

**STATE OF NEW YORK
PUBLIC SERVICE COMMISSION**

Case 12-E-0201 - 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 12-G-0202 – 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

**Statement Of
Niagara Mohawk Power Corporation
d/b/a National Grid
In Support Of Joint Proposal**

Dated: December 21, 2012

Table Of Contents

I.	Summary Of The JP.....	1
II.	The JP Is Consistent With The Commission’s Guidelines Governing Settlements, Fully Supported By The Testimony Submitted In These Proceedings, And Otherwise In The Public Interest.....	10
A.	The Standard Of Review.....	10
B.	The JP Proposes A Result That Is Within The Range Of Results That Likely Would Have Resulted From A Commission Decision In A Litigated Proceeding.....	11
C.	The JP’s Preferred Methodology For Passing Back Deferred Credits To Customers Will Result In More Gradual Increases For Customers Over The Term Of The Rate Plan And Avoid Significant Automatic Increases In Rates At The End Of The Term.....	15
D.	The JP’s Revisions To The Company’s Gas Safety Performance Metrics Reflect The Company’s Commitment To Assuring Gas Safety And Provide An Additional Reason For The Commission To Find That The JP Is In The Public Interest	17
E.	Each Of The New Or Modified Deferral Mechanisms Established Under The JP Is Fully Supported By The Record And/Or Applicable Commission Precedent.....	18
F.	The Provisions Of The JP That Provide For The Recovery Of Dunkirk And Other RSS Costs Are Reasonable And Supported By The Record	21
G.	The Testimony, Exhibits And Discovery Conducted In These Proceedings Justify Approval Of The Increases In Rates In The JP On A Permanent Basis.....	22
H.	The Testimony And Exhibits Support The Signatory Parties’ Agreement That Savings Related To The Management Audit Are Fully Reflected In The Gas And Electric Revenue Requirements.....	26
III.	Conclusion	27

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In Support Of Joint Proposal**

In accordance with Presiding Administrative Law Judges’ “Ruling Modifying Schedule” issued October 22, 2012 in these proceedings, Niagara Mohawk Power Corporation d/b/a National Grid (“Niagara Mohawk” or “the Company”) hereby submits this Statement in Support of the Joint Proposal (“JP”) by and among Niagara Mohawk, New York State Department of Public Service (“Staff”), Multiple Intervenors (“MI”), Utility Intervention Unit of the New York State Department of State’s Division of Consumer Protection (“UIU”), United States Department of Defense, the Retail Energy Supply Association (“RESA”) and the New York Power Authority (“NYPA”) dated December 7, 2012. Answers to the specific questions propounded by the Presiding Judges on December 12, 2012 and December 18, 2012 are attached as Appendix A.

I. Summary Of The JP

The JP sets forth the comprehensive terms and conditions of a three-year Rate Plan for Niagara Mohawk’s electric and gas operations. For the Company’s electric operations, the JP provides for an electric revenue requirement increase of \$43.395

million in Rate Year One,¹ \$51.361 million in Rate Year Two² and \$28.342 million in Rate Year Three.³ These increases equate to increases in aggregate revenues of 3.26 percent, 3.79 percent and 2.06 percent in Rate Years One, Two and Three, respectively. As an offset to these revenue requirement increases, the JP provides that forecast electric deferral credits of \$35.715 million⁴ will be credited to customers over the term of the Rate Plan. Under the JP's preferred approach, \$16.137 million of the deferred credits would be credited in Rate Year One and \$19.578 million would be credited in Rate Year Two.⁵ For the Company's electric business, the proposed Rate Plan is timed such that new electric delivery rates will replace a portion of an expiring annualized electric surcharge of approximately \$190 million annually. The net result is a decrease in electric delivery revenues, continued rate stability and, for the majority of customers, lower electric delivery bills.

For the Company's gas operations, the JP provides for a decrease in the gas revenue requirement of \$3.290 million in Rate Year One, and increases of \$5.854 million and \$6.268 million in Rate Years Two and Three, respectively.⁶ Those changes represent a decrease of 0.98 percent in Rate Year One and increases of 1.58 percent and 1.42 percent in Rate Years Two and Three, respectively. The JP further proposes that a

¹ Rate Year One is the twelve months ending March 31, 2014.

² Rate Year Two is the twelve months ending March 31, 2015.

³ Rate Year Three is the twelve months ending March 31, 2016.

⁴ JP Section 2.2. The \$35.715 million balance is the net result of the Company surcharging street lighting customers \$3.696 million and crediting all other customers \$39.411 million. The surcharges to street lighting customers will recover a portion of a \$6.845 million forecast street lighting deferral balance in a manner consistent with the Commission's December 16, 2011 Order in Case 10-E-0050.

⁵ JP Section 3.4.1. The JP also provides the Commission with an alternative to the preferred approach under which the forecast electric deferral balance could be surcharged and credited to customers to achieve stable rates (*i.e.*, rates that do not materially change from Rate Year One to Rate Year Two to Rate Year Three). Under this approach, customers would be surcharged \$37.916 million in Rate Year One and credited \$18.764 million and \$54.867 million in Rate Years Two and Three, respectively. JP Section 3.4.4. As discussed more fully below, Niagara Mohawk does not believe that this approach is preferable.

⁶ JP Section 2.1.

forecast gas deferral credit balance of \$32.778 million will be credited to gas customers over the term of the Rate Plan.⁷ Under the JP’s preferred approach, \$21,990 million would be credited in Rate Year One and \$10,788 million would be credited in Rate Year Two.⁸

The revenue requirements for the Company’s gas and electric businesses are based on a return on equity (“ROE”) of 9.3 percent, which includes a stay out premium for the term, and a capital structure that includes a 48 percent common equity component.⁹ The electric and gas rate bases used to establish rates during the term of the Rate Plan are as follows:

	Electric (Billions \$)	Gas (Billions \$)
Rate Year One	\$4.107	\$1.086
Rate Year Two	\$4.365	\$1.122
Rate Year Three	\$4.626	\$1.163

The JP provides for updated gas transmission and distribution plant depreciation rates and the continuation of the Company’s existing depreciation rates for electric and common plant and gas general plant.¹⁰

With respect to revenue allocation and rate design for the electric business, the JP provides, *inter alia*, for:

⁷ JP Section 2.2.

⁸ JP Section 4.4.1. As with the electric deferred credits, the JP also provides the Commission an alternative to the preferred approach to achieve stable rates over the term of the Rate Plan. Under this approach, the amounts credited would be \$3.744 million in Rate Year One, \$10.917 million in Rate Year Two and \$18.117 million in Rate Year Three. JP Section 4.4.3. As discussed below, Niagara Mohawk does not believe that this approach is preferable.

⁹ JP Section 2.1. The weighted pre-tax cost of capital set forth in the JP is 9.44 percent in Rate Year One, 9.59 percent in Rate Year Two and 9.79 percent in Rate Year Three.

¹⁰ *Id.*

- (i) An allocation of electric and lighting revenue increases that ranges between 3.88 percent (for SC-1) and 1.86 percent (for SC-1C, SC-2 and Street Lighting) in Rate Year One, and across the board increases of 3.79 percent and 2.06 percent in Rate Years Two and Three, respectively;¹¹
- (ii) Modest increases in the monthly customer charges for SC-1, SC-3A Secondary/Primary and SC-3A-Transmission;¹²
- (iii) The elimination of historic demand for NYPA Replacement and Expansion customers beginning April 1, 2013;¹³ and
- (iv) Updates to various charges, credits and reconciliation mechanisms, including the Revenue Decoupling Mechanism (“RDM”), the Merchant Function Charge (“MFC”), the billing back-out credit, time of use commodity rates,¹⁴ the re-establishment charge and the ESCO discount charge.¹⁵

With respect to revenue allocation and rate design for the gas business, the JP provides, *inter alia*, for:

- (i) An allocation of the revenue decrease in Rate Year One that achieves a pro-rata revenue decrease to SC-2, SC-3 and SC-7;¹⁶
- (ii) An allocation of the revenue increases in Rate Years Two and Three that results in increases in delivery revenue of between 0.00 percent for SC6,

¹¹ JP Section 3.2, Appendix 2, Schedule 3, Page 1.

¹² JP Section 3.3(b). The customer charge increases from \$16.21 to \$17.00 for SC-1, from \$902 to \$1,000 for SC-3A Secondary/Primary and from \$3,172 to \$3,500 for SC-3A-Transmission. JP Appendix 2, Schedule 4 at 1, 8 and 10.

¹³ JP Section 3.3(a).

¹⁴ Time of use commodity rates will now be available to residential customers under SC-1.

¹⁵ JP Sections 3.5-3.7.

¹⁶ JP Section 4.2.

- 12 and 13, and 2.52 percent for SC8 in Rate Year Two, and 0.00 percent for SC6, 12 and 13, and 2.29 percent for SC8 in Rate Year Three;¹⁷
- (iii) An SC-1 minimum charge of \$20.35 for all three Rate Years¹⁸ that includes the impact of the year to year increases in the Low Income Discount Program;¹⁹
- (iv) An increase in the Low Income Discount Program to \$10 per month in Rate Year One, \$10.50 per month in Rate Year Two and \$11.00 per month in Rate Year Three;²⁰
- (v) Changes to the Company's Lost and Unaccounted For ("LAUF") incentive mechanism that will result in an increase in the LAUF target from 1.62 percent to 1.84 percent as of April 1, 2013 and modifications to the Company's LAUF incentive mechanism consistent with the recommendations in the Staff White Paper effective September 1, 2013;²¹
- (vi) Modification to the MFC to expand the application of the charge to SC-3, modify the calculation of the return on storage inventory balances to reflect actual storage inventory balances, include a new charge to recover the return on Gas Purchase Related Working Capital, and update other components of the MFC;²² and

¹⁷ JP Appendix 3, Schedules 5.3 and 6.3.

¹⁸ This is an increase of \$2.50 from the current SC-1 minimum charge of \$17.85. JP Appendix 3, Schedule 4.5 at 1.

¹⁹ JP Section 4.3(a).

²⁰ JP Section 4.5.

²¹ JP Section 4.6.

²² JP Section 4.7.

- (vii) Updates to various other charges, credits and reconciliations, including the RDM, the billing back-out credit, the re-establishment charge and the ESCO disconnect charge.²³

The JP provides for earnings sharing to the extent that earnings calculated in the manner provided for in the JP exceed the 9.3 ROE over the term of the Rate Plan.²⁴

Earnings will be calculated using a capital structure that includes an equity component equal to the lesser of that reflected in the Company's actual capital structure or 48 percent.²⁵ The impact of discrete negative revenue adjustments and incentives approved by the Commission such as service quality, safety and reliability related adjustments and gas off-system sales and capacity release sharing mechanisms will be excluded from the ROE calculation.²⁶

With respect to deferral rights, the JP provides for the continuation of existing deferral rights, in either their current or a modified form, for expenses such as pension and other post-employment benefit expenses, low income discount program expenses, economic development costs, auction debt costs, expenses associated with legislative and other regulatory changes, expenses associated with externally imposed and internally adopted tax and accounting changes, the under spending of net utility plant and depreciation expenses, major storm expense, site investigation and remediation expenses, electric transmission revenues, affordability program costs, and RDM-related revenues, revenue sharing from various gas service classifications, accrued unbilled revenues associated with gas operations, service quality negative revenue adjustments, aggregation

²³ JP Section 4.9 and 4.11.

²⁴ JP Section 5.5.

²⁵ JP Section 5.2.

²⁶ JP Section 5.3.

fees, voltage migration fees, and various deferral mechanisms that operate outside base rates.²⁷ The Company will implement new deferral mechanisms for its electric business with respect to NYPA discounts, the underspending of transmission and sub-transmission tower painting and footer inspection expense, the impact on the Company's cash flow of an audit by the Internal Revenue Service ("IRS") concerning the Company's ability to recognize expense deductions of certain repair costs for income tax purposes, the underspending of variable pay expenses, and property tax expenses.²⁸ Finally, the Company will also implement new deferrals for its gas business with respect to the economic development fund and economic development grant program attributable to that business, expenses associated with externally imposed and internally adopted tax and accounting changes, the impact on the Company's cash flow of an audit by the IRS concerning the Company's ability to recognize expense deductions of certain repair costs for income tax purposes, the underspending of variable pay expense, property tax expense, the underspending of net utility plant and depreciation expenditures, 50 percent of the annual expenses associated with a new program intended to promote conversions from oil to natural gas, and the underspending of affordability program expenses.²⁹

The JP also establishes comprehensive gas safety performance metrics under which a total of 150 pre-tax basis points will be at risk per calendar year in connection with the Company's performance relative to targets for leak prone pipe removal, leak management, damage prevention, emergency response and violations of the

²⁷ See JP Sections 6.1 to 6.1.18, and 7.1.1 to 7.1.10 for a description of all continuing deferral mechanisms for the electric and gas business, respectively.

²⁸ JP Sections 6.21-6.26.

²⁹ JP Sections 7.2.1 to 7.2.9.

Commission's gas safety regulations.³⁰ The targets associated with violations of the gas safety regulations are far more comprehensive than any similar target adopted previously by the Commission and reflect the Company's commitment to achieving full compliance with the Commission's safety regulations. The JP also continues, with certain updates and modifications, the Company's electric and gas customer service and electric reliability performance metrics.³¹

The JP contains a number of programs that will benefit customers. For low income customers, the Company will provide:

- (i) a \$5.00 per month bill credit for electric non-heating customers receiving HEAP assistance and a \$15.00 per month billing credit for electric heating customers receiving HEAP assistance;³²
- (ii) a monthly bill credit for gas customers receiving HEAP assistance that will increase from \$10.00 in Rate Year One to \$11.00 in Rate Year Three;³³
- (iii) the ability to participate in an Affordability Program that will provide, *inter alia*, arrears forgiveness of \$30 per month for up to 24 months and deferral of portions of the customers' monthly budget bills for electric and gas services;³⁴ and

³⁰ JP Sections 10.1 to 10.5

³¹ JP Section 9.

³² JP Section 11.1.1.

³³ JP Section 11.1.2. The credit will increase by \$0.50 in each of Rate Years Two and Three.

³⁴ JP Section 11.2.

- (iv) a one-time credit of \$46.00 to the electric and gas re-establishment fee for customers who receive HEAP and have had their service disconnected for non-payment.³⁵

In addition to programs that benefit low income customers, the Company will also continue its existing economic development fund program and will fund economic development grant programs of \$11 million per year on the electric side and \$1 million on the gas side.³⁶ The Company will also spend \$3 million on outreach and education related to safety, storm readiness, customer education and the benefits of natural gas.³⁷ The Company will also implement an ESCO bill calculator, offer incentives for customers to participate in electronic billing, convene a gas expansion collaborative, and work with Staff to implement an oil to gas conversion program.³⁸

The JP contains provisions that provide a framework to permit the Company to recover through the use of deferral credits and a Reliability Support Services (“RSS”) surcharge the RSS costs associated with the Dunkirk generation plant and other RSS agreements with generators.³⁹ The JP adopts procedures and requirements related to Service Level Agreements and service company budgeting, bill review and reporting requirements.⁴⁰ The JP further reflects the Signatory Parties’ agreement that the savings arising from the management audit conducted in Case 08-E-0827 are reflected in the rates established in this proceeding.⁴¹ The JP also resolves certain ESCO operational issues, and provides for the development of a policy by the Company and Staff for relocating

³⁵ JP Section 11.3.

³⁶ JP Section 11.4.1 and 11.4.2.

³⁷ JP Section 11.4.3.

³⁸ JP Sections 11.5-11.8.

³⁹ JP Section 12.1.

⁴⁰ JP Section 12.2 to 12.3.

⁴¹ JP Section 12.3.

inside meters sets.⁴² In addition, the JP addresses a number of electric and gas capital investment and O&M issues, including capital investment reporting requirements, an analysis of the appropriate level of spare transformers, the development of a long term streetlight replacement program for the City of Buffalo and reporting requirements related to the implementation of the new SAP financial platform.⁴³

II. The JP Is Consistent With The Commission’s Guidelines Governing Settlements, Fully Supported By The Testimony Submitted In These Proceedings, And Otherwise In The Public Interest

A. The Standard Of Review

The JP is the result of complex and difficult negotiations among normally adversarial parties. The negotiations fully complied with the Commission’s settlement rules⁴⁴ and provided all parties the opportunity to participate. The Commission’s “Procedural Guidelines for Settlements”⁴⁵ set forth the following criteria for determining whether a joint proposal is in the public interest:

- (1) A desirable settlement should strive for a balance among (1) protection of the ratepayers, (2) fairness to investors, and (3) the long term viability of the utility; should be consistent with sound environmental, social and economic policies of the Agency and the State; and should produce results that were within the range of reasonable results that would likely have arisen from a Commission decision in a litigated proceeding.
- (2) In judging a settlement, the Commission shall give weight to the fact that a settlement reflects the agreement by normally adversarial parties.

As discussed herein, based upon the application of these guidelines, the JP meets the public interest standard. The JP is the result of complex and far-ranging negotiations

⁴² JP Sections 12.4 and 12.5.

⁴³ JP Sections 12.6.1, 12.6.2, 12.6.4, 12.7.1 and 12.9.

⁴⁴ 16 NYCRR §3.9(a).

⁴⁵ See Cases 90-M-0225 and 92-M-0138 - *Proceeding on Motion of the Commission Concerning its Procedures for Settlement and Stipulation Agreements, filed in C 11175; In the Matter of the Rules and Regulations of the Public Service Commission Contained in 16 NYCRR, Chapter 1, Rules of Procedure – Proposed Amendments to Subchapter A, General Part 2, Hearing and Rehearings by the Addition of a New Section 2.6, Settlement Procedures, filed in C 11175, Opinion 92-2, dated March 24, 1992, at Appendix B.*

among parties with diverse interests, including the Company, Staff, Multiple Intervenors, UIU, RESA, NYPA and other interested parties. The Commission should give considerable weight to the fact that the JP is supported by parties having normally adverse interests. In addition, as demonstrated below, the compromises memorialized in the JP produce results that are both objectively reasonable and within the range of results that would likely have arisen from litigation of these proceedings.

B. The JP Proposes A Result That Is Within The Range Of Results That Likely Would Have Resulted From A Commission Decision In A Litigated Proceeding

The rates set forth in the JP are the product of significant compromises among adversarial parties. The Company's filing in these proceedings, after updates, proposed increases in Rate Year One electric revenues of \$119.404 million and Rate Year One gas revenues of \$22.520 million.⁴⁶ Staff, the only other party to propose in testimony a comprehensive cost of service, recommended an annual base rate increase in electric revenue of \$18 million and an annual base rate decrease in gas revenue of approximately \$13 million.⁴⁷ The Rate Year One electric revenue requirement increase of \$43.395 million and gas revenue requirement decrease of \$3.290 million provided for under the JP reflect substantial movement towards Staff's position.

Specifically, the Rate Year One revenue requirements reflect a number of adjustments proposed by Staff and opposed by the Company, including:

- (1) The use for ratemaking purposes of a capital structure that reflects a 48 percent common equity component;⁴⁸

⁴⁶ See Rebuttal Testimony of Revenue Requirements Panel at 5.

⁴⁷ See Corrected Prepared Testimony of Staff Accounting Panel at 12-13.

⁴⁸ See JP at 5-6, Testimony of Kwaku Duah at 6. The 48 percent equity component is consistent with that approved by the Commission in the Company's last electric rate proceeding in Case 10-E-0050. It is also

- (2) Gas depreciation rates for transmission and distribution plant;⁴⁹
- (3) Adjustments to management labor expense, service company expenses and return, and a variety of other O&M expenses;⁵⁰ and
- (4) A number of rate base adjustments that reflect Staff's position concerning the Company's forecast of capital investments.⁵¹

In addition, the JP reflects significant revenue requirement related compromises that are well within the range of results that would likely have resulted from litigation. For example, the stipulated ROE of 9.3 percent reflects a stay out premium for a three-year rate plan that is consistent with Commission practice⁵² and is far closer to the 8.9 percent ROE recommended by Staff⁵³ for a traditional one-year rate case than the 10.22 percent recommended by the Company.⁵⁴ Moreover, the JP's 9.3 percent ROE would be slightly lower, but relatively close to the ROEs recently adopted by the Commission under multi-year rate plans for similar gas and/or electric utilities.⁵⁵ While Niagara Mohawk has concerns that the Commission's methodology for establishing ROE results

consistent with equity ratios that have been adopted for similar utilities including Central Hudson Gas & Electric Corporation and Consolidated Edison Company of New York, Inc. See Case 10-E-0050, *Niagara Mohawk Power Corporation – Electric Rates*, “Order Establishing Rates For Electric Service” at 71 (Issued and Effective January 24, 2011); Case 09-E-0588 *et al.*, *Central Hudson Gas and Electric Corporation – Electric and Gas Rates*, “Order Establishing Rate Plan” (Issued and Effective June 18, 2010) (“Case 09-E-0588 Order”); Case 09-E-0428 *et al.*, *Consolidated Edison Company of New York, Inc. – Electric Rates*, “Order Establishing Three-Year Electric Rate Plan” at 15 (Issued and Effective March 26, 2010).

⁴⁹ See JP at 6-7, Testimony of Staff Depreciation Panel.

⁵⁰ See JP at Appendix 1, Schedule 1 at 6-8.

⁵¹ JP Appendix 1, Schedule 1 at 9, Schedule 2 at 3.

⁵² The Commission has consistently approved stay out premiums as part of multi-year settlements. See Case 11-E-0408, *Orange and Rockland Utilities, Inc. – Electric Rates*, “Order Adopting Terms of Joint Proposal, With Modification, And Establishing Electric Rate Plan” at 13 (Issued and Effective June 15, 2012) (“Case 11-E-0408 Order”).

⁵³ See Prepared Testimony of Kwaku Duah at 6-7.

⁵⁴ See Rebuttal Testimony of Robert B. Hevert at 2.

⁵⁵ See Case 11-E-0408 Order at 13. (Adopting an average ROE of 9.5 percent for a three year rate plan for Orange and Rockland Utilities, Inc.'s electric operations), Case 11-G-0280 – *Corning Natural Gas Corporation – Gas Rates*, “Order Adopting Terms of Joint Proposal And Establishing A Multi-Year Plan” at 8-9 (Issued and Effective April 20, 2012) (“Case 11-G-0280 Order”) (adopting a 9.5 percent ROE for a three-year rate plan).

in returns that are among the lowest in the country for gas and electric utilities, the Company is willing to accept this result in these proceedings as part of the overall settlement.

The JP also reflects compromises among the parties with respect to, *inter alia*, uncollectible expense adjustments and vegetation management expenses.⁵⁶ These compromises reflect a reasonable resolution of issues that were contested on the record.⁵⁷

The revenue requirement increases in Rate Years Two and Three are also supported by the pre-filed testimony and applicable Commission policy and precedent. The Company's filing in these proceedings included data not only for a traditional "one year" rate proceeding but also provided detailed financial information for "Data Years" ending March 31, 2015 and March 31, 2016 – Rate Years Two and Three under the JP.⁵⁸

The revenue requirements included in the JP for Rate Years Two and Three were generally determined (i) by carrying forward adjustments reflected in the JP for Rate Year One to Rate Years Two and Three, (ii) as a result of Staff's and other parties thorough review of the Company's proposed capital expenditures, and/or (iii) through the application of general inflation factors that were determined in accordance with well-established Commission policies.⁵⁹ In sum, the Rate Year Two and Rate Year Three

⁵⁶ See JP, Appendix 1, Schedule 1 at 7-8.

⁵⁷ See Rebuttal Testimony of the Company Shared Services and Customer Panel at 6-10. Testimony of Staff Accounting Panel at 66-76, Testimony of Staff Vegetation Management Panel at 14, 16-17, Rebuttal Testimony of Company Electric Infrastructure And Operations Panel at 24-30.

⁵⁸ See Direct Testimony of the Company Revenue Requirements Panel at 8.

⁵⁹ See JP, Appendix 1, Schedule 1 at 10-22, Schedule 2 at 10-22; See JP at 47 for electric and gas capital investment levels through Rate Year Three. The Commission has long approved multi-year rate plans that employ general inflation factors to escalate the majority of operation and maintenance expenses to the additional rate years covered under the plans. See e.g. Case 90-G-0981, *The Brooklyn Union Gas Company – Gas Rates*, "Opinion and Order Determining Revenue Requirement And Rate Design" (October 9, 1991), Cases 91-W-0724, *Saratoga Water Services, Inc. – Water Rates*, "Opinion and Order Adopting Stipulation and Determining Revenue Requirement" (May 12, 1992).

revenue requirements are the product of reasonable compromises among normally adverse parties that comport with applicable Commission policy.

In addition, the benefits to customers of a three year rate plan are augmented by the earnings sharing provisions that provide that customers will share in any earnings that exceed the 9.3 percent ROE underlying the gas and electric rates proposed in the JP over the term of the Rate Plan. In National Grid's experience, earnings sharing mechanisms associated with multi-year rate plans typically provide for a band of 75 or more basis points above the ROE underlying the stipulated rates in which the regulated entity retains one hundred percent of the additional earnings.⁶⁰ The earnings sharing provisions set forth in the JP provide a greater level of potential benefit to customers than earnings sharing provisions approved in other multi-year rate plans for similarly situated utilities.

With respect to revenue allocation and rate design, the applicable provisions of the JP reflect reasonable compromises of the competing positions advanced by the Company, Staff and Multiple Intervenors⁶¹ concerning both electric and gas revenue allocation and rate design issues. From the Company's perspective, the various revenue allocation and rate design changes move the Company closer to achieving cost-based rates that are consistent with the Commission's policy goals.⁶²

⁶⁰ See e.g. Case 08-G-0609 – *Niagara Mohawk Power Corporation – Gas Rates*, “Order Adopting The Terms Of A Joint Proposal And Implementing A State Assessment Surcharge” at 5-6 (Issued and Effective May 15, 2009) (approving a joint proposal that established rates reflecting a 10.2 percent ROE, with earnings sharing commencing when the ROE exceeded 11.35 percent); See Case 11-G-0280 Order (approving a joint proposal with an underlying ROE of 9.5 percent and an earnings sharing mechanism that applies to earnings exceeding 10.25 percent); Case 11-E-0408 Order at 14 (earnings sharing begins at 80 basis points above the allowed ROE).

⁶¹ See Rebuttal Testimony of the Electric Rate Design Panel at 21-30; Rebuttal Testimony of Gas Rate Design Panel at 18-22; Testimony of Staff Electric Rate Panel at 14-23; Testimony of the Staff Gas Rates Panel at 16-38; Direct Testimony of Jeffrey Pollack at 5-7, 23-38, 46-47.

⁶² Case 10-E-0362, *Orange and Rockland Utilities, Inc. – Electric Service*, “Order Establishing Rates for Electric Service” at 88-91 (Issued and Effective June 17, 2011). See also Case 95-G-1095 *et al. – Niagara Mohawk Power Corporation – Gas Rates*, “Opinion and Order Conditionally Approving Settlement Agreement With Changes” at 20 (Issued and Effective December 17, 1996).

Finally, the provisions of the JP that provide relief for lower income customers are also the product of significant compromises among the Company, Staff and UIU.⁶³ These provisions are consistent with the Commission's longstanding commitment to providing assistance to lower income customers without imposing undue burdens on other customer classes.⁶⁴

C. The JP's Preferred Methodology For Passing Back Deferred Credits To Customers Will Result In More Gradual Increases For Customers Over The Term Of The Rate Plan And Avoid Significant Automatic Increases In Rates At The End Of The Term

As discussed *supra*, the JP presents for the Commission's consideration two approaches to applying deferred credits to reduce revenue requirements during the term of the Rate Plan. Under the Signatory Parties' preferred approach, the credits are applied in a manner that results in the assessment of the total revenue requirement increases adopted pursuant to the JP in Rate Year Three. For the electric business, the revenue requirement will gradually rise over the term of the Rate Plan and in Rate Year Three will be \$123.098 million greater than would have otherwise been the case on April 1, 2013.⁶⁵ For the gas business, the revenue requirement will decline in Rate Year One and increase

⁶³ Testimony of Staff Consumer Issues Panel at 13-16, Rebuttal Testimony of Greg C. Collar at 3-9.

⁶⁴ See e.g., Case 06-G-1185 *et al*, *The Brooklyn Union Gas Company d/b/a KeySpan Energy Delivery New York and KeySpan Gas East Corporation d/b/a KeySpan Energy Delivery Long Island*, "Order Approving Disbursement of Funds From Low Income Programs Balancing Accounts" at 9 (Issued and Effective October 15, 2010) wherein the Commission stated:

We have approved low income programs at every major electric and gas utility in this state. Such programs primarily serve to ensure that energy services remain available and accessible for households with low incomes, but can also benefit utilities and the general body of rate payers. By helping customers maintain service, these programs reduce the fixed costs of delivery service that would otherwise need to be paid by the general body of ratepayers. Low-income programs also help reduce utility costs associated with credit and collection, arrears and bad debt, deposit maintenance, regulatory expenses, repeated payment plan negotiations, and credit agency fees.

⁶⁵ It should be noted that on March 31, 2013, the Company's current annualized electric surcharge of \$190 million will expire. See Testimony of Kenneth D. Daly at 11-12. As a consequence, even with increases in electric revenues of \$123.08 million over the three year term of the Rate Plan, the Company's annual electric revenue requirement in Rate Year Three will still be approximately \$67 million less than it is today.

gradually in Rate Years Two and Three such that it will be \$8.832 million greater in Rate Year Three than it is today. However, under the Signatory Parties' preferred approach, absent approval of a rate increase by the Commission, customers will experience no automatic increase in rates at the end of Rate Year Three as a result of the expiration of deferral credits.

In contrast, under the alternate approach, \$54.867 million and \$18.117 million of credits would be applied to reduce the electric and gas revenue requirements, respectively, in Rate Year Three. As a consequence, customers would experience an automatic revenue requirement increase at the end of the Rate Plan's three year term of \$54.867 million for the electric business and \$18.117 million for the gas business even if the Company sought no further rate increase. Under the alternative approach, if the Company seeks and receives a further rate increase at the end of the term of the Rate Plan, that increase will be on top of the automatic revenue increase that will result from the expiration of the deferred credits.

In Case 06-G-1185 *et al.*, the Commission stated that it was its "long standing regulatory policy" to favor "gradual revenue changes over abrupt ones."⁶⁶ Application of this policy in this case supports adoption of the Signatory Parties' preferred approach to applying deferral credits. The Signatory Parties' preferred approach will send customers proper signals about the direction of the Company's rates both during and at the conclusion of the Rate Plan and ensure that Niagara Mohawk's rates rise in a gradual manner over the next few years.

⁶⁶ Case 06-G-1185 *et al.* – *The Brooklyn Union Gas Company Rates Gas and KeySpan Gas East Corporation d/b/a KeySpan Energy Delivery Long Island – Gas Rates*, "Order Adopting Rate Plans For KeySpan Energy Delivery New York and KeySpan Energy Delivery Long Island" at 65 (Issued and Effective December 21, 2007).

D. The JP’s Revisions To The Company’s Gas Safety Performance Metrics Reflect The Company’s Commitment To Assuring Gas Safety And Provide An Additional Reason For The Commission To Find That The JP Is In The Public Interest

As discussed *supra*, the JP provides that up to 150 basis points of the Company’s pre-tax return on its gas business will be at risk in each calendar year for the Company’s performance under the Gas Safety Performance metrics. The most groundbreaking of these measures is the Gas Safety Violations metric, under which the Company is subject to negative revenue adjustments of up to 100 basis points per calendar year for violations of a significant number of the Commission’s pipeline safety regulations as set forth in 16 NYCRR Parts 255 and 261. While the Commission adopted a gas safety violations metric for Corning Natural Gas Company (“Corning”) in Case 11-G-0280,⁶⁷ the number of potential violations covered by the metric in this case is far greater than that adopted for Corning.⁶⁸ This new metric demonstrates a commitment by the Company to comply with the Commission’s safety regulations or face significant negative revenue adjustments and a commitment by Staff to drive this compliance. Moreover, this new metric considered along with (i) the other elements of the Company’s Gas Safety Performance metrics, and (ii) the provisions of the electric and gas service quality assurance program set forth in the JP⁶⁹ provides an additional reason for the Commission to conclude that the JP is in the public interest. The totality of the performance metrics included in the JP should assure the Commission and the Company’s customers that the

⁶⁷ See Case 11-G-0280 Order at 19.

⁶⁸ In Case 11-G-0280, violations of twenty-three regulations or subparts of regulations were characterized as “high risk.” See Article V.G.7 to Attachment 1 to the Case 11-G-0280 Order. In this case, as set forth in Appendix 8 to the JP, far more sections of Parts 255 and 261 of the Commission’s regulations are considered “high risk.”

⁶⁹ See JP, Appendix 7, Attachment 1.

Company's overall service performance in its electric and gas businesses will not diminish during the term of the JP.

E. Each Of The New Or Modified Deferral Mechanisms Established Under The JP Is Fully Supported By The Record And/Or Applicable Commission Precedent

Commission policy and precedent support the use of deferral and reconciliation mechanisms in the context of multi-year rate plans for the benefit of utility customers and shareholders alike.⁷⁰ In this proceeding, testimony and/or Commission precedent specifically support the new or modified deferral mechanisms under which the Company will defer and reconcile:

- (i) the difference between the amount of NYPA discounts reflected in rates and the actual discounts;⁷¹
- (ii) underspending of transmission and sub-transmission tower painting and footer inspection expenses;⁷²
- (iii) the difference between the cash flow impact associated with the Company's deduction of repair costs for federal income tax purposes as reflected in gas and electric rates and the impact that may result once the IRS completes its audit of the repair cost deduction;⁷³

⁷⁰ See e.g. Case 29670 *et al.*, *Niagara Mohawk Power Corporation – Electric Rates*, “Opinion and Order Approving Rate Moratorium Settlement Agreement” (Issued and Effective August 30, 1988) (Deferral provisions “are intended mainly to protect the company and ratepayers against material changes not reflected in projections of net income.”) See also Case 09-E-0715 *et al.*, *New York State Electric & Gas Corporation/Rochester Gas & Electric Corporation – Electric and Gas Rates*, “Order Establishing Rate Plan” Joint Proposal at 71-73 (Issued and Effective September 21, 2010) (“Case 09-E-0715 Order”).

⁷¹ See Direct Testimony of Company Revenue Requirements Panel at 124-125, Testimony of Staff Accounting Panel at 123.

⁷² See Direct Testimony of the Company Revenue Requirements Panel at 124, Direct Testimony of the Company Electric Infrastructure and Operations Panel at 72-78, Rebuttal Testimony of the Company Electric Infrastructure and Operations Panel at 22-23, Testimony of Staff Accounting Panel at 123, Testimony of Staff Electric Infrastructure Panel at 88, 97-98.

⁷³ Testimony of Staff Accounting Panel at 139-140, Rebuttal Testimony of Company Revenue Requirements Panel at 65.

- (iv) the difference, on a downward basis only, of the amount of variable pay reflected in both gas and electric rates and the amount actually paid out by the Company;⁷⁴
- (v) the difference between the level of property tax expense reflected in electric and gas rates and the Company's actual property tax expense subject to a sharing of any positive or negative differences on an 80 percent customer/20 percent Company basis;⁷⁵
- (vi) the difference between the economic development fund expenses reflected in gas rates and the actual costs incurred by the Company;⁷⁶
- (vii) any downward difference between the economic development grant program costs reflected in rates and the Company's actual expenditures;⁷⁷
- (viii) incremental costs or cost reductions associated with externally imposed and internally adopted tax and accounting changes;⁷⁸

⁷⁴ Direct Testimony of Company Revenue Requirements Panel at 123-124, Direct Testimony of the Company Human Resources Panel at 31, Testimony of the Staff Accounting Panel at 125. The Signatory Parties agreement to this deferral addresses the Commission's previously expressed concern that it would be reluctant to approve recovery of variable pay in rates to the extent that a utility could recover the expense in rates and then not pay the variable compensation to its employees, thus creating a windfall for its shareholders. *See* Case 08-E-0539, *Consolidated Edison Company of New York, Inc. – Electric Rates*, “Order Setting Electric Rates” at 52 (Issued and Effective April 24, 2009).

⁷⁵ The deferral of property tax expenses subject to various sharing percentages is a common feature of multi-year rate plans. *See* 11-G-0280 Order at Attachment I, Article V.G.4, Case 11-E-0408 Order at 30-31, Case 09-E-0428, *Consolidated Edison Company of New York, Inc. – Electric Rates*, “Order Establishing Three Year Electric Rate Plan” at 14-15 (Issued and Effective March 26, 2010), Case 09-E-0588 Order, Joint Proposal at 10, Case 06-M-0878 *et al.*, *Joint Petition of National Grid plc and KeySpan Corporation For Approval Of Stock Acquisition and Other Regulatory Authorizations*, “Order Authorizing Acquisition Subject To Conditions And Making Some Revenue Requirement Determinations For KeySpan Energy Delivery New York and KeySpan Energy Delivery Long Island,” Merger and Gas Revenue Requirement Joint Proposal at 24-25, 46-47 (Issued and Effective September 17, 2007, Case 09-E-0715 Order at 71-73).

⁷⁶ Direct Testimony of Company Revenue Requirements Panel at 126.

⁷⁷ Direct Testimony of Company Revenue Requirements Panel at 122-123, Testimony of Staff Consumer Issues Panel at 23-24.

⁷⁸ Direct Testimony of Company Revenue Requirements Panel at 119, Testimony of Staff Accounting Panel at 127-128.

- (ix) any downward difference between the net utility plant and depreciation expense revenue requirement target for each Rate Year and the Company's actual revenue requirements associated with net plant and depreciation expense;⁷⁹
- (x) 50 percent of the costs of an annual program to encourage customers to convert from oil to natural gas;⁸⁰
- (xi) underspending of amounts reflected in gas rates for the Company's affordability program;⁸¹
- (xii) major storm costs that differ from amounts reflected in electric rates;⁸² and
- (xiii) the difference between SIR costs reflected in rates and actual SIR costs.⁸³

The deferrals and reconciliations set forth above are typical of multi-year rate plans and contain important protections for customers and the Company. The downward-only reconciliations⁸⁴ are appropriate because they create an incentive for the Company to spend budgeted amounts needed to provide safe and adequate service while protecting customers from over spending. The symmetrical deferral mechanisms⁸⁵ protect both customers and the Company against unexpected variations in estimated costs over which the Company does not have direct control

⁷⁹ See Testimony of Davide Maioriello at 9-10. Testimony of Staff Electric Infrastructure Panel at 113-114.

⁸⁰ See Rebuttal Testimony of Company Gas Infrastructure and Operations Panel at 36-38 (encouraging the Commission to establish rates that will encourage incremental investment in the gas system), Testimony of Michael Colby at 5-10.

⁸¹ Testimony of Staff Consumer Issues Panel at 16-17.

⁸² Testimony of Company Revenue Requirements Panel at 109-118, Testimony of Staff Electric Infrastructure Panel at 103-107; See JP, Appendix 7 at Section 1.2.3.

⁸³ Testimony of Company Revenue Requirement Panel at 118-119, Testimony of Charles Willard at 16-18, Testimony of Staff Accounting Panel at 123-126. The provisions of the JP governing the deferral of SIR Costs are consistent with the principles outlined by the Commission in Case 11-M-0304 – *Proceeding on Motion of the Commission to Commence Review and Evaluation of the Treatment of the State's Regulated Utilities Site Investigation and Remediation (SIR) Costs*, "Order Concerning Costs For Site Investigation and Remediation" (Issued and Effective November 28, 2012).

⁸⁴ Items (ii), (iv), (vii), (ix) and (xi) above.

⁸⁵ Items (i), (iii), (vi), (viii), (xii) and (xiii) above.

or that are difficult to forecast. Finally, for items such as differences in property taxes from the amount reflected in rates and expenses associated with a program to convert customers from oil to gas,⁸⁶ the JP provides for a sharing of such costs to either, in the case of property taxes, provide an incentive for the Company to continue its efforts to hold expenses to the lowest possible level or, in the case of expenses associated with promoting conversions, to provide an equitable sharing of the costs of a program that will benefit customers and the Company alike. The new or modified deferral mechanisms will enable the Company to achieve results that are consistent with the Commission's policy objectives.

F. The Provisions Of The JP That Provide For The Recovery Of Dunkirk And Other RSS Costs Are Reasonable And Supported By The Record

Under Section 12.1 of the JP, up to \$57 million of electric deferral credits will be used to offset RSS costs associated with RSS agreements relating to the Dunkirk plant or other RSS agreements with other generators. Any RSS costs above \$57 million relating to the Dunkirk Plant or any other RSS agreements will be recovered through a generic RSS surcharge that will be implemented April 1, 2013. This surcharge will initially be set at \$0 and will remain at that level unless and until the Company incurs \$57 million of RSS costs. These provisions are reasonable, fair and well-supported by the record.⁸⁷

⁸⁶ Items (v) and (x) above.

⁸⁷ See Testimony of Company Electric Infrastructure and Operations Panel at 53-55, Testimony of Company Revenue Requirements Panel at 120. Testimony of the Staff Electric Infrastructure Panel at 52-53. See also Case 12-E-0136 – *Petition of Dunkirk Power LLC and NRG Energy, Inc. for Waiver of Generator Retirement Requirements*, “Order Deciding Reliability Issues and Addressing Cost Allocation and Recovery” (Issued and Effective August 16, 2012) (referring the issues related to recovery of costs associated with procuring RSS from Dunkirk Power LLC to this rate proceeding).

G. The Testimony, Exhibits And Discovery Conducted In These Proceedings Justify Approval Of The Increases In Rates In The JP On A Permanent Basis

In the Company's previous electric rate case, Case 10-E-0050, the Commission required \$50 million of the annual rate relief provided to the Company to be temporary pending the outcome of the audit of service company transactions conducted by Overland Consulting in Case 10-M-0451.⁸⁸ The testimony, exhibits and discovery provided in these proceedings do not support the continuation of temporary rates once the rates set forth in the JP supersede those approved in Case 10-E-0050.

In that proceeding, the Commission and Staff identified, *inter alia*, the following service company issues: (i) whether National Grid's business structure, then centered around a line of business model, lacked internal procedures and safeguards necessary to ensure the proper allocation of service company costs to National Grid's individual operating companies, including Niagara Mohawk; and (ii) whether Niagara Mohawk properly normalized service company charges. In response to these concerns, National Grid retained Liberty Consulting ("Liberty") to conduct an independent review and evaluation of the affiliate relationships and transactions that affect or may affect the costs incurred by National Grid's utilities.⁸⁹ After a five-month review, Liberty provided National Grid with findings and a comprehensive list of 60 recommendations primarily in the areas of systems and data, cost allocations and assignments and organization and management.⁹⁰ National Grid has closed 30 of Liberty's recommendations as of

⁸⁸ Case 10-E-0050 – *Niagara Mohawk Power Corporation – Electric Rates*, "Order Establishing Rates For Electric Service" at 9-10 (Issued and Effective January 24, 2011).

⁸⁹ Testimony of Company Service Company Panel at 19.

⁹⁰ *Id.* at 20.

December 31, 2011.⁹¹ These recommendations pertain primarily to organization and structure, cost allocation and financial controls and processes. Twenty-one additional recommendations are linked to the implementation of the SAP financial platform that is replacing the PeopleSoft and Oracle systems and those recommendations have been reflected in the design of the system.⁹² With respect to the remaining nine Liberty recommendations, National Grid is developing action plans to implement the recommendations in the manner that will best serve the needs of customers, regulators, and shareholders.⁹³

National Grid has also made significant changes to its management structure since Case 10-E-0050 in both the service company structure itself and the management of National Grid's operating utilities, including Niagara Mohawk.⁹⁴ In January 2011, National Grid began a major restructuring initiative and evolved from a global line of business to a regional model, supported by global functions, with a heightened jurisdictional and local focus.⁹⁵ The reorganization significantly reduced the number of employees and lowered costs.⁹⁶

National Grid has established a New York organization, instituted a monthly management and governance process and developed a suite of periodic financial reports that enable the New York organization to fulfill its responsibilities to (i) oversee development of budgets designed to enable Niagara Mohawk to meet its obligations to provide safe, adequate and reliable utility service at just and reasonable rates, (ii) monitor

⁹¹ *Id.* at 23.

⁹² *Id.* at 24.

⁹³ *Id.*

⁹⁴ *Id.* at 25.

⁹⁵ *Id.*

⁹⁶ *Id.* at 25.

its actual performance against those budgets, and (iii) sample service company charges to provide confidence that the costs charged to Niagara Mohawk by National Grid's service companies are appropriate.⁹⁷

In anticipation of the consolidation of its two financial systems, the Company has also revised its cost allocation methodologies to allow for a common cost assignment and allocation process.⁹⁸ To assist in its effort to revise its cost allocation methodologies, National Grid engaged PA Consulting Group to review National Grid's cost allocation practices and recommend a methodology consistent with industry best practices.⁹⁹ National Grid has revised its cost allocation and accounting practices and procedures and instituted mandatory cost allocation training for all management employees.¹⁰⁰

In response to the concerns raised by Staff and the Commission with the Company's review and normalization of costs in the historic test year in Case 10-E-0050, and to facilitate review of the historic test year in these proceedings, National Grid Service Company retained Ernst & Young LLP to assist with reviewing the accounting for costs charged from the service companies to Niagara Mohawk and its affiliates in the historic test year.¹⁰¹ This detailed review was designed to identify misallocations that may have occurred in the historic test year so that they could be corrected. The review was focused on verifying that service company costs charged to Niagara Mohawk and its affiliates were charged appropriately, and were proper to include in Niagara Mohawk's cost of service.

⁹⁷ *Id.* at 26.

⁹⁸ *Id.* at 47.

⁹⁹ *Id.*

¹⁰⁰ *Id.* at 48.

¹⁰¹ *Id.* at 29-41.

The JP provides a framework for the Company, Staff and other interested parties to continue to work to improve the transparency of National Grid's Service Company structure. As discussed *supra*, the JP contain specific provisions that address reporting requirements related to the new SAP financial platform, service level agreements and service company budgeting, bill review and reporting.¹⁰² However, the fact that improvements in Service Company governance and reporting are still in the works does not justify the establishment of temporary rates in these proceedings. The testimony, exhibits and discovery supplied by the Company in these cases support adoption by the Commission of the rates set forth in the JP as final rates.

Indeed, the Staff Finance Panel testified in these proceedings that it did not have the same service company cost allocation concerns that it did in Case 10-E-0050.

Specifically, Staff stated:

From our review, our previous concerns related to the misallocation of service company charges to Niagara Mohawk appear to have been addressed by Company's actions over the last year. We did not find any instances of cross-subsidization by Niagara Mohawk of the other National Grid affiliates . . . Also, the previous concern of the difficulties of auditing service company costs assessed to Niagara Mohawk did not reappear throughout our current rate case audit. Our limited review of the historic year service company costs was done without the difficulties and constraints that previously existed.¹⁰³

The Company is subject to the Commission's findings in Case 10-M-0451 regarding its policies, procedures, governance and controls relating to service company charges. In addition, in compliance with the Commission's Order in Case 10-E-0050, the Company filed a credit mechanism for refunding to electric customers any amounts determined to have been overcharged to Niagara Mohawk customers as a result of the

¹⁰² See JP Sections 12.2.1, 12.2.2 and 12.9.

¹⁰³ Testimony of Staff Accounting Panel at 147.

review of service company allocations in Case 10-M-0451. This credit mechanism, which was established to address temporary rates, was approved by the Commission, remains in place and will be used to refund to electric customers any overcharged amounts following the Commission's determination in Case 10-M-0451. However, based on the record in this proceeding, the temporary rates established in Case 10-E-0050 should not continue in effect once the rates set forth in the JP are adopted.

H. The Testimony And Exhibits Support The Signatory Parties' Agreement That Savings Related To The Management Audit Are Fully Reflected In The Gas And Electric Revenue Requirements

The JP reflects the Signatory Parties' agreement that the savings related to the implementation of the recommendations in the Company's most recent Management Audit in Case 08-E-0827 are fully reflected in the stipulated gas and electric revenue requirements.¹⁰⁴ As set forth in Appendix 9 of the JP, the JP's gas and electric revenue requirements reflect an annual operation and maintenance expense reduction of \$11.1 million embedded in the historic test year, capital cost avoidance of \$1.3 billion of the period April 1, 2011 through March 31, 2014 and incremental ongoing staffing costs of \$1.6 million in the historic test year.¹⁰⁵ These costs and cost savings estimates were supported in the Company's testimony and exhibits,¹⁰⁶ reviewed by Staff,¹⁰⁷ and not challenged by any party. Accordingly, the agreement reflected in the JP should be adopted by the Commission in conformance with Section 66(19) of the Public Service Law.¹⁰⁸

¹⁰⁴ JP at Section 12.3.

¹⁰⁵ JP, Appendix 9 at 1.

¹⁰⁶ Testimony of the Company Management Audit Panel at 11-12, Exhibit __ (MAP-1).

¹⁰⁷ Testimony of Kathleen A. Talmadge at 7-9.

¹⁰⁸ PSL§66(19) (McKinney's 2011).

III. Conclusion

For all the foregoing reasons, Niagara Mohawk respectfully requests that the Commission adopt the terms of the JP in full and without modification.

Respectfully submitted,

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Dated: December 21, 2012

Appendix A

CASE 12-E-0201 - 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 12-G-0202 - 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.

ALJ questions regarding the Joint Proposal filed December 7, 2012

Question numbers follow the section numbering in the Joint Proposal.

(ALJ 1)

JP 2.2

- a) What is the significance of excluding Economic Development Grant, Low Income Discount Program, AffordAbility Program, and the street lighting deferral from the deferral credits?
- b) Is there expected to be a balance of deferral credits at the end of Rate Year Three?

Response:

- a) The Economic Development Grant, Low Income Discount Program, AffordAbility Program and the street lighting deferral are excluded from the deferral credits because these deferrals are subject to previous agreements specifying the treatment of over and under collections that the Signatory Parties believe should remain in place. Per the Low Income and Economic Development Stipulation in Case 10-E-0050, under spending in the Economic Development Grant, Low Income Discount Program, and AffordAbility Program is deferred for future use in these programs. In the deferral compliance filing in Case 10-E-0050, the recovery of deferral costs from streetlighting customers' rates was limited by a cap, which resulted in \$6.845 million of costs deferred for future recovery from streetlighting customers.
- b) Yes, the Company is projecting a balance of deferral credits of approximately \$37 million at the end of Rate Year Three (approximately \$130 million forecast balance less \$35 million of proposed credits to be passed back to customers less \$57 million to offset estimated reliability support services costs).

(ALJ 2)

JP 3.2

How is the expiring electric surcharge allocated? Does the expiration of the surcharge affect the gradualism reflected in the revenue allocation schedules in the JP?

Response:

Both the current and proposed deferral surcharge/credit amounts were allocated among the service classes and voltage delivery levels by their percentage of delivery revenue. The allocation methodology was approved in Case 10-E-0050. The current deferral surcharge used the actual delivery revenue for calendar year 2010 as the basis for the allocation methodology. The current deferral surcharge for Outdoor Lighting was modified to collect less than the resulting allocation to mitigate bill impacts. Unlike the other classes, Outdoor Lighting did not have any simultaneous delivery rate reductions to offset the deferral collection. Therefore, the Outdoor Lighting deferral surcharge was designed to limit that class' delivery increase to five percent.

Here, the proposed delivery credit updates the delivery revenue by using Rate Year One Revenue at Present Rates (Appendix 2, Schedule 3, Page 5 of the JP). With respect to Outdoor Lighting, the Joint Proposal proposes to more than offset that class' allocated credit to recover a portion of the deferral balance remaining from the previous rate case. Similarly, the Company limited the delivery rate impact to five percent.

In addition, the revenue allocation methodology agreed to in the Joint Proposal for Rate Year One allocates base delivery revenue only, not the deferral credit (Appendix 2, Schedule 3, Pages 1) and takes into account each class' relative rate of return. Rate Years 2 and 3 assigned the system average increase to everyone.

(ALJ 3)

JP 3.3

A public comment was submitted on December 4, 2012 related to electric customers with solar installations that pay a year-round demand charge by virtue of exceeding a 2,000 kWh threshold during a winter month. Respond to this comment, and explain whether a revision to accommodate solar customers should or could be entertained without substantially affecting the JP.

Response:

In accordance with PSC No. 220 Electricity, specifically SC2D, Leaf No. 371:

“A demand meter shall be installed whenever the monthly energy consumption for any four consecutive months of a customer exceeds 2000 kWh per month or whenever the connected load of customer indicates that the energy consumption will exceed 2000 kWh per month. A demand meter, once installed, shall not be removed until after the energy consumption has been less than 2000 kWh per month for twelve consecutive months, which requirement may not be avoided by temporarily terminating service.”

This customer was an SC2D customer before the installation of the solar electric generating equipment and, in accordance with the tariff, would remain on the demand rate until consumption drops below 2000 kWh for 12 consecutive months. Many customers on demand rates, regardless of whether they net meter, have fluctuations in their demands and may fall below the threshold of 2000 kWh for a number of months. All customers, however, remain subject to the requirements in the tariff. Public Service Law 66-j does not exempt net metered customers from the tariff requirements.

To accommodate a solar net-metered customer, a tariff change would be required. To avoid undue discrimination, such a change would need to apply to all net metered customers. If the tariff is modified, exempt customers would need to be reclassified into a different service class to correctly calculate revenue allocation, and rate design and rates would need to be revised.

As the customer noted above indicates, there is a potential for the customer to hit the 2,000 kWh limit during the winter months. The Company and Staff maintain that the SC-2D rate classification is correct until the customer uses less than 2,000 kWh for 12 consecutive months.

(ALJ 4)

JP 3.3(a)

Would a customer whose demand in Rate Year One turns out to be identical to the customer's historic demand pay the same overall amount with and without the change proposed?

Response:

No. If the proposed historic demand change were approved, the customer, assuming they have an existing allocation, would pay less in both delivery revenues and their overall amount. Their delivery revenues would decrease because the customer would be able to maximize their NYPA Replacement and/or Expansion allocations before paying standard tariff rates on any additional load taken from the Company. Also from a total bill perspective, the overall amount would decrease because their lower-priced hydroelectric allocation would displace higher-priced market supply. For customers with new allocations, there would be no change in the delivery revenues. However, these customers, like the customers with existing allocations, would see a decrease in their overall bill due to the reduced supply costs as discussed above.

If the proposed change to historic demand were not approved, the customer would not be able to utilize any of their lower-priced NYPA Replacement and/or Expansion allocations and would pay full standard tariff delivery rates on their total demand because it is equal to their historic demand.

(ALJ 5)

JP 3.4.1

Is any provision made for applying any credit balance in Rate Year Four or beyond in the event the company does not file for new rates at the conclusion of the rate plan?

Response:

No, as stated in Section 13.5, there is no intent to apply any deferral credits in Rate Year Four or beyond in the event the company does not file for new rates at the conclusion of the rate plan.

(ALJ 6)

JP 3.4.4

a) Confirm that, under the Alternate Proposal for Use of Deferred Credits, in year four (all other things being equal) revenues would increase by \$54.867 million.

b) Related to JP 13.2, is the parties' support of the JP contingent on a choice between the preferred approach (3.4.1) and the alternate proposal (3.4.4) or are the parties agreeable to any alternate schedule for disposition of the credits determined by the Commission?

Response:

a) Yes, under the Alternate Proposal the credit would expire at the end of Rate Year Three. The effect of this expiration would be that bills would increase by \$54.867 million (all other things being equal). The Company and Staff believe the preferred approach provides the most stable rate path during and after the rate plan. Moreover, the Company and Staff believe that the JP should not be modified without the agreement of all Signatory Parties. Nonetheless, the Company and Staff would not be opposed to an alternative schedule that utilizes the same overall level of deferral credits.

(ALJ 7)

JP 3.7.5

During the last ten years, what has been the difference, if any, between the month of the New York Control Area summer peak and the month of the NMPC system peak?

Response:

The table below shows the New York Control Area (NYCA) and the NMPC summer peaks for each of the last ten years, 2003 to 2012. In all but year 2005, the month of the peak is the same between the NYCA and NMPC.

<u>Year</u>	<u>NYISO Summer Peak</u>		<u>Company Summer Peak</u>		<u>Same Month?</u>
	<u>Date</u>	<u>Month</u>	<u>Date</u>	<u>Month</u>	
2003	06/26/2003	June	06/26/2003	June	Yes
2004	06/09/2004	June	06/09/2004	June	Yes
2005	07/26/2005	July	08/04/2005	August	No
2006	08/02/2006	August	08/02/2006	August	Yes
2007	08/08/2007	August	08/02/2007	August	Yes
2008	06/09/2008	June	06/09/2008	June	Yes
2009	08/17/2009	August	08/17/2009	August	Yes
2010	07/06/2010	July	07/08/2010	July	Yes
2011	07/22/2011	July	07/21/2011	July	Yes
2012	07/17/2012	July	07/17/2012	July	Yes

(ALJ 8)

JP 4.4.3

Same questions as for 3.4.4 above. Confirm that the rate impact in year four would be an \$18.117 million increase (all else equal) and indicate whether parties' agreement is limited to the two alternatives provided in the JP.

Response:

Yes. Under the Alternate Proposal, the credit would expire at the end of Rate Year Three. The effect of this expiration would be that bills would increase by \$18.117 million (all else being equal). The Company and Staff believe the preferred approach provides the most stable rate path during and after the rate plan. Moreover, the Company and Staff believe that the JP should not be modified without the agreement of all Signatory Parties. Nonetheless, the Company and Staff would not be opposed to an alternative schedule that utilizes the same overall level of deferral credits.

(ALJ 9)

JP 3.5(b)

Explain why the electric revenue forecast in Appendix 2 Schedule 2 differs from the target revenues for RDM reconciliation purposes in Appendix 2, Schedule 14.

Response:

Please see Attachment 1 for a reconciliation of Appendix 2, Schedule 2 to Appendix 2, Schedule 14. In accordance with the Revenue Decoupling Mechanism Stipulation in Case No. 10-E-0050, load served by NYPA is exempt from RDM. Street Lighting customers are also exempt from the RDM until the Commission approves an energy efficiency program for street lighting service. Actual billed delivery service revenues are defined as customer, demand, reactive and delivery kWh rate components only, therefore, Merchant Function Revenues are not included in RDM.

(ALJ 10)

JP 3.5(d)

Explain why EZR customers will be exempt from RDM reconciliation. Provide an estimate of the percent of total sales that would be exempt under this provision.

Response:

This exemption was initially established in the Company's previous electric rate case (10-E-0050). Specifically, Section D of the Revenue Decoupling Mechanism Stipulation provides that all delivery loads and delivery revenues of EZR customers shall be included in the RDM in the class to which such customers belong, but such customers shall not be subject to an RDM charge or credit on the EZR portion of their loads.

Customers paying discounted commodity or delivery rates are generally exempt from the RDM targets because those customers may be less incented to implement energy efficiency measures. While EZR customers pay discounted delivery rates, EZR revenues were included in the RDM targets for administrative reasons. To achieve consistent treatment among customers paying discounted commodity or delivery rates, EZR customers are excluded from receiving the RDM surcharge or credit. Circumstances have not changed since the previous rate case and the Company and Staff maintain that the exemption should continue.

A percentage of EZR sales to total sales is approximately 1.7% (EZR kWhs of 574,689,884 divided by total sales of 32,966,811,443 kWhs) on an annual basis.

(ALJ 11)

JP 3.7.2 and 3.7.3

Provide a mathematical bill comparison of regular and time-of-use rates giving a breakdown of all delivery and commodity charges, detailing information that would be relevant to the decision of an average single-family home residential customer on whether to switch to time-of use rates. Provide a similar bill comparison for an average multi-family dwelling residential customer.

Response:

3.7.2 The Company does not currently have SC1 time of use (“TOU”) delivery rates and thus a bill comparison is not available at this time. As provided in Section 3.7.2 of the Joint Proposal, the Company, Staff, and other interested parties will meet to discuss the feasibility of SC 1 time differentiated delivery rates. A report summarizing the outcome of those discussions will be filed with the Secretary by the end of Rate Year One.

3.7.3 (part 1) With respect to SC1 time of use commodity rates, Attachment 1 provides a comparison of regular and TOU commodity rates for a typical central load zone residential customer using 600 kWh on October 1, 2012. The SC1 TOU commodity charges are calculated using 7.5% on-peak, 12% shoulder peak, and 80.5% off peak usage. All other rates, other than the Electricity Supply Reconciliation Mechanism, New Hedge Adjustment and the customer charge in the bill comparison, are the same for a regular and TOU customer. Please note that this comparison will vary depending on the customers’ total usage and the distribution of that usage during each of the commodity time periods. Customers would have to know their energy usage and its distribution during the specified time periods of this rate to see if TOU pricing would benefit them.

This comparison would be the same for an average multi-family dwelling residential customer.

(ALJ 12)

JP 3.7.3

Describe in more detail the expansion of time of use commodity rates to SC-1 customers. Will the time of use rate be voluntary? Will the customer charge for time of use customers differ from the customer charge for non-time-of-use customers?

Response:

Currently, only large SC-1C customers have the option of time of use commodity rates. In addition, the SC-1C time of use periods are complex (consisting of on-peak, off-peak and shoulder-peak as well as having seasonal distinctions). The proposal is therefore to expand time of use commodity rates to SC-1 customers consistent with the SC-2 Non Demand time of use rate in PSC No. 220, which consists of a simple on-peak, off-peak and shoulder peak rate design.

The time of use rate for these customers will be on a voluntary basis. The customer charge will be the same for these customers with the addition of a \$3.36 incremental metering charge to cover the incremental costs of procuring and installing a time of use meter.

(ALJ 13)

JP 3.7.6 and 4.11.2

- a) Is there a low-income rate or credit for the charges to re-establish service?
- b) Explain why charges for reestablishing electric service during business hours are increasing while similar charges for gas are being reduced.

Response:

a) In accordance with the Joint Proposal, Section 11.3, the Company has an Electric and Gas Re-Establishment fee waiver. The Company will apply to the re-establishment fee a one time credit of \$46.00 to electric, gas and combination electric and gas customers who receive HEAP and have had their service disconnected for non-payment.

b) As discussed in the Electric Rate Design Panel testimony submitted in Case 12-E-0201, specifically Section H, Page 68 of 117, the current electric service re-establishment rates were last modified in 2000 based on labor costs and overhead costs for that time period. The proposed rates were developed and can be seen in Exhibit_(E-RDP-7), Schedule 4. The proposed electric and gas re-establishment rates are based on the current estimated travel and field times for service to perform these functions. These updated charges were designed using the current time estimates and labor rates effective in 2011, adjusted for current labor overheads.

The gas re-establishment charges were last updated in the last general gas rate case (08-G-0609). At that time, the gas re-establishment charge was updated from \$41.00 to \$53.13 based on estimated travel and field times for service work based on labor rates effective in April 2009, adjusted for the then current labor overheads.

In performing the updates for the gas re-establishment charges for Case 12-G-0202, the average time for cut-ins and re-establishment of service during regular business hours, which includes travel, field contact and service work, has decreased since 2008. Therefore, the gas re-establishment charge has been decreased accordingly.

(ALJ 14)

JP 4.4.1

Is any provision made for applying any credit balance in Rate Year Four or beyond in the event the company does not file for new rates at the conclusion of the rate plan?

Response:

No, as stated in Section 13.5, there is no intent to apply any deferral credits in Rate Year Four or beyond in the event the company does not file for new rates at the conclusion of the rate plan.

(ALJ 15)

JP 4.10

Provide a plain language explanation for each item.

Response:

(a) Pursuant to Rule 16.2 of the Company's gas tariff, the Company is required to file with the Commission a Gas Appliance Repair Statement ("AR Statement") setting forth the cost of performing a thermocouple replacement for a customer. Under Rule 16.2, a customer requesting that the Company perform a thermocouple replacement is required to pay the amount set forth on the AR Statement. A thermocouple replacement is considered a minor appliance repair that falls under the umbrella of "screwdriver repairs" addressed by the Commission in Case 93-G-0804, *Proceeding on Motion of the Commission to Examine Guidelines for Gas Utility Marketing/Appliance Service Programs*. In that case, the Commission ordered utilities to discontinue providing appliance repair services to customers because of concerns that they might perform such services below cost. However, the Commission allowed utilities to continue to perform what it called minor "screwdriver repairs" to customers' appliances at no direct charge as long as the utilities provided a standard for determining what repairs would be considered to be screwdriver repairs. In its order, the Commission clarified that parts replacement would not be considered screwdriver repairs, and therefore generally could not be performed by utilities. However, the Commission made an exception for thermocouple replacements, which it indicated could be performed if the customer were charged for the service. Subsequently, the Company amended its gas tariff to include thermocouple replacements as a service that the Company would perform at a charge as set forth on the AR Statement on file with the Commission.

The proposal is to stop charging for replacing thermocouples, and instead replace them at no direct charge to customers, because the work is only performed by the Company when it is incidental to other work already being performed by the Company in response to no heat and/or gas odor complaints. The very limited cost associated with this work will instead be recovered in delivery rates. The impact is negligible given that the Company replaced thirteen thermocouples in 2010 and ten thermocouples in 2011. If this proposal is accepted, the AR Statement would no longer be necessary.

(b) Rule 18.1.2 of the Company's gas tariff provides that a customer taking service for a gas-fired emergency electric generator shall, among other things, pay all costs associated with

inspection of the generator. Under Rule 18.1.2, the cost of conducting the inspection is required to be set forth on a statement to be filed with the Commission. The Company incurs no incremental costs to perform these inspections and therefore the Joint Proposal proposes to eliminate the requirement that a statement setting forth the inspection fee be filed.

(c) In the Restructuring Settlement Agreement in Case 99-G-0336, the Company estimated that it would incur approximately \$345,000 in incremental annual operating and maintenance costs to provide gas marketers with new monthly balancing services under its transportation program. The \$345,000 was intended to recover Information Services costs incurred as part of the effort to modify the Company's Transportation Services Application computer system, as well as to recover the cost of a one-time license fee for proprietary software to provide monthly balancing services to marketers. In the Restructuring Settlement Agreement, the Company agreed to recover these incremental costs from marketers through a new volumetric charge to be set forth on the Balancing Services Cost Recovery ("BSCR") Statement, which was implemented on September 1, 2000. Given that these costs have now been fully recovered, the Joint Proposal proposes that the Company be authorized to discontinue charging marketers the BSCR charge and that the BSCR statement be eliminated.

(d) Rule 34.3 of the Company's gas tariff requires that the Company file with the Commission a Statement of Late Payment Charge Refund/Surcharge ("LPC Statement") that sets forth a monthly adjustment to gas commodity-related late payment charges applicable to customers taking firm sales service under SC-1, 2, and 3. To the extent gas commodity costs increase or decrease relative to the commodity costs and related late payment charges built into base rates, the LPC Statement sets forth the associated credits or surcharges to customers to return or collect the difference. Each month, the Company estimates its commodity-related late payment charge revenues based on the filed monthly cost of gas and compares these revenues to the gas commodity-related late payment charges included in the Company's revenue requirement. The monthly adjustment to the commodity-related late payment charges has an extremely small impact on customers' overall bills, and therefore the proposal is to eliminate the adjustment. For example, the total Historic Test Year LPC adjustment for a typical residential heating customer was a net surcharge of 69 cents. This represented a 0.06 percent increase for a typical residential customer with an annual bill of \$1,176.

(e) The Company's SC-4 Interruptible Sales service is a grandfathered service that has not been available to new customers since June 1, 1996. There are no longer any customers taking this service and therefore the proposal is to eliminate this service classification from the Company's tariff.

(f) The Company's SC-3 Large Supply service includes a monthly minimum delivery service charge that is based on a ratchet usage provision. The ratchet usage is equal to one-third of the customer's highest monthly consumption during the months of January through March. To the extent a SC-3 customer's monthly usage drops below this level at any point during the year, the customer's minimum delivery service charge is determined as if the customer had consumed the ratchet amount. The Joint Proposal provides that this provision will be eliminated from the tariff and that, instead, SC-3 customers will be charged delivery service rates based on their actual monthly usage. This change will align SC-3 with the Company's SC-5, SC-7, and SC-8 transportation services, which do not contain ratchets.

(g) Pursuant to Title 16 of the New York Codes, Rules and Regulations, Part 720-6.5 Gas Cost Adjustment Clauses, utilities are permitted to implement interim refunds or surcharges each gas

cost year for the purpose of preventing large gas cost over or under collections from accruing. The specific method of refund or surcharge is to be determined by the utility and filed with the Commission. The Joint Proposal proposes that the Company be authorized to implement a monthly gas cost imbalance surcharge or refund that would be included as an adjustment to the monthly cost of gas to minimize any year end gas cost over or under collections.

(ALJ 16)

JP 6.1.3

What are the constraints on the total amount of economic development discounts granted?

Response:

Unlike the Economic Development Grant Program (6.1.4), which is funded at a specific annual level, the economic development discounts are fully reconciled to the amount reflected in rates, with no annual constraints. However, the total amount of economic development discounts granted will be limited in several respects. EZR discounts will be provided only to the current population of customers who have been previously Empire Zone certified by New York State. Similarly, Excelsior Jobs Program discounts will be offered only to a limited number of businesses who receive Excelsior Jobs certification from New York State. Lastly, discounted delivery service under SC-12 will continue to be limited to customers who have a viable competitive alternative to delivery service from the Company, as demonstrated through a rigorous application and approval process.

(ALJ 17)

JP 6.1.14 (and 5.5)

The Commission's November 28, 2012 order in Case 11-M-0034 stated that individual rate decisions might impose a sharing requirement for SIR costs in the context of excess earning sharing mechanisms. Address whether it would be reasonable for the Commission to impose such a mechanism in this case.

Response:

A SIR sharing mechanism would be inconsistent with the intent of the parties to the settlement. The parties negotiated the joint proposal in good faith to achieve a reasonable, fair and balanced settlement. The parties were aware of the November 28, 2012 decision before filing the Joint Proposal.

(ALJ 18)

JP 6.1.18(a)

Why are no carrying charges to be calculated on RPS program costs? What is the annual balance of such costs held by the company for the last three years?

Response:

It should be noted the RPS program is outside base rates and is not included in the costs being discussed in this Joint Proposal. The Company has not calculated carrying charges on RPS program costs because the Commission's Orders issued in Case No. 03-E-0188, Proceeding on Motion of the Commission Regarding a Retail Renewable Portfolio Standard dated September 24, 2004 and April 2, 2010, do not discuss carrying charges on RPS balances.

The balances of RPS costs held by the Company for the last three years as of October 31 of each year are:

October 2010	\$ 2,623, 454
October 2011	\$17,002,497 (Note 1)
October 2012	\$ 6,400,753

Note 1: October 2011 balance does not reflect payment made to NYSERDA in the amount of approximately \$8 million in November 2011.

(ALJ 19)

JP 6.2.1 through 6.2.6

What happens to the proposed reconciliations in Rate Year Four or beyond in the event of a stayout?

Response:

As stated in Section 13.5, following the expiration of the Term of the Rate Plan, all provisions of this Joint Proposal (except for the application of deferral credits to offset revenue requirements) will continue until changed by Order of the Commission. 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.

(ALJ 20)

JP 6.2.5

Will variable pay extend to management?

Response:

The variable pay rate allowance includes both represented as well as most management employees. The rate allowance excludes all the variable pay for Band A management employees and the financial component of variable pay from Band B and C management employees.

(ALJ 21)

JP 6.2.6

Is reconciliation of property tax expense performed by any other New York utilities? Explain the rationale for this change, including support for the 80/20 ratio, and describe whether, or how, the new reconciliation formula will create incentives for the company to minimize this expense.

Response:

Yes, property tax reconciliation mechanisms have been approved for KEDNY and KEDLI, Corning Natural Gas, NYSEG and RG&E, Central Hudson, O&R and ConEd in their most recent rate proceedings.

The Company's and Staff's forecasts of property tax expense were materially different. Accepting the lower expense with a reconciliation represents a reasonable compromise by the Signatory Parties and protects both the Company and customers in the event actual property tax expense departs from the rate allowance over the three year rate plan. Including the sharing of increases and decreases maintains an incentive for the company to minimize property taxes as the Company will share in the changes in expense. To the extent the Company is able to reduce property tax expense below the level in rates, the Company would retain 20 percent of the difference and customers would receive the benefit of the remaining 80 percent. Conversely, if property tax expense exceeds the level in rates, the Company would absorb 20 percent of the difference and customers would be responsible for the remaining difference.

(ALJ 22)

JP 7.2.1 through 7.2.9

What happens to the proposed reconciliations in Rate Year Four or beyond in the event the company does not file for new rates at the conclusion of the rate plan?

Response:

As stated in Section 13.5, following the expiration of the Term of the Rate Plan, all provisions of this Joint Proposal (except for the application of deferral credits to offset revenue requirements) will continue until changed by Order of the Commission. 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.

(ALJ 23)

JP 8

- a) It is possible that various investigations following Hurricane Sandy may result in recommendations for substantial departures from current practice in planning and designing infrastructure – for example, increased undergrounding of electric lines. Does the JP either include or preclude a mechanism to accommodate such changes if they occur within the time-frame of the rate plan? Explain how such changes in planning (if any) should be treated by the Commission.
- b) Describe the consistency of electric and gas capital investment plans with the Energy Highway Blueprint.
- c) What happens to capital investment levels in Rate Year Four or beyond in the event the company does not file for new rates at the conclusion of the rate plan?

Response:

- a. The JP establishes rates based on agreed upon annual capital investment levels. However, the JP also provides the Company with flexibility to substitute, change or modify its capital projects during the term of the rate plan. If changes to the capital plans are warranted due to changed circumstances, new information or revised priorities, the Company would endeavor to accommodate such changes within the overall capital funding levels established in the JP. To the extent that new design standards were imposed legislatively, by a court, or through a regulatory process, and those new design standards resulted in an increase in the Company's costs of providing electric or gas service, absent an alternative recovery or deferral mechanism established as part of the legal or regulatory process, such cost increases would be subject to deferral pursuant to Section 6.1.7 of the JP.

- b. The Governor's Energy Highway Blueprint ("EHB") recommends thirteen actions in four focus areas to modernize and enhance the State's energy system:
 1. Expand and Strengthen the Energy Highway
 - Initiate AC transmission system upgrades to increase the capacity to move power from upstate to downstate;
 - Develop and implement reliability contingency plans to prepare to large power plant retirements;
 - Provide public power entities flexibility in contracting to for public-private partnerships;

 2. Accelerate Construction and Repair
 - Accelerate investments in electric generation, transmission and distribution for reliability, safety and storm resilience;
 - Accelerate investments in natural gas distribution to reduce costs to customers and promote, reliability, safety and emissions reductions;

 3. Support Clean Energy
 - Conduct a competitive solicitation for renewable resources in New York as part of the State's RPS;
 - Initiate transmission upgrades in Northern New York to help facilitate renewable energy development;
 - Characterize offshore wind resources and evaluate cost recovery opportunities;
 - Initiate Process for repowering of inefficient power plants on Long Island and support additional efforts to transition to a cleaner power generation fleet on Long Island;
 - Require utilities to evaluate repowering as an alternative to power plant retirements when the plant is needed for reliability;
 - Establish a Community Support Plan and GHG Emissions Reduction Program in the electricity sector;

 4. Drive Technology Innovation
 - Fund Smart Grid demonstration Projects;

- Develop an Advanced EMS Control Center and pursue a federal Smart Grid Technology Hub.

The EHB was issued October 22, 2012, after much of the basis for the JP was developed. As a result, the JP was not developed specifically in response to the EHB. Nevertheless, the JP is generally consistent with the EHB, and several aspects of the JP directly support EHB areas of focus. For example, the Company's electric capital investment plan, which underlies the capital investment levels reflected in the JP, includes investments to promote the reliability and resilience of the transmission and distribution systems. Maintaining the integrity and reliability of the existing transmission and distribution system is necessary and fundamental to improving and expanding the system to serve new needs. The plan also includes funding for a Smart Grid demonstration, which leverages investment from the U.S. DOE. Although not included in the funding levels reflected in the JP, the Company's capital investment filings in the rate case provided estimated investment levels related to a new transmission line (Leeds-Pleasant Valley), which has been identified as a potential investment to increase capacity to move power from upstate to downstate.

In addition, although not part of the JP, the Company is working with DPS Staff and other parties to explore processes for evaluating repowering of power plants as an alternative to retirement. The Company is in the midst of a request for proposal process to explore the potential for non-traditional solutions to more efficiently address system reliability needs.

Consistent with the EHB's directive to accelerate investments in natural gas distribution, the JP contemplates that the Company will invest more than \$258 million over a three year period on capital projects to enhance the reliability, safety and availability of gas service, including a commitment by the Company to significantly increase the rate of leak-prone pipe replacements on the system.

With the goal of increasing the availability of low-cost natural gas to customers in New York, the Company will facilitate a Gas Expansion Collaborative to consider: (i) expanding the Company's current gas franchise area, (ii) actions to address current upstream capacity constraints, including acquiring additional pipeline capacity or revising the use of current pipeline capacity to optimize system and customer benefits; and (iii) the Company offering compressed natural gas and liquefied natural gas vehicle programs. The Gas Expansion Collaborative will complement the Commission's pending Proceeding to Examine Policies Regarding the Expansion of Natural Gas Service in Case 12-G-0297.

- c) The Company annually develops a forward-looking five-year electric and gas capital investment plan. The current capital investment plan provides for combined electric system investment (transmission, sub-transmission and distribution) in FY17 (Rate Year Four) of \$452.7 million. The current capital investment plan provides for gas system investments in FY17 of \$98.2 million. The Company will continue reviewing its investment plans, incorporate input from Staff and file those plans with the Commission.

(ALJ 24)

JP 9

Do the performance metrics provide for levels in Rate Year Four or beyond in the event the company does not file for new rates at the conclusion of the rate plan?

Response:

As stated in Section 13.5, following the expiration of the Term of the Rate Plan, all provisions of this Joint Proposal (except for the application of deferral credits to offset revenue requirements) will continue until changed by Order of the Commission. 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.

(ALJ 25)

JP 10

Do the performance metrics provide for levels in Rate Year Four or beyond in the event the company does not file for new rates at the conclusion of the rate plan?

Response:

As stated in Section 13.5, following the expiration of the Term of the Rate Plan, all provisions of this Joint Proposal (except for the application of deferral credits to offset revenue requirements) will continue until changed by Order of the Commission. 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.

(ALJ 26)

JP 11.5

The collaborative has no target date for a report to the Commission. What would be a reasonable target date, consistent with Case 12-M-0476?

Response:

The Joint Proposal indicates that the Company will convene a collaborative as soon as practicable but no later than 60 days following the Commission's Order adopting the Joint Proposal. The Company and Staff believe a reasonable target date for a report to the Commission would be 75 days following commencement of the collaborative.

(ALJ 27)

JP 11.6

Provide an estimate of the actual avoided cost per customer of paperless billing. Explain why any difference between the actual avoided cost and \$.40 is retained by the Company.

Response:

The proposed \$0.40 per customer paperless billing credit consists of \$0.46 of avoided paper billing costs offset by \$0.06 of incremental electronic billing costs. The differences between the actual avoided and incremental costs and the estimated \$0.40 per customer credit could be positive or negative. The Joint Proposal has no provision to track either the actual avoided or incremental costs because any changes would be de minimis and the costs associated with tracking these costs would likely exceed the benefits.

(ALJ 28)

JP 11.7

The collaborative has no target date for a report to the Commission. What would be a reasonable target date, consistent with Case 12-G-0297?

Response:

Whereas the Commission's generic proceeding regarding gas expansion (Case 12-G-0297) will examine broad policy issues for New York utilities, the collaborative will focus more narrowly on the issues specific to potential customers in Niagara Mohawk's service territory (e.g., upstream capacity issues currently hindering the expansion of gas service to large commercial and industrial customers in the Capital Region and Northeast). The Company and Staff propose that a status report to the Commission within 90 days of the commencement of the collaborative is reasonable. The status report will include an update on (i) the issues being a considered in the collaborative, (ii) the parties participating and (iii) a timeline. The expectation is that the Company would issue a final report no later than one year from commencement of the collaborative.

(ALJ 29)

JP 11.8

Provide an estimate of the number of customers that can participate, given a \$1 million annual budget, and the potential demand for the program.

Response:

It is difficult to estimate the number of customers who will participate in the conversion program until the details have been finalized in consultation with Staff. This program could benefit 800-1,000 residential customers assuming full participation. The Company is also considering a commercial conversion program that will benefit a smaller group of commercial customers.

(ALJ 30)

JP 12.1

Does any provision of the JP address the anticipation of future plant closings and the minimization of related expected and unexpected expense to ratepayers?

Response:

Although there are no provisions in the Joint Proposal that are tailored to address potential future plant closings, the Joint Proposal taken as a whole provides the Company with flexibility to address such closings. The \$57 million of deferral credits to be used to offset the section 12.1 RSS costs are not limited to Dunkirk but also may be used to offset RSS costs associated with “other RSS agreements with other generators.” In addition, the Joint Proposal provides the Company with flexibility to move capital dollars around within budget categories. Such flexibility provides another potential source from which the Company could address plant closings.

(ALJ 31)

JP 12.2.1(a)

Explain in more detail the meaning of the phrase “SLAs that contain service descriptions that align with the stated budget cost for each service ...”

Response:

There will be Service Level Agreements (“SLAs”) for each Service Company function that will include descriptions of the individual services to be provided and the budgeted cost of providing those services or group of services. Current SLAs provide a description of services to be provided and overall budget. Prospectively, the Company will provide a more detailed breakdown of services that will align with more granular costs. Because definable quantities and unit prices are not available for many SLA services, National Grid will also rely on budget information to present the costs for individual services in the SLAs. The Company will detail the budgeted costs by the individual services or groups of services to be provided and will develop reports detailing variances between budgeted amounts and actual spending for each individual service or group of services to provide greater transparency to the actual cost of providing services from the various functional areas within the Service Company.

(ALJ 32)

JP 12.2.1(b)

Staff Accounting Panel testimony (pp 151 ff) describes concerns over a lack of external comparisons of service company costs. The JP provides for a three-year process for developing such comparisons. Assuming that this process is effective on a prospective basis, what assurance

does the Commission have that the costs reflected in the JP for Rate Years 1-3 are reasonably competitive?

Response:

The Company and Staff have reviewed the costs in the rate years to assure that those costs are reasonable. The data to date shows that the costs reflected in the JP are reasonably competitive. If future external cost comparisons identify instances where SLA related costs are not reasonably competitive, Staff will propose adjustments in the next rate proceeding.

(ALJ 33)

JP 12.6.4

Does the rate plan in the JP contain funding to implement the Buffalo street light cable replacement plan?

Response:

Yes. The capital investment levels agreed to in the JP include funding for the Buffalo Street Light cable replacement program at an annual level of \$2.5 million.

(ALJ 34)

JP 12.9

a) Will the 12-month review of SAP compare allocations under SAP to allocations in the test year that support the rate plan in the JP? What recourse is available to the Commission if the review reveals problems in allocation or other factors assumed in the JP that may have operated to the detriment of Niagara Mohawk ratepayers?

b) Staff Accounting Panel testimony (p. 165) recommends that the 12-month review analyze whether Niagara Mohawk is properly benefitting from economies of scale. Will economies of scale be considered in the 12-month review, and if not, explain why not.

Response:

a) The analysis is for the 12 month period ending March 31, 2014 (Rate Year One) and will analyze the actual impact of the implementation of the new allocators as compared to the previous allocators for the same period. To the extent that the use of new allocators causes the Company to exceed the 9.3 percent return on equity underlying the rates set forth in the Joint Proposal, the earnings sharing mechanism ensures that customers receive at least 50 percent of such earnings. There is no protection for the Company, however, if the costs reflected in rates are understated as a result of the use of revised allocators and such understatement causes the Company to earn a return on equity of less than 9.3 percent. While the Joint Proposal does not provide for any adjustments or process based on the results of the study, the Commission could always institute a proceeding to resolve any issue prospectively.

b) The study undertaken will evaluate whether the Company is properly following its revised cost allocation methodology and documenting the results appropriately. While the Company believes that following the revised allocation factors will ensure that Niagara Mohawk is benefiting from economies of scale, the study is not intended to demonstrate that particular economies of scale have been achieved in the period analyzed.

(ALJ 35)

JP 12.10

Considering the ongoing reviews of allocation and external cost comparison established in the JP, explain why a temporary rate mechanism, comparable to the one implemented in Case 10-E-0050, is not warranted in this proceeding.

Response:

In the Company's last electric rate case, Case 10-E-0050, the ALJs expressed a concern that the structure of National Grid's business organization around lines of business and the service companies lacked the internal procedures and controls necessary to ensure the proper allocation of costs to the individual operating companies. This concern served as the basis for the Commission to institute an investigative audit to examine past service company allocations. The Company also hired Liberty Consulting Group to perform an internal investigation of these issues.

The Company's decision to change from a global line of business model to a regional and jurisdictional model, which was completed in September 2011, substantially alleviated issues that could have led to incorrect allocations charged against the Company.

Based on a review of Niagara Mohawk's historic test year charges, both incurred charges from Niagara Mohawk itself and from the service companies, the testimony in this case indicates that the previous concerns related to the misallocation of service company charges to Niagara Mohawk have been adequately addressed by the Company's actions over the last year. Staff testified that its own audit of transactions in this rate case did not find any instances of cross-subsidization by Niagara Mohawk of the other National Grid affiliates and previous concerns regarding the difficulties in auditing service company costs assessed to Niagara Mohawk did not reappear in this rate case.

Section 12.10 of the JP provides a general discussion of the Overland audit, and the temporary rates established from Case 10-E-0050. In its compliance filing following the Commission's January 24, 2011 Order in Case 10-E-0050, the Company filed a credit mechanism for refunding to electric customers any amounts determined to have been overcharged to Niagara Mohawk customers as a result of the Overland review of service company allocations. This credit mechanism, which was established to address temporary rates in Case 10-E-0050 and approved by the Commission, remains in place and will be used to refund to electric customers any overcharged amounts following the Commission's determination in Case 10-M-0451. The Company will be subject to the Commission's findings in that proceeding regarding its policies, procedures, governance and controls relating to service company charges.

This rate case deals with a different historic year period – the twelve months ending.

December 31, 2011 – from the time period the Overland audit covers. As Staff has not found the same level of concerns in this rate case, the parties agreed that there was no need for temporary rates going forward given that temporary rates from Case 10-E-0050 continue to preserve any dollars that may be due to ratepayers for the prior periods being addressed by the Overland audit.

(ALJ 36)

JP 12.11

a) Do the figures of \$10.1 million and \$2.7 million represent the stay-out premium for electric and gas, respectively?

b) Explain the value to ratepayers of a stay-out premium where the Company retains the option to file for new rates.

Response:

a) Yes.

b) The intent of the provision is that the Company will not file to reset base delivery rates during the term of the rate plan. If, however, the Company does file to reset rates, the premium will be refunded to customers. The same approach was utilized and approved by the Commission in the Company's previous electric and gas rate proceedings – Case 10-E-0050 and Case 08-G-0609, respectively. *See* Case 10-E-0050, "Order Establishing Rates for Electric Service" at 83-84 (Issued and Effective January 24, 2011) and Case 08-G-0609, "Order Adopting The Terms of a Joint Proposal And Implementing A State Assessment Surcharge" at 5 (Issued and Effective May 15, 2009).

(ALJ 37)

JP 2S

a) For each rate year, express in percentage terms the net change in electric revenues (i) not including the expiration of the surcharge or the application of deferred credits, (ii) including the expiration of the surcharge, and (iii) including the expiration of the surcharge and the preferred approach for treatment of deferred credits.

b) For each rate year, express in percentage terms the net change in gas revenues (i) not including the application of customer credits, and (ii) including the application of customer credits.

Response:

a) Please see Attachment 1 to JP-2S(ALJ-37) for a detailed calculation of the table below.

	% Change in Electric Revenues		
	RY Ending March 31, 2014	RY Ending March 31, 2015	RY Ending March 31, 2016
(i) : not including the expiration of the surcharge or the application of deferred credits	1.66%	1.94%	1.04%
(ii): including the expiration of the surcharge	- 5.62%	- 5.25%	- 5.97%
(iii): including the expiration of the surcharge and the preferred approach for treatment of deferred credits	- 6.26%	- 6.01%	- 5.97%

b) Please see Attachment 1 to JP-2S(ALJ-37) for a detailed calculation of the table below.

	% Change in Gas Revenues		
	RY Ending March,31 2014	RY Ending March,31 2015	RY Ending March,31 2016
(i) : not including the application of customer credits	-0.54%	0.97%	1.03%
(ii) : including the application of customer credits	-4.32%	0.90%	1.03%

(ALJ 38)

JP 9

Is the \$2 million increase in potential negative adjustments for electric reliability attributable to the “Estimating” metric?

Response:

No, the \$2 million increase in potential negative adjustment is attributable to the new Inspection and Maintenance Program metric. Section 4.5 of Attachment 1 to Appendix 7 of the Joint Proposal provides details of the new metric.

(ALJ 39)

JP 10

Explain how the components of the Gas Safety Performance Metrics differ from current measures.

Response:

The following is a summary of the specific changes to each of the Gas Safety Metrics:

Leak Prone Pipe (LPP)

- The current metric provides for removal of 25 miles of LPP per year and 150 miles over five years (CYs 08-12). The Joint Proposal (JP) provides that the Company would be subject to a negative revenue adjustment if it failed to remove a minimum of 35 miles of LPP in CY13 and 35 miles in CY14 or a cumulative three-year total of 120 miles by the end of CY15.
- Under the JP, the negative revenue adjustment for failure to achieve the metric would decrease from \$840,000 to \$720,000. \$720,000 is equivalent to 8 basis points.

Leak Management

- Under the JP, the current year-end leak backlog metric for Type 1, 2A and 2 leaks would continue for CY13 and CY 14. The performance targets for this metric would be lowered for the year-end backlog of Type 1, 2A and 2 leaks from 40 leaks to 35 in CY13 and 30 in CY14.
- For CY15, the leak management metric would shift to a new total leak measure (Type 1, 2A, 2 and 3) and the Company would incur a negative revenue adjustment for failure to reduce total leaks in the backlog to 1,000 by the end of CY15.
- Under the JP, the negative revenue adjustments would be changed from a sliding scale (leaks 40-50: \$10,000 per leak; 51-60: \$100,000 + \$20,000 per leak; +60: \$1,260,000) to a flat \$1,080,000 (12 basis points) for failure to meet the applicable year-end leak backlog target.

Emergency Response

- No change to the current metric’s performance levels.
- Under the JP, the negative revenue adjustments would be reduced as follows:
75% in 30 min - \$1,050,000 to \$540,000 (6 basis pts)

90% in 45 min - \$630,000 to \$360,000 (4 basis pts)

95% in 60 min - \$420,000 to \$180,000 (2 basis pts)

Damage Prevention

- Under the JP, the performance targets would be lowered as follows:

Damage Prevention Measure	Current	CY13	CY14	CY15
Overall Damages per 1,000 one-call tickets	4.2	2.9	2.7	2.5
Damages due to Mismarks per 1,000 one-call tickets	0.9	.48	.48	.48
Damages due to Company and Contractors per 1,000 one-call tickets	.25	.10	.10	.10

- The negative revenue adjustments would be changed from a sliding scale to a flat basis point adjustment for failure to meet target, as follows:

Metric	Current Rate Plan	JP
Overall Damage	4.2 \$0 4.2-4.4 \$210,000 > 4.4 \$420,000	\$360,000 (4 basis pts)
Mismarks	0.90 \$0 0.91-1.00 \$525,000 > 1.00 \$1,050,000	\$900,000 (10 basis pts)
Company and Contractor	0.25 \$420,000	\$360,000 (4 basis pts)

Gas Safety Violations Metric

- This is a new metric.
- Up to \$9,000,000 at risk (100 basis points).

(ALJ 40)

JP 11.5S

a) Staff Retail Access panel testimony (pp 22-31) recommended that the bill comparisons should be included in monthly bills, and provided to payment troubled customers. Explain whether (and to what extent) these recommendations are included in the agreement that the Company will develop a bill calculator.

b) Does the \$0.298 cost cap encompass the measures described above?

Response:

- a) Yes, the Company responded in testimony that it would develop a bill comparison to be displayed on the customer website and to be included in residential customer bills, deferred payment agreement (DPA) default notices, and disconnect notices. Testimony also addressed development of a one-time letter with a bill comparison for residential customers currently served by a consolidated bill ESCo and currently participating in a low-income assistance program or currently on a DPA.
- b) Yes, the \$0.298 cost estimate includes all of the above.

(ALJ 41)

JP 12

- a) Describe the timeframe of the plan for constructing upgrades to alleviate the need for RSS costs related to Dunkirk.
- b) Assuming completion of the upgrades according to schedule, provide any estimate of RSS costs exceeding \$57 million.
- c) Does the RSS surcharge remain in place beyond the end of rate year three?

Response:

- (a) There are two primary time frames associated with the planned transmission system investments affecting Dunkirk: (1) prior to May 31, 2013, and (2) June 1, 2013 – June 2015.

Prior to May 31, 2013 – The current RSS agreement covers two of the Dunkirk 115 kV-interconnected generators and has a nine-month term (September 1, 2012 – May 31, 2013). The Company is working to deliver several short-term transmission projects by May 31, 2013, which will reduce reliance on Dunkirk from two 80 MW units to one unit.

June 1, 2013 – June 2015 – Implementation of projects planned for this period is expected to reduce reliability risks to acceptable levels such that all Dunkirk units could be removed from service. There is one project currently estimated to be completed in June 2016, though a review is underway to determine what could be done to accelerate it to June 2015. The completion of this last project will determine the date that generation will no longer be required. During this period, the Company anticipates incurring RSS costs to procure system reliability support from one 80 MW Dunkirk unit or an equivalent resource.

The foregoing timeframes are approximate, and may change depending on actual implementation schedules and system conditions. In addition, the Company is undertaking a request for proposal (RFP) process to try to reduce overall RSS costs.

(b) Assuming completion of the planned short-term transmission projects by May 31, 2013, costs under the existing two-unit RSS agreement with Dunkirk would be less than \$57 million. The Company anticipates entering an RSS agreement for one 80 MW Dunkirk unit or an equivalent resource for the period June 1, 2013 – June 2015; however, at this time the Company has no estimate of the costs it would incur under such an agreement.

(c) Yes. The RSS surcharge has no expiration date and does not end at the end of Rate Year three. The Company has provided a proposed tariff leaf for the RSS surcharge under Rule 50 in its original filing. The RSS surcharge is generic in nature and not specific to the Dunkirk RSS costs. As described in the JP in Section 12.1, the surcharge rate will be set to \$0 until such time as RSS costs incurred are greater than \$57 million. Any costs above \$57 million will be subsequently recovered and reconciled through the RSS surcharge.

Niagara Mohawk Power Corporation d/b/a National Grid

Case No. 12-E-0201

Attachment 1 to 3.5 (b)

<u>Line</u>	<u>Source</u>	<u>Description</u>	<u>Amount</u> (\$000's)
1	Appendix 2, Schedule 2	T&D Revenue for Base Rate Design	\$1,338,321
2	Appendix 2, Schedule 4	Less: Merchant Function Revenue	\$20,655
3	Appendix 2, Schedule 4	Less: Street Lighting T&D Base Revenues	\$50,751
4	Appendix 2, Schedule 14	Less: R&E T&D Revenues	\$16,892
5	Appendix 2, Schedule 14	Less: HLF T&D Revenues	\$793
6	Appendix 2, Schedule 14	Total T&D Revenues included in the RDM	<u>\$1,249,230</u>

Line 2 = Sum of Lines 7-17

Line 3 = Sum of Lines 18-21

Line 6 = Line 1 - Lines 2-5

<u>Line</u>	<u>Merchant Function Revenues - Appendix 2, Schedule 4</u>		
7	Page 1	Parent Service Class No. 1	\$17,513
8	Page 2	Parent Service Class No. 1C	\$562
9	Page 3	Parent Service Class No. 2	\$767
10	Page 4	Parent Service Class No. 2 Demand	\$744
11	Page 5	Parent Service Class No. 3 Secondary	\$335
12	Page 6	Parent Service Class No. 3 Primary	\$119
13	Page 7	Parent Service Class No. 3 SubT and Transmission	\$55
14	Page 8	Parent Service Class No. 3A Secondary/Primary	\$50
15	Page 9	Parent Service Class No. 3A SubTransmission	\$61
16	Page 10	Parent Service Class No. 3A Transmission	\$415
17	Pages 11-14	Street Lighting	\$33
		Total Merchant Function Revenues RY1	<u>\$20,655</u>

<u>Line</u>	<u>Street Lighting T&D Base Revenues - Appendix 2, Schedule 4</u>		
18	Page 11	Service Classification No. 1	\$3,545
19	Page 12	Service Classification No. 2 & 5	\$45,678
20	Page 13	Service Classification No. 3 & 6	\$520
21	Page 14	Service Classification No. 4	\$1,008
		Total Street Lighting T&D Base Revenues	<u>\$50,751</u>

SC1
Central Load Zone Bill

SC1 TOU
Central Load Zone Bill

Commodity	\$	25.55
T&D	\$	50.48
Total	\$	76.03

Commodity	\$	20.99
T&D	\$	53.95
Total	\$	74.94

Prices (in effect October 1st)

Prices (in effect October 1st)

			<u>600</u>
Commodity	\$0.04661	\$27.97	
On-Pk	0.00000		
Shoulder-Pk	0.00000		
Off-Pk	0.00000		
Uncollectible	1.96%	\$0.55	
Working Capital	0.344%	\$0.10	
Supply Procurement	\$0.00017	\$0.10	
Credit and Collection.	\$0.00076	\$0.46	
ESRM	(\$0.01186)	(\$7.12)	
NHA	\$0.00539	\$3.23	
Delivery			
Per Customer	\$16.21	\$16.21	
Per kWh	\$0.04206	\$25.24	
Deferral Recovery Surcharge	\$0.01057	\$6.34	
LTC	(\$0.001774)	(\$1.06)	
SBC/RPS	\$0.00577	\$3.46	
TRAC	\$0.00121	\$0.73	
ISAS	\$0.00307	\$1.84	
RDM	(\$0.00632)	(\$3.79)	
GRT			
Commodity	0.99		
Delivery	0.97		

				<u>600</u>
Commodity	\$0.00000	\$0.00		
On-Pk	\$0.07997	\$3.60	7.5%	
Shoulder-Pk	\$0.04438	\$3.20	12.0%	
Off-Pk	\$0.03461	\$16.72	80.5%	
Uncollectible	1.96%	\$0.46		
Working Capital	0.344%	\$0.08		
Supply Procurement	\$0.00017	\$0.10		
Credit and Collection.	\$0.00076	\$0.46		
ESRM	(\$0.00639)	(\$3.83)		
NHA	\$0.00000	\$0.00		
Delivery				
Per Customer	\$19.57	\$19.57		
Per kWh	\$0.04206	\$25.24		
Deferral Recovery Surcharge	\$0.01057	\$6.34		
LTC	(\$0.001774)	(\$1.06)		
SBC/RPS	\$0.00577	\$3.46		
TRAC	\$0.00121	\$0.73		
ISAS	\$0.00307	\$1.84		
RDM	(\$0.00632)	(\$3.79)		
GRT				
Commodity	0.99			
Delivery	0.97			

(\$000's)

A)

% Change in Electric Revenues
(ii) : not including the expiration of the surcharge or the application of deferred credits

	Revised		Revised		Revised		Revised		
	R Y Ending March,31 2014	% Change	R Y Ending March,31 2014	R Y Ending March,31 2015	% Change	R Y Ending March,31 2015	R Y Ending March,31 2016	% Change	R Y Ending March,31 2016
Operating Revenues	\$ 2,428,181		\$ 2,428,181	\$ 2,462,025		\$ 2,462,025	\$ 2,525,787		\$ 2,525,787
Base Revenue Increase	\$ -		\$ 43,395	\$ -		\$ 51,361	\$ -		\$ 28,342
Surcharge	\$ 190,636		\$ 190,636	\$ 190,636		\$ 190,636	\$ 190,636		\$ 190,636
Deferred credits	\$ -		\$ -	\$ -		\$ -	\$ -		\$ -
	<u>\$ 2,618,817</u>	1.66%	<u>\$ 2,662,212</u>	<u>\$ 2,652,661</u>	1.94%	<u>\$ 2,704,022</u>	<u>\$ 2,716,423</u>	1.04%	<u>\$ 2,744,765</u>

% Change in Electric Revenues
(ii): including the expiration of the surcharge

	Revised		Revised		Revised		Revised		
	R Y Ending March,31 2014	% Change	R Y Ending March,31 2014	R Y Ending March,31 2015	% Change	R Y Ending March,31 2015	R Y Ending March,31 2016	% Change	R Y Ending March,31 2016
Operating Revenues	\$ 2,428,181		\$ 2,428,181	\$ 2,462,025		\$ 2,462,025	\$ 2,525,787		\$ 2,525,787
Base Revenue Increase	\$ -		\$ 43,395	\$ -		\$ 51,361	\$ -		\$ 28,342
Surcharge	\$ 190,636		\$ -	\$ 190,636		\$ -	\$ 190,636		\$ -
Deferred credits	\$ -		\$ -	\$ -		\$ -	\$ -		\$ -
	<u>\$ 2,618,817</u>	-5.62%	<u>\$ 2,471,576</u>	<u>\$ 2,652,661</u>	-5.25%	<u>\$ 2,513,386</u>	<u>\$ 2,716,423</u>	-5.97%	<u>\$ 2,554,129</u>

% Change in Electric Revenues
(iii): including the expiration of the surcharge and the preferred approach for treatment of deferred credits

	Revised		Revised		Revised		Revised		
	R Y Ending March,31 2014	% Change	R Y Ending March,31 2014	R Y Ending March,31 2015	% Change	R Y Ending March,31 2015	R Y Ending March,31 2016	% Change	R Y Ending March,31 2016
Operating Revenues	\$ 2,428,181		\$ 2,428,181	\$ 2,462,025		\$ 2,462,025	\$ 2,525,787		\$ 2,525,787
Base Revenue Increase	\$ -		\$ 43,395	\$ -		\$ 51,361	\$ -		\$ 28,342
Surcharge	\$ 190,636		\$ -	\$ 190,636		\$ -	\$ 190,636		\$ -
Deferred credits	\$ -		\$ (16,669)	\$ -		\$ (20,225)	\$ -		\$ -
	<u>\$ 2,618,817</u>	-6.26%	<u>\$ 2,454,907</u>	<u>\$ 2,652,661</u>	-6.01%	<u>\$ 2,493,161</u>	<u>\$ 2,716,423</u>	-5.97%	<u>\$ 2,554,129</u>

B)

% Change in Gas Revenues
(i) : not including the application of customer credits

	Revised		Revised		Revised		Revised		
	R Y Ending March,31 2014	% Change	R Y Ending March,31 2014	R Y Ending March,31 2015	% Change	R Y Ending March,31 2015	R Y Ending March,31 2016	% Change	R Y Ending March,31 2016
Operating Revenues	\$ 609,122		\$ 609,122	\$ 601,684		\$ 601,684	\$ 607,664		\$ 607,664
Base Revenue Increase	\$ -		\$ (3,290)	\$ -		\$ 5,854	\$ -		\$ 6,268
Deferred credits	\$ -		\$ -	\$ -		\$ -	\$ -		\$ -
	<u>\$ 609,122</u>	-0.54%	<u>\$ 605,832</u>	<u>\$ 601,684</u>	0.97%	<u>\$ 607,538</u>	<u>\$ 607,664</u>	1.03%	<u>\$ 613,932</u>

% Change in Gas Revenues
(ii) : including the application of customer credits

	Revised		Revised		Revised		Revised		
	R Y Ending March,31 2014	% Change	R Y Ending March,31 2014	R Y Ending March,31 2015	% Change	R Y Ending March,31 2015	R Y Ending March,31 2016	% Change	R Y Ending March,31 2016
Operating Revenues	\$ 609,122		\$ 609,122	\$ 601,684		\$ 601,684	\$ 607,664		\$ 607,664
Base Revenue Increase	\$ -		\$ (3,290)	\$ -		\$ 5,854	\$ -		\$ 6,268
Deferred credits	\$ -		\$ (22,998)	\$ -		\$ (11,283)	\$ -		\$ -
	<u>\$ 609,122</u>	-4.32%	<u>\$ 582,834</u>	<u>\$ 601,684</u>	-0.90%	<u>\$ 596,255</u>	<u>\$ 607,664</u>	1.03%	<u>\$ 613,932</u>