether the customer is a sales or transportation customer. Any customer migration among SCs needed to effectuate these modifications will occur within 45 days following the effective date of tariff leaves implementing this Joint Proposal.

In addition, the Monthly Cost of Gas and the Merchant Function Charge will be applied to sales customers served under SC-5, SC-7, and SC-8. Moreover, the Load Factor, Lost and Unaccounted For ("LAUF") factor and System Performance Adjustment ("SPA") rate formulas will include SC-5, SC-7, and SC-8 sales customers' volumes.

Additionally, the SC-6 delivery rate for consumption in excess of the first 100 therms will be set as a 40-percent discount rate of the SC-8 tail block base delivery rate.

4.5.2. Earnings Adjustment Mechanism Surcharge

The Company will continue to recover earned gas EAM positive revenue adjustments through the existing EAM surcharge. EAM revenue will be allocated to firm sales and transportation customers exclusive of EZR and EJP load, as follows:

(i) gas peak reduction EAM revenue will be allocated on the basis of percentage of peak sendout; and

(ii) Gas Energy Efficiency Share-the-Savings and Low-to-Moderate Income Energy Efficiency Customer Savings EAM revenue will be allocated based on the percentage of firm gas deliveries, using the same allocation methodology that is used to recover gas energy efficiency costs as discussed in Section IV.17.7.2.

The Company will file and serve on parties annual changes to its EAM Surcharge 15 days in advance of their effective date.

4.5.3. Research and Development Surcharge

The Research and Development surcharge will be capped at $0.0174 per dekatherm consistent with the Commission's February 14, 2000 Order issued in Case 99-G-1369.

4.5.4. Delivery Service Adjustment

The Company will modify the tariff rule reference made under the Delivery Service Adjustment ("DSA") section to refer back to the refund provision under Rule 17.6 of the Gas Tariff in each applicable service classification (SC-1, SC-2, SC-5, SC-7, SC-8, SC-12, SC-13, and NYSEG).

The Company will file an initial DSA statement to become effective on the effective date of a Commission order adopting the terms of this Joint Proposal and will file subsequent updates to the DSA statement as necessary. The DSA statement will include, but is not limited to, the following components for firm sales and firm transportation customers: NRS (Net Revenue Sharing), R&D (Research and Development Surcharge), RDM (Revenue Decoupling Mechanism Adjustment), GSRS (Gas Safety and Reliability Surcharge), EAM (Earnings Adjustment Mechanism), SPA (System Performance Adjustment), TRA (Gas Transportation Rate Statement: Annual Transportation Imbalance Surcharge or Refund), NPA (Non-Pipe Alternative), NUP (Net Utility Plant Tracker Surcharge) and IEE (Incremental NE:NY Costs). The pro-forma statement is included in Appendix 3, Schedule 12.

4.5.5. Tariff Alignment Study

Within 120 days of the effective date of a Commission order adopting the terms of this Joint Proposal, the Company will file to modify its tariff to incorporate the results of the tariff alignment study performed in accordance with the 2018 Rate Order. The tariff alignment study was performed to determine which section of the Company's tariff could be aligned with those of its downstate affiliates, The Brooklyn Union Gas Company d/b/a National Grid NY ("KEDNY") and KeySpan Gas East Corporation d/b/a National Grid ("KEDLI") (collectively "Downstate Affiliates").

4.5.6. Energy Affordability Program Tariff Provision

The Company will file to modify the EAP provision of its tariff to eliminate references to Tier 5 of the program.

4.5.7. Expansion of Energy Efficiency Programs to SC-6

The Company will make appropriate changes to its tariff to include SC-6 Interruptible Transportation service on the list of services eligible for the Company's energy efficiency programs.

4.5.8. Daily Balancing Demand Charge

The Company will update its Daily Balancing Demand Charge calculation applicable to electric generators served on SC-14 similar to the current methodology that is being used for KEDNY and KEDLI electric generators. The Daily Balancing Demand Charge reflects the fixed upstream capacity assets the Company uses to manage the imbalances for all customers and the associated costs to secure these assets. The Company will modify the tariff to align the Company's electric generator tariff provisions with those of KEDNY and KEDLI. An illustrative example of the calculation of the Daily Balancing Demand Charge calculation is set forth in Appendix 3, Schedule 16.

In addition, the Company will modify the tariff to clarify that all peaking supplies will be included in the calculation of the demand charge component associated with peaking assets for monthly balanced customers.

4.5.9. Excelsior Jobs Programs

The Company will modify its tariff to include a requirement that newly certified EJP customers explore energy efficiency opportunities through programs offered by the Company, NYSERDA or other entities offering such opportunities.

The Company will adopt new marginal cost rates, as shown in Appendix 3, Schedule 3.9. The Company will phase in the gas EJP rates over a six-year period, as shown in Appendix 3, Schedule 17, for those classes seeing an increase, subject to EJP customers receiving the lower EJP rates or standard tariff rates. The Company will perform an annual review of all of EJP customer classes that may pay more on EJP marginal rates than on the otherwise applicable standard tariff rate. If that review indicates a customer paid more on EJP rates than on the standard tariff rate, the Company will provide a refund of the difference.

4.5.10. Gas Transportation Rate Statement

The Company will include language in its tariff to clarify that the Gas Transportation Rate Statement is applicable to SC-12 customers. The Gas Transportation Rate Statement is applicable to SC-12 customers currently under Rule 17.6.3 in the General Information section of the gas tariff.

4.5.11. Exemption from Reconnection Fees

The Company will modify its tariff to provide an exemption from reconnection fees for EAP customers.

4.5.12. Deferral Surcredits

The Company will modify Rule 41 to reflect updated deferral surcredits.

4.5.13. Net Utility Plant and Depreciation Expense Reconciliation Mechanism Surcharge

The Company will add a new rule to the tariff to implement a surcharge during the Stayout Period to recover costs related to the new Net Utility Plant and Depreciation Expense Reconciliation Mechanism as further specified and conditioned in Section IV.19.2(i) and (iii) of this Joint Proposal. The surcharge will be based on the cap of the forecasted net utility plant and depreciation levels for the nine months ending March 31, 2025, which are set forth in Appendix 1, Schedule 9 and subject to a two-way reconciliation. An illustration of this surcharge is provided in Appendix 3, Schedule 11.

4.5.14. Incremental New Efficiency: New York Costs Surcharge

The Company will add a new rule to the tariff to implement a surcharge to recover costs related to any Commission-approved NE:NY budget (or other approved energy efficiency programs) not otherwise recovered in rates needed to achieve energy efficiency targets in the nine months ending March 31, 2025, as further specified and conditioned in Section IV.19.2 (ii) and

(iii) of this Joint Proposal. The surcharge will recover the difference of such Commission-approved NE:NY budgets (or other approved energy efficiency programs) less the forecast of Commission-approved NE:NY energy efficiency budgets in the nine months ending March 31, 2025, which are set forth in Appendix 1, Schedule 9 as well as in Appendix 6, Schedule 12. This surcharge will be subject to a downward-only reconciliation. An illustration of this surcharge is provided in Appendix 3, Schedule 11.

4.5.15. Non-Pipe Alternatives Cost Recovery Mechanism

The Company will add a new NPA cost recovery mechanism consistent with the "Report of Niagara Mohawk Power Corporation d/b/a National Grid Concerning the Non-Pipeline Alternatives Incentive Mechanism Collaborative" filed December 21, 2018 in Case 17-G-0239. NPA Proposal costs and any incentive recovered, subject to true-up, under the NPA Incentive Mechanism will be allocated to each service class based on the type of traditional gas project the NPA would defer, using the following allocators: (1) Peak Sendout for projects that defer the need for infrastructure designed to meet the peak day demand; and (2) Total Gas Deliveries for projects that defer the need for infrastructure designed to meet daily demands.

4.5.16. Eliminate Outdated Language in the Gas Tariff

The Company will modify its tariff to eliminate outdated language related to refunds from pipeline transporters and storage providers. The refunds from the settlement agreements in Cases 95-G-1095 and 10-G-0251 have ended and are no longer applicable.

4.5.17. Residential Automatic Meter Reading Opt-Out Fees

The Company will modify Rule 13.6 of the tariff to update AMR Opt-Out fees. The initial fee and re-installation fee, for removal of existing AMR meter and installation of non-AMR meter will be updated to $61.19 for a gas only meter and to $89.03 for an electric and gas meter replacement. The monthly meter reading fee for a gas-only meter will be updated to $11.64 and for a gas and electric meter, the fee will be $17.71. The updated fees are further provided in Appendix 3, Schedule 5.3. In addition, Rule 13.6 in the tariff will be modified to include the same fees for AMI opt-outs, once AMI meters are installed.

4.6. Lost and Unaccounted for Gas

The LAUF targets and deadbands that will apply during the term of the rate plan are as follows:

Targets	%
LAUF Target	1.672%
Upper Band	2.672%
Lower Band	0.672%

The new LAUF targets and dead bands will become effective in the month subsequent to the month in which the Commission issues an order adopting the terms of this Joint Proposal and will be prorated as necessary for the Gas Adjustment Clause ("GAC") year in which they are implemented. The LAUF factor of adjustment calculation will be modified to gross up gas costs for LAUF Gas. The loss percentage will be calculated by dividing losses into system receipts including any necessary adjustments. The Factor of Adjustment ("FOA") will be calculated as follows: FOA = 1/(1-loss percentage). The development of the LAUF targets and deadbands is provided in Appendix 3, Schedule 8.

4.6.1. Inactive Accounts Adjustment to LAUF Calculation

Niagara Mohawk will perform a calculation to remove from the LAUF calculation an estimate of the gas usage associated with meters that have been inactive for more than 90 days. This calculation will be converted to a monetary adjustment by multiplying the inactive account volumes by Niagara Mohawk's Weighted Average Cost of Gas for the period applicable to the calculation. The monetary inactive account adjustment shall be included in the annual GAC reconciliation as a separate line item that increases gas cost revenues.

4.7. Revenue Decoupling Mechanism

Niagara Mohawk will modify its RDM for SC-1, SC-2, and SC-7 to change revenue per customer targets to revenue per class targets. The RDM targets for each Rate Year and the Stayout Period (assuming the Stayout Period extends through March 31, 2025) are shown on Appendix 3, Schedule 7.

4.8. Merchant Function Charge

Niagara Mohawk's current MFC (as set forth in PSC 219 Rule 33) will continue with the following modifications:

(a) The Company's MFC will be expanded to apply to firm sales service customers that migrate to SC-5, SC-7, or SC-8. Appendix 3, Schedule 6.3, page 10 sets forth an illustrative MFC statement that is modified to reflect updated targets as set forth on Appendix 3, Schedule 6.1.

(b) The MFC annual expense targets and annual reconciliation will be on a Monthly Cost of Gas ("MCG") year (12 months ending August 31) basis. The conversion of the annual expense targets of the gas supply procurement and commodity-related credit and collection charge from Fiscal Year to MCG year is shown in Appendix 3, Schedule 6.2. An illustrative example of the stub period reconciliation is shown on Appendix 3, Schedule 6.4.

(c) The MFC will be updated to reflect the Gas Supply Procurement target of $674,066. The commodity-related credit and collection expense target revenue requirement will be allocated between residential and non-residential customers in the amount of $664,719 and $30,274, respectively, as shown in Appendix 3, Schedule 6.2.

(d) The return requirement on purchased gas related to working capital will be updated to reflect the lead-lag rate and the Company's pre-tax weighted average cost of capital, as shown in Appendix 3, Schedule 6.3, page 7.

(e) The Company will separately reconcile revenues to targets for residential and non-residential commodity-related credit and collection expenses. The Company will reset its commodity-related credit and collection expense per therm charge annually based on the latest sales forecast every September 1, and reconcile the revenue to target, effective the following January 1 of each year.

(f) The commodity-related uncollectible rate, which is 2.1 percent for residential and 0.2 percent for non-residential customers, is calculated by dividing net write-offs by the sum of (i) total revenue exclusive of Other Gas Revenues; (ii) Late Payment Charge Revenues; and (iii) receivables purchased under the Company's Purchase of Receivables program.

(g) The Company will update the discount rate applicable to the purchased receivables to reflect the commodity-related uncollectible percentage and will update the commodity-related credit and collections rates applicable to the Purchase-of-Renewables program that is being proposed in this case. The credit and collections rate and the uncollectible percentage applicable to ESCOs will equal the Company's MFC charged to its sales customers.

(h) The Company will update the return requirement on gas storage inventory target annually based on the latest storage cost forecast and will also update the pre-tax weighted average cost of capital. An illustrative example of the calculation is shown in Appendix 3, Schedule 6.3.

4.9. Next Base Rate Case

In its next base rate filing, Niagara Mohawk will submit an historical Embedded Cost of Service Study as part of its responses to the pre-filing information requests to the active parties in that proceeding. Niagara Mohawk will not be required to use the results of that study for any purpose.

4.10. Paperless Billing Credit

The Company's current paperless billing credit will remain in effect during the term of the rate plan. The calculation showing that no change is necessary for the Paperless Billing Credit is provided in Appendix 3, Schedule 5.2.

4.11. Billing Charge/Billing Back-out Credit

During the term of the rate plan, the Company's billing charges to an ESCO that supplies gas to a gas only customer will be $0.82 per bill. The billing charge to an ESCO that supplies gas to a dual gas and electric customer will be $0.41 per bill. The backout billing credit to a dual gas and electric customer that is supplied gas by an ESCO and receives a consolidated bill from either the Company or the ESCO will be $0.41 per bill. The backout billing credit to a gas only customer that is supplied by an ESCO and receives a consolidated bill from the Company or an ESCO will be $0.82 per bill. The Company will modify the tariff to update the applicable Billing Charges and Billing Back-out Credits as further specified in Appendix 3, Schedule 5.1.

4.12. Re-establishment Charge

During the term of the rate plan, the gas re-establishment meter fee will be $54 during normal business hours and $68 after normal business hours.

5. <u>Computation and Disposition of Excess Earnings</u>

5.1. Earnings Report

By August 31 of each year, commencing in calendar year 2022, the Company will file an earnings report using the methodology described in this Section and Shown in Appendix 4. The earnings report will be used for the Earnings Sharing Mechanism set forth in Section IV.5.3.

The earnings report will calculate Niagara Mohawk's ROE for the preceding Rate Year using a capital structure with an equity component equal to 48 percent. In the event Niagara Mohawk does not file for new rates to be effective until after July 1, 2024, the earnings sharing threshold of greater than 9.5 percent for any period of time less than a year before new rates take effect will be prorated to develop a stub period earnings sharing threshold. The stub period will be calculated by adjusting the actual average rate base for that period by an operating revenue ratio factor. The operating revenue ratio factor will be calculated as the ratio of operating revenue during the same partial period in the previous Rate Year to the total operating revenue for that Rate Year. An example of the calculation for the stub period is shown in Appendix 4, Schedule 1.

5.2. Discrete Incentives and Revenue Adjustments

Niagara Mohawk will calculate its ROE by excluding the effects of the following discrete incentives and negative and positive revenue adjustments:

- Amounts previously booked in excess of earnings thresholds;
- Supplemental executive retirement plan;
- Electric and gas property tax sharing;
- Electric and gas customer service quality revenue adjustments;
- Gas safety performance revenue adjustments;
- Electric and gas EAMs;

- Gas LAUF;
- Electric reliability revenue adjustments, which include the electric cost estimating and inspection and maintenance metrics;
- Gas revenue sharing for capacity release and off-system sales;
- Gas revenue sharing for SC-6, SC-9, and SC-14;
- Non-wires alternative and non-pipe alternative revenue adjustments;
- Leak prone pipe productivity incentives;

The Company will also exclude any new incentives, if any are implemented by the Commission separate from the order setting rates in these proceedings.

5.3. Earnings Sharing Mechanism

If Niagara Mohawk's actual ROE in any Rate Year, excluding the discrete incentives and negative and positive revenue adjustments identified in Section 5.2, exceeds 9.5 percent, the amount in excess of 9.5 percent will be deemed "shared earnings" for the purposes of this Joint Proposal and be treated as follows:

5.3.1. ROE > 9.5% and ≤ 10.0%

If the level of earned ROE for Niagara Mohawk exceeds 9.5 percent but is less than or equal to 10.0 percent, 50 percent of the revenue equivalent of earnings will be deferred for the benefit of customers and 50 percent will be retained by Niagara Mohawk.

5.3.2. ROE > 10.0% and ≤ 10.5%

If the level of earned ROE for Niagara Mohawk exceeds 10.0 percent but is less than or equal to 10.5 percent, 75 percent of the revenue equivalent of earnings will be deferred for the benefit of customers and 25 percent will be retained by Niagara Mohawk. The Company will use

50 percent of its retained earnings under this Section IV.5.3.2, if any, to reduce regulatory asset balances associated with Site Investigation and Remediation ("SIR") activities.

5.3.3. ROE > 10.5%

If the level of earned ROE for Niagara Mohawk exceeds 10.5 percent, 90 percent of the revenue equivalent of earnings will be deferred for the benefit of customers and 10 percent will be retained by Niagara Mohawk. The Company will use 50 percent of its retained earnings under this Section IV.5.3.3, if any, to reduce regulatory balances associated with SIR activities.

6. Electric and Common Capital Investment Levels and Infrastructure and Operations Programs

6.1. Capital Investment Levels

Appendix 1, Schedule 5 sets forth the Company's forecast level of electric and common capital, cost of removal (where applicable) and the Energy Storage Order regulatory asset investments for each Rate Year. Notwithstanding the specified segment-level spending amounts set forth in Appendix 1, Schedule 5, nothing in this Joint Proposal is intended to limit Niagara Mohawk's flexibility during the term of the rate plan to substitute, change, or modify its capital projects.

6.2. Gilmantown Energy Storage

The Company proposes to own and operate an energy storage facility in Gilmantown, New York. The projected capital costs of the project of $8.931 million are reflected in the Company's revenue requirements. However, the Company is still evaluating whether to construct and own the project itself or contract with a third-party energy storage provider for the project. The Company will select the project that best meets the evaluation criteria regardless of whether the project will be owned by the Company or a third party. The Company will consult with Staff prior to bid selection for the project as to how the Company should proceed once all bids have been received and analyzed. If the Company selects a third-party energy storage provider then the Company will defer for future recovery from customers the revenue requirement associated with the third-party project and create a regulatory liability for amounts reflected in the revenue requirement for the Company-owned project, as further described in Section IV.12.2.3 of this Joint Proposal.

6.3. Vegetation Management

The Company's electric revenue requirements reflect costs for vegetation management of $78.856 million in Rate Year One, $80.666 million in Rate Year Two, and $82.323 million in Rate Year Three. These costs will remain subject to a downward-only reconciliation mechanism applied to the Company's aggregate total vegetation management costs over the term of the rate plan. Any under-expenditure in total program costs in a given Rate Year will be carried forward and reconciled at the end of Rate Year Three. An example of the reconciliation is set forth in Appendix 5, Schedule 16.

6.4. Major Storms

For cost recovery and deferral purposes, the definition of a "Major Storm" will be modified from what had been previously used to that currently set forth in 16 NYCRR § 97.1(c) ("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"). During the term of the rate plan the deferral threshold for a major storm will be $0.750 million to be applied to all qualifying regions, in aggregate, in the Company's service territory for a given storm event. The Major Storm revenue allowance reflected in rates will be $30 million. The treatment of Major Storm costs is more fully described in Appendix 14 and Appendix 5, Schedule 17.

6.5. Capital Reporting Requirements

The Company will provide quarterly and annual capital reports on a Fiscal Year basis. The capital reporting requirements are set forth in Appendix 17.

6.6. Non-Wires Alternatives

The Company will amortize all NWA project costs over a ten-year period. In addition, the existing NWA incentive and cost recovery mechanisms shall be modified to eliminate the distinction between small and large NWAs. As modified, the existing NWA incentive mechanism will continue for the term of the rate plan. The treatment of the NWA incentive mechanism is more fully described in Appendix 13.

7. Gas Capital Investment Levels and Infrastructure and Operations Programs

7.1. Gas Capital Investment Levels

Appendix 1, Schedule 5 sets forth the Company's forecast level of gas capital and cost of removal (where applicable) investment by program for each Rate Year. Notwithstanding the specified segment-level and program/project level spending amounts set forth in Appendix 1, Schedule 5, nothing in this Joint Proposal is intended to limit Niagara Mohawk's flexibility during the term of the rate plan to substitute, change, or modify its capital projects.

7.2. Withdrawal of Application for the Albany Loop Project

The Company will withdraw its Article VII application to construct and operate the Pipeline E37 Reliability and Resiliency Project (Albany Loop)[12] within 60 days of the issuance of a Commission order adopting the terms of this Joint Proposal, and will not refile such a petition during the term of this agreement except for the limited circumstance where the Company determines the project is necessary to address exigent operating conditions that would impact safe and reliable service to the Company's existing customers. If submitted, the Article VII filing must include a detailed engineering assessment and other support for the exigent operating conditions that the Company asserts required the Company to submit the Article VII application during the term of the rate plan. The Company is authorized to defer, with carrying charges at the pre-tax weighted average cost of capital and subject to Staff review, the preliminary engineering and development costs incurred through July 31, 2021, $4.599 million, for future recovery from customers. To the extent that the Company submits a new application under Article VII and the Commission issues a certificate to construct and operate the Albany Loop Project, the Company may seek recovery of the costs of the project incurred after July 31, 2021 in a subsequent rate filing.

7.3. Service Line Proceeding

In compliance with the Commission's Order in Case 15-G-0244, the Company amended its tariffs to include tariff penalties for customers that do not cooperate with inside service line inspections (*e.g.*, after one refusal, two scheduled and then cancelled appointments, or failure to

[12] Case 19-T-0069, *Application of Niagara Mohawk Power Corporation for a Certificate of Environmental Compatibility and Public Need Pursuant to Article VII for the Pipeline E37 Reliability and Resiliency Project in the Town of Bethlehem, Albany County and the Towns of East Greenbush and North Greenbush, Rensselaer County* (filed February 1, 2019).

respond to notifications).[13] The amounts recovered through assessment of the penalties will be used to offset the costs of service line inspections. Service line inspections will be coordinated with other activities whenever reasonably feasible. The Company agrees to develop a mechanism to offset program costs with penalty revenues during the rate plan period for incorporation in next rate proceeding.

7.4. Smart Meters and Smart Residential Methane Detectors

In the June 15, 2020 "Order Authorizing Use of Funds for Pipeline Safety Programs" issued in Case 17-G-0239, the Commission addressed $6.351 million in deferred credits reserved for use on gas safety programs. That order directed the Company to use $4.485 million on two gas safety programs, including $1.95 million on the Incremental Residential Methane Detector Program (of which approximately $0.989 million remains unspent). Additionally, that order deferred $1.866 million of the total $6.351 million for future use. Unless otherwise directed by the Commission, the Company will use the $1.866 million of deferred credits and any unspent portion of the $0.989 million not needed to complete the Incremental Residential Methane Detector Program to develop and distribute AMI-enabled residential methane detection ("RMD") devices until these deferral credits are exhausted. Any unspent credits at the end of the rate plan will be used for the benefit of customers in a future rate proceeding.

The Company will file with the Secretary to the Commission an annual report by April 1 following the first calendar year in which it begins installing Smart RMD devices, detailing the number of smart meters and RMDs installed in the subject calendar year, the total number of smart

[13] Case 15-G-0244, *Proceeding on Motion of the Commission to Develop Implementation Protocols for Complying with Inspection Requirements Pertaining to Gas Service Lines Inside Buildings*, Order Establishing Statewide Inspection Schedules and Procedural Requirements (issued April 20, 2017); Case 15-G-0244, *supra*, Niagara Mohawk Tariff Filing (filed May 10, 2017).

meters and RMDs installed to date, the per device cost and total costs for installation in the subject calendar year, the costs for installation to date, the alarms received by the control center in the subject calendar year, the number of alarms associated with methane leakage in the subject calendar year, and the actions taken by the Company in response to each of the alarms received.

7.5. Relocating Inside Gas Meters

The Company will relocate gas meters that are located inside a customer's premises and install them outside when performing any planned service line replacements (whether by insertion or direct burial), new service installations that offer the customer and the Company the opportunity to relocate meters outside (*e.g.*, major renovation projects), and other opportunities where work can feasibly be performed. The Company may also consider whether and where to relocate meters if the premises are located in a flood plain (*e.g.*, elevating the gas meter to a higher location). The following exceptions will apply to the Company's obligation to relocate inside gas meters: (i) where the customer refuses to provide consent to such relocation; (ii) where local building codes, regulations, or authorities preclude such relocations; (iii) where exterior or interior obstacles, space constraints, or physical barriers preclude such relocations; (iv) when the work involved is an emergency service line repair or replacement; (v) where relocation requires extensive interior or exterior restoration and/or complicated interior piping work that would involve excessive costs or present increased operational risks for the Company and/or customer; or (vi) where the gas meter should not be moved outside for safety reasons. Customers who already have services installed, and who have no greater than two dwelling units, will be moved to a list of customers for meter relocation at a later date unless one of the above exceptions apply. The Company will also make reasonable efforts to relocate for premises that are greater than two dwelling units and where none of the above indicated exceptions apply. Customers that refuse to move meters outside: (1) will be asked to sign a form explaining the reason(s) for refusal and stating that they are aware of the benefits of having their meters outside; and (2) will be subject to charges for future costs related to survey/inspection of inside piping in accordance with the Company's applicable tariff provisions. In instances where one or more of the above exceptions apply, the Company will track and document each customer meter it does not relocate outside, as well as the reason(s) the relocation was not performed. The Company will file with the Commission an annual report by April 1 of the following calendar year that includes: (1) the number of meters relocated outside; (2) the number of meters left inside; and (3) of the meters left inside, the specific reason that the meters were not moved and the number that involved service replacements by installation of a new service line in premises for one- and two-family homes. The Company will develop a plan to address any remaining meters that are not located in a readily accessible location and provide that plan as part its next base rate filing.

7.6. First Responder Training Program

The Company will consider adopting the principles of the Pipeline Emergency Responders Initiative in conducting regular drills with local fire departments and municipalities once the principles are finalized. The Company will provide, within 90 days of the end of each Rate Year, an annual report detailing its progress including, but not limited to, the date and times of the drills, who was in attendance, what topics were reviewed, and any applicable recommendations. The Company will address the status of the adoption of the Pipeline Energy Responders Initiative principles in its annual report.

7.7. Bundled Walking, Atmosphere, and Inside Inspection Programs

Within 90 days of the issuance of a Commission order adopting the terms of this Joint Proposal, the Company will file with the Secretary to the Commission a revised operation and maintenance procedure to reduce the current five-year leakage inspection cycle to align with the three-year atmosphere corrosion inspection cycle. To the extent that any inspection requirements or relevant regulations change in the future, the Company may propose to modify its O&M procedure to comply with such changes.

7.8. Enhanced Inactive Account Process

The Company will continue to follow its current process of immediately performing a site analysis on every inactive account site to determine whether conditions warrant immediately disconnecting the service, and, if so, disconnecting the service within 24 hours. For those sites that do not present an urgent circumstance, the Company will implement a phased approach to reduce the number of days to resolve inactive accounts to 45 days by the end of Rate Year One and to 30 days by the end of Rate Year Three. The Company will file with the Secretary to the Commission a comprehensive annual inactive account program report no later than 60 days following the close of each calendar year. The first report will be filed in 2023 for calendar year 2022 data. The report will include, at a minimum: (1) the total number of inactive accounts, broken down by a unique identifier, whether the inactive account site is occupied or unoccupied, and the number of days of inactivity entering the calendar year; (2) the total number of occupied and unoccupied accounts, broken down by a unique identifier, that were visited during the calendar year and when they were visited during the calendar year; (3) the course of action (*e.g.*, locking the meter, disconnecting the service, entering the replevin process, etc.) taken by the Company for each inactive account, broken down by a unique identifier; and (4) the total number of inactive accounts broken down by a unique identifier, whether the residence is occupied or unoccupied and the number of days of inactivity at calendar year's end. The Company will provide Staff with additional inactive account data, to the extent reasonably available, upon request. Any such request will be made by letter to the Company's Vice President of Gas Operations in New York. The data shall be provided to Staff within 20 days of the request date.

7.9. Construction Safety Inspections

By the end of the rate plan period, the Company will establish a baseline ratio of approximately one inspector to two contractor crews depending upon the work being inspected, and work to ensure adequate levels of on-site inspections and oversight for all contractor crews, including field verification of operator qualifications, work methods and construction standards/procedures compliance, and work scope documentation.

7.10. Enhanced High Emitter Methane Detection Program

The Company will develop an Enhanced High Emitter Methane Detection Program that will target leaks of ten standard cubic feet per hour or greater for repair or replacement to reduce methane emissions from the distribution system and prevent lost gas. The scope of the program is identified in Appendix 11. The Company will hire an advanced leak detection contractor to aid in prioritizing for repair possible large emitters within areas previously identified as possible high leak concentration areas, and begin advanced leak surveying within twelve months of the issuance of a Commission order adopting the terms of this Joint Proposal.

7.11. Gas Capital Reporting Requirements

7.11.1. Leak Prone Pipe Prioritization, Type 3 Leak, and Capital Plan Report

On or before April 1 of each year, the Company will file with the Secretary to the Commission a LPP prioritization summary identifying: (i) the proposed projects and their estimated costs; (ii) an inventory of Type 3 leaks on each system; and (iii) the approved five-year capital plan in the same format as Appendix 1, Schedule 5, Page 2.

7.11.2. Quarterly Capital Report

The Company will file with the Secretary to the Commission a quarterly variance report within 45 days after the end of each of the first three quarters of each Fiscal Year. The report will be in the same format as Appendix 1, Schedule 5, Page 2 with explanations for variances between the approved budget and the actual expenditures, details on the progress of LPP retirement mileage, Type 3 leaks repaired, and a summary of the current Type 3 leak inventory, and new customers connected to the system.

7.11.3. Annual Capital Report

The Company will file with the Secretary to the Commission an annual report not later than not later than May 31 of each year that includes, for the preceding Fiscal Year: (i) a final variance summary of capital expenditures for all capital projects and programs, including all ongoing and active construction projects and programs in the same format as Appendix 1, Schedule 5; (ii) a narrative explaining any cost or timeline differences exceeding 10 percent; (iii) a narrative on project design, permitting, and/or construction status (including a detailed construction schedule for each project) for any ongoing projects; (iv) a description of any new projects or programs; and (v) capital project sanctioning documents for any projects exceeding $1 million that were authorized during the previous Fiscal Year.

7.11.4 Continued Reporting

The reports listed in Sections 7.11.1-7.11.3 above shall continue until a new rate plan is adopted by the Commission.

7.12. Additional Gas Safety Programs

The Company will conduct the following gas safety projects and programs during the term of the rate plan:

(i) Expanded Quality Assurance / Quality Control Re-Dig Program;

(ii) Single Meter Regulator Inspection Program;

(iii) Gas Technical Training Transformation Project;

(iv) Smart Meter and Residential Methane Detection Programs;

(v) Enhanced First Responder Train-the-Trainer Program;

(vi) Transmission Station Integrity Program;

(vii) Instrumentation and Regulator Supervisor Onboarding Initiative; and

(viii) Voluntary Integrity Management Program.

8. Advanced Metering Infrastructure

8.1. Downward-Only Tracker for Operation and Maintenance Costs

The Company will be authorized to recover $119.17 million of AMI-related O&M expense as defined below and incurred during the six-year AMI deployment period beginning Fiscal Year 2022 subject to a downward only reconciliation at the end of the six-year AMI deployment period. The downward only tracker applies to the following categories of costs as reflected in the Company's updated AMI Benefit/Cost Analysis model.

- AMI Demonstration Period Costs;
- Network Communications LTE Backhaul Cost (Electric Meters);
- AMI Meter Cellular Service Cost (Electric Meters);
- AMI External Project Management Labor Costs;
- AMI Internal Project Management Leadership Staff;
- AMI Internal Project Management Business Support;
- AMI Communications Equipment Software Maintenance Cost;
- Account Maintenance and Operation (AMO) Implementation;
- AMI Additional Meter Data Services Labor Costs;
- Customer Engagement Plan Costs;
- Customer Engagement Plan Labor Costs;
- Professional Services – Head End/Meter Data Management (MDM) Solution Program Management Costs;
- Energy Monitoring Portal O&M Costs;

- Professional Services – Head End/MDM Systems Implementation Workstream Costs;
- Software Purchase Fees – Head End Software (HES, MDMS, NMS, FDM) Costs;
- Software Fees – Head End Software (HES, MDMS, NMS, FDM) Costs;
- Telecom O&M Costs;
- Enterprise Service Bus (ESB) O&M & RTB Costs;
- Data Lake O&M & RTB Costs;
- Information Management O&M Costs;
- Customer Service System (CSS) Enhancements O&M & RTB Costs;
- Meter Inventory Management Upgrade Costs;
- Load Disaggregation Software Cost;
- Outage Management System (OMS) Integration O&M & RTB Costs; and
- Cyber Security Project OPEX Initial.

In future rate proceedings, the Company may seek recovery of costs incurred over the six-year AMI deployment period in the aforementioned categories in excess of the O&M tracker amount for costs associated with incremental work on AMI implementation beyond that described in this Joint Proposal, upon a showing that the incremental work and associated costs are both prudently incurred and are justified by measurable incremental benefits. The structure of this AMI O&M tracker will afford the Company flexibility to substitute, change, or modify the timing of its AMI investments as necessary to deliver the scope of the program without requiring Commission approval for any implementation adjustments. In addition, to the extent that the AMI deployment period is extended beyond six years, the AMI downward-only tracker will be extended to reflect the extension of the period (the $119.17 million cap will not be modified and can only be used to deliver the scope of work that was intended at the time of this Joint Proposal to be completed during the planned six-year deployment period). The Company shall provide notification to the Secretary of the Commission of the extension of the AMI deployment period. Such notification shall include an explanation as to the circumstances that lead to the need for the extension of the deployment period and a status update of the O&M costs incurred to date. An example of the AMI downward-only O&M tracker is set forth in Appendix 5, Schedule 13 for the Company's electric operations and Appendix 6, Schedule 13 for the Company's gas operations.

8.2. AMI Opt-Out, Meter Read and Meter Replacement Fees

Once AMI meters are deployed, the Company will read meters for customers who opt-out of AMI on a bi-monthly basis, *i.e.*, once every two months. The Company will apply the same fees for customers who opt out of AMI meters as it charges for customers who opt out of AMR meters, as specified in Sections IV.3.4.19 and IV.4.5.17 of this Joint Proposal. The monthly AMI-opt out fees shall be $11.64 for either a gas or electric meter reading customer and $17.71 for a combined gas and electric meter reading customer. In addition, the Company will charge AMR meter-replacement fees of $44.63 for electric, $61.19 for gas, and $89.03 for a combined electric and gas customer. In addition, the monthly AMR meter reading fees will be $11.64 for either a gas or electric meter reading and $17.71 for a combined gas and electric meter reading.

8.3. Miscellaneous AMI-related Matters

8.3.1. Resiliency Enhancements to AMI Communications System

The Company will continue to evaluate opportunities to enhance resiliency through development of the AMI deployment plan.

8.3.2. Potential Incentives Under the AMI Project

The Company will consider AMI project incentives and may propose incentives in its next base rate filing.

9. <u>Electric Vehicles</u>

All Electric Vehicle Program costs will be recovered through a surcharge to be determined annually on an as-spent basis. Consistent with the Commission's July 16, 2020 Order in Case 18-E-0318 ("Make Ready Order"), cost recovery will be permitted for the Company's:

(i) Make-Ready Program;

(ii) Environmental Justice Community Clean Vehicles Transformation Prize;

(iii) Clean Personal Mobility Prize;

(iv) Clean Medium-Duty and Heavy-Duty Innovation Prize;

(v) Fleet Assessment Service;

(vi) Medium- and Heavy-Duty Make-Ready Pilot Program; and

(vii) Transit Authority Make-Ready Program.

Particular Electric Vehicle-related program costs will be recovered as follows:

a. Utility-side program and future-proofing costs as defined in the Make Ready Order:

i. Will be treated as Capitalized Plant in Service, but excluded from plant in service reconciliation mechanism;

ii. Will be recovered through an existing surcharge mechanism;

iii. Will be allocated to service classifications in proportion to each class's transmission and distribution revenues;

iv. Will be charged on a $/kW basis for demand-billed classes (Contract Demand kW for standby service and buyback service) and on a $/kWh basis for energy-billed classes;

v. Will include an annual charge amount developed based on depreciation expense related to utility-owned Make-Ready work and return on average unrecovered investment net of deferred income taxes; and

vi. Will provide for annual recovery of remaining un-recovered balance to be included in base rates the next time base rates are reset.

b. Customer-side program, incentive, and futureproofing costs as defined in the Make Ready Order:

i. Will be deferred as a regulatory asset (including associated carrying costs determined at the Company's pre-tax weighted average cost of capital), amortized over a 15-year period, and excluded from Plant in Service Reconciliation;

ii. Will be recovered through an existing surcharge mechanism;

iii. Will be allocated to service classifications in proportion to each class' transmission and distribution revenues;

iv. Will be charged on a $/kW basis for demand-billed classes (Contract Demand kW for standby service and buyback service) and on a $/kWh basis for energy-billed classes; and

v. Will provide for annual recovery of remaining un-recovered balance to be included in base rates the next time base rates are reset.

c. Make-Ready Program Implementation and Fleet Assessment Service costs as defined in the Make Ready Order:

i. Will be deferred as regulatory asset (including associated carrying costs determined at the Company's pre-tax weighted average cost of capital), amortized over a five-year period;

ii. Will be recovered through an existing surcharge mechanism;

iii. Will be allocated to service classifications in proportion to each class' transmission and distribution revenues;

iv. Will be charged on a $/kW basis for demand-billed classes (Contract Demand kW for standby service and buyback service) and on a $/kWh basis for energy-billed classes; and

v. Will provide for annual recovery of remaining un-recovered balance to be included in base rates the next time base rates are reset.

10. Information Technology

10.1. Information Technology Capital Investment Level

Niagara Mohawk's rates include costs associated with Information Technology ("IT") capital investments that are owned by National Grid USA Service Company, Inc. ("Service Company") and allocated to Niagara Mohawk in the form of rent expense. Rent expense includes the return on, and the amortization or depreciation of current IT capital investments along with incremental IT capital investments that are forecast for the Rate Years. The incremental IT capital investment for the Advanced Distribution Management System, AMI, Core IT, Vision of Leadership in Transmission, S4HANA and Grid Modernization projects is $251.5 million in Rate Year One, $265.3 million in Rate Year Two, and $297.1 million in Rate Year Three. These costs do not include costs associated with the Gas Business Enablement ("GBE") program which is described in Section IV.10.2 below, or costs associated with the Customer Information System

("CIS") which is described in Section IV.10.3 below. Appendix 1, Schedule 7 sets forth the IT capital investment plan by program.

The schedules set forth actual capital spending through June 30, 2021 and the incremental capital spending from July 1, 2021 through the end of each Rate Year. Notwithstanding the specific program level spending amounts shown in Appendix 1, Schedule 7, nothing in this Joint Proposal is intended to limit the Company's flexibility during the term of the rate plan to substitute, change or modify capital projects.

10.2. Gas Business Enablement

The Company will continue to implement the GBE program during the term of the rate plan. The GBE program, which is more fully described in Appendix 10 is a shared investment across all National Grid USA operating companies that will be owned and implemented by Service Company, with a portion of the costs allocated to Niagara Mohawk. The GBE costs are presented in Appendix 1, Schedule 7. The GBE program is addressed in Sections IV.7.8-7.8.4 of the Case 17-E-0238 Joint Proposal. These provisions of the Case 17-E-0238 Joint Proposal are attached hereto as Appendix 10.

The provisions in Appendix 10 shall continue to apply during the term of the rate plan set forth in this Joint Proposal, except that the initial measurement period for the Key Performance Indicators ("KPIs") applicable to the GBE program shall be extended to the fiscal year ending March 31, 2024 to align with the revised expected in-service date of the GBE program in Niagara Mohawk's service territory. If there is further delay in the in-service date of the GBE program, Niagara Mohawk may petition the Commission to further extend the initial measurement period for the KPIs.

10.3. Customer Information System

The Company's revenue requirements do not include any operating expense or capital expenditures for a new CIS. The Company may, at any time during the rate plans, file a petition with the Commission setting forth its proposed CIS project and seeking authorization to defer CIS-related development costs. Such a petition will not be subject to the materiality threshold that normally applies to deferral petitions. In any such petition, the Company shall submit a detailed description and estimate of the CIS costs it seeks to defer. The petition shall also include, at a minimum, the Company's sanction papers that demonstrate the project and associated costs were approved by all required National Grid management in accordance with its normal sanctioning process; an updated business case; a detailed project implementation timeline; and proposed key performance indicators. The Company will also, as part of any such petition, identify the costs and benefits of certain CIS upgrades recommended in these proceedings by PULP to enable the Commission to determine whether the Company should include such upgrades in the CIS project. In the absence of Commission deferral authority for the costs of PULP's proposed CIS upgrades, the Company will have no obligation to include PULP's upgrades in the CIS. PULP's proposed upgrades include CIS enhancements that would provide: (1) all residential customers with online access to six years of their billing and transaction history; (2) a secure web-based portal through which elderly, blind or disabled (EBD) customers or their representatives can apply and track the progress of their EBD coding; and (3) enhancements that would prepare customers for the return of abeyance amounts to their monthly bill and/or who have discrepancies between their Niagara Mohawk account(s) and Department of Social Services records.

10.4 Service Company Rents, IT, and GBE Net Utility Plant and Depreciation Expense Reconciliation Mechanism

The Company will implement a downward-only IT and GBE Net Utility Plant and Depreciation Expense Reconciliation Mechanism. Each Rate Year, the Company will reconcile its respective annual IT and GBE Program average net utility plant and depreciation expense revenue requirements to the forecast revenue requirements as set forth below and as shown in Appendix 5, Schedule 11 for the Company's electric operations and Appendix 6, Schedule 11 for the Company's gas operations. The Mechanism will not continue beyond Rate Year Three except that if the Company is below its target at the end of Rate Year Three, the mechanism will continue until the targets are met.

	Rate Year One	Rate Year Two	Rate Year Three
Electric	$53.022 M	$52.604 M	$60.112 M
Gas	$13.849 M	$13.705 M	$14.812 M

The IT and GBE Program average net utility plant and depreciation expense revenue requirement will be calculated by applying the Company's pre-tax weighted average cost of capital in the respective Rate Years to the IT and GBE Program average net utility plant balances and adding the depreciation expense to the product. The difference between the actual IT and GBE Program average net utility plant and depreciation expense revenue requirement and the target average net utility plant and depreciation expense revenue requirement will carry forward for each Rate Year and be summed at the end of Rate Year Three. As illustrated in Appendix 5, Schedule 11, and Appendix 6, Schedule 11, if, at the end of Rate Year Three, the cumulative actual IT and GBE Program average net utility plant and depreciation expense revenue requirement is negative, the Company will defer the revenue requirement impact for the benefit of customers. If, at the end of Rate Year Three, the cumulative actual IT and GBE Program average net utility plant and depreciation expense revenue requirement is positive, there will be no deferral.

The reconciliation mechanism will apply to the aggregate total IT and GBE Program average net plant and depreciation expense combined, and not to individual components. The net plant target balances and reconciliation will not consider the impact of ADIT.

10.5 IT Capital Budgeting and Reporting

The IT reporting requirements require further development so that on a forward going basis, the annual and quarterly reports that are filed by the Company will provide information in a format that permits easy monitoring and understanding of any individual IT project's status and progress, and will enable full comprehension of the entire IT portfolio. Following the issuance of a Commission order adopting the terms of this Joint Proposal, the Company and Staff will collaborate to develop modified and improved IT annual and quarterly reporting requirements. The Company will develop IT reporting requirements that apply uniformly as well as on a consistent timeline with the analogous reporting requirements applicable to its Downstate Affiliates. Therefore, the Company shall file with the Secretary to the Commission a report describing the reporting requirements agreed to through collaboration with Staff no later than December 31, 2022.

The revised process should provide greater transparency into the Company's IT investments, sanctioning, budgeting, and approval process, while avoiding placing an undue burden on both the Company to compile the information and on Staff to review the information. The reporting requirement modifications should be intended to streamline the IT quarterly reporting so that strategic, executive-level information regarding the status of IT-related projects is provided, enabling easier monitoring of project status and progress in terms of schedule, scope, and budget, for each of the program categories (and individual projects within each category) and also major projects (CIS, GBE, AMI, etc.). Any modified reporting will include, at a minimum, quarterly reports that would identify project issues and risks; identify project milestones; and provide the details on project governance for each of the individual projects. Annual IT reporting will provide a more detailed description of the status of projects, expanding as necessary to address any issues identified. Further, because National Grid manages its IT portfolio at the Service Company level, IT reporting needs to be consistent across all New York jurisdictions. The reporting should include the Service Company's full IT portfolio, not just programs that will be allocated to Niagara Mohawk. Items such as variance reporting (including root cause determination of variances and corrective actions taken), allocation to each company, and status of savings associated with retirement of legacy systems being replaced by new IT investments will continue to be addressed and included in the modified reporting requirements.

Once a reporting format is developed through the collaboration described above, the Company shall file with the Secretary to the Commission an annual report prior to the beginning of each Rate Year, and quarterly variance reports within 60 days after the end of each Rate Year quarter.

On a semi-annual basis, the Company will meet with Staff to: (i) discuss budget and actual spending to date; (ii) provide an update on the status of ongoing projects; (iii) discuss proposed projects for the next six months; (iv) review quarterly filings; and (v) review the Company's variance analyses for the top ten projects. These meetings, which will occur in April and October each year, will include a discussion of cybersecurity projects and notification to Staff cybersecurity personnel of the status of the sanctioning or partial sanctioning of cybersecurity projects.

Beginning with the first semi-annual meeting (October 2021),[14] the Company will work with Staff to develop mutually agreeable sanction paper enhancements needed to justify IT investments and allow for adequate review. These enhancements are intended to reduce the number of budget items supported by IRS papers[15] and increase the number supported by completed sanction papers. At a minimum, the enhancements will include information that more fully supports the Company's costs estimates, and demonstrates that such estimates are reasonable, and information concerning whether the project was the minimum-cost alternative. If the Company chooses a higher cost or enhanced alternative, then the sanction paper will present an analysis that compares the project benefits and costs over the project life cycle and supports the decision to pursue the chosen solution.

10.5.1 IT Project Approvals

The National Grid New York Chief Information Officer, or successor with ultimate responsibility for IT projects and services in whole or in part for the New York jurisdiction, will be required to approve or disapprove any newly proposed IT project business case before the project can proceed. This officer, as well as any relevant sanctioning body (*e.g.*, the U.S. Sanctioning Committee or Senior Executive Sanctioning Committee), must review project closure papers that contain information concerning costs incurred, benefits derived, and lessons learned, and report that such review was completed and include a summary of the review in the IT report for the last quarter of each Rate Year.

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[14] The October 2021 semi-annual meeting is required for Niagara Mohawk's Downstate Affiliates. To ensure consistency across all three affiliates, the October 2021 semi-annual meeting will address Niagara Mohawk, as well as its Downstate Affiliates.

[15] The Company may phase out the use of IRS papers and, if so, will replace them with an alternative that provides the information described herein in a manner to be determined after collaboration with Staff.

10.5.2 Key Performance Indicators

The Company will modify its IT sanctioning papers to include KPIs. Within the timeframe applicable to its Downstate Affiliates, the Company will implement on-time/on-cost KPIs that will be reported quarterly on a portfolio basis. The Company will also work with Staff to determine whether different or additional information would be useful to include in the quarterly reports.

11. <u>Street Lighting</u>

11.1. Street Lighting Rate Design

Niagara Mohawk's street lighting rate design is set forth on Appendix 2, Schedule 8.

11.2. SC-2 Pricing Exception

The SC-2 Pricing Exception facility prices will be eliminated over a 10-year period. The SC-2 tariff provisions will be updated to list each component of the pricing exception and eliminate outdated language.

11.3. Outage Credit Allowance

The Outage Credit Allowance for SC-2, SC-3, and SC-6 will be updated as shown in Appendix 2, Schedules 8.11b, 8.11c, 8.11d and 8.12a.

11.4. Lighting Service Charges

The Company will update the SC-2 and SC-6 lighting service charges as shown in Appendix 2, Schedules 8.10b, 8.10c, 8.10d, and 8.11a. The Company will also implement new Lighting Service Charges for SC-3 as shown in the table below.

Service	Rate per Occurrence
Overhead Service:	$258.17
Underground Service:	$638.72
Underground Residential Service:	$263.01
Overhead Emergency:	$598.05
Underground Emergency:	$797.81

11.5. Closed or Obsolete Facilities

References to closed or obsolete facilities will be eliminated from SC-2 and SC-6.

11.6. Street Light Asset Sales

The Company will continue to utilize its Net Book Value methodology for pricing assets when selling its PSC 214, SC-2 street light assets.

11.6.1 Purchase and Sale Agreement

Until the Commission next sets Niagara Mohawk's base electric rates, the Company agrees to sell its PSC 214 SC-2 street lighting assets at net book value to any municipal customer that agrees to purchase all street light assets serving it within the municipality's taxing jurisdiction. Sales of less than all street light assets serving the customer within a municipal taxing district will be subject to negotiating a mutually-agreeable sale price as currently specified in the tariff governing street light asset sales.

The Company will use a standardized purchase and sale agreement ("PSA") to execute street light sales to municipal customers purchasing all the street light assets serving them within their respective taxing jurisdictions. The Company will make minor revisions to the PSA, if any, on a semi-annual basis to be effective January 1 and June 1 of each year. The Company will have the right to make unscheduled revisions to the standardized PSA to the extent the Company believes that such changes will have a material impact on the sales process or particular sales. The Company will provide notification to all parties to these proceedings as well as entities engaged in negotiating potential sales with the Company (customers) within 14 days of when revisions are made if such revisions are made outside the semi-annual process. The Company will ensure that the up-to-date template PSA is filed with the Secretary to the Commission, for informational purposes only, in Case 15-E-0747, *Tariff filings to Effectuate Amendments to Public Service Law – New §70-a (Transfer of Street Light Systems)*.

The Company will provide a template (not-ready-to-sign) PSA to customer when it provides initial pricing for the sale. The Company will identify to the customer any changes between the not-ready-to-sign and the ready-to-sign PSA.

The Company will send customers an email to confirm key sale milestones including the initial sale price request, initial PSA request, pole attachment agreement, and receipt of a signed PSA from customer acknowledging that PSA is complete or identifying any additional requirements.

11.6.2 Ongoing Maintenance and Replacement Work

The Company will inform customers, at the time it provides the initial purchase price, of the types of work that the Company may perform prior to the transfer of the street lighting assets that could affect the price. To the extent practical and consistent with the Company's responsibilities, including performing capital and O&M work as part of its periodic safety inspections, equipment replacement due to failure or damage in the field, and third-party (*e.g.*, Department of Transportation) relocations or compliance projects, the Company will provide customers that have executed a PSA with the (1) option to opt-out of more expensive fixtures such as LEDs (subject to equipment availability), and (2) information on how to request deferral of any non-essential maintenance and replacement work.

11.6.3 Final Sale Price

Where the final sale price differs from the initial price, the Company will quantify changes in the original cost of assets and changes in the allocation of the depreciation reserve associated with those assets that make up the price change. In cases where the final sale price is equal to or greater than $100,000, and the final price exceeds the initial price by $25,000 or 15 percent, whichever is greater, the Company will also provide a description of the principal factors (*e.g.*, significant plant additions, retirements, other sales) that contributed to the change in price. In cases where the final sale price is less than $100,000, and the final sale price exceeds the initial price by more than 20 percent, the Company will provide a description of the principal factors that contributed to the change in price.

11.7 Street Light Program Initiatives

During the term of the rate plan, the Company will continue to implement the following programs:

(i) the LED Luminaire Conversion Plan program in which LED outdoor lighting technology replaces high intensity discharging ("HID") luminaires;

(ii) the LED Street Lighting Energy Efficiency Program in which incentives are provided for customers to replace their existing luminaires with higher efficiency LED luminaires;

(iii) the Outdoor Lighting Customer Portal which provides customers with secure, direct access to their near real time component inventory; and

(iv) the REV Smart City Demonstration Project which tests whether the Company's outdoor lighting infrastructure can serve as a platform to animate the outdoor lighting and smart city markets by developing various technologies to promote energy savings and enhanced public services.

11.8 The Attachment Process for Smart City Devices

Within three months of a Commission order adopting the terms of this Joint Proposal, the Company will facilitate an information exchange with NYPA, interested customers, and other interested entities in a technical conference regarding "Smart City" attachments so the Company may obtain additional information regarding the customers' desires, concerns, and concept suggestions. This process will allow the Company to obtain input to improve the process for future enhancements. Within three months of the technical conference, the Company will file a report with the Secretary to the Commission that describes how the attachment process may be improved to accommodate "Smart City" projects.

The key topics to be discussed in the technical conference and report include, but are not limited to, actions by Company and customers to:

(i) Streamline engineering review, including developing preapprovals (as appropriate) for standards, etc.;

(ii) Streamline or limit field investigation/survey review for similarly situated attachments as appropriate, including exploring the use of technology to assist in field investigations;

(iii) Streamline or limit design review for similarly situated attachments as appropriate;

(iv) Develop a catalog of preapproved or streamlined attachments as appropriate. Identify optimal locations for smart city attachments (*e.g.*, those similar to previously approved locations, with minimal existing attachments); and

(v) Clarify the criteria and analyses required for each device.

11.9 Tariff Offerings – Street Lighting

The Company will modify its Street Lighting tariff to include:

(i) Customer Lighting Service Charges as set forth in Appendix 2, Schedules 8.10 and 8.11;

(ii) an LED Luminaires Opt-Out provision pursuant to which the Company will replace an existing HID Luminaire that fails with an LED Luminaire, unless a customer opts-out (subject to available inventory); and

(iii) an Advanced Technology Innovation Platform in which the Company will modify its Street Lighting tariff for SC-2 to address the inclusion of various forms of supplemental small-load devices sourced from either unmetered street light electric circuitry or directly from distribution secondary sources for which a standard revenue grade meter is not applicable.

11.10 Adaptive Lighting Schedules

The Company will offer SC-3 (customer-owned, customer maintained) customers four adaptive lighting schedules. The Company will undertake measures to verify municipal customers' adaptive lighting schedules. Customers will be required to either: (i) install control devices or nodes preset to a specific schedule; (ii) install network lighting control nodes to remotely control operation of the LED luminaires, including all field adjustable luminaires; or (iii) present an alternative basis for validation acceptable to the Company. Customers will be required to provide specific information identified by the Company to determine or validate monthly energy consumption to qualify for the appropriate adaptive schedule for energy billing purposes. The adaptive lighting schedule will be updated every three years at a minimum. The municipalities will provide the information as requested by the Company in a format acceptable to the Company for the Company to perform the validation at no cost to the Company. The Company will revise its street lighting tariff to incorporate this change.

11.10.1 Notification of Changes to Adaptive Lighting Schedules

The Company will amend its tariff to require municipal customers to notify the Company in writing of changes to the customers' adaptive lighting schedules. Significant changes will only be permitted once per year. Changes in operating schedules that are infrequent, temporary or event driven would not be subject to written notice requirements. Examples of operating schedule changes that do not require written notice include changes to accommodate emergency response situations, community events (*e.g.*, parades; marches; festivals; other special events), and similar situations that warrant relatively short-term deviations from normal operating schedules.

11.11 General Lighting Tariff Changes

The Company will implement the following General Lighting Tariff changes:

(i) a revision to its general service electric tariff to allow non-demand, unmetered energy consumption (kilowatt hours) from non-street lighting load to be calculated based on the maximum power consumption 24 hours per day each and every day of the year;

(ii) SC-1: Change the presentation of facility pricing from monthly to annual values; revise Volumetric Energy Consumption provision; modify the payment recovery term to address capital investment recovery of prematurely removed LED luminaires; modify the provisions addressing transitional management of underground served HID facilities without a comparable LED replacement.

(iii) SC-2: Change the Discontinuance provisions to facilitate appropriate cost recovery; make clarifying revisions to the Change of Existing Company Facilities provision; modify payment administration associated with LED conversion application; develop a provision to address special project applications for new technology assessment.

(iv) SC-3: Add provisions addressing worker qualifications, elevated voltage incident response criteria, participation in the National One-Call Damage Prevention Network and National Joint Utilities Notification System. Add provisions addressing customer-owned street light inventory records and electrically connected supplemental device attachment requirements.

(v) SC-4: Changes to promote clarity and promote increased compliance with SC-4 provisions for customers that do not follow existing tariff provisions for unmetered traffic control service, including the reporting of new or changed equipment, reconstructed traffic control locations, or the response to the Company's annual inventory billing records; and

(vi) SC-6: Add a provision for establishment of a sunset date of June 30, 2025 for cessation of all SC-6 services.

11.12 Street Light Replacement Cost Study

The Company will conduct a street lighting luminaire replacement cost study including a review of O&M expense, depreciation, and new materials cost versus tariff rates and energy consumption. This study will address whether the Company's allocated cost study appropriately adjusts the allocator values to reflect changes in asset ownership and customer usage. The Company will provide the results of the study in its next electric rate filing.

12. Electric and Gas Reconciliations, Deferrals, and True-Ups

12.1 Existing Electric and Gas Reconciliations, Deferrals, and True-Ups

Appendix 5, Schedule 1 and Appendix 6, Schedule 1 set forth the electric and gas deferral accounts and other regulatory assets and liabilities balances, respectively, as of June 30, 2021. With the exception of the deferral accounts and other regulatory assets and liabilities identified as "Discontinued," Niagara Mohawk is authorized to continue using reconciliation mechanisms and/or deferral accounting (with certain modifications) with respect to the electric and gas expenses set forth in Appendix 5, Schedule 1 and Appendix 6, Schedule 1.[16]

Except where otherwise noted, Niagara Mohawk will accrue carrying charges on all electric and gas deferral accounts and other regulatory assets and liabilities, net of deferred taxes, using the pre-tax weighted average cost of capital for the respective Rate Year.[17] An example of the calculation of carrying charges is set forth in Appendix 5, Schedule 2 for electric and Appendix 6, Schedule 2 for gas.

[16] The deferral accounts and other regulatory assets and liabilities identified as "Discontinued" will be discontinued as of the Effective Date. These accounts contain forecast balances as of June 30, 2021, which are set forth in Appendix 5, Schedule 1 and Appendix 6, Schedule 1. The discontinuance of these accounts is not intended to preclude the Company from returning to or recovering from customers the balances as of June 30, 2021 plus any applicable carrying charges.

[17] This applies to deferred balances referenced in other sections of this Joint Proposal unless specifically stated otherwise.

12.1.1. Pension and Other Post-Employment Benefit Expenses (Electric and Gas)

Niagara Mohawk will continue to defer and reconcile its actual electric and gas pension and Other Post-Employment Benefit ("OPEB") expenses to the levels allowed in rates (set forth in the tables below) in accordance with the Commission's Pension & OPEB Statement of Policy.

Pension Expense	Rate Year One	Rate Year Two	Rate Year Three
Electric Business	$ 6.131 million	$ (10.271) million	$ (14.092) million
Gas Business	$ 1.244 million	$ (2.119) million	$ (2.899) million

OPEB Expense	Rate Year One	Rate Year Two	Rate Year Three
Electric Business	$ 6.268 million	$ 5.661 million	$ (3.192) million
Gas Business	$ 1.337 million	$ 1.231 million	$ (0.571) million

Additional provisions relating to the reconciliation of electric and gas pension and OPEB expenses are set forth in Appendix 9. Carrying charges will not be calculated on pension or OPEB deferred balances. An example of the reconciliation is set forth in Appendix 5, Schedule 3 for electric and Appendix 6, Schedule 3 for gas.

12.1.2. Energy Affordability Program (Electric and Gas)

The Company will implement its electric and gas EAP as set forth in Section IV.15.1 of this Joint Proposal. The EAP rate allowances are $23.484 million in Rate Year One, $20.973 million in Rate Year Two and $19.401 million in Rate Year Three for the Company's electric business, and $6.611 million in Rate Year One, $5.645 million in Rate Year Two and $5.413 million in Rate Year Three for the Company's gas business. Each Rate Year, the Company will fully reconcile EAP costs to the rate allowance. Amounts in excess of the rate allowance will be deferred for future recovery from customers. Any under-expenditures will be deferred for future use in a low-income assistance program. An example of the reconciliation is set forth in Appendix 5, Schedule 4 for electric, and in Appendix 6, Schedule 4 for gas.

12.1.3. Economic Development Fund Program (Electric and Gas)

The Company will continue its electric and gas Economic Development Fund Programs, as set forth in Section IV.17.6.1. Each Rate Year, the Company will fully reconcile economic development discounts (*i.e.*, for electric, EZR, EJP, new discount contracts under SC-12, and existing discount contracts under SC-12; for gas, EZR and EJP discounts) to the amount reflected in rates for refund to or recovery from customers. The target amounts for economic development discounts are as follows:

Economic Development Fund Programs	Rate Year One	Rate Year Two	Rate Year Three
Electric Business	$2.065 million	$2.100 million	$1.625 million
Gas Business	$0.434 million	$0.332 million	$0.290 million

The electric and gas Economic Development Fund Programs will be a separate deferral account from the electric and gas Economic Development Grant Programs set forth below. An example of the reconciliation is provided in Appendix 5, Schedule 5 for electric, and in Appendix 6, Schedule 5 for gas.

12.1.4. Economic Development Grant Program (Electric and Gas)

The Company will continue its electric and gas Economic Development Grant Programs, as described in Section IV.17.6.2. The Economic Development Grant Program for electric and gas will be funded at $11 million and $1 million per year, respectively, subject to downward-only reconciliations over the term of the rate plan. Any difference between the respective rate allowance and actual program costs in a given Rate Year will be carried forward and reconciled at the end of Rate Year Three, with any under-expenditure to be deferred for future use in the respective Economic Development Grant Programs. The Company may petition the Commission to utilize any deferral balances related to the Economic Development Grant Programs to fund emergency economic assistance or other incremental economic development programs. An example of the reconciliation is provided in Appendix 5, Schedule 6 for electric, and in Appendix 6, Schedule 6 for gas.

In the event of any anticipated over-expenditures, the Company may petition the Commission for deferral treatment and will have no obligation to make any additional expenditure unless and until the Commission authorizes the Company to defer amounts in excess of the three-year aggregate rate allowance for future recovery.

12.1.5. Site Investigation and Remediation Expense (Electric and Gas)

Each Rate Year, the Company will fully reconcile actual SIR expense to the annual rate allowance of $17.92 million for electric and $3.16 million for gas. Any under- or over-expenditures will be deferred for future refund to, or recovery from, customers. An example of this reconciliation is set forth in Appendix 5, Schedule 8 for electric and Appendix 6, Schedule 8 for gas. SIR costs are defined on Page 2 of each Appendix.

Consistent with the Commission's August 12, 2021 Order in Case 19-G-0309 *et al.*, the Company will continue to submit annual reports to the Secretary to the Commission that will, in addition to the information provided in previous annual report, also include:

(i) details of the specific remedial and programmatic activities scheduled and performed at all contaminated sites during each of the Rate Years and the Stayout Period;

(ii) identification and copies of the Department of Environmental Conservation or United State Environmental Protection Agency administrative orders and approved work plans and schedules for implementation of remedial activities; and

(iii) breakdowns of the remedial costs incurred for such activities, including, but not limited to, a detailed identification of the costs associated with the Company's general SIR program and the costs expended on various SIR participants, *i.e.*, consultants, engineers, contractors, attorneys, and others.

12.1.6. Property Tax Expense (Electric and Gas)

Each Rate Year, the Company will reconcile actual property tax expense to the rate allowance. The difference between actual property tax expense, excluding the effects of property tax refunds, and the rate allowance (set forth in the table below) will be deferred for future refund to or recovery from customers. Differences will be shared 90 percent/10 percent between customers and the Company, respectively. An example of this reconciliation is set forth in Appendix 5, Schedule 9 for electric, and in Appendix 6, Schedule 9 for gas.

Property Tax Expense	Rate Year One	Rate Year Two	Rate Year Three
Electric Business	$217.760 million	$234.545 million	$249.829 million
Gas Business	$56.017 million	$61.125 million	$66.803 million

If Niagara Mohawk is successful in obtaining property tax refunds, it will have the right to petition the Commission to share in such refunds. Other parties may take any position concerning any petition filed by Niagara Mohawk.

12.1.7. Negative or Positive Revenue Adjustments (Electric and Gas)

Niagara Mohawk will defer (i) any negative revenue adjustments associated with the electric and gas Service Quality Assurance Program (Section IV.13 of this Joint Proposal), and/or

(ii) any negative or positive revenue adjustments associated with the Gas Safety Performance Metrics (Section IV.14 of this Joint Proposal).[18]

12.1.8. Externally Imposed Costs (Electric and Gas)

One hundred percent of all Externally Imposed Costs (including any credits) associated with or caused by an individual instance (as described below) will be deferred, once such costs exceed the threshold set forth below. If Externally Imposed Costs caused by an individual instance in any one Rate Year exceed 25 basis points for the year in which the change first occurs, calculated and applied separately for electric and gas, and the Commission does not otherwise address the treatment of such costs (the "Externally Imposed Cost Threshold"), the total impact of the Externally Imposed Costs as applicable to the Company's regulated electric or regulated gas operations, respectively, will be deferred. "Externally Imposed Costs" means all of the incremental effects on Niagara Mohawk's costs, revenues, or revenue requirements above or below the amounts set forth in Appendix 1, Schedules 1 and 2, associated with or caused by an individual instance of:

a. any externally imposed accounting change;

b. any change in the federal, state, or local rates, laws, regulations, or precedents governing income, revenue, sales, or franchise taxes;

c. any refunds or payments (with interest and net of deferred taxes) reasonably made to or by Niagara Mohawk associated with electric and/or gas operations as a result of any ongoing or new examinations by federal and/or state tax authorities of Niagara Mohawk's tax returns; or

[18] Any negative revenue adjustments associated with the Gas Safety Performance Metrics will be deferred for future disposition by the Commission.

d. any legislative, court, or regulatory change that imposes new or modifies existing obligations or duties.

In addition, the Signatory Parties recognize that:

i. there is a pending Pipeline and Hazardous Materials Safety Administration ("PHMSA") rulemaking regarding pipeline integrity management, integrity verification and related issues in PHMSA Docket ID 2011-0023;

ii. there is a possibility that legislation will be enacted requiring proposed engineering review and approval of all gas engineering plans ("PE Stamping");

iii. there is the potential for further changes to federal and state income taxes; and

iv. there is the potential that the Commission will adopt changes to its safety regulations governing tasks that are required to be performed by Qualified Operators and the training and testing of Qualified Operators.

Should new regulations and/or legislation identified in items (i), (ii), and (iii) above be enacted that affect Niagara Mohawk's costs during the term of the rate plan, Niagara Mohawk will defer all incremental costs or decreases in costs arising from such actions without regard to whether such changes exceed the Externally Imposed Cost Threshold. Should new regulations concerning item (iv) above be adopted, Niagara Mohawk will defer all incremental costs or decreases in costs, subject to the Externally Imposed Cost Threshold. In the event that Externally Imposed Costs are incurred, Niagara Mohawk will file a letter with the Secretary setting forth the rationale for the deferral and its calculation. Any disagreement associated with the filing will be referred to the Commission for a decision.

12.1.9. Internally-Adopted Accounting Changes (Electric and Gas)

Niagara Mohawk will notify the Director of the Department of Public Service's Office of Accounting, Audits and Finance of any significant changes to its accounting policies. Approval of the Director of the Office of Accounting, Audits and Finance is necessary before Niagara Mohawk records on its books any deferral for the net impact of an internal accounting change pursuant to this Section. If such approval is granted, the Company will be allowed to book the deferral prospectively from the date of approval, regardless of whether the accounting change was previously reflected in an account other than the deferral account. The Director of the Office of Accounting, Audits and Finance will use best efforts to rule on any request for the deferral of the impact of an internal accounting change within 90 days of submission, provided that the Company's initial submission is complete and includes full support for the accounting change and the quantification of the net impact of the accounting change, including any required offsets. Niagara Mohawk will include in the deferral account the net impact of any accounting change adopted as a matter of internal accounting policy when the accounting change, evaluated individually, increases or decreases Niagara Mohawk's costs or revenues from regulated operations or changes Niagara Mohawk's policy for capitalizing or expensing any item by more than $500,000 per year for the electric business and/or $100,000 per year for the gas business.

12.1.10. Variable Pay (Electric and Gas)

Each Rate Year, the Company will defer for refund to customers any variable pay compensation amounts reflected in rates that are not paid to employees. The rate allowance for variable pay is set forth in the table below. An example of this reconciliation is set forth in Appendix 5, Schedule 10 for electric and Appendix 6, Schedule 10 for gas.

Variable Pay Expense	Rate Year One	Rate Year Two	Rate Year Three
Electric Business	$18.926 million	$19.627 million	$20.280 million
Gas Business	$4.623 million	$4.809 million	$4.971 million

12.1.11. Electric Net Utility Plant and Depreciation Expense Reconciliation Mechanism

The Company will implement a downward-only electric Net Utility Plant and Depreciation Expense Reconciliation Mechanism during the rate plan. Each Rate Year, the Company will reconcile its actual electric average net utility plant (which includes the allocation of common plant to the electric business) and depreciation expense revenue requirement to the target electric average net utility plant and depreciation expense revenue requirement, which are: $925.062 million for Rate Year One; $967.698 million for Rate Year Two; and $1,027.663 million for Rate Year Three.

The electric average net utility plant and depreciation expense revenue requirement will be calculated by multiplying the Company's pre-tax weighted average cost of capital in the respective Rate Years by the electric average net utility plant balance, and adding this product to the electric depreciation expense.

With the exception described below regarding the implementation of NWAs, the difference between the actual electric average net utility plant and depreciation expense revenue requirement and the target electric average net utility plant and depreciation expense revenue requirement will carry forward for each Rate Year and be summed at the end of Rate Year Three. As illustrated in Appendix 5, Schedule 7, if, at the end of Rate Year Three, the cumulative actual electric average net utility plant and depreciation expense revenue requirement is negative, the Company will defer the revenue requirement impact for the benefit of customers. If, at the end of Rate Year Three, the cumulative actual electric average net utility plant and depreciation expense revenue requirement is positive, there will be no deferral.

The reconciliation mechanism will apply to the Company's aggregate total electric average net plant and depreciation expense combined, and not to individual components. The net plant target balances and reconciliation will not consider the impact of ADIT.

To the extent the Company implements an NWA that results in the displacement of a capital project reflected in the average electric net utility plant, the balance(s) will be reduced to exclude the forecast net plant associated with the displaced project. The carrying charge, or a portion thereof, as warranted, on the reduction of the average electric net utility plant that would otherwise be deferred for customer benefit will instead be applied as a credit against the recovery of the NWA, as shown in Appendix 5, Schedule 7.

12.1.12. Major Storm Expense (Electric Only)

The provisions relating to major storm expense are set forth in Section IV.6.4 of this Joint Proposal Appendix 14. An example of the reconciliation is set forth in Appendix 5, Schedule 17.

12.1.13. Aggregation Fee (Electric Only)

The Company will continue to accrue and amortize aggregation fee amounts collected pursuant to PSC 220 Rule 47. No carrying charges will be calculated for aggregation fee amounts.

12.1.14. Voltage Migration Fee (Electric Only)

The Company will continue to accrue and amortize voltage migration fee amounts collected pursuant to PSC 220 Rule 44.2. No carrying charges will be calculated for voltage migration fee amounts.

12.1.15. Transmission Revenue Adjustment Clause (Electric Only)

Pursuant to PSC 220 Rule 43, the Company will continue to reconcile the actual transmission revenue realized, exclusive of revenue taxes, to the forecast transmission revenue credit assumed in rates of $216,182,439 for Rate Year One, $216,620,592 in Rate Year Two, and $220,179,098 in Rate Year Three. NYPA load (including ReCharge New York load) will be subject to the Transmission Revenue Adjustment Clause ("TRAC"). The TRAC will be subject to a monthly true-up, with any over/under collection at the end of each month to be included in the TRAC balance for refund or recovery, subject to the caps. An example of this reconciliation is set forth in Appendix 5, Schedule 15. Carrying charges will be calculated as set forth in PSC 220 Rule 43.5.1.

12.1.16. Gas Net Utility Plant and Depreciation Expense Reconciliation Mechanism

The Company will implement a downward-only gas Net Utility Plant and Depreciation Expense Reconciliation Mechanism. Each Rate Year, the Company will reconcile its actual gas average net utility plant (which includes the allocation of common plant to the gas business) and depreciation expense revenue requirement to the target gas average net utility plant and depreciation expense revenue requirements, which are: $231.001 million for Rate Year One; $245.987 million for Rate Year Two; and $266.460 million for Rate Year Three. The gas average net utility plant and depreciation expense revenue requirement will be calculated by multiplying the Company's pre-tax weighted average cost of capital in the respective Rate Years by the gas average net utility plant balance, and adding this product to the gas depreciation expense.

With the exception described below regarding the implementation of NPAs, the difference between the actual gas average net utility plant and depreciation expense revenue requirement and the target gas average net utility plant and depreciation expense revenue requirement will carry forward for each Rate Year and be summed at the end of Rate Year Three. As illustrated in Appendix 6, Schedule 7, if, at the end of Rate Year Three, the cumulative actual gas average net utility plant and depreciation expense revenue requirement is negative, the Company will defer the revenue requirement impact for the benefit of customers. If, at the end of Rate Year Three, the cumulative actual gas average net utility plant and depreciation expense revenue requirement is positive, there will be no deferral.

In years that incremental LPP replacement costs are recovered through the Gas Safety and Reliability Surcharge, the net plant and depreciation components of the Gas Safety and Reliability Surcharge for incremental LPP replacement costs will be added to the overall Net Utility Plant and Depreciation Expense Reconciliation Mechanism target to avoid any double recovery. An example is shown in Appendix 6, Schedule 15.

The reconciliation mechanism will apply to the Company's aggregate total gas average net plant and depreciation expense combined, and not to individual components. The net plant target balances and reconciliation will not consider the impact of ADIT.

To the extent the Company implements an NPA that results in the displacement of a capital project reflected in the average gas net utility plant, the balance(s) will be reduced to exclude the forecast net plant associated with the displaced project. The carrying charge, or a portion thereof, as warranted, on the reduction of the average gas net utility plant that would otherwise be deferred for customer benefit will instead be applied as a credit against the recovery of the NPA, as shown in Appendix 6, Schedule 7.

12.1.17. Net Revenue Sharing (Gas Only)

The Company's Net Revenue Sharing Mechanism set forth in PSC 219 Rule 26 will continue. The delivery revenue service targets for SC-6, SC-9, and SC-14 have been updated for each of the Rate Years. The updated targets are set forth in Appendix 3, Schedule 10. Carrying charges do not apply.

12.1.18. Accrued Unbilled Revenue Deferral (Gas Only)

Niagara Mohawk will continue its current deferral practice concerning accrued unbilled revenues pursuant to the Commission's August 30, 1988 Order in Case 29670. No carrying charges will be calculated for accrued unbilled revenues.

12.1.19. Service Company Rents, IT, and GBE Program Net Utility Plant and Deprecation Expense Reconciliation Mechanism (Electric and Gas)

This deferral is set forth in Section IV.10.4. An example of this deferral is set forth in Appendix 5, Schedule 11 for electric and Appendix 6, Schedule 11 for gas.

12.1.20. Vegetation Management (Electric Only)

The Company will defer for future refund to customers any costs arising from the continued operation of its downward-only vegetation management tracker as discussed in Section IV.6.3.

12.1.21. Continuing Electric Reconciliation Mechanisms

The following electric reconciliation mechanisms will continue outside of base rates:

a. System Benefit Charge ("SBC") costs, which include the Clean Energy Fund ("CEF") surcharge and the Integrated Energy Data Resource Surcharge, will continue to be reconciled pursuant to PSC 220 Rule 41. Carrying charges will be calculated using the other customer capital rate.

b. Pursuant to PSC 220 Rule 46.2.6, the Company will continue to pass the benefits associated with the net market value of NYPA Rural and Domestic Power to residential customers. No carrying charges will be calculated for this deferral balance.

c. Commodity costs will be reconciled through the Electricity Supply Reconciliation Mechanism pursuant to PSC 220 Rule 46.3. No carrying charges will be calculated for this deferral balance.

d. Pursuant to PSC 220 Rule 46.2.7, the Company will reconcile costs associated with the Nine Mile Unit #2 Power Purchase Agreement. Carrying charges will be calculated as set forth in Rule 46.2.7.

e. Purchased power contract costs will be reconciled through the Legacy Transition Charge pursuant to PSC 220 Rule 46.2. No carrying charges will be calculated to this deferral balance.

f. Dynamic Load Management program costs will be reconciled pursuant to PSC 220 Rule 64. Carrying charges will be calculated as set forth in Rule 64.

g. The MFC reconciliation, as modified in Section IV.3.6, will continue.

h. The Clean Energy Standard Supply and Delivery charges will be reconciled pursuant to PSC 220 Rule 46. No carrying charges will be calculated for this deferral balance.

i. Value of Distributed Energy Resources Value Stack costs will be reconciled pursuant to PSC 220 Rule 46. No carrying charges will be calculated for this deferral balance.

j. The Electric Vehicle Make-Ready Surcharge will be reconciled pursuant to PSC 220 Rule 52. Carrying charges at the Company's pre-tax weighted average cost of capital will be calculated for this deferral balance.

k. The Energy Storage Surcharge will be reconciled pursuant to PSC 220 Rule 56. Carrying charges at the Company's pre-tax weighted average cost of capital will be calculated for this deferral balance.

12.1.22. Continuing Gas Reconciliation Mechanisms

The following gas reconciliation mechanisms will continue outside of base rates:

a. SBC costs, which include the CEF surcharge, no longer need to be reconciled pursuant to PSC 219 Rule 31. On December 15, 2020, the Company filed an updated SBC statement to become effective January 1, 2021 to include the final reconciliation balance. Although the CEF budget for Calendar Year 2021 was zero, the Company included the prior period overcollection for Calendar Year 2020 in that filing. The Company will continue to refund that overcollection through December 31, 2021 and will file on December 15, 2021 to set the SBC rate to zero effective January 1, 2022. Carrying charges were calculated using the other customer capital rate.

b. The Company will continue to recover and reconcile research and development Millennium Fund costs in accordance with PSC 219 Rule 30 and the Commission's February 14, 2000 Order in Case 99-G-1369. No carrying charges will be calculated for this deferral balance.

c. The Company will continue to recover and reconcile its cost of gas in accordance with PSC 219 Rule 17. Carrying charges will be calculated as set forth in PSC 219 Rule 17.7.2.

d. The MFC reconciliation as modified in Section IV.4.7 will continue. Carrying charges for the annual MFC reconciliation will be calculated at the other customer capital rate;

e. The LAUF reconciliation as modified in Section IV.4.5 will continue. Carrying charges for the annual LAUF reconciliation will be calculated at the other customer capital rate; and

f. The ETIP reconciliation applicable to SC-5 and SC-8 will continue to recover and reconcile energy efficiency costs included in base rates in accordance with PSC 219 Rule 31.2. Carrying charges will be calculated at the other customer capital rate.

12.2. New Electric and Gas Reconciliations, Deferrals, and True-Ups

The following new electric and gas deferral accounts will be implemented. Niagara Mohawk will accrue carrying charges on the new deferral account balances, net of deferred taxes, calculated using the pre-tax weighted average cost of capital for the respective Rate Year.

12.2.1 Income Tax Repair Adjustment

The Company will be permitted to defer for future recovery from customers $24,747,243 of interest expense associated with additional income taxes that the Company was required to pay as a result of an Internal Revenue Services' audit of the deductions for repair and maintenance expense. $19,797,794 of this interest is attributable to the Company's electric operations and $4,949,449 is attributable to its gas operations.

12.2.2 Case 19-M-0133 – Pension Settlement Loss

The Company will be permitted to defer 50 percent of the early accounting recognition of normally occurring actuarial expense losses of $8.4 million associated with lump sum pension payments to the Company's employees upon their retirement and paid out in the twelve months ending March 31, 2019. Within 30 days of the date of a Commission order adopting the terms of this Joint Proposal, the Company shall file with the Secretary to the Commission in Case 19-M-0133, a calculation of the savings created by the retirements that gave rise to the actuarial expenses loss.

12.2.3 Energy Storage

If the Company enters into a contract with a third-party energy storage provider for the Gilmantown energy storage project, the Company will defer the capital budget-related revenue requirement amount based on $8.931 million of capital expenditures for this energy storage project as a regulatory liability and adjust the Net Utility Plant and Depreciation Reconciliation Mechanism targets accordingly.

12.2.4 Minor Storms

The Company's electric revenue requirement reflects a minor storm allowance of $41 million. Over the three-year term of the rate plan this equates to a $125.7 million allowance for minor storms, which includes inflation for Rate Year Two and Rate Year Three.

The three-year minor storm allowance will be subject to a cumulative reconciliation including inflation as follows:

(i) If the Company incurs less than $125.7 million of minor storm costs, the difference between the Company's actual minor storm costs and $125.7 million will be deferred for return to customers;

(ii) If the Company incurs between $125.7 million and $155.7 million ($125.7 million plus $30 million deadband) of minor storm costs, there will be no deferral; and

(iii) If the Company incurs more than $155.7 million of minor storm costs, then 90 percent of the amount in excess of $155.7 million will be deferred for future recovery from customers.

The reconciliation will continue during the Stayout Period but will be a stand-alone reconciliation for that nine-month period and will be subject to a deadband prorated for the nine-month period, *i.e.*, a threshold of $7.5 million. The Company will develop and retain data of the type set forth in Appendix 14 to support any charges made to the minor storm account. No later than 120 days after the end of each Rate Year the Company will file a report concerning its actual minor storm expense for the appliable Rate Year. An example of the minor storm deferral is set forth in Appendix 5, Schedule 17.

12.2.5 Pre-Staging Storm Costs

The Company is authorized to charge the major storm reserve for pre-staging and mobilization costs incurred in reasonable anticipation that a storm will affect its electric operations to the degree of meeting the criteria of a major storm, but which ultimately does not do so. The Company can charge the following incremental costs: contractors and/or utility companies providing mutual assistance (including the costs of crews from affiliate companies), employee labor, meals, lodging, and mutual aid travel to and from National Grid's service territory as defined in Appendix 14.

Incremental pre-staging costs less than $0.250 million per storm event will be charged to minor storm expense. If incremental pre-staging costs for a particular storm event reach $0.250 million, then 100 percent of the incremental pre-staging costs up to $1.5 million will be charged to the major storm reserve. To the extent incremental pre-staging costs for a particular storm event exceed $1.5 million, then the Company will also charge 85 percent of the incremental pre-staging costs greater than $1.5 million to the major storm deferral and 15 percent to minor storm expense.

12.2.6 Electric Vehicles

As more fully discussed in Section IV.9.1 of this Joint Proposal, the Company will be permitted to defer as a regulatory asset electric vehicle-related customer-side program costs, incentive costs and futureproofing costs. These costs will be amortized over a 15-year period and recovered through a surcharge mechanism. These costs will be excluded from the downward only net plant and depreciation expense reconciliation mechanism described in Section IV.12.1.11 of this Joint Proposal.

As also discussed more fully in Section IV.9.1 of this Joint Proposal, the Company will also be permitted to defer as a regulatory asset make-ready program implementation costs and fleet assessment service costs. These costs will be amortized over a five-year period and recovered through an existing surcharge mechanism. These costs will be excluded from the downward only net plant and depreciation expense reconciliation mechanism described in Section IV.12.1.11 of this Joint Proposal.

12.2.7 Deferral of Leak Prone Pipe Amortization

As discussed more fully in Section IV.2.1(e) of this Joint Proposal, the Company will defer $3 million of amortized LPP costs for future recovery from customers.

12.2.8 Reconnection Fees from EAP Recipients

As discussed more fully in Sections IV.3.4.20, IV.4.5.11, and IV.15.1.1 of this Joint Proposal, the Company will be permitted to defer for future recovery from customers revenues foregone in Rate Year One as a result of the waiver of reconnection fees for EAP recipients. An example of this deferral calculation is set forth in Appendix 5, Schedule 14 for electric and Appendix 6, Schedule 14 for gas.

12.2.9 Hydrogen Energy Transfer Station Operation and Maintenance Expense/Revenues

As discussed more fully in Section IV.17.4 of this Joint Proposal, the Company will defer the net of (i) non-labor O&M expense related to operating the Hydrogen Energy Transfer Station including, but not limited to, demand charges for electric vehicle charging and costs associated with purchase of bulk power to operate the facility's electrolizer, and (ii) the customer's portion of the revenue from the facility. Any net balance will be paid to, or recovered from, customers through a non-bypassable delivery surcharge/surcredit included on the delivery line of electric customers' bills. An example of this deferral is set forth in Appendix 5, Schedule 18. An illustrative example of the surcharge calculation is set forth in Appendix 2, Schedule 9.

12.2.10 Albany Loop Engineering and Development Costs

As set forth in Section IV.7.2, the Company is authorized to defer, with carrying charges at the pre-tax weighted average cost of capital, for future recovery from customers, subject to Staff review, engineering and development costs incurred for the Albany Loop project through July 31, 2021 in the amount of $4.599 million.

12.3 Additional Reconciliations, Deferrals, and True-Ups

Nothing in this Joint Proposal prevents Niagara Mohawk from implementing additional reconciliations or deferral mechanisms if approved by the Commission.[19]

13. Electric and Gas Service Quality Assurance Program and Other Performance Metrics

13.1. Service Quality Assurance Program

Niagara Mohawk's Service Quality Assurance Program, which includes electric and gas customer service and electric reliability performance metrics, is set forth in Appendix 15. The Company will keep the existing metrics and targets for calendar year 2021. The Parties recognize that COVID-19 could impact the Company's performance under certain metrics. To that end, the Company can file a petition with the Commission requesting to avoid a negative revenue adjustment due to the performance impacts that the Company can demonstrate resulted from the COVID-19 pandemic for calendar year 2021. Should the COVID-19 pandemic affect the Company's performance for these metrics in future years, an additional petition for exclusion may be submitted to the Commission.

The Signatory Parties recognize that if the Commission takes action regarding gas safety performance metrics in Case 20-M-0266, *Proceeding on Motion of the Commission Regarding the Effects of COVID-19 on Utility Service*, or any similar proceeding, the Commission's determination in that proceeding shall control.

[19] To the extent a deferral is not addressed by a specific provision of this Joint Proposal or as otherwise ordered by the Commission, in determining whether a change in Niagara Mohawk's costs or revenues that falls within a provision of this Joint Proposal is incremental or decremental, Niagara Mohawk's actual cost or revenue for the year affected by the change will be compared to the corresponding annual cost or revenue item reflected in rates. The cost or revenue forecast underlying rates established in these proceedings will be as stated in this Joint Proposal or as modified by the Commission in its rate order in these proceedings, increased as appropriate for inflation and reduced to reflect the total net productivity savings assumed in rates.

13.2. Residential Service Termination and Uncollectible Expense Incentive Mechanism (Electric and Gas)

In light of the COVID-19 pandemic and Chapters 108 of the Laws of New York of 2020 and 106 of the Laws of New York of 2021, which amended Public Service Law § 32 and imposed moratoriums on termination of service for residential and eligible small business customers, the Company's existing termination and uncollectible incentive mechanism shall be suspended for the term of the rate plan, subject to the outcome of the generic COVID-19 proceeding.

13.3. Uncollectible Expense (Electric and Gas)

If the level of actual net write-offs by the Company during the term of this rate plan is material, the Company has the right to file a petition seeking deferral authority with the Commission for any increase in uncollectible expense or lost revenues due to waived late payment charges and tariff fees, or to utilize any applicable provisions in this rate plan to address the issue.

13.4. Elimination of Gas Cost Estimating Metric

The Gas Cost Estimating metric adopted in the 2018 Rate Order will be eliminated.

14. Gas Safety Performance Metrics

The Company's gas safety performance will be measured for each calendar year against a set of Gas Safety Performance Metrics. A total of 150 pre-tax basis points of return on common equity will be at risk per calendar year for the Company's performance under the Gas Safety Performance Metrics. Basis points at risk shall be allocated as shown in the table below and further described in the discussion of each metric in this Section.

Performance Measure	Basis Points at Risk
LPP Removal	15
Leak Management	15
Damage Prevention	20
Emergency Response Time	25
Gas Safety Regulations Performance Metric	75
Total Basis Points at Risk	**150**

Any Gas Safety Performance Metrics negative revenue adjustments incurred by the Company will be deferred for future disposition by the Commission. The Gas Safety Performance Metrics will be in effect for the term of the rate plan, and will continue on a year-to-year basis, unless discontinued or modified by the Commission. If the Company believes in any year that its inability to meet any of the established incentive targets was attributable to demonstrable *force majeure* circumstances (including causes that are outside its control and could not be avoided with the exercise of due care), the Company may petition the Commission for relief from any associated negative revenue adjustment.

The Signatory Parties recognize that the COVID-19 pandemic could impact the Company's performance under these metrics during the rate plan. To that end, the Company can petition the Commission requesting to avoid negative revenue adjustment due to performance impacts that it demonstrates resulted from the COVID-19 pandemic from the calculation of the gas safety metrics for calendar year 2021.

If the Commission takes action regarding gas safety performance metrics in Case 20-M-0266, *Proceeding on Motion of the Commission Regarding the Effects of COVID-19 on Utility Service*, or any similar proceeding, the Commission's determination in that proceeding shall control.

14.1. Leak Prone Pipe Removal

14.1.1. Annual Leak Prone Pipe Removal

Niagara Mohawk will incur a negative revenue adjustment of 15 basis points should it fail to remove from service the minimum number of miles of LPP in calendar years 2021, 2022, or 2023, or the cumulative four-year total of miles of LPP by the end of calendar year 2024. Niagara Mohawk's respective targets are as follows:

	Calendar Year 2021	**Calendar Year 2022**	**Calendar Year 2023**	**Cumulative (Calendar Years 2021-2024)**
Minimum Removal Targets	40 miles	45 miles	45 miles	195 miles

The Company will continue to utilize its risk-based prioritization algorithm to identify and rank segments of LPP for removal. The Company will also continue to use leak data to prioritize LPP removals.

14.1.2. Leak Prone Pipe Removal Incentive

Niagara Mohawk will earn a positive revenue adjustment of two basis points for each full mile of LPP removed above the incentive thresholds set forth below. The positive revenue adjustment will be capped at ten basis points per calendar year and deferred, as discussed in Section IV.12.1.7.

	Calendar Year 2021	**Calendar Year 2022**	**Calendar Year 2023**	**Calendar Year 2024***
Incentive Threshold Incremental Mileage	45 miles	50 miles	50 miles	50 miles
Incentive (capped at 10 basis points annually)	2 basis points per mile above threshold	2 basis points per mile above threshold	2 basis points per mile above threshold	2 basis points per mile above threshold

*Any mile collected through the GSRS (*i.e.*, above the rate allowance/incentive) will not count against the target in subsequent years.

In the event Niagara Mohawk fails to achieve its minimum removal target in any calendar year or the cumulative target at the end of the rate plan, it will return to customers any LPP removal incentives earned during the term of this rate plan.

14.1.3. Leak Prone Pipe Removal Reporting

The Company's annual reports regarding LPP removal and replacement will be consistent with the recommendations in the Company's management audit in Case 18-M-0195.[20]

14.2. Leak Management

Niagara Mohawk will incur negative revenue adjustments if it fails to achieve year-end leak backlog targets for (i) workable leaks (Type 1, 2, and 2A leaks) and (ii) total leaks (Type 1, 2, 2A, and 3), as follows:

Leak Metric	Calendar Year Targets		Negative Revenue Adjustment
Workable Leaks (Type 1, 2, 2A)	Each Calendar Year	≤ 25	10 basis points
Total Leaks[21] (Type 1, 2, 2A, 3)	2020	750	5 basis points
	2021	675	
	2022	600	
	2023	525	
	2024	450	

The Company will be considered to have met its annual backlog targets if the target is achieved any time between December 21 and December 31 of the respective calendar year.

[20] Case 18-M-0195, *Proceeding on Motion of the Commission to Conduct a Comprehensive Management and Operations Audit of National Grid USA's New York Electric and Gas Utilities*, National Grid Management Audit Final Report (issued November 19, 2020).

[21] Total Leaks are inclusive of any high emitting leaks repaired.

Successful elimination of a leak does not require Type 3 leak follow-up inspections. Re-check inspections that fail will be incorporated into the Company's leak backlog.

For every 50 additional leaks repaired beyond the Total Leaks target in a calendar year, the Company will earn a positive revenue adjustment of two basis points. This incentive is capped at 150 or more additional leak repairs, *i.e.*, six basis points. In the event that the Company earns a positive revenue adjustment in a calendar year, the following year's target will be adjusted by rounding the remaining leak backlog up to the nearest 25 leak increment and setting the following calendar year's target 75 leaks below that amount. For example, if in calendar year 2021 the Company was to have a leak backlog of 615, it would earn a PRA of two basis points. The subsequent calendar year 2022, 2023, and 2024 targets would be reset to 550, 475, and 400, respectively.

14.3. Damage Prevention

All damages will be tracked, measured, and counted following the guidelines for the data reported for the Annual Pipeline Safety Performance Measures Report, excluding homeowners and hand damages that did not provide a one-call ticket. The Company will incur negative revenue adjustments of up to 20 basis points or positive revenue adjustments of up to ten basis points for damage prevention performance within the following targets:

NRA/PRA	Basis Points	Calendar Year 2021	Calendar Year 2022	Calendar Year 2023	Calendar Year 2024
NRA	20	>2.50	>2.50	>2.50	>2.50
NRA	10	2.26-2.50	2.26-2.50	2.26-2.50	2.26-2.50
NRA	5	2.01-2.25	2.01-2.25	2.01-2.25	2.01-2.25
	0	1.51-2.00	1.51-2.00	1.51-2.00	1.51-2.00
PRA	5	1.26-1.50	1.26-1.50	1.26-1.50	1.26-1.50
PRA	10	≤1.25	≤1.25	≤1.25	≤1.25

14.4. Emergency Response

The Company will incur a negative revenue adjustment for failure to meet the leak and odor call response targets as shown in the table below:

Required Response Time ("RRT")	Calls that must be responded to within RRT	NRA for failure to meet RRT
30 minutes	75%	12 basis points
45 minutes	90%	8 basis points
60 minutes	95%	5 basis points

Niagara Mohawk can earn a positive revenue adjustment of up to six basis points as shown in the table below.

Emergency Response Incentive	Response within 30 minutes		
Response Rate	86%-88%	>88%-90%	>90%
Positive Revenue Adjustment	2 basis points	4 basis points	6 basis points

Instances of 20 or more odor calls in a two-hour period resulting from a mass area odor issue that is not caused by the Company can be excluded from this measure contingent upon Staff consent. The Company will provide notification to Staff (through an email to safety@dps.ny.gov) within seven days after such events.

14.5. Gas Safety Regulations Performance Metric

a. Niagara Mohawk will incur negative revenue adjustments for instances of non-compliance (occurrences of violations) of certain gas safety regulations identified during Staff's field and records audits. Appendix 8 lists the high risk and other risk gas safety regulations pertaining to this metric.

b. Subject to section (c), below, Niagara Mohawk will be assessed negative revenue adjustments for each high risk and other risk violation, up to a maximum of 75 basis points per calendar year, as follows:

<table>
<tr><th>Audit</th><th>Type</th><th>Occurrence</th><th>Basis Points</th></tr>
<tr><td rowspan="5">Records</td><td rowspan="3">High Risk</td><td>1 to 5</td><td>0</td></tr>
<tr><td>6 to 20</td><td>0.5</td></tr>
<tr><td>21+</td><td>1</td></tr>
<tr><td rowspan="2">Other Risk</td><td>1-15</td><td>0</td></tr>
<tr><td>16+</td><td>0.25</td></tr>
<tr><td rowspan="3">Field</td><td rowspan="2">High Risk</td><td>1 to 20</td><td>0.5</td></tr>
<tr><td>21+</td><td>1</td></tr>
<tr><td>Other Risk</td><td>All</td><td>0.25</td></tr>
</table>

c. The number of occurrences of non-compliance with each high risk and other risk regulation listed in Appendix 8 subject to a negative revenue adjustment is capped at ten per audit type (Field or Records) per calendar year. If Niagara Mohawk is cited for more than ten occurrences of non-compliance with a particular high risk or other risk regulation in a calendar year, Niagara Mohawk will file with the Secretary a compliance improvement plan that contains: (i) a root cause analysis of Niagara Mohawk's compliance deficiency; and (ii) a proposed mitigation plan to address future performance. Niagara Mohawk and Staff will meet to develop a mutually agreeable mitigation plan, which will include provisions for tracking and regular reporting on Niagara Mohawk's efforts to address the compliance deficiency. The compliance improvement plan will be filed with the Secretary to the Commission within 90 days of Staff's audit letter identifying the compliance deficiency. Should the Company fail to comply with its compliance improvement plan, those violations of a code section in excess of ten that were previously capped shall count towards this metric.

d. At the conclusion of each audit, Staff and Niagara Mohawk will have a compliance meeting where Staff will present its findings to Niagara Mohawk. Niagara Mohawk will have ten business days from the date the audit findings are presented to cure any identified document deficiency. Only official Niagara Mohawk records, as defined in Niagara Mohawk's O&M plan, will be considered by Staff as a cure to a document deficiency. Staff will submit its final audit report to the Secretary to the Commission under Case 20-G-0381. If Niagara Mohawk disputes any of Staff's final audit results, Niagara Mohawk may appeal Staff's findings to the Commission. Niagara Mohawk will not incur a negative revenue adjustment on the contested findings until such time as the Commission has issued a final decision on the contested findings. Niagara Mohawk does not waive its right to seek an appeal of any Commission determination regarding a violation or penalty under applicable law.

e. If an alleged occurrence of non-compliance with a high risk or other risk regulation is the subject of a separate penalty proceeding by the Commission, the occurrence will not count under the performance metric. Any violation of a pipeline safety regulation that has a corresponding procedural violation under 16 NYCRR 255.603(d) will count as one occurrence for purpose of calculating a negative revenue adjustment.

14.6. Gas Safety Reporting and Exceptions

Niagara Mohawk will report its annual performance in each of the areas set forth in Sections IV.14.1 through 14.5 to the Secretary to the Commission no later than April 1st of the following calendar year.

15. Customer Programs

15.1. Energy Affordability Program

The Company will implement its EAP in accordance with its EAP implementation plan, and the *Order Adopting Energy Affordability Policy Modifications and Directing Utility Filings* issued August 12, 2021 in Case 14-M-0565 (the "EAP Phase Two Order").

The Company will modify its tariff, as necessary, to expand the existing manual enrollment process for EAP to include customers who provide proof of participation in any of the following programs:

- Temporary Assistance for Needy Families (Family Assistance)
- Safety Net Assistance - Public Assistance
- Supplemental Security Income
- Medicaid
- Food Stamps
- Low Income Home Energy Assistance Program
- Veteran's Disability Pension
- Veteran's Surviving Spouse Pension
- Child Health Plus
- LifeLine – income eligible phone service
- Tribal Programs

The benefit levels for each tier in the EAP will be updated annually in accordance with the requirements of the EAP Phase Two Order and published in the Company's tariff statements. As directed in the EAP Phase Two Order, the Company will not lower the EAP discounts prior to November 30, 2022. From December 1, 2022 forward, the Company may adjust benefit levels to align the energy burden and discounts as necessary to conform with the two percent budget cap as directed by the EAP Phase Two Order. When adjusting discounts downward, the Company will follow the "glide rule," which provides that discounts cannot be reduced by more than 20 percent when conducting an annual recalculation in order to mitigate the impacts from otherwise larger discount reductions.

The annual rate allowance for the EAP is $23.484 million in Rate Year One, $20.973 million in Rate Year Two and $19.401 million in Rate Year Three for the Company's electric business, and $6.611 million in Rate Year One, $5.645 million in Rate Year Two and $5.413 million in Rate Year Three for the Company's gas business. The rate allowances for the Company's EAP is subject to reconciliation, as set forth in Section IV.12.1.2 above.

The Company will revise its EAP structure to eliminate duplicative tiers, consolidating into a four-tier structure by eliminating Tier 5. Current Tier 5 Participants shall be moved to Tier 1 and will continue to receive the same level of benefits.

15.1.1. Reconnection Fees for Energy Affordability Program Participants

EAP participants will be exempt from paying reconnection fees. In Rate Year One, the costs incurred to exempt EAP participants from reconnection fees shall be deferred and recovered by using offsetting deferral credits from the Company's deferral balance related to EAP or other low-income assistance programs. In Rate Year Two and Rate Year Three, these costs are included in the EAP budgets identified in Section IV.15.1, above.

15.1.2. Generic Energy Affordability Program Proceeding

The Signatory Parties acknowledge that certain issues related to the Company's EAP, including the calculation of bill discounts and expanded eligibility criteria, are being modified in accordance with the EAP Phase Two Order. Further, Staff, the Company, and other stakeholders will participate in the EAP collaborative working group recently established by the EAP Phase Two Order. The Company anticipates further changes could be adopted by the Commission in response to the collaborative working group. Such changes may supersede the provisions of this rate plan as the Commission may direct in an order adopting such changes.

15.1.3. Consumer Advocate Checklist

As a consequence of the COVID-19 pandemic, moratorium on utility terminations, and related economic impacts, there is a growing number of customers who have arrears in excess of $300 or who have not made a payment in more than three months. Certain of these customers may not be fully aware of their options for assistance because their situation is relatively new to them, resulting from the effects of the COVID-19 pandemic. The Company will implement new training for Consumer Advocates involving use of a checklist of steps targeted at assisting these customers. An example of a Customer Advocate checklist is provided in Appendix 12.

15.2. Collections and Special Protections

15.2.1. COVID-19 Moratorium on Terminations and Disconnections

The Company shall continue to follow Staff guidance as has been and may be issued[22] in Matter No. 20-01676 regarding the COVID-19 moratorium on terminations and disconnections for residential and eligible small business customers.

[22] Subject to the Company's rights to reasonably challenge guidance that has not yet been issued.

15.2.2. Extreme Weather Protections

As directed by the Commission herein, during the "cold weather period," as defined in 16 NYCRR § 11.5(c)(2), the Company will provide the following protections to customers:

- acceptance of all Home Energy Assistance Program ("HEAP") payments and suspending field collections for residential customers that receive a HEAP payment during the cold weather period, regardless of the amount due and/or the customer's payment status;
- agreeing to offer a deferred payment agreement ("DPA") when a Regular and/or Emergency HEAP payment is received during the cold weather period, regardless of any previous DPA defaults;
- No terminations of residential service during the cold weather period on days when the local forecast predicts below-freezing temperatures; and
- No terminations of residential service to accounts identified as "elderly, blind, or disabled" ("EBD") during the cold weather period.

Further, the Company will also suspend residential electric service terminations for non-payment during a "heat advisory" declared by the National Weather Service in any given region in 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 consecutive days.

15.3. Outreach and Education Plan

The Company will file its annual outreach and education plan electronically with the Secretary to the Commission, due April 1 of each year, under Case 17-M-0475, *In the Matter of Utility Outreach and Education Plans*.

15.4. Ancillary Service Rate Calculation

Beginning in Rate Year Two, the Company will provide the New York State Office of General Services monthly ancillary service rate calculation information via electronic mail within three days of Company's monthly electric supply rate filing.

15.5. Telephone Consumer Protection Act

The Company will develop and implement a plan to add functionality to its telephone system to support compliance with the Telephone Consumer Protection Act ("TCPA"). Niagara Mohawk's share of the cost for the TCPA project is estimated to be $0.537 million, of which $0.139 million is for expense and $0.398 million is for capital.

15.6. Submetering

The Company will provide the option of a temporary volumetric rate for applicants and customers with a pending submetering application before the Commission for which a notice has been published in the New York State Register. The Company shall revise its tariffs to reflect the temporary volumetric rate, security deposit, and limited waiver language below.

The temporary rate will be 20 percent higher than the otherwise applicable service class base delivery rate. Additionally, a customer requesting this temporary service shall provide the Company with a per unit security deposit prior to energization, which deposit the Company will return once Commission approval for submetering is granted and submetering of residents commences. The per-unit security deposit will be determined by the Company as an estimate of the residential class average electric bill multiplied by two. The submetering security deposit will be separate from any other applicable security deposits and will not accrue interest while being held by the Company. If the customer or applicant is 60 days or more delinquent on its electric service bills while the deposit is being held, the Company may apply the deposit to offset the arrears.

Implementing the temporary rate described in the preceding paragraph requires a limited waiver of 16 NYCRR 96.2(a)(1), which precludes Niagara Mohawk from providing electric service without authorization by Commission Order, and the Company may energize service to a premise prior to receipt of Commission authorization provided that: (1) applicant has filed a submetering application that is pending with the Commission and a notice has been published in the New York State Register; (2) the applicant's petition contains all filing requirements identified in 16 NYCRR Part 96; (3) the applicant has completed all Company-required paperwork and remitted payment for service; and (4) applicant has resolved all other concerns identified by Company in its review of applicant's submetering request. Accordingly, a Commission order adopting the terms of this Joint Proposal would grant the necessary waiver.

15.6.1 Submetering Rate Calculator

At least three months prior to its next base rate filing, the Company will file cost estimates for a submetering rate calculator that would be available on the Company's website.

15.7. Arrears Resolution

The Company will participate in the collaboration commenced by its Downstate Affiliates to discuss arrears resolution-related issues and in the report that will address those issues. The report will describe any arrears resolution programs that the Company and its Downstate Affiliates are planning to undertake, and shall request, to the extent necessary, Commission authorization for such programs. The Company shall not be obligated to undertake any arrears resolution program without obtaining approvals that it determines to be necessary. If the Commission makes a determination concerning arrears resolution on a generic basis, such determination will control and eliminate the requirement for the collaboration.

15.8. Language Access

Consistent with the efforts of its Downstate Affiliates, the Company will work with Staff and other interested parties to assess the Company's program to communicate with customers and other parties in different languages. The Company will file a report with the Secretary to the Commission in Cases 20-E-0380 and 20-G-0381 concerning its efforts and programs no later than six months from the issuance of a Commission order adopting the terms of this Joint Proposal.

16. Earnings Adjustment Mechanisms

The Company will implement the EAMs in accordance with the terms and conditions set forth in Appendix 7. If the Commission takes action on EAMs on a generic state-wide basis this Joint Proposal will not preclude that action from taking effect during the term of the rate plan.

17. Non-Pipe Alternatives, Gas Demand Response, Energy Efficiency, Locally Produced Biomethane, Economic Development and Related Matters

17.1. Non-Pipe Alternatives

The Company will consider NPAs in the planning of proactive leak-prone pipe replacement. The Signatory Parties agree, however, that any such NPAs must not jeopardize the safety and reliability of the gas distribution system. The Company's NPA proposals are described in greater detail in Section IV.18.1.5.

17.2. Gas Demand Response Program

Before implementing a Gas Demand Response Program, the Company will file a petition to the Commission for its approval. At the time of filing such petition, the Company will also submit a draft Implementation Plan and draft tariff amendments regarding the proposed Gas Demand Response Program.

17.3. Locally Produced Biomethane

17.3.1. Locally Produced Biomethane Procurement

The Company's contracts for and procurement of locally produced biomethane (also known as renewable natural gas) will be limited to one percent of its total annual supply portfolio by volume per year for the winter 2020/21, increasing one percent a year over five years to a cap of five percent of the overall gas supply portfolio by volume. To further minimize price volatility and risk for gas customers, the Company will not purchase title to any environmental attributes for the locally produced biomethane thereby allowing such attributes to be retained by developer(s) of the locally produced biomethane. As such, for any locally produced biomethane the Company purchases where the Company does not purchase or restrict the use of the renewable attributes, the Company will make no claims regarding decarbonization or environmental benefits associated with locally produced biomethane procurement.

The Company may enter into supply contracts for locally produced biomethane with terms longer than five years. Any such long-term supply contract pricing terms will be tied to a reasonable gas pricing index (*e.g.*, the Company's Citygate) for the interconnection location. The Company's assessment of biomethane costs will also consider any associated interconnection costs that would be borne by the Company's customers.

All locally produced biomethane supply contracts must comply with the Commission's "Statement of Policy Regarding Gas Purchasing Practices" (Purchasing Policy Statement), issued in Case 97-G-0600 on April 28, 1988. The Company will discuss the potential terms of any potential locally produced biomethane supply contract with DPS Staff at least 60 days before executing any such contract. The Company will also file all executed locally produced biomethane supply contracts with the Secretary to the Commission in accordance with the Purchasing Policy Statement.

17.3.2. Locally Produced Biomethane Direct Interconnection

The Company may incur capital expenditures up to a cap of $2 million to construct direct interconnections with biomethane facilities (other than centralized biomethane facilities) during the term of the rate plan. If the Company exceeds its net plant and depreciation targets established for the rate plan as set forth in this Joint Proposal, the Company may petition the Commission during the term of the rate plan for authorization to recover the costs associated with direct interconnections for biomethane. The petition shall include details on the project costs, timeline, a benefit/cost analysis for each of the proposed projects, and a proposed cost recovery mechanism. The inclusion of this provision does not indicate any Signatory Party's support for such potential petition. Absent Commission authorization, during the term of the rate plan the Company will not proceed with the customer-funded construction of a centralized biomethane interconnection facility.

17.4. Multi-use Hydrogen/Energy Transfer Station Facility

The Company is authorized to recover certain costs associated with a Multi-use Hydrogen Production and Utilization Facility (the "Energy Transfer Station" or "ETS") that is the subject of a contract between the Company and Standard Hydrogen Corporation of Ithaca, NY. The ETS facility will be developed around a nominal one megawatt electrolyzer that produces hydrogen from produced or purchased renewable electricity. That hydrogen will be used immediately or compressed and stored on site.

Hydrogen produced by the ETS may be used: (1) to provide electricity to the host site as back-up using the ETS facility's fuel cell; (2) as a source of revenue by providing demand or capacity to the electric grid or for Level 3 charging of electric vehicles without using grid capacity; (3) as a source of revenue by providing fueling services for hydrogen fuel cell vehicles; or (4) if approved by the Commission, for blending into the Company's gas distribution system. The Company shall not commence hydrogen blending from the ETS facility in its gas distribution system until it has (i) filed a proposal with the Commission detailing the blending planned for the ETS facility, including support demonstrating the safety of the proposed level of blending, and (ii) received authorization from the Commission to proceed with blending. The Signatory Parties take no position with regard to blending hydrogen in the gas distribution system, which will be separately considered, as discussed above.

Capital costs for the ETS facility will be allocated among the Company's electric and gas businesses based on percentage of plant as follows: Electric Plant 19 percent, Gas Plant 9.5 percent, and Common Plant 71.5 percent (83 percent/17 percent Electric/Gas). The Company's electric revenue requirement includes $6.738 million of capital expenditures for the development of the ETS facility (based on estimated electric-only costs and electric portion of allocated common costs, less the value of a NYSERDA grant), shareholders will fund the expenditures allocated to the gas business.

All O&M costs will be considered Common costs and will be allocated to the electric and gas businesses as follows: 83 percent Electric and 17 percent Gas. The Company's electric revenue requirement includes $0.130 million of operating costs associated with the ETS facility. The O&M costs allocated to the gas business will be funded by shareholders.

Niagara Mohawk's electric customers and shareholders will share 75 percent/25 percent, respectively, in any net revenues and sales proceeds generated from the ETS facility.

As discussed in Section IV.12.2.9 of this Joint Proposal, non-labor O&M expenses related to operating the ETS facility (*e.g.*, demand charges for electric vehicle charging, purchase of bulk power to operate electrolyzer), which are currently forecast at $381,000 for Rate Year Three, will be netted against the customer-retained portion of ETS-related revenues and any net balance will be passed back or recovered through a non-bypassable delivery surcharge included on the delivery line item of customers' bills.

17.5. Online Fuel Switching Calculator

The Company will implement its proposed Online Fuel Switching Calculator in Rate Year One. The costs reflected in the Company's revenue requirement recognize that the cost of the Online Fuel Switching Calculator is allocated to all National Grid affiliates that provide comparable gas distribution services.

17.6. Economic Development Programs

17.6.1. Economic Development Fund Program

The Company will continue its existing electric and gas Economic Development Fund Programs, which provide discounted electric and gas delivery rates to qualifying customers under the EZR and EJP programs, and discounted delivery rates to customers qualifying for electric discount contracts under SC-12 or to customers with existing SC-12 discount contracts. All newly certified recipients of the EJP will be required to explore energy efficiency opportunities through the Company, NYSERDA, and/or other entities. The discounts provided are subject to full reconciliation as set forth in Section IV.12.1.3.

17.6.2. Economic Development Grant Program

The Company will administer its portfolio of electric and gas Economic Development Grant Programs at funding levels of $11 million and $1 million per year, respectively, subject to downward-only reconciliation over the term of the Rate Plan, as set forth in Section IV.12.1.4.

17.6.3. Economic Development Reporting

The Company will file with the Commission an annual report no later than April 1 each year that will include a review of program activity and results for the previous calendar year, as well as the Company's proposed economic development grant programs for the current calendar year. The Company may propose program adjustments in its annual report. The Signatory Parties recommend that Staff may review and approve minor adjustments without further Commission review or approval. Minor program adjustments include: administrative changes such as clerical changes, contact information changes and wording updates to bring program descriptions up to date; adding customer rate classifications or industry types to eligible criteria to participate in a grant program; and increases to maximum grant funding provided that the increase in the maximum grant amount does not exceed $25,000 and increase the maximum grant amount by more than 25 percent. Commission approval will continue to be required for other program adjustments, including any proposal to: eliminate a grant program; downscale a program in either grant amounts or alter eligibility requirements; create a new grant program; or increase overall annual funding to economic development grant programs. Additionally, any change in the matching capital investment ratio, such as reducing a matching capital requirement from 4:1 to 3:1, will continue to require Commission approval. The Company will continue to meet on an annual basis with Staff and interested parties to discuss the Economic Development Program Plan.

17.7. Energy Efficiency Programs

17.7.1. Energy Efficiency Program Costs

The Company's electric and gas energy efficiency program costs will be recovered in base rates consistent with the Commission's orders issued in Case 18-M-0084.[23] The electric and gas energy efficiency program costs included in base rates reflect the amounts authorized by the Commission in the NE:NY Order.

The NE:NY Order caps the Company's total 2021-2025 energy efficiency program budget at $513.481 million for electric programs[24] and $101.830 million for gas programs. Pursuant to the NE:NY Order, the Company is permitted to carry deferred overspent or underspent funds forward from year to year, through 2025, for offset or use in future year energy efficiency programs provided that the Company does not exceed the cumulative budgets authorized by the NE:NY Order. The Company will continue to be afforded the flexibility to shift funds within the respective electric and gas energy efficiency portfolios of programs.

The Company will reconcile the revenue requirement effect of the actual level of costs incurred for the energy efficiency programs to the cumulative electric and gas reconciliation targets and defer any cumulative over- or under-collection over the term of the rate plan for future recovery from or refund to customers. The reconciliation applies to the Company's aggregate total energy efficiency spending, not to individual program components. Consistent with the NE:NY Order, the Company's electric and gas energy efficiency program budget and targets will be

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[23] Case 18-M-0084, *In the Matter of a Comprehensive Energy Efficiency Initiative*, Order Authorizing Utility Energy Efficiency and Building Electrification Portfolios Through 2025 (issued January 16, 2020) (the "NE:NY Order"); Case 18-M-0084, Order Adopting Accelerated Energy Efficiency Targets (issued December 13, 2018).

[24] The $513.481 million for electric programs is broken out as $436.066 million for the electric energy efficiency portfolio and $77.415 million for the heat pump portfolio.

subject to a mid-point review period in 2022. In the event the Commission changes electric and gas energy efficiency budgets and targets during the term of this rate plan but does not adjust the Company's revenue requirements or otherwise provide for recovery of such costs, such modifications shall be included in the reconciliation.

If the rates set forth in this Joint Proposal continue beyond Rate Year Three, then the energy efficiency program budget will be subject to the terms of Section IV.19.2(ii) of this Joint Proposal. Energy efficiency program costs incurred beyond Rate Year Three will be reconciled annually to the costs reflected in base rates. The Company will be permitted to recover through a surcharge any Commission-approved energy efficiency program budget not reflected in base rates. An example of this reconciliation is set forth in Appendix 5, Schedule 12 for electric and Appendix 6, Schedule 12 for gas. The reconciliation applies to the Company's aggregate total Energy Efficiency spending, not to individual program components.

17.7.2 Allocation of Energy Efficiency Program Costs

The Company's electric energy efficiency costs included in base rates will be allocated to the service classifications based on a study of the beneficiaries of the various programs. The costs of the heat pump programs will be recovered from the service classifications based on the Tot_DistRev (total distribution revenue) allocator and the costs of all other energy efficiency programs will be based on a combination of 1CP-Trans (coincident peak transmission), NCP_Pri (non-coincident peak primary, MWh-Gen (energy) and Tot_DistRev (total distribution revenue). The resulting percentage allocations are shown on Appendix 2, Schedule 2.4.

The Company's gas energy efficiency costs will be allocated to the service classifications based on firm gas deliveries. The resulting percentage allocations are shown on Appendix 3, Schedule 2.4.

17.8. Unspent Energy Efficiency Funds

There are unspent energy efficiency funds from years prior to the NE:NY program, *i.e.*, before 2019, which remain deferred on the Company's books. The pre-NE:NY funds shall be used to offset incremental NE:NY activity required as a result of the mid-point NE:NY review. Additionally, as explained in Section IV.19(ii), the pre-NE:NY funds shall be used to offset incremental Commission-authorized energy efficiency budgets during the Stayout Period.

18. <u>Gas Matters</u>

18.1. Reducing Billed Gas Usage/Non-Pipe Alternatives

The Company will operate its gas networks with the objective of reducing billed gas usage, normalized for temperature, in its service territory over the term of the rate plan. For purposes of measuring this goal, the Company will endeavor to achieve weather-adjusted reductions in billed gas usage of one percent as compared to the forecast levels of non-generator gas use in Rate Years Two and Three (which would effectively achieve a net-zero increase in billed gas usage as compared to the level of usage reflected in the Rate Year One sales forecast underlying this Joint Proposal). The forecast levels are 1.289 million therms for Rate Year Two and 1.301 million therms for Rate Year Three. As set forth in this Joint Proposal, in furtherance of the targeted reductions, the Company will (i) implement Commission-approved energy efficiency (NE:NY) and incremental demand response programs, (ii) pursue non-gas NPA projects for certain LPP replacements and customer connections, (iii) promote geothermal/electric heating options with prospective customers and through the Company's energy efficiency program offerings, (iv) provide a new, shareholder-funded incentives for gas-to-heat pump conversions (including both air- and ground-source heat pumps), (v) collaborate with community organizations to promote heating alternatives, and pursue other initiatives intended to achieve target reductions.

Notwithstanding these efforts, the Signatory Parties acknowledge that billed gas usage could be impacted by economic conditions and other factors beyond the Company's control. The Company will report on its progress against these gas usage reduction goals in semi-annual filings to be made on April 30th and October 31st of each year. These reports will identify monthly billed use by sector (residential, commercial, industrial) and will track gas customer counts and net changes in gas customers by month, as well as the results of the Company's initiatives and any external factors influencing billed gas usage during the reporting period. Before the end of Rate Year Two, the Company will file a report that assesses the energy efficiency and other non-infrastructure programs necessary to achieve climate appropriate reductions in billed gas usage in future years. These programs will be presented for consideration in the Company's next rate filing. The Company will convene a meeting of Staff and other interested parties to discuss this report and potential actions to support the Company's billed gas usage reduction targets. This report and meeting, including potential actions will not affect revenue requirements or rates during the term of this rate plan.

18.1.1 Termination of Gas Expansion Programs and Marketing

(a) *Programs*. The Company will terminate all gas promotional and rebate programs and will not implement any such programs during the term of the rate plans, including any heating oil-to-gas conversion programs. Nothing contained herein will preclude the Company from marketing its approved energy efficiency programs, nor will anything herein prevent the Company from providing information to current or prospective customers concerning their rights to purchase service from the Company.

(b) *Marketing*. The Company will cease all marketing for new gas connections and conversions, including any customer rebates for heating oil-to-gas conversions or new gas customers, and will not resume gas marketing for the term of the rate plans. Within six months of the issuance of a Commission order adopting the terms of this Joint Proposal, the Company will modify its website, customer mailings, customer emails, and marketing materials to remove any reference to gas conversion promotional or rebate programs.

(c) *Energy Efficiency Marketing*. In its marketing of gas energy efficiency programs to customers, the Company will encourage customers to explore electrification options where possible given the nature of the program (*e.g.*, full equipment replacements). The Company's future direct energy efficiency marketing will not include language referring to gas as having environmental benefits. The Company will implement the forthcoming recommendations of the Performance Management and Improvement Process regarding marketing of energy efficient gas equipment.

18.1.2 Alternate Heating Options

The Company commits to developing educational materials, in coordination with its energy efficiency and demand response programs, that will inform customers of alternative heating options, including air- and ground-source heat pumps and district geothermal heating systems. The Company will also add these options to any materials showing the comparative advantages of one fuel choice or option over another, highlighting federal and state incentives.

The Company will also provide prospective customers with information on organizations and initiatives providing alternate heating options (*e.g.*, heat pumps) in its service territory. The Company will work directly with local non-profits and community groups to expand outreach. The Company will also work with NYSERDA-funded programs in the Company's service territory to develop and distribute educational materials. The Company will also refer customers to NYSERDA's website for information on available heat pump programs.

18.1.2.1 Heat Pump Conversion Program

The Company will implement a new gas-to-heat pump conversion program that will provide incentives to customers that convert from natural gas to either air- or ground-source heat pumps. The Company, and not its customers, will provide up to $1 million of funding for the program over the term of the rate plan.

18.1.3 CLCPA Study

On or before March 31, 2023, the Company will complete a report (the "CLCPA Study") that evaluates how the Company's businesses may evolve in the future to support the emission reduction and renewable energy goals of the CLCPA and any emission reduction goals the Company has independently adopted. The CLCPA Study will provide an analysis of the scale, timing, costs, risks, and uncertainties (translated into sensitivity analyses around key cost and availability assumptions), and customer bill impacts of a range of strategies for achieving significant, quantifiable reductions in carbon emissions from the use of gas delivered by the Company in its service territory. The CLCPA study will provide further analysis to identify the projects and programs needed to achieve specific decarbonization goals (*e.g.*, 85% CO_2e reductions by 2050). The analysis will include an assessment of the Company's current direct and indirect greenhouse gas ("GHG") emissions, potential CO_2e reductions per year, MMBTU reductions in billed annual usage, and the numbers of customers heating with gas in residential, commercial, and industrial classes per year under different scenarios, including a scenario that assumes full electrification where reasonably capable of providing an alternative energy option to natural gas. A pathways analysis will identify potential barriers to achieving the targeted carbon emission reductions and recommended solutions. The Company will incorporate and respond to any findings or guidance of the New York State Climate Action Council in the CLCPA Study.

The study will also consider how the Company will take steps to avoid disproportionately burdening disadvantaged communities.

The study process will include: (i) a scoping meeting at which the Company will present a draft scoping plan for feedback from the parties including the opportunity to ask questions; (ii) an opportunity for parties to review the draft study before publication, including all underlying data sources, assumptions, and analyses; and (iii) a meeting where parties will have an opportunity to provide feedback to the Company on the study before it is finalized and published.

In its next rate filing, the Company will detail investments, programs, and initiatives that have been added, altered, or removed to achieve the objectives detailed in the CLCPA Study. The CLCPA Study will include presentation of the Company's findings using the 20-year warming potential of GHG emissions as may be developed by the Department of Environmental Conservation in accordance with the CLCPA. The Company will make the underlying data and models used in the study available to the participating parties and, as practical, file publicly.

If the Commission commences a generic proceeding to consider issues to be addressed in the CLCPA Study within twelve months from the date of the issuance of a Commission order adopting the terms of this Joi int Proposal, the Company will not prepare or provide a separate report to the extent items are included in the generic proceeding. The Company will continue to produce its own report for any items not included in the generic proceeding.

The Company will be permitted to defer its allocated portion of 50 percent of the third-party costs to conduct the CLCPA Study, up to $500,000 for National Grid's New York gas utilities in the aggregate. The study will address all three of National Grid USA's New York gas operating companies.

18.1.4 Depreciation Study

Unless required to do so earlier by the Commission, the Company will complete and file, at least three months before its next base rate filing, a study on the potential depreciation impacts of climate change policies and laws – including the CLCPA – and the statewide GHG emission limits established therein – on the Company's gas assets. The study will include an examination of the potential impacts of climate change policies and laws on average service lives, reserve deficiency/surplus, salvage value, cost of removal, depreciation rates, and customer bills, and an assessment of the appropriate survivor curve to help inform the Company's next base rate filing. The process will include: (i) a scoping meeting at which the Company will present a draft scoping plan for feedback from the parties; (ii) an opportunity for parties to review the draft study before publication; (iii) and a meeting where parties will have an opportunity to provide feedback to the Company on the study before it is finalized and published.

18.1.5 Heat Pump Non-Pipe Alternatives: Leak Prone Pipe Alternatives and Customer Connections Pilots

(a) *Geothermal Heating*. The Company will support the deployment of geothermal heating as an NPA in its service territory. This support will involve various actions including, but not limited to, proactive customer outreach in response to new gas service requests and analysis as an NPA for LPP replacement.

(b) *LPP Replacement Alternatives*. The Company will identify instances where planned LPP replacement projects could be avoided by deploying shared geothermal loops or individual ground- or air-source heat pumps to serve affected customers. The Company will, to the extent practicable, use experience and lessons learned from pilot programs by other utilities in New York and elsewhere to identify and potentially address operational, billing, and customer service hurdles for purposes of informing the Company's long-term strategy for main replacement and geothermal deployment.

The Company will initially identify areas of the gas distribution system that are slated for LPP replacement where non-gas NPAs could be used to address customers' heating needs. The Company will then conduct outreach to affected customers to determine customer interest in the NPA(s). If material customer interest exists, the Company will then issue RFPs for contactors and vendors to support the potential NPA projects.

For LPP to be removed beginning in Rate Year Two, the Company will annually identify at least five segments of LPP in the Company's service territory that could be removed if all customers' natural gas loads are met with cost-effective NPAs that would allow the section of LPP to be removed. For each such section of LPP, the Company will pursue NPAs allowing the section of LPP to be abandoned, or otherwise demonstrate that abandonment of such section of LPP is not possible. The LPP projects identified pursuant to this section will count toward the minimum amounts of LPP required to be replaced regardless of whether the pipe segments are replaced or abandoned. The Company shall report on this program in its semi-annual reports that will include a summary of the analyzed NPA projects and their outcomes and a discussion of the barriers to LPP NPAs and any potential changes necessary to overcome them.

(c) *Customer Connections*. For gas service requests that involve a main extension of more than 500 feet and which would serve five or more customers, the Company will perform a preliminary analysis of the potential to meet the needs of the prospective customers with a non-gas NPA. If this analysis shows that it is feasible and beneficial for customers from a cost perspective and would lead to reduced GHG emissions, the Company will contact those customers to present alternatives, including a discussion of the climate, cost, and other benefits to customers of non-gas alternatives, including geothermal and solar. The Company's promotional materials and scripts for the presentation of alternatives shall be developed in consultation with NYSERDA-funded programs in the Company's territory. If the customers are willing to consider an alternative to natural gas, the Company will issue RFPs for contractors and vendors for installing the non-gas NPA.

Any proposal for a program or project involving utility ownership of non-gas infrastructure or equipment (*e.g.*, thermal loop fields and heat pumps) must receive further and specific Commission approval prior to recovery of costs in gas distribution rates.

Consistent with the "Report of Niagara Mohawk Corporation d/b/a National Grid Concerning the Non-Pipeline Alternatives Incentive Mechanism Collaborative" filed December 21, 2018 in Case 17-G-0239, the Company will propose a mechanism to retain a percentage of the difference between the costs of a traditional investment and the proposed cost of an NPA, adjusted for other net benefits. This mechanism will be filed at the time the Company submits its first petition for approval of an NPA. The NPA Incentive Mechanism will not be available to projects that make use of utility-owned non-gas infrastructure, consistent with the Commission's REV Track One Order's requirements that utility ownership of Distributed Energy Resources as a regulated asset will be restricted to recovery of actual costs.[25]

The Company will undertake reasonable efforts to prioritize potential projects to transition LPP replacement to NPAs in low income and environmental justice communities in all service areas. The Company will continue to use its risk rating model to identify and rank segments of

[25] 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) ("REV Track One Order"), p. 66.

LPP. It will then consider the use of NPAs throughout its service territory, and prioritize areas in low income and environmental justice communities.

The Company will implement an NPA screening process and conduct solutions for NPAs as part of its capital planning process. The process will be implemented to account for any relevant Commission decisions in Case 20-G-0131, *Proceeding on Motion of the Commission in Regard to Gas Planning Procedures* ("Gas Planning Procedures Proceeding"). For each proposed NPA, the Company will submit a project-specific benefit/cost analysis computation consistent with the BCA framework order until such time as a Benefit/Cost Analysis ("BCA") Handbook is developed in the Gas Planning Procedures Proceeding, or another generic proceeding. Following development of the Gas BCA Handbook, each NPA proposed will include a benefit/cost analysis consistent with the Gas BCA Handbook.

During the term of the rate plan, the Company may petition the Commission for approval of a program to allow potential customers requesting new gas service to be provided with information about alternatives of thermal energy and offer such customers an incentive based on the cost of the gas connections that can be used for heat pump installations. The proposal would tailor this program to constrained areas of its service territory such as East Gate. In any such petition the Company would be required to explain the derivation of the incentive amount and provide a benefit/cost analysis in support of that amount.

18.1.6 Climate Assessment of Investments and Initiatives

Unless required to do so earlier by the Commission, in its next rate filing, the Company will provide the following information:

(a) A 1990 GHG emissions baseline (including Scope 1, 2 and 3 emissions) for its gas network and a description of the methodology used to calculate or otherwise develop the baseline;

(b) A calculation of annual GHG emissions for the Company at the time of filing – a current GHG emissions baseline (including Scope 1, 2 and 3 emissions) – and a description of the methodology used to calculate the emissions;

(c) An assessment of the impact that investments, programs, and initiatives described in the rate case filing will have on the Company's GHG emissions from its gas network, including a breakdown of the emissions impact of specific programs and investments proposed in the rate filing; and

(d) An analysis of NPAs considered for each investment, program, or initiative, including an explanation if an NPA option was not selected.

The Company's next rate filing will reflect any guidance or standards regarding the calculation of GHG emissions issued by the New York State Department of Environmental Conservation, the Climate Action Council, the Commission, or other applicable regulatory bodies.

The Company's compliance with any requirements resulting from the Gas Planning Procedures Proceeding, will not serve to narrow the Climate Assessment detailed above. However, the Company will not be required to duplicate any efforts they must undertake pursuant to orders the Commission may issue in the Gas Planning Procedures Proceeding.

18.2. Gas Supply Matters – Non-Core Daily Balanced Customers

The Company will retain its existing non-core daily balancing service for existing customers. New firm non-core daily balanced customers will not be permitted to commence service absent proof that the customer, or an ESCO acting as its supplier, has contracted for firm primary point upstream capacity to the Company's city gate delivery point or points in a quantity sufficient to serve customer's anticipated peak day requirements for at least one year with the explicit understanding that such firm primary point capacity must be renewed for as long as the customer wishes to remain a firm customer.

Within 180 days of a Commission order adopting the terms of this Joint Proposal, the Company will complete an audit of direct customers taking firm transportation service and ESCOs providing service to such customers to determine, what, if any, portion of their load is not served with upstream, primary point pipeline capacity to the Company's citygate. Direct customers and ESCOs are required to cooperate with the Company's requests for information for such audit and the Company will use reasonable efforts to audit all firm non-core, customers.

Once the Company completes its audit it will convene a meeting (or multiple meetings as necessary) of all interested parties to determine what, if any, actions should be taken with respect to the reliability of upstream deliveries to existing firm, non-core, customers and issue a report with findings (including anonymized audit results) and recommendations within one year of a Commission order adopting the terms of this Joint Proposal. If there are disagreements with the Company's findings and recommendations among the parties, they will be identified in the report.

19. <u>Filing for New Rates</u>

19.1. During the Term of the Rate Plan

The Company agrees not to file for new base delivery rates to be effective prior to July 1, 2024. The following exceptions will apply:

(a) The Company may petition the Commission to implement changes to their base rates as may be required or warranted by newly-enacted legislation or regulations and nothing in the Joint Proposal shall prohibit Niagara Mohawk from implementing changes to rates or charges, in a manner to be determined by the Commission, as may be required by newly enacted legislation or regulations;

(b) The Company may petition the Commission for deferral of extraordinary expenses;

(c) The Company may petition the Commission for approval of new services and/or discrete incentives;

(d) The Company may petition the Commission for changes to rate design or revenue allocation that are revenue neutral, including, but not limited to, the implementation of new service classifications and/or elimination of existing service classifications. Such petitions must demonstrate that the proposed changes are consistent with the overall rate designs and revenue allocations provided for in this Joint Proposal;

(e) The Company may petition the Commission for minor changes in base rates, provided the effect is de minimis or is essentially offset by associated changes in other base rates, statements, terms, or conditions of service; and

(f) The Company may file tariff amendments to implement changes as described in this Joint Proposal.

Any party may take any position on any filing made by the Company pursuant to this Section. Moreover, any party may petition the Commission for minor changes in base rates, provided the effect is de minimis or is essentially offset by associated changes in other base rates, statements, terms, or conditions of service. Notwithstanding the foregoing, nothing in the Joint Proposal shall prohibit the Commission (upon its own motion or upon motion of an interested party) from exercising its ongoing statutory authority to act on the level of the Company's rates in the event of unforeseen circumstances that, in the Commission's judgment, have such a substantial impact on the rate of return as to render the return on common equity devoted to either the

Company's gas or electric operations, unreasonable, unnecessary, or inadequate for the provision of safe and adequate service.

19.2. Following the Term of the Rate Plan

If Niagara Mohawk does not file for new rates to be effective on or before July 1, 2024:

(i) The Net Utility Plant and Depreciation Expense Reconciliation Mechanisms for the Company's gas and electric will be converted to two-way reconciliations through March 31, 2025, capped at the capital forecast levels for the twelve months ending March 31, 2025. The forecast net utility plant and depreciation levels to be used as the cap during the Stayout Period are set forth in Schedules 8 and 9 of Appendix 1 for the Company's electric and gas operations. Those schedules present examples of this reconciliation for the Company's electric and gas operations, respectively. Subject to Section IV.19.2(iii) below, the Company will establish surcharge mechanisms to recover the pre-tax revenue requirement associated with net utility plant and depreciation levels to the extent they exceed the level of net utility plant and book depreciation expense reflected in rates. The costs will be allocated to the firm service classifications in the same manner as they would have been allocated if they had been included in base rates; and

(ii) The Company will be permitted to recover through a surcharge any Commission-approved NE:NY budget (or other approved energy efficiency programs) not otherwise recovered in rates needed to achieve energy efficiency targets in the nine months ending March 31, 2025. The forecasted incremental energy efficiency levels to be recovered during the Stayout Period are set forth in Schedules 8 and 9 of Appendix 1 for the Company's electric and gas operations. The energy efficiency expenditures for the Stayout Period are also included in

Appendix 5, Schedule 12 and Appendix 6, Schedule 12 for the Company's electric and gas operations, respectively.

(iii) Notwithstanding provisions (i) and (ii) of this Section IV.19.2, to the extent that the Company would otherwise be authorized to assess a surcharge under those provisions, the Company will first use any net deferred credits, that are not otherwise committed to a specific program (*e.g.*, low income assistance programs, economic development grant program, energy efficiency program) or have not been designated for a specific purpose by the Commission, in excess of $50 million for its electric operations to offset any potential surcharge to its electric customers, and any net deferred credits in excess of $25 million for its gas operations, to offset any potential surcharge to its gas customers. In addition, the Company will not surcharge any incremental energy efficiency costs during the Stayout Period to the extent the Company has unspent energy efficiency funds from prior NE:NY years or pre-NE:NY programs available to offset such increased costs.

If utilized, these accounting/rate mechanisms and surcharges will take effect July 1, 2024 and continue until the earlier of the effective date of new base rates for the Company or March 31, 2025. The Company will not be permitted to recover incremental revenues through the mechanisms described in this section (or defer such revenues for future recovery) to the extent they would cause the Company to earn a ROE in excess of 9.0 percent during the period in which the mechanisms are in effect.

20. <u>Corporate Structure and Affiliate Rules</u>

The corporate structure and affiliate rules that apply to the Company are set forth in Appendix 16.

21. Other Provisions

21.1. Submission to the Commission

The Signatory Parties agree to request that the Commission adopt the terms of this Joint Proposal without modification. The Signatory Parties intend that the terms of this Joint Proposal will be adopted by the Commission as being in the public interest and agree individually to advocate its adoption by the Commission in its entirety and to act so as to expedite that result.

21.2. Conditioned on Commission Adoption/No Severability

The Signatory Parties intend this Joint Proposal to be a complete resolution of all issues in these proceedings. It is understood that each provision of this Joint Proposal is in consideration and support of all the other provisions, and expressly conditioned upon acceptance by the Commission. Except as set forth herein, none of the Signatory Parties is deemed to have approved, agreed to, or consented to any principle, methodology, or interpretation of law underlying or supposed to underlie any provision herein. If the Commission does not adopt this Joint Proposal according to its terms, then the Signatory Parties to the Joint Proposal will be free to pursue their respective positions in this proceeding without prejudice.

21.3. Application of Agreement/No Precedent

Except as otherwise stated in this Joint Proposal, the provisions of the Joint Proposal apply solely to and are binding only in the context of this Joint Proposal and this proceeding. None of the terms of this Joint Proposal and none of the positions taken by any Signatory Party with respect to this Joint Proposal may be referred to, cited by, or relied upon by anyone in any manner as precedent or otherwise in any other proceeding before the Commission or any other regulatory body or before any court of law for any purpose other than the adoption, implementation, furtherance, or extension of this Joint Proposal. Concessions made by any Signatory Party on any issue do not preclude that party from addressing such issues in future rate proceedings or in other proceedings.

21.4. Future Actions/Dispute Resolution

The Signatory Parties recognize that certain provisions of this Joint Proposal contemplate actions to be taken in the future and agree to cooperate with each other in good faith in taking such actions.

In the event of any disagreement over the interpretation of this Joint Proposal that cannot be resolved informally among the Signatory Parties, the party claiming a dispute will serve a Notice of Dispute on the remaining parties, briefly identifying the provision or provisions of this Joint Proposal under dispute and the nature of the dispute, and convening a conference in a good faith attempt to resolve the dispute. If any such efforts are not successful in resolving the dispute among the Signatory Parties, the matter can be submitted to the Commission for resolution.

21.5. Continuation

Except as set forth in this Joint Proposal, following the expiration of the term of the rate plan, all provisions of this Joint Proposal will continue until changed by order of the Commission. Except as expressly provided otherwise, any targets, goals, deferral thresholds, or other similar items set forth in this Joint Proposal for Rate Year Three will continue beyond Rate Year Three until modified by the Commission. Notwithstanding the foregoing, the following provisions of this Joint Proposal will terminate at the expiration of the term of the rate plan without further order from the Commission:

(i) the application of deferred credits to offset the revenue requirements; and

(ii) the downward only tracking mechanism for IT, GBE and electric and gas net utility plant and depreciation expense set forth in Sections IV.10.4, IV.12.1.11, and IV.12.1.16

21.6. Extension

Nothing in this Joint Proposal will be construed as precluding the active parties from convening additional conferences and from reaching agreement to extend this Joint Proposal on mutually-acceptable terms and from presenting an agreement concerning such extension to the Commission for its consideration.

21.7. Entire Agreement

This Joint Proposal sets forth the entire agreement of the Signatory Parties and supersedes any prior or contemporaneous written documents or oral understandings among the Signatory Parties concerning the matters addressed herein. In the event of any conflict between this Joint Proposal and any other document addressing the same subject matter, this Joint Proposal will control.

21.8. Counterparts

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

Signature Pages Follow

Niagara Mohawk Power Corporation d/b/a National Grid has this day signed and executed this Joint Proposal.

By: ______________________________
Philip A. DeCicco
Vice President and Deputy General Counsel

Date: September 24, 2021

Case 20-E-0380
Case 20-G-0381
Case 19-M-0133

New York State Department of Public Service Staff has this day signed and executed this Joint Proposal.

By: ______________________________
Brandon F. Goodrich
Staff Counsel

Date: September 24, 2021

Multiple Intervenors has this day signed and executed this Joint Proposal.

By: Michael B. Mager

Michael B. Mager, Esq.
Couch White, LLP
Counsel for Multiple Intervenors

Date: September 24, 2021

New York Power Authority has this day signed and executed this Joint Proposal.

By: Sarah Salati (Sep 24, 2021 13:54 EDT)

Sarah Salati

Date: September 24, 2021

Direct Energy Services LLC has this day signed and executed this Joint Proposal.

By: ______________________

George M. Pond, Esq.
Attorney for Direct Energy Services LLC

Date: September 24, 2021

Marathon Power LLC has this day signed and executed this Joint Proposal.

By: ______________________________

Date: September 24, 2021

New York State Office of General Services has this day signed and executed this Joint Proposal in support of Section IV.15.4 only and takes no position with respect to any of the other provisions in the Joint Proposal.

By: Konstantin Podolny

Konstantin Podolny
Read and Laniado, LLP
Outside Counsel for the New York State Offices of General Services

Date: September 24, 2021

Walmart, Inc. has this day signed and executed this Joint Proposal.

By: ______________________________

Barry Naum
Spilman Thomas & Battle, PLLC
Counsel for Walmart, Inc.

Date: September 24, 2021

International Brotherhood of Electrical Workers, Local Union 97 has this day signed and executed this Joint Proposal.

By: Richard J. Koda

Richard Koda, Principal
Koda Consulting, Inc.
On behalf of the International Brotherhood of Electrical Workers, Local Union 97

Date: September 24, 2021