

STATE OF NEW YORK  
DEPARTMENT OF PUBLIC SERVICE



- 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

***NEW YORK STATE DEPARTMENT OF PUBLIC SERVICE STAFF STATEMENT IN  
SUPPORT OF JOINT PROPOSAL***

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PUBLIC SERVICE COMMISSION

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***NEW YORK STATE DEPARTMENT OF PUBLIC SERVICE STAFF STATEMENT IN  
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**BACKGROUND**

On April 27, 2012, Niagara Mohawk Power Corporation d/b/a National Grid (“Niagara Mohawk” or the Company) filed tariff leaves and supporting testimony and exhibits for new rates and charges for electric and gas service to be effective April 1, 2013. The proposed tariffs were designed to increase electric delivery revenues by approximately \$131 million and gas delivery revenues by approximately \$40 million. The filings were timed such that new rates would become effective contemporaneously with the expiration of an annualized electric surcharge of approximately \$190 million and the elimination of a gas base rate allowance of approximately \$15 million of deferral recovery.

The administrative law judges (“ALJs”) appointed to conduct the rate proceedings and to review Niagara Mohawk’s rate filings held a procedural and technical conference for these proceedings on May 23, 2012.<sup>1</sup> The active parties (“Parties”) engaged in extensive discovery throughout these proceedings. On July 16, 2012, the Company filed corrections and updates

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<sup>1</sup> On May 2, 2012 and August 31, 2012, the Commission issued Orders suspending the effective date of the Company’s new rates until March 23, 2013.

testimony and exhibits to its initial submission. New York State Department of Public Service Staff (Staff), Multiple Intervenors (“MI”), the Public Utility Law Project, and the Utility Intervention Unit of the New York State Department of State (“UIU”) filed testimony addressing the Company’s filing on August 31, 2012. On September 10, 2012, Staff filed certain corrections to its testimony and exhibits. Niagara Mohawk, Staff, MI and UIU filed responsive testimony on September 25, 2012. That same day, the active parties were notified of the commencement of settlement negotiations pursuant to the Commission’s settlement procedures<sup>2</sup> and a formal notice of impending settlement negotiations was filed with the Secretary.

Duly noticed settlement negotiations were held at the Company’s offices in Albany, New York and by telephone conference on October 2, 4, 5, 9, 10, 15, and 29, November 28 and 29, and December 4 and 6, 2012.

On October 17, 2012, the Parties notified the ALJs that an agreement in principle had been reached. After an October 18 conference call with the Parties, the ALJs issued a Ruling Modifying Schedule on October 22, 2012. A comprehensive settlement developed pursuant to, and in accordance with, the Commission’s settlement procedures was reached and a joint proposal by and among Niagara Mohawk Power, Staff, MI, UIU, Retail Energy Supply Association, NYPA and United States Department of Defense (collectively, the “Signatory Parties”) was executed and filed on December 7, 2012. The Signatory Parties believe that this Joint Proposal represents a fair and reasonable resolution of the issues presented in these proceedings.

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<sup>2</sup> 16 NYCRR §3.9.

## **OVERVIEW OF JOINT PROPOSAL**

Staff's Statement in Support demonstrates why the material provisions of the Joint Proposal are in the public interest and should be adopted by the Commission. On balance, the Joint Proposal provides Niagara Mohawk with revenues to meet their reasonable forecast expenses, along with the opportunity for the Company's shareholders to earn a fair return on their investment. Moreover, despite providing necessary increases in revenues to cover growing expenses due to factors such as increased capital spending and inflation, both the Company's gas and electric departments had mechanisms available to moderate their respective increased revenue needs.

For Niagara Mohawk electric, the increased revenue need is offset by the expiration of an expiring annualized surcharge. This offset actually results in a net decrease from current revenue levels for the balance of the three year agreement. For Niagara Mohawk gas, the revenue increase is mitigated through the discontinuance of the recoveries associated with certain gas deferrals. This mitigation provides a net decrease in necessary revenue collection in the first year, when compared to current levels, followed by rate increases (above present levels) in the remaining two years.

The rates provide for capital expenditures necessary to provide safe and adequate service to the Company's customers. The rates also provide the Company with necessary cash flow leverage to borrow, where necessary, financing for its capital investments.

Staff's Statement in Support addresses many of the Joint Proposal's provisions, and is structured such that it generally tracks the provisions of that agreement for ease of reference. To facilitate its use as supporting document, the Staff Statement in Support does not address certain areas of the Joint Proposal where the benefits of the provisions are clearly self-evident. Such

omission should not be read to indicate that Staff has no position on those items, nor should it be understood to indicate that Staff is any less supportive as to the need of including those items in any Recommended Decision or Commission Order. Rather, Staff supports the Joint Proposal as a complete document providing an all encompassing and balanced agreement.

Finally, Staff notes that additional information as to several of Joint Proposal's provisions can be found in the responses to the ALJ's written questions prepared jointly by the Company and Staff that Staff understands will be submitted as an attachment to the Company's Statement in Support.

### **STANDARD OF REVIEW**

The Commission's Settlement Guidelines state that all decisions, including those to adopt the terms of settlement agreements (Joint Proposals) must be just and reasonable and in the public interest.<sup>3</sup> In addition to compliance with proper procedures, determining whether the terms of a Joint Proposal are in the public interest involves substantive consideration of the following:

1. consistency with the law and regulatory, economic, social and environmental State and Commission policies;
2. whether the terms of a Joint Proposal compare favorably with the likely result of a fully litigated case and produces a result within the range of reasonable outcomes;
3. whether a Joint Proposal fairly balances the interests of ratepayers, investors and the long-term soundness of the utility; and,

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<sup>3</sup> Cases 90-M-0225 and 92-M-0138, Opinion, Order and Resolution Adopting Settlement Procedures and Guidelines, Opinion No. 92-2 (issued March 24, 1992), p. 30.

4. whether a Joint Proposal provides a rational basis for the Commission's decision.

Additional consideration is given to the completeness of the record and whether a Joint Proposal is contested. The Settlement Guidelines also explain that the Signatory Parties' burden to show that the agreement compares favorably with a litigated result increases when the record is less developed.<sup>4</sup>

The Joint Proposal entered into in this case resolves all outstanding issues presented in pre-filed testimony and settlement negotiations. In doing so, it fully comports with the Commission's Settlement Guidelines. The fact that seven active Parties have executed the Joint Proposal and no opposition is anticipated from any other active party is a testament to the extensive efforts employed by the Signatory Parties to address key issues and the equitable resolution, comprehensiveness and reasonableness of the Joint Proposal's provisions. Given the interests of the specific parties involved in the negotiations, clearly, the Joint Proposal is an agreement reached among normally adversarial parties. Comparing the pre-filed positions of the Parties to the terms of the Joint Proposal supports the conclusion that the Joint Proposal produces a result within the range that could be expected in litigation. The rate increases under the agreement are significantly lower than what the Company originally sought in its filing.

The Joint Proposal contains various provisions that place a very strong emphasis on Niagara Mohawk managing its costs, and provides enhanced incentives to that end (*e.g.*, the reliability performance and the customer service performance mechanisms). At the same time, Niagara Mohawk will be receiving sufficient additional revenues enabling it to implement new programs and make repairs and improvements to its electric and gas systems to ensure the

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<sup>4</sup> Id., p. 31.

continued provision of safe and reliable service (*e.g.*, the new gas safety metrics mechanism).

Not surprisingly, the Joint Proposal also incorporates reconciliation mechanisms that are characteristic of other Commission adopted rate plans.

In addition, the Joint Proposal recognizes that savings have been and will be realized as a result of Niagara Mohawk's implementation of the recommendations resulting from the Management Audit performed by NorthStar Consulting, Inc. The Joint Proposal's recommended authorized Return on Equity (ROE) of 9.3% per year, is well below the 10.22% ROE requested by Niagara Mohawk in its rebuttal filing and much closer to the 8.9% ROE set forth in Staff's pre-filed testimony.

In sum, the Joint Proposal provides a reasonable resolution of all issues raised by parties in pre-filed testimony and negotiations.

## **ELEMENTS OF THE JOINT PROPOSAL**

### **Section 1. Term of the Rate Plan**

The rate plan contained in the Joint Proposal covers three years with each rate year (RY) comprising a 12-month period. Thus, RY1 is the period April 1, 2013 to March 31, 2014, RY2 is the period April 1, 2014 to March 31, 2015, and RY3 is the period April 1, 2015 to March 31, 2016. Although Staff's direct testimony advocated for a one-year rate plan, the benefits to customers inherent in this negotiated multi-year rate plan warrant Staff's support for this three-year rate plan.

**Section 2. Electric and Gas Revenue Requirements Use of Deferral Credits<sup>5</sup>**

a. **Electric**

1. **Rate Year 1 Base Rate Increase**

As set forth in Exhibit \_\_\_ (SAP-1 Corrected), Staff supported a single year electric base rate increase of \$17.616 million.<sup>6</sup> Staff premised its recommendation on, among other considerations, an 8.9% return on equity and a 6.26% overall after-tax rate of return. On a pre-tax basis, Staff's recommendations equaled a 9.07% rate of return. In comparison, the Company in its rebuttal filing requested a \$119.404 million base rate increase, including a return on equity of 10.22% and a 7.21% overall after-tax rate of return.

The Joint Proposal provides a first year electric base rate increase of \$43.395 million (Section III.2.1). Comparing the Joint Proposal provision to Staff's recommendation, the revenue requirement difference between Staff's litigation position of \$17.616 million and the Joint Proposal position of \$43.395 million is approximately \$25.8 million. This \$25.8 million

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<sup>5</sup> The revenue requirement schedules supporting the first year electric base rate increase of \$43.395 million are provided in Appendix 1, Schedule 1 of the Joint Proposal, and the first year gas base rate decrease of -\$3.290 million are provided in Appendix 1, Schedule 2. The beginning point of those schedules are Exhibits \_\_\_ (SAP-1 Corrected) and \_\_\_ (SAP-2), *i.e.*, the Staff Accounting Panel's pre-filed revenue requirements. Each adjustment agreed to / or conceded in the rate case negotiations that led to the Joint Proposal has been added to the Summary of Adjustments schedule in Appendix 1. This presentation totally eliminates any possibility of problems associated with "black box" types of settlements, as every allowed cost can be traced back to the Company's original filing. The electric and gas revenue requirement schedules for both RY2 and RY3 are also found in Appendix 1, Schedules 1 and 2, with similar Summary of Adjustment schedules supporting the adjustments made from RY1 to RY2, and RY2 to RY3.

<sup>6</sup> On August 31, 2012, Staff submitted its initial direct testimony that included a recommendation for an electric base rate decrease for RY1 of -\$10.763 million (Exhibit \_\_\_ SAP-1). Subsequent to the initial filing, Staff discovered its proposed electric sales forecast adjustment contained within its initial filing was incorrectly computed. On September 10, 2012, Staff submitted its corrected RY1 revenue requirement, recommending instead an electric base rate increase of \$17.616 million (Exhibit \_\_\_ (SAP-1 Corrected)).

difference is made up of adjustments to four main areas – gross margin (a reduction of approximately \$6.0 million); operation and maintenance (O&M) expenses (an increase of \$15.5 million); the change in return on equity from 8.9% to 9.3% (an increase of \$13.5 million); and changes in the long term debt cost rates (an increase of \$2.1 million).

The differences from Staff's litigation position to the final agreed upon settlement position includes both corrections resulting from the Company's rebuttal testimony, as well as settlement compromises. First, in light of arguments put forth in the Company's rebuttal filing, Staff adjusted its sales forecast to be in sync with the Company's forecast, having the impact of decreasing revenue requirement by approximately \$6.0 million. Additionally, accepting some of the arguments made in the Company's rebuttal filing, Staff made corrections and further adjustments to the O&M areas of consultant expense, other expense, rent expense, vegetation management expenses, transportation expense, ex-pat proxy expense, regulatory assessment fees, inflation, and miscellaneous expense, increasing revenue requirement by approximately \$5.5 million. To reach settlement, Staff accepted further adjustments in three main areas of expense – labor capitalization (\$3.0 million), fringe benefits capitalization (\$1.6 million), and uncollectibles expense (\$4.9 million). These adjustments, totaling approximately \$9.5 million, are appropriate when the Company's arguments are balanced against Staff's adjustments and the risks of litigation. For example, the Company's rate year forecast of uncollectible expense (UCB) was calculated by dividing the historic twelve months of net write-offs by revenues to arrive at percentage (UCB rate) and multiplying that rate by Rate Year revenues. (RSSCP at 28-29) In its pre-filed testimony, Staff disagreed with the Company's use of the latest twelve month's information to calculate the rate and instead proposed using a three year aggregate rate. (SAP 74-75) Staff argued that the Company's use of the latest information to calculate a UCB rate is

improper since the current period is impacted by the Company's Transfer-to-Active Program (TAP) and abnormal weather conditions. Staff stated that the use of a three year average rate smoothes over the impacts of TAP and mitigates the abnormal weather conditions. (SAP at 69-70)

In rebuttal, the Company agreed that there was an impact of TAP on the UCB rate and it therefore updated the rate to remove TAP. However, the Company still contended that a one year aggregate rate was appropriate considering the current UCB trend for Niagara Mohawk. Additionally, the Company noted that it stopped collecting CTC revenue at the beginning of 2012. CTCs were largely borne by non-residential customers, which typically have much lower UCBs and therefore drive down the overall UCB rate. As such, all else being equal, the elimination of CTC revenues will, according to the Company, result in an increase the UCB rate going forward. (SSCP Rebuttal at 6-10)

Staff agrees with the Company's assertion that the decrease in CTC revenues will result in an increase in the UCB rate. However, Staff continues to maintain that a multi-year average rate is needed to smooth over the impact of the abnormal conditions in the historic test year. Although Staff believes its position is strong, there is always litigation risk. The Joint Proposal resolves this issue by providing a UCB rate in between the Company's rebuttal rate and Staff's rate. When taken in the context of the entire Joint Proposal, a split of the difference is acceptable.

The remaining \$15.6 million of Joint Proposal base rate increase above Staff's as-adjusted litigated position is related to the allowed return on equity, and a change in the capital structure related to the long term debt cost rates. Staff recommended a 8.9% return on equity. The Company had requested a 10.22% return on equity. The Joint Proposal includes a 9.3%

return on equity. From Staff's perspective, the 0.4% increase in the Joint Proposal's allowed return on equity compared to the Staff recommendation is based upon two considerations: a three year stay-out premium and the additional business risks incorporated onto the three-year agreement. For the long-term debt cost rates, Staff recommended a cost rate of 3.95%, while the Company had requested a cost rate of 4.14%. The Joint Proposal capital structure includes a long term debt cost rate of 4.04%. Staff agreed to an increase from its litigated position because of an error in the cost of debt calculation. These items are further discussed in Section 5 of this Statement in Support.

2. Rate Years 2 and 3 Base Rate Increase

The Joint Proposal provides for agreed upon revenue requirements for electric base rate increases in RY2 of \$51.361 million and RY3 of \$28.342 million. As shown in Appendix 1, Schedule 1, of the Joint Proposal the revenue requirements for both RY2 and RY3 reflect increases in various expenses associated with inflation, with specific forecasts applied to some expenses, significant increases in net utility plant resulting from significant capital spending, and reflection of a decrease in the sales forecast for RY2 and an increase in the sales forecast for RY3.

3. Deferred Credit Offsets

The Joint Proposal provides for projected electric deferred credits of \$16.137 million and \$19.578 million to be applied as an offset to the electric base rate increases in RY1 and RY2, respectively (Section 2.2, and Appendix 1, Schedule 1). The amounts being passed back are intended to achieve consistent revenue increases, or levelized rate increases, from RY1 to RY2, and from RY2 to RY3.

As an alternative to the preferred approach for passing back deferred credits, the Signatory Parties identified an alternative use of the deferral credits that would initially lower revenues at the beginning of the rate plan and keep those revenues constant over the term of the rate plan. (Section III, 3.4.4) While this approach provides for rate stability for customers, it does have drawbacks. Specifically, for the electric business the alternative approach would result in a surcharge in RY 1 of about \$37.9 million, whereas under the preferred approach, customers would be refunded approximately \$16.1 million. The alternate approach also provides for the use of credits in RY 3 of about \$54.9 million, which would expire at the end of the rate plan. The effect of this expiration would be that customer bills would go up by this amount regardless of whether the Company came in for a rate case. Under the preferred approach, there is no use of credits in RY 3, thus no automatic increase will result when the rate plan expires. Overall, the preferred approach passes credits back to customers more quickly and does not result in a rate increase at the rate plan's expiration as compared to the alternative approach. Because of these two important aspects, Staff believes customers would be better off with the use to the preferred approach and, therefore, recommends its adoption.

**b. Gas**

1. Rate Year 1 Base Rate Increase

As set forth in Exhibit \_\_\_ (SAP-2), Staff supported a single year gas base rate decrease of -\$12.604 million. Similar to the electric base rate increase, Staff premised its recommendation on, among other considerations, an 8.9% return on equity and a 6.26% overall after-tax rate of return. On a pre-tax basis, Staff's recommendations equaled a 9.07% rate of return. In comparison, the Company in its rebuttal filing requested a \$22.520 million base rate increase, including a return on equity of 10.22% and a 7.21% overall after-tax rate of return.

The Joint Proposal calls for a first year electric base rate decrease of -\$3.290 million (Section III.2.1). Comparing the Joint Proposal provision to Staff's recommendation, the revenue requirement difference between Staff's litigation position of -\$12.604 million and the Joint Proposal's -\$3.290 million position is approximately \$9.3 million. This \$9.3 million difference is made up of adjustments to four main areas – O&M expenses (an increase of \$3.7 million), property taxes (an increase of \$1.3 million), change in return on equity from 8.9% to 9.3% (an increase of \$3.6 million), and changes in the long term debt cost rates (an increase of \$0.6 million).

Again, the differences from Staff's litigation position to the final agreed upon settlement includes both corrections resulting from the Company's rebuttal testimony, as well as concessions based on an assessment of litigation risk and the benefits encompassed in this three year rate plan. First, in light of further support for certain positions put forth in the Company's rebuttal filing, Staff made corrections and further adjustments to the O&M areas of consultant expense, other expense, rent expense, transportation expense, ex-pat proxy expense, and inflation, thereby increasing revenue requirement by approximately \$1.3 million. Offsetting these adjustments was a reduction of \$1.5 million to adjust the alternative fuel vehicle grant. In addition, an adjustment was made to increase the property tax expense by \$1.3 million to correct for an incorrect allocation to gas operations. Staff accepted further adjustments in three main areas of expense – labor capitalization (\$0.6 million), fringe benefits capitalization (\$0.3 million), and uncollectibles expense (\$2.7 million). These adjustments, totaling approximately \$3.6 million, are appropriate when balanced against the Company's arguments, and the risks of litigation.

The remaining \$4.2 million of Joint Proposal base rate increase above Staff's as-adjusted litigated position is related to the allowed return on equity (\$3.6 million) and a change in the capital structure related to the long term debt cost rates (\$0.6 million). Staff recommended a 8.9% return on equity. The Company had requested a 10.22% return on equity. The Joint Proposal includes a 9.3% return on equity. As with the electric case, the 0.4% increase in the Joint Proposal's allowed return on equity compared to the Staff recommendation is based upon two considerations: a three year stay-out premium and the additional business risks incorporated into the three-year agreement. For the long-term debt cost rates, Staff recommended a cost rate of 3.95%, while the Company had requested a cost rate of 4.14%. The Joint Proposal capital structure includes a long term debt cost rate of 4.04%. Staff agreed to an increase from its litigated position because of an error in the cost of debt calculation. These items are further discussed in Section 5 of this Statement in Support.

2. Rate Years 2 and 3 Base Rate Increase

The Joint Proposal provides for agreed upon revenue requirements for gas base rate increases in RY2 of \$5.854 million and RY3 of \$6.268 million. As shown in Appendix 1, Schedule 2, the revenue requirements for both RY2 and RY3 reflect increases in various expenses associated with inflation, with specific forecasts applied to some expenses, and significant increases in net utility plant resulting from significant capital spending.

3. Deferred Credit Offsets

The Joint Proposal provides for projected gas deferred credits of \$21.990 million and \$10.788 million to be applied to the gas base rate decrease in RY1 and the gas base rate increase in RY2, respectively (Section 2.2, and Appendix 1, Schedule 2). The amounts being passed back

are intended to achieve consistent revenue increases, or levelized rate increases, from RY1 to RY2, and from RY2 to RY3.

As was provided for the electric business, the Signatory Parties identified an alternative approach for passing back deferred credits for the gas business that would lower revenues at the beginning of the rate plan and keep those revenues constant over the term of the rate plan.

(Section III, 4.4.3) Again, while this approach provides for rate stability for customers, it has drawbacks and should not be adopted by the Commission. Specifically, for the gas business the alternative approach would result in a credit in RY 1 of about \$3.7 million, whereas under the preferred approach, customers would be refunded approximately \$22.0 million. The alternate proposal also provides for the use of credits in RY 3 of about \$18.1 million, which would expire at the end of the rate plan, the effect of which would be that customers bills would go up by this amount regardless of whether the Company came in for a rate case. Under the preferred approach, there is no use of credits in RY 3, thus no automatic increase will result when the rate plan expires. Overall, the preferred approach passes credits back to customers more quickly and does not result in a rate increase at the rate plan's expiration as compared to the alternative approach. Because of these two important aspects, Staff believes customers would be better off with the use to the preferred approach and, therefore, recommends its adoption.

**c. US Restructuring Savings**

The Company's US Restructuring Program savings are reflected in all three rate years of the Joint Proposal, and are comprised of both labor and non-labor savings. Throughout the historic year, and up to the beginning of the rate year, National Grid will have eliminated over 1400 positions. The expected labor savings from the US Restructuring Program are reflected in the Rate Year forecast of the labor expense component. National Grid, in its Corrections &

Updates filing, estimated it would achieve approximately \$68.996 million of annual non-labor savings by March 31, 2013. (Exhibit \_\_ (RRP-11CU), Schedule 48) Niagara Mohawk's allocated share of the non-labor savings was determined to be \$20.925 million (\$17.618 million electric; \$3.307 million gas). Of the \$20.925 million allocable to Niagara Mohawk, it was estimated that \$7.220 million (\$6.186 million electric; \$1.034 million gas) of non-labor savings had been achieved and reflected in the actual historic test year costs, and thus inherent in the rate year forecast. The Company reflected an adjustment in RY1 for the remaining \$14.291 million (\$11.921 million electric; \$2.370 million gas) of non-labor savings.

Staff, in its pre-filed testimony, increased the Company's RY1 projection by \$0.540 million (\$0.440 million electric, \$0.100 million gas) for additional initiative savings that were not reflected in the Company's savings calculation. (SAP at 78) The Joint Proposal reflects Staff's modifications for RY1, and additional amounts for inflation in RY2 and RY3.

**d. E&Y Analysis**

The Company hired Ernst and Young (E&Y) to review the accounting for costs charged from the service companies to Niagara Mohawk during the historic test year. E&Y reviewed O&M charges to determine (1) if the charges were incurred in the historic test year; (2) if the charges were made to the appropriate companies and segments; (3) if allocated, if the appropriate bill pool was used; and (4) if the charges should have been below the line for ratemaking purposes. (Service Company Panel at 29-31) As a result of this analysis, the Company increased its rate year electric expenses by \$2.420 million and reduced its rate year gas expenses by \$.673 million. (Service Company Panel at 29-31) Staff disagreed with the Company's analysis stating that study was not reasonably representative, unbiased or statistically valid due to problems with E&Y's sampling methodology. (Schuler at 37-40) Additionally, Staff showed

that E&Y only examined a fraction of the costs it claimed to have reviewed and therefore removed the Company's adjustments. (SAP at 80-88). In rebuttal, the Company noted its disagreement with Staff. (Michael Barret Rebuttal at 2-3) The Joint Proposal reflects staff's recommendations in their entirety and the increase of \$2.420 million for electric and the reduction of \$.673 million for gas were removed from the rate year forecast.

**e. Revenue Requirement Conclusion**

From both the electric and gas revenue requirement perspectives the Joint Proposal is clearly in the public interest. The Joint Proposal reflects the strength of the Staff case as the Joint Proposal contains few concessions in terms of electric revenue requirement in RY1 of the \$43.395 million electric base rate increase, especially when compared with the \$76 million decrease from the Company's rebuttal position of a \$119.404 million electric base rate increase. Similarly, the Joint Proposal's - \$3.290 gas base rate decrease compares favorably with Staff's litigated position of a RY1 gas base rate decrease of -\$12.604 million, versus the Company's rebuttal position of a gas base rate increase of \$22.520 million. For these reasons and the reasons stated above, Staff supports adoption of the Joint Proposal's revenue requirement provisions.

**Section 3. Electric Revenue Allocation and Rate Design**

**a. Electric and Lighting Revenue Allocation (Section III, 3.2)**

Niagara Mohawk filed a pro-forma embedded cost of service study (ECOSS) to support its revenue allocation and rate design proposal (Exhibit (E-RDP-1)). The ECOSS allocates the Company's operating costs to the different service customer classes based on an analysis of the forecast rate base and operating expenses associated with each service class for rate year ending March 31, 2014. The Company first used the ECOSS output for its revenue allocation by

realigning the current revenue collection among the existing rates so that each rate class moved one-third of the way toward eliminating its surplus or deficiency compared to the system average return. Then it allocated the total increase in revenue collection across all the rate classes, in the same proportion as the realigned current revenue collection mitigating any extreme rate impacts by adjusting class revenues such that no class would experience a rate increase greater than 1.5 times the system average.

In its testimony, Staff proposed using historic test year information as the basis for the ECOSS and also recommended that line transformer plant account (Account 368) and related accounts be classified and allocated using a zero-intercept approach, as was done for other distribution plan accounts. (Staff Electric Rates Panel (ERP) – Corrected at 7-13) The Staff method of revenue allocation was the same as the Company, save that Staff relied on data from the historic test year.

MI recommended modifying the Company ECOSS by allocating the primary and secondary distribution system to the demand and customer components of rates in the same proportions. MI also recommended that distribution load dispatching costs (Account 581) be allocated on the basis of non-coincident peak and that none of the costs be allocated to the service class (“SC”) 3/3A customers taking service at sub-transmission or transmission level and proposed using its own proposed alternative ECOSS as a guide in revenue allocation. (Pollack at 9-17 and 37-39)

All three ECOS studies revealed that the relative rate of return (RROR) for SC-1 was below 1.0 and that certain service classes, SC-1C, SC-2ND, SC-2D, SC-3 Secondary, SC-3 Primary and Street Lighting, all produced RRORs above 1.0. To maintain a balance and move each service class RROR toward the system rate of return, the Joint Proposal allocates 1.25 times

the system-average increase for SC-1; 0.75 times the system-average increase to SC-2D, SC-3 Secondary and SC-3 Primary and a system average increase for SC-3 Transmission/Subtransmission, SC-3A Secondary/Primary, SC-3A Subtransmission and SC-3A Transmission. Any extra revenues were then returned to all classes on a delivery revenue basis. All classes were allocated system-average increases for Rate Year 2 and 3. The Joint Proposal provides a reasonable outcome for the equitable allocation of incremental revenue requirement based on the outcome of three ECOS studies. This provision is reasonable because it moves all classes toward the system average while insuring that no class experiences a rate increase greater than 1.5 times the system average.

**b. Electric and Lighting Rate Design (Section III, 3.3)**

The rate design set forth in the Joint Proposal is essentially the same as that proposed by Niagara Mohawk with adjustment to the SC-1, SC-3A secondary/primary and SC-3A transmission customer charges. The current customer charges for those classes are: \$16.21; \$902.00; \$3,172.00, respectively. The Company proposed a minimum charge of \$17 for SC1, which is consistent with the results of the Marginal Costs of Service Study. MI proposed increased customer charges of \$1,000.00 for SC-3A secondary/primary and \$3,500 for SC-3A transmission customers, which are more in line with the ECOSS results.

Under the Joint Proposal, base delivery rates will increase 3.26% on average for the first rate year. As shown on Joint Proposal Appendix 2, Schedule 3, the increases consist of 3.88% for SC-1 Residential Service, 1.86% for SC-2 Small General Service, and 2.33% SC-3 Large General Service.

Overall, the Joint Proposal provides for the equitable allocation of incremental revenue requirement premised upon established cost of service principles while tempered to mitigate customers' impacts.

**c. Revenue Decoupling Mechanism ("RDM") (Section III, 3.5)**

New York's Gas and Electric utilities are provided with an RDM primarily to remove any disincentive a utility might otherwise have to provide less than complete support for their customers to implement energy efficiency measures. At its basic level, an RDM provides the utility with a mechanism to recover lost revenues associated with decreased energy use from energy efficiency programs and measures. This mechanism calculates the lost revenue and allows the Company to collect it across all customers subject to the RDM.

The Company's current RDM reconciles actual billed delivery service revenues to annual target revenues for the RDM reconciliation period. The reconciliation groups are: 1) SC-1 and SC-1C, 2) SC-2ND, 3) SC-2D, 4) SC-3 and 5) SC-3A. The SC-4 and SC-7 customers are also included in RDM as part of their parent service classification, while SC-11, SC-12, NYPA load, Qualifying EZR load, and Outdoor Lighting customers are exempt from the RDM.

Staff supports the modifications that the Joint Proposal makes to the Company's RDM. The Company reconciles its RDM on a rate year basis. The Company's rate year is moving from mirroring the calendar year to aligning with its fiscal year, and the Company will, under the Joint Proposal, reconcile the hanging period, January 1, 2013 through March 31, 2013, that is created by this move. Empire Zone Rider (EZR) customers will be included in the RDM in the class to which they belong, but they will not be subject to an RDM charge or credit on the EZR portion of their loads.

The SC-12 customers will now be included in the RDM reconciliation group for their parent service classification. These SC-12 customers contribute toward energy efficiency programs and have an appropriate incentive to implement cost-effective energy efficiency measures. Therefore, it is reasonable to include them in the RDM reconciliation group for their parent service classification. These minor changes to the RDM are reasonable in that they further the Commission's goals of promoting energy efficiency while reducing any disincentive the Company may have to support such efficiency where measures might otherwise decrease Company revenues.

**d. Merchant Function Charge - Electric ("MFC") (Section III, 3.6)**

In its testimony, the Company proposed to 1) update its Merchant Function Charge by using the results from the Company's Embedded Cost of Service Study (ECOSS) to determine its commodity Credits and Collections and Electric Supply Procurement; 2) exempt SC-12 customers from both Credits and Collections and Uncollectible charges; and 3) set the uncollectible rate of 2.06%, 0.23% and 0.22% for non-demand, demand, and street lighting, respectively, using test year data.

Staff's position in testimony agreed with the Company to exempt SC-12 from both Credits and Collections and Uncollectible charges and to use the results of the ECOSS to set the targets for credits and collections and Supply procurement (Staff Electric Rates Panel at 19-20). Staff, however, proposed to set the uncollectible rates using the average data of the most recent three years (Staff Electric Rates Panel at 19-20). The uncollectible rates would be set at 2.054%, 0.2488%, and 0.1250% for non-demand, demand, and street lighting, respectively. Staff also proposes to use the Commission's "Other Customer Capital Rate" as oppose to the Company's

weighted average cost of capital to determine to return requirement for commodity purchases (Staff Electric Rates Panel at 20-23).

The Joint Proposal adopts the Company's position to exempt SC-12 from Credits and Collections and Uncollectible. This position is fair because SC-12 customers do not incur any Credit and Collections and Uncollectible costs because have agreed to stay current with their payments, and should they be late, they would be reclassified to a different service class. The adoption of the ECOSS to set the targets for Credits and Collections and Supply Procurement is fair because it uses historic data as the basis for those targets. The Joint Proposal continues the Company's current method of calculation the return requirement for working capital using the Company's weighted average cost of capital. This difference in the rate applied is a compromise position which allowed the parties to reach an overall settlement agreement and is reasonable on balance given all the surrounding terms contained in the Joint Proposal.

**e. Miscellaneous Electric and Lighting Provisions (Section III, 3.7)**

The Joint Proposal requires the Company to make a number of tariff changes that effectuate various provisions of the Joint Proposal that were not disputed by the Parties. Staff supports those changes as described in the Joint Proposal.

**Section 4. Gas Revenue Allocation and Rate Design**

**a. Embedded Cost of Service Study and Gas Revenue Allocation**

Niagara Mohawk filed an embedded cost of service study (ECOSS) to support its revenue allocation and rate design proposal. In its ECOSS, the Company classified distribution mains using the results of a zero intercept methodology, essentially allocating 45.5% of the costs of distribution mains to the customer component and 54.5% of the costs to the demand component. Niagara Mohawk also provided results of its ECOSS with its distribution mains classified as

100% demand for purposes of determining minimum customer costs to be used as a guide in setting the minimum monthly delivery service charges.

In its testimony, MI recognized that the Company's ECOSS generally conforms to industry practice, but identifies two disputed issues related to cost-of-service. MI testified that the Company's ECOSS was flawed in that it classifies gas distribution load dispatching expense and sales expenses to commodity, while such gas distribution load dispatching expenses should instead be classified to demand and then allocated to customer classes relative to peak day delivery, and that sales expenses should be classified as customer-related and then allocated to sales customers only.

Staff testified to modifications for the Company's zero intercept methodology and used the results to classify distribution mains as 70% demand-related and 30% customer related. (Staff Gas Rates Panel at 12-15) Staff did agree with the Company's proposal to use the results of the ECOSS with distribution mains classified as 100% demand to more closely identify the minimum customer costs for each service classification.

All three proposals, the Company's, Staff's and MI's, use a combination of two of several possible methods for classifying distribution main costs as outlined in the National Association of Regulatory Utility Commissioners Gas Distribution Rate Design Manual (NARUC Rate Design Manual). Staff primarily was concerned that under the Company's proposal not enough of the distribution mains costs were classified as demand-related costs, thus creating an inequity for smaller use customers. As the NARUC Rate Design Manual suggests, there is no definitive way to classify distribution main costs. Instead, classification of these costs is often a judgment call, as indicated by the numerous methods favorably described as alternatives in the NARUC Rate Design Manual.

The Joint Proposal does not favor any party's particular ECOSS. Within all three studies, the resulting rates of return varied somewhat significantly between service classifications. The results of the three ECOS studies were consistent in that certain service classifications were overearning while the remaining service classifications were underearning. Specifically, the three different ECOSS results each demonstrated that firm customer classes SC-2, SC-3, SC-7, and SC-12&13 all produced relative rates of return well above 1.0, while the rest of the firm customer classes were below 1.0.

The Joint Proposal resolution is reasonable because the revenue allocation agreed upon uses a blend of the results of all of the parties' ECOS studies that fairly falls within the range established by the parties' positions. In the case of rate design, seeking to achieve such a balance between costs that can be fairly attributed to any customer use versus those additional costs that may be driven by larger customer demands is a reasonable result.

The allocation of the entire revenue reduction for Rate Year One to SC-2, SC-3, and SC-7 only on a pro rata basis proportionate to delivery revenues, while the remaining firm classes' revenues from base rates are frozen and unchanged, is consistent with the results of all three ECOS studies in this case. The three studies all recognize that SC-2, SC-3, and SC-7 rates of return were well above the system average rate of return and, therefore, should be allocated the entire decrease in order to move rates toward aligning them with their respective cost of service. For Rate Years Two and Three, the parties agreed that any incremental revenue requirement would be allocated to the service classes as set forth in Appendix 3, Schedules 5.3 and 6.3 of the Joint Proposal, respectively. Staff believes that overall, the Joint Proposal provides for an equitable allocation of the Rate Year One revenue decrease as well as the incremental revenue requirement for Rate Years Two and Three premised upon proper cost of service principles.

**b. Gas Rate Design (Section III, 4.3)**

Consistent with Commission policy, gas delivery rates have been designed to implement the incremental revenue requirement with fully unbundled rates for natural gas delivery, natural gas supply, and billing and payment processing services while also considering customer bill impacts.

The rate design set forth in the Joint Proposal is essentially the same as that proposed by Niagara Mohawk with some further adjustments to the monthly minimum delivery service charges. Niagara Mohawk proposed a minimum charge of \$20.35 for SC-1. Staff proposed a minimum charge of \$18.00 for SC-1 (excluding the additional surcharge added to fund the low income discount program). The Joint Proposal recommends that the minimum charge for SC-1 be set at \$20.35 (inclusive of the surcharge that funds the low income discount program).

The Joint Proposal includes a provision that the total SC-1 monthly minimum delivery service charge remain at \$20.35 (including the surcharge added to fund the low income discount program) in both Rate Years Two and Three. Maintaining the monthly minimum delivery service charge at \$20.35 in Rate Years Two and Three is reasonable because it mitigates the SC-1 bill impacts due to the increases over the second and third Rate Years, while keeping the monthly minimum delivery service charge at the approximate level of the minimum cost of service for SC-1 customers.

For SC-5 and SC-8, the base customer charges will increase at the same percentage as the increase to the volumetric block rates in Rate Years Two and Three. The total monthly minimum delivery service charges for SC-5 and SC-8 would be the sum of the base customer charge and the surcharge that funds the low income discount program for the corresponding Rate Year. Increasing the base customer charges for SC-5 and SC-8 is reasonable because it moves

the base customer charges incrementally toward alignment with each class's minimum cost of service.

For service classes other than SC-1, SC-5, and SC-8, the base customer charges for Rate Years Two and Three will remain at the Rate Year One levels and the total monthly minimum delivery service charge will be equal to that base customer charge plus the surcharge adder to fund the low income discount program in that year. These base customer charges are set such that they are relatively in line with the results of the Company's unit cost analysis. Details of the customer charges for Rate Years One, Two, and Three are listed in Appendix 3, Schedules 4.4, 5.4, and 6.4 of the Joint Proposal, respectively.

**c. Low Income Discount Program – Rate Design (Section III, 4.5)**

The Company proposed to modify the current rate design for collecting the revenues to fund the low income discount program. The Company's rate design proposal accounted for the funding of the low income discount program by increasing rates to all blocks as opposed to the current surcharge adder included in the monthly minimum delivery service charge.

Staff proposed to continue funding the low income discount program via the surcharge adder method, in order to maintain the continuity from the current rate design and to more easily track the total actual funding for reconciliation purposes.

The Joint Proposal adopts Staff's proposal to continue funding the low income discount program through a surcharge adder that is included in all firm customer monthly minimum delivery service charges, with the exception of SC 9 (Special Contracts) and SC 10 (Natural Gas Vehicle Service).

**d. Lost and Unaccounted For (LAUF) Gas (Section III, 4.6)**

New York gas utilities reconcile their purchased gas costs to their recoveries for such costs annually. When making such reconciliation, the utility's annual cost of gas is determined by adding to its actual costs a Fixed Factor of Adjustment (FOA). The addition of an FOA is based on the recognition that the utility will experience some amount of unaccounted for gas losses on its system. Staff's goal in a rate proceeding is to set the FOA at a level that provides an incentive to the Company to keep its LAUF at acceptably low levels without being punitive, recognizing that utilities can take some action to minimize sources of LAUF gas. Ultimately, to the extent that the Company's lost gas exceeds its FOA, the Company absorbs the extra costs. Conversely, where the Company's lost gas is under the FOA, it benefits by retaining the extra revenue collected to cover the forecasted actual costs plus the FOA. Staff's draft LAUF White Paper, issued on January 27, 2012, recognizes that recent historic multi-year averages have become relatively stable suggesting that New York's gas utilities are approaching optimum performance in minimizing LAUF. Accordingly, Staff drafted the LAUF white paper, among other goals, to remove the financial volatility caused by year to year variations based on data collection measured against the FOA (Staff White Paper on Lost and Unaccounted For (LAUF) Gas at 6-7).

In its testimony, the Company proposed changes to its LAUF mechanism consistent with the recommendations contained in Staff's draft LAUF White Paper. The Joint Proposal adopts the Company's proposal to set its FOA at 1.01841 along with several other proposed modifications to the current LAUF incentive mechanism. The LAUF target in the Joint Proposal is reasonable because it was developed using actual experience in the most recent five year period using the calculation methodology contained in Staff's draft LAUF white paper.

The Company also proposed to implement a dead band around the FOA to further minimize the effects of de minimis data collection errors. The Company's dead band provides an upper band of 2.261% and lower band of 1.429%. If the actual FOA is within the dead band, the difference between the actual FOA and the fixed FOA will be surcharged or refunded to both transportation and sales customers. Staff believes the Company's proposal is reasonable because the dead band will reduce the Company's financial risk while still keeps the incentive to keep gas lost to a minimum. In addition, both firm and transportation customers will be equitably surcharged or refunded for the Company's performance on LAUF.

**e. Merchant Function Charge ("MFC") (Section III, 4.7)**

The Company's current Merchant Function Charge (MFC) is a mechanism designed to recover the costs associated with supply procurement, commodity-related credit and collection expenses, commodity-related uncollectible account expenses, and the return requirement on storage gas. The Company proposes to make four modifications to its current mechanism for gas operations: expanding MFC to include SC-3, calculating the return requirement on gas storage using actual storage gas inventory rather than a preset target, reconciling the Company's recovery of the commodity-related credits and collections expenses to an annual target, and implementing a new surcharge to recover the return requirement on working capital for the purchased gas.

Staff agreed with the Company's proposed changes to the MFC, however, Staff also recommended some additional modifications to the Company's proposals. Staff proposed to apply the Commission's "Other Customer Capital" rate when calculating the return requirement on gas storage and working capital for the purchased gas.

The Joint Proposal adopts the Company's proposals to expand MFC to include SC-3, to use the actual storage gas inventory to calculate the return on storage, to reconcile the Credits and Collections to an annual target and to implement a surcharge for the return requirement on working capital for gas. In addition, the Joint Proposal continues the Company's current method to calculate the return requirement on gas storage and working capital for purchased gas using the Company's weighted average cost of capital. Staff supports the Joint Proposal result because it is reasonable. It does result in a position different than Staff's as to the rate to be applied, with the Company continuing its present practice, which, although not necessarily the optimal rate in Staff's view, is an allowable rate. Given the concessions made by the Company on other issues, the overall product results in a balanced agreement.

**f. Revenue Decoupling Mechanism ("RDM") (Section III, 4.9)**

In the Company's direct testimony, it proposed to modify the calculation of the revenue per customer ("RPC") targets and actual delivery service revenues to discontinue excluding the customer charges associated with the low income discount program. Currently, the RPC targets and actual revenues are adjusted to remove the effects of the low income discount program by excluding the discount, as well as the surcharge adder to fund the program. The delivery service revenues that the Company tracks against the RPC targets are then correspondingly adjusted to exclude the program discounts and surcharge adders. The Company's position to modify the RDM was directly related to their position to change the way in which the low income discount program was funded through rate design.

Staff disagreed with the Company's proposal to modify the current RPC targets in the RDM, based on Staff's low income discount program rate design proposal. Staff proposed to continue the existing RDM, to update the RPC targets based on the forecast revenues and

customer counts, and for the Company to provide information for a materiality review in each of their annual RDM reconciliation filings. Staff wanted the materiality information so that if the 5% materiality standard is exceeded, that the Company would have to further provide an analysis of the reasons for the deviations from the forecast and a proposal to modify the RDM mechanism and targets.

The Staff proposal regarding materiality was based on the Commission's Order in Case 09-G-0716 and 09-G-0718, issued August 20, 2012. In that<sup>7</sup> August 20, 2012, Order, the Commission indicated that under certain circumstances where an RDM impact is unrelated to energy efficiency incentives and is material in nature, whether positive or negative to the utility or ratepayers, the RDM design and targets may require modification to provide for the equitable treatment of either utility or ratepayer interest.

The Joint Proposal adopts Staff's proposal related to RDM furthering the Commission's goal of achieving equitable treatment of utility and ratepayer interests.

**g. Statements to be Eliminated and Tariff Modifications (Section III, 4.10)**

The Company proposed to make modifications to its tariff and eliminate certain Statements to streamline and reduce what it viewed as superfluous tariff filing and updating requirements.

Specifically, the Company proposed to eliminate updating and filing the following statements:

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<sup>7</sup> Case 09-G-0716 et al., Proceeding on Motion of the Commission as to the Rates, Charges, Rules and Regulations of New York State Electric and Gas Corporation for Gas Service, Order Modifying Gas Revenue Decoupling Mechanisms and Establishing Further Procedures (issued August 20, 2012).

- 1) Statement of Appliance Repair. In Case 93-G-0804,<sup>8</sup> the Commission ordered utilities to discontinue providing appliance repair services to customers, however, it allowed utilities to continue to provide minor “screwdriver repairs” to customers’ appliances at no direct charge. Parts replacement would not fall under “screwdriver repairs,” with the exception of thermocouple replacement that could be replaced at a charge to the customer. Subsequently, the Company filed the AR Statement to set such a charge. The Company proposed to replace thermocouples at no charge to customers, as the work is incidental to other work performed in response to no heat and/or gas odor complaints. The Company proposed to simply recover these immaterial expenses through delivery rates. As there is but a negligible impact, as only 13 were replaced in 2010 and 10 in 2011, the Company proposal is reasonable and included in the Joint Proposal.
- 2) Statement of Inspection Fee. Customers that install gas-fired emergency generators are required to pay an inspection fee to the Company in addition to the costs associated with meter installation, system reinforcement, mains, and service lines. The inspection fee is listed separately on the Inspection Fee Statement. The Company has found that it does not incur any incremental costs for this inspection over and above those costs to construct reinforcement and install mains, service lines and meters. Thus, the Company proposed to eliminate this fee altogether and the tariff statement associated with it. This proposal was included in the Joint Proposal because the lack of any incremental costs negate the need for a statement to be produced.

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<sup>8</sup> CASE 93-G-0804 - Proceeding on Motion of the Commission to Examine Guidelines for Gas Utility Marketing/Appliance Service Programs. Order Concerning Gas Appliance and Repair Service (issued April 4, 1997)

- 3) Statement of Balancing Services Cost Recovery (BSCR). The Company filed BSCR Statement was implemented in September 2000 for the purpose of recovering incremental costs associated with information services needed to provide marketers with new monthly balancing services. These incremental costs have been fully recovered, so this charge is no longer needed. Therefore, the Company's proposal to eliminate the Statement is adopted in the Joint Proposal as it is not expected to have any cost recovery to report.
- 4) Statement of Late Payment Charge Refund/Surcharge. This credit/surcharge sets a monthly adjustment to gas commodity-related late payment charges applicable to firm sales customers in SC-1, SC-2, and SC-3 based on estimated monthly late payment charge revenues versus the late payment charge revenues already built into the revenue requirement. The Company proposed to eliminate this statement due to the de minimis (0.06% historic year, or \$0.69 net surcharge in historic year for typical residential heat customers) impact on customers. Staff agrees that the impact is minimal and that the statement is not necessary.

The Company also proposed the following modifications to tariff services, fees, and provisions:

- 1) Terminate SC-4. SC-4 is a grandfathered service class that has not been available to new customers since June 1996 and no longer has any customers. There is no reason to maintain a service classification to which no customers belong.
- 2) Eliminate SC-3 ratchet provision such that SC-3 customers delivery service rates would be based on the customers' actual monthly usage, aligning SC-3 with other transportation service classes, SC-6, SC-7, and SC-8. As there is no reason why SC-3 customers should

be singled out from other transportation only customers for a ratchet, rather than being billed for actual monthly usage, the Company's proposal is reasonable.

- 3) Implement a monthly imbalance adjustment to the monthly cost of gas (MCG) to prevent large gas cost over/under collections from accruing. Pursuant to NYCRR 720-6.5, utilities are permitted to implement refunds or surcharges each gas cost year to minimize year end over or under collections. The Company proposed to implement, as needed, a monthly gas cost imbalance surcharge or refund no earlier than October 1 and no later than July 31 to minimize such gas cost imbalances. The Company's proposal is in line with Commission regulations.

Staff agrees that these tariff modifications, as proposed by the Company, are reasonable in that they will reduce a number of immaterial tariff filings and updates lessening the administrative burden on the Company while having no effect on its ability to continue to provide safe and adequate service.<sup>9</sup>

## **Section 5. Computation and Disposition of Excess Earnings**

### **a. Rate of Return**

On April 27, 2012, Niagara Mohawk submitted testimony requesting an overall after-tax rate of return of 7.38% and 10.95% pre-tax return for a one-year rate plan ending March 31, 2014. Staff filed testimony on August 31, 2012 recommending an after-tax rate of return of 6.26% and a corresponding pre-tax rate of return of 9.07%. The difference between Staff's recommendation and the Company's request resulted from:

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<sup>9</sup> Additional information on these tariff modifications are provided in the joint response to ALJ question on 4.10 appended to the Company's Statement in Support.

1. A staff recommended 8.9% return on common equity (“ROE”) versus Niagara Mohawk’s request for a pre-filed ROE of 10.55% allowance (updated to 10.22% in Company’s rebuttal),
2. A Staff recommended capital structure utilizing a 48.00% common equity ratio versus Niagara Mohawk’s proposed pro forma stand-alone equity ratio of 51.4% or in the alternative National Grid plc’s 50.7% common equity ratio, and
3. A recommended 3.95% (later revised to 4.08%) cost of debt as opposed to Niagara Mohawk’s estimate of 4.14%.

Staff’s recommended 8.9% return on equity was calculated based upon the Commission’s well-established cost of equity methodology of employing a two-third/one third weighting of the discounted cash flow model (DCF) and the capital pricing model (CAPM) applied to a surrogate group of companies. The Joint Proposal adopts in large part Staff’s methodology regarding the calculation of the rate of return for Niagara Mohawk with an allowance made for the Company’s acceptance of some terms that increase its potential exposure and then includes a stay-out premium for the three-year term of the rate plan that specifically recognizes the increase in risk facing the Company while it stays out.

**b. Capital Structure (Section III, 5.2)**

Niagara Mohawk’s requested common equity ratio was based upon an estimate of its stand-alone rate year capital structure. As an alternative, the Company proposed that if the Commission chooses to consider using National Grid plc’s capital structure, then a common equity ratio of 50.7% is appropriate. The 50.7% figure was based on the parent’s common equity ratio under United States Generally Accepted Accounting Principles (US GAAP) adjusted for regulatory asset value (RAV) as of March 31, 2011.

Due to the concern of the presence of double leverage in National Grid plc's financing of Niagara Mohawk, Staff rejected the Company's proposed standalone capital structure. Double-leverage occurs when a parent company issued debt to fund the equity of its subsidiary. In instances of double leverage, the Commission generally uses either the parent company's capital structure or a hypothetical capital structure to estimate the subsidiary's cost of capital.

Staff also rejected the use of National Grid plc's RAV adjusted equity ratio to establish Niagara Mohawk's capital structure. Instead, Staff proposed a 48.00% common equity ratio and demonstrated that the 48.00% ratio produces overall financial parameters supporting the Company's A-/A3 credit rating and is reasonable, cost effective and does not burden ratepayers with excessive costs.

Staff's recommendation is consistent with the methodology used by the Commission in Niagara Mohawk's 2010 electric rate case (Case10-E-0050). Moreover, the 48.00% common equity ratio is similar to that found in recent past rate cases including Cases 09-E-0715, 09-G-0716, 09-E-0717, and 09-G-0718 for NYSEG/RG&E, Cases 09-E-0588, 09-G-0589 for Central Hudson and Cases 10-E-0362 and 11-E-0408 for Orange & Rockland Utilities, Inc.<sup>10</sup> The Joint Proposal reflects Staff's recommended 48.00% equity ratio.

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<sup>10</sup> Case 09-E-0715 et.al. - Proceeding on Motion of the Commission as to the Rates, Charges, Rules and Regulations of New York State Electric & Gas Corporation for Electric and Gas Service, Order Establishing Rate Plan (issued September 1, 2010). Cases 09-E-0715 et.al., *supra*; Case 09-E-0588et. al. Proceeding on Motion of the Commission as to the Rates, Charges, Rules and Regulations of Central Hudson Gas & Electric Corporation for Electric Service, Order Establishing Rate Plan (issued June 18, 2010); Case 10-E-0362 -Proceeding on Motion of the Commission as to the Rates, Charges, Rules and Regulations of Orange and Rockland Utilities, Inc. for Electric Service, Order Establishing Rates For Electric Service (issued June 17, 2011); Case 11-E-0408 -Proceeding on Motion of the Commission as to the Rates, Charges, Rules and Regulations of Orange and Rockland Utilities, Inc. for Electric Service, Order Adopting Terms Of Joint Proposal, With Modification, And Establishing Electric Rate Plan (issued June 15, 2012)

**c. Cost of Long-Term Debt**

The Joint Proposal reflects an embedded cost rate of long-term debt of 4.04%, 4.32%, and 4.82% in rate year one, two, and three respectively. There are two components of Niagara Mohawk's rate year long-term debt that required estimates of cost rates. The first component is the approximately \$575 million of auction rate NYSERDA tax exempt debt for Rate Year One and \$529 million for Rate Years Two and Three. The interest rate on this debt is established through a series of auctions during the three-year term of the Joint Proposal.

Due to the current uncertainty in the financial markets, buyers have not offered to purchase the bonds and the auctions have been failing. When an auction fails, the interest rate of the bonds are established based upon a percentage of the then existing LIBOR rate. Given the uncertainty of future LIBOR rates and the prospect that the auctions will become successful during the three-year period of the rate plan, a true-up mechanism for the electric and gas debt was established to protect both the Company and customers from the uncertainty of the future NYSERDA bonds interest rates.

The second component is the interest rates associated with future debt issuances. The Joint Proposal assumes that Niagara Mohawk will issue \$674 million of 30-year debt prior to the beginning of the rate year. Additionally, the Joint Proposal assumes that 30-year debt of \$30.358 million, \$587.840 million, and \$288.509 million will be issued in 2013, 2014, and 2015 respectively at an all-inclusive cost rate of 4.32%. The forecasted issuance rates are consistent with current interest rate levels and no true-up mechanism was established for the projected bond issuances during the term of the Joint Proposal. The calculation of the interest rates associated with the Company's planned debt issuances is consistent with Commission's precedent as indicated in Staff's direct testimony (Duah at 35). The embedded cost of debt rates are

reasonable in that they conform to long standing Commission precedent establishing rates that are consistent with current interest rate levels.

**d. Cost of Equity**

The Joint Proposal contains a 9.3% multi-year rate plan return on equity (ROE). The ROE and the overall cost of capital reasonably and equitably reflects the current economic conditions as well as the additional business and financial risks inherent in the terms of the three year rate plan. In addition, the 9.3% ROE is consistent with investor expectations while being slightly below other recently authorized rate plans. For instance, in its June 15, 2012 decision, the Commission granted Orange and Rockland an average 9.5% ROE during the term of its three-year rate plan.<sup>11</sup> Since Staff's testimony was based upon a one year rate case presentation the figure differs from Staff's ROE testimony recommendation of 8.9% in order to reflect the additional risks incorporated into the three year agreement. The agreed upon ROE figure is 92 basis points lower than the Company's rebuttal ROE position of 10.22% and provides the Company with a reasonably achievable rate to maintain and grow its business interests while not overburdening the Company's customers.

**e. Earnings Sharing Mechanism (Section III, 5.5)**

The Joint Proposal contains an earnings sharing mechanism that shares any potential over-earnings by Niagara Mohawk during the term of the rate plan with ratepayers. The achieved ROE for the three-year period ending March 31, 2016 will be the average of the achieved ROE for each of the three rate years ending March 31, 2014, March 31, 2015, and March 31, 2016 and will be aggregated during the three year plan term. With respect to the equity ratio for earning sharing purposes, the Joint Proposal provides that the lower of the

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<sup>11</sup> Case 11-E-0408 - Orange and Rockland Utilities, Inc. – Electric Rates, Order Adopting Terms of Joint Proposal, with Modification, and Establishing Electric Rate Plan (issued June 15, 2012).

Company's actual common equity ratio or a hypothetical 48.00% common equity ratio used to establish the overall rate of return allowance be used to calculate earnings levels during the rate plan term. The Joint Proposal provides that any Company earnings above 9.3% threshold and up to and including 10.3% ROE will be shared equally (50%/50%) between customers and the Company. Earnings above 10.3% ROE and up to and including 11.3% are to be shared 75%/25% between customers and the Company, respectively. Finally, earnings in excess of 11.3% ROE will be shared 90%/10% between customers and ratepayers, respectively.

The provision for the Earnings Sharing Mechanism will continue beyond March 31, 2016 until the Company's rates are reset in a subsequent rate proceeding, thus assuring customers of any efficiency gains beyond the rate plan.

In the event that earnings are at a level to be shared with ratepayers, the amount would be applied to reduce the Company's revenue requirement in the next general rate case or as may be directed by the Commission.

These earnings sharing proposals provide distinct benefits. The first tiered band whereby earnings are shared equally provides incentive to the utility while providing an opportunity for ratepayers to further share in efficiency gains. The second and the final tiered dead band, where 75% and 90% respectively of earnings are credited to ratepayers provide a safeguard for the Commission and ratepayers against any potentially excessive overearnings by the utility.

### **Sections 6 and 7. Reconciliations, Deferrals and True-Ups**

Sections 6 and 7 contain the provisions on electric and gas reconciliations, deferrals and true-ups. This section includes a summary section discussing briefly all of the deferrals, many of which should be clear on their face, and follows with more specific discussions of certain sections.

**a. Deferrals**

The Joint Proposal contains most of the Staff deferral recommendations (Sections III 6.1 for electric and 7.1 for gas, and Appendix 7, Section 1.2). As supported by the Staff Accounting Panel testimony (and other Staff testimony), the Joint Proposal contains the continuation of deferrals for: pension and OPEBs expense (Section III, 6.1.1 and 7.1.1, electric and gas), low income discount program (Section III, 6.1.2 and 7.1.2, electric and gas), economic development fund (Section III, 6.1.3 electric), economic development grant program (Section III, 6.1.4 electric), auction debt true-up (Section III, 6.1.5 and 7.1.6, electric and gas), service quality negative revenue adjustments (Section III, 6.1.6 and 7.1.5, electric and gas), legislative or regulatory changes (Section III, 6.1.7 and 7.1.3, electric and gas), aggregation fees (Section III, 6.1.8 electric), voltage migration fees (Section III, 6.1.9 electric), generation stranded cost adjustments (Section III, 6.1.9 electric), externally imposed and internally adopted tax and accounting changes (Section III, 6.1.11 electric), transmission revenue adjustment clause (Section III, 6.1.15 electric), AffordAbility Program (Section III, 6.1.16) net revenue sharing (Section III, 7.1.7 gas), accrued unbilled revenues (Section III, 7.1.8 gas), and the revenue decoupling mechanism (Section III, 6.1.17 and 7.1.9, electric and gas, respectively).

In addition, the Joint Proposal provides for the continuation of current ratemaking mechanisms for: renewable portfolio standard program costs, systems benefit charge program costs, temporary state assessment 18-a fees, NYPA residential hydropower benefit reconciliation, electric supply reconciliation mechanism, new hedge adjustment and the legacy transition charge, merchant function charge reconciliation, research and development Millennium fund costs, GAC surcharge/refund adjustment, and the gas lost and unaccounted for reconciliation. (Section III, 6.1.18 and 7.1.10)

Two deferrals contained in the Joint Proposal are exclusively Staff recommendations. These are the electric and gas net utility plant and depreciation expense reconciliation mechanisms (Section III, 6.1.12 and 7.2.7, electric and gas), and they are restricted to only underspent amounts.

There are a number of new deferrals that have been incorporated into the Joint Proposal, and are consistent with Staff's recommendations in its pre-filed testimony. Several of these new deferrals are being put in place to provide consistency between the electric and gas operations, as there is little or no rationale to have different ratemaking with respect to electric but not with gas, and vice versa. These deferrals include, gas economic development fund for rate discounts (Section III, 7.2.1), gas economic development grant program (Section III, 7.2.2), gas externally imposed and internally adopted tax and accounting changes (Section III, 7.2.3), and gas affordability program (Section III, 7.2.9).

Two deferrals contained in the Joint Proposal requiring specific mention, the site, investigation and remediation (SIR) deferral, and the federal income tax (FIT) repair cost deferral, are also included to maintain consistency between electric and gas operations. Currently the gas SIR deferral allows for a full true-up between actual and allowed costs, while the electric deferral provides for an 80% to the customer / 20% absorbed by the Company sharing of any differences. As further discussed within, it was Staff's pre-filed testimony that the SIR deferral, for both electric and gas, allow for 100% true up, and the 80/20 sharing on the electric side be terminated. (SIR Panel at 15) The SIR deferral in the Joint Proposal (Section III, 6.1.14 and 7.1.4, electric and gas) is consistent with Staff's pre-filed testimony.

Regarding the FIT repair cost deferral, in 2009, the Company began taking a tax deduction on certain repairs and maintenance costs that had previously been capitalized and

depreciated. This change in policy resulted in \$30.113 million of projected cash flow enhancements for gas operations from inception through March 31, 2013 (the beginning of the new rate plan). (SAP at 138-139) Section 4.2.1 of the Joint Proposal in Case 08-G-0609<sup>12</sup> requires that the Company defer these cash flow enhancements for the future benefit of ratepayers. As such, Staff proposed an adjustment to establish a defined credit to capture these cash flow benefits. However, in rebuttal, the Company argued against passing back the benefits to customers. The Company argued that this policy change was not an “accounting charge” and therefore not covered under Section 4.2.1 of the Gas Joint Proposal. (RRP Rebuttal at 60-61)

In the most recent electric case, Case 10-E-0050,<sup>13</sup> the same situation arose. Staff proposed an adjustment to defer the cash flow enhancements for the benefit of ratepayers and the Company argued that the policy change was not an “accounting change” and therefore not covered under the electric rate plan in effect. Despite the Company’s arguments against establishing a credit, the Commission adopted the Staff’s recommendation and required the Company set up a deferred credit to capture all the cash flow enhancements.<sup>14</sup> In the Joint Proposal, the Company accepted Staff’s position and agreed to establish a \$30.113 million credit to reflect the benefits of the repair tax deduction for gas operations. (Section III, 6.24 and 7.24). This deduction is subject to audit and the \$30.113 million will be fully reconciled to the actual amount approved by the IRS.

A subset of new deferrals in the Joint Proposal is restricting the deferral to only under-spent amounts, rather than two way deferrals. These include electric transmission and sub-

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<sup>12</sup> Case 08-G-0609 – Niagara Mohawk Power Corporation for Gas Service, Order Adopting the Terms of a Joint Proposal and Implementing a State Assessment Surcharge (issued May 15, 2009).

<sup>13</sup> Case 10-E-0050 – Niagara Mohawk Power Corporation for Electric Service, Order Establishing Rates for Electric Service (issued January 24, 2011).

<sup>14</sup> Id. at 90.

transmission tower painting expense (Section III, 6.2.2), electric transmission and sub-transmission footer inspection expense (Section III, 6.2.3), and variable pay (Section III, 6.2.5 and 7.2.5, electric and gas). Two additional new deferrals contained in the Joint Proposal are the NYPA discount reconciliation (Section III, 6.2.1 electric), and property tax expense (Section III, 6.2.6 and 7.2.6 electric and gas). Any actually incurred property taxes that over or under the rate allowance will be shared 80% to the customer and 20% absorbed by the Company.

Two final deferrals need to be addressed; one is the major storm expense (Section III, 6.1.13) and the second is the customer conversions from oil to natural gas program (Section III, 7.2.8). Although the major storm expense deferral is not a new deferral, the calculation of it as contained within the Joint Proposal has been modified since the last electric case, and is supported by Staff's pre-filed testimony as more explicitly discussed below. The oil to natural gas conversion program deferral was not addressed by any party in the pre-filed testimony, but is an additional program resulting from the negotiations.

Although the Joint Proposal in this case contains many deferrals and true-up mechanisms, they are supported by recommendations contained within the various Staff panels' pre-filed testimony, and very little, if anything, was given up in reaching agreement in the Joint Proposal. In particular, Staff was able to achieve establishing a \$30.113 million deferred credit for the FIT repair cost deferral. This, in Staff's opinion, far outweighs anything that Staff conceded with any of the other deferrals.

**b. Electric Net Utility Plant and Depreciation Expense Reconciliation Mechanism (Section III, 6.1.12)**

The Company did not address any mechanism to reconcile capital investment in its initial testimony or in its rebuttal. Staff testified that net utility plant and depreciation expense reconciliation mechanism is necessary to protect customers from the Company collecting for, but

then not making, necessary capital investments. (Electric Infrastructure Panel (EIP) at 113-115) Included in the Joint Proposal, the mechanism is a downward only refund associated with both the electric and gas net utility plant, which includes allocated common plant, and depreciation expense in the reconciliation mechanism. This mechanism allows customers to receive a refund of the revenue requirement associated with both gas and electric plant expenditure rate base differences from the levels included in customer rates.

**c. Storm Fund (Section III, 6.1.13)**

The Company proposed a base rate allowance of \$29 million for storm expenses. The \$29 million is based on a ten year average of storm costs and more accurately reflects the Company's actual historic storm expenses. Additionally, the Company proposed to modify the storm deferral to make it easier to apply and more reasonable. The Company's proposal included eliminating the annual storm deductible, reducing the per storm deductible to \$.750 million and only applying the per storm deductible to events where restoration exceeds ten days. The Company provided data showing that the deductibles previously in place were not allowing it to recover prudently incurred storm costs. The proposal also included changing the post storm exclusion rule from five days to ten days, as the five day period can be insufficient to capture all relevant costs. If the Company wishes to defer costs after the ten days, it will have to petition the Commission. Finally, the Company modified the contractor disallowance rule and reduced the number of job titles included in the calculation. (EIOP at 84-92)

Staff agreed that the deferral mechanism should be simplified and agreed with most of the Company's changes. However, Staff disagreed with the Company's limited staffing levels included in the contractor disallowance calculation. The Company appropriately included titles related to work on overhead facilities, but failed to include positions related to work on

underground facilities. As a result, Staff recommended adding five titles to the calculation. Additionally, the per storm deductible amount of \$.750 million was based on an analysis of the December 2008 Albany ice storm— a single, unique event. Staff did not adjust the amount, but did recommend that the Company perform similar analyses for any event with more than 10 days post-restoration work, as this data can be used in future rate proceedings. (SAP at 103-106)

The Joint Proposal reflects the Company's proposal with Staff's modifications adopted.

**d. Site Remediation and Investigation (SIR) (Section III, 6.1.14 and 7.1.4)**

In its filing, the Company proposed to increase its rate year SIR base rate allowance of \$35 million to \$42 million. The Company also proposed to eliminate the 80/20 cost sharing mechanism currently in place for the electric SIR costs and instead defer any electric or gas costs incurred in excess of the annual base allowance for future recovery. After a thorough review, Staff agreed with the Company's SIR proposal (SIR Panel at 9 and 15), however, Staff also recommended the Company file annual reports to allow Staff to closely monitor its SIR activities and costs. (SIR Panel at 19) The Joint Proposal adopts the Company's proposed changes along with Staff's recommendations to require the Company's to file an annual report monitoring its SIR costs and activities. The SIR provisions in the Joint Proposal provide the Company the ability to collect costs that are legitimate costs of doing business. The \$42 million target is based on the Company forecast which carefully considered the Department of Environmental Conservation's schedule, past spending, and potential delays; it is reasonable.

In addition, during the negotiation period the Commission issued its decision in Case 11-M-0034.<sup>15</sup> Regarding any sharing, the Commission contemplated applying sharing in cases

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<sup>15</sup> Case 11-M-0034 - Proceeding on Motion of the Commission to Commence a Review and Evaluation of the Treatment of the State's Regulated Utilities' Site Investigation and Remediation

where it could serve as an incentive to contain SIR costs, or as part of an earnings sharing mechanism in multi-year rate plans.<sup>16</sup> As stated, Staff's review found no indication that SIR costs were not being controlled. Moreover, this Joint Proposal is unique in that excess earnings sharing begins without a dead band. In such an unprecedented situation, it seems inappropriate to apply a sharing of SIR costs. Thus, the SIR terms in the Joint Proposal are appropriate.

Finally, the Joint Proposal's provision for annual reporting is consistent with and will be followed in conjunction with the reporting required in the generic SIR case.

**e. Transmission and Sub-Transmission Tower Painting Expense Downward Only Reconciliation and Footer Inspection Expense Downward Only Reconciliation (Section III, 6.2.2)**

After reviewing the Company's initial and Corrections and Updates filings, Staff proposed downward adjustments for Transmission and Sub-Transmission Footer Inspection and Repair Programs of \$1 million and \$0.227 million, respectively. (EIP at 94) Staff did not propose any adjustments to the Transmission and Sub-Transmission Tower Painting Programs. The Joint Proposal includes Staff's adjustments. The spending levels in the Joint Proposal are \$2.441 million and \$0.773 million for Transmission and Sub-Transmission Footer Inspection and Repair, respectively, and \$2.448 million and \$0.5 million for Transmission and Sub-Transmission Tower Painting, respectively, for each Rate Year. Staff's review determined that the Company would be able to meet these spending levels. Moreover, the Joint Proposal provides for a downward only reconciliation for the various spending levels, as recommended in Staff's direct testimony, in the event the Company fails to perform the work. (EIP at 88-89, 98 and 114-115)

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(SIR) Costs. Order Concerning Costs for Site Investigation and Remediation (issued November 28, 2012).

<sup>16</sup> Case 11-M-0034 at 31.

**f. Incentive Compensation ( Variable Pay -Section III, 6.2.5)**

The Company requested \$20.6 million related to incentive pay to be included in its revenue requirement for Rate Year 1. (Human Resources Panel (HRP) Corrections and Updates at 4.)<sup>17</sup> The Company’s Human Resources Panel indicates that the Company “must attract, retain and engage high performing, qualified personnel” in order to achieve its goals of providing “safe, reliable and efficient utility service to its customers.” The Company states that its total compensation package “recognizes and rewards excellence, maintains fair and competitive market pay and benefits for employees, and encourages employees to improve skills.” (HRP at 14.) Furthermore, the Company contends that its “total overall compensation and benefit programs are reasonable and market competitive.” (HRP at 6.) The Human Resources Panel also “explains specifically why the costs of the variable pay plan should be included in the revenue requirements and how that plan is structured to align the interests of the Company with its customers.” (HRP at 6.)

The Commission has previously indicated what a utility company must demonstrate in order to recover the costs of incentive pay in rates. On page 40 of its Order in Case 10-E-0050 regarding Niagara Mohawk rates, the Commission disallowed variable pay because the Company failed to show the linkage between its variable pay incentive performance targets and ratepayer benefits. The Commission stated that the Company “failed to separate and distinguish any incentives and amounts serving ratepayers from those that serve shareholders.” The incentive compensation program should not focus largely on financial targets which benefit shareholders. The Company must also demonstrate that the variable compensation plan benefits ratepayers in terms of customer satisfaction, safety and reliability. More recently, on page 40 of its Order

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<sup>17</sup> The Company also requested recovery of incentive pay for union employees, but Staff did not address this issue in its testimony, mostly due to time and resource constraints.

Setting Electric Rates for Orange and Rockland Utilities in Case 10-E-0362,<sup>18</sup> the Commission explained that, in order to justify recovery of incentive pay costs in rates, the Company must demonstrate that its overall management compensation levels, including its incentive compensation, are reasonable relative to compensation levels of similarly situated companies. The Commission articulated its expectation that this is best demonstrated through a compensation study that compares each of the elements the utility company's total management compensation, including base pay, incentive compensation and employee benefits, to the relevant market. Finally, the Commission clarified its direction in its November 21, 2011 Order Denying Petitions for Rehearing. In that O&R case, the Commission indicated that its "fundamental objective, where utility labor expense is concerned, is to ensure that customers pay no more, and no less, in rates than what is necessary and sufficient to attract and retain employees with the qualifications and motivation to ensure the provision of safe and adequate service." The Commission reiterated these requirements in the 2012 Order approving O&R's recent rate request in Case 11-E-0408.<sup>19</sup>

Although in previous cases Staff had general concerns regarding how such a comparative study of incentive compensation must be performed, those concerns were not an issue in this proceeding. A consistent peer group was used for all components of the total compensation package being evaluated including base pay, incentive pay and benefits. (Schuler at 16.) That peer group also included all types of companies with which the utility competes for employees, not just energy companies. (Schuler at 16.) To support the composition of its peer group, the

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<sup>18</sup> Case 10-E-0362 - Proceeding on Motion of the Commission as to the Rates, Charges, Rules and Regulations of Orange and Rockland Utilities, Inc. for Electric Service. Order Establishing Rates For Electric Service (issued June 17, 2011)

<sup>19</sup> Case 11-E-0408 - Orange and Rockland Utilities, Inc. for Electric Service. Order Adopting Terms Of Joint Proposal, With Modification, And Establishing Electric Rate Plan (issued June 15, 2012)

Company provide a five-year listing of the employers from which new management hires were previously employed.<sup>20</sup> Finally, the Company provided underlying data for each peer company and each benchmarked subject to a Non-Disclosure Agreement entered on June 15, 2012 between the Company and its consultant, Towers Watson, and the Protective Order in this case issued by the ALJs on June 6, 2012.<sup>21</sup> Although Staff had a few minor concerns regarding the Company's comparative analysis and how it could be improved, none of these concerns rose to the level of concluding that the comparative analysis was unreasonable. (Schuler at 41.) Thus, the Joint Proposal reasonably includes incentive compensation for Company management.

1. Incentive Compensation Inflation Factor

The Company cited market studies to argue that its proposed percentage increases in compensation should be in the 3% range for 2012 through 2015. (HRP at 36) The Company also increases the first year's escalation factor from 3.0% to 3.37% to reflect its belief that certain positions were compensated much less than market levels. (HRP at 37). Staff testified that a more recent version of the survey indicated 2.9% for salary budget forecasts for the first year. (Schuler at 32). Moreover, Staff pointed out that other Company positions were being compensated at higher than market levels and that the Company has not explained why it is reasonable to only adjust the escalation rate for the two types of positions it cited as being undercompensated. (Schuler at 33). The level of incentive compensation included in the Joint

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<sup>20</sup> Staff noted that the Company's presentation could have been improved if it had included a list of companies to which National Grid employees departed (if they were seeking future employment and not retiring). (Schuler at 17)

<sup>21</sup> The Company also offered to allow Staff the opportunity to travel to Towers Watson's offices for purposes of looking over its consultant's shoulders if Staff wished to have sensitivity analyses of the benefits valuation model performed. Schuler at 18. The Company did not provide the underlying cash compensation information for each of the 38 peer companies. This peer company specific information was used to calculate the median cash compensation amounts that were included in the confidential response to DPS-183 (RES-13)

Proposal reasonably reflects Staff's combined electric and gas expense adjustment of \$434,000 in RY1 related to the compensation inflation factor.

**g. Property Taxes (Section III, 6.2.6 and 7.2.6)**

As shown in Exhibit \_\_ (RRP-5CU), Schedule 1, Pages 3-4, the Company's rate year forecast of property taxes was derived by taking the actual property tax expense for the fiscal year ending March 31, 2012 and increasing it by 3.2% in fiscal year 2013 and fiscal year 2014. The Company further increased this expense by forecasting increases to property taxes associated with incremental additions to Plant in Service. Staff disagreed with the Company's calculation of the 3.2% growth rate and the calculation of incremental plant additions. (SAP at 115,117) In rebuttal, the Company noted its agreement with Staff's adjustment for the calculation of incremental plant additions, with a small adjustment to the gas/electric allocation. (Shared Services and Customer Panel Rebuttal at 4-5) However, the Company disagreed with Staff's adjustment related to the calculation of the 3.2% growth rate. (SSCP Rebuttal at 3)

The Joint Proposal resolves this issue in a manner that Staff believes provides the best forecast for rate year property tax expense, while providing the Company some level of protection for costs that may be outside of their control. This was accomplished by utilizing Staff's forecast of property tax expense for all rate years and allowing a property tax reconciliation. The reconciliation includes 80/20 sharing of costs above or below the forecast, thereby providing an incentive for the Company to minimize costs where possible. (Section III, 7.2.6) This is similar to PSC Case 29327, the Financial Recovery Agreement, wherein the costs above or below the forecast were shared 90/10 between ratepayers and shareholders.

Additionally, ConEd,<sup>22</sup> Central Hudson,<sup>23</sup> NYSEG and RGE<sup>24</sup> and Corning<sup>25</sup> all have reconciliations with sharing mechanisms which range from 80/20 to 95/5.

**h. Gas Net Utility Plant and Depreciation Expense Reconciliation Mechanism (Section III, 7.1.1)**

The Company did not address any mechanism for reconciling gas capital investment expenditures in its initial testimony or in its rebuttal. Staff testified that a gas net utility plant and depreciation expense reconciliation mechanism is necessary to protect customers from the Company collecting for, but then not making, necessary capital investments. (Maioriello at 10-12) Included in the Joint Proposal, the mechanism is a downward only refund associated with both the electric and gas net utility plant, which includes allocated common plant, and depreciation expense in the reconciliation mechanism. This mechanism allows customers to receive a refund of the revenue requirement associated with both gas and electric plant expenditure ratebase differences from the levels included in customer rates.

**i. Collaborative Research & Development (R&D) for Gas Technology**

In the Company's initial testimony (Shared Services and Customer Panel, at 75-79), it proposed to use a portion revenues collected by the surcharge associated with the Millennium

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<sup>22</sup> Cases 09-E-0428, et al., Consolidated Edison Company of New York, Inc., Order Establishing Three-Year Electric Rate Plan, (issued March 26, 2010); Cases 09-S-0794, 09-G-0795 and 09-S-0029, Consolidated Edison Company of New York, Inc., Order Establishing Three-year Steam and Gas Rate Plans and Determining East River Repowering Project Cost Allocation Methodology, (issued September 22, 2010).

<sup>23</sup> Cases 09-E-0588 and 09-G-0589, Central Hudson Gas & Electric Corp., Order Establishing Rate Plan, (issued June 18, 2010).

<sup>24</sup> Cases 09-E-0715, et al., NYSEG and RG&E, Order Establishing Rate Plan, (issued September 21, 2010).

<sup>25</sup> Case 11-G-0280 - Corning Natural Gas Corporation for Gas Service, Order Adopting Terms of Joint Proposal and Establishing a Multi-year Rate Plan, (issued April 20, 2012).

Fund, a natural gas R&D program established in Case 99-G-1369 (Millennium Order),<sup>26</sup> to support customer-facing gas technologies or gas supply research. The Company added that it understood that the Millennium Order specifically stated that the resulting funds should not be used for end use or supply related projects, so it asked for a waiver from the Order's requirements. In response (Colby at 10-15), Staff stated that the Millennium Order was clear in the usage of its funds and that there are already existing vehicles for other types of research as the Company proposed, and therefore Staff did not support the Company's proposal. The Company did not rebut Staff's position and the R&D funding included in the Joint Proposal will remain in use as the Commission directed in the Millennium Order.

**j. Net Revenue Sharing (Section III, 7.1.7)**

Niagara Mohawk proposed a continuation of the current sharing formula for SC 6 non-firm revenues with the customers retaining or absorbing 90% of the difference above or below the level imputed in base delivery rates, and the remaining 10% retained or absorbed by the Company. Niagara Mohawk also proposed a continuation of the current sharing formula for SC 9 non-firm revenues with the customer retaining or absorbing 100% of the difference above or below the level imputed in base delivery rates.

The Company offered the following modifications to the Net Revenue Sharing Mechanism: SC-4 be eliminated from the delivery revenue targets, new targets be set based on the Company's revenue forecasts for SC-6 and SC-9, and expand the net revenue sharing to include all of the firm service classifications. The Company proposed that SC-4 be removed from the net revenue sharing going forward, as there are no longer any customers served under

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<sup>26</sup> Case 99-G-1369 - Petition of New York Gas Group for Permission to Establish a Voluntary State Funding Mechanism to Support Medium and Long Term Gas Research and Development (R&D) Programs. Approved as Recommended and so Ordered, (issued February 14, 2000)

this service classification. As noted previously, the Joint Proposal proposes to eliminate the SC-4 service classification from the Company's tariff. The Company's forecast revenues for Rate Year One are \$0 for SC-4, \$7.199 Million for SC-6, and \$10.864 for SC-9.

The current Net Revenue Sharing mechanism provides for the sharing credit or surcharge only to apply to SC-1, SC-2, and SC-3 firm sales classes. The Company proposed to expand the sharing to include all firm classes, adding SC-5, SC-7, SC-8, SC-12, and SC-13. Staff agreed with the Company that including all firm classes results in the most equitable delivery revenue allocation. (Staff Gas Rates Panel at 7)

Staff also agreed with the Company's position to continue the 90% customer/ 10% Company sharing mechanism for SC-6 (Staff Gas Rates Panel at 7). Using the foregoing, the Joint Proposal establishes Rate Year One, Two, and Three targets of \$7.199 Million, \$7.940 Million, and \$8.776 Million, respectively. Staff further agreed with continuing the current SC-9 sharing mechanism (Staff Gas Rates Panel at 7-8). The Joint Proposal does continue the existing SC-9 sharing mechanism at the Company's SC-9 revenue forecast. After direct testimony had been filed, it was discovered that a power generation customer had migrated from SC-9 to SC-14 (Transportation Service for Dual Fuel Electric Generators), therefore, the Net Revenue Sharing around SC-9 revenues was expanded to include SC-14 as well. The Joint Proposal's combined SC-9 and SC-14 Rate Year One, Two, and Three targets are \$10.864 Million, \$10.920 Million, and \$10.978 Million, respectively.

The Joint Proposal's treatment of these non-firm revenues, as set forth in Section III, 7.1.7, reflects both the Company's and Staff's direct testimony positions and recommendations. This outcome is reasonable because it provides the Company with an incentive to maximize

these non-firm revenues, but allows for sharing by all firm customers should the Company exceed its sales forecasts.

### **Section 8. Electric and Gas Capital Investment Levels**

The electric, gas and common capital investment levels underlying the rates in this Joint Proposal<sup>27</sup> (exclusive of cost of removal) are as follows:

Segment	FY13	RY1	RY2	RY3
Electric Transmission	\$142,250,000	\$142,849,000	\$153,049,000	\$155,432,000
Electric Sub-Transmission	\$46,000,000	\$50,000,000	\$48,526,000	\$50,708,000
Electric Distribution	\$235,000,000	\$233,430,000	\$245,730,000	\$246,590,000
DOE Smart Grid Project	\$7,000,000	\$2,000,000	\$0	\$0
Gas	\$65,398,220	\$80,509,265	\$85,515,569	\$92,377,472
IS	\$10,950,000	\$3,625,000	\$200,000	\$956,000
Facilities	\$10,288,000	\$6,888,000	\$6,888,000	\$6,888,000
Fleet & IM-IR	\$966,000	\$542,000	\$542,000	\$542,000
<b>Total Capex</b>	<b>\$517,852,220</b>	<b>\$519,843,265</b>	<b>\$540,450,569</b>	<b>\$553,493,472</b>

<sup>27</sup> The electric incremental operating costs associated with electric capital investment underlying rates were determined by applying historic operating percentages, by segment, to the incremental capital investment levels by Rate Plan Year. The historic operating percentages were determined by averaging the last three years of electric operating costs associated with electric capital expenditures, as a percentage of electric capital expenditures, by segment.

**a. Electric Transmission Capital Expenditures**

In its initial filing, Niagara Mohawk proposed transmission capital expenditures of \$132M, \$145M, \$160M, and \$165M for fiscal years 2013, 2014, 2015, and 2016, respectively. In its subsequent Corrections and Updates filing, the Company made corrections to its initial filing and proposed to implement several new projects in response to the mothball notice filed by the owners of the Dunkirk Power LLC generating station (“Dunkirk”). However, the Company did not propose any changes to its initial transmission capital expenditures; instead, it requested deferral treatment for the Dunkirk related projects.

In its direct testimony, Staff recommended adjustments to several programs and also provided funding for the Dunkirk related projects that were scheduled to be completed in fiscal years 2013 and 2014. Staff also recommended that the Dunkirk related projects should be funded through rates rather than be subject to deferral treatment. As a result, Staff made adjustments of \$6.75M, (\$4.15M), (\$6.75M), and (\$10.57M) for fiscal years 2013, 2014, 2015, and 2016 respectively, providing spending levels of \$138.750M, \$140.849M, \$153.250M, and \$154.432M for the respective fiscal years.

In its rebuttal testimony, the Company accepted all of Staff’s adjustments except for the Conductor Clearance Strategy. For the Conductor Clearance Strategy, Staff had recommended downward adjustments of \$5.35M in FY15, and \$5.0M in FY16. Niagara Mohawk also claimed that additional funding of \$3.5M in FY13 and \$2M in FY14 for the Dunkirk related projects should have been included in Staff’s direct testimony. The Company also reduced a Dunkirk related project for the Gardenville Substation by \$1.2M in FY15 due to the original expenditure being covered by projects scheduled for completion in 2013. Consequently, the Company’s

position after rebuttal proposed transmission capital expenditures of \$142.250M, \$142.849M, \$157.401M, and \$159.432M for FY2013 through FY2016 respectively.

The Joint Proposal uses the Company's position on Dunkirk related projects and increases funding for the Conductor Clearance Strategy by \$1M in both FY15 and FY16. Staff believes this position is a reasonable compromise given its potential litigation risk. The Transmission Capital Expenditure budget is \$142.250M, \$142.849M, \$153.049M, and \$155.432M for fiscal years 2013 through 2016, respectively.

**b. Electric Sub-Transmission Capital Expenditures**

In its initial filing, Niagara Mohawk proposed sub-transmission capital expenditures of \$50M, \$54M, and \$58M for fiscal years 2014, 2015, and 2016, respectively.

In its direct testimony, Staff recommended adjustments to the Asset Condition reserve budget that listed expenditures of(\$7.0M), \$16.3M and \$19.4M for fiscal years 2014, 2015, and 2016 based on the Company's lack of providing a forecast of what assets condition project work will be performed in future years. Due to the high reserve for fiscal years 2015 and 2016, Staff recommended a \$5.474M reduction for 2015 and \$7.292M reduction for 2016.

In rebuttal, the Company rejected Staff's adjustments to the Asset Condition reserve budget stating it "would appreciably limit the Company's ability to efficiently deliver needed sub-transmission projects."

The Joint Proposal incorporates Staff's position on the reduction to the Asset Condition reserve budget by \$5.474M in 2015 and \$7.292 in 2016. The Sub-Transmission Capital Expenditure budget is \$50.0M, \$48.526M, and \$50.708M for fiscal years 2014 through 2016, respectively.

**c. Electric Distribution Capital Expenditures**

In its initial filing, Niagara Mohawk proposed Distribution Capital Expenditures of \$247M, \$258M, and \$269M for fiscal years 2014, 2015, and 2016, respectively.

In its direct testimony, Staff recommended adjustments to Distribution Blankets (damage/failure blanket, reliability blanket, meter purchase blanket, and general blanket), Asset Condition reserves, Smart Grid (Advanced Grid Applications), Side Tap Fusing, and Arc Flash Mitigation. Staff's total recommended reduction was \$14.67M, \$13.37M, and 23.51M for fiscal years 2014, 2015, and 2016 respectively, providing spending levels of \$232.33M, \$244.63M, and \$245.49M for the respective fiscal years.

In its rebuttal testimony, the Company accepted all of Staff's adjustments to the above Distribution Blankets except for Staff's adjustments to the Meter Purchases Blanket, Side Tap Fusing, Smart Grid, and Asset Condition Reserves.

Here again, the Joint Proposal incorporates all of Staff's adjustments to the Distribution Capital Expenditure Programs. However, Staff withdrew its adjustment of \$1.1M for fiscal years 2014 through 2016 to the Side Tap Fusing program. The Joint Proposal includes a Distribution Capital Expenditure budget of \$233.43M, \$245.73M, and \$246.59M for fiscal years 2014, 2015, and 2016 respectively.

**d. Side Tap Fusing**

The Company proposed to spend \$1.8 million yearly in Fiscal Years 2014 thru 2017 to install side tap fusing on distribution circuits. The installation of side tap fuses decreases the number of customers that will be interrupted when faults occur and decreases the amount of infrastructure subjected to the fault current.

Staff agreed with the benefits of side tap fusing, but noted that the Company did not identify the number of locations that would be targeted for installing side tap fuses and, historically, had low spending on this program. Therefore, Staff recommended a downward adjustment from \$1.8 million to \$0.7 million for fiscal years 2014 thru 2017, thus providing the Company with a 50% increase over Fiscal Year 2012 expenditures for side tap fusing.

The Company, in its rebuttal testimony, provided additional information that allowed Staff to further evaluate the original request for \$1.8 million for Fiscal Years 2014 thru 2017. The added information identified 2,400 locations for side tap fusing based on a review of 398 distribution feeders.

After considering the additional data provided for installing side tap fusing, the Company's \$1.8 million budget for Fiscal Year 2014 thru 2017 appears reasonable. Staff believes that the low cost and the benefits derived from side tap fusing will provide an increase in reliability on the Company's Distribution System.

**e. Gas Capital Expenditures**

In its initial filing, Niagara Mohawk proposed gas capital expenditures of \$72.4M, \$89.7M, \$88.4M, and \$88.7M for fiscal years 2013, 2014, 2015, and 2016, respectively. In its subsequent Corrections and Updates filing, the Company maintained its initial position. Staff recommended adjustments to several programs and also provided funding for additional leak prone pipe removal. As a result, Staff made adjustments of (\$0.85M), (\$0.25M), \$4.05M, and \$8.35M for fiscal years 2013, 2014, 2015, and 2016 respectively, providing spending levels of \$65.3M, \$81.1M, \$84.3M, and \$88.8M for the respective fiscal years.

In its rebuttal testimony, the Company accepted all of Staff's adjustments except for the adjustments for the increased leak prone pipe replacement capital amounts. Staff had

recommended upward adjustments of \$4.3M in FY15, and \$8.6M in FY16. Niagara Mohawk claimed that the additional funding provided by staff was not enough for the increased costs of pipe replacement due the nature of the urban work environment. The additional pipe removal targets would fall within urban city locations which are more costly to remove due to the nature of the work and its work environment versus that of less densely populated areas. Niagara Mohawk recommended an additional increase of \$2.7M in FY15 and \$6.0M in FY16 from Staff's adjustment.

The Joint Proposal incorporates the Company's position and increases funding for the leak prone pipe replacement targets by \$2.7M in FY15 and \$6.0M in FY16. Staff believes this position is a reasonable compromise given the potential litigation risk. The Joint Proposal includes a Gas Capital Expenditure budget of \$65.4M, \$80.5M, \$85.5M, and \$92.4M for fiscal years 2013 through 2016 respectively.

**Section 9. Electric and Gas Service Quality Assurance Programs (Section III, 9 and Appendix 7)**

Niagara Mohawk currently operates under a Service Quality Assurance Program (SQAP) designed to maintain and improve the Company's service quality by providing earnings consequences for unacceptable customer service provided by the utility to its customers. Niagara Mohawk's SQAP places a maximum \$19.8 million of electric and gas earnings at risk for failure to provide satisfactory levels of service on a variety of measures of customer service (Exhibit \_\_CSP-1).

As shown in Exhibit \_\_ (CIP-2), the Company proposed to lower the PSC complaint rate gas threshold to make it consistent with the electric measures; eliminate the percentage of meters read and the low income program enrollment measures; increase the C&I threshold as

recommended by a C&I satisfaction survey collaborative, and maintain the current total potential amount at risk at \$19.8 million.

In testimony Staff agreed with the Company's proposal, but testified that the Company should also provide a \$30 bill credit to individual customers if the Company misses a scheduled appointment (CIP at 8-9).

The Joint Proposal includes both the Company's proposals and the \$30 bill credit for missed appointments. Together these programs should provide the Company with the incentive to maintain and improve its service quality to the benefit of its customers.

#### **Section 10. Gas Safety Performance Metrics**

##### **a. Leak-Prone Pipe (LPP) Removal (Section III, 10.1)**

Removing all leak prone pipe from the Company's distribution system is an important goal that can provide a number of benefits. Such removal can improve the safety of the Company's gas system by substantially reducing the number of underground leaks which can lessen the opportunity for safety incidents related to gas leaks. Additionally, because removing leak prone pipe minimizes active leaks, its removal can reduce the Company's overtime and O&M costs needed to address such leaks. Moreover, the proactive removal of leak prone pipe can reduce the amount of lost and unaccounted for gas on the distribution system. These resulting effects provide benefits to the Company and ratepayers alike.

To arrive at reasonably achievable, yet aggressive targets to produce real benefits as soon as possible, the Parties started by looking at the Company's historical performance. Niagara Mohawk averaged 30 miles per year of leak-prone main removal over the years 2008-2012. In its filing, Niagara Mohawk had proposed to increase its removal rate to 35 miles per year. Staff agreed with Niagara Mohawk's proposal to increase its pipe removal level for calendar year

2013, but also recommended accelerating the removal rates thereafter to 40 miles and 45 miles for calendar years 2014 and 2015, respectively. (Gas Safety Panel (GSP) at 12) Staff's proposal, and the resulting agreement, allows for Niagara Mohawk to ramp up its LPP program, while also furthering public safety by removing the highest risk pipe from service, along with providing other corresponding distribution system and Company operating benefits.

**b. Leak Management (Section III, 10.2)**

The safety benefits of reducing and, where possible, eliminating any leak backlog, especially the backlog associated with potentially hazardous leaks are self-evident. As with leak prone pipe removal which proactively seeks to reduce any backlog from growing, addressing active leaks reduces the possibility of safety incidents on the Company's gas system. Containing the gas in the distribution system where it belongs reduces its potential exposure to reactive elements that could cause incidents.

Although Niagara Mohawk's existing rate plan does contain targets for reducing potentially hazardous leaks, also known as repairable leaks, on its system to no greater than 40 by the end of the calendar year 2012, Niagara Mohawk did not propose any future leak backlog target in its filing. The term repairable leaks used in conjunction with the identification of hazardous leaks only indicates that these classified leaks are mandated to be repaired, not that other leaks are not able to be repaired. Instead, for those other leaks, the Company is only required by law to monitor them to insure that they do not become hazardous. Staff notes that the Company has regularly exceeded the existing repairable leak backlog target since 2007 by not ending any year with more than 17 of these leaks in its backlog.

Because of the Company's known historic performance as to repairable leaks, instead of recommending the continuation of leak backlog target addressing only repairable leaks, Staff

instead, recommended Niagara Mohawk have a target to reduce all of the total known leaks on its system. (GSP at 16) The benefits of reducing all known leaks are the same as those identified with removing leak prone pipe, yet with some more immediacy as this target goes after already existing leaks where gas is known to be escaping in some quantity.

Accordingly, included in the all inclusive category of total leaks are those leaks classified as Type 3, which otherwise have no defined time frame for repair. Staff recommended that the Company reduce its total leak backlog to 1,500 by year end 2014, 1,250 by year end 2014, and 1,000 by year end 2015. The Joint Proposal includes final total leak backlog targets of 1,000 in 2015, which gets the Company to the final targeted amount set forth in Staff's testimony. The Joint Proposal also includes a reduced repairable leak backlog of 35 in 2013, and 30 in 2014 to insure that the Company continues to prioritize hazardous leaks as it works over the entire three year term of the Joint Proposal to achieve its final total leak backlog target. In balance, this provision focuses Niagara Mohawk's efforts on reducing all known leakage on its system, decreasing potential safety risks, and lowering lost and unaccounted for gas; all of which are issues that, when unaddressed, cost customers due to allowed losses and continuing O&M expenses.

**c. Damage Prevention (Section III, 10.3)**

Damage prevention targets are included in Gas Safety provisions to address the costs associated with repairs made necessary by excavation damage, and to reduce the potential for any safety incidents related to rupture to the gas system caused by excavation. Any damage to a pipeline can result in an uncontrolled release of natural gas which could lead to a very serious safety incident.

Niagara Mohawk has been operating under excavation damage prevention targets established in its rate plans for many years and did not propose any targets in its filing. The Company has improved its performance over the past several years, but its performance has remained worse than the statewide normalized level in overall damage prevention.

Staff recommended targets for 2013 to encourage Niagara Mohawk to improve its overall damage performance that would move it towards the statewide level, while essentially maintaining its damages targets due to mismarks and damages due to company and company contractor error performance. (GSP at 27-28) The Joint Proposal encourages the Company to improve its overall damage prevention performance in each year. The targets for damages due to mismarks and damages due to Company and contractor error are near Staff's proposed levels. The targets included in the Joint Proposal achieve a balance of interests in that they are aggressive enough to create conditions that will lead to reducing excavation damage incidents but are set at achievable levels. Excavation damage is the leading cause of natural gas pipeline failures, and minimizing excavation damage furthers both public and worker safety.

**d. Emergency Response (Section III, 10.4)**

Responding to gas leak and odor calls reported by the public in a timely manner minimizes the potential for serious incident to occur. The Company has been operating under targets related to emergency response in its rate plans for several years. The Company has demonstrated historically that it can meet the response targets to which it is currently subject. The Company did not propose to continue any emergency response targets in its filing. The existing established targets are the same as those established in several existing rate plans for other New York gas utilities. Staff, therefore, recommended the continuation of those same targets in this case as it was satisfied that those targets adequately address the concerns that

accompany emergency response situations. (GSP at 31) The Joint Proposal contains the targets recommended by Staff.

**e. Gas Safety Violations Metric (Section III, 10.5)**

Staff performs regular record and field audits of the Company for compliance with the Commission's gas safety requirements as delineated in 16 NYCRR Part 255 and 16 NYCRR Part 261. Staff has found numerous violations during audits of Niagara Mohawk operations, and the Company has had very little incentive to improve its compliance in a timely manner.

Accordingly, Staff proposed a new metric that is intended to measure Company compliance with the Commission's regulations, and, where violations are found, provide appropriate incentives to achieve timely correction and insure future compliance. (GSP at 32-40)

This Gas Safety Violations Metric is based on a list of Commission regulatory code sections, identifying each section of the regulations as a high risk violation, or an other than high risk violation. The binary system of high risk identifies sections that are critical to minimizing immediate or exceptional risk and attaching appropriately ratcheted incentives to such violations, but allowing for administrative ease by not creating an overly burdensome number of categories, each with their own distinct set of incentives. The list was developed by Staff using a subject matter expert approach to ranking the regulation sections into one of the two categories, high risk and other risk.

Because the Commission establishes rates based on an expected level of safe and reliable service, and total compliance with its pipeline safety regulations is considered safe operation, Staff proposed that each violation it finds in its audits should result in a financial credit to customers. Staff's proposal was that each high risk violation results in one pre-tax basis point owed to customers, and each "other risk" violation results in a one-third pre-tax basis point owed

to customers. The Joint Proposal phases in Staff's new metric over the three year term, but still makes Niagara Mohawk accountable for every violation discovered by Staff during the phase-in. Further, in order to add transparency to the process, both Staff's audit letters and the Company's response to such audit letters are to be filed with the Secretary. Niagara Mohawk is able to appeal any disputed findings to the Commission.

This new metric furthers public safety by ensuring that the Company is accountable for its non-compliance with all of the Commission's pipeline safety regulations recognizing that any failure to comply with the pipeline safety requirements could potentially lead to serious incidents.

### **Section 11. Customer Programs**

The Joint Proposal includes several continuing or new programs designed to assist customers in many aspects of receiving utility service. These include programs targeted to certain types of customers and efforts that benefit all customers.

#### **a. Low Income Programs (Section III, 11.1)**

In its direct testimony, Staff agreed with the Company's proposals to continue the AffordAbility program at an annual budget of \$1.296 million; to continue the electric \$5 bill credit program at an annual cost of \$7.296 million and the \$10 electric bill credit for electric heating HEAP recipients at an annual budget of \$3.24 million. (CIP at 14) Staff proposed increasing the gas bill credit to \$8.50 for an annual budget of \$6.9 million (CIP at 16), instead of the Company's proposed \$10 per month. The Joint Proposal provides for an increase in the gas low income bill credit to \$10, \$10.50, and \$11.00 in Rate Years 1, 2, and 3, respectively. This will provide increased assistance to low-income customers in need without unduly burdening ratepayers.

**b. Economic Development Grant Programs ( Section III, 11.4.2)**

The Company administers a portfolio of 18 economic development grant programs at an annual funding level \$9.1 million. The Company proposed to increase funding to \$11 million per year and proposed to create a natural gas economic development grant program funded at about \$1 million per year. In addition, the Company proposed to defer expenses for underspending and recover costs for overspending in subsequent years. Staff did not object to the proposed increased levels of funding for the respective programs, but testified that it should be capped at \$11 and \$1 million, respectively. Staff testified that if the Company intends to increase funding for the program above the requested amounts, then the Company should petition the Commission for approval. (CIP at 24-25)

The Joint Proposal provides that any under expenditures in a year will be deferred for future use in the grant program but it does not provide for deferral or cost recovery for overspending. (Section III, 6.1.4)

**c. Customer Outreach and Education (Section III, 11.4.3)**

The Company proposed to increase its outreach and education budget from \$2.1 million to \$3.5 million. Staff testified that spending levels of the outreach and education program should be increased by \$0.9 million for a total budget of \$3.0 million (CIP at 21-22). The Joint Proposal adopts Staff's position and establishes an annual budget of \$3.0 million and requires annual outreach and education plan filings to include detailed budgets and describe the specific outreach campaign messages to be disseminated, the communication vehicles to be used, the goals of the outreach program and the criteria for measuring their achievement. This process will ensure that outreach and education activities are well developed and adequately funded to foster the achievement of the outreach program goals.

**d. ESCO Issues (Section III, 11.5)**

Staff raised concerns in testimony over the competitiveness of the retail energy market. Of particular concern is that ESCO customers are not able to evaluate their energy costs, because they cannot easily compare their prices with other options (Retail Access Panel at 15-16). To address this problem, Staff recommended that Niagara Mohawk provide price comparisons for ESCO customers to what they would have paid if they remained with utility supply service: 1) through a web calculator that shows the bill differential over each of the past 12 months; 2) on consolidated bills, showing a differential for the current month and the over the past 12 months; and, 3) with termination and deferred payment agreement default notices. (Retail Access Panel at 22) In its rebuttal testimony, Niagara Mohawk supported Staff's recommendations (SSCP at 26-27). The Company explained that the cost of implementing Staff's proposal would be approximately \$298,000 (SSCP at 29).<sup>28</sup> Exhibit \_\_ (SSCP-6R) describes the costs entailed in implementing the Staff proposal. These costs include tool/communications development, testing, and deployment of: web presentation; bill presentation; termination and deferred payment agreement default notices; and, low income and payment troubled customer communications. The Company requested authority to defer the cost for future recovery from ESCOs and/or ESCO customers or as otherwise determined by the Commission.

The Joint Proposal provides that Niagara Mohawk will develop an ESCO Bill calculator and convene a collaborative as soon as practicable to develop the materials to be provided to residential customers. The Joint Proposal's reference to the development cost of \$298,000 covers all of Staff's proposal. The collaborative may also explore other aspects to ESCO

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<sup>28</sup> UIU and PULP proposed additional methods of providing additional information about ESCO energy prices which Niagara Mohawk did not support.

customer issues.<sup>29</sup> While Staff originally proposed to recover the expense of the program through charges to ESCOs and their customers, the Joint Proposal provides for the development costs to be collected through deferrals paid for by all customers. Because of the small budget of the program and its benefits to all customers by employing mechanisms that should improve the competitiveness of the market, Staff supports this provision.

**e. Expansion of Gas Service, Gas Expansion Collaborative, and Oil to Gas Conversion Incentive (Section III, 11.7 and 11.8)**

In the Company's initial testimony (Gas Infrastructure and Operations Panel, at 35-42), it proposed to expand the gas usage in its service territory through targeting capital investments in areas where there is sufficient demand to economically justify such investments, to introduce community based outreach in areas where expansion is viable, and to establish a collaborative (Gas Expansion Collaborative) of interested stakeholder to consider the issues associated with gas expansion.

Staff stated (Colby at 2-5) that the Company is already free to expand gas service, as long as it abides by Commission policies on franchise expansion and line extension. Staff supports the Company's proposal to introduce a community based outreach program (CIP at 20). Staff testified that if strategically and logically implemented, Staff believes this outreach and education initiative will benefit the Company, the existing and new customers, and the community as a whole.

Staff supported the Company's proposal (Colby at 6-10), including the Gas Expansion Collaborative, but stated that the Company also needed to include the consideration of how

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<sup>29</sup> We note that the Commission has instituted a proceeding in Case 12-M-0476, et al. seeking comments on the operation of retail energy markets in New York that may include a statewide response to some of the concerns raised by Staff, but it will be a more holistic approach to the energy market issues. The bill calculator and other notifications proposed here provide some immediate help for a specific identified problem.

address pipeline capacity constraints in specific locations which limit the expansion of gas service in such a collaborative.

The Joint Proposal includes a Gas Expansion Collaborative to: (1) to analyze pipeline capacity constraints considering future design day delivery requirements and determine appropriate actions to acquire additional pipeline capacity or revise the use of current pipeline capacity to optimize system and customer benefits; (2) to discuss and review the possibility of the Company offering a compressed natural gas vehicle program that balances costs and benefits between customers and the Company; (3) to discuss and review the possibility of the Company offering a liquefied natural gas vehicle program that balances costs and benefits between customers and the Company; and (4) to incorporate, as necessary, the results of Case 12-G-0297.<sup>30</sup> The Company will file a report with the Secretary summarizing the outcome of the collaborative.

The Joint Proposal also provides for a customer incentive to promote the conversion from oil to natural gas heating. This incentive will be capped at \$1M and the costs will be shared 50/50 between the Company and the customers. This conversion incentive is reasonable balancing environmental interests through cost sharing that may also benefits both the Company, with the increased customer count and system through put, and the customers, by paying down conversion costs and increasing the likelihood that they will convert to the clean, low priced fuel.

**f. Alternate Fuel Vehicle Program**

The Company proposed an Alternate Fuel Vehicle grant program, for both natural gas vehicles (NGVs) and plug-in electric vehicles (PEVs), to be ratepayer funded at the level of

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<sup>30</sup> CASE 12-G-0297 – Proceeding on Motion of the Commission To Examine Policies Regarding the Expansion of Natural Gas Service. Order Instituting Proceeding And Establishing Further Procedures (issued November 30, 2012)

\$1.5M and \$200,000 respectively. (Shared Services and Customer Panel at 70-75) The NGV portion of the proposed program would have provided an up-front incentive available to new compressed natural gas (CNG) filling stations or for increases in capacity at existing stations, and would be capped at the lower of 50% of the project cost or \$250,000, while the PEV portion of the proposed program would have provided an up-front incentive for the construction of new PEV charging stations.

Staff did not support either portion of the Alternate Fuel Vehicle program and proposed a \$1.7M adjustment to the revenue requirement. Regarding the NGV program, Staff maintained that the structure of the program did not align with the Commission's NGV Policy Statement, as expressed in Case 92-G-0451,<sup>31</sup> in that there was no sharing of risk and reward between the ratepayers and the Company's shareholders. Under the Company's proposal, the grant was completely paid for with the ratepayer funds, while the Company did not analyze whether there would be any benefits to ratepayers.

In its rebuttal testimony (Rebuttal Testimony of the Shared Services and Customer Panel, at 31-32), the Company stated that they understood Staff's concerns and invited additional dialog with Staff to explore opportunities to develop alternative fuel vehicle programs.

While the Signatory Parties didn't agree to a specific NGV program, they did agree the Gas Expansion Collaborative which, among other things, will investigate the possibility of initiating NGV programs, for both CNG and a liquefied natural gas (or LNG) vehicles, which balance the costs and the benefits between ratepayers and shareholders.

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<sup>31</sup> Case 92-M-0451 – Proceeding on Motion of the Commission to Investigate the Development of Natural Gas and Electric Vehicles (NGV and EV) Industries in New York. Opinion And Order Concerning The Role Of The Public Service Commission In The Development Of The Ngv And Ev Industries In New York (issued December 24, 1993).

## **12. Miscellaneous Provisions**

### **a. Use of Deferral Credits to Offset RSS Costs and the Generic RSS Surcharge (Section III, 12.1)**

The Company filed its testimony prior to the Commission's ruling on August 16, 2012 regarding the Dunkirk RSS Contract ordering the Company to solicit for alternate reliability solutions. Staff in its testimony identified \$128 million in available customer credits that could potentially be used to offset costs such as the RSS Costs and recommended that the Company be allowed to use a portion of those credits to offset the RSS costs. Staff also recommended that if RSS costs continued in the future that a surcharge mechanism be used for cost recovery. (Staff EIP at 52)

The Company in its rebuttal agreed in part to Staff's recommendation but sought to clarify the period for which the deferral would commence. The Company recommended to defer the RSS costs from September 1, 2012 through March 31, 2013 and to implement a surcharge to recover all RSS costs remaining to be reconciled or incurred on or after April 1, 2013, when new base rates take effect. The Joint Proposal provides for the use of up to \$57 million of electric deferral credits to offset RSS costs associated with RSS agreements relating to the Dunkirk plant or other RSS agreements with other generators. Unless and until the Company incurs \$57 million of RSS costs, the generic RSS surcharge will be set at \$0. To qualify for recovery through this surcharge, the RSS agreements must be approved or authorized for recovery by the authority having jurisdiction over the agreement, including but not limited to the Commission or other regulatory entity.

Given the circumstances of the mothballing of the Dunkirk units and possible future closures Staff believes this is a reasonable outcome.

**b. Electric Capital Investment Reporting (Section III, 12.6.1)**

Staff testified to continue quarterly electric capital investment reporting, to implement quarterly reporting for O&M programs and to also implement quarterly reporting for gas capital investment and O&M programs. The Company in its rebuttal agreed to the Staff request.

**c. Spare Transformer Program Analysis (Section III, 12.6.2)**

The Company will perform a sensitivity analysis to consider how assumptions about factors such as future lead times, forecast capacity needs, and incremental reliability and availability benefits versus costs may affect recommended spare transformer levels.

**d. Northeast Region Reinforcement Spier-Rotterdam Line (Section III, 12.6.3)**

Several steel poles obtained for the new Spier-Rotterdam 115 kV line are not within allowable tolerances for straightness as a result of fabrication errors by the manufacturer. To the extent the Company incurs any incremental costs related to correction of the pole straightness issues related to the new Spier-Rotterdam 115 kV line, the Company will expense those costs below the line to exclude them from future revenue requirements and/or earnings sharing calculations.

This Section is not intended to address any issues included in the Company's filing dated August 15, 2012 in Case 10-T-0080.<sup>32</sup>

**e. Buffalo Street Light Cable Replacement (Section III, 12.6.4)**

In its initial filing, the Company discussed its plan to budget \$2.5M per year for 10 years and requested \$2.5M yearly for fiscal year 2014, 2015, and 2016.

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<sup>32</sup> CASE 10-T-0080 - Application of Niagara Mohawk Power Corporation d/b/a National Grid for a Certificate of Environmental Compatibility and Public Need Pursuant to Article VII for the Construction of a New 115kV Electric Transmission Line from Spier Falls, Saratoga County to Rotterdam, Schenectady County.

In its direct Testimony, Staff accepted the proposed spending level because it believes the Company has demonstrated that there are significant street lighting problems and there are legitimate safety concerns. However, Staff found the programs plan insufficient to support the proposed spending level over a 10 year time period and recommended the Company provide a more comprehensive plan with the Department no later than April 15, 2013.

In its rebuttal testimony, the Company accepted Staff's request to submit a more comprehensive plan for implementing the program.

In the settlement negotiations, Staff accepted the Company's proposed Buffalo Street Light Cable Replacement Program budget of \$2.5M yearly for fiscal years 2014, 2015, and 2016 and the Company agreed to submit a more comprehensive program plan by April 15, 2013.

**f. Gas Capital Investment and O&M Issues – Reporting (Section III, 12.7)**

Staff testified to continue quarterly electric capital investment reporting, to implement quarterly reporting for O&M programs and to also implement quarterly reporting for gas capital investment and O&M programs. The Company in its rebuttal agreed to the Staff request.

**g. Allocation Reclassification and SAP Reporting (Section III, 12.9)**

The Company included an "Allocation Reclass" cost element on Exhibit \_\_ (RRP-3CU) that shows an adjustment to the historic test year based on an analysis to derive the change in historic test year costs which are the result of the revisions to the general allocator and other cost allocators used by legacy National Grid USA and KeySpan Companies. The Company explained that, in anticipation of the consolidation of its two separate financial systems, National Grid USA's use of Peoplesoft and KeySpan's use of Oracle, onto SAP, it was revising its cost allocation methodologies to allow for a common cost assignment and allocation process. The Company employed a consultant, PA Consulting Group, to review its cost allocation practices

and recommend a methodology consistent with industry best practices and capable of being implemented as part of the US Foundation Project initiative. National Grid planned to implement the recommended and revised methodologies when its financial systems were consolidated, with the implementation date targeted for October 2012 (Service Company Panel at 47).

The Company undertook an analysis to see how its historic test year costs would change if the revised allocation policies and procedures were implemented. If the revised allocation policies and procedures had been put in place in calendar year 2011, Niagara Mohawk's electric O&M costs would have decreased by \$14.844 million and its gas O&M costs would have increased by \$0.402 million, as per Exhibit \_\_ (SCP-7). The Company made a normalizing adjustment to remove the labor expense reductions and any costs to achieve the US Restructuring efficiency savings from the total change in costs that was computed. The net change in costs from the use of the new allocators after normalizing adjustments, and the imputation of inflation, was a decrease to electric O&M expense of \$13.382 million and an increase to gas O&M expense of \$0.374 million. Adjusting these revised 2011 historic year amounts, and adjusting for inflation of 4.2785%, results in a total decrease to projected rate year O&M expenses of \$13.008 million- a decrease of \$13.382 million to electric and an increase of \$0.374 million to gas.

Staff, in its pre-filed direct testimony, indicated that from the review of PA Consulting's cost allocation review project report in Exhibit \_\_ (SCP-6) and the new allocators derivation and impact study in Exhibit \_\_ (SCP-7), it appeared that the Company's consultant did a thorough analysis in deriving the proposed new general allocator and also the cost causative allocation factors. (SAP at 100-101) However, Staff also noted that the true impacts of the change in allocators would not be known until the US Foundations Program and the consolidated

accounting system is implemented, when actual results, rather than projected impacts, can be analyzed. The specific allocators put in place, including the amounts used for each component in deriving the general allocator, would need to be reviewed. Staff therefore recommended that, after the consolidated accounting system has been in place long enough that twelve months of actual cost data were available, the Company should undertake an analysis of the actual impacts, as well as a testing of transactions to assure they are properly documented and allocated, and provide the results of their analysis to the Commission. (SAP at 96-101)

The Joint Proposal provides in the revenue requirement, an adjustment for the forecasted impact of the modification of allocation factors in conjunction with implementation of the Company's new accounting system. As shown by the schedules in Appendix 1, the RY1 electric and gas adjustments to O&M expenses are a decrease of \$13.382 million, and an increase of \$0.374 million, respectively, with RY2 and RY3 amounts increasing by inflation. Section III, 12.9 of the Joint Proposal provides the agreed upon reporting requirements for actual data that will be obtained from the Company's new accounting system. For the twelve months ended March 31, 2014, which will coincide with its fiscal year, the Company will perform (a) an analysis of the actual impact of the implementation of the new allocators, and (b) a testing of transactions to ensure proper allocation and documentation. The tested transactions will include accounts payable, payroll, employee expenses, payroll and expense report comparisons, and adjusting general ledger journal entries. The results of the analysis will be submitted to the Commission no later than July 1, 2014.

**h. Service Company Investigation and Cost Allocations (Overland Audit) (Section III, 12.10)**

**1. Overland Audit**

Staff, in its direct testimony, described the status of the independent audit being conducted by Overland Consulting in Case 10-M-0451.<sup>33</sup> (SAP at 172) The Commission retained Overland Consulting in Case 10-M-0451 to perform a historical review of National Grid's allocation of service company costs to Niagara Mohawk and National Grid's other New York utilities over the period of October 2008 through May 2010, as well as its service company affiliate policies and procedures. The Overland audit report still has not been issued. (SAP at 172-173).

Section III, 12.10 of the Joint Proposal provides a general discussion and agreement regarding the status of the Overland audit and the temporary rates established from Case 10-E-0050. In a 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, approved by the Commission, was established to provide for the disposition of temporary rates in Case 10-E-0050 and remains in place. The money collected via the temporary rates mechanism may be used to refund to electric customers any overcharged amounts following a Commission determination in Case 10-M-0451. The Company is also subject to any Commission findings in that proceeding regarding its policies, procedures, governance and controls relating to service company charges, however, Staff does not believe that these will materially deviate from efforts the Company has already undertaken as a result of its own internal audit performed by Liberty Consulting Group.

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<sup>33</sup> Case 10-M-0451 - Proceeding on Motion of the Commission to Investigate National Grid Affiliate Cost Allocations, Policies and Procedures.

Additionally, the Joint Proposal contains a provision that the Signatory Parties agree that the testimony, exhibits and discovery conducted in these proceedings do not support the continuation of temporary rates. As noted, temporary rates already have been collected to cover a refund of overcharges found to be imbedded in the Company's last rate proceeding. The issues that led to the concerns necessitating the look at those historical allocations have largely been addressed by the Company on a prospective basis.

This section of the Joint Proposal is in the public interest and is supported by Staff's testimony in the rate case. The rate case deals with a different historic year period – the twelve months ending December 31, 2011 – than the time period the Overland audit covers, and as discussed in the Service Company Costs section within, Staff has not found the same concerns this rate case that would require the need for the imputation of temporary rates going forward. However, until the Overland audit report is released, and the Commission provides direction as to whether or how the results should be incorporated into this pending rate case, temporary rates from Case 10-E-0050 continue to preserve any dollars that may be due to ratepayers for the prior period being addressed by the Overland audit.

## **2. Service Company Costs**

There are four service companies that provide centralized services to National Grid affiliates. This includes National Grid Service Company, KeySpan Corporate Services LLC, KeySpan Utility Services LLC, and KeySpan Engineering and Survey Inc. National Grid planned to implement its US Foundation Program in October 2012 to consolidate its finance, human resources and supply chain systems on a single SAP platform. At the same time, the legacy KeySpan Corporate and Utility Service Companies will be consolidated into the National Grid Service Company.

The direct testimony of the Company's Service Company Panel, discusses some of the key service company issues identified in the last electric rate case, specifically, (1) whether National Grid's business structure lacked internal procedures and safeguards necessary to ensure proper allocation of service company costs to operating companies; (2) whether National Grid's cost allocation methodology reasonably credited Niagara Mohawk for the economies of scale it creates as the largest US based operating company in the National Grid system; (3) whether Niagara Mohawk properly normalized historic test year service company charges; (4) the difficulties in auditing service company costs assessed to Niagara Mohawk; (5) the service companies' lack of operating budgets and variance reporting; (6) the lack of review of service company charges at the operating company level; and (7) the personnel from the service companies making the decision as to what services Niagara Mohawk should take rather than Niagara Mohawk personnel independently making those decisions.

Staff's direct testimony identifies these historic concerns and discusses their relevance to this proceeding. In Case 10-E-0050, one concern, as stated by the ALJs in the Recommended Decision, and shared by Staff, found 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 specific concern regarding corporate structure was mitigated by 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.

Staff reviewed Niagara Mohawk's historic test year charges, both incurred charges from Niagara Mohawk itself and from the services companies. From its review, the previous concerns related to the misallocation of service company charges to Niagara Mohawk largely appear to

have been addressed by Company's actions over the last year. Staff did not find any instances of cross-subsidization by Niagara Mohawk of the other National Grid affiliates, although Staff did identify and discuss some normalization of historic year costs concerns, but they were not of a service company cost allocation nature. Staff's review of the historic year service company costs was done without the difficulties and constraints that previously existed.

First, the SLAs do not adequately address both the 2009 NYPSC management audit and the 2011 Liberty Consulting report recommendations. They currently do not contain pricing information, such as price and quantities of services to be provided, and most of the 16 SLA's do not contain key performance indicators. Furthermore, the SLAs contain no provisions for benchmarking or market testing of the services that are provided to Niagara Mohawk. Such provisions are necessary to ensure the costs are competitive with the pricing of non-affiliated vendors or of Niagara Mohawk performing the service itself. (SAP at 151) In its testimony, Staff discussed concerns it had with the SLAs as designed.

For the types of centralized services being provided by the service companies, the costs incurred and paid for by Niagara Mohawk should be coming from the most cost effective provider, whether from an affiliate, a non-affiliated vendor or Niagara Mohawk itself. Niagara Mohawk needs to have the information so it can monitor the cost of the services provided by the SLAs and the corresponding service agreements. Without it, the Company cannot compare the costs of the services being provided and determine whether receiving the services from its affiliates is the most cost effective alternative.

A second concern discussed by Staff was the Company not segregating out the budgeted direct versus centralized service company cost amounts in the various SLAs. Again, with the expected service company costs not broken out from the total budgeted operating expenses for

the functional area in the SLAs, Niagara Mohawk cannot affirmatively determine that the costs and services provided are reasonable. (SAP at 153-154)

In Exhibit \_\_ (SCP-2) page 7, item VI:R6, National Grid indicates it uses a “deep dive” process, that is considered to be a comprehensive analysis of a function or service area that addresses the business model or sourcing opportunities. This could include benchmarking, market testing and consultant services and where appropriate, comparisons of obtaining the services from alternative sources. However, Staff in its direct testimony highlighted its concern with the deep dive process, by stating the benchmarking is done from a high level type of overview, with the specific details missing. The deep dive process doesn’t provide a comparison to the cost of Niagara Mohawk obtaining the service from another vendor or performing the service itself. Rather, it only provides the allocated cost of National Grid providing the service, which is only one half of the comparison. As a result, it is not a proper market test or benchmarking. The deep dive and benchmarking details need to be formulated and incorporated into the SLAs for the SLAs to be an effective performance tool. (Staff Accounting Panel at 154-155)

Section III, 12.2.1 of the Joint Proposal contains provisions that address Staff’s SLA concerns. First, National Grid will develop SLAs that contain service descriptions that align with the stated budgeted cost for each service and, where possible, targets to demonstrate and ensure that the services provided by the service companies achieve reasonable levels of quality and performance. Second, National Grid will also develop external cost comparisons to demonstrate and ensure that SLA costs are reasonable relative to appropriate market alternatives. National Grid will develop the enhanced SLA service descriptions and corresponding budgets and submit amended SLAs to Staff no later than September 30, 2013. Further, National Grid

will submit to Staff by March 31, 2014 the external cost comparisons developed for no less than one-third of the Service Company functions. By March 31, 2015, National Grid will submit to Staff the external cost comparisons for another one-third of the Service Company functions; and by March 31, 2016, National Grid will submit to Staff the external cost comparisons of the final one-third of Service Company functions. Section III, 12.2.2 of the Joint Proposal provides for the budgeted costs in each SLA to be broken down by the individual services provided and their expected quantities, where applicable, segregated by direct costs and service company costs.

Staff explained why Niagara Mohawk's Service Level Agreements should be designed to ensure that Niagara Mohawk only purchase services from an affiliate if the cost of obtaining those services from the affiliate would be less than the cost of Niagara Mohawk performing the services with its own employees, or less than obtaining those services elsewhere in the market. (SAP at 166-171) Staff estimated that compensation levels for Niagara Mohawk related tasks would be \$2.7 million lower if all Niagara Mohawk related work was done by employees of Niagara Mohawk as opposed to by National Grid. (Schuler at 37) The Joint Proposal's inclusion of half of Staff's \$2.7 million adjustment reflects a reasonable settlement since clause 12.2.1 of the Joint Proposal requires the Company to enhance its SLAs to include market based external cost comparisons for all of the service company functions utilized by the Company. This will help protect Niagara Mohawk against unreasonably high management compensation levels in the future.

Another of Staff's service company costs concern was related to the review and approval of the monthly service company bill, and the Company's lack of internal controls to ensure the proper amount is being paid. The Company indicated there are multiple levels of review for the service company costs being charged, from a review of the accounting that is required as part of

the approval process to the detailed review currently being performed by the NY Jurisdiction Finance team. However, Staff's concern was that there was no one from the Niagara Mohawk operating company who objectively or independently reviewed and made sure the charges being incurred from the services companies were correct. Instead, the service company personnel were verifying the accuracy and appropriateness of its own bill calculations for Niagara Mohawk.

Furthermore, as Staff highlighted, the intercompany bill is automatically paid in lieu of any review. The service company, who is by far Niagara Mohawk's largest vendor, should be considered a vendor similar to any other non-affiliated third-party vendor, with the charges not being paid before the bill is reviewed and the charged amounts being verified as being correct. This issue was discussed in both the last electric rate case, Case 10-E-0050; as well as in the independent audit performed by Liberty Consulting. Staff recommended that, ideally, the Company should designate personnel who are solely Niagara Mohawk employees to review and approve payment of the service company bills and charges. (SAP at 156-158)

The Company in its rebuttal filing disputes Staff's concern of the review of the service company bill. It indicates the service company bill review process is ongoing and multiple levels of review occur, and whether this review occurs before or after the service company bill is paid makes very little difference as long as the review takes place within a reasonable period of time.

Section III, 12.2.2 of the Joint Proposal addresses Staff's concerns of the review and approval of the monthly service company bill. The monthly review of the service company bill will be performed by an employee of Niagara Mohawk, and generally within 30 days of the monthly financial close. This will involve examining a sample of accounts payable transactions and their allocation to Niagara Mohawk to determine if the charges are accurate, properly documented and properly allocated. The Company will provide workpapers and underlying data

identifying the number of transactions examined and the results of each monthly review to Staff. If the Company is unable to perform this review within 30 days, the Company will provide an explanation and expected timeline to Staff. There will also be an annual review of bills, whose purpose will be to ensure accountability and to demonstrate that the charges are accurate, properly documented and properly allocated. This review will be performed by either an employee of Niagara Mohawk or by an outside consultant.

Staff's third concern of the service company costs relates to the Company's relatively new monthly reporting and review process. The Company described this review process as an additional measure put in place that serves as a review of service company charges to Niagara Mohawk. The NY Finance team who is undertaking the monthly review, is made up of National Grid personnel who are service company employees. Again, Staff's concern was service company employees are undertaking a process where they are reviewing and monitoring their own charges, rather than an independent review coming from Niagara Mohawk employees. Staff indicated the review process as described was inadequate and ineffective in determining if the service charges coming into Niagara Mohawk are appropriately charged and allocated. While the monthly reporting of actual versus budget process may serve the process of highlighting service company charge variances, it does nothing to monitor, review and ensure that service company charges are appropriately allocated, especially in the event that actual costs do not exceed the budgeted amount.

The Company, in its rebuttal filing, indicates when variances from budgets are identified, they receive a closer review, and to the extent that variances result from an erroneous allocation of affiliate costs, they would be identified and corrected as a result of the monthly review of actuals versus budget. Also, the Company states, the New York Finance monthly budgeting

process is more than a reporting of actuals versus budget, but also compares prior year actuals for Niagara Mohawk and the allocations to all other National Grid companies, to review allocation shifts and identify and address any improper allocations or cross subsidization concerns.

National Grid also says it implemented in fiscal year 2013 additional in-depth analyses that will enhance the internal review of service company charges. Specifically, a report was developed to sample service company accounts payable costs (direct or allocated) charged to Niagara Mohawk. The sampling includes all line items that allocate more than \$10,000 to Niagara Mohawk, as well as any line items under \$10,000 that appear unusual based on the vendor name and/or allocation percentage. The sample comprises more than 75 percent of the accounts payable costs charged to Niagara Mohawk. Decision support teams representing each service company function perform a line by line review of the items for their respective functions to determine whether the charges are correctly allocated to Niagara Mohawk, and submit their findings to New York Finance with a brief description of the nature of the charge, whether each line item is correct, and when a correction will be processed if the charge is incorrect. National Grid says this additional analysis provides improved attention to line item detail in the review of service company charges. Finally, National Grid hopes to build on this new process to develop service company budgeting and billing processes that will address the concerns identified by Staff and improve the accuracy of service company billings.

Although the Joint Proposal does not specifically address improvements in the monthly budgeting process, the Company's commitment as described in its rebuttal testimony for all of its monthly budgeting process activities, including the added in-depth analyses that are now being performed, have mitigated Staff concerns in this area.

Finally, while Staff still has some reservations regarding any savings based on economies of scale provided by the merged companies, Staff acknowledges that the sharing of services among the utilities does provide some cost benefit to Company ratepayers. Staff believes that the Joint Proposal provisions for tighter controls on the Company's SLAs and its provision for Niagara Mohawk personnel to review service company bills can help insure that Niagara Mohawk receives its fair share of such savings, in its capacity as National Grid's largest operating company.

### **13. Other Provisions**

Finally, the Joint Proposal includes various provisions setting forth the Signatory Parties' understanding on issues such as the dispute resolution process to be followed should a disagreement between the Signatory Parties arise (Section III, 13.4) and what happens in the event the rate plan expires and the Company does not file for new rates (Section III, 13.5). While these are typical or standard provisions, having them set forth clearly in the document reduces the likelihood of misunderstandings now and in the future.

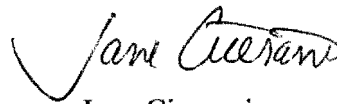
### **CONCLUSION**

The terms of the Joint Proposal entered into in this case fully satisfy the Commission's Settlement Guidelines. As described more fully above, when evaluated in its entirety, the terms of the Joint Proposal would fall within the potential result of a litigated case. The fact that the Company, Staff, UIU, MI, RESA, NYPA and the DOD, parties with differing interests, have signed on to the Joint Proposal, coupled with the fact that no opposition from other active Parties is expected supports the conclusion that the proper balancing of the interests of ratepayers and Niagara Mohawk is contained in its terms. The Joint Proposal significantly continues and advances the Commission's goals and policies, while minimizing the potential economic impact

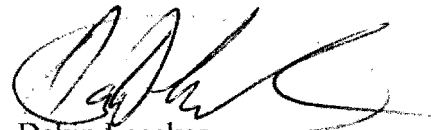
of the recommended rate increases on ratepayers. Niagara Mohawk, meanwhile, will receive sufficient funds to operate and manage its electric and gas business, and maintain safe and reliable service.

For all of the above reasons and as supported in the Signatory Parties' testimony and exhibits, Staff respectfully recommends that the terms of the Joint Proposal be found to be in the public interest and adopted by the Commission in their entirety.

Respectfully submitted,



Jane Cicerani  
Staff Counsel



Dakin Eeakes  
Staff Counsel

Dated: December 21, 2012  
Albany, New York